ASSET MANAGEMENT PLAN

APRIL 2023 – MARCH 2033

Aurora
ENERGY

31 March 2023

EXECUTIVE SUMMARY

This Asset Management Plan (AMP) outlines Aurora Energy's approach to managing its electricity distribution assets during the period from 01 April 2023 to 31 March 2033. Our AMP demonstrates to customers, stakeholders and other interested parties how we plan to invest in our network over this period and deliver on our vision 'to enable the energy future of our communities'. This AMP sets out a 10-year plan to deliver a safe, reliable, sustainable and digitally enabled future across all our sub-networks.

Network Investment and a Customised Price-Quality Path (CPP)

In 2018, Aurora Energy commissioned an independent review of our network by WSP, which identified areas of elevated risk due to the existing condition of network assets. The report indicated that a continued period of increased investment would be required to ensure that our network was safe and reliable. The required level of expenditure exceeded that supported by customer line charges, as set under our Default Price-Quality Path (DPP). In June 2020, Aurora Energy applied to the Commerce Commission (the Commission) for a Customised Price-Quality Path (CPP) outlining the additional investment required.

Our 2020 Asset Management Plan formed part of our CPP Application. The 2020 AMP set out our proposed areas of additional investment to improve network safety and reliability. We developed our asset renewal plans to address the findings of the WSP risk review and our additional assessments of network risk. In its final CPP Determination, the Commission granted Aurora Energy a five-year CPP Period from 01 April 2021 to 31 March 2026 in which we were given the ability to recover additional costs through line charges for the purposes of fixing, upgrading and maintaining our network.

The CPP Determination did not fully approve all expenditure proposed in our CPP Application. This 2023 AMP further prioritises our 2020 and 2022 plans to ensure that we allocate our available resources to network and non-network initiatives that deliver on our CPP commitments to achieve the best possible safety risk reduction and asset management improvement opportunities. Our plan also allocates resources to meet strong growth (particularly in Central Otago), and to address areas where reliability performance has not met our current expectations of the network.

Our revised analysis and 10-year planning period forecasts demonstrate the need to continue with sustained levels of investment above those seen prior to 2018.

Focus of our 2023 AMP Investment Plans

As indicated above, Aurora Energy requires sustained investment across its network throughout the 10-year planning horizon. With low levels of pre CPP Period investment, our assets had deteriorated into poor condition. Investment in the network began to increase in 2017 and has now reached peak levels as we progress through the middle of the CPP Period. This sustained investment has enabled progress towards the remediation of historic safety risks above our risk appetite. However, detailed planning and analysis continues to indicate an ongoing need to invest in the maintenance and renewal of safety targeted fleets throughout the 2023 AMP planning period.

In addition to continued investment in a safe network we have observed a changing landscape since submitting our CPP application in June 2020. Our revised plan takes account of new and modified drivers for increased investment in the network:

- **The impact of COVID-19 on growth was significantly less than forecast in 2020** and we have brought forward a number of major projects in Central Otago to support strong population growth and a return to normal levels of tourism. The CPP Determination assumed COVID-19 would cause a slow-down of growth, including the number of network connections and the level of reinforcement required to the high voltage network. Recent history has shown our 2020 COVID-19 forecast assumptions to be incorrect.
- **The CPP process includes a mechanism to 're-open' the Determination** where strong growth requires an additional Capex allowance for capacity related network investment to connect new customers and reinforce the high voltage network. This AMP suggests a total CPP Period capacity re-opener application of approximately \$20M will be required. The Commerce Commission will assess our application to ensure that our capital expenditure proposal is prudent and in the long-term interests of consumers. When approved, the associated revenue increase for Aurora will be deferred beyond the CPP Period.

  We forecast the need for an increased provision of network capacity investment to support decarbonisation through electrification. He Pou a Rangi (the Climate Change Commission) has noted that a significant increase in electricity demand will occur as the country transitions to meet its 2050 carbon emission targets. Increased uptake of EVs, solar generation and battery storage are likely to play a significant role in shaping our business in the future. The future will offer challenges and opportunities as we seek to cope with potentially greater consumer reliance on electricity and more complex, two-way electrical flows as businesses and households install distributed generation. Preparing early for these changes will provide the resilience required to operate in a dynamic environment. As we have demonstrated with our Upper Clutha Distributed Energy Resources (DER) solution, changes in technology can also be utilised to provide support to our network (see Chapter 6).
- **Chapter 6 outlines three growth scenarios** and the importance of a coordinated/managed transition to electrification to minimise the impact to the network and consequential line charges for connected businesses and households. The forecasts in this AMP make provision for an additional \$25M of capital expenditure over the period 2027 to 2033 to enable the network transition to a low carbon future. There is significant uncertainty in this forecast, which is dependent on the uptake rate of electric transport, process heat conversions and large-scale embedded generation connections such as solar farms. The impact of electric transport on our network investment is also dependent on the charging behaviour of vehicle owners and the vehicle charging technology choices they make to help minimise the impact on the power system.
- **Increases in the cost to undertake network expansion, renewal and maintenance.** Recent construction costs reflect the global landscape of supply constraints and inflationary pressure. When preparing our expenditure forecasts, we have revised our cost estimation rates and sought expert advice on our cost escalation indices. In general, cost escalation/inflation is stronger than forecast in the CPP determination.
- **Provision for targeted reliability improvements**. We have made a relatively small adjustment to our forecasts to reflect the need to target reliability performance improvement in communities where the network is not meeting expectations. The post-CPP Period target level of reliability

performance is yet to be set. We will utilise our ongoing customer surveys to inform our understanding of the reliability preferences of our communities. Our expenditure forecasts may require further adjustment to meet target levels of reliability performance.

- **Digital Transformation is required to enable a new energy future.** Data, analytics and visualisation technologies are key enablers of new customer service capability, efficiency improvements and risk optimisation. We are revisiting our Digital Enablement Plan in 2023 with the intention of expanding our digital system capabilities, automating core business processes to drive production, accessing new data sources, and seeking support from specialist data analytics and artificial intelligence businesses, to ensure that we are maximising the value that can be obtained from data to support our asset management decisions and the services we provide to customers. This capability will be fundamental to supporting a modern power system with greater information (including operational real-time information) sharing between sector participants including new entrants providing services from distributed energy resources.

Investment Uncertainty

As outlined above, this AMP contains input drivers with different levels of forecast uncertainty. In addition to the above drivers, we have also begun to consider the impact of climate change on network resilience. For example, climate change is expected to cause a rise in sea level and an increase in wind and snow-storms. We also need to continue to prepare for increased resilience to major earthquakes and implement further actions to reduce the risk of fire.

The table below outlines the key areas of investment forecast uncertainty:

Investment Driver	Forecast to RY26 (CPP Period)	Forecast RY27 to RY33
Asset Renewals	The need case is understood with overall spend flexing depending on other investment drivers. There is a risk that short-term diversion of investment to meet growth etc may lead to an extended period of safety and reliability performance risks.	Ongoing asset management improvement and reviews of asset health and criticality frameworks introduce uncertainty in our long-term forecasts, although sufficient evidence that the current elevated/sustained level of overall renewals will need to continue throughout the AMP period.
System Growth	Stronger than forecast CIW growth requires higher than forecast CIW and capacity related investment. Capacity Event Reopener mechanism helps to address this forecast uncertainty.	Greater uncertainty exists around the impacts of global economic factors. Central Otago likely to continue to grow, which may be further accelerated by enhanced air travel operations.
Decarbonisation and DER	No major (above 10 MW) customer electrification projects expected on the network. Customer boiler conversions will in most cases be treated as CIW expenditure. DER update and timing of flexibility services and associated back-office systems uncertain – modest investment has started but could ramp up quickly. New industrial/commercial electrical load that might previously have been gas or other carbon based fuels.	Large DG connection applications may require major sub-transmission investment. Uncertainty over the pace of air travel conversion to electric or electric assist, and ground power. The uptake rate of electric vehicles and solar etc will impact the level of investment in our low voltage networks. Further enhancement to real-time systems to coordinate/dispatch DG and DER likely, with design dependent on the development of the role of distribution system operator.

INVESTMENT DRIVER	FORECAST TO RY26 (CPP PERIOD)	FORECAST RY27 TO RY33
Reliability	Linked mainly to our focus on improving the health of assets with safety improvement benefits. The level of reliability hotspot investment to be further investigated.	Level of investment linked to 'yet to be established' customer reliability preferences. Enhanced network configuration, remote switching and automation may be the solution to meet customer reliability preferences.
Resilience	Short-term actions (see below) identified. Uncertain level of resiliency event response and recovery expenditure.	Possible impact on network configuration/equipment standards. Accelerated renewals for assets at risk to major events.
Digital Transformation	Core asset management and ADMS systems development certain. LV visibility investment uncertain – smart meter data versus network sensors or other third-party data sources.	Options and solutions for integrated risk quantification and investment optimisation uncertain. Need case for a network twin uncertain – could significantly enhance resiliency modelling.

To improve resiliency, we have created and started a 20-year plan to implement a more resilient 33 kV meshed network architecture in Dunedin. This enables an interconnected back-feed arrangement should a flood or earthquake event cause the loss of a Transpower grid exit point or an Aurora 33 kV sub-transmission link or substation. In RY24 we will replace all pole mounted 11 kV fuses in the Central Otago high risk fire zone with a type that prevents an arc forming when operating.

Following our review of resiliency preparedness, we will update our forecasts in our 2024 AMP to reflect the actions and investments we propose are in the long-term interests of consumers.

Customer and Stakeholder Needs

The investment priority plans and improvement initiatives set out in this 2023 AMP have been developed and set to reflect customer preferences.

During our CPP consultation, we engaged extensively with customer groups, including the establishment of a customer advisory panel and three customer voice panels. We have an ongoing customer engagement programme, including customer surveys and attendance at both community and business events. These forums inform our customer engagement plan, advertising/promotion, and customer service initiatives. During 2023 we will consult with customers on a refresh of our Customer Charter to ensure that our customer commitments are aligned to their preferences. We consistently hear from customers that they understand the need for essential work to improve the network safety, but the impact on price needs to be managed. Most respondents during the CPP consultation were satisfied with their current level of network reliability and there was little appetite for added investment in that area at that time. There are some areas on our network where customers have since indicated a preference for improved reliability. We have reflected these views within our investment decisions during the planning period.

In summary, we have used the following customer-focused priorities to guide decision-making:

- Our primary, short-term focus is on investment in asset replacements to reduce the level of safety risk on the network

- Reflecting customer feedback, we will not actively pursue widespread reliability improvements, but we will target areas where communities have indicated a preference for improved reliability, or where we have identified ourselves that reliability is lower than our expectations, and we agree that the network can be improved without diverting major resources from our safety focussed plan. We note that consequential improvement to reliability will occur as we renew our assets for safety reasons
- We will ensure that the expansion of our network keeps pace with the growth of connected communities, including sufficient capacity to support decarbonisation
- We will continue to address investment backlogs that have resulted from past underinvestment
- We will achieve good industry practice through provision of sufficient asset management capacity and targeted improvements to our asset management capability
- We will pursue improvements to our delivery capability and supporting processes
- We will continue to improve our processes towards delivering more streamlined and informative customer services.

2023 AMP Investment Priorities

The investment plans and improvement initiatives set out in this AMP have been developed to deliver our investment priorities and to reflect customer preferences. We expand on these below.

- **Keeping our networks safe:** we continue to adopt an uncompromising approach to safety and will act when we believe there are safety risks for the public, our contractors or our staff. There is evidence of persistent asset-failure risk that requires us to maintain elevated investment levels in overhead line and protection assets. We will also continue to focus on poor condition substation assets to reduce the safety risk posed by failure.
- **Stabilise asset health:** we need to stabilise our asset fleets through proactive renewal with a focus on poor condition assets. We prioritise asset replacement by safety criticality where applicable. Based on an improved understanding of overhead asset condition, we have established conductor and standalone crossarm replacement programmes.
- **Defect management:** there remains a backlog of assets in poor condition, leading to increased levels of network risk. We need to continue addressing this legacy of historical underinvestment and reach sustainable (steady-state) volumes as quickly as practicable (informed by criticality-based prioritisation). We have achieved our objective to remove the backlog (circa 1,000 poles in 2018) of red-tagged poles, and we are confident that our inspection and renewal programme will identify and remediate new discoveries of red-tagged poles within regulatory timeframes. We have transitioned our focus toward removal of the orange-tagged pole backlog by the end of 2024.
- **Improving capability:** as outlined in our CPP Improvement Plan, we are committed to further improving our overall asset management capability. We have specific plans to target advanced asset management practices in areas that we believe will enhance optimisation of investment decision-making, and ultimately ensure that we meet the needs of customers while ensuring an appropriate level of investment in maintenance, renewals and growth. We will invest in the capability of our people and ensure that our systems, supporting data, and processes effectively enable our asset management planning.

- **Foundations for future networks:** feedback from customers indicated that our future network should not limit options for residential customers to adopt technologies such as rooftop solar generation and electric vehicles. In the short-term we will make targeted, 'least regret' investments in enabling technology. As the planning period progresses and we begin to see material uptake of new technologies, we expect to increase our focus in this area.
- **Deliver a reliable service:** based on consultation feedback, improving widespread reliability in addition to consequential improvement from our safety focussed investment is not a short-term priority. However, we will invest in targeted reliability improvements where current performance does not meet expectations, and we can achieve an improvement without diverting resources from critical improvements to network safety. As the AMP period progresses, we expect to increase our focus on ascertaining customer reliability preferences and adapting our reliability targets and plans accordingly.
- **Supporting network growth:** during the current AMP planning period, we expect to see continued development activity, and supporting this growth is a focus for us. We will work closely with key developers, customers, councils and agencies to ensure our planning assumptions are aligned, and that capacity is available when needed. For example, we are planning and investing in network capacity and security of supply enhancements in the Queenstown and Wānaka regions to support strong growth. This requires coordination with Transpower for investment in the upstream grid and also Aurora investment into the 66 kV and 33 kV sub-transmission networks and associated zone substations, including Arrowtown, Dalefield, Cardrona and Riverbank (Wānaka).

Of the above, managing safety risk, and the provision of asset management capacity and improving capability will be our key focus areas in the coming years. These are further explained below.

Managing Network and Safety Risks

As a lifeline utility, it is critical that we invest prudently to ensure our assets are safe, secure and resilient in the longer-term. In the short-term, we will prioritise safety related investments. This involves carefully managing our asset fleets, with the aim of stabilising their condition and performance to effectively manage network and safety risk.

Over recent years, we have significantly increased our levels of investment in renewal and maintenance, but more needs to be done. Our pole renewal programme has substantially reduced the risk of pole failure, and we will continue to remediate new defects as required. Other overhead asset fleets such as conductor and crossarms (including insulators) continue to experience a level of asset failure above our target performance. There are also significant volumes of assets either at or approaching poor health in other fleets, indicating that a number of end-of-life assets will require remediation over the planning period.

Our plan will arrest these issues through targeted investment to stabilise the underlying condition of our network and reduce the rate at which assets are failing in service. Alongside increased renewal rates, we will continue to address the remaining backlog of maintenance regimes and stabilise our vegetation management, which has transitioned into a steady-state cyclic programme.

Planning our renewals programme requires good information

To cost-effectively achieve the required risk reductions, we need to ensure our work programmes prioritise those assets within each fleet that pose the greatest risk. Our enhanced asset inspection programme has significantly lifted the quantity and quality of the asset data used to inform our asset lifecycle interventions. As outlined in our CPP Improvement Plan we will continue to improve our data management and analytics capability to help ensure that our plan is informed by comprehensive, robust asset information.

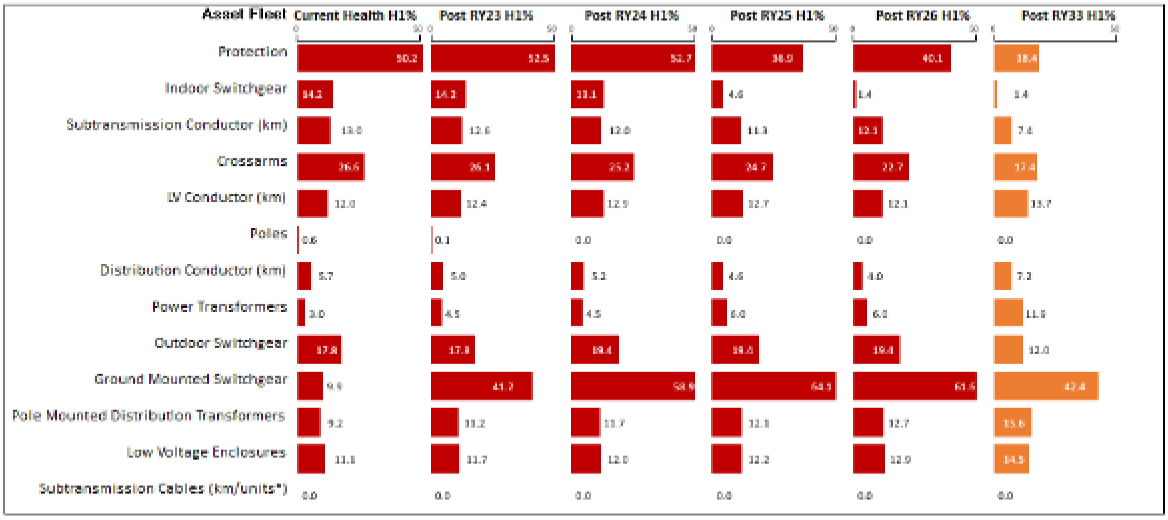
Improved inspection and condition assessment regimes include the use of pole-top photography, conductor sampling, and the introduction of our conductor inspection application within the pole inspection programme. Data and information management practices will be enhanced as we continue development of our new fit-for-purpose asset management software solution (Maximo).

Together these initiatives will deliver a better understanding of asset health and associated risk, facilitate enhanced asset management, and support optimised investment that lowers overall lifecycle costs.

Our planned renewal investments will achieve a safer network

The graphic below provides a summary of the impact of our investment on improved asset health during the CPP Period and over the AMP period. The graphic demonstrates that despite our sustained investment in renewals the quantity of ageing assets coming to end of useful life remains high. Continued investment in renewals throughout the AMP period and beyond is required to manage asset health and safety risks to a tolerable level. Our Safety Delivery Plan (a CPP disclosure reporting requirement) provides additional detail on the level of reduction of safety risk across our high-risk asset fleets during the CPP Period.

Summary of asset fleet investment outcomes over the CPP Period

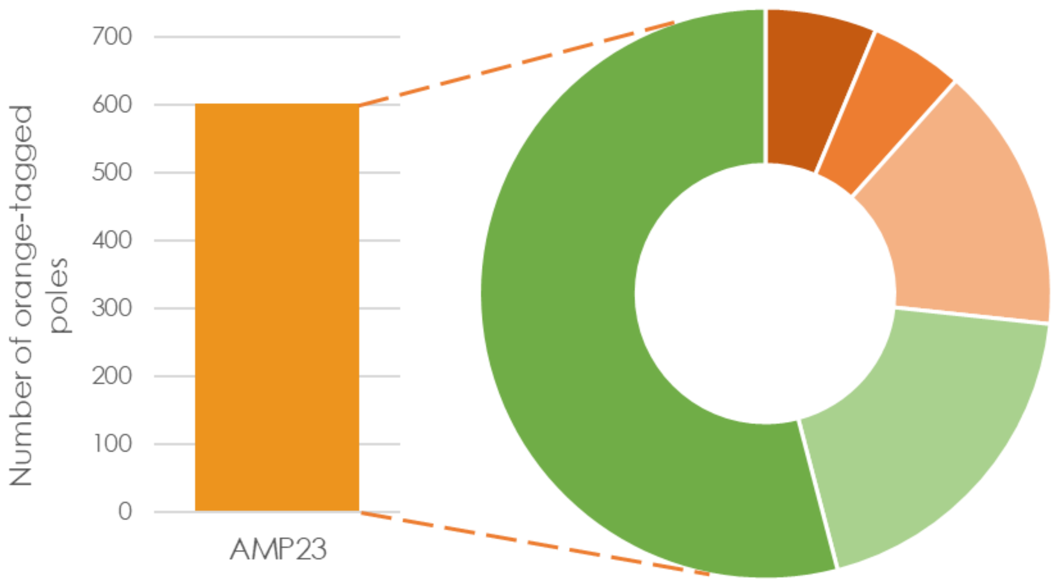


Update on our poles programme

We have made significant progress with pole renewals, and we can confirm that red-tagged poles are now in a managed state. New red-tagged poles can mostly be replaced through our rapid response programme within 90 days of discovery.

Our pole inspection programme has completed its first five-year cycle through the network. As expected, the number of poles requiring remediation in the second cycle is significantly less but remains relatively high, reflecting the age profile of the pole fleet. Our focus has shifted to orange-tagged poles, which we aim to remediate within 12 months of inspection discovery. Our plan is to eliminate the backlog of orange-tagged poles by the end of 2024. The chart below shows our orange-tagged poles as of February 2023, with most poles being in low public safety criticality zones (green segments).

Orange-tagged poles by criticality zone (as of February 2023)



	Assets near:	Assets on roads that are:
Zone 1	Schools, pre-schools, tertiary institutions	National, arterial or regional
Zone 2	Air transport facilities, emergency services, shopping centres	Primary collector
Zone 3	Motels/hotels, camping areas, health services, sports complexes	Secondary collector
Zone 4	Commercial areas, places of worship, tourist spots	Access
Zone 5	Not in densely populated areas, no public congregation	Not next to any roads

Impacts of Decarbonisation on the Energy Sector

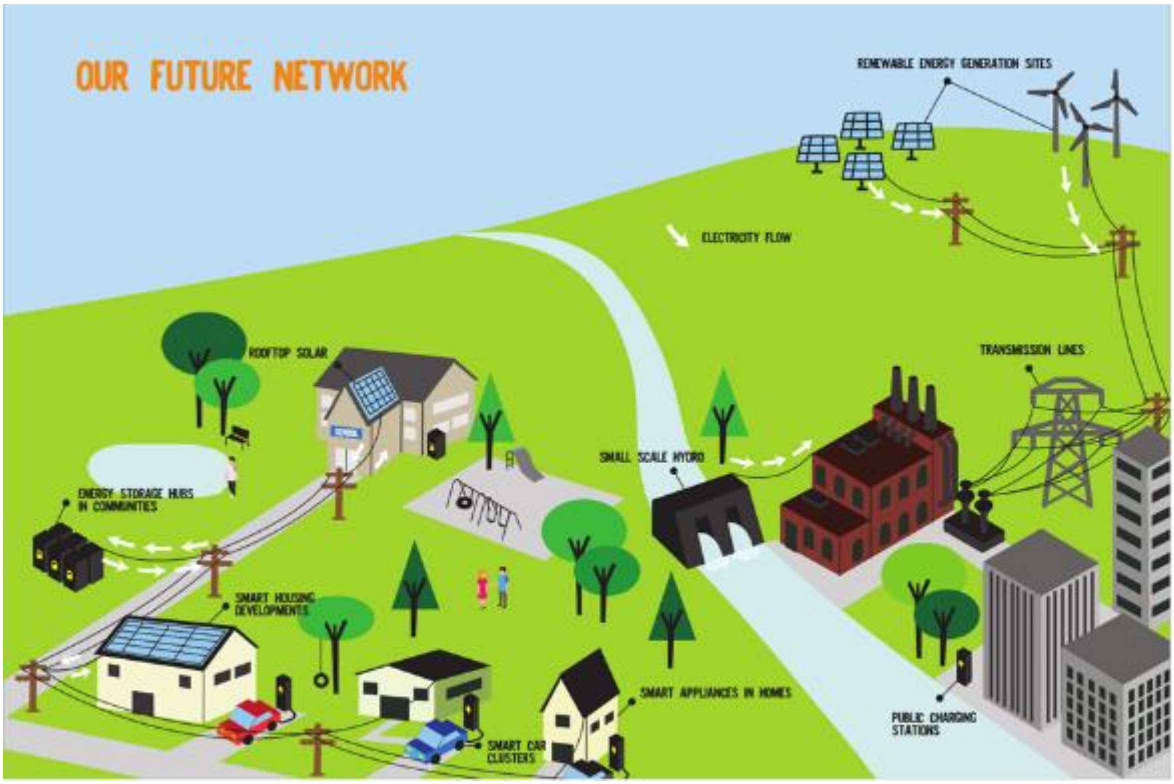
Technology will play a major role as New Zealand shifts towards a carbon neutral future. With climate change becoming an ever-increasing concern globally, we anticipate increased efforts to adopt decarbonisation initiatives within our community. As such, we expect to see more electric vehicles, photovoltaic installations and battery storage systems on our network. We believe it is prudent to make some preparation now for an increased uptake of these resources, rather than react at a later stage.

We have made some investment provision for this in the 10-year planning period, but we note the uncertainty associated with this forecast and anticipate that this is likely to need to increase depending on the uptake of low carbon technologies and customer behavioural use of these technologies. For example, the timing/management of electric vehicle charging will make a significant difference to the level of investment needed in the network.

As part of our approach to better understanding the impact of decarbonisation on our network, we have developed three possible future scenarios relating to the following areas of electricity usage: residential, commercial and industrial usage, and transportation. For each scenario, we have modelled our expected changes to peak demand and overall electricity usage across our three sub-networks. Going forward, we are looking to incorporate our overall decarbonisation/electrification strategy into our Strategic Asset Management Plan (SAMP) and supporting network and fleet strategies.

This approach is supported by customers, who asked us during the CPP consultation to begin making foundational investments to ensure we do not limit their options relating to the adoption of emerging technologies.

A possible future network



A key decarbonisation aspect is the extent to which distributed energy resources such as battery storage and electric vehicles can be used to support the power system. Similar to hot water management, mass uptake of these new technologies has the potential to create sufficient energy storage to manage daily supply side variability from solar and wind generation. Effective integration of these technologies will help to defer the need for investment in peak distribution network capacity and also peaking generation to cover for times of low wind and solar generation. We will monitor the uptake of distributed energy resources and adjust our planning to ensure that we stay ahead of new capacity requirements to support decarbonisation.

A glimpse into this future is our deferral of a large growth investment in the Upper Clutha region by using a distributed energy resource (DER) solution to address a capacity constraint. This innovative solution leads to cost savings and flexibility to cater for fast-changing demand. It is providing valuable learnings to our teams and to the wider industry, as we continue to share our experience. See Chapter 6, Section 6.6 for more on non-network solutions and the Upper Clutha DER project.

Our asset management development plan

We have put in place a series of business improvement initiatives in recent years as outlined in our CPP Improvement Plan. Many of these initiatives form part of our Asset Management Development Plan (AMDP) and will lay the foundations for improving our asset management capability, including our efforts to achieve alignment with the ISO 55001 asset management standard.

We monitor our progress through annual AMMAT (Asset Management Maturity Assessment Tool) reviews.[1] Our most recent assessment (discussed in Chapter 9) resulted in an improved score of 2.35 out of 4. We have shown modest improvement year on year, which demonstrates our initial focus on building an asset management team and the foundations for future improvement.

Gaps identified during our AMMAT review are prioritised and addressed as part of an updated AMDP (see chapter 9). The key focus areas remain aligned to our CPP Improvement Plan and include:

- **asset data collection and asset data quality:** accurate and reliable asset data is a prerequisite for effective asset management decision-making. Good quality data enables us to improve our budgeting, risk assessment and forecasting abilities. We have progressed initiatives to improve documentation of our network related data requirements, and associated data quality exception reports and dashboards. We will continue with the implementation of an Asset Management Software Solution (Maximo) to support an uplift in data accessibility and quality and the efficient delivery of our work programme.
- **asset management practices:** a critical part of our asset management improvement involves refining our risk framework to better understand the likelihood of particular assets failing, and to identify the potential outcomes of that failure. Refined health modelling will help us to better identify the likelihood of asset failure and to implement appropriate preventive measures. Criticality helps us to understand the potential consequences of asset failure so that we might introduce appropriate controls. In regard to consequence of failures, we have already established Safety Criticality Zones in our GIS. We have used these safety zones to guide our pole replacement programme where we prioritised replacements in areas of high traffic or public density such as main roads, schools and tertiary institutions.
  In RY23 we made progress to document failure modes, effects and criticality analysis (FMECA) across all asset fleets to support a standardised approach to managing asset risks across different areas, including Safety, Reliability, Environment and High Impact Low Probability (HILP) events. We have also developed high level risk treatment plans to help inform critical controls and aid governance reporting. Documentation of our SAMP and fleet strategies and plans are underway, with an aim to complete a first draft in RY24.
- **cost estimation practices:** improved cost estimation enables us to more accurately forecast future network investment levels and optimise our decision-making by ensuring that solution options are accurately costed for business case assessment.

[1] The Asset Management Maturity Assessment Tool (AMMAT) is an Information Disclosure requirement.

In RY23 we have scoped our cost estimation improvement project for major projects (growth and renewal), including a stage gate approach to increasing accuracy as a project moves from inception to delivery. We have also undertaken a high-level review of our Opex 'base step trend' models, which will be further refined as we complete our fleet strategies/plans outlined above. Incremental progress has been made on establishing unit rates for routine work.

quality assurance processes: appropriate quality assurance processes and resources must be in place to ensure that the escalated level of planned works during the CPP Period are delivered to all applicable standards. In our approach to improving quality assurance, we plan to implement two separate focus areas: works management capability and construction works quality assurance.

Within works management, we have rolled out continuous staff development in alignment with PRINCE2 methodology to manage project risks and drive efficient delivery of capital and maintenance projects.

We aim to improve our works quality assurance by introducing internal standards and quality assurance metrics that guide the review of constructed works. We also plan to extend the scope of our quality assurance review process to include inspection and maintenance tasks, connection services, and zone substation works.

In RY23 we conducted a review of our quality assurance resourcing, and we are in the process of formulating a plan for staff training and development. We also developed a quality assurance standard and further work is underway to develop quality metrics.

Our CPP Improvement Plan also includes:

- voltage quality management
- planned interruption management
- customer charter review

Chapter 9 provides a summary of these initiatives. These combined asset management and CPP Improvement Plan initiatives are directed towards aspects of our asset management systems, processes, and culture where improvement is most needed but also where the benefits are likely to be material. In many cases, the initiatives implement recommendations from independent reviews, and reflect knowledge and experience of approaches adopted in leading distribution companies.

Our underlying objective in undertaking these initiatives is to ensure customers receive a safe and reliable service that they value, while minimising the whole-of-life cost of managing our assets. We note that while some of these initiatives will be developed during the CPP Period, others will take several years to fully implement.

The linkages between our initiatives and quality improvements or efficiency gains is complex and often lagged. As a result, we expect that the impact of these initiatives on our performance will be gradual.

Asset Management Development Plans

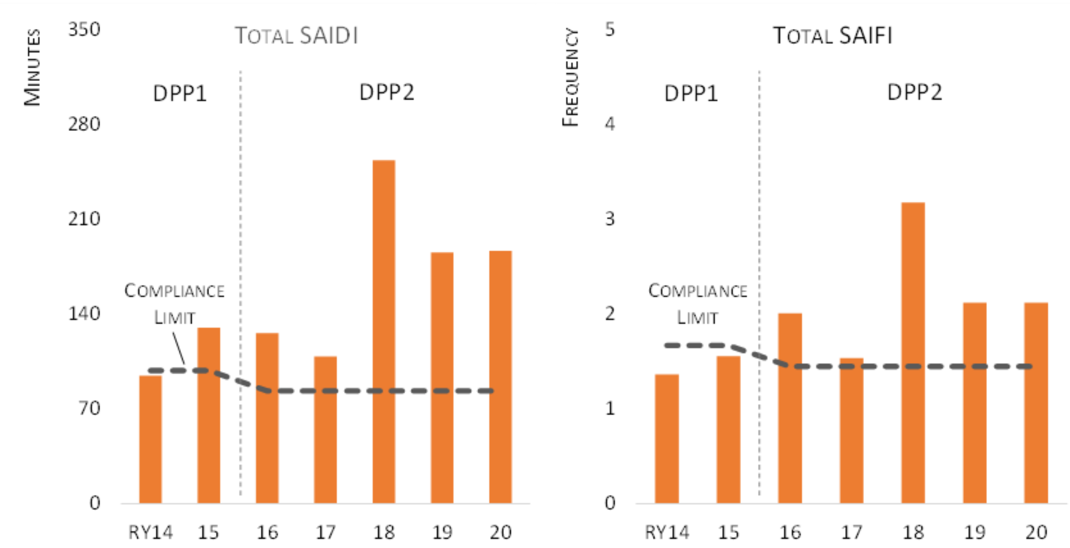
As a regulated business, Aurora Energy is required to meet existing information disclosure requirements set by the Commission. As part of our CPP, we have been set additional requirements that ask us to demonstrate to customers and other stakeholders how we aim to deliver our investment plans, and to improve our overall performance. These plans have been developed in tandem with this AMP and they are outlined further in Chapter 9. The key improvement areas are:

- voltage quality
- customer charter and compensation arrangement
- planned outage management
- asset data collection and data quality
- asset management practices and processes, including practices for identifying and reducing safety risks
- practices for estimating the costs of capital expenditure and operational expenditure
- Quality Assurance processes.

Our Quality Standards

Our reliability performance is measured using SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index)[2]. These metrics represent the impact of outages on customers in terms of duration and frequency respectively. Both had begun to deteriorate for a period prior to our CPP Determination. As shown in the graph below, we were unable to meet our SAIDI and SAIFI quality standards on several occasions during the period from RY14-20. This period correlates to the underlying deterioration in asset health.

Historical Reliability (SAIDI and SAIFI) performance[3]



While safety remains our primary focus, we recognise the importance of appropriate quality of supply to customers. Typical drivers of historic reliability performance are described below.

2 SAIDI (System Average Interruption Duration Index) indicates how long an average customer is off supply in a year. SAIFI (System Average Interruption Frequency Index) indicates how many times an average customer is off supply in a year.

3 The historical values shown are based on our compliance statements, values relating to planned outages are unweighted to allow comparability over time. (During DPP2, for Information Disclosure and compliance purposes, planned SAIDI and SAIFI are weighted at 50%). Values are normalised to allow comparison with compliance limits.

- **Increased outage duration for safety:** outage durations have increased as a result of safety-driven changes to operational practice. For example, we now routinely patrol the length of a line following a fault before attempting to re-liven, and during summer we suspend the use of automatic reclosers to reduce fire risk. As an example, the dry summer of 2019/20 had extended periods of auto recloser disablement which contributed to our RY20 unplanned SAIDI result.
- **Increasing asset faults:** underlying reliability performance at specific locations across our networks is being impacted by a combination of increasing asset age leading to deteriorating condition, encroaching vegetation, and asset model or type-related issues.
- **Increased frequency and duration of planned outages:** these are necessary to undertake current levels of investment, particularly for overhead line work. The frequency and duration of planned outages has also increased due to a reduction in live-line work. We see this as appropriate as we look to ensure worker safety is not compromised.
- **Weather:** parts of our network appear to be becoming more vulnerable to severe weather and increasing storm events.

To better understand this deteriorating performance, we have started to improve our fault root cause capture information, enabling us to better analyse the cause of unplanned outages and the actions we can take to improve reliability over the AMP planning period.

We have stabilised unplanned outages

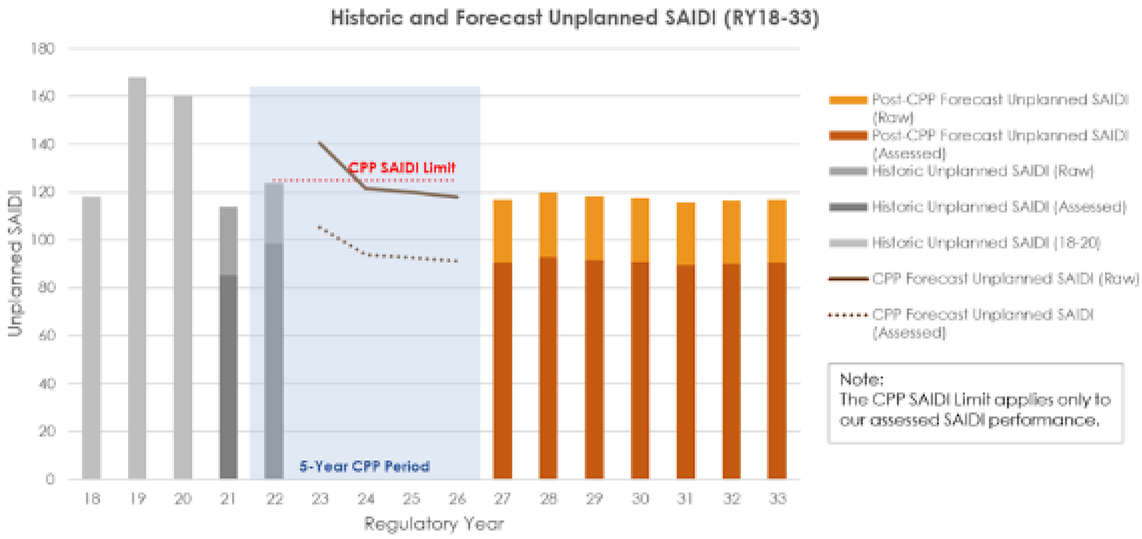
Historical quality standards are based on a combination of planned and unplanned outages. Under the CPP compliance limits, separate targets have been set for planned and unplanned outages. The reliability forecasts presented in this AMP reflect these new limits. During our CPP consultation, the majority of our customers indicated that they were satisfied with their current level of reliability. Given concerns around affordability, they indicated there was little appetite for improving reliability if this resulted in price increases. However, we expect that our planned asset renewal programmes outlined to address safety risk will also reduce the likelihood of asset failures. As such, we expect some degree of improvement in our reliability performance, as shown in our revised forecasts for unplanned SAIDI and SAIFI below.

For context, we have included our historical performance with our forecasts for unplanned SAIDI and SAIFI. For consistency, we have used our raw results without additional de-weighting or normalisation applied, since different rules have been applied across the various years.[4]

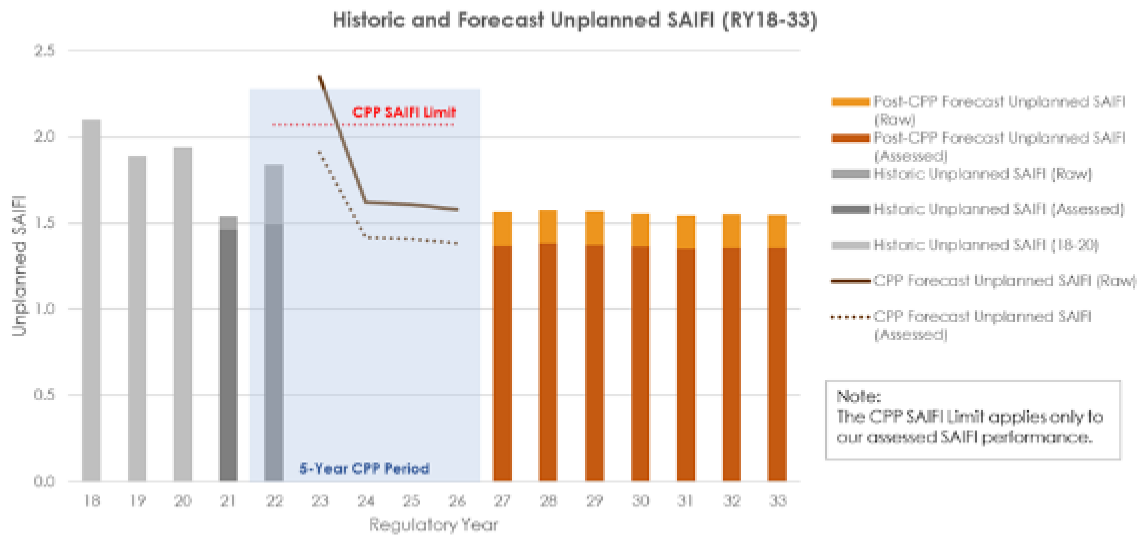
The RY23 forecast has been revised from the 2022 AMP to take account of year-to-date performance. While most parts of the network continue to see either a stabilisation or improvement in reliability, there are pockets of the network, including Arrowtown and the upper Clutha, where a small number of large-scale outages have significantly impacted the overall result/forecast. We have taken action to address these outages and we expect RY24 and RY25 performance to better reflect our medium-term reliability performance expectations.

[4] As part of each DPP, the rules for de-weighting and normalisation of planned and unplanned outages have been refined.

Historical and forecast unplanned SAIDI



Historical and forecast unplanned SAIFI



During 2022 (RY23) we introduced a targeted reliability hotspot programme to complement our safety-based plan. We considered this necessary to address some areas across the network where reliability performance was not meeting our, or our communities', expectations. We have made a relatively small adjustment to our forecasts to reflect the need to target reliability in these areas. The post CPP Period target level of reliability performance is yet to be set. We will utilise our ongoing customer surveys to inform our understanding of the reliability preferences of our communities. Our expenditure forecasts may require further adjustment to meet agreed target levels of reliability performance.

We can manage our work programmes under the CPP planned reliability allowances

Given that our investment will remain at an increased level, we expect that the current number of planned outages will persist over the medium-term. Feedback from consultation indicates that customers generally accept the need for planned work to maintain, replace and upgrade our network assets as long as notification and communications are well-managed.

We believe we can manage our CPP work programme within our planned quality standards. At times this will present a challenge, however we are confident we can achieve it given our initiatives for driving delivery and outage planning improvements.

We note that the CPP planned outage framework encourages (through a penalties/incentives scheme) accurate and timely notification of outages. This is consistent with what customers have told us they want, and we have developed improved processes with our contractors to ensure that planned outages are communicated correctly and managed to plan. During the CPP Period, we expect ongoing initiatives to improve our processes and practices relating to the planning and communication of planned outages.

Our 2023 AMP Investment Plans

Our expected total capital and operating expenditure profiles over the AMP period are set out below. These profiles represent our best estimate of network needs based on currently available information and reflect our current levels of delivery capability.

We plan to sustain increased levels of network investment over the planning period, spending $875 million in capital (net of consumer capital contributions) and operational expenditure on renewing and maintaining the existing network. Of this, $274 million will be invested during the remainder of our CPP Period.

These levels of investment are necessary if we are to effectively manage safety risk, stabilise network performance and deliver a valued service to customers. To achieve this, we are focusing our short-term investments on replacing assets that pose safety risks due to elevated likelihood of failure, and on addressing a backlog of poor condition assets.

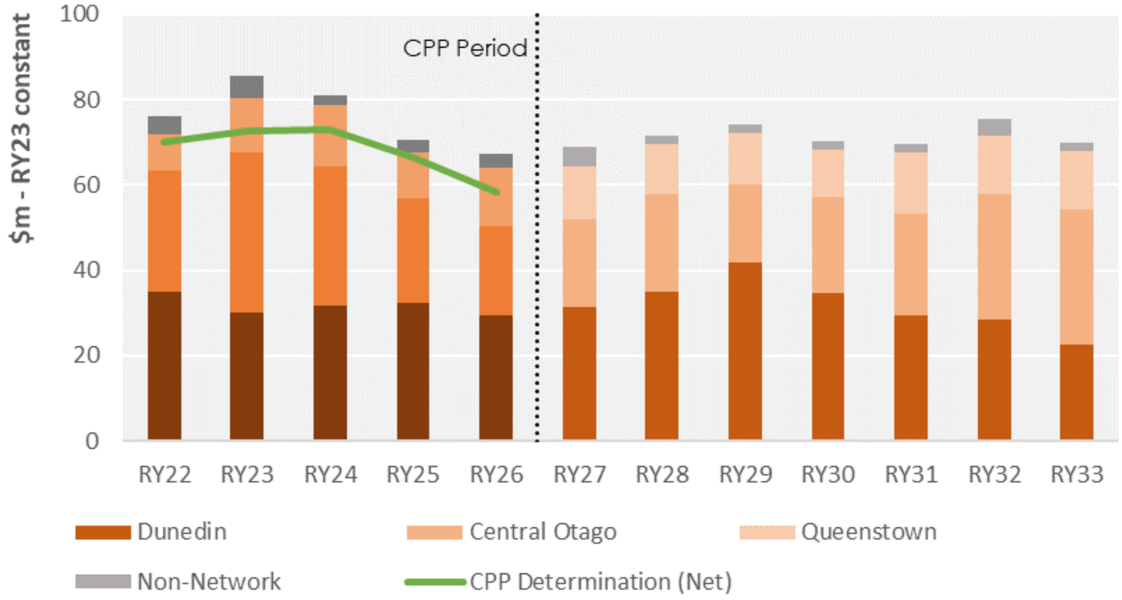
As outlined above, our short- to medium-term forecasts may be further refined, in terms of priority and timing, as we further enhance our asset health and risk modelling, and we balance the need to invest to meet strong electrification growth as an enabler of decarbonisation, reliability and resiliency enhancements. We will include updated long-term investment outlooks in our 2024 AMP.

Capital expenditure

Our capital expenditure for the AMP planning period is set out below. As we outline in the main body of the document, this level of expenditure is needed due to our ageing asset base and is required if we are to achieve our investment priorities and, importantly, ensure our network remains safe.

In general, the initial four years (RY23 to RY26) are more certain and supported by more detailed plans. This higher level of certainty covers the remainder of our five-year CPP Period (denoted by the darker orange bars). The CPP Period forecast capital expenditure exceeds the CPP Determination allowances by approximately $43M. $26M of this forecast overspend is associated with stronger than expected post COVID-19 growth in Central Otago. Strong growth has required some major projects to be brought forward and a higher than forecast number of new connections to the network.

Total planned Capex during the AMP period (net of customer contributions)



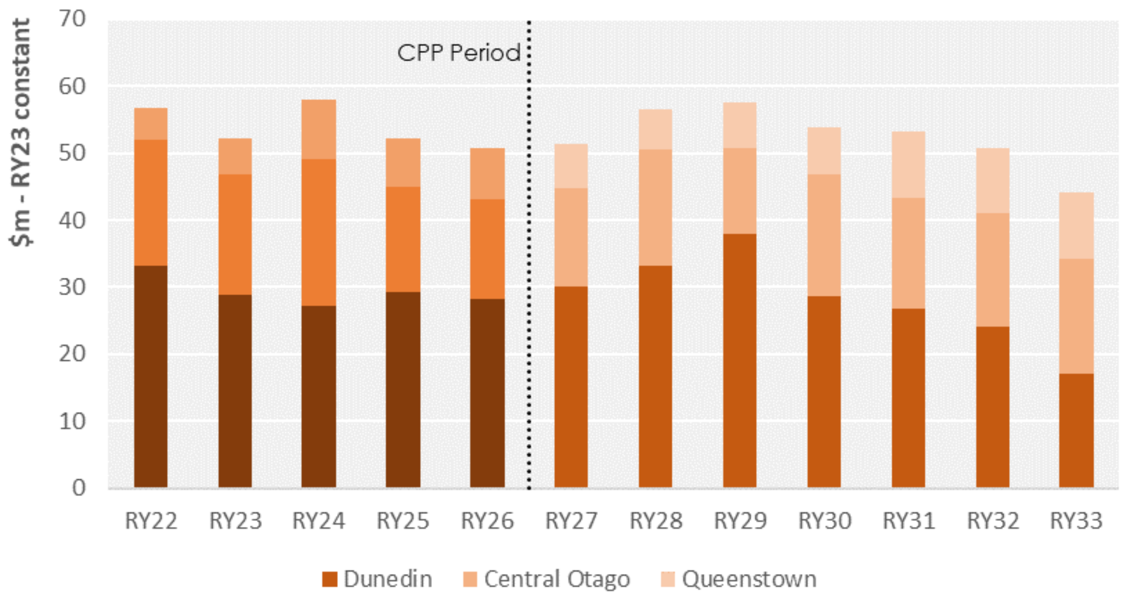
As part of the CPP Determination, the Commerce Commission acknowledged the uncertainty in our growth forecast via the provision of a 'capacity event' reopener mechanism. This mechanism creates a process for Aurora to apply for additional allowances where there is evidence to support an additional investment need within the CPP Period. We have signalled to the Commerce Commission that we will be seeking a 'capacity event' reopener, which we consider is an appropriate mechanism to manage this kind of investment uncertainty. Any increase in our capital allowance will flow through to additional revenue in the post-CPP Period. Price increases to consumers during the CPP Period will be limited to those commensurate with the original CPP Determination.

The remainder of the CPP Period forecast overspend ($17M) is required to meet our safety objectives within the CPP Period and better position our delivery capability for the post-CPP Period investment levels. We forecast sustained levels of asset renewals, and an increase in growth related expenditure associated with decarbonisation and climate change resilience in the post-CPP Period.

We are cognisant that the CPP Period overspend is not supported in the short-term by increased revenue allowances and carries a revenue penalty. However, our analysis and forecasts show that this investment is necessary if we are to achieve our safety risk reduction objectives, keep pace with growth, and enable a new energy future for our communities.

Our total Replacement Expenditure (Repex) investment, shown below, indicates the significant portion of the total investment that relates to asset renewal.

Total asset renewals Capex during the AMP period



Beyond the CPP Period, we will continue to reprioritise work as we obtain better asset information or refine our current assumptions. This includes adjusting our spending to meet new or diminishing risks and meeting the long-term interests of customers.

The assets that we plan to invest in during the AMP period include:

- maintaining our elevated pole replacement programme throughout the planning period
- targeted renewal of conductor and crossarms over the period
- continuing our programme to replace electromechanical relays
- replacing poor condition assets in our switchgear fleets that present safety risks, particularly ring main units and zone substation indoor switchgear
- supporting new connections to our network
- capacity required to facilitate electrification and general demand growth
- implementing new ICT (Information Communications and Technology) systems and supporting processes, including an Asset Management Software Solution (AMSS).

We are mindful of current global events (ongoing COVID-19 and Russian war) and the impact these are having on some equipment procurement, including supply shortages and rising costs. Very recently, we have experienced cost escalation on a number of key network assets. We have made some adjustments to our Capex unit rates but the longevity of these cost escalations will be an area of future attention in our forecasting.

There are potential efficiencies to be achieved based on a composite of potential sources, including:

- works coordination: reflects a shift from addressing spot risks to fleet-wide risks
- improved decision-making: driven by asset management improvements, including expanded network analytics using better data and condition-based risk management
- improving capability: expected benefits from improvements to our asset management systems and processes, and as we embed new ICT capabilities investments (E.g. AMSS).

We think there is limited opportunity for improved contractor productivity as we have been operating at scale with increased competitive tension over the last three years and there is unlikely to be any significant short-term improvement in this area.

Operating expenditure

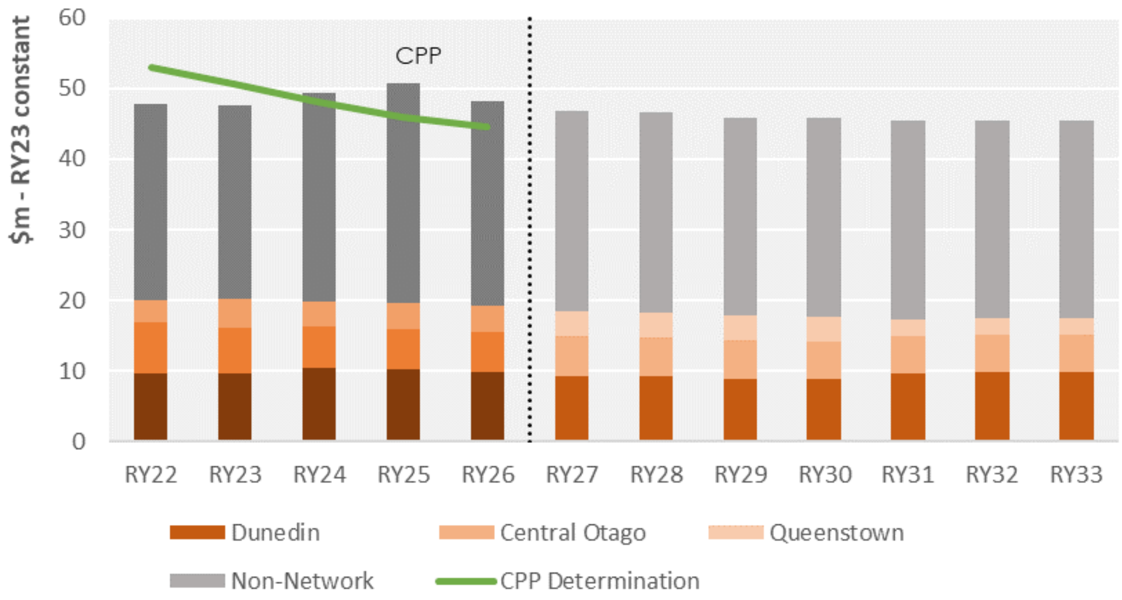
Our planned Opex remains somewhat constant over the AMP planning period. Network Opex costs decrease marginally due to reduced investment in vegetation and reactive maintenance, reflecting the completion of the first vegetation cut and improving reliability leading to less fault response. This is partly offset by elevated levels of corrective maintenance associated with the consumer pole programme and a backlog of asset defects which decline as we enter the post-CPP Period.

Our total CPP Period Opex forecast exceeds the CPP Determination by approximately $1M.

The overspend is a combination of factors, including higher than forecast cost escalation, a growing need for non-network solutions, and services to support low voltage network visibility and digitally enabled capability. Our Opex profile is also different to the CPP Determination profile. To date (RY22 and RY23) we have not spent up to the CPP Determination Opex level, but we forecast to overspend in RY25 and RY26. This is largely due to the CPP Determination requiring a significant year-on-year reduction in non-network Opex over the CPP Period. Our forecasts do not concur with this view, and we forecast a relatively stable level of non-network Opex going forward.

Similar to our Capex overspend, the Opex overspend incurs a revenue penalty in the post-CPP Period, but we do not consider that an alternative level of expenditure will enable us to meet our critical network safety and asset management objectives.

Planned Opex during the AMP period



For those investments later in the AMP period, we will reprioritise work as we obtain better asset information or refine our current assumptions. This includes adjusting our spending to meet new or diminishing risks and meeting the long-term interests of customers.

The activities that will drive Opex during the AMP period include:

- improving our inspection techniques to better understand asset condition and network risks. Data and information management practices will also be enhanced
- bringing backlogs of outstanding maintenance defects under control and reducing these to steady-state levels during the CPP Period
- pursuing improvements in our approach to asset management, to achieve industry good practice and to realise future efficiencies. To achieve this, we will bolster our internal capabilities and skills
- increasing our capacity to efficiently deliver our work programme
- beginning to inspect consumer-owned poles to support our planned programme to ensure pre-1984 poles can be handed back to customers
- increasing ICT Opex as we adopt more service-based solutions
- further developing vegetation management to a good practice proactive approach to enhance safety, reduce unplanned outages, and ensure full compliance with the Tree Regulations
- further implementation of non-network solutions across the network, such as the solarZero solution to defer capacity constraints in the Upper Clutha region.

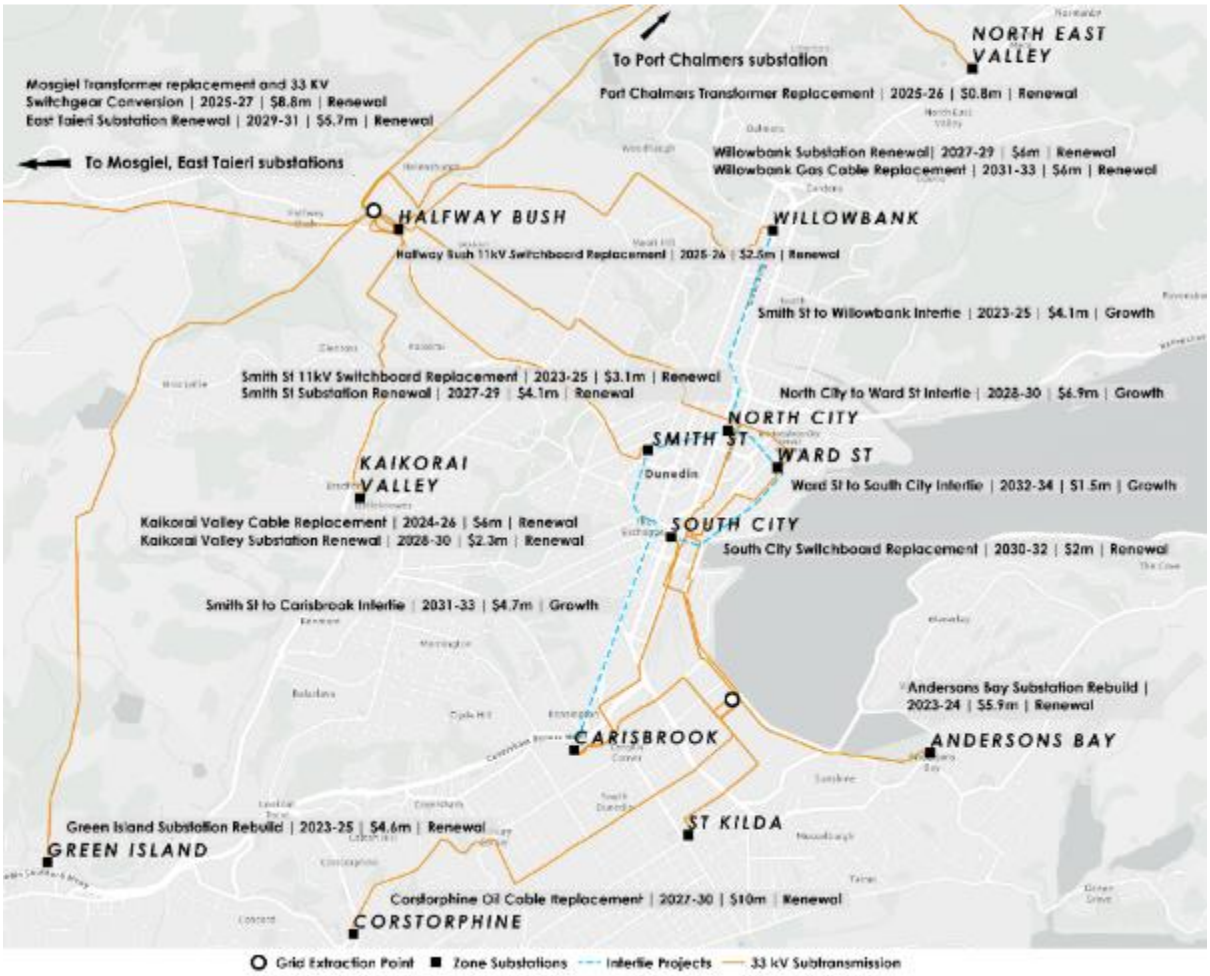
Summary of key investments

Over the next 10 years we will continue to invest in large projects to renew, upgrade and expand our networks. A selection of these projects is set out in the three maps below with an indication of whether the investment is driven by renewal or growth. These works are in addition to the programme-based work such as pole renewals.

Much of the Dunedin network was constructed 50-70 years ago and many of its assets are near end-of-life, requiring renewal over the AMP period. This, coupled with historical low rates of replacement, means we will replace assets including 33 kV cables, power transformers and switchgear over the AMP period. Example projects include:

- cable 'intertie' projects that will ensure appropriate levels of security and resilience, particularly around Dunedin CBD
- rebuilding Andersons Bay and Green Island substations
- switchboard or transformer replacements at Port Chalmers, Smith St, Halfway Bush, Kaikorai Valley and South City

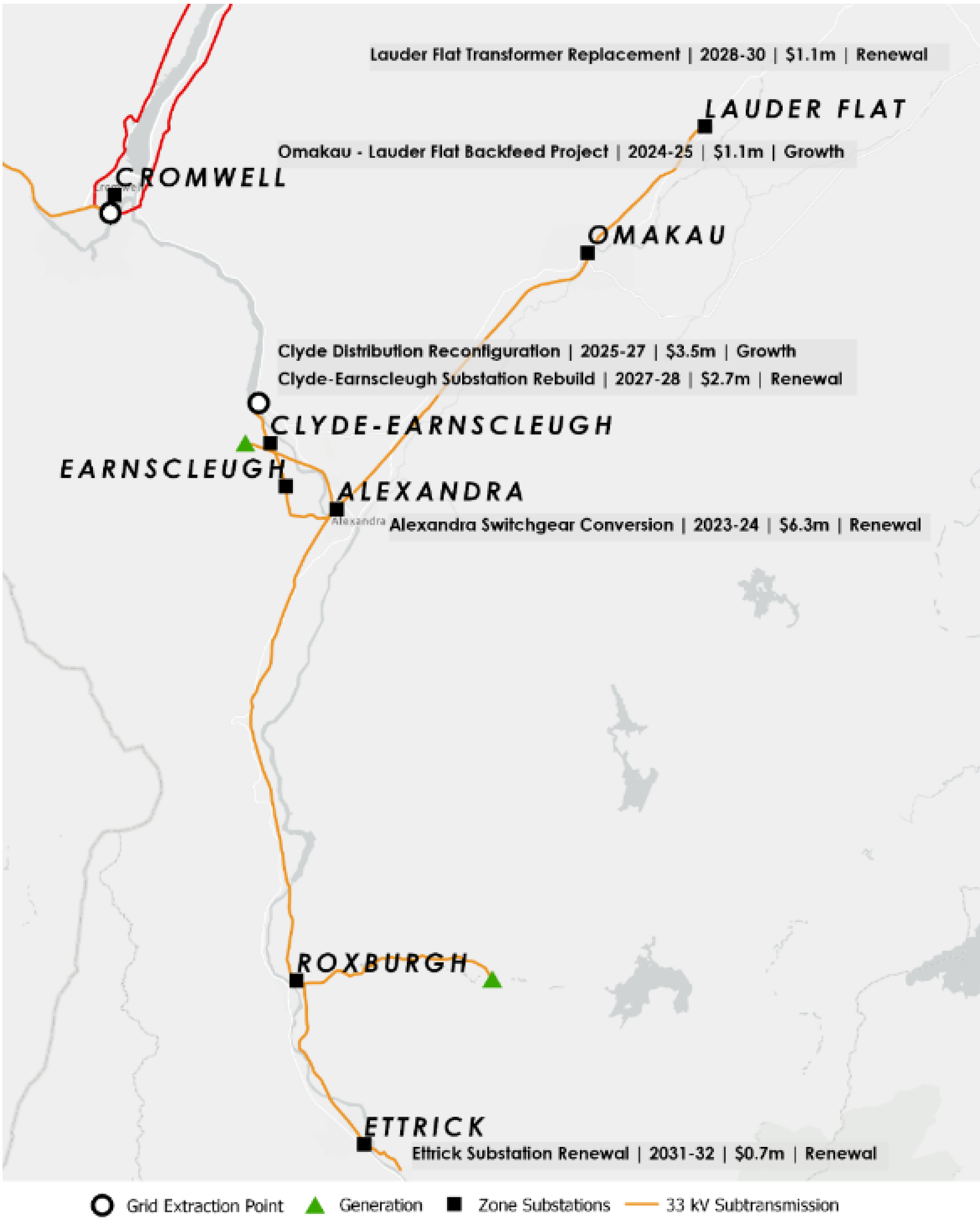
Large planned projects in Dunedin



Large planned projects in Cromwell and Upper Clutha

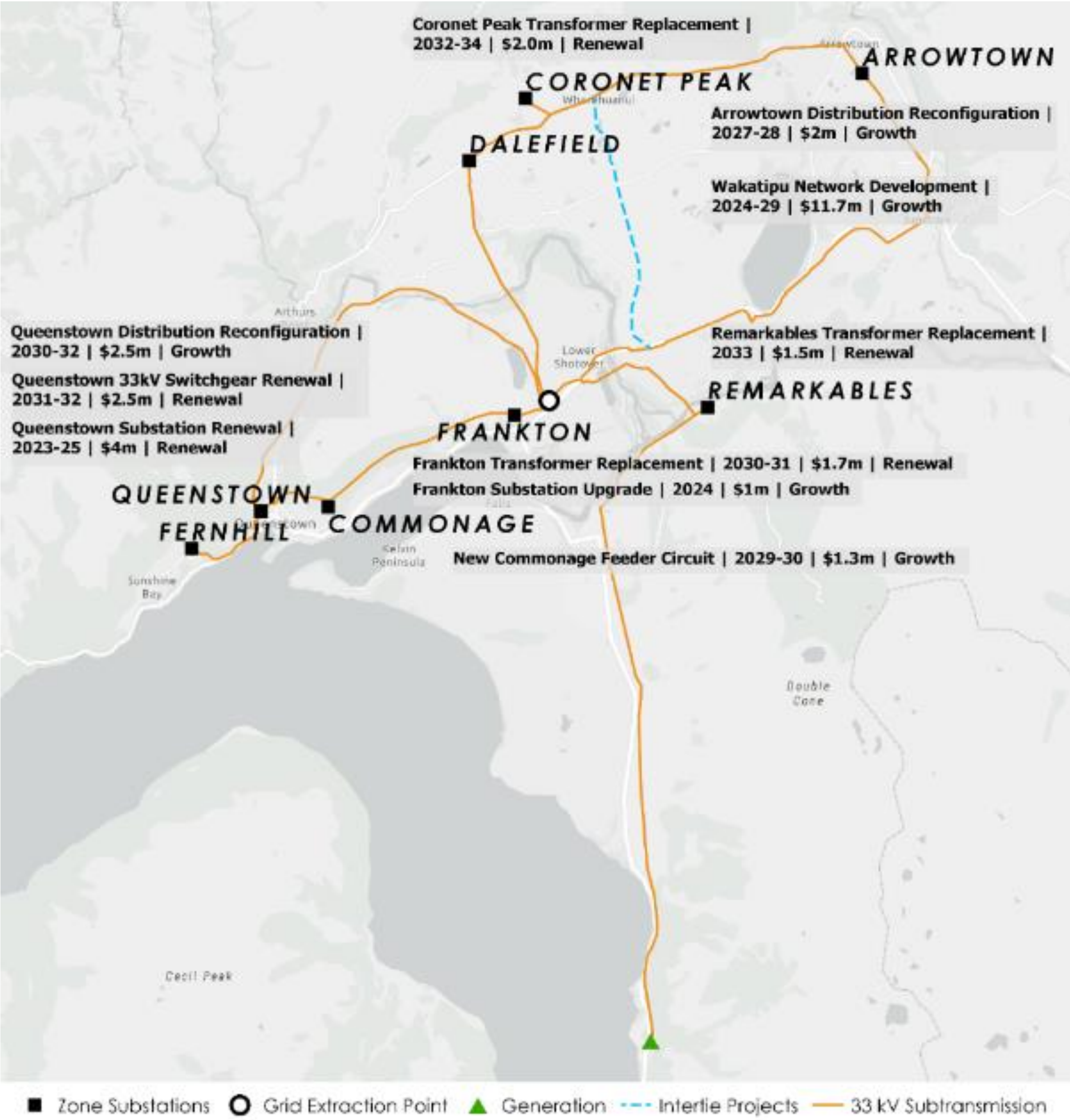
In our 2020 AMP, we expected that the economic impact of the COVID-19 pandemic would subdue any expected demand growth in Central Otago. Against expectations, the region has shown strong growth in recent years, and continued investment is required in our network to meet future demand.

Large planned projects in Clyde area`



Our major projects in the Clyde area also include a rebuild of the Omakau zone substation in RY23/24 to provide an increase in capacity and improved network configuration flexibility. The Clyde Earnscleugh substation rebuild/decommissioning is a staged project with the first stage in RY23 to establish a new Dunstan substation adjacent to the Clyde dam. Decommissioning of the Clyde Earnscleugh substation will occur over the next 2-3 years as we install 11 kV feeders from the new Dunstan substation.

Large planned projects in Queenstown



We have retained most of our planned growth projects from the 2020 AMP, and added replacement projects for our Coronet Peak, Fern Hill and Remarkables substations. Some work has been brought forward, such as the Frankton zone substation upgrade, which has recently experienced peak demand exceeding firm capacity.

The Arrowtown Ring Upgrade project will provide additional capacity and reliability to the ring circuit that supplies four zone substations (Arrowtown, Coronet Peak, Dalefield and Remarkables).

A final word on Safety

Customer and stakeholder concern for network safety, and a desire for it to improve, had been apparent prior to 2018 and was one of the factors in our decision to apply for a CPP in 2020. As set out in our CPP consultation report, stakeholders and customers again clearly told us that avoidable safety risk was unacceptable.

Our investment plans focus on ensuring our network continues to be repositioned to safely serve the communities in Dunedin and Central Otago. We need to build on our progress to date and continue our asset renewal programmes to minimise the potential for assets to cause harm.

While delivering our critical investment programmes, we will not compromise our efforts to ensure the safety of our staff and the general public. This will always be our foremost priority that informs everything we do.

The Aurora Energy team along with the broader efforts of contractors over the last five years has made a demonstrable step toward a safe network for the public, our contractors and staff. We know that we must build on this momentum, continue to improve or safety planning, and deliver a network that meets the safety needs of our communities, our families and our friends.

SAFETY NOTHING LESS

Safety Pledge
We will strive for 'safety, nothing less', meaning all our activities and decisions will focus on safeguarding the public and ensuring an injury free workplace.

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1. INTRODUCTION

Aurora Energy's 2023 Asset Management Plan (AMP) sets out our asset management strategies, initiatives and expenditure forecasts across a 10-year period. The forecast period starts from 01 April 2023, which marks the beginning of the 2024 regulatory year (RY). This introductory chapter establishes the overall purpose of the AMP and outlines the scope and content for each of the remaining chapters.

RY 2024 is the third year of the Customised Price-quality Path (CPP[1]) regime. Each AMP publication is an opportunity for us to demonstrate to customers and stakeholders how we have utilised our investment plans to support network improvements in key areas.

1.1. PURPOSE OF THE AMP

Our AMP documents the processes that Aurora Energy undertakes to develop our planned investments and improvement initiatives over the coming 10-year period. Our plans will allow us to continue to deliver a safer, more reliable and valued service, connect new customers, and begin to position our network for the future. The AMP demonstrates to interested persons that the long-term management of network assets and our planned initiatives will allow the business to meet its overall objectives, which align with the needs of customers and key stakeholders. We hope that it will help stakeholders to understand our approach to managing our network assets. An overview of stakeholders and their needs is covered in Chapter 2.

Box 1.1 Business Vision: Enabling the energy future of our communities

As we progress beyond our CPP Period, we will ensure that we continue to provide a safe, reliable and efficient supply of electricity to our customers. We also have an eye towards the future of an electricity distribution business in light of the potential impacts of de-carbonisation and increased electrification. He Pou a Rangi, the Climate Change Commission, has noted that a significant increase in electricity demand will occur as the country transitions to meet its 2050 carbon emission targets. Increased uptake of EVs, solar generation and battery storage may play a significant role in shaping our business in the future. The future offers challenges and opportunities coping with greater consumer reliance on electricity and more complex electrical flows. Preparing early for these changes will provide the resilience required to operate in a dynamic environment. As we have demonstrated with our Upper Clutha Distributed Energy Resources (DER) solution, changes in technology can be utilised to provide support to our network (see Chapter 6).

While decarbonisation and increased electrification have yet to make a significant impact on our network, we anticipate the need for greater investment in future AMPs to prepare our network to meet these challenges on the path to New Zealand's net-zero carbon emission target in 2050.

Aligning with our previous AMP publications, our investment programmes will continue to prioritise network safety. Our asset inspection and maintenance initiatives include a strong focus on identifying safety risks (see Chapters 5 and 7), while our approach to asset renewals is heavily guided by the need to replace assets that can cause harm, especially when these assets are located in highly

1 A CPP is a regulatory mechanism that the Commission can use to establish a price-quality path that better suits the company's individual circumstances.

populated areas (see Chapter 5). By improving the overall health of our assets, we are also improving network reliability for our customers.

> **Box 1.2: Aurora Energy CPP Reporting Requirements**
> Aurora Energy produces an Asset Management Plan to meet reporting requirements set by the Commerce Commission. As part of our CPP application, Aurora Energy have been set additional disclosure requirements to allow the Commerce Commission to assess our performance. (Our development plans are summarised in Chapter 9).

1.1.1. AMP 2023 Objectives

This AMP meets the requirements of the Electricity Distribution Information Disclosure Determination 2012 (Determination). A reference of how it meets the detailed regulatory Information Disclosure requirements is included in Appendix G. In addition to these requirements, we have developed our AMP to explain to stakeholders our approach to managing our electricity distribution network.

The objectives of our 2023 AMP are to:

- reaffirm our commitment to minimising safety risks on our network
- highlight our approach to managing long-life assets by providing clear descriptions, objectives and targets for them
- be transparent with our stakeholders, particularly around inherent network risks and the systematic processes in place to mitigate those risks
- explain the challenges we face as a business and our developments plans for improvement
- set out our corporate mission and vision and how these inform our asset management approach
- summarise our asset management documentation, show how these are aligned with corporate goals, and set out our work plans for the planning period
- demonstrate the interaction (or line-of-sight) between the objectives of the AMP, our asset management policy, corporate goals, business planning processes, and plans
- provide visibility of forecast investment programmes to external users of the AMP
- provide updates to stakeholders on improvements to our asset management practices.

Aurora Energy’s approach to asset management aims to ensure that all future investment plans and supporting initiatives are aligned with our overall business objectives. Therefore, our asset management practices are underpinned by the following strategic objectives:

- Safety first without compromise
- Network performance to defined levels
- Affordability through cost management
- Responsive to a changing landscape
- Sustainability by taking a long-term view

These objectives, outlined further in Chapter 4, provide a point of focus across all areas of the asset management lifecycle, including network development, design and installation, asset maintenance, and asset renewals. These areas are outlined further in Chapters 5-8. For more information on the business units that support our asset management practices, see Chapter 9.

Our Energy Future

As an electricity distribution business, we are aware of our responsibility to play an active role in the decarbonisation and electrification of the nation, particularly in response to changes in the transportation and industrial sectors. It is important that we engage with our various stakeholders to ensure that the medium- to long-term impacts of this transition are widely recognised.

In lieu of future challenges brought about by decarbonisation and greater electrification, we will continue to monitor the potential impacts on the distribution sector. These challenges will vary across individual areas, but they include:

- Population growth
- Intensification of residential development, including infill in urban areas
- New commercial/industrial loads, including data & hydrogen centres
- Electric vehicles
- Electrification demand from gas and heat conversion
- Network scale solar/wind farms
- Climate adaptation
- Need for enhanced low voltage management/visibility

Many of these drivers for change are as yet uncertain and have the potential to become significant disruptors within electricity distribution. Through our association with the Electricity Networks Association (ENA), we will participate in developing more robust demand forecasts that emerge as part of our transition to a net-zero carbon nation by 2050.

Once we become more aware of the potential impact that decarbonisation and increased electrification brings to our network, it will be prudent for us to adapt our investment plans to suit. We anticipate that subsequent AMP publications will outline how we adapt our long-term investment focus for the years towards 2050.

1.1.2. Period Covered by the AMP

Our AMP covers a 10-year planning period, from 01 April 2023 to 31 March 2033. This includes the remainder of our five-year CPP Period which commenced on 01 April 2021 and runs until 31 March 2026.

As might be expected, the initial years of the AMP period are based on more detailed analysis of demand forecasts and asset information, resulting in greater levels of certainty. The latter period of the AMP is progressively less certain and is suitable for provisional planning purposes only.

1.2. STRUCTURE OF THE AMP

CHAPTER		DESCRIPTION
1	Introduction	Current chapter
2	Background	Overview of our business, our stakeholders, and our operating context
3	Network Overview	Describes our sub-networks in Dunedin, Central Otago and Queenstown, and provides key statistics
4	Strategy and Governance	Explains how we make asset management related decisions, and how we ensure our investments support the needs of stakeholders
5	Overview of Lifecycle Management	Explains our overall approach to managing assets across the whole life, from design to replacement
6	Network Development	How we address demand growth, impact of decarbonisation, uptake of DERs and connect new customers
7	Operate and Maintain	Explains how we operate and maintain our network assets
8	Renew or Dispose	Sets out the condition and risks for each of our asset fleets, and our planned investments
9	Asset Management Enablers	Discusses our asset management capability and non-network assets
10	Summary of Expenditure Forecasts	Sets out our planned investments over the AMP planning period
APPENDICES		**DESCRIPTION**
A	Glossary	List of specified meanings for acronyms and technical terms
B	Disclosure Schedules	Technical and financial disclosures and background on these disclosures
C	Reliability Management	Provides detail on historical reliability of our network and plans for improvement across the planning period
D	Work Programme Update	Provides an update on our RY22 work programme
E	ICT Asset Information	Provides further detail on our ICT assets and systems, and how we manage them
F	Growth Project Details	Details on our larger network investments over the AMP period
G	Disclosure Requirements	Sets out how the AMP addresses Information Disclosure requirements
H	Director’s Certificate	A copy of the AMP’s director certification

2. BACKGROUND

This chapter provides background on our business, including the following information:

- **overview of Aurora Energy**: provides background information on our history, our ownership and our business structure
- **our stakeholders**: identifies our key stakeholders and discusses their individual needs
- **our customers**: outlines the key values and expectations of our customers and our approach to identifying them. Also includes initiatives to improve the level of service that we deliver to customers
- **context for our 2023 AMP**: sets out general factors that influence our approach to asset management, including our regulatory requirements under the CPP, the impacts of COVID-19, and the influence of climate change and new technology on how we manage our network.

Box 2.1: A note on COVID-19

The impacts of COVID-19 have been felt globally over the past few years and now the pandemic is transitioning towards an epidemic we are adjusting to a new 'normal' of living with COVID-19 in the community. Fortunately, these impacts on New Zealand, particularly the southern regions, have not be felt as overtly as elsewhere. We continue to see strong growth in Central Otago and Queenstown, and we have corrected the reduced growth assumptions we made in our 2020 CPP application. This has led to an acceleration of previously delayed growth projects. We propose to treat these projects as 'capacity event' projects and engage the Commerce Commission to ensure that we have sufficient regulatory allowances to deliver growth related work on top of our asset renewal projects.

The planning and engineering analysis underpinning our 2023 AMP have been undertaken with full knowledge of the ongoing impacts of COVID-19 as a significant social and economic 'disruptor'. As such, we have developed our investment plans to accommodate these potential risks.

We have established working policies that allow our team to continue delivering to their capability in a changing environment and respond quickly and efficiently to local spikes in confirmed cases. Our service providers continue to deliver upon their work programmes with limited impact. Therefore, against this uncertainty, and as a lifeline utility, we are currently operating on the basis that we can meet our RY23 work plans and manage the potential ongoing effects of COVID-19.

2.1. OVERVIEW OF AURORA ENERGY

Aurora Energy owns and operates electricity distribution network assets throughout the Otago region. We operate across three sub-networks: Dunedin, Central Otago/Wānaka and Queenstown. We own and manage a wide range of assets that are used to transport electricity from the national grid, owned by Transpower, to end-use consumers. Our role is to ensure the safety and resilience of the network and deliver a reliable electricity service to over 93,600 homes, farms and businesses throughout the regions we serve.

For further detail on each of our networks, including network configuration, load profiles and major customers, see Chapter 3.

Aurora Energy was set up as a new organisation in July 2017. Prior to this time, Aurora Energy acted as owner of the electricity network, while Delta Utilities Services Ltd. (henceforward referred to as

Delta) undertook asset management and service provider roles on its behalf. As the result of an independent review into the organisation, the two sister companies were separated into stand-alone entities, with Delta continuing to act as service provider for Aurora Energy, who now oversee the management of network assets. Each company established its own independent Board, and some Delta staff made the transition to Aurora Energy. Today we have approximately 159 staff members mostly located in our two regional offices in Dunedin and Cromwell.

The formal separation from Delta ensures that our team can provide a dedicated focus to the management and operation of our electricity assets, without the additional challenge of overseeing a contracting business. Structural separation has created clearer accountabilities for network ownership and service provision in the two entities. The separation has also increased transparency and commercial tension in our procurement processes. Under the new and current operating model, Delta is one of three 'arms-length' service providers and is subject to commercial terms. Over time, these benefits have the potential to reduce the underlying cost of delivering our service to customers.

In 2018, following a contestable tendering process, we appointed two additional contractors – Unison Contracting and Connetics. We now tender large projects – such as substation rebuilds and line construction – to pre-qualified firms. We are ensuring a controlled integration of our new suppliers by gradually increasing the volume and scope of contestable work.

2.1.1. Ownership and Governance

The aim of the governance arrangements and organisational structure is to ensure the necessary accountabilities are in place for good asset management. This section describes the governance arrangements, organisation structure and key responsibilities of our executive management, asset management and operational teams.

Ownership

Aurora Energy Limited is one of New Zealand's largest electricity distribution business (EDB) and is a subsidiary company of Dunedin City Holdings Limited, which is owned by the Dunedin City Council.

Our directors are appointed by our shareholders to govern and direct our activities. The Board is responsible for the direction and control of the company including commercial performance, business plans, policies, budgets, and compliance with the law. The Board receives formal updates from management of progress against objectives, legislative compliance, and risk management and performance against targets.

Dunedin City Council Review

In late 2019, Dunedin City Council commissioned an independent assessment of Aurora Energy and the current management of its network by an electricity sector expert. The review found the organisation was performing well and that its Board, executive and staff are working hard to improve and maintain the network. The report considered the actions taken by the incoming Aurora Energy Board and executive from early 2018 and whether they addressed the issues around its legacy asset management approaches and are establishing a path to having a safe and future proofed network. The report author concluded that the Dunedin City Council could have confidence that the business is working to reduce critical risks and is developing the culture required to deliver a safe and reliable network.

Our Board

The Board is responsible for enabling the organisation to secure the resources necessary to implement its programmes and services to accomplish its goals and meet the needs of stakeholders. In support, it has established policies to safeguard and guide the use of resources and assets, including appropriate management of risk. These policies extend to ensuring clear, accountable performance management.

Our Board reviews and approves our AMP to ensure that it meets all regulatory requirements. This AMP was approved by our Board on 29 March 2023.

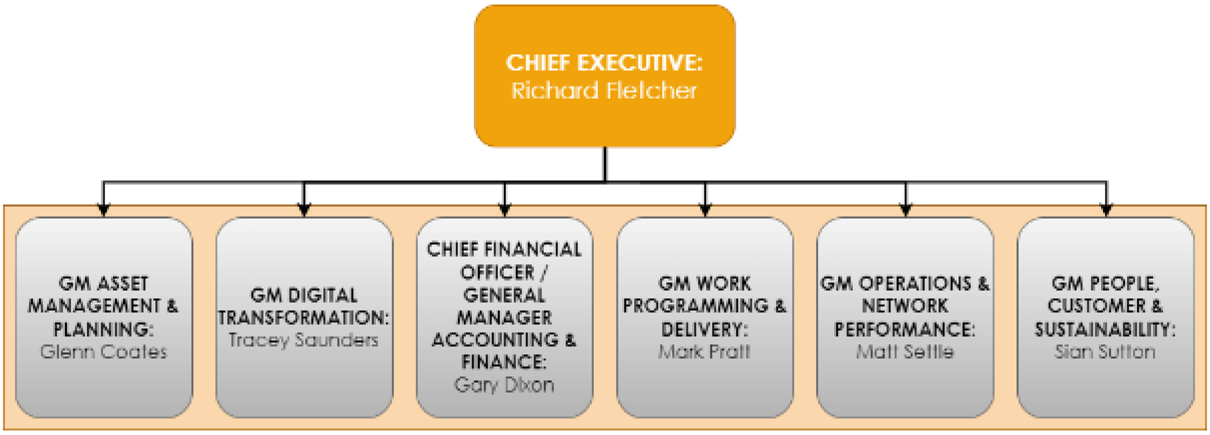
Our Board provides strategic guidance, monitors effectiveness of management and is accountable to shareholders for the company's performance. Overall governance and decision-making rests with the Board and CEO. From an asset management perspective, the Board is required to endorse key documentation (including this AMP and our annual business plans) that establishes our objectives and strategies for achieving our objectives, and for monitoring performance. The main asset management responsibilities of the Board are as follows.

- The Board reviews and approves our AMP, which includes our long-term (10-year) investment plans and ensures that the AMP meets regulatory requirements.
- The Board has overall accountability for maintaining a safe working environment and ensuring public safety is not compromised by our assets and operations.
- The Board approves projects or programmes with expenditure greater than $0.5 million.
- The Board reviews performance reports on the status of key work programmes and important network performance metrics. This includes updates on high value and high criticality projects. It uses this information to provide guidance to management on improvements required, or changes in strategic direction.
- The Board is responsible for overseeing risk management practices. The Board also receives and reviews reports by external auditors.

Executive Team

Like most organisations, support is provided by a group of general managers (GM), each responsible for a functional area of the organisation. Core responsibilities of the executive team include delivering the organisation's strategic goals and providing advice and leadership to the wider business. The executive team structure is illustrated by the figure below.

Figure 2.1: Executive Team



The following section outlines the responsibilities of the main business groups, with a focus on their roles within the asset management system.

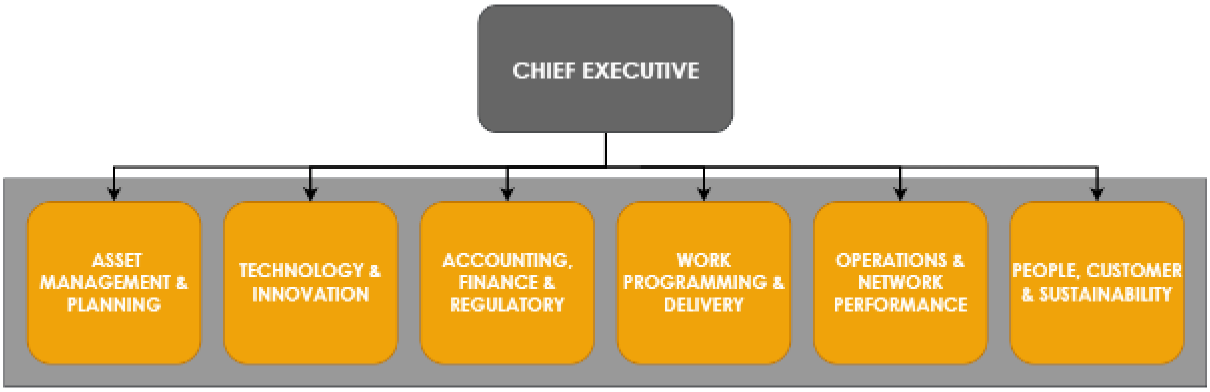
2.1.2. Governance Roles and Responsibilities

Asset management decision-making occurs at a variety of different levels, from the Board to our engineering teams.

Organisation Structure

Reflecting our role and priorities, we are structured into six functional groups as depicted below.

Figure 2.2: Functional Groups



The primary responsibility for the day-to-day management of our network lies with the following teams:

- Asset Management and Planning
- Operations and Network Performance
- Works Programming and Delivery

The following sections provide an overview of the roles and responsibilities of these groups.

Asset Management and Planning

The Asset Management and Planning group is responsible for ensuring that our network allows for safe and reliable delivery of electricity as per our key customer requirements. The team is also responsible for ensuring that the network is practical to operate and is technically efficient. Key tasks include maintaining accurate and up-to-date information about the performance of the network, and about our assets. The team is also tasked with monitoring changing trends in load demand, and in the uptake of DER such as EVs and solar. These trends need to be assessed for their potential impact on our network, and strategies must be developed to address them through our investment plans.

This group consists of four specialist functions focused on key asset management activities. The following table sets out these teams and their responsibilities.

Table 2.1: Asset Management and Planning functions

TEAM	KEY RESPONSIBILITIES INCLUDE
Network Planning	Load forecasting Network HV power flow model maintenance Fault studies and Low Voltage (LV) network modelling Major project and reinforcement planning and scoping Demand-side management and emerging technology strategy Security of supply guide Standards and guidelines for HV/LV network architectures Property and asset relocation planning Transpower planning interface Contingency planning
Asset Lifecycle	Asset lifecycle strategies Preparing plans/scopes aligned to asset lifecycle strategies Monitoring and interpreting asset condition Risk assessment Identifying assets for intervention Scope asset intervention ready for implementation Developing asset maintenance and replacement plans Asset specialist support to design teams
Engineering	Technical support to projects including design reviews Leading the development and review of design standards Scope for customer works and major projects (where applicable) Protection modelling in network model Power quality monitoring and incident review New equipment assessment Safety-in-design Technical specifications Developing scopes for planning and replacement where appropriate
Strategy and Reliability	Coordinating AMP preparation and AMMAT reviews Optimisation of planning and lifecycle network investment forecasts Development of long-term network investment forecasts

TEAM	KEY RESPONSIBILITIES INCLUDE
	Asset management strategy Lead the development of specifications for risk management and quantification Lead asset management development plan Lead network reliability/performance forecast

Operations and Network Performance

The Operations and Network Performance group is responsible for ensuring the 24/7 real-time, safe, reliable, and resilient operation of our networks.

If supply is interrupted unexpectedly, we respond by restoring it as quickly and safely as possible. Our operations staff are in constant contact with field staff when supply needs to be restored. We collect information to help us reduce the risk of future outages. This includes recording what caused the power cut, what areas were affected, and for how long. This supports network asset management by providing information to support root cause analysis and renewals planning.

Table 2.2: Operations and Network Performance functions

TEAM	KEY RESPONSIBILITIES INCLUDE
Network Access	Outage planning and work scheduling Assessment and prioritisation of planned outage requests Notifying planned outages to retailers and customers Authorisation of third-party ‘close approach’ Coordination of oversized transport movements
Network Operations	Network Operations Centre (NOC) Real-time network management (system monitoring, switching and load control) Contractor access permits Operational resilience Emergency management
Operational Performance	Network event and major event day investigation and review Monitoring compliance with reliability and public safety obligations Advanced Distribution Management System (ADMS) Outage Management System (OMS) Rapid response (public safety risks)
Health and Safety	Incident management processes

Work Programming and Delivery

The Work Programming and Delivery group is responsible for managing the delivery of field activities (E.g. maintenance) and our capital works programmes. An important aspect of this is managing relationships with field service contractors, and monitoring deliverables to achieve safety, operational and financial targets.

The group enables an increased focus on managing external service providers and streamlining works delivery and scheduling. The following table sets out the functions and accountabilities for the Works Programming and Delivery group.

Table 2.3: Works Programming and Delivery functions

TEAM	KEY RESPONSIBILITIES INCLUDE
Works Delivery	Delivery of network capital programmes/projects Delivery of maintenance programme Delivering standard and strategic customer-initiated works
Programming and Scheduling	Programme/project expenditure reporting Programme/project scheduling Oversee work programming and service delivery portfolio
Contracts Performance	Negotiate service provider contracts Develop and manage supplier relationships with Field Services Agreements (FSA) partners and other contractors Maintaining contractor management plans Contractor performance Contract management (extensions, variations, renewals)
Network Procurement	Procurement of major plant and network equipment Critical spares process Preparation and evaluation of tender programme
Health and Safety	Field auditing of contractor health and safety performance

Technology and Information

The Technology and Information group is responsible for ensuring the required information, communications and technology is provided and operated efficiently. It supports network asset management by providing current and accurate information about the extent and performance of the network and assets.

The group is responsible for monitoring technology, customer and industry trends, assessing the effectiveness of new technologies, and determining the optimum time to implement those best suited to meet business and customer needs. This includes ensuring technology and information plans provide effective direction to network performance and asset management planning and delivery.

The group provides cyber security capability to safeguard corporate and network systems. We discuss our approach to managing our IT assets in Section 9 and Appendix E.

Accounting, Finance and Regulatory

The Accounting, Finance and Regulatory group is responsible for coordinating financial planning and business performance reporting, the maintenance of a company-wide risk management framework, business assurance programmes and cashflow management to ensure financial resources are available and utilised effectively in the business. The team manages our key accounting processes of accounts payable and payroll, and it maintains internal control procedures to support the achievement of efficiency objectives, timely and accurate financial reporting, risk assurance and legislative, regulatory and taxation compliance.

The group provides strategic and financial planning support to the CEO and executive leadership team. Responsibility for non-network expenditure on premises and lease commitments in respect of property, plant and equipment also sits with this group.

The group also maintains our commercial relationships with major connected customers and retailers, as well as other interested parties, such as distributed generators. The team is responsible for managing commercial agreements. It collects data associated with consumer connections to the network and provides advance information on customers' growth intentions to support effective planning. The group ensures that pricing strategy and the associated pricing methodology is fit-for-purpose, and that pricing outputs are compliant and generally fair.

Further responsibility includes monitoring the development of regulation, preparing appropriate submissions to regulatory consultations, and conducting appropriate analysis to ensure that the impact and risk of regulatory change is understood. This includes ensuring regulatory control processes and procedures are developed and deployed across the business, to ensure regulatory compliance.

People, Customer and Sustainability

The People, Customer and Sustainability group is responsible for managing stakeholder and customer interfaces within the organisation and reflecting these in stakeholder engagement and communications plans. The group ensures that stakeholders, including the community and customers, have opportunities to provide feedback and input into future network investment plans, and to proactively share information about Aurora Energy's work and how it benefits them. The information we provide is informed by relevant information about the operation, performance and future development of the network.

The group is responsible for the development, design and implementation of people-related frameworks, policies and practices to attract, align, develop, engage and retain quality people to deliver business goals and help facilitate the development of desired organisational culture.

Partnering with senior managers, the group drives cyclical activities, development planning, performance management, remuneration and rewards, talent management, retention, succession planning, and measuring employee engagement. This includes providing advice, guidance and coaching to managers and staff in relation to people-related matters, ensuring consistency of policy application and legal compliance.

2.2. OUR STAKEHOLDERS

Effective consultation with our stakeholders is a key component of our asset management plan. Stakeholder engagement allows us to communicate our approach to managing our assets, and it helps to identify priorities and concerns that can then inform our own decision making. Within our AMP, we aim to provide sufficient detail to explain our plans and decisions in a way that enables interested parties to understand our approach to asset management and the drivers behind our investment decisions. Our AMP outlines our investment focus over the planning period and explains how we prioritise specific works. Within the AMP, we aim to provide all supporting information in a clear and straightforward document.

Our key stakeholders include:

- electricity consumers
- new connection customers and their agents
- landowners and communities hosting our assets
- Transpower, electricity retailers and distributed generators
- our regulators: Commerce Commission, Electricity Authority and WorkSafe
- Government agencies
- property developers
- territorial authorities
- our staff
- contractors and service providers
- shareholders and the Board
- media

In Chapter 4, we explain how we accommodate these stakeholder interests in our asset management framework and investment decisions. In some cases, each of our stakeholder groups may provide contrasting interests. If a conflict between stakeholder interests is identified, then we will endeavour to provide a suitable resolution. Ultimately, our Board decides the most appropriate means to remove any significant conflict between stakeholder interests. In some cases, the Utilities Disputes is an appropriate entity to help resolve conflicts.

Below we provide further context on some of our key stakeholders.

2.2.1. Electricity Consumers

Electricity consumers are our primary focus. We identify their needs through surveys, feedback, and direct interaction. While there may be diversity in the level of service sought by some groups, our customers tend to be concerned with four main aspects of our service: safety, reliability, cost of the service they receive, and the level of customer service and communication we provide.

We have sought to reflect these views within our investment plans and across our priorities for the AMP period, and in particular our CPP Period investment plans. We discuss the views of customers in further detail in Section 2.3.3.

As part of our mid- to long-term planning, we are also conscious of responding to the changing needs of electricity consumers. Future investment plans will need to accommodate factors such as climate change, population growth, and the adoption of future technologies such as electric vehicles, DERs, and large scale industrial/commercial activity. Meeting these challenges will be particularly important to ensure the nation meets its 2050 goal of net-zero carbon emissions.

2.2.2. Communities

We have a responsibility to the wider community in which we operate, and its needs are a critical focus for us. Using a number of channels, we seek to develop a better understanding of the community's needs and concerns, which we believe centre on network resilience, safety, and the impact of our assets on the environment. These issues are important to us and are reflected in our approach to managing our assets and planning future investment. Our objectives and approach for public safety, environmental issues and resilience are described in Chapter 4.

2.2.3. Retailers

We frequently communicate with retailers through our operational, billing and payment interactions and regular consultation. We understand retailers' requirements of us as an electricity distributor. These requirements include: the delivery of effective business-to-business services; use of transparent, simple and appropriate network tariff structures and prices; and fair contractual arrangements. We view retailers as customers in their own right and representatives of end-consumers.

The retail market is undergoing considerable change. We expect retail competition to intensify, become more sophisticated and require further segmentation. These changes will likely occur during the coming AMP planning period.

Working with retailers to ensure a simple and effective energy supply for customers is a key part of what we do. We also ensure that retailers understand the impact of their business approach on our operations. An example would be the retailers' approach to accommodating technologies such as solar and electric vehicles (EVs), which may impact our network and require changes to our pricing approach or demand forecasting methodology.

2.2.4. Regulators

As an electricity distribution business, our operations are subject to regulations established under New Zealand Legislation, including the Commerce Act and the Electricity Industry Participation Code. The rules are primarily administered by the Commission and the Electricity Authority.

The Commission is our economic regulator and manages regulations around price-quality performance and disclosure of relevant information (Information Disclosure). Our 2023 AMP is a key document to demonstrate to the Commission our long-term plans for managing network assets. During the CPP Period, the Commission requires us to provide additional information requirements in the form of development plans and annual delivery reports.

The Electricity Authority is responsible for regulating an efficient electricity market and other related aspects of an electricity distribution business, such as pricing structure and commercial agreements with retailers.

WorkSafe is responsible for regulating workplace safety and electrical safety.

2.2.5. Transpower

We distribute electricity to consumers, the majority of which we receive via five grid exit points (GXPs), located across our network areas. These GXPs are owned by Transpower, the New Zealand transmission company. We discuss these GXPs and how we connect to them in Chapter 3.

Transpower also holds the role of system operator, giving it responsibility for, amongst other things, maintaining the integrity of the electricity system, including the coordination of electricity generation and demand.

We consult with Transpower on our respective investment plans, commercial relationships, and other industry issues. We have established systems and protocols with the system operator to facilitate immediate communications for operational issues and incidents.

2.2.6. Service Providers

Service providers are essential to our ability to supply electricity distribution services to consumers. Accordingly, we are focused on ensuring they perform and deliver the services required of them in an effective and efficient manner. They in turn require our interactions with them to be predictable, transparent, and commercially sound.

To achieve stable, efficient use of resources we review and refine our forward workplan. This enables our service providers to be effectively and efficiently deployed. This is a key part of managing future work deliverability.

2.2.7. Our Staff

Our staff are the driving force behind our business. Our staff value job satisfaction, a safe, flexible and enjoyable working environment, and being fairly remunerated for the work they perform.

As we develop our asset management approaches, we are placing increased emphasis on effective internal communication and staff engagement in the delivery of our asset management activities. These requirements will be expanded as we progress our internal competency framework and extend these to external parties working on our network.

We strive to be a good employer and have incorporated health and safety, flexible working, wellbeing initiatives, performance reviews, and forward work planning so that staff can maintain an appropriate work/life balance.

2.2.8. Other Stakeholders

We also interact with a range of other stakeholders. These include Waka Kotahi, the New Zealand Transport Agency, and territorial local authorities that frequently require us to move our lines or cables for road projects. House relocation organisations may also require us to switch off our lines during their operations. Developers require us to provide connection services to housing developments.

2.3. CUSTOMERS

Aurora Energy distributes electricity to over 93,600 homes, farms and businesses in Dunedin, Central Otago/Wānaka and Queenstown Lakes. Safe and reliable electricity supply is at the heart of everything we do.

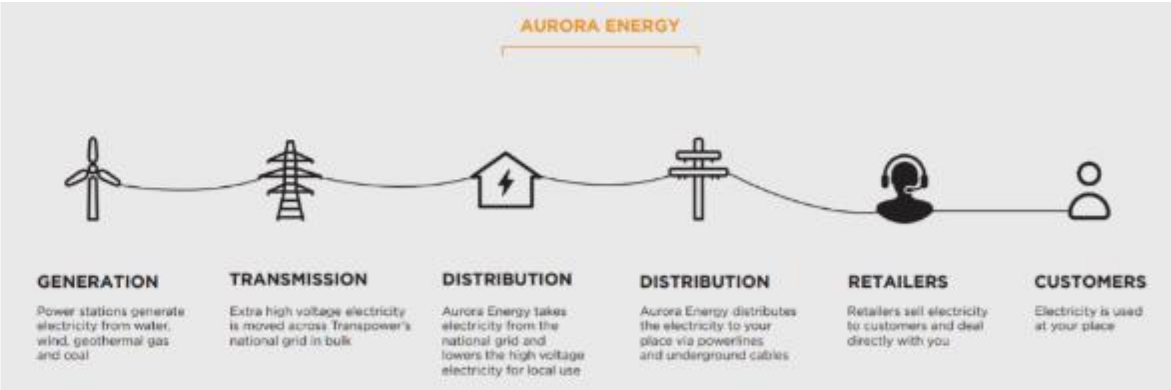
We are continuing to build Aurora Energy as a consumer-centric business, with people at the centre of day-to-day decision-making and planning.

As one of the largest electricity distributors in New Zealand, we play an important role in supplying consumers with reliable electricity now by maintaining the health of the existing network, as well as upgrading the network and positioning it for the future.

The drive for decarbonisation and a more sustainable way of life means we must be ready to invest at the right time. A robust and efficient electricity network is central to this rapidly changing future, which is why our investment programme is so important. We know electricity users want an affordable energy supply that supports their changing lifestyles and energy needs.

Consumer expectations about the reliability of their supply continues to grow and, given the amount of work underway, it's imperative that we keep electricity users and communities informed about the status of work in their local area. In addition to excellent customer service, consumers increasingly expect accurate and timely information about their service.

Figure 2.3: Our role in the electricity sector



Like most EDBs, we operate an interposed model. That means retailers purchase our services, combine them with energy supply and the cost of accessing the transmission grid, and provide a bundled price for delivered energy to their customers. Currently, over 20 retailers sell electricity to end-consumers on our network. Generally, retailers are responsible for collecting revenue on our behalf and maintaining direct contractual relationships with end-consumers.

2.3.1. Residential and Small Commercial

The majority of our connections (approximately 99%) fall into this category, which includes residential consumers and small-to-medium enterprises. These consumers typically buy bundled energy supply services directly from retailers and may not be fully aware of our electricity distribution role within the industry. This is a situation we are actively trying to improve, for example, by publishing relevant information on our website and on social media, in our bi-annual community update 'Your Network, Your News', at events, and in other communications materials where relevant. We also plan to work more closely with retailers in the future.

Service expectations vary, depending on where the consumer lives (rural or urban) or their recent experiences of reliability. Customer satisfaction survey results show that having a reliable electricity supply, and our ability to keep consumers informed with accurate and timely information if there is an unplanned outage, is what people value the most. We are working to improve the accessibility and quality of information about unplanned outages.

Growth in our mass market consumer base has been closely tied to population and is regionally diverse across our network. Our networks in Queenstown Lakes and Central Otago/Wānaka continue to see significant growth and we will need to continually revise our growth projections for this region (see Chapter 6). Historically, the number of connections on our Dunedin network has been stable and we expect this to continue in the medium term. The potential changes in consumer numbers and demand means we need to continually refine our forecast load estimates.

Our approach to connecting new consumers to our network is discussed in Chapter 6.

2.3.2. Major Customers

Our major customers are from the healthcare, farming, food processing, transport, manufacturing, tourism, council and university sectors. Growth in this category is closely tied to general economic growth as indicated by GDP.

Open dialogue with major customers is important to ensure we understand their business needs so that we can better meet their supply requirements. We engage directly with them on their future investment plans, as increases in their capacity needs can have implications for our network development investments. Our growth and security investments during this planning period, discussed in Chapter 6, have been informed by such discussions.

Due to the size and complexity of their operations, our major customers often have more specific service requirements than residential customers. The timing of outages and degree of notice provided (in the case of planned outages) can have significant operational and financial impacts on these customers. We plan to continue building our relationships with large consumers to help us better understand their needs and factor this into our planning and have introduced Customer Outage Guidelines to help mitigate impact early in the planning process.

Chapter 3 provides further detail on our larger customers.

2.3.3. What Customers tell us they care about

As discussed above, we have a diverse consumer base, comprising residential, rural, commercial and industrial consumers across a large area of the South Island. In the lead up to our CPP application, we carried out comprehensive engagement and research on what consumers value and expect in their electricity supply and from Aurora Energy as their lines company.

Since then, we have conducted a benchmark customer satisfaction survey in the 2021-22 financial year (FY22), which will be followed by annual surveys involving a panel of consumers so we can measure our performance throughout the CPP Period. See more in the 'Customer Surveys' section below.

Based on the customer satisfaction survey carried out during FY22, as well as engagements during the CPP and previous research, we know that consumers care about:

- **Reliability**: a reliable electricity supply is directly linked to the level of trust consumers have in Aurora Energy. Residential consumers care more about power outages in winter and/or evenings. Business consumers are most concerned about outages during business operating hours.
- **Good communications:** consumers value timely and accurate information about their supply, including information on planned outages, and expect that information should be readily available through a number of channels. If there is a power outage, people want to be kept up to date with accurate information about when the power is likely to be restored and what caused the fault. Consumers are generally more understanding about not receiving direct communication when the power goes out due to circumstances beyond our control. Information regarding planned outages is critical to business consumers due to the potential financial losses associated with outages during their operating hours. It has become more important to residential consumers also, due to increased numbers of people working from home following the COVID-19 pandemic.
- **Maintenance programmes/network upgrades:** Consumers are interested in what maintenance and network upgrade projects are planned for their area.
- **Responsiveness**: responding quickly to issues on the network is key to reducing their impact and lessening potential safety and reliability risks. This is achieved through coordinated activity by our network operations teams and our service providers.
- **Affordability**: while the industry structure can mean consumers often do not associate their monthly bill with the cost of providing a safe and reliable service, we know they are conscious of cost increases for what is an essential service. Where line charges need to increase, consumers have a strong preference for smoothing any increase over time versus sudden step changes. With upcoming distribution pricing changes across the industry, we will need to help consumers understand what this means for them.
- **A safe network**: we know delivering electricity safely to consumers is important to them and other stakeholders.
- **Resilience**: consumers value a network that can speedily recover from shocks such as natural disasters like storms and earthquakes.

We also asked consumers about future trends and green technologies. They told us that:

- **Electric vehicles**: environmental benefits, running costs compared to combustion engine vehicles and charging convenience all make EVs attractive, however price is preventing some people from purchasing one.
- **Roof-top solar**: While PV is of interest, costs and sunshine hours were mentioned as barriers to considering solar panels as an alternative to network-supplied electricity. Those who were interested talked about generating and using their own energy, and being an environmentally friendly alternative, as reasons for why they would consider solar.

- **Future trends**: People can see the possibility of climate change affecting energy use, the rise of alternative energy resources impacting electricity infrastructure, and increased population and housing impacting electricity demand. Residents living in the Queenstown Lakes area, people under 45 years old, males, and consumers who have experienced a disrupted power supply, were more likely to be interested in or already own green technologies.

Customer Advisory Panel (CAP)

In June 2019, we established a Customer Advisory Panel (CAP) to advise on and present the perspectives and preferences of consumers. The CAP members represent a range of consumers across our network and the diverse interests of the community, including residential, industrial, commercial and rural electricity consumers. The CAP includes members from organisations including Chambers of Commerce, district/city councils, Grey Power, Cosy Homes Trust and Federated Farmers.

The CAP's primary focus was to provide meaningful input into our CPP proposal and it continues to be utilised, with a half-day workshop held in November 2021 on our proposed changes to electricity distribution pricing. We intend to continue engagement with the CAP when relevant and will involve the members in the upcoming customer charter and consumer compensation scheme consultation.

Customer Voice Panels (CVP)

In addition to the CAP, we also engaged three Customer Voice Panels (CVPs) in Dunedin, Cromwell and Queenstown. CVP members represent a cross-section of age, gender, employment and socio-economic demographics of our consumers, and provide valuable insight into consumer opinions and expectations. The CVPs are different from the CAP in that the members are consumers, compared with CAP members who represent groups/communities. Also, CAP members tend to have a broader understanding of the electricity distribution sector than the CVP members.

The CVPs also continue to be utilised, with two-hour workshops held in November 2021 on our proposed changes to electricity distribution pricing. We will engage them for the upcoming customer charter and consumer compensation scheme consultation.

2.3.4. Customer Surveys

We carried out a benchmark customer satisfaction survey in FY22 to help us understand if we are meeting the needs of our consumers and to see if there are areas where we need to improve and/or make changes. We will hold annual surveys with a consumer panel throughout the CPP Period so we can measure our progress.

Findings from the FY22 customer satisfaction survey were broadly consistent with similar surveys undertaken in previous years and include:

- Awareness of Aurora Energy as the lines company has remained steady, with around a third of residents able to name Aurora Energy (higher for business consumers)
- Both residents and businesses indicated similar levels of low knowledge. 60% of residents and 61% of business consumers know nothing or very little.

– Performance and service rated moderately. Those who rated performance poorly were concerned about the need for network maintenance and upgrades.
– Four in ten residents/business respondents trust Aurora Energy. Reliability was the overwhelming reason for positive trust levels while maintenance/network upgrade issues and (historic) poor management were cited as reasons to not trust Aurora Energy.
– The majority of consumers (both business and residential) who experienced power outages were satisfied with the fixing of the outage and the response from Aurora Energy/Delta.
– There was some low-level interest expressed in future technologies such as electric vehicles, solar panels and storage batteries by both residents and business. Smaller businesses (1-4 staff) were more likely than larger businesses to express interest in or already own green technologies.

Customer Service Initiatives

We continually listen to feedback from consumers and look for ways we can improve their experience and how we engage. Our focus areas are outlined in Box 2.2.

We have published a Customer Charter on our website, setting out our commitments to consumers, including safety, consumer feedback, complaints resolution, responsiveness, and quality of service. We are the only EDB in New Zealand that has a customer charter, and we have started a review of our current charter based on input from the customer satisfaction survey. The review will be followed by extensive consultation both internally with Aurora Energy staff and externally with our consumers (utilising the CAP and CVP as well as public consultation), so we can refine and update our commitments to consumers to ensure they are fit for purpose, measurable, and can be reported on.

Box 2.2: Customer service initiatives

We have developed a set of initiatives to improve the effectiveness of our consumer engagement:

– Multi-channel approach to provide regular updates on Aurora Energy's works programme
– Public safety campaign/communications
– Website redevelopment to provide a better user experience based on user research (due to be launched early 2023)
– Attendance at public events such as A&P shows and hosting BA5 events with the business community
– Multi-channel approach to promote public safety messages and outage notifications
– Development of a brand narrative to help consumers better understand who Aurora Energy is and what we do (to be integrated into all communications where possible)
– Improved processes and notification for outages
– Community relations programme – working directly with communities impacted by multiple power outages
– Improvements to our customer-initiated work processes

We continually review, refine and update our public communications about our network and its performance, to ensure we have regular and open engagement with our communities as well as provide avenues for feedback. We are integrating reporting requirements for our CPP into our 'business as usual' communications to show we are committed to deliver on our promise to upgrade the network.

We also have a regular schedule of communications across a range of channels to ensure we are communicating with consumers using the channels they prefer. This includes network updates, outage notifications, public safety campaigns and recruitment.

We have an ongoing campaign, targeted at both contractors/tradespeople and residential consumers, to increase public awareness of electricity network hazards and to engage the community in understanding electricity safety. We commenced a review of the safety campaign during 2022 and will update it to ensure it is still relevant and engaging, and to target safety messaging more effectively.

We have improved the information consumers receive when their power is interrupted and are enhancing website information on outages – the number one reason consumers visit our website. Fault calls are now answered by our call centre, Telnet, on a 24/7 basis, resulting in shorter waiting times, and introducing an interactive voice response (IVR) system has also improved the customer experience by uploading messages about current outages, further reducing call wait times.

Any outage is inconvenient for consumers and, due to our increased work programme, there will be an increase in planned outages for a number of years. To ensure consumers are at the centre of planning, we have developed outage guidelines to minimise the impact on consumers. We continue to refine outage planning processes and work on ways to improve notification on planned outages to our consumers.

Our community relations programme enables us to work with communities that are impacted by multiple outages, and we have found that upfront communications about what work is planned and the benefits of the work help to provide context around why multiple outages may be required, and that bundling work together where possible means fewer overall outages. We aim to support those communities where we have carried out major projects as a way of thanking consumers and showing we appreciate their support while we upgrade the network in their area.

We're looking at how to stabilise and improve the reliability of electricity supply in areas that have worse-than-average performance and how we can be proactive in keeping consumers informed. This project is still being developed and we look forward to seeing outcomes that will benefit consumers.

We continue to refine our approach to facilitating consumers connecting to our network. Our connection team has automated the application process for individual consumers and online guides are now available to simplify the process. Our existing delivery model is now outsourced, with an internal processing team to manage the overall experience for the consumer through the establishment of hybrid connection staff roles. We will continue to automate our processes and also look to improve functions including decommissioning, distributed generation applications and larger network connections. We also plan to strengthen our relationships with key major consumers and service providers working in this industry. We now regularly engage with our connection contractors to ensure safe practices and timely service provision on consumer projects. Strong growth in new connections continues across the region.

We continue to focus on the consumers and communities we serve, building our community engagement through a series of planned engagement events. We are taking a more proactive approach to community engagement and have developed a calendar of events that staff will attend to engage with the communities we serve in a positive and proactive manner.

This AMP is a further opportunity for stakeholders to let us know how we are doing. We welcome feedback on the plans set out in this AMP or any concerns that our stakeholders may have.

Over time, we plan to publish a series of substantive updates on our network and its performance. These regular, open engagements will help stakeholders to provide input into our future plans and performance objectives. Details on these engagements will be published on our website and in our bi-annual community update, 'Your Network, Your News'.

Customer Service Practices

Aurora Energy aims for continual improvement of customer service practices in order to meet consumer expectations. Feedback received through customer satisfaction surveys is analysed, and customer service initiatives that are implemented (see previous section) are designed to reflect this feedback. Two-way engagement provides other avenues for consumers to tell us what they think and for Aurora Energy to act on this, with a number of opportunities for this outlined in the initiatives designed to communicate and engage with consumers.

Protocols are being introduced to regularly review complaints to identity potential themes where improvements to systems, processes or customer service may prevent situations occurring that could result in a complaint.

A robust complaints process that includes target timeframes for response and resolution ensures all complaints are captured, resolved and reported on. It is clearly communicated across a range of channels that consumers can seek advice from Utilities Disputes if they are unhappy with the response that they receive from Aurora Energy.

2.4. FURTHER CONTEXT FOR OUR 2023 AMP

Reflecting our ongoing asset management improvement programme, this 2023 AMP builds upon our previous full AMP from last year. We continue to offer an expanded amount of detail about our investment plans to reflect the significant work required throughout our CPP Period.

We continue to deliver a growing investment programme to ensure our network is safe and reliable for the Dunedin, Central Otago/Wānaka and Queenstown communities. Our network investment priorities remain on asset renewal, maintenance and condition assessment to reduce backlogs of poor condition assets. This work will stabilise the overall health of our asset fleets and stabilise network reliability performance.

This section sets out an overview of key factors that have impacted our approach to asset management over the planning period.

2.4.1. Asset Safety

Safety of our assets is our uncompromised objective. Prior to our current CPP Period we experienced a lengthy period of underinvestment, which led to deteriorating safety due to poor asset condition. Our CPP application was developed based on one top target: to ensure safe operation of our network assets. We recognised that one of the most effective ways of improving safety of our assets has been removal of unsafe assets from operation with their replacement with newer and/or safer alternatives. We stay committed to the safety goal, however, we also recognise overall improvement of the performance of our network as a secondary benefit of the aggressive asset renewal programmes.

We also place considerable importance on reducing the risk of wildfires around our network assets, particularly in fire prone areas around Central Otago. During fire seasons, we limit operation of assets which may cause any sparking, we dedicate more time and resourcing to those areas of our network that are marked with a higher wildfire criticality according to the advice we receive from FENZ. We are in the process of developing a fire risk framework, which will inform our asset replacement programmes, including additional inspections, prioritised defect remediation and vegetation management.

We describe safety-based decision-making in detail in Chapter 5.

2.4.2. Regulatory Context

Electricity distribution businesses such as Aurora Energy operate within a regulatory framework administered by our sector regulator, the Commerce Commission. The framework specifies the level of revenue we can recover and sets out minimum quality standards in terms of supply interruptions.[1]

On 01 April 2021, Aurora Energy moved from the default price-quality path (DPP) regime to a CPP regime. A CPP provides a mechanism for the Commerce Commission and stakeholders to review and have a say on an EDB's proposed investment and the potential impact on consumer pricing before it finalises its investment plans. A regulated business can apply for a CPP if it believes its current price-quality path does not meet its needs, particularly its future investment needs. As a part of moving to the CPP, the Commerce Commission set a customised revenue allowance and quality standards for Aurora Energy to enable us to fund the investment needed to maintain a safe and reliable network.

We are now entering the third year of our five-year CPP Period.

2.4.3. Industry Relationships

We actively seek higher knowledge of successful EDB practices through engagement with the wider energy industry, including the Electrical Engineers' Association (EEA) framework and direct communication with professionals. We also collaborate with the Electricity Networks Association and the Southern Distribution Group to learn and coordinate our response to future energy market

[1] Some consumer-owned EDBs are subject to a more limited regime based around Information Disclosures.

challenges. This helps us to achieve better results for our customers through more efficient delivery of our business objectives.

2.4.4. Impact of COVID-19

At this point, we are in a position to better understand the impacts of COVID-19 on our work programmes in the short-term and our demand-driven investments over the medium term, even more so now the pandemic is over and we are living with COVID-19 within the community. In previous AMPs, we had deferred growth investments in a number of areas to reflect the expected downturn in demand. For this year's work plan, we have a better understanding of network growth and development under COVID-19, and our forecast investments have been tailored/accelerated to meet steady post COVID-19 growth.

2.4.5. Our Energy Future

To meet the nation's 2050 net zero target, He Pou a Rangi (the Climate Change Commission) has recommended an overall transition away from fossil fuels towards renewable energy. Coupled with greater cost efficiencies and pricing incentives, we anticipate greater uptake from our customers toward new technologies such as electric vehicles and distributed energy resources (DERs).

During the planning period, we are taking steps to evolve our network to accommodate decarbonisation-driven electrification. In the Upper Clutha region, we are currently trialling the use of third-party DERs as a non-network solution to meet our increasing electricity demand. As an alternative to significant network investment, the solution allows us to meet peak demand by utilising the electricity stored in consumer-owned batteries. For more on the Upper Clutha non-network solution, see Chapter 6: Network Evolution.

As more consumers become electricity generators, the safe control two-way power flows will place added pressure on our LV distribution network. As such, we are placing greater focus on our LV network so that we can identify potential capacity constraints.

We have identified environmental risks for specific asset fleets and have begun to modify our investment plans to suit. For example, we monitor transformers and oil-filled cables for leaks and perform maintenance and renewals when required.

2.4.6. Climate

Prevailing weather, particularly extreme conditions (E.g. wind or snowstorms), can have a significant impact on the condition and reliability of our assets. Central Otago has a continental climate with hot summers, cold winters, and low humidity. These conditions are relatively benign for metallic assets (E.g. conductor), with low levels of corrosion compared with the maritime climate in Dunedin.

Weather-related events contribute to the incidence of interruptions to our customers, particularly in rural areas. This is due to the presence of overhead lines and outdoor assets which are subject to interference from vegetation and windblown debris, and failure during weather events.

The Cromwell, Alexandra and Roxburgh areas have very low relative average rainfall but the availability of water in the region's lakes makes irrigation a viable option for agriculture. This demand for irrigation (pumps) drives investment in additional capacity.

Extreme weather will present challenges to the resilience of our network in the coming years. In addition to improving the condition of our network assets, we will also consider alternative solutions such as microgrids and distributed energy resources to provide additional security of supply to at-risk areas. We will consider these options more closely as part of future investment plans.

2.4.7. Land Access

Our ability to gain access to existing assets or obtain land for new assets is critical to timely and effective asset interventions. We have been granted certain rights under the Electricity Act for assets built prior to 1992 to remain where they are currently located. We are also entitled to access road reserves under the relevant council's conditions.

We acquire easements when installing new assets on private property to formalise the respective parties' legal rights. Obtaining the rights is usually straightforward when a private landowner will directly benefit from providing access, as in the case of a new connection. However, obtaining access for new assets to transit private land is often challenging and can impact our project planning. As such, we begin work to obtain the necessary land access rights as soon as practical in the planning process. We aim to minimise (as far as practical) the amount of land access required as changes in access requirements can cause additional expense and delay in the delivery of new assets.

2.4.8. Improvements to our Asset Management Capability

Building on our most recent self-assessment of asset management maturity (AMMAT), and inputs from stakeholders, we are continuing with our development plan to improve our asset management processes and capabilities.

Over the planning period we will focus on improving staff competency, developing fit-for-purpose systems, and adopting proven innovations. This includes further improvements to our risk management approach as we progress through the CPP Period. Further refining our asset health modelling and embedding a network-wide criticality framework will be key elements of this approach. These initiatives will enable targeted interventions and better inform our renewal forecasts over the planning period.

As discussed in Chapters 4 and 9, we have updated and revised our AMMAT assessment following an internal review of our current capability. The resulting modest increase in our overall score reflects our initial focus on building an asset management team and the foundations for future improvement. We continue to be open and transparent about our current capability and we plan to put in place a series of initiatives to improve key areas in future.

Our aim is to ensure our asset management is consistent with leading New Zealand practice. We are progressing towards our goal of having an ISO55001 aligned Asset Management System. Periodic reviews against ISO55001 will enable us to monitor and demonstrate our progress to stakeholders. Chapter 9 provides further detail on our asset management development plan.

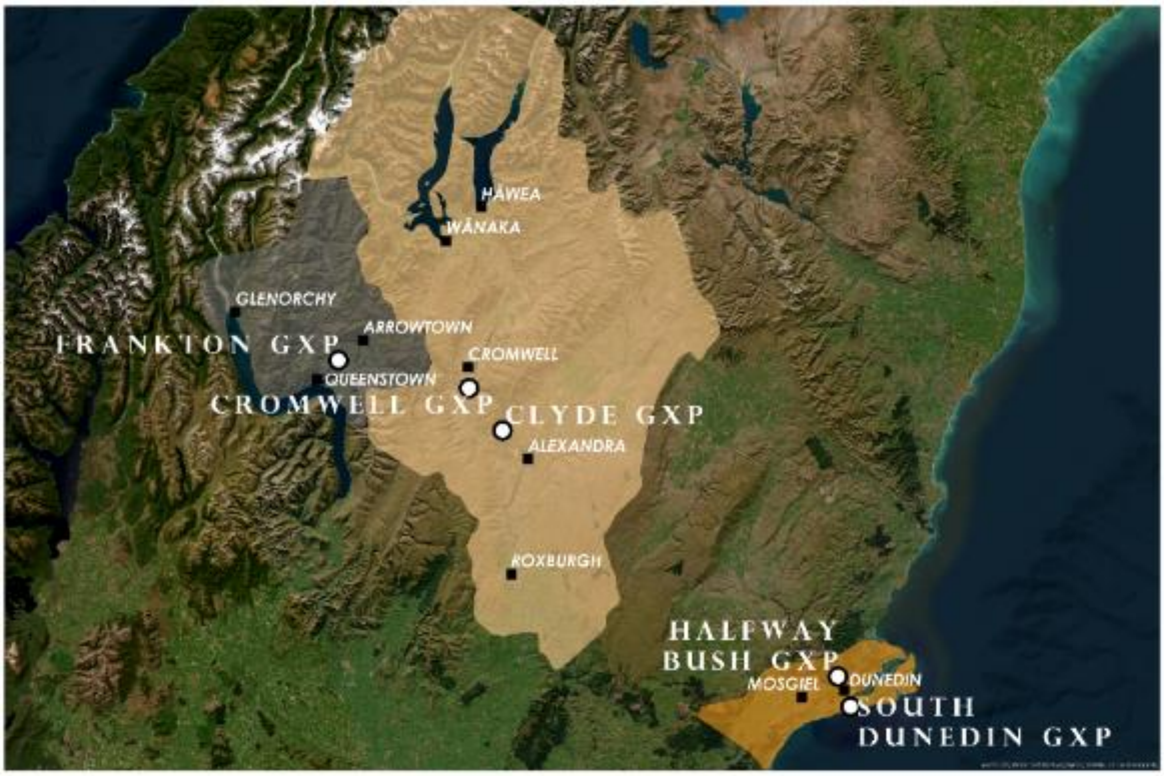
3. NETWORK OVERVIEW

This chapter provides an overview of our networks and briefly introduces the assets we manage. It sets out how our network is configured including its connections to the national grid, and a profile of the major customers on each of our networks.

3.1. BACKGROUND

We own and operate two non-contiguous distribution networks that supply electricity to around 93,600 homes and businesses in Dunedin and Central Otago. Our network is shown in Figure 3.1. These networks include the power lines, poles, underground cables, substations and transformers that take electricity from the national grid to the homes, farms and businesses we supply.

Figure 3.1: Aurora Energy pricing regions including major towns and GXPs



Queenstown Pricing Region Central Otago and Wanaka Pricing Region Dunedin Pricing Region

Like many other networks in New Zealand, our infrastructure has developed along with the local population and industry, spanning over 100 years. As a result, large portions of our network are now due to be renewed. Over the next 10 years we need to make significant investments to maintain and renew our distribution network whilst catering for growth and security of supply.

We have two regional networks, Dunedin, and Central Otago, with five distribution networks fed from Transpower Grid Extraction Points (GXPs) as listed below:

DISTRIBUTION NETWORK	SUB-NETWORK	GXP
Dunedin Network	Dunedin	Halfway Bush South Dunedin
Central Otago Network	Central Otago and Wānaka	Clyde Cromwell
	Queenstown	Frankton

In the following sections we discuss each sub-network in further detail, including network configuration, typical load characteristics and major customers.

The two Dunedin networks are the oldest networks – Halfway Bush and South Dunedin. The development of these networks started around 1910, although there were pockets of electricity supply before that. The three Central Otago networks – Frankton, Cromwell, and Clyde – were mostly developed after 1960, although these also include pockets of older assets.

Our Dunedin and Central Otago networks supply close to 56,300 and 37,300 customers, respectively. Both networks include a number of major and smaller industrial and commercial connections. In Dunedin, these mostly relate to the city infrastructure, including the port, university, and local council operations. Large consumers on our Central Otago network include tourism, irrigation, and council loads.

Figure 3.2: Energy throughput and GXP peak demand

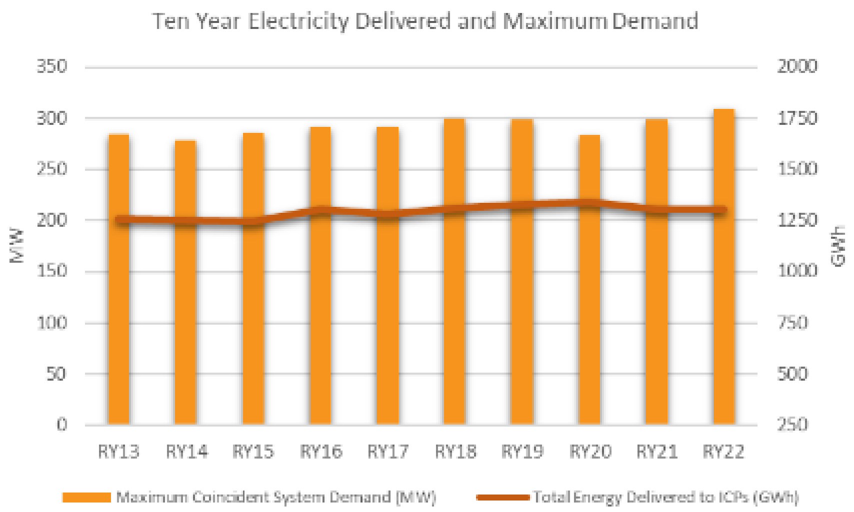


Figure 3.2 shows the electricity delivered to the ICPs and system peak demand in the last 10 years. The graph shows that the peak demand has progressively increased from RY20 (due to the pandemic).

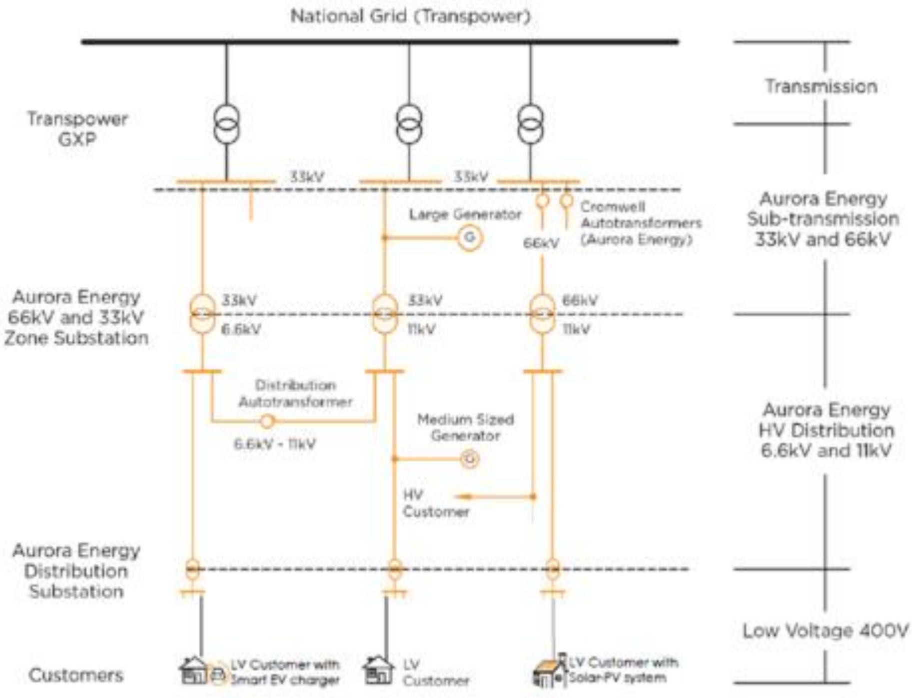
3.2. NETWORK CONFIGURATION

Our network is hierarchical in nature, with lines and cables operating at three distinct voltage ranges:

- sub-transmission: operating at 66 kV (minority) and 33 kV
- distribution: generally operating at 11 kV in Central Otago and 6.6 kV in Dunedin
- low voltage (LV): operating at 400 V three phase or 230 V single phase.

Figure 3.3 provides an example single line diagram illustrating the various voltages through which power is supplied and transformed from the national grid to end-consumers.

Figure 3.3: Representative single line diagram



Our sub-transmission network conveys electricity to our zone substations that supply our distribution network, which in turn supplies our low voltage network. Our sub-transmission network has two operating voltages, 66 kV and 33 kV. We use 66 kV where there are long distances between GXPs and zone substations, as this reduces line losses incurred. Currently, we only use 66 kV in parts of the Cromwell network while the rest of the sub-transmission network is operating at 33 kV.

As of 31 March 2022, the Dunedin sub-transmission network runs for a total of 210 km, with 144 km of that overhead. Our Central Otago sub-transmission network is largely overhead with a total length of 402 km, with 22 km of underground cable and 380 km of overhead line.

Our zone substations convert the sub-transmission voltage to 11 kV and 6.6 kV. The majority of Central Otago network distribution voltage is 11 kV with parts of Clyde township at 6.6 kV. Most of Dunedin network is 6.6 kV with suburbs such as Outram, East Taieri and Mosgiel at 11 kV. The distribution voltage is further transformed by distribution substations (either pole mounted or ground mounted) to 400V/230V to supply homes, farms, and businesses.

The Dunedin distribution and LV networks are largely overhead, with 331 of 1,062 km of distribution and 302 of 1,113 km of LV network being underground. In Central Otago, 838 km of 2,394 km of distribution and 801 of 1023 km of LV is underground.

3.3. GRID EXIT POINTS

We receive electrical energy from Transpower's network at five points of supply, known as grid exit points (GXPs). These are Halfway Bush, South Dunedin, Frankton, Cromwell, and Clyde. These are the interface between Transpower's transmission network and our distribution network. There is redundancy (N-1) built into GXPs through duplication of supply, which means that the system can continue to function after a failure of one component.

Figure 3.4: GXPs and transmission lines (map from Transpower)

Table 3.1: GXP area stats

	HALFWAY BUSH	SOUTH DUNEDIN	FRANKTON	CROMWELL	CLYDE
Number of customers	35,300	21,000	15,100	14,600	7,600
RY22 Peak Demand (MW)	116	73	64	49.0	19
Zone substation transformers	22	12	14	8	8
Zone transformer capacity (MVA)	364	266	164	119	50

GXP sites are owned by Transpower, but we have some equipment co-located at each GXP. A list of this equipment is shown in Table 3.2.

Table 3.2: Selected Aurora Energy assets at GXPs

ASSET	HALFWAY BUSH	SOUTH DUNEDIN	FRANKTON	CROMWELL	CLYDE
Ripple control plants	2	1	1		
Buildings	2	1			

ASSET	HALFWAY BUSH	SOUTH DUNEDIN	FRANKTON	CROMWELL	CLYDE
Protection relays	Yes	Yes	No	Yes	Yes
SCADA and metering	Yes	Yes	Yes	Yes	Yes
Structures and air break switches	Yes	Yes	Yes	Yes	No
Other	33 kV cable gassing bank	33 kV cable oil reservoirs		2 x 30 MVA 33/66 kV auto-transformers	

3.4. DISTRIBUTED GENERATION IN OUR NETWORK

Distributed generation (DG) schemes have the potential to make a significant contribution toward meeting the electricity requirements of local customers. DG supports our network by reducing peak demand, enhancing security of supply, and by increasing efficiency and economy of network operation. However, DG can also produce adverse effects on the network, including harmonic distortion, localised congestion, voltage instability, safety issues and network reliability issues. Accordingly, care is required when approving new distributed generation connections. As such, we continually improve our small-scale and large-scale DG application process.

Guidelines and application information for the connection of distributed generation are published on our website: https://www.auroraenergy.co.nz. For each proposal we consider the likely effect of the distributed generation on our network.

For small scale DG (less than 10 kW) applications, we have aligned our process with Electricity Engineers' Association's (EEA) *Connection of Small-Scale Inverter-Based Distributed Generation (Interim Guide)*.

For large scale DG (greater than 10 kW), depending on the size, assessment of the impact of DG to the network is necessary. The processing timeframe is outlined in Part 6 of the Electricity Industry Participation Code.

Most DG connections are photovoltaic (PV), but PV-battery systems are gaining ground. The former generates electricity during sunlight hours but will not materially impact peak demand during winter evenings. However, the latter provides the consumer the benefit of using battery to supply its own load during peak times where electricity prices are high and sunlight hours are short. Also, the battery supply can fully or partially meet the customer electricity requirements during brownouts. Plus, battery systems also support NZ's goal of decarbonisation. These individual systems, when aggregated by a Flexibility Trader, can be called on to provide peak demand capacity support or other services to the electricity distribution business (EDBs). These multiple benefits are referred to as 'value-stacking'. This is further discussed in Chapter 6, Section 6.3.9.

As of 31 March 2022, the total generation connected to our network is 1846 MW with an aggregate installed capacity of 143 MW (46% of system maximum demand). Figure 3.5 shows the proportion of each type of generation, with hydro (89.3MW) and wind (38.3MW) at 62% and 27% share of the total capacity respectively.

Figure 3.5: Generation by type as of 31 March 2022

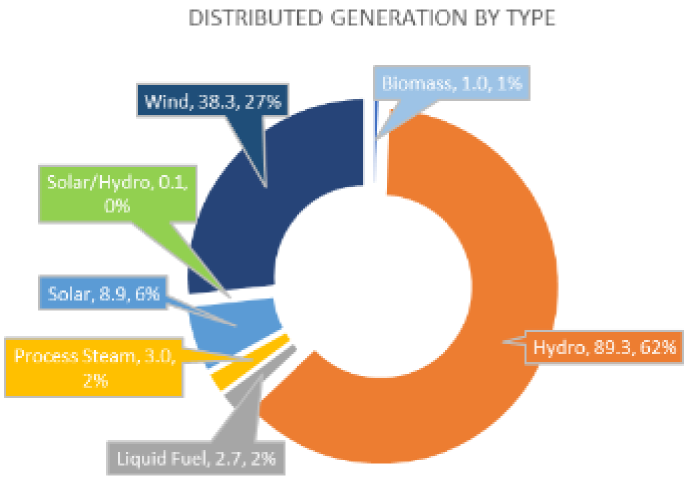
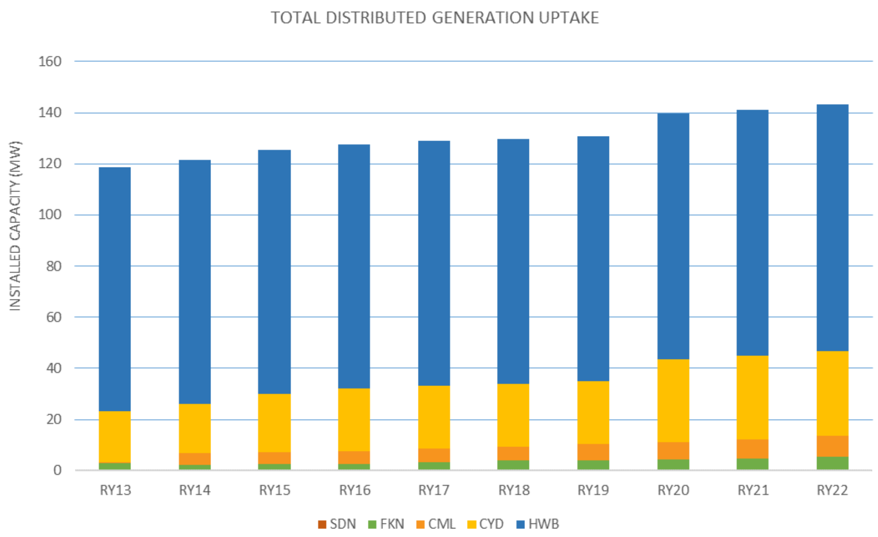


Table 3.3: Large embedded generations (1MW and above)

Name	GXP	Type	Capacity (MW)	Total per GXP
Waipori 33 kV, Waipori gen & Deepstream 1A, 2A	HWB	Hydro	53	95
Waipori 33 kV - Mahinerangi		Wind	36	
Ravensdown generation		Process steam	3	
Container Port (Port Otago)		Liquid fuel	2	
DCC wastewater treatment plant		Biomass	1	
Wye Creek	FKN	Hydro	2	2
Teviot stations	CYD	Hydro	12	32
Earnscleugh station		Hydro	8	
Horseshoe Bend		Hydro	4	
Fraser Generation		Hydro	3	
Horseshoe Bend Wind		Wind	2	
Talla Burn		Hydro	2	
Roaring Meg	CML	Hydro	4	4

Table 3.3 shows the list of large, embedded generation (>1MW) and Figure 3.6 shows the uptake of generation per GXP over 10 years.

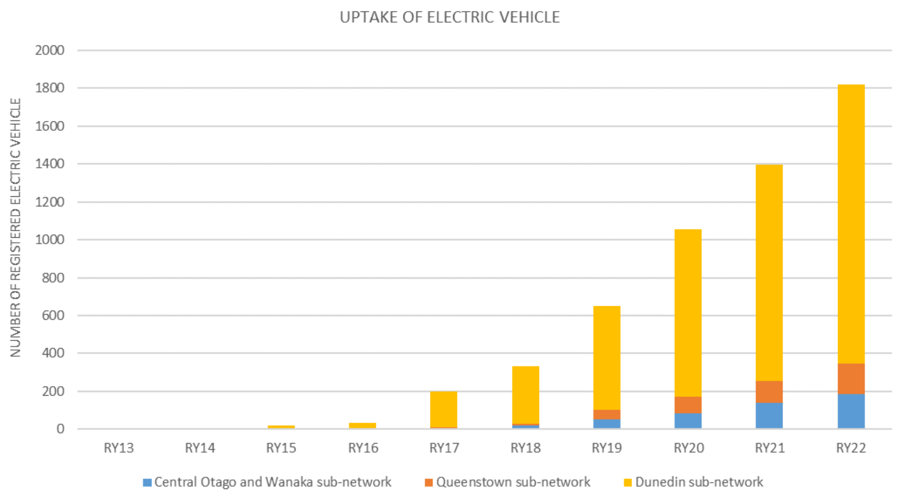
Figure 3.6: Total Generation uptake per GXP



3.5. ELECTRIC VEHICLES IN OUR NETWORK

The number of registered EVs in our network has increased considerably in ten years, as shown in Figure 3.7, with over 1,820 vehicles as of 31 March 2022. The Dunedin sub-network has the highest number of EV at 1,471 (81%) and in the last three years, averaged 306 units annual increase.

Figure 3.7: NZTA registered electric vehicles in our network



3.6. DUNEDIN SUB-NETWORK

Until the 1970s, Dunedin was supplied entirely from the Halfway Bush GXP. Construction of the South Dunedin GXP resulted in the network supply points from some zone substations being altered. The additional GXP provides some added resilience for the city's supply, however, this does not provide us the capability to transfer significant load between GXPs.

Figure 3.8: Dunedin sub-transmission networks

Most of Dunedin's sub-transmission is radial, where each zone substation is fed directly from the GXP. To attain N-1 security level (where the loss of one circuit can be taken up by the remaining assets), each zone substation has two zone transformers (with the exception of Berwick and Outram), each with a designated overhead line or underground cable directly from the GXP. In our 10-year plan we propose to create a sub-transmission ring configuration to increase security of supply at the Dunedin central business district (CBD). This gives us the capability to transfer significant load between GXPs (see Section 6.5.3).

The 33 kV underground cables installed in Dunedin vary in age and construction. The older cable construction in Dunedin uses high pressure gas insulation. Excavating around this type of cable requires significant care due to the pressure the cable maintains within its sheath. We also have several other types of cable, as described in Chapter 8.

3.6.1. Dunedin Load

The Dunedin area load is a mixture of residential, commercial, and industrial. Due to the climate, residential and commercial heating contribute significantly to the network peak load, which follows an expected pattern of morning and early evening peaks. These peaks are greater on colder winter days. Load control (predominately of domestic hot water storage systems) is used to reduce these peaks. A small amount of dairy farming on the Taieri Plains gives rise to irrigation and milking loads during summer, especially on the Berwick zone substation.

Table 3.4: Dunedin load and customer statistics

	APPROX. CUSTOMER NUMBERS	RY22
Halfway Bush[1]	35,300	116 MVA
South Dunedin	21,000	73 MVA
Total Customers	**56,300**	
Coincident Demand		**192 MVA**
Total Energy Delivered		**780 GWh**

[1] Aurora peak demand only

3.6.2. Major Customers

Below we discuss key customers on the network and how we manage and operate our assets to ensure they receive required levels of service.

Dunedin City Council

The combined load of all the Dunedin City Council operated sites is significant. The most important sites are those associated with water and wastewater pumping and treatment. Long-term failure of supply to these sites can cause significant social and environmental impacts. The larger, more critical sites have alternative feeds from multiple zone substations, and the Council has installed backup generation for added security. These sites would become a priority for restoration of supply for any natural disaster, most likely in co-operation with Civil Defence Emergency Management.

Dunedin Hospital

The Dunedin Hospital is a significant and critical load which is supplied via two feeders from North City zone substation. An internally operated changeover arrangement enables switching of supply between these feeders and/or backup generators as required. An alternative direct feed from the Ward Street zone substation is available should both North City feeders fail.

The proposed new Dunedin Hospital will have two buildings – the Outpatient building which will draw a 2 MVA load and the Inpatient building which will draw a 7 MVA load. Both buildings require N-1 security. We plan to supply the Outpatient Building with N-1 security from our North City zone substation and the Inpatient Building with N-1 security from our Ward Street zone substation. The buildings are proposed to be electrically interconnected as part of the hospital plans; this provides the capability to supply the total load of the hospital from either zone substation.

University of Otago

The University of Otago operates a number of buildings in the northern part of Dunedin City. University load – and load from surrounding student-occupied accommodation – reduces over the university holiday periods.

Originally, the university was supplied from a private HV network fed from our North City zone substation. However, the university has grown over time to encompass additional buildings, a number of which are connected to other feeders. The addition of load and alternative feed arrangements into the North City feeders has complicated our protection, and we have elected to run the main university busbar open. There are a number of alternate feed possibilities into the university area from the Ward Street, Willowbank and Smith Street zone substations.

Port Otago

Port Otago is also a sizable customer, and the port is a critical business for the Otago area. If the port were not able to operate for any reason, this would have significant financial and social implications for the city and the region. In addition, power outages are extremely undesirable due to the businesses' need to turn around shipping traffic in a timely manner. Electricity is also required for refrigerated containers at the port, to protect perishable goods.

Port Otago is fed via two separate feeders from the Port Chalmers zone substation, with a manual changeover arrangement. The port operates some standby generation, mainly for refrigeration. The port will be a critical customer should any significant natural disaster event occur anywhere in the southern part of the South Island. It will likely be a key facility for transportation of emergency equipment and supplies.

Dunedin Airport

Loss of supply to the Dunedin Airport has both commercial and air traffic safety implications. The airport operates a standby generator and has an auto-changeover system that switches between a feeder from the Outram zone substation and a feeder from the Berwick zone substation. As with the port, the airport will likely become a key facility in times of natural disaster.

3.6.3. Halfway Bush Network

Our overhead sub-transmission system in Dunedin consists of seven 33 kV radial lines originating at the Halfway Bush GXP. These feed mainly rural areas, although some significant urban areas – Mosgiel, East Taieri, North East Valley and Port Chalmers – are supplied. Throughout the overhead 33 kV lines, small sections of underground 33 kV cable – known as siphons – are installed where it was not practical to retain overhead lines, generally because of development. The sub-transmission system from Halfway Bush supplies approximately 35,300 customers.

The Halfway Bush GXP supplies the following zone substations.

Table 3.5: Halfway Bush zone substations

ZONE SUBSTATION	FEEDER TYPE	TRANSFORMER[2] (MVA)	RY22 PEAK DEMAND (MW)
Berwick	Overhead line	3	1.6
East Taieri	Overhead line	12/24 and 12/24	18.0
Green Island	Cable	15 and 15	14.6
Halfway Bush	Cable	24 and 24	13.6
Kaikorai Valley	Cable	12/24 and 12/24	10
Mosgiel	Overhead line	10 and 10	7.1
North East Valley	Cable/overhead line	9/18 and 12/24	10.4
Outram	Overhead line	7.5	3.3
Port Chalmers	Overhead line	7.5/10 and 7.5/10	7.6
Smith Street	Cable	9/18 and 9/18	16.2
Ward Street	Cable	12/24 and 12/24	9.6
Willowbank	Cable	15 and 15	12.5

[2] Dual rated transformers are denoted with X/Y ratings where 'X' is the base rating and 'Y' is a rating that is achievable through the operation of cooling fans and/or pumping oil through the tank and cooling fins.

Figure 3.9: Halfway Bush sub-transmission networks

3.6.4. South Dunedin Network

The South Dunedin network is fed by a single GXP (South Dunedin). The sub-transmission network is fully underground, consisting of dual circuit cables feeding six zone substations. The sub-transmission system supplies approximately 21,000 customers.

The South Dunedin GXP feeds the following zone substations.

Table 3.6: South Dunedin zone substations

ZONE SUBSTATION	FEEDER TYPE	TRANSFORMER (MVA)	PEAK DEMAND RY22 (MW)
Andersons Bay	Cable	15 and 15	14.2
Carisbrook	Cable	18/24 and 18/24	9.5.0
Corstorphine	Cable	12/24 and 12/24	12.0
North City	Cable	14/28 and 14/28	15.4
South City	Cable	9/18 and 9/18	14.8
St Kilda	Cable	12/24 and 12/24	14.6

Figure 3.10: South Dunedin sub-transmission networks

3.7. CENTRAL OTAGO AND WĀNAKA SUB-NETWORK

The Central Otago and Wānaka sub-networks are supplied from the Clyde GXP and Cromwell GXP respectively. Each of the GXPs supplies a geographically distinct network with no interconnection between them. See Figure 3.11.

Central Otago sub-network has the most extreme climate on mainland New Zealand, which has implications for electricity supply. The climate is characterised by hot summers, cold dry winters, low air humidity and a predominantly dry westerly wind. Central Otago host a number of large, embedded generation with an aggregated capacity of 32MW, the majority of which is hydro generation. See Table 3.3 for the complete list.

Wānaka sub-network is unique and supplies to separate areas with minimal interconnection. The Upper Clutha area has the majority of its load served by two 54 km 66 kV sub-transmission circuits. Cromwell township is fed from our Cromwell substation which is close to the GXP and is supplied by two 33 kV sub-transmission circuits.

3.7.1. Central Otago and Wānaka Load

Central Otago load is predominantly residential and irrigation. However, the load is smoothed by the large number of embedded generators, which most of the time are supplying the load and exporting to the national Grid.

Wānaka is experiencing significant growth driven by steady growth in residential subdivisions, and commercial developments. Wānaka also host two ski fields and a number of irrigation loads.

Typically, Wānaka sub-network peak demand occurs during the two-week July school holidays. Peak demand has continued to increase, even during the RY20 pandemic. The forecast indicates this increase in peak demand will continue beyond the 10-year planning horizon. This is not the same in Clyde where growth has slightly decreased since the pandemic. However, we forecast that growth will increase with developments and electrification in the area.

Figure 3.11: Central Otago Region Cromwell and Clyde GXPs

Table 3.7: Load and customer statistics for Central Otago and Wānaka sub-network

GXP	APPROX. CUSTOMER NUMBERS	Y22 PEAK DEMAND
Cromwell	14,600	49.0 MVA
Clyde	7,600	19.3 MVA
Total Customers	22,200	
Coincident Demand		62 MVA
Total Energy Delivered		291 GWh

3.7.2. Major Customers

This section discusses the key customers connected to our Central Otago and Wānaka network and how we manage and operate our assets to ensure they receive required levels of service.

Ski Fields

Cardrona and Treble Cone ski fields are among our largest customers in the Wānaka network. Load at these sites includes ski lifts and snow-making machinery, and supply to related buildings. Ski lift load is relatively consistent on days that the fields are open. Snow-making load occurs mainly on cold mornings early in the winter season but can run all day if natural snow is lacking and conditions are suitable for snowmaking. Peak loads generally occur when snow-making overlaps with lift operations.

All ski fields receive supply via single feeders over difficult terrain, with only limited backup. Ski fields are typically open for around 80 days per year, depending on snow conditions. Loss of electricity supply during a busy day – such as during school holidays – would cause significant financial loss. Ski field load outside the ski season is generally very low.

Irrigation

The Central Otago and Wānaka networks have a significant amount of irrigation load. Some of this has been driven by dairy conversions. Irrigation demand is relatively consistent over the summer period but may be delayed by an unusually wet spring. At the end of the season irrigation load may reduce if it becomes too dry and sources of race water become limited.

The Hāwea, Queensberry, Bendigo, and Tarras areas have seen a large increase in irrigation demand. In these areas water is often pumped over relatively long distances and/or to relatively significant heights, resulting in high electrical load per irrigated land area. The Omakau, Ida Valley, Poolburn and Lauder Flat area has also seen a significant growth in irrigation, but here the demand per irrigated land area has been significantly lower as the pumping is usually from nearby surface ponds and races.

Except for Alexandra, all the zone substations connected to Clyde GXP are summer peaking and required development specifically to supply irrigation load. Similarly, Lindis Crossing, Camp Hill and Queensberry zone substations are summer peaking substations connected to Cromwell GXP.

Local Councils

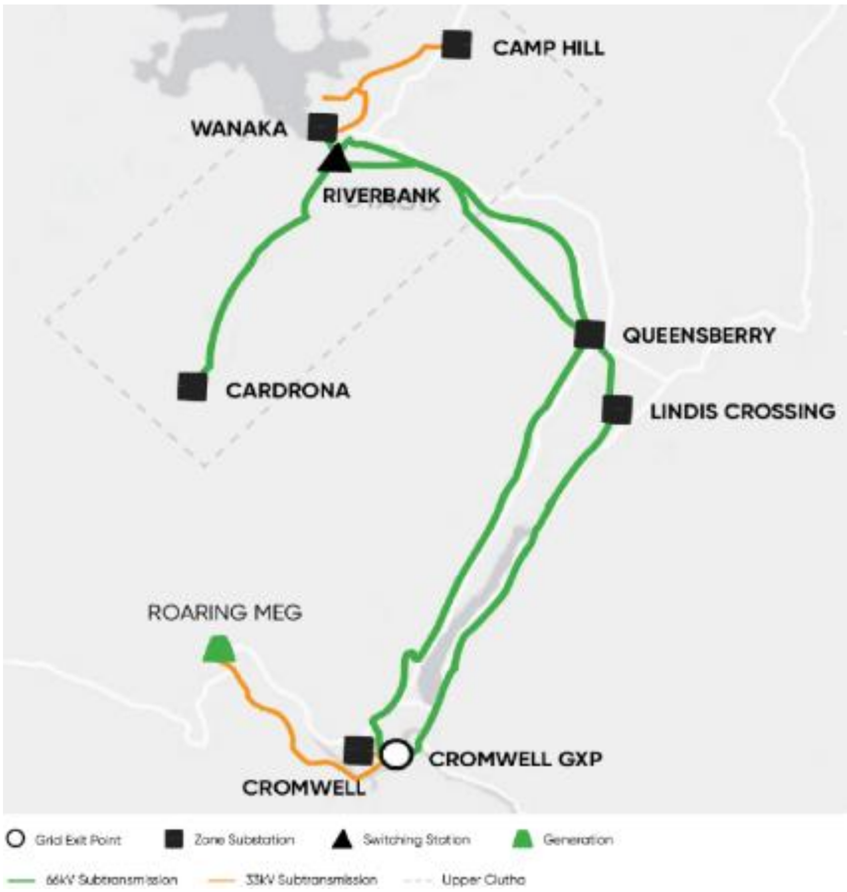
The total load of the Central Otago District Council and Queenstown Lakes District Council sites are significant. As in Dunedin, the most important loads are those associated with water and wastewater pumping and treatment. Most of the CODC and QLDC sites have alternative HV feeds that are manually switched as required. These sites would be a priority for restoration following any natural disaster.

3.7.3. Cromwell Network

The two Cromwell GXP transformers have three windings; the 220 kV side takes supply from the national grid, the 110 kV side supplies Frankton GXP and the 33 kV supplies Aurora Energy's Cromwell network. This network provides electricity supply to Cromwell township and Upper Clutha area, which consists of the Wānaka, Cardrona and Hāwea areas. Since the Upper Clutha area is located 55 km away from the GXP, we need to transform the 33 kV voltage from the GXP to 66 kV using two autotransformers (33/66 kV) and supply the large electricity demand with 66 kV voltage.

Two 66 kV overhead lines run from Cromwell to Wānaka, one on either side of Lake Dunstan. These lines supply zone substations – Queensberry and Lindis Crossing – on the way to terminating at Riverbank switching station. From the switching station, 66 kV overhead lines supply the Wānaka and Cardrona zone substations. Wānaka zone substation has two three-winding transformers where the 11 kV side supplies Wānaka area and the 33 kV side is connected to a 33 kV bus that supplies Camp Hill zone substation with a single 33 kV overhead line. All zone substations supplied from the Cromwell GXP supply the distribution network at 11 kV. Roaring Meg generation is connected to the GXP through 33 kV overhead lines. The Cromwell network supplies approximately 14,600 customers including Treble Cone and Cardrona ski fields.

Figure 3.12: Cromwell GXP sub-transmission network



The Cromwell GXP supplies the following zone substations.

Table 3.8: Cromwell zone substations

ZONE SUBSTATION	FEEDER TYPE	TRANSFORMER (MVA)	PEAK LOAD RY22(MW)
Camp Hill	Overhead line	7.5	5.7
Cardrona	Overhead line	5/6.7	3.9
Cromwell	Cable/Overhead line	12/24 and 12/24	14.4
Lindis Crossing	Overhead line	7.5	7.0
Queensberry	Overhead line	3/4	33.8
Wānaka	Overhead line	12/24 and 12/24	27.2

3.7.4. Clyde Network

The Alexandra, Clyde, Manuherikia, Ida Valley and Teviot Valley areas are supplied via two 33 kV sub-transmission circuits connected to the Clyde GXP. Most of the electricity demand in the Clyde GXP area is supplied from distributed hydro generation sites at Teviot, Ettrick and Earnscleugh. The sub-transmission plays an important role in injecting excess generation into the national grid at the Clyde GXP. Two parallel 33 kV lines run between the Clyde GXP and Alexandra, and then on to Roxburgh. Ettrick is supplied by a single 33 kV line from Roxburgh. Omakau and Lauder Flat, to the north-east of Alexandra, is supplied by a single 33 kV line from Alexandra 33 kV outdoor switchboard. All zone substations supplied from the Clyde GXP supply the distribution network at 11 kV with the exception of parts of the Clyde and Earnscleugh township. The Clyde network supplies approximately 7,600 customers.

The Clyde GXP supplies the following substations.

Table 3.9: Clyde zone substations

ZONE SUBSTATION	FEEDER TYPE	TRANSFORMER (MVA)	PEAK LOAD RY22 (MW)
Alexandra	Overhead line	7.5/15 and 7.5/15	11.5
Clyde/Earnscleugh	Overhead line	4	4.1
Ettrick	Overhead line	3	2.2
Lauder Flat	Overhead line	3	1.2
Omakau	Overhead line	3/3.6	3.2
Roxburgh	Overhead line	5	1.7

Figure 3.13: Clyde GXP sub-transmission network

3.8. QUEENSTOWN SUB-NETWORK

The Queenstown sub-network is fed from the GXP at Frankton. The region has seen significant growth, chiefly due to tourism and residential developments. As with the rest of Central Otago, Queenstown's extreme climate poses a challenge for electricity distribution. The climate is characterised by hot summers, cold dry winters, low air humidity and a predominantly dry westerly wind. The Frankton GXP is supplied through two 110 kV transmission circuits from Cromwell GXP. The GXP transforms the voltage from 110 kV to 33 kV where Aurora Energy takes its supply. The Frankton network conveys electricity to the Wakatipu basin with eight zone substations that transform the voltage from the 33 kV sub-transmission voltage to 11 kV distribution. From there, 11 kV circuits distribute power to smaller distribution transformers.

The Frankton, Queenstown and Commonage zone substations are supplied through 33 kV overhead lines from Frankton GXP, with Fernhill zone substation supplied with underground cables from the Queenstown 33 kV outdoor switchboard. Arrowtown, Coronet Peak, Dalefield and Remarkables zone substations and Wye Creek generation are connected via 33 kV Arrowtown open ring configuration (open at Arrowtown zone substation 33 kV outdoor substation). This configuration provides backfeed capability should one section of the ring fail. Most of our zone substations have supply redundancy through N-1 33 kV lines or cables. The Frankton network supplies approximately 15,100 customers including Coronet Peak and The Remarkables ski fields.

3.8.1. Frankton Load

We have seen steady load growth on the Queenstown network, driven by steady growth in residential subdivisions together with significant one-off projects such as ski field developments. We have also seen high growth in irrigation load in some areas. Network growth has remained steady in the region in spite of COVID-19. Typically, Frankton peak demand occurs during the two-week July school holiday, and this has not changed during the pandemic. The region's ski fields are significant users and can control their own peak load, while some use diesel generation to supplement available supply.

Table 3.10: Load and customer statistics for Queenstown sub-network

GXP	APPROX. CUSTOMER NUMBERS	PEAK LOAD RY22 (MW)	TOTAL ENERGY DELIVERED
Frankton	15,100	63.6[3]	235 GWh

3.8.2. Major Customers

This section discusses the key customers connected to our Frankton network and how we manage and operate our assets to ensure they receive required levels of service.

Queenstown Airport

In conjunction with tourism to the region, the Queenstown Airport has grown from a small regional airfield to a busy airport. As in the case of Dunedin's airport there are commercial and air traffic safety implications in the event of loss of supply. The airport operates a standby generator for critical loads and peak demand management. A feeder from Frankton substation supplies the airport. The network is meshed, and a number of alternative supply options exist, including supply from Commonage substation in the unlikely event the Frankton substation is out of service.

Ski Fields

The Queenstown ski fields at Coronet Peak and Remarkables are among our largest customers. Load at these sites includes ski lifts and snow-making machinery, and supply to related buildings. Ski lift load is relatively consistent on days that the fields are open. Snow-making load occurs mainly on cold mornings early in the winter season but can run all day if natural snow is lacking and conditions

[3] Aurora Energy load only

are suitable for snowmaking. Peak loads generally occur when snow-making overlaps with lift operations.

All ski fields receive supply via single feeders over difficult terrain, with only limited backup. Ski fields are typically open for around 80 days per year, depending on snow conditions. Loss of electricity supply during a busy day – such as during school holidays – would cause significant financial loss. Ski field load outside the ski season is generally very low.

Figure 3.14: Frankton GXP sub-transmission network

Local Councils

The load of the Queenstown Lakes District Council sites is significant. As in Dunedin, the most important loads are those associated with water and wastewater pumping and treatment. Most of these sites have alternative HV feeds that are manually switched as required. These sites would be a priority for restoration following any natural disaster.

The Frankton GXP supplies the following zone substations.

Table 3.11: Frankton zone substations

ZONE SUBSTATION	FEEDER TYPE	TRANSFORMER (MVA)	PEAK LOAD RY22 (MW)
Arrowtown	Overhead line	5.5 and 7.5/10	9.7
Commonage	Overhead line	14/17 and 14/17	11.6
Coronet Peak	Overhead line	5/6	5.1
Dalefield	Overhead line	3	1.7
Fernhill	Cable	7.5/10 and 7.5/10	6.3
Frankton	Cable/Overhead line	12/24 and 7.5/15	18
Queenstown	Overhead line	10/20 and 10/20	12.4
Remarkables	Overhead line	3	2.3

3.9. Network Assets

This section provides a high-level overview of the asset fleets that we own and operate, including the overall populations of our key fleets. Further detail on these assets, including their condition and ages, is included in Chapter 8.

Table 3.12 below illustrates the relatively small number of high voltage assets and the very large number of distribution and low voltage assets that make up our network. This view provides an indication of the breadth of knowledge and competency required to plan for, operate, and maintain distribution networks where failure of any electrical asset insulator can have a significant impact on the network in terms of both safety and reliability.

Table 3.12: Summary of network assets (as of 31 March 2022)

<table>
<tr><th>Sub-network</th><th>GXP</th><th colspan="2">Zone Substations</th><th colspan="2">Distribution Transformers</th><th colspan="2">Customer Connections</th></tr>
<tr><td rowspan="2">Dunedin</td><td>Halfway Bush</td><td rowspan="5">33 and 66 kV</td><td>12</td><td rowspan="5">11 and 6.6 kV</td><td rowspan="2">2,648</td><td rowspan="5">400 and 230 V</td><td>35,300</td></tr>
<tr><td>South Dunedin</td><td>6</td><td>21,000</td></tr>
<tr><td rowspan="2">Central Otago and Wānaka</td><td>Cromwell</td><td>7</td><td rowspan="2">3,274</td><td>7,600</td></tr>
<tr><td>Clyde</td><td>6</td><td>14,600</td></tr>
<tr><td>Queenstown</td><td>Frankton</td><td>8</td><td>1,287</td><td>15,100</td></tr>
<tr><td colspan="2"></td><td colspan="2">Sub-transmission</td><td colspan="2">Distribution</td><td colspan="2">Low Voltage</td></tr>
</table>

The final two tables provide some insight into the physical distances covered by our electrical network across each voltage level. Our Central Otago and Wānaka sub-network cover a significant area compared to Dunedin and Queenstown, as is reflected in the line lengths.

Table 3.13: Summary of overhead network (as of 31 March 2022)

Sub-Network	GXP	Sub-transmission (km)		Distribution (km)		Low Voltage (km)	
Dunedin	Halfway Bush	33 and 66 kV	144	11 and 6.6 kV	731	400 and 230 V	811
	South Dunedin						
Central Otago and Wānaka	Cromwell		310		1,271		176
	Clyde						
Queenstown	Frankton		70		285		46
Total			524		2,287		1033

Table 3.14: Summary of underground network (as of 31 March 2022)

Sub-Network	GXP	Sub-transmission (km)		Distribution (km)		Low Voltage (km)	
Dunedin	Halfway Bush	33 and 66 kV	66	11 and 6.6 kV	331	400 and 230 V	302
	South Dunedin						
Central Otago and Wānaka	Cromwell		9		553		490
	Clyde						
Queenstown	Frankton		13		285		311
Total			88		1,169		1,103

4. STRATEGY AND GOVERNANCE

This chapter describes our asset management strategy, which covers all decision-making and governance roles that inform our proposed network investment during the planning period. To ensure appropriate 'line-of-sight' between stakeholder needs and our investment plans, our asset management framework translates our corporate vision and strategic priorities into asset management objectives that guide all investment and operational decisions. Effective risk management is a core function of our approach to asset management. Our organisational risk framework is set out later in this chapter.

4.1. ASSET MANAGEMENT FRAMEWORK

An overview of our asset management framework is given in Figure 4.1 below. This illustrates how our asset management strategy informs all stages of the asset lifecycle, and how ongoing and systematic review drives continuous improvement. By setting clear service level targets across each of our asset management objective areas (see Section 4.6), we can monitor and improve the performance of our strategy through an ongoing review process.

Figure 4.1: Asset management framework

Our framework incorporates a standard plan-do-check-act process, which is being progressively embedded into our activities. We use this to monitor and control the effectiveness of our asset management activities. As part of our continuous improvement process in March 2022 we published a suite of forward-looking documents one of which is our (asset management) Development Plan.[1] This will take on a greater role in the continuous improvement of our processes and systems.

The innermost circle reflects how we interpret the stages of an asset's lifecycle. Chapter 5 explains how we manage our fleets throughout their total lifecycle within our asset management practices.

4.1.1. Asset Management System

The core function of our business is to deliver electricity safely, reliably and affordably to customers, both now and into the future. The overarching purpose of our asset management system is to ensure we can meet the performance targets set within our asset management objectives. The areas covered in our asset management system include all electricity distribution network assets, all supporting assets such as protection and monitoring equipment, and non-network equipment including offices, computers and software solutions. The system also considers human resources such as internal staff that directly or indirectly support our asset management activities, plus organisations to which we outsource asset-related activities, including service providers and contractors. Ultimately, our asset management system includes all elements of our business that contribute to asset performance, whether directly or indirectly.

Our asset management framework encapsulates all key elements of our asset management system. The elements that support our framework are undergoing significant change and development at present and will be refined as we scope and plan to achieve alignment with ISO 55001. As we reach greater maturity with our asset management system, we will continually review and update key processes and documents to reflect any improvements. Our investment plans are reviewed annually to take account of improvements in our decision-making processes.

4.2. STRATEGIC FRAMEWORK

As discussed above, our strategic framework seeks to reflect industry best practice.[2] Our strategic framework provides a general overview of the processes that contribute to our asset management plan. Each process is explained under a core set of asset management documents that provides clear alignment from our overarching business needs and objectives to our everyday actions. The top level of our document hierarchy (Figure 4.2) establishes the needs of customers and key stakeholders, which inform our business plan and asset management policy. Our Strategic Asset Management Plan (SAMP) outlines a series of asset management objectives that reflect our business plan, and it sets out the principal decision-making processes that we use to direct each of our investment plans. Our planning documents detail specific works to be completed on an annual basis in order to best meet our service targets; these plans include asset maintenance and replacement, and network improvement plans. Finally, our delivery documentation ensures that all planned works are completed within set timeframes and according to our specified requirements.

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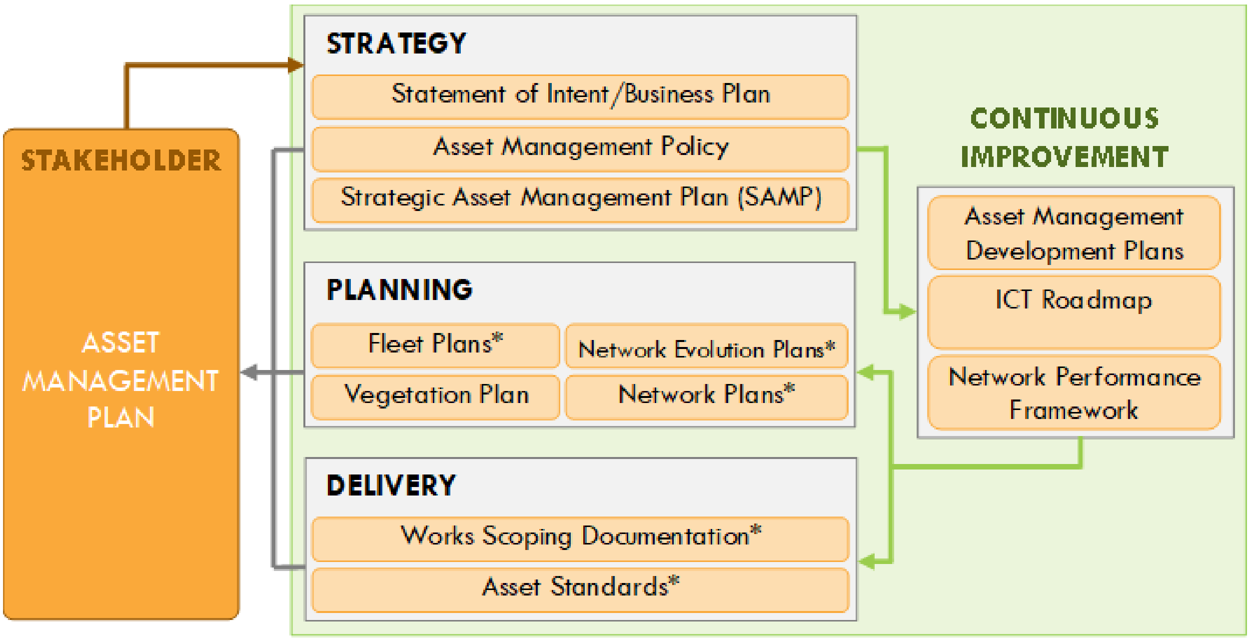
[1] Aurora Energy public website. https://www.auroraenergy.co.nz/disclosures/delivering-our-cpp/

[2] This framework will evolve as we progress our asset management improvement initiatives towards ISO 55001 alignment.

The hierarchy illustrates how we link our corporate vision (included in our business plan) into our day-to-day investment and operational decisions. This ensures effective line-of-sight from stakeholder needs, through our strategies to our daily activities.

Figure 4.2: Asset management document hierarchy



** indicates documents in review or development*

The main documents that describe and define our asset management framework are as follows:

- **Statement of Intent (SOI):** our SOI sets out our high-level strategic/corporate objectives, intentions and performance targets over a period of three years. The document was most recently published in July 2022 and is updated annually.
- **Business Plan**: published in 2021, this document sets out our business direction over the 2021-25 period. The business plan outlines the key outcomes that we aim to deliver over this period, what factors can impact upon the success of these outcomes, and how these outcomes relate back to the business. The plan also provides financial forecasts over the period.
- **Asset Management Policy**: established in 2019 and refined in 2022, the policy aligns our asset management approach with our corporate objectives through a set of strategic priorities.
- **Strategic Asset Management Plan (SAMP):** (in development) explains the set of processes and decisions required to develop a set of investment plans that best meet our asset management objectives while remaining within our financial and delivery capability. The SAMP will also outline initiatives to increase efficiency by driving improvements to our asset data and to our capacity to deliver.
- **Planning documents, including our fleet and network plans**: (some are currently in development) which will reflect our asset lifecycle model and set out how these processes and activities are applied to individual asset fleets. In the interim we have provided an enhanced level of detail in Chapters 7 and 8 to inform all decision-making regarding each of

our fleets. Our network evolution plan and vegetation management strategy have been added to our document hierarchy and reflect key focus areas during the AMP period.

- **Delivery plans, including works scoping and asset design and installation standards**: used to manage and deliver our investments and operational and maintenance activities. An annual work plan is utilised to ensure that project and maintenance work can be scheduled and delivered efficiently and to plan.
- **Asset Management Plan**: (this document) describes our investment plans over a period of 10 years. The AMP provides an overview of expenditure and the supporting information that guides our decision-making. Aside from its regulatory purpose, the AMP provides the opportunity to explain to key stakeholders how our asset management objectives and investment plans over the AMP period align with their needs. Stakeholder feedback informs our Strategy and business planning.
- **Continuous improvement plans**: as discussed below, we continue to improve and refine our asset management related capability and processes. Three important initiatives (and related documents) are our Asset Management Development Plan (AMDP), ICT Roadmap, and Reliability Management Plan (RMP). Our improvement plans are outlined in Chapter 9. Note that our ICT Roadmap is under review with an intent to deliver a strategy and plan with a growing focus on Digital Transformation.

Each of the above elements has a defined ownership. For example, this AMP is the responsibility of the general manager for Asset Management and Planning, while final approval is granted by our CEO and board. Each document owner oversees the review and approval process to ensure consistency with our values, vision and mission. The documents are managed through our controlled documentation system (CDS) and by defining required reviewers and level of sign-off.

Our asset management practices are also supported by a series of standards and work instructions to ensure that our staff and contractors carry out their functions in a consistent fashion that meets the needs of the business. Asset management standards cover the minimum set of requirements when performing asset related tasks such as design, inspection or maintenance. Work instructions contain sufficient guidance for our contractors and staff to ensure that tasks are performed to a consistently high standard.

An important aspect of our asset management system is to ensure that all aspects of the business align with our overall business objectives, which themselves align with stakeholder needs. One of the objectives of our AMP is to demonstrate to external stakeholders and interested parties that our documented strategies and processes are well developed and targeted at our set objectives.

4.3. STAKEHOLDER INTERESTS

Our asset management approach recognises the diverse interests of our stakeholders. The table below outlines our key stakeholders, their main interests, and the methods to identify these interests.

We accommodate these stakeholder interests in our asset management practices through:

- provision of meaningful, accurate and timely information

- compliance with regulatory and legal frameworks
- safety plans, including addressing end-of-life assets and safety-in-design
- network growth and development plans
- use of a security of supply guideline reflecting consumers' needs and expectations
- optimising asset lifecycle capital and operational expenditures
- tracking and addressing quality of supply issues in a timely manner
- audit programmes
- continuously striving to improve the quality of our service.

Table 4.1: Stakeholder interests and how they are identified

STAKEHOLDER	MAIN INTERESTS	HOW INTERESTS ARE IDENTIFIED
Electricity consumers	Reasonable prices Accurate and timely information on unplanned and planned outages Timely response to enquiries, faults, complaints Safe and reliable supply of electricity Resilience of the network A network that enables future DER choices	Consumer satisfaction surveys Direct liaison Customer voice panels Safety and information campaigns Customer Advisory Panel
New-connection customers and their agents	Reasonable prices Timely response and clear communication through connection process Service delivery on time, in full	Direct communication with customers, electricians and approved contractors Consultation
Government / Regulator	Long-term interests of consumers Economic efficiency Compliance with statutory requirements Accurate and timely information De-carbonisation	Submissions Relationship meetings Workshops and conferences
Landowners and communities who host our assets	Safety Easement conditions Appropriate access arrangements	Direct communication Periodic consultation
Electricity retailers and distributed generators	Line charges Reliability of supply Contractual arrangements How we manage customer complaints Ease of doing business with us	Use of System Agreements Relationship meetings Feedback on AMPs
Property developers	New-connection policies and costs Timely network expansion	Direct communication
Service providers	Safe working environment Maintenance and design standards Maintaining good contractual relationships Clear forward view of work	Contractual requirements Discussions with field staff Quality documentation feedback

STAKEHOLDER	MAIN INTERESTS	HOW INTERESTS ARE IDENTIFIED
Territorial authorities and NZ Transport Agency	Public safety Minimising environmental impacts Support for economic growth Control of assets in road reserve	Direct communication Submissions RMA applications
Transpower	Effective working relationship Reliability of supply Investment for growth	Direct communication System operator communication
Media	News, background information	Direct communication
Shareholder and the Board	Prudent risk management Compliance Strong governance	Board meetings Shareholder briefings

Engaging regularly with key stakeholders ensures that our business objectives are directed in the appropriate areas. Chapter 2 provides further information about our key stakeholders and how we engage with them.

4.4. BUSINESS PLAN AND OBJECTIVES

The core function of our business is to deliver electricity safely, reliably and affordably to our customers, now and into the future. Our corporate objectives focus on improving the delivery of this core function. We have adopted five strategic priority areas as the foundations for general improvement.

Table 4.2: Our five strategic priorities (overall business)

STRATEGIC PRIORITY	TODAY	TOMORROW
Our People, Our Place	We're establishing our core capabilities and creating a positive culture	We're a leading learning organisation, recognised for our people-centric culture and our flexible, inclusive and diverse work environment
Efficient Delivery	We're focused on delivery, building core systems, and collaboration	We're efficient, forward-thinking and digital-enabled
Our Communities	We're improving our customer and partner relationships	We're partners with our customers and industry peers, and our brand is synonymous with green thinking
Enabling Decarbonisation	We're operating and maintaining a strong, safe and reliable network, and planning for the future	We're leaders of green energy innovation and have enabled two-way energy sharing with our communities
License to Operate	We're developing sustainable management practices	We have a sustainable workplace, focused on delivering value to our shareholders, customers and communities

4.4.1. Vision, Mission and Values

Our AMP seeks to explain how our corporate vision and mission inform our asset management approaches and how these reflect the interests of stakeholders. Our vision, as a regional EDB, reflects the importance of serving each of our communities: Dunedin, Central Otago/Wānaka, and Queenstown.

Our **Vision** is to

"Enable the energy future of our communities."

Our mission below reflects our core purpose as an EDB, which is to deliver electricity safely, reliably and affordably to our customers.

Our **Mission** is to

"Deliver electricity to our communities when and where it is needed, safely, reliably and efficiently."

Our values (see Figure 4.3) will be important if we are to achieve our vision and mission. Our values were developed for our people, by our people. They are the key mindsets and standards of behaviour that guide how we work with each other and with our stakeholders. By living these values every day, we will support a work environment that brings out the best in everyone.

Figure 4.3: Our values

As part of our mid- to long-term business planning, we will expand our focus towards increased electrification within our communities due to a wider push for decarbonisation. We anticipate that technological improvements and changes to customer behaviour will present new challenges to our industry. As we prepare plans and deliver actions to address these emerging challenges, we must also continue to deliver the network foundations to maintain a safe and reliable network for our customers.

4.5. ASSET MANAGEMENT POLICY

Our asset management policy sets out high-level asset management principles that reflect our vision and values. Our policy document was put in place in 2019 and updated in 2022. It highlights our Board's expectations for the way we will manage our assets and make our decisions. The policy has been developed to ensure a continuous focus on delivering the services our customers want in a sustainable manner that balances risk and long-term costs.

The policy covers a broad range of asset management principles, including the following statements that are particularly relevant to managing our assets at the current time. We will:

- take all reasonably practicable steps to protect all people affected by our assets and asset management activities
- use robust processes and improved asset data to make asset management and lifecycle decisions, balancing cost, risk and performance
- understand and meet our customers' and stakeholders' needs and values, including iwi and environmental agencies to align our decisions to our understanding of their balanced needs and values
- develop 'least regrets' plans that balance meeting short-term needs with an agile response to changing preferences of our customers in an uncertain future.
- seek best practice asset management including alignment with international asset management system ISO 55001
- comply with all statutory and regulatory requirements.

4.6. ASSET MANAGEMENT OBJECTIVES

Our asset management objectives set the direction for all network management decisions. They have been developed to achieve the following aims in line with our overall business objectives:

- guide how our organisational objectives are related to our day-to-day activities
- provide context for internal and external issues that may affect our ability to achieve intended asset management outcomes
- provide clarity on how our asset management objectives support achievement of our business plan objectives
- ensure we have the right frameworks, skills, technical capability, systems, and processes to efficiently deliver our strategy and to optimise asset investments
- drive our continuous improvement programme.

To ensure consistent alignment in our asset management activities, we have defined five key areas that link our corporate strategic priorities to our asset management and asset fleet objectives.

Table 4.3: Our five strategic priorities (asset management)

OBJECTIVE	DESCRIPTION
Safety first	– asset management activities support meeting our health and safety compliance and community obligations – we take all reasonable practical steps to manage safety risks – safety of community and personnel is never compromised – safety is prioritised when operating or managing our assets – safety criticality is factored into our decision-making – we identify, forecast, analyse and track safety risks and implement and monitor the effectiveness of controls
Reliability to defined levels	– reliability targets reflect short and long-term consumer preferences

OBJECTIVE	DESCRIPTION
	– network performance is analysed, and underperformance is investigated and remediated to meet consumer preferences – reliability criticality is factored into our decision-making
Affordability through cost management	– we aim to ensure we do the right work, at the right time, for the right cost – we focus on the value we deliver to customers – costs are tested and benchmarked to support future improvement – we use alternative solutions to improve cost outcomes
Responsive through a changing landscape	– we respond to changes in customer preferences and demand – technological developments are monitored, and feasibility tested – strategic scenarios are developed to support network evolution – asset data is defined and managed with fit-for-purpose ICT solutions – target 'least-regret' investments to create long-term flexibility, enabling greater customer choice and value
Sustainability by taking a long-term view	– we comply with relevant standards and codes of practice – negative environmental impact is minimised – investment decision-making considers long-term sustainability of our business – environmental criticality is factored into our decision-making

Further discussion of our asset management objective areas is set out in the following sections. Where relevant, we provide further detail about historic performance, key performance targets and our strategies to achieve the targets.

4.6.1. Safety

Safety is our foremost priority. As an electricity asset owner, we are responsible for safeguarding the general public, as well as staff and service providers. As a PCBU[3], we aim to take all necessary precautions in ensuring an injury-free work environment. We have set out our commitments to health, safety and the environment in a policy published on our website.[4]

Our network assets and some asset management activities pose potential safety hazards if not sufficiently managed. Asset health and condition is linked to likelihood of failure; for some assets, failure can lead to negative consequences. Public safety risk is greatest for asset classes near people, particularly overhead line assets. As outlined in Chapter 5, we have established a system of prioritisation that allows us to identify and replace assets with a significant safety risk. Working within our substations often requires working in close proximity to high voltage assets. As such, some asset replacements within zone substations are driven by the need for safety improvements.

Effective management of safety risks associated with our assets and activities is fundamental to our business and to fulfilling our statutory obligations. During the consultation process for our CPP application, our customers identified safety as their highest priority. As such, safety forms a key component for our asset management practices. This preference has been reflected in our CPP investment plans, particularly in our asset maintenance and renewals expenditure.

3 A person conducting a business or undertaking (PCBU) is a term used to describe working arrangements referred to as a business.

4 Health, Safety and Environment – Our commitment to you, Aurora Energy.

> **Box 4.1: Safety objective**
> Our safety objective is to safeguard the public, service providers, and to ensure an injury-free workplace.

Asset Safety Risk

Our assets form the pathway for electricity from the Transpower grid to customers, covering domestic, business and industrial users. The network carries several voltages ranging from 240V to 66,000V dependent upon location and technical requirements.

Electricity at the levels we operate offers inherent risks, which in many cases can be a significant safety hazard to anyone exposed to them. As a responsible business operator, we place a corresponding emphasis upon ensuring assets are inspected and maintained to an appropriate standard. We achieve this through inspection regimes with regular reviews to confirm that they are relevant and comprehensive.

Since our last AMP we have actively improved our capability in forecasting asset safety risk (See Chapter 5 for more detail). As asset replacements and renewals are made the corresponding improvement in risk is calculated. This allows us to check the efficiency of our renewals programmes and associated targeted utilisation of capital with respect to managing and treating asset safety risk.

During the CPP process we have also introduced a Safety Delivery Plan which outlines our approach to reducing safety risks across our network. For more details on our development plans, see Chapter 9.

Our Performance

We have continued making improvements in our performance against the requirements of NZS 7901:2014 and NZS 7901:2008 Electricity and Gas Industries – Safety Management Systems for Public Safety. In 2022 certification continued against these standards, which require a strong focus on network demarcation and risk management. Our recent annual safety audit results are shown below:

Table 4.4: Safety system audit results

CRITERIA	2018	2019	2020	2021	2022
Unattained (UA)	0	0	0	0	0
Partial Attainment (PA)	7	2	3	1	3
Opportunities for Improvement (OI)	5	4	2	11	4

The most recent report from 2022 recognised the substantial work that had been done on our public safety management system and the clear linkage it shares with the AMP. The 2021 audit was a recertification audit, which occurs every five years and involved a thorough review of both our system and our in-field assets.

Our incident reporting and investigation journey continues to progress and move from strength to strength. Aurora Energy are looking to invest in complimentary incident investigation tools for asset

-related public safety events, to allow for a deeper dive analysis of critical controls, their failure modes and effectiveness monitoring.

Our key performance targets for health and safety are set out below. Recognising the need for continuous improvement, the key strategies and initiatives discussed here will help drive a stronger safety culture. Over time, this will improve our TRIFR towards a best practice performance level of 4.0 or better. Zero public harm is our ultimate commitment, and our target for public safety incidents and specifically harm to any member of public is zero. A key focus of our TRIFR reduction programme is wider spread utilisation and integration of Safety in Design principles. Working with our field service providers, we are challenging our thinking on topics such as materials we use, location of assets, job design, and lifecycle maintenance.

As a prudent utility, we will revise our safety targets over time and reflect the progress we make in our improvement initiatives. In the interim we expect our RY23 targets to apply for the remainder of the AMP planning period.

Table 4.5: Health and safety performance targets (for calendar years)[5]

TARGET	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
TRIFR[6]	5.10	4.90	5.00	<4.00	<4.00	<4.00	<4.00	<4.00	<4.00	<4.00
Actual harm to public	1	2	0	0	0	0	0	0	0	0

We have no recent cases of harm to a member of public.

Our view is that our safety performance targets reflect the expectations of consumers, our employees, contractors and other stakeholders, including the expectation that we will pursue and achieve continuous improvement in our safety performance.

Key Strategies and Initiatives

We aim to deliver our safety objectives through the following initiatives:

- continue to analyse asset risks by safety consequence and defining adequate controls, including review of ICAM and root cause analysis findings against existing risk analyses
- continue implementing our safety-in-design process
- prioritising our asset renewal programme on those asset fleets with greatest inherent risk
- deliver the integrated health and safety strategy which will elevate our critical risk management and assurance processes
- continued focus on Visible Felt Leadership
- continue to implement the asbestos management and removal programme
- improve the reporting of hazards and near miss incidents and apply these to our critical risk framework

5 Our TRIFR targets for 2018-19 were <4.75, and for 2020 it was <4.50. We targeted zero harm for each of these years.

6 Total Recordable Injury Frequency Rate (TRIFR) per 200,000 hours worked.

- enhance our approach to safety-in-design, working closely with field service providers to encourage innovation in reducing manual handling
- complete our current prioritised programme of replacement of assets that present a risk to the public or to our service providers
- promote public awareness of safety around our network.

We have an ongoing public awareness programme to inform the community about keeping safe around our electricity network and this is currently being reviewed and updated. Targeted safety messages are promoted through print and online advertising on the hazards of working near overhead lines, digging near underground cables, reducing summer fire risk, what to do if your car hits a power pole, and being prepared in the event of power outages. We have been working on improving our safety message around trimming trees near electricity lines and updating associated communications.

4.6.2. Reliability

Reliability of supply is measured in terms of frequency of interruptions per customer and their duration. Major factors in determining levels of reliability performance include asset health, field response times, and security of supply in terms of our ability to back up or restore lost supply. The service our customers receive from the network is partly determined by the condition of assets in their region. External factors also contribute to our reliability, such as poor weather conditions, vegetation, possums and other wildlife, and third-party incidents such as vehicle impacts. Network reliability reflects an historical trade-off between cost and service; improved reliability performance often requires significant investment. Achieving target levels of service performance requires identification and mitigation of multiple risks that can cause asset failure.

> **Box 4.2: Reliability Objective**
> Our objective is to deliver a cost-effective and sustainable level of reliability performance that reflects customer preferences.

Historical Performance

In previous years, up until RY20, our network reliability had shown a deteriorating trend. As a consequence, we exceeded our regulatory compliance limits across multiple years. Ageing assets have played a significant role in this deteriorating trend. Not only did we experience an increase in unplanned outages due to the poor condition of many assets, but the increased work volumes required to improve the state of our network have led to higher levels of planned outages also.

Objectives and Targets

While preparing our expenditure plans for the CPP Period, we engaged with customers and stakeholders in order to understand their preferences regarding network reliability and affordability. Their feedback indicated that, in general, customers were happy with current levels of reliability and did not seek improvements if this required an increase in prices.

For several years, our investment plans have focused on reducing safety risk due to poor condition assets through our renewals and maintenance programmes. This work has increased overall asset health, which has had some positive impact on overall network reliability.

It is important to note that our renewal programmes are taking place during a time of deteriorating asset performance due to the increased age of some of our fleets. Reversing this trend can be expected to take several years given the number of replacements required; our work programmes are limited by the capacity of our service providers to deliver and by the number of planned outages that we can schedule each year. In this context, stabilising current levels of performance is itself a considerable challenge for us during the CPP Period.

We anticipate that continued investment in safety beyond the CPP Period will improve reliability performance. We will consult with customers in RY24 on their preferred levels of reliability beyond the CPP Period, and further reliability improvements could be achieved through targeted investment if customers prefer this outcome.

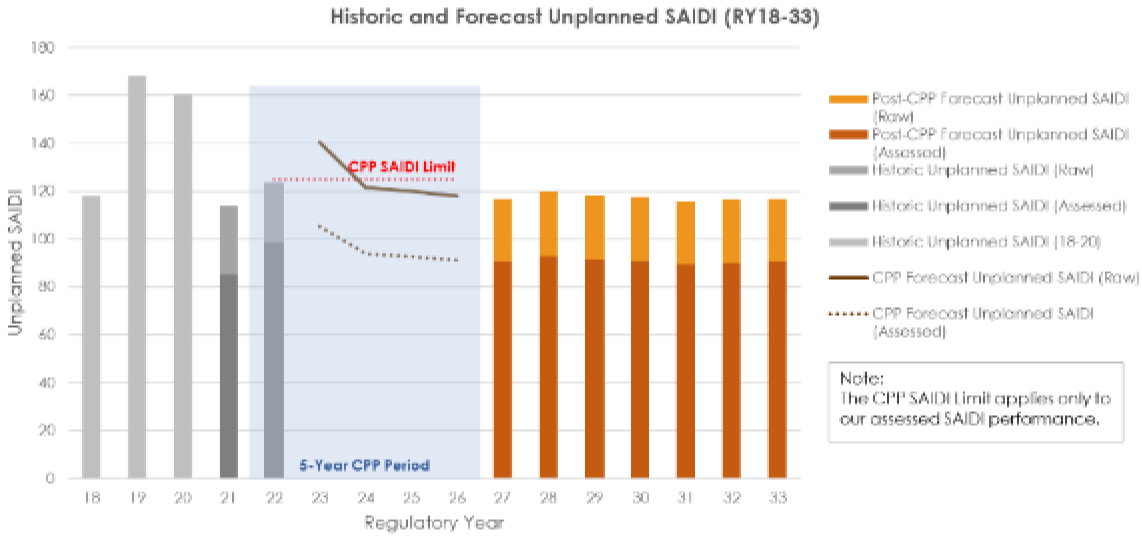
Subject to future consultation with customers, we may look to improve future network reliability by investing in network automation and similar capabilities. Such upgrades to the network can help to limit the impact of outages in some areas by reducing the duration and number of customers affected. Given the additional cost of investment, these upgrades would be best suited to poorly performing areas of our network.

The charts below (Figures 4.5 and 4.6) set out our forecast unplanned reliability for the AMP period, outlining the reliability performance we expect during the remainder of the CPP Period. Each metric serves to indicate the total duration (SAIDI) and frequency (SAIFI) of network interruptions felt by an average customer across each 12-month period. These forecasts have been created using our own modelling capability developed as part of our asset management improvement initiatives (discussed in Chapter 9).

The charts indicate that our actual reliability performance has shown some improvement since RY20. We believe that extensive investment in asset renewals across several years has stabilised the overall condition of our network. As such, our assets have a reduced likelihood of failure, and are more resilient against external forces such as extreme weather events. We continue to experience faults on our network due to external factors such as fallen vegetation, wildlife and third-party events like car crashes and cable strikes. Therefore, our forecast indicates slight improvements to unplanned SAIDI and SAIFI across the planning period due to improved network condition.

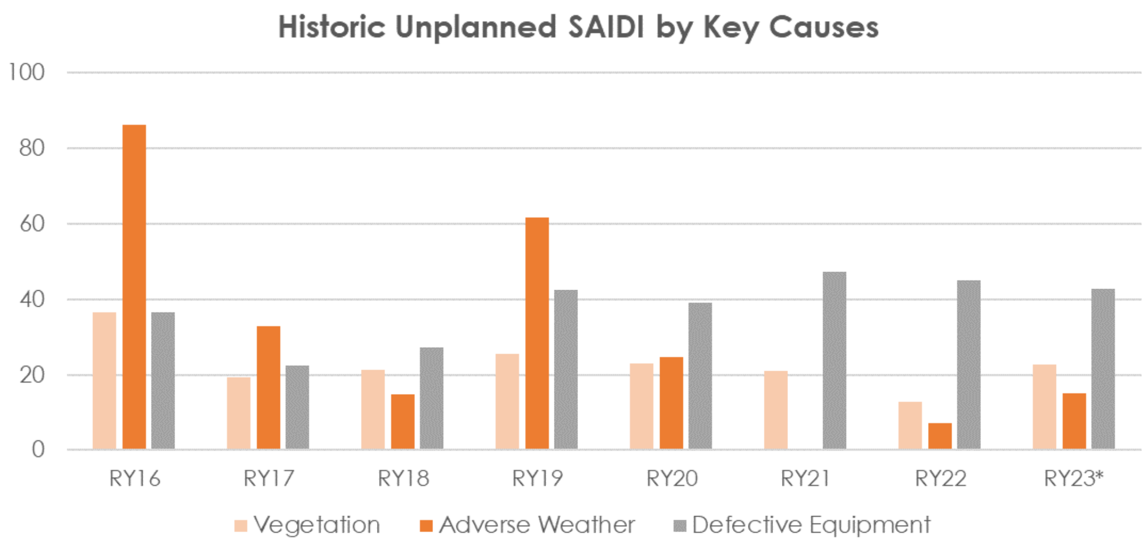
In spite of improvements in recent years, our reliability performance to date for RY23 has been below expectations in some areas, impacting the overall network performance. Asset failures remain steady but we have seen a rise in extreme weather events causing damage, which has also prompted an increase in vegetation-related outages. In previous years, such as RY16 and RY19, weather had caused significant outages, and so we are confident that the network has shown greater resilience recently due to our investment in improving asset health and in our vegetation programme.

Figure 4.4: Forecast unplanned SAIDI



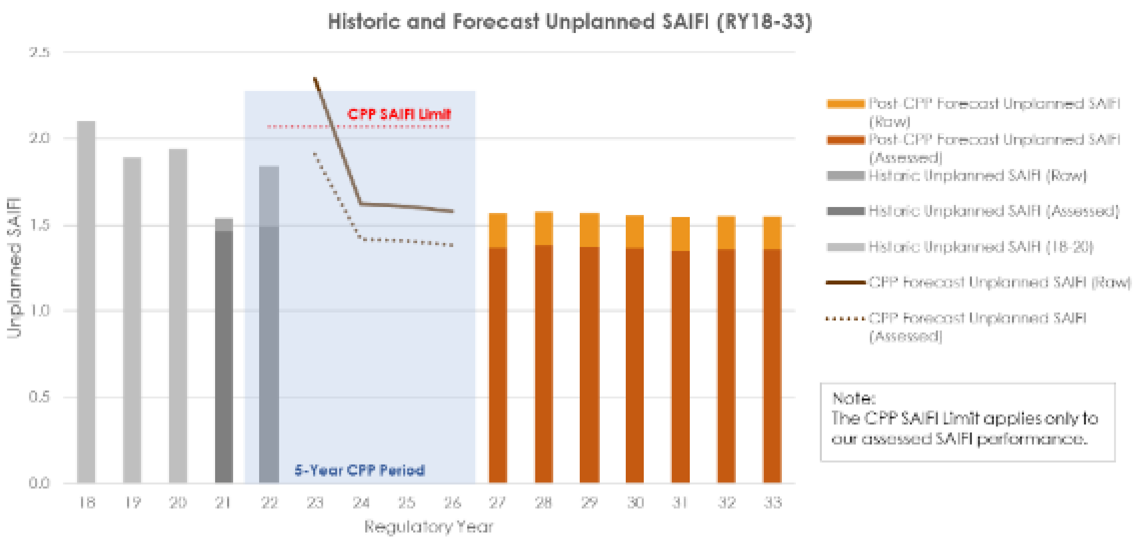
In RY23 we experienced a small number of one-off events that have caused a spike in our SAIFI performance. Two such outages in the Upper Clutha area affecting over 10,000 ICPs in October and December were resolved quickly, which resulted in a minimal impact on SAIDI. The SAIFI impact, however, was significant (see Figure 4.7). These events are discussed in Section 8.2.2 along with our mitigation actions. See also Section 7.2.2 for improvements to operational performance which will help to reduce the impact of outages on customers over time.

Figure 4.5: Key Causes of historic unplanned SAIDI



We anticipate that continued investment in safety beyond the CPP Period will improve reliability performance.

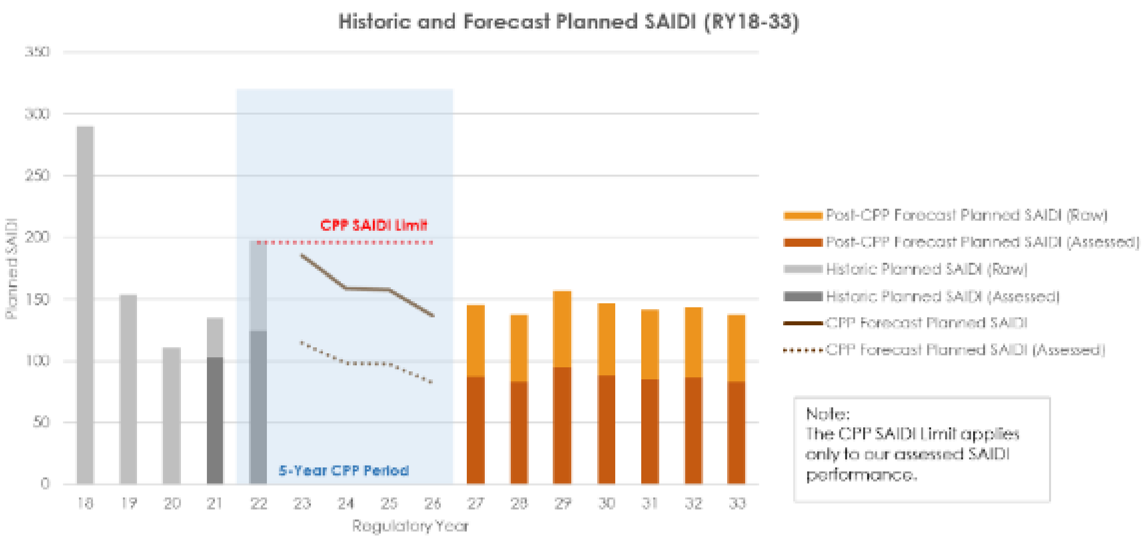
Figure 4.6: Forecast unplanned SAIFI



We can manage our work programmes under the CPP planned reliability allowances

Given our elevated levels of investment during the CPP Period, we expect that current levels of planned outages will persist over the medium-term. Feedback from stakeholder consultation indicates that customers generally accept the need for planned work to maintain, replace and upgrade our network assets so long as notification and communications are well-managed.

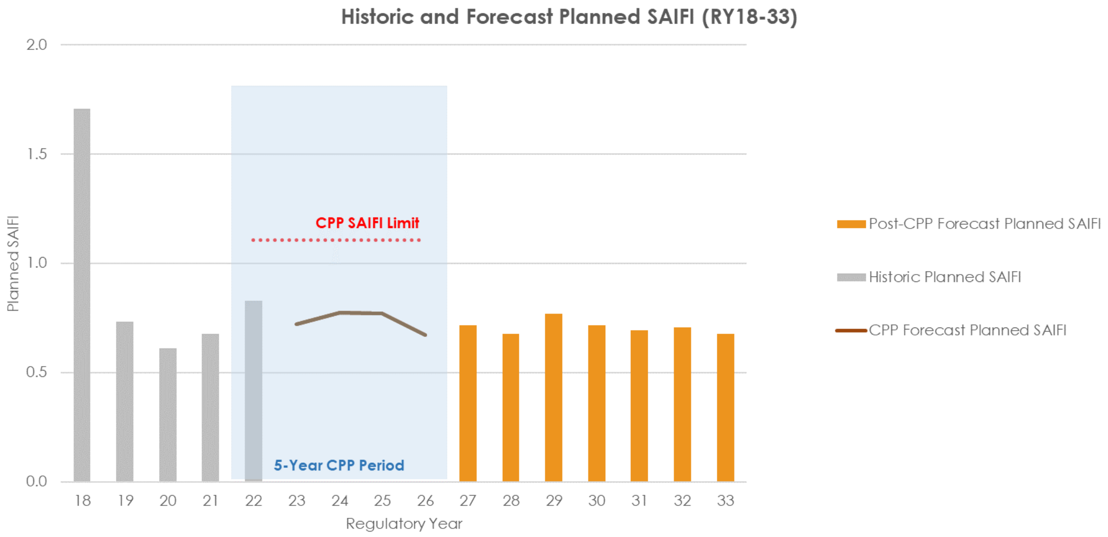
Figure 4.7: Forecast planned SAIDI



We have a significant number of work packages to deliver during the CPP Period, but we are forecast to remain well within our compliance limits.

We note that the DPP3 planned outage framework encourages accurate and timely notification of outages. This is consistent with the views of our customers, and we continue to refine improved processes with our contractors to ensure that planned outages are communicated correctly and managed to plan.

Figure 4.8: Forecast planned SAIFI



Reliability Targets

Reflecting the discussion above, the table below sets out our reliability forecast for the next five years. The forecasts are generated based on previous reliability performance in conjunction with the results of our network investments over the planning period.

Table 4.6: Five-year SAIDI and SAIFI (raw values, by regulatory year)[7]

MEASURE	RY24	RY25	RY26	RY27	RY28
SAIDI - Planned	159.07	157.98	137.13	145.84	137.79
SAIDI - Unplanned	121.48	119.94	117.79	116.76	119.80
SAIFI - Planned	0.77	0.77	0.67	0.71	0.68
SAIFI - Unplanned	1.63	1.62	1.59	1.57	1.58

As discussed above, we intend to consult with customers again later in the CPP and will seek to understand their price-quality preferences at that point in time. This will inform our future reliability targets and guide future investment programmes.

Key Strategies and Initiatives

Although our reliability performance has seen an overall improvement in recent years, we acknowledge that some areas continue to experience an unacceptable number of unplanned outages. In 2022, we began work to identify under-performing network feeders which we have termed 'reliability hot spots'. These hotspots have been identified based on several factors: network SAIDI/SAIFI, average number of outages per ICP, and number of outages per 100 km of network length.

7 It should be noted that our forecasts use raw SAIDI and SAIFI values. The assessed values that we report for compliance purposes will utilise any applicable de-weighting or normalisation mechanisms.

We are conducting further analysis into these areas to identify:

- common outage causes
- any deteriorating trends in performance
- what practical actions can be applied to improve reliability for customers in these areas.

In 2023 we shall communicate with customers in reliability hot spot areas to provide information around work being undertaken and what improvements to expect in the future. We will continue to monitor these areas over time to ensure that targeted improvements have been met. Each year, we will assess performance across the network to ascertain whether new hot spot areas are emerging for targeted attention. Over time, we envisage a better balance of performance across the network, albeit reflecting practically achievable performance taking account of factors such as sparsity, terrain and customer affordability preferences.

The reliability hot spots identified in 2022 have represented a significant portion of our total unplanned SAIDI and SAIFI values. By making improvements in these areas, we expect benefits for overall network reliability.

See Appendix C for more information on our improvement initiatives for network performance.

4.6.3. Affordability

The affordability objective area was introduced into our business as part of our 2020 AMP. As a result, we have limited historical performance information. In future, we expect to report on our performance in this area as we develop clear metrics to monitor our progress.

Context

We recognise that affordability is a key concern of the customers we serve. To reflect their interests, we have included this new objective area in our asset management framework to ensure that affordability continues to be a central objective informing our investment planning and network operations.

> **Box 4.3: Affordability Objective**
> Our objective is to right size our service, delivering a safe network that balances reliability performance with the impact of prices on customers.

We understand that the affordability of our service will be different for each customer and, in this context, it is difficult to strike the right balance between level of service and affordability for all customers. However, our affordability objective ensures that we consider the impact of our asset management decisions on affordability across all customers.

It is common to create 'optimum investment' objectives in asset management and, as part of delivering an affordable service, we will ensure that our decisions are cost-effective. We have introduced an 'affordability' objective to create an extra level of challenge to manage costs. For example, consultation told us that cost-effective or optimal levels of reliability are not affordable at this time and we need to focus on delivering a safe but affordable service in the short-term.

We plan our future investment to deliver a safe and a valued network service to customers, but we must sometimes balance a range of competing, and potentially conflicting, objectives. We need to right-size the services we provide, costs we incur, and the impact of prices on customers in such a way that ensures safety and promotes customers' long-term interests.

Customers told us that affordability was a key concern of theirs (see Section 2.3). Our 2020 CPP application took this feedback into account and adjusted our planned expenditure. We introduced expenditure reductions and efficiencies compared to our initial proposals so that overall, price increases will be more affordable.

We believe this outcome aligns with feedback we received from customers that we should focus on affordability and efficiency of our spend.

This process of customer engagement and internal challenge has helped to ensure that we focus on affordability of our investment plans. We aim to strike the right balance between keeping electricity costs affordable while investing in our assets to ensure they are safe and deliver valued service to today's customers and to future generations.

Box 4.4: What we mean by 'price'

As we developed our proposed CPP investment plan, we consulted extensively on our planned investments and the potential impact on future electricity prices. When referring to price here, we note that retailers' tariffs determine how actual distribution charges are passed through to end-consumers.[8] These tariffs are driven by other considerations including the retailer's competitive stance, pervading energy prices, and transmission tariffs.

Key Strategies and Initiatives

Our AMP investment plans seek to maintain a balance between the desire to minimise price increases today against the need to deliver safe and reliable network services over the long-term. Fundamentally, we need to maintain an adequate level of network investment not only to ensure that we meet the required performance levels, but to prevent the need for significant re-investment in future years. To ensure we get this balance right, we have identified the following strategies and initiatives:

- we will develop a set of enduring measures to monitor our success in delivering services that are affordable and represent value for money to customers and stakeholders
- we will optimise our cost performance through process and capability improvements
- we will aim to do the right work, at the right time, for the right cost
- recognising that our customers are diverse and value a range of price-quality trade-offs, we will look to tailor our consultation processes to understand their preferences
- we will focus on the value we deliver to customers
- we will test our costs and benchmark these to support future improvement
- we will actively seek alternative solutions to improve cost outcomes.

8 Like most EDBs in New Zealand, we operate under an interposed model where distribution costs are 'bundled' into electricity prices by retailers. Consumer bills may not be disaggregated sufficiently to identify the distribution portion of the bill.

As a lifeline utility that operates assets that pose significant safety risks, we have limited discretion in some of our decision-making. Ensuring overhead assets are properly maintained is one such example. However, there are alternative approaches and investment pathways to achieving safe outcomes. We will pursue the most cost-effective of these approaches and pathways over the AMP planning period.

During the CPP Period, we are committed to making improvements towards our cost estimation capability. Our Cost Estimation Practices Plan will support greater accuracy and efficiency in terms of project costs, and it should help us to deliver improved value to our customers. For more on our development plans, see Chapter 9.

4.6.4. Responsiveness

The responsiveness objective area addresses the need for network improvements to address changes in technology and in electricity usage, and we have begun to increase our focus in this area as we take no regret actions to prepare for the future.

Context

As outlined in our asset management policy, we anticipate future disruptive shifts in technology, customer expectations, and the way our network is used. Aligned with this are the Governmental targets for carbon zero initiatives with stage gates for the public sector to be carbon neutral by 2025 and reducing all greenhouse gases, except biogenic methane (which has its own targets) to net zero by 2050. We will need to develop 'least regrets' plans that meet short-term needs while providing long-term practical value to our customers against an uncertain future.

Box 4.5: Responsiveness Objective

We aim to anticipate changes in the environment, new business models and customer preferences around new technology, to allow us to develop plans and least regrets actions that enable improved resilience and the flexibility to provide enhanced services in the future.

We are also aware of climatic changes and the increasing rate and severity of natural disaster events. We need to develop our plans to respond to changing weather patterns and build additional resilience to natural disaster events. Fortunately, technological improvements such as improved automation and artificial intelligence (AI) solutions afford us greater predictive capacity to plan and respond to such events.

By making responsiveness a key asset management objective, we aim to maintain a network that meets the long-term needs of customers by embracing opportunities to better align with a changing landscape. To achieve our aim, we need to pursue learning and innovation, a positive and agile culture where individuals are engaged, and teams collaborate to deliver business outcomes. We will need to continue to invest in improving our teams' capability to identify and monitor disruptive and opportunity factors that may impact the planning and operation of our network.

Aurora Energy recognises that our network will be impacted by a general increase in electrification due to decarbonisation. Increasing adoption of electric vehicles (EVs), distributed energy resources (DERs), and other innovations will prompt a change in demand and increased use of 'edge' solutions that may cause significant change to typical demand profiles.

By adapting to evolving technologies, we can also explore alternative means to improve network performance. As an example, we have engaged a third-party DER solution in our Upper Clutha region to provide a non-network solution to reduce peak load demand. As a result, we can postpone the need for expensive network upgrades. For more on our Upper Clutha DER solution, see Chapter 6.

Key Strategies and Initiatives

The levels of network investment we are proposing during the AMP period are significant. Our approach will need to respond to a changing natural and business environment and evolving customer needs if our investments are to remain prudent and efficient, thereby moderating costs and limiting price increases to customers.

As an organisation committed to continually improving our asset management approach, we understand that capability development (E.g. embedding appropriate processes, systems, and techniques in the organisation) is a key enabling step in ensuring we can effectively respond to a changing environment.

Responding effectively to opportunities in network architecture, enhanced resilience, and new generation sources will need new skillsets and analytical techniques. While more traditional engineering competencies (E.g. network planning and demand forecasting) will see change and refinement.

To ensure we can effectively respond to the opportunities and challenges we will face over the AMP planning period, we have developed a set of initiatives, including:

- monitoring the preferences and expectations of our customers through surveys and consultations
- engaging with leading industry and academic groups to enhance our approach to asset management and new distribution network operating models
- building skills related to innovation, research and development, piloting new solutions, and developing these to a maturity suitable for incorporating into ‘business-as-usual’
- developing our asset management competency, including collaboration with our industry peers, to allow staff to develop new skills, and provide new challenges
- increasing use of scenario analysis to inform our long-term planning
- developing a comprehensive roadmap for the ICT solutions that support network operations
- managing and effectively analysing increasing volumes of network and asset data
- building a ‘learning’ approach to asset management and operational decision-making
- enhancing our customer-facing capabilities, to help us better understand customer requirements and emerging trends, and how these could be reflected in our decision-making.

The above initiatives will be formalised and embedded within our asset management development plan (discussed in Chapter 9).

4.6.5. Sustainability

We introduced our sustainability focus in our previous AMP. As a result, we are still in the process of establishing standard requirements and measures of performance throughout the business. In future, we expect to report on our performance in this area as we monitor our progress.

Context

Sustainability, in a broad sense, means undertaking our role as a long-term, financially stable EDB in a way that does not negatively impact on the communities we serve or the wider environment. Sustainability includes our role as an electricity distribution business and the manner in which we manage our assets.

> **Box 4.6: Sustainability Objective**
> Our objective is to make asset management decisions that consider the long-term impact on our communities and the wider environment, while ensuring the long-term viability of our business.

We aim to provide an enduring network that meets customers' long-term needs, to ensure that we can provide electricity services to support the future growth and wellbeing of our communities. However, we understand that our activity (like most infrastructure operators) can have unintended negative impacts. We will look to put in place right-sized processes and practices that enable us to measure and ultimately reduce our overall environmental impact.

Of course, we will aim to comply with all statutory and regulatory requirements and follow all required standards and codes of practice.

Thinking of our organisation and our role as asset managers, being a sustainable business means having the ability to endure, providing assurance that we can 'be in it for the long haul'. It means operating and investing in a way that ensures our success over the long-term. In the three years prior to the 2021 CPP determination, we have lifted network investment well above our regulatory allowances to address our ageing asset fleets and in support of economic growth in our communities. The CPP determination has provided additional revenue, which allows us to continue sustainably in our efforts to return our network to a healthy state.

Key Strategies and Initiatives

To support an increased level of sustainability practice within our business, we have developed a Waste Reduction Strategy and an Emissions Reduction Strategy. These strategies formalise our approach to reducing waste and emissions, articulating our commitment in these areas and contain an action plan with targets for us to achieve.

Our overall sustainability strategy includes the following set of initiatives:

- managing the environmental aspects of our assets by considering use of available space, resource consents required, constructability, resource availability, and equipment materials and manufacture
- assessing environmental risks with investment options and maintenance approaches
- limiting negative impacts from insulating mediums (E.g. oil, SF_6)
- extending investment analysis to include noise pollution and visual impact

- over time, we will aim to reduce carbon-footprint by reducing emissions related to our activities and investigating ways to further offset any remainder (E.g. tree planting)
- reviewing tenders from the perspective of environmental impact associated with the manufacture of assets and materials
- managing disposal practices for end-of-life assets, including responsible handling of recyclable and hazardous materials
- encouraging sustainable energy solutions in the regions we serve, including defining workable criteria and conditions for sustainable generation (DER) and enabling adoption of EV transport.

We believe that being a sustainable business will help us improve our performance as an EDB, provide a stream for innovation, help attract and retain staff, and strengthen our relationship with stakeholders. It will be an increasingly important focus for us over the coming years.

Within each of our asset fleets, we have identified sustainability objectives where appropriate. For example, within our zone substation assets we aim to prevent oil spills and release of hazardous SF_6 gases by ensuring that we manage these assets according to good industry practice. See Chapter 8 for further information.

4.7. RISK MANAGEMENT

Risk management is a fundamental asset management discipline, and all our asset management decisions are linked in various degrees to managing risk. In our 2023 AMP, we have continued our focus on network risk and developing a more robust risk management framework.

Our Risk Control and Management Standard outlines the necessary requirements for successful risk management. This includes establishing policies and standards, as well as procedures and rules to manage the activities of our employees or any contracted entities. The Standard applies to all aspects of planning, investigation, design, construction, commissioning, operations, and maintenance work.

Our risk management activity includes controls across several risk areas: managing safety risks, avoiding capacity constraints, managing failure likelihood through maintenance and renewals, and ensuring resilience to help mitigate the consequences of major events.

Risk management is applied at all levels of our organisation – from decisions at Board level, through to operational decisions in the field. The purpose of risk management is to understand the types and extent of adverse events that our business may face, and ensure we respond effectively to these adverse events by applying appropriate controls and mitigations to manage the risks to acceptable levels.

4.7.1. Roles and Responsibilities

Our Board is accountable for the effectiveness of our risk management framework. This helps to ensure that risk management extends throughout the hierarchy of the organisation. The Board is responsible for governing risk policy and overseeing risk management practices.

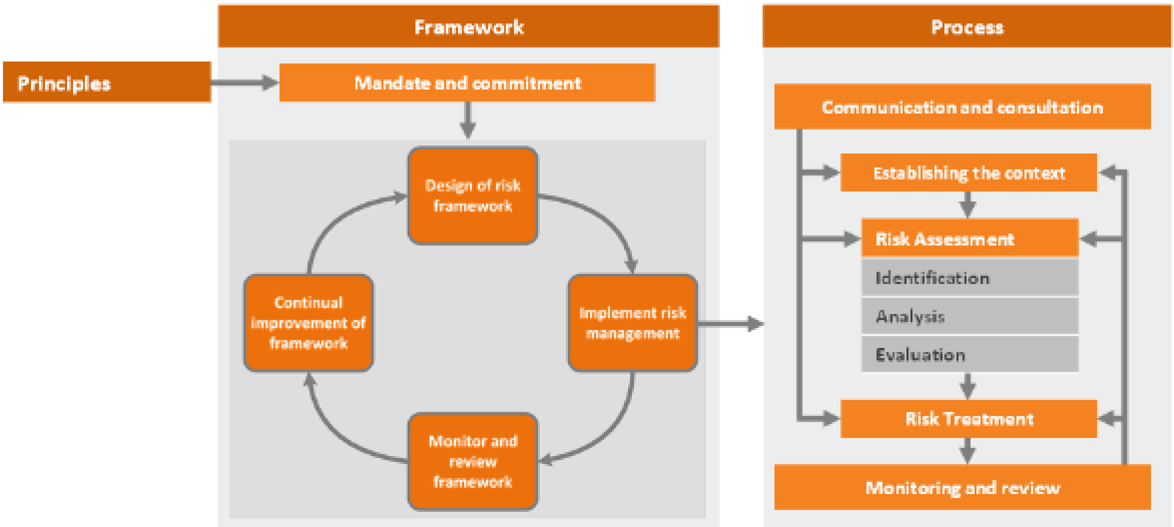
The executive team reviews risk issues regularly and evaluates changes in the strategic and operational environment.

Our management has responsibility for implementing the risk management framework. For example, departmental managers and employees are responsible for risk identification, the development of risk treatment plans and the operation of controls such as policies, standards and procedures that mitigate risk within their area of responsibility. Managers also ensure staff are aware of their risk management obligations through training and assessment.

4.7.2. Risk Management Framework

Effective risk management requires a framework that is built on sound governance processes and uses effective procedures and controls.

Figure 4.9: Risk management framework



We have defined a set of principles (listed below) that help guide the operation of the framework and ensure that it reflects our objectives as a business. Our risk management framework should:

- be an integral part of organisational processes
- form part of decision-making
- explicitly address uncertainty
- be systematic, structured and timely
- utilise the best available information
- be tailored
- take human and cultural factors into account
- be transparent and inclusive
- provide dynamic, iterative responses to change
- facilitate continual improvement and enhancement of the organisation.

The risk framework we apply is consistent with ISO 31000, and is illustrated below.[9]

Our risk framework covers all areas of our business, including health and safety, financial, legal and regulatory, delivery, and so forth. For the following, we focus primarily on our approach to risk from an asset management perspective. Chapter 5 sets out in more detail how this framework is applied to our lifecycle management of network assets.

4.7.3. Safety Risk Management

Our asset management policy requires safety, nothing less. It also requires us to create a safe working environment for our staff and contractors and to take all reasonably practicable steps to protect all people affected by our assets and asset management activities. We will achieve this through safety-in-design, building a high-performance safety culture, and implementing and monitoring critical controls. Our safety focus to asset management also prioritises a proactive approach to asset renewals to limit as low as reasonably practical the risk of public harm due to asset failure. Chapter 5 outlines clearly our approach to asset renewals from a safety mitigation perspective.

In the event of safety incidents or near-misses, our ICAM investigation process is used to identify a root cause, to implement methods of control, and to monitor the effectiveness of these controls. The ICAM process involves representatives from several areas of the business to ensure wider coverage of the issue and its resolution.

Our business plan supports our asset management policy by seeking a safer workplace through improved operational discipline. Identifying and managing safety risks associated with our network and activities is fundamental to our business.

Workplace Safety Risk Management

Our commitments to workplace safety include that we:

- are committed to providing a safe working environment
- believe that safety is everybody's responsibility and that our leaders both influence and set the tone for wider safe behaviours at work and in the community
- actively seek to build a positive culture that places safety at the forefront of all that we do while recognising we must always strive to improve
- believe that all incidents are preventable: that anyone can stop an unsafe act and all our people and contractors are empowered to manage and control all the hazards and safety risks they see. We expect our people to take a lead in this
- believe that everyone has the right to come to work with the expectation that they will return home safe and healthy, every day.

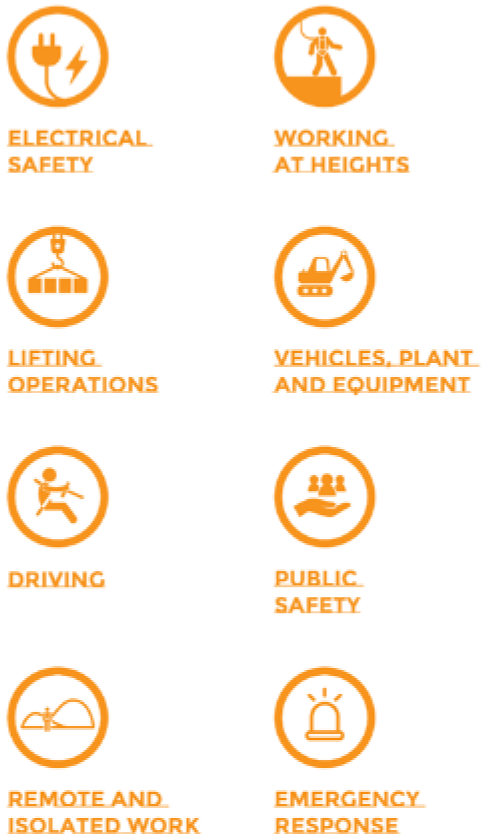
[9] ISO 31000 is a family of international standards relating to risk management codified by the International Organisation for Standardisation.

Public Safety Risk Management

We are committed to maintaining and improving the physical safety of all assets on our network and to educating the community on how they can stay safe around electricity.

We are required to have a public safety management system (PSMS) under Section 61A of the Electricity Act 1992. We maintain a PSMS that complies with NZS7901:2008 Electricity and Gas Industries – Safety Management Systems for Public Safety, and this is audited annually. The intent of our PSMS is to prevent serious harm to any members of the public or significant damage to their property. The methodology we adopt is to ensure that we:

- identify hazards associated with our electricity assets in both normal and abnormal conditions
- assess the risk of serious harm to the public, or significant damage to their property, that may arise from any identified hazard
- eliminate, isolate or minimise significant hazards to the extent that the residual risk is as low as reasonably possible.



Our safety rules

We have established a set of safety rules based on critical risk areas where there is a significant risk of serious harm or fatality during work activities on our network. The purpose of defining the nine critical risk areas is to focus our safety behaviour and improvement initiatives in areas that will have the most impact in reducing the risk of serious harm. The critical risk areas include:

- always use equipment that is fit for its intended purpose and wear personal protective equipment
- always protect the Public from the work site
- never leave electrical equipment unsecured
- always tell someone where you are when you are travelling or working alone
- always know the emergency response plan
- always follow all electrical isolation and operating instructions
- never work or walk under a suspended load
- always keep a minimum safe distance from moving vehicles live equipment or working machinery
- always protect yourself from a fall when working at height

4.7.4. Asset Risk Management

Consideration of risk plays a key role in our asset management decisions – from network planning and asset replacement decisions through to operational decisions. Our asset management systems and our core planning processes are designed to manage existing risks, and to ensure that emerging risks are identified, evaluated and managed appropriately.

Chapter 5 discusses our approach to fleet management in terms of asset-specific risk, while Chapter 6 covers our approach to managing network-wide risks.

4.7.5. Major Hazards and Incidents

Our network is exposed to a wide range of natural hazards and other causes of severe incidents. We have a responsibility as a lifeline utility to provide levels of resilience that will minimise loss of service when we are exposed to a major natural hazard or in the event of extensive outages. Our approach to managing the risks of major hazards and incidents is set out in Section 4.9.

4.7.6. Other Risk Areas

In addition to safety and asset-related risks, we monitor a number of other risks. These include:

- deliverability/resourcing: the risk of not being able to access sufficient numbers of competent staff, service providers and suppliers to implement our asset management plans in a timely manner.
- environmental planning delays: resource consent requirements and the possibility of objector delays creates uncertainty and the potential for delays to implementation of planned works.
- regulatory and compliance: failure to comply with legislative and regulatory requirements.

4.8. ASSET MANAGEMENT GOVERNANCE

Asset management governance is our term for the system of roles, responsibilities, authorities, and controls that support our asset management decision-making. This section explains our approach to asset management governance and outlines the process used to test our individual investment plans and our overall expenditure.

Asset management decision-making occurs at various levels in our organisation – from the Board through to our planning and delivery teams. Investment decisions take place within a system of responsibilities and controls that reflect the cost, risk, and complexity of the decision being considered.

As discussed in Box 4.7, we have made a series of improvements to our approach to expenditure governance. We expect these processes and structures will continue to evolve as we improve our asset management capability and support this with improved systems.

Box 4.7: Expenditure governance

Since our 2018 AMP, we have continued to adjust and improve our approach to investment decision-making and expenditure governance. This has included introducing:

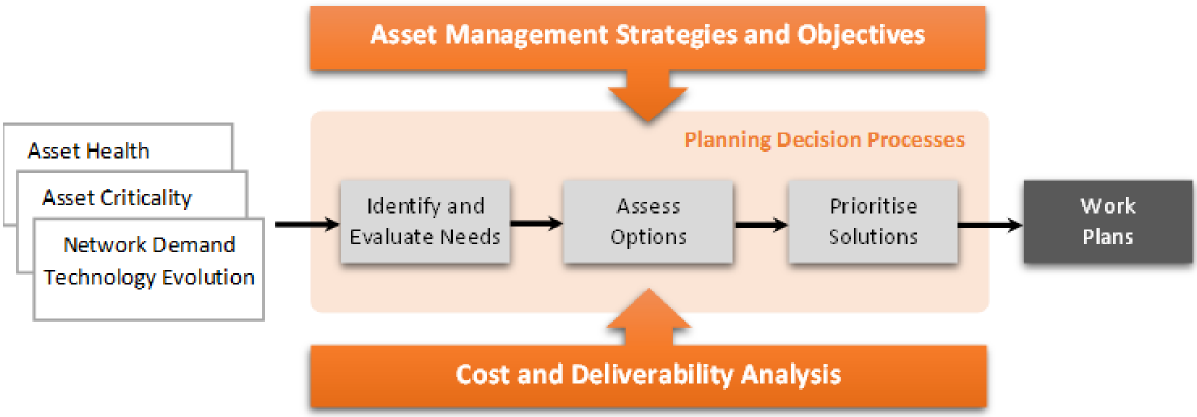
- formal deliverability testing to ensure our work programmes can be delivered cost-effectively and to plan
- implementation of a centralised price-book to ensure transparent and repeatable project costing
- benchmarking of maintenance costs to inform our forecasting approach
- external review of capital project costs to test and review internal cost estimates

We describe our organisational structure and its main governance levels in Chapter 2.

4.8.1. Decision-Making

We have transitioned to a more systematic decision-making approach for network investments, as illustrated below. Chapter 5 provides detail on how this generalised process is applied to all our lifecycle and network investments.

Figure 4.10: Generalised investment decision-making process



The main steps in the investment decision-making process illustrated above are:

- **identify and evaluate needs**: this involves the systematic review of asset safety, network capacity constraints, network security, performance, asset health, maintainability, spares availability, and a range of technological, network and site-specific feedback.
- **assess options**: in this step, potential options are developed for each identified need. These options are defined and costed to varying degrees based on the complexity and scale of the identified need, and the costs of feasible solutions. The potential solution is evaluated against approval criteria and challenged.
- **prioritise solutions**: in this step, solutions that have been developed in previous stages or previous planning rounds are prioritised based on the risks associated with the identified need, deliverability, across project coordination, and trade-offs with other investment needs. A preferred solution is identified that may include bundling of multiple needs into one packaged solution.
- **work plans**: the prioritised solutions will be entered into a draft work plan, which sets out planned works with the associated expenditure forecasts. The deliverability of the overall set

of solutions is evaluated in more detail, and cross-portfolio expenditure balancing is undertaken if required.

The degree to which the above steps have been formally adopted varies across our expenditure categories.

Delegated Financial Authority

Our delegated authority policy (FS-S018) sets out the limits to which employees can commit Aurora Energy to financial transactions or contractual obligations, managing the exposure to financial risk. The limits assigned to a role reflect whether the expenditure is Capex or Opex, budgeted or unbudgeted.

4.8.2. Service Delivery

Our field service activities, including maintenance and construction, are fully outsourced.

As described in more detail in Chapter 2, we have recently established new contracting arrangements via three new field service agreements. This involved the establishment of two new service providers to operate alongside the previous incumbent. This allows for the increased use of competitive tendering, and will lower the risk of under-delivery and help ensure we receive efficient and market-tested pricing.

Our delivery team manages service provider contracts and the delivery of all Network Capex and Opex work. The works delivery process relies upon technical standards to help ensure safety, quality and cost-effectiveness. We have developed an extensive set of specific technical standards for design, procurement, installation, and maintenance. These standards are subject to ongoing review and improvement.

Delivery of New or Altered Connections

Aurora's new way of planning and managing communication with consumers about new or altered connections is the Aurora Customer Initiated Works (CIW) Contractor Portal, whereby a connection application is made to Aurora by the Authorised Network Contractor or Inspector engaged in the pursuit of a new or altered connection. The contractor enters application data into the portal, which is then used by Aurora to approve the applications and create ICPs where necessary. Upon submission of the application, all relevant parties are notified that the application has been submitted, via an email notification. Once an application is approved, again, approval is communicated to all parties via an email notification. Once the Customer, Network Contractor(electrician), Inspector & Retailer (New connections only) receive their approval notification, the job can then be arranged to go ahead.

Once a job is complete and the inspector has filled out the livening report imbedded in the portal application, Aurora's database is updated, along with the Electricity Authority Registry (When applicable) and a final email notification is sent out to all relevant parties.

We acknowledge that our customers sometimes experience delays with the delivery of network connections, which is often beyond Aurora's control as the timeframes are usually in the contractor's realm. To alleviate delays in network projects, growth and maintenance, Aurora introduced the external contractor model to enable more Network Contractors to be authorised and available, so that more design and manpower is available to enable more options for customers to engage contractors to do CIW work and for Aurora to be able to ensure more service work done in time. We anticipate this approach will also help improvement of the costs for customers and Aurora through the competition between contractors.

4.8.3. Works Delivery

We assess potential delivery constraints as part of our investment decision-making and project management process. The primary factors to be considered when accessing deliverability of our works programme include: seasonal timing to meet customer preferences, avoid planned outages during peak loading periods, the necessary order of interconnected projects, resource constraints, and professional engineering judgement.

Works Cost Management

For capital works we have developed a 'price-book' taking account of works pricing across the NZ electricity distribution sector and recent pricing on our network. These prices (or unit rates) include design, project management and construction, but exclude contingency.

For volumetric work such as poles, we apply modified unit rates that consider the percentage of associated works that would be undertaken at the same time as a pole replacement. These are applied to our long-term forecasting and short-term budgets, knowing that the risk of variances in actual volumes and construction costs will generally average out across a large number of assets over time.

For low volume, major project work such as zone substation rebuilds, we go for competitive tender with contractors with suitable competency. Where tender prices or project variations lead to costs that exceed approved budget, Board approval is sought for additional budget.

Our 10-year plan is reviewed every year, taking account of changes in demand, customer preferences and works coordination (see below). Generally, this results in a reprioritisation of projects and does not lead to significant changes in forecast costs. Customer-driven works can be dynamic and can lead to under or overspend of budgets in consumer connections and network reinforcement. These exceptions are managed as required through DFA and our Board where necessary.

Over the CPP Period, we aim to improve our approach to cost-estimation. See Chapter 9 for our cost estimation improvement plan, as well as other key initiatives that are being undertaken.

Works Resourcing and Contract Management

We aim to maintain a steady workflow to service providers and ensure project diversity is preserved within a given year. This ensures that contractor personnel and equipment levels and availability of materials match our capital build programme year-on-year at a consistent level, reducing the risk of our contractors being over- or under-utilised.

Works Coordination

As we refine our delivery processes and address critical risks, we will be able to place greater emphasis on works coordination to minimise community disruption and increase works efficiency. This may cause us to bring forward, or defer, if possible, projects to avoid major additional outages and related expenditure (E.g. traffic management). This includes coordination with the New Zealand Transport Agency and other utility activity (E.g. future road-widening or resealing programmes) to avoid the need to re-lay cables or excavate and then reinstate newly laid road seal.

Required Outages

In recent years, we have escalated the amount of planned works on our network in response to worsening asset condition. As a consequence, our customers have experienced an increased number of outages as these works are carried out. The feasibility and timing of projects is assessed by considering both the need for planned outages and their impact on customers (as reflected in our regulatory quality standards). While it is important to ensure outages are minimised as far as practicable to manage customer expectations, we must also consider the need to maintain our network to ensure safe and reliable performance.

Coordination with Transpower

We endeavour to coordinate any major network structural changes adjacent to a GXP with Transpower's planned asset replacement programmes, and also engage with Transpower to ensure consistency with our sub-transmission upgrade plans.

Other Work Programmes

We extensively review areas of the network where scheduled asset replacement programmes occur to ensure the most efficient and cost-effective solution is implemented to fit in with the current and long-term network development structure, for example replacement of switchgear in substations. We seek to schedule any major substation works and upgrades to coincide with asset maintenance programmes.

4.9. RESILIENCE

Planning for resilience is an essential element of asset management for lifeline utilities. We respond to many incidents routinely, as part of normal business. Our business continuity framework guides our strategy to the management of high-impact, low probability (HILP) events and other hazards that result in business interruption. Some examples include natural disasters, pandemics and cyber-attacks. We have a responsibility as a lifeline utility under the Civil Defence Emergency Management Act to provide levels of resilience that will minimise loss of critical business processes during an emergency event. The approach is outlined in the diagram below.

Figure 4.11: Business continuity approach

Reduction	Readiness			Response	Recovery		Review
Risk Management	Business readiness			Emergency response	Business as usual		Lessons learnt
Business impact assessment	Business continuity plans	Recovery plans	Document review & training	Incident management	BCP in action	Return to business as usual	Incident review and continuous improvement

4.9.1. Our Approach

Our current approach is based on the 4 Rs of business continuity – Reduction, Readiness, Response and Recovery, as used by emergency services, Civil Defence, emergency management organisations, and other lifeline utility operators in New Zealand. Reduction not only focusses on risk identification, but also includes risk mitigation plans, which may encompass resilience projects. We have added an additional R of review to ensure we are continually improving our business continuity framework.

Therefore, our approach (as depicted above) has the following five elements:

- reduction: identifying and analysing risks to the business, assets and community, and taking steps to eliminate or reduce those risks in accordance with our Risk and Control Management Standard
- readiness: developing operational systems and capabilities before an incident occurs so that the organisation is prepared, trained and tested to respond in a way that will ensure the business can return to full operational capacity as soon as is possible
- response: actions taken immediately after an incident occurs to protect life and assets, and take initial actions to ensure the business can consider returning to full operational capacity
- recovery: coordination of the organisation (and potentially external organisations) to return the business to full capability (recovery can take weeks, months or years depending on the severity of the incident, E.g. the Canterbury earthquakes)
- review: periodically reviewing documentation in the business continuity framework to ensure they reflect current best practice. Following a major business interruption response and recovery, conducting lessons learned to identify improvements to be incorporated into the 4 Rs.

All lifeline services rely to some extent on some or all of the other lifeline services in order to operate. Therefore, a hazard impacting on one lifeline service is likely to have a knock-on effect on others, such as the loss of power impacting water and wastewater services. Similarly, the loss of mobile phone networks (E.g. following an earthquake) can severely impede restoration efforts, in the absence of a dedicated radio system. To mitigate the risk that arises from this interdependence, many lifeline utilities have backups (for example, on-site generators) should other lifeline services fail. We consider the extent of the interdependence between our operations and other lifeline sectors when developing our business continuity planning and our network development and lifecycle investment plans.

4.9.2. Potential Impacts of Natural Hazards

We have participated in the Otago lifelines project to identify risks relating to potential hazards. The purpose of this project was to assess the potential impacts of hazards on the region's lifeline infrastructure, identify mitigation strategies to reduce that risk, and to improve critical infrastructure resilience. To aid our resiliency planning, we also sought additional expert advice on the impact of natural disasters on the Dunedin and Queenstown sub-transmission networks.

This programme of work identified that storm/flooding, earthquakes (including secondary impacts such as landslips, tsunami and liquefaction) and high winds are our major natural disaster risks. These are discussed in more detail below.

Storm/flooding

While distribution lines are unlikely to suffer damage from floodwaters, the biggest potential for damage is inundation of our Dunedin substations. Full restoration following such an event could take days or weeks. Critical sites in flood risk areas include:

- Transpower's South Dunedin substation (GXP) which services 21,000 customers
- Mosgiel zone substation
- our underground substations in the Dunedin CBD.

We have effectively mitigated some of these risks, for example the use of temporary barriers at Mosgiel zone substation. We are progressively addressing the remaining identified risks and will continue to do so over the AMP planning period. We also have a long-term plan for the staged introduction of a more interconnected Dunedin sub-transmission network to enable load switching between GXPs.

Earthquakes

There are a large number of active faults in Otago, and many more outside the region are capable of affecting infrastructure in the region. While ground shaking will almost always be felt during large earthquakes, the extent of liquefaction, lateral spread and surface rupture is dependent on the size and characteristics of earthquakes and the ground conditions in the area under consideration. Completed and continued investments in a number of our zone substation buildings and asset restraints will improve their capability to withstand seismic events.

4.9.3. Emergency Procedures and Plans

Aurora Energy is defined as a lifeline utility under the Civil Defence Emergency Management Act 2002 and is required to ensure that it can operate to the fullest extent, even if at a reduced level, during and after an emergency. We have recently updated our business continuity and emergency response plans to enable us to respond to events beyond our control, as set out below.

Business Continuity and Emergency Preparedness Programme

We developed a business continuity and emergency management standard. Supporting reduction and readiness under the standard is the organisational business continuity plan (BCP) in place that defines our critical business processes and maximum acceptable downtime for these processes. The

BCP also defines the process for activating a response and the level of response required depending on the assessed severity of the business interruption. We have developed an emergency response plan (EMP), which provides a scalable process for managing a response to an event. The EMP is based on the NZ Government Coordinated Incident Management System (CIMS). A number of specific hazard response plans have been developed to support the EMP.

The programme also includes staff training in CIMS level 4, and simulation exercises to demonstrate capability and competence.

Within the business we have also established an Emergency Communications Plan to ensure effective communication within the business, with other organisations, and with our customers and external stakeholders. The plan outlines responsibilities for key personnel, pathways for communicating with various groups, and processes for assessing our performance.

Pandemic

In accordance with our business continuity and emergency management standard, during the initial stages of the COVID-19 outbreak, we developed a specific pandemic plan under the business continuity framework to ensure readiness should the situation escalate. As the situation escalated in New Zealand, we activated our emergency response plan to ensure critical business processes identified in the BCP were maintained to minimum acceptable levels.

An Emergency Response Team (ERT) was formed to manage the operational response, which included successfully transitioning staff to work from home, maintaining a safe working environment for the network control room, identifying safety critical work required on the network, and establishing a safe working framework in the field. The ERT remained in place until the end of the level three lockdown.

By applying the emergency procedures and plans, we were able to control and clearly communicate actions required and taken to manage the situation and reactivate the works programme in a seamless manner.

Whilst the pandemic is over, we are well placed to manage any future COVID-19 outbreaks, or pandemics.

Contingency Plans

Contingency plans are used to assist in the timely restoration of supply following an outage to a major distribution feeder or zone substation. It should be noted that it is not possible to transfer peak loads at most substations for rare double-failure events such as failure of both sub-transmission circuits, or both transformers at the larger substations.

Contingency Plant

We own one mobile zone substation, mobile distribution substations and generators, as described in Chapter 8. The range of these assets are designed to provide backup to our N-security zone substations and HV feeders under a variety of contingent scenarios. We also have an agreement with other Dunedin City Holdings Limited (DCHL) companies to facilitate sharing of equipment in supporting an emergency response.

4.9.4. Incident Management

Our response planning incorporates the use of CIMS, which is used by emergency services, Civil Defence emergency response organisations, and many utility operators in New Zealand for managing the response to an incident involving multiple responding agencies.

5. OVERVIEW OF ASSET LIFECYCLE MANAGEMENT

In this chapter we describe our approach to how we manage assets throughout their lifecycle. As we progress through the CPP, we seek to remove or reduce to acceptable levels, the safety risk that our assets may pose.

This chapter covers:

- How we group our assets into portfolios and fleets to better control work streams (section 5.2)
- How we define and apply safety risk to our assets (section 5.3)
- How we approach the four key stages of lifecycle management (section 5.4)

5.1. INTRODUCTION

We use the term 'lifecycle' to recognise that there are distinct phases in the ownership of an asset, where the term 'management' describes our custodianship of an asset. We realise that effective asset management relies upon a holistic approach that considers the full asset lifecycle.

Our methodology is typical of an infrastructure utility company in that it governs the 'why and how' we manage assets through their life. We have exited a period of reduced investment in the Aurora Energy asset base that resulted in an increase in safety risks presented by our assets (our approach to safety risk is discussed below).

To ensure that we commit capital to areas that reduce our public safety risk we have tailored the 'why' to reflect this. Our approach is consistent with the key driver of our CPP proposal as accepted by the Commerce Commission, to effectively address current and emerging safety risk associated with our network.

As part of this process some assets may be cascaded from locations that have a higher impact if they fail to lower impact positions in our network, even though the asset may still have several years of operational life remaining. In this chapter we discuss the opportunities to relocate these assets with associated costs, to maximise their value.

5.2. ASSET FLEETS

Aurora Energy owns and operates a substantial number of assets to supply electricity to 93,600 customers. Our current categorisation of assets has seven asset portfolios, which are then further subdivided into 28 fleets by their functionality, shown in table 5.1 below.

This structure was developed for our CPP application and is used in our day-to-day and longer-term asset intervention strategies. It offers the granularity required for the appropriate level of safety interventions and accounting for works. Our portfolio and fleet structure differs slightly from the asset categories used in the Commerce Commission Information Disclosure. We believe that a bespoke solution better reflects the way we manage our assets and plan our investments. Furthermore, we have continued working on a new asset classification within the scope of our Maximo AMS project (see Section 9.3.3).

Asset data is held in two systems, the primary being our GIS database, which is mirrored in our under-development computerised asset management system, MAXIMO (part of our asset management framework that outlines our pathway to ISO 55000 certification). Each of these databases are searchable by asset fleet.

Table 5.1: Portfolio to fleet mapping

PORTFOLIO	ASSET FLEET
Support structures	– Poles – Crossarms
Overhead conductor	– Sub-transmission conductor – Distribution conductor – LV conductor
Underground cables	– Sub-transmission cable – Distribution cable – LV cable
Zone substations	– Buildings – Power transformers – Indoor switchgear – Outdoor switchgear – Ancillary equipment
Distribution switchgear	– Reclosers and sectionalisers – Ground-mounted switchgear – Pole mounted fuses – Pole mounted switches – LV enclosures – Ancillary distribution substation equipment
Distribution transformers	– Ground-mounted distribution transformers – Pole mounted distribution transformers – Voltage regulators and auto-transformers – Mobile distribution substations
Secondary systems	– Remote terminal units (RTUs) – Protection – Batteries and DC supplies – Communication assets – Metering

5.3. ASSET RISK

We have opted to adopt a non-negotiable approach to the safety risk presented by our assets. This covers every aspect of asset lifecycle management. The way in which we address risk forms part of our maturity pathway.

In our safety delivery plan, developed as part of our CPP documentation, we differentiate network safety risk by:

- Safety to the public, the health and proximity of assets to the public
- Safety of personnel, the health and intrinsic safe design of assets

We draw a distinction between the public and staff recognising that there are different levels of training, experience and exposure to any hazards presented by our assets. The safety driver is equally paramount for everyone, be they public, staff or contractor.

Once we have defined the safety risk for our assets, we can apply treatments and mitigations to bring them to an acceptable level.

5.3.1. Network Critical Risk Special Cases

In our safety delivery plan, we define network critical risk as "*harm to either a member of public or to personnel by an asset*". We recognise the greatest gain for our risk management framework is reduction of the Network Critical Risk by replacing poor asset health items. It must be noted that criticality can have two distinct meanings, the network critical risk defined above as opposed to areas of criticality as given in our GIS.

The groups of assets that present the greatest public safety-sensitivity:

- Support Structures
- Overhead Conductor
- Overhead Switchgear
- Overhead Transformers
- Underground Cables (exposed parts and terminations)
- Ground Mounted Switchgear
- Ground Mounted Transformers

5.3.2. Risk calculation approach

We have developed an innovative process to assess asset risk based on a tailored combination of industry accepted procedures. These are based on guides from the Electricity Engineers Association (EEA) and the Office of Gas and Electricity Markets UK (Ofgem) with some input from other research. The approaches are modified to reflect our fleets and asset mix, augmented by advice from subject matter experts. Fundamentally, risk is the product of an asset's probability of failure (asset health/condition generally used as a proxy) and its consequence (impact generally used as a proxy). The general term criticality is sometimes used, as stated above this should not be confused with network safety criticality which has a very specific definition. This analysis is used to trigger and prioritise investments to manage the identified risks to an acceptable level. Asset health, condition and criticality are explained below.

5.3.3. Asset Health

Asset health reflects the expected remaining service life of an asset and serves as a proxy for its likelihood of failure. Industry guidelines recognise that asset health is not purely age based but also addresses components of historical usage, cost of ownership and compliance. Traditionally age has been the proxy for health thus has been the main driver behind our asset replacement and renewal forecasts. Data from inspections is now feeding condition (see below) into our models improving the accuracy of prediction. Our approach combines condition and age data to modify the base maximum practical life to calculate remaining life. This is a proprietary solution developed in-house which we are calibrating with field data to prove the validity of our model.

Table 5.2 sets out our asset health categories, including the basis for the categories and the expected replacement period. It should be noted that when an asset has reached the end of its useful life (H1), it does not mean that failure is necessarily imminent. Asset health scores serve as an indicator that an asset requires intervention before becoming a safety risk and that further action may be required. We acknowledge that Table 5.2 does not fit all asset fleets; under this scale, a new battery bank with an expected life in the region of 10 years would begin service with an AHI of H3. Current work is set to follow fleet lives more accurately.

Table 5.2: Asset Health (AH) categories

AH Score	Category Description	Indicated Replacement Period
– H1	Asset has reached the end of its useful life	Within one year
– H2	Material failure risk, short-term replacement	Between 1 and 3 years
– H3	Increasing failure risk, medium-term replacement	Between 3 and 10 years
– H4	Normal deterioration, monitor regularly	Between 10 and 20 years
– H5	As new condition, insignificant failure risk	Over 20 years

Changes to Asset Health Modelling in our Disclosure Schedules

As we mature our understanding of asset risk, we continue to refine our criteria for assessing asset health (AHI). As a result, for some fleets, the asset condition ratings in Schedule 12a differ noticeably from previous years. The difference partly derives from greater use of condition data to inform health grading, whereas in previous years the AHI grades were primarily based on age.

The following factors have also influenced our current approach to categorising asset health:

- Incorporating non-conditional factors such as obsolescence into our health grading
- Changing expected maximum practical life (MPL) impacting the grading for age-based fleets
- Adjusting the model to make assumptions around the progression of asset deterioration over time.

While we believe our matured view of asset condition presents us with an opportunity to validate and refine renewal planning, we acknowledge remaining limitations. As our understanding of asset condition across all fleets improves, we anticipate the need to adjust our model and response accordingly. At the current stage, where we recognise asset criticality by public safety exposure, we choose a more conservative approach in our assessment. We anticipate updates to our modelling in future years as our approach to asset risk matures further. We see further improvement of our approach to asset health assessment in greater reliance upon conditional and non-conditional factors incorporated in the asset health index calculations.

Asset condition

Asset condition either reflects normal deterioration due to the asset aging processes or points to an excessive impact of external factors. These factors vary from an adverse environment such as wind or air pollutants to operational regimes and third-party damage such as vegetation or vehicle contact. We have made good progress over the last four years with our plan to include inspection programmes for all our fleet assets.

Our scheduled inspection and testing programmes capture a range of condition information across the asset fleets. Where asset condition data is available at a consistent level of detail across a whole fleet, it is fed directly into asset health modelling. Where there is a lack of previous inspection data or the quality is questionable, we will default to age-based AHI. Asset condition from inspections provides the basis for short-term renewal and refurbishment decision-making.

5.3.4. Criticality of assets with critical risk

For the assets with network critical risks mentioned earlier, we apply asset criticality (1-5) to indicate how high is its potential to harm the public based upon its location and probability of exposure. We have developed criticality frameworks across several fleets from data held in our GIS database. This enables us to prioritise investment in assets by safety consequence of failure, assisting us to achieve our safety risk goals outlined in our CPP Safety Delivery Plan. As part of our maturity journey, we are developing a more comprehensive approach, which will define criticality of assets by several risk categories.

Criticality of Assets segregated from the public

For some of our fleets such as zone substations, criticality is assessed based primarily on worker safety and operational reliability since the public are not allowed access to these secure assets. As such we have a customised criticality framework using weighted aspects regarding:

- worker safety: incorporating protection, clearing time and equipment fault rating compared to actual fault levels
- reliability: load at risk considering size of load, security of substation, type of load (CBD vs urban vs rural), the percentage that can be back-fed from other sources, and network performance
- obsolescence: availability of spare parts and whether the asset continues to operate effectively with other systems.

Impact on environment

Limiting impact on the natural environment of network assets is a core task for our objective of sustainability. We understand that the level to which each asset can interact with its surroundings is particular to that asset type. As a responsible asset owner/operator, we follow the rules and requirements set out in the Resource Management Act, regional and district plans and other relevant legislation.

Some of our assets that pose elevated environmental risks, are those that contain insulation means such as mineral oil or sulphur hexafluoride (SF_6). We have a commitment to maintaining high standards of environmental compliance and managing assets in a manner that minimises, as much as possible, our impact on the natural environment.

We have preventative environment management strategies and procedures in place which seek to reduce or remove the environmental risk associated with our assets in accordance with environmental statutory obligations and industry best practice. These relate to the leakage or spillage of oil into water or onto land, the leakage of SF_6, transformer noise, visual amenity, waste, asbestos, erosion of soil and disturbance to wildlife natural habitat. These risks can drive us to either introduce greater controls, such as through upgrades to oil bunding and containment systems, or to replace assets where the increased failure likelihood leads to unacceptable environmental risk.

5.3.5. Asset risk calculation

Asset risk is the primary driver for our network investments, particularly regarding asset renewal. We recognised the need to develop the methodology laid out below. This populates the risk framework to show the impact and likelihood of asset failures resulting in a forecast for numbers of asset replacements in each field.

We prioritised the development for assessment of volumetric fleets and are using this solution to guide the best outcomes for allocating capital to renewal and replacement work. Continuing this innovative approach we are currently developing the forecasting tool for targeted and scheduled fleet replacement and renewals; Table 5.3 on page 98 shows the renewal strategy to fleet type.

To calculate network risk we take fleet data from our company databases and perform quality analysis to ensure the information generated from this data is fit for purpose. Aurora asset health criteria (given in Table 5.2 above) are then applied to rank the assets in order of health, the scores of which are then allocated to 'bins'. This results in the Asset Health Index for each fleet that can be ranked in order of worst to best. Criticality from the asset location is then applied, resulting in the asset criticality index. The risk matrix is then generated for each fleet similar to that shown in Figure 5.1 below.

Figure 5.1: Network risk matrix

		Risk Impact				
		Immaterial	Minor	Moderate	Severe	Catastrophic
Likelihood	Almost Certain	Low	Medium	High	Extreme	Extreme
	Likely	Low	Low	Medium	High	Extreme
	Possible	Low	Low	Medium	High	High
	Unlikely	Insignificant	Insignificant	Low	Medium	High
	Rare	Insignificant	Insignificant	Low	Medium	Medium

Risk Appetite Boundary

Interpreting the matrix is straightforward. Increased likelihood and consequence of asset failure runs from the bottom left-hand corner to the top right-hand corner, which identifies the area of greatest risk.

The Impact levels are defined in our Risk Control and Management Standard for various risk categories. The top right-hand section is bounded by a black line that indicates the intolerable level of risk. Assets are located on a risk matrix developed for their fleet according to the analysis of their physical location, their hierarchical position, condition and age. Assets within the intolerable area are then triaged, allowing programmed remediation of the assets based on their overall risk score. It can be considered that, by adopting this approach, we are moving from replacement and renewal purely on age to a more targeted safety (risk) driven methodology.

Projects, works and actions that reduce a risk level across the risk appetite boundary (black line) are justified by a requirement to take 'all reasonable practical steps' to reduce risk, while projects that reduce risk outside of the "Intolerable Risks" area are considered on the base of their cost-benefit analysis. This methodology is broadly consistent with an "As Low as Reasonably Practicable" (ALARP) approach to risk reduction.

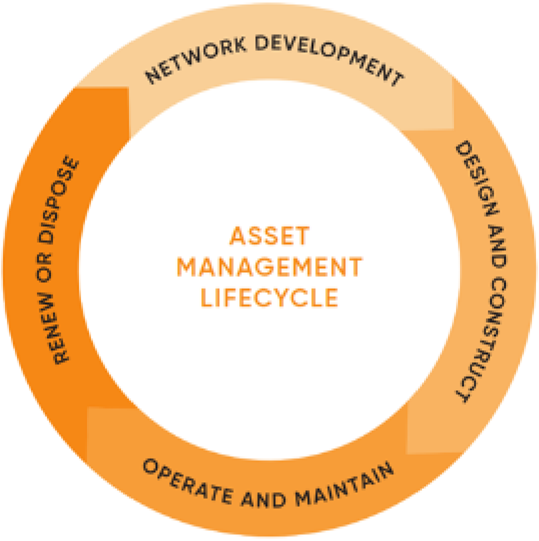
Traditionally our long-term renewal forecasts have been based on asset health, with short-term prioritisation of interventions being based on criticality (within and across fleets). We are challenging this paradigm by targeting remediation to remove key risks thus optimising the projected use of capital.

We are committed to further development and implementation of our risk-based decision-making framework. It includes further refinement of the definition of asset functionality, evaluation of the associated risks and application of effective controls.

5.4. ASSET LIFECYCLE MANAGEMENT

The four stages of asset management lifecycle, introduced in chapter 4 are reproduced in Figure 5.2. 'Network Development' is covered in Chapter 6, but the remaining stages are discussed here. Given our current focus on improving the health of our network during the CPP Period, we provide detailed information to cover the key processes of the 'Renew and Dispose' stage of the lifecycle.

Figure 5.2: Asset management lifecycle



The business model of any asset heavy company such as an electricity utility is necessarily based around the assets that generate revenue. Asset management activities must align with the corporate vision and support the business plan. This section sets out our approach to ensuring that we effectively respond to changes in asset or network risk (or opportunity) through timely delivery of capital works, network operations and asset maintenance activities. Renewal and disposal processes are also covered in this section.

Below we list some considerations that inform our decision-making for asset lifecycle management:

- **Practical and safe operation:** decisions made at the concept and planning stages consider the operational implications of different assets and how these impact worker and public safety over the asset's life.
- **Operational thresholds and maintenance requirements:** identified and captured, to ensure the value of an asset is maximised.
- **Whole-of-life investment optimisation:** investment options consider operational, maintenance and refurbishment costs over the expected life of the asset.
- **Future trends:** the way in which electricity will be delivered to customers in the upcoming years is a topic of great debate. With the life of assets being counted in several tens of years the decisions around the complete lifecycle need to be robust and as future-proof as can reasonably be expected or forecast.

5.4.1. Network Development

We use the term 'network development' to describe capital investment aimed at increasing network capacity or improving network security and reliability. Network development also includes investment for customer connections and for network upgrades to meet changes in technology brought on by decarbonisation.

Chapter 6 covers this topic in more depth.

5.4.2. Design and Construct

This stage includes detailed design, tendering, construction, project management, commissioning, and handover of new assets to operational teams.

To meet our targets for network safety as expressed in our CPP, we recognise a need to increase both the capacity and rate of delivery of our internal resources and field service providers. An additional consideration with current supply chain limitations is that improved productivity can be constrained by availability of trained personnel, plant and materials. It is essential that good planning practices are used to limit these potential hold ups.

Work that is approved in the network development stage flows into the design and construct stage. At this point, the handover of capital projects from our network planning team to delivery teams takes place. This process covers detailed design, tendering, construction and project management, commissioning, and handover of new assets to the operational teams.

The main activities in this phase (discussed below) include:

- detailed design
- procurement
- construction
- project close-out

These activities are managed by a dedicated project manager, who is responsible for ensuring the work is delivered on time, per specification and within budget.

Detailed Design

Depending on the type and complexity of the work, detailed designs are undertaken by either our in-house design team, approved contractors, or design consultants.

When undertaking larger projects detailed design is essential to maintain control over cost, quality and timelines. The detailed design identifies construction methods to help minimise risks to safety and reliability. The Design/Engineering team is available for the duration of the project and will provide inputs such as design variations, should the need be identified during construction.

Design reviews take place at various stages of the project depending on project scale and complexity. Reviews cover safety, adherence to standards, technical requirements, and completeness. Design reviews are an opportunity for all departments to collectively appraise the robustness of a project, allowing for the consideration of input from a more diverse team.

Our design approach aims to standardise our network assets as much as reasonably practicable by following a suite of design standards and standard designs. Our standardised approach works well for typical installations and smaller defect jobs (business as usual), allowing for efficiencies in design, construction, maintenance, operations, and spares management.

Since 2017 we have continued to expand upon our existing document library (Controlled Document System) to include all requisite design, construction and maintenance standards, procedures and forms. As these documents are developed and approved, they are made available online to our approved service providers. This has been a key development focus. These standards help to simplify delivery and achieve long-term consistency across our network. Safety-in-design is a key driver for our design standards.

We have also signed period supply agreements for 6.6/11 kV indoor switchgear and zone substation power transformers. These agreements will provide consistency in pricing, designs, and equipment spares, making both projects and lifecycle management of these assets more efficient.

Procurement

The procurement phase of projects includes tendering and other related processes. We have a long-term relationship with our main service provider, and in 2019 we signed up two additional service providers to ensure work volumes can be delivered at a competitive price. We have Field Service Agreements (FSAs) with these three service providers for undertaking capital and maintenance work (including fault and emergency response). Each FSA sets out the scope of services and the terms and conditions that apply, and is reviewed to ensure that it maintains alignment with company policies and goals.

Larger works are individually tendered on a case-by-case basis according to the requirements of the specific project or programme. We are monitoring the level of competition evident in our tender markets and will develop initiatives to increase competition where appropriate.

Construction

This process includes all commissioning, planning, construction, testing, livening, and handover of the asset to our operations and maintenance teams. Where appropriate, we prepare a commissioning plan to ensure all required activities are completed. We specify construction requirements that our service providers must follow and may be included as part of tendering documents.

Quality control over construction and commissioning works is critical to ensure that our assets operate effectively and safely over their intended lives. Quality control ensures that projects are constructed in a way that enables design intentions and, therefore, limiting premature reactive maintenance – as per least whole-of-life cost principles.

While the primary responsibility for quality control over construction work lies with our service providers, we carry out regular quality checks and inspections on construction projects. These are to ensure compliance with our standards, to ensure high standards of work, to ensure the required scope of work is being delivered, and to verify that safe working practices are followed. The process is managed by the project managers using a mix of internal quality assurance officers and external technical resources.

Project Close-out

We undertake project close-out activities when the construction works are complete. These include:

- confirming the asset information systems have been updated with as-built information
- capitalisation of assets within the financial systems
- archiving relevant documentation

- analysing final costs to update our unit rates and costing assumptions (this function is currently being implemented and will be formally adopted following implementation of our asset management software solution)
- undertaking a review of lessons learned during the project, particularly on health and safety performance
- feeding these lessons back into our planning and design processes.

At project close, we report back to our planning team so they can review the performance of the design solution and its cost against our initial estimation. This is an essential step to ensure the ongoing improvement of our planning and design processes.

Delivery Model

Our field work, including network field switching, is delivered entirely by external field service providers, in contrast to some EDBs. In the main, our field capability is delivered through three FSAs. These include agreements to deliver planned maintenance, reactive maintenance, vegetation management, and capital projects investments. Additional resources are also available as required, and sourced via our tendering processes.

Our strategy to outsource all field operations, as well as other services (E.g. detailed design as required), is set to maximise cost and delivery efficiency, allowing our teams to focus more closely on our core areas of competency. This approach strikes an appropriate balance by allowing us to develop productive relationships with service providers, fostering innovation, incentive and control mechanisms, while also ensuring broader competitive tension through tendering in the wider market.

Our service delivery model seeks to ensure:

- a works delivery approach with clear accountability of core business functions
- integrated works programming, scheduling, and governance capability to ensure a smooth and well-coordinated flow of work to the field
- appropriate end-to-end investment planning and capital works process to enhance delivery efficiency, including taking a multi-year approach
- appropriate end-to-end maintenance processes to enhance delivery efficiency
- appropriate fault and emergency processes
- effective procurement, safety management and information architecture.

Whole-of-life design considerations are covered in Chapter 6 for major projects and Chapter 8 for individual fleets.

5.4.3. Operate and Maintain

Operation and Maintenance covers all operation and maintenance activities relating to our network assets. These actions ensure that assets perform safely and reliably over their expected lives.

Once an asset is commissioned and put into service the maintain and operate stage commences. Many assets have a practical life span of 40-60 years which means the operate and maintain stage has the longest duration of the asset lifecycle.

By monitoring and proactively maintaining our assets in a condition where they can operate safely and economically, we maximise operating life and return on investment. The operate and maintain stage includes network operations, maintenance, vegetation management and spares management.

Network Operations

Network operation is overseen and undertaken by an internal team, the only exception to which is field switching.

The primary role of the operations team is to ensure a constant supply of electricity to our customers by operating the network to meet operational, safety and asset performance objectives on a 24/7 basis. Key activities are real-time network control, monitoring, event response and planning for equipment outages to enable safe access to network assets. Our 24-hour control rooms in Dunedin and Cromwell are configured to allow both the Dunedin and Central Otago/Queenstown networks to be controlled from either region, creating site and resource resilience.

Both our operators and planners consider factors related to network and asset performance. They assess how asset loading and operation frequency affects asset life and performance, and how best to safely remove assets from service for maintenance.

Operations activities provide feedback to the lifecycle planning process on network and asset performance or risks, considering safety, reliability, cost, and environmental impacts. Section 7.2 covers our approach to network operations in more depth, including the advanced distribution management system (ADMS) and outage management system (OMS), as well as emergency management.

Maintenance

Maintenance can be described as all the activities we undertake during the life of an asset to understand and manage the condition and performance of an asset, and thus ensure our assets function in a safe and reliable manner, throughout their lifetime. Our maintenance activities include monitoring condition and performance of assets as well as managing their deterioration. The level of maintenance intervention is driven by safety, business continuity, finance and obsolescence. Information gathered through maintenance activities is used to inform our Capex renewals programme. As discussed above, network maintenance is an outsourced activity.

Our safety orientated approach to asset management requires us to make certain trade-offs between maintaining our assets in service (Opex) and replacing or refurbishing them (Capex). For example, we may increase the frequency of maintenance for a particular asset type to increase asset life/defer renewal within the context of public safety, cost-performance and reliability.

We have split our maintenance activity into three operational areas:

- **preventive maintenance**:[1] encompasses inspections, condition assessments and servicing. These are typically programmed activities that are carried out on a regular basis. Inspection periods for each fleet are carried out in accordance with manufacturer's recommendations and our maintenance standards. Recorded condition assessment data is used for analysis,

[1] Our preventive maintenance category is a subset of Routine and Corrective Maintenance and Inspections (RCI) used in the Information Disclosure. Our corrective category is also included within RCI.

forecasting and renewal planning and to drive defect and repair work (corrective maintenance). Preventative maintenance is covered in more depth in section 7.3, including drivers and initiatives.

- **corrective maintenance**: describes planned work arising from preventive maintenance reporting, ad-hoc identification of a defect or as a follow-up to a fault. It includes defect rectification, repairs, and replacement of minor components to restore the condition of an asset. Work in this category is prioritised and scheduled as determined by engineers. Corrective maintenance activities are categorised as requiring 'Rapid Response' and rectified within 90 days.
- Often this work requires planned outages to ensure the work can be safely undertaken. Failure to undertake this work increases reliability and safety risks. Corrective maintenance is covered in section 7.4 including objectives and initiatives.
- **reactive maintenance**:[2] includes fault response and emergency switching, carried out in response to an unplanned event or incident that impairs normal network operation. Unlike the other maintenance activities, reactive work is dispatched by the control room in response to network events. Failure to undertake this work in a timely manner can adversely affect both the service provided to our customers and the long-term health of our assets, and may increase public safety risk. Reactive maintenance is covered in more detail in Chapter 7, with drivers, objectives and initiatives explained.

Details on the maintenance activities that apply to specific asset fleets are discussed in the respective fleet sections of Chapter 7. Chapter 7 also outlines our forecast operations and maintenance expenditure for the planning period.

Vegetation Management

Vegetation management is one of the key activities that enables our assets to perform to expected service levels. We undertake vegetation management to ensure that trees are kept clear of our overhead lines. By proactively monitoring our network, we minimise vegetation-related outages and meet our safety and statutory obligations. The main activities undertaken in the vegetation management portfolio are inspections to determine the amount of work required, liaison with landowners when work is required, and subsequent tree trimming and removal.

Vegetation management is covered in more detail in Chapter 7 expanding upon drivers, regulations objectives and initiatives along with a forecast.

Spares Management

We keep a pool of spare parts for our assets on order to minimise down time of common fault and hard to source items. We place these in locations that are appropriate to the assets they cover. We categorise replacement parts as either strategic or critical spares.[3] The number and type of spares

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2 Our reactive maintenance category is equivalent to System Interruptions and Emergencies (SIE) used in the Information Disclosures.

3 Critical spares are items that are unique to a particular asset, and whose absence would negatively impact asset availability, safety, the environment, or our ability to meet regulatory requirements. In contrast, strategic spares are items that can be used for multiple applications or be installed temporarily as substitutes for failed components.

retained for each asset family varies depending on asset usage and lead times for returning the network to operation.

Spares management is complex for any business operating legacy equipment, having a wide spectrum of different makes and models in service. As we transition to standardised equipment manufacturer, type, and rating the inventory of spares required for maintenance will be reduced. The outputs of this work will form the basis of our spares management requirements, which will be covered by our contractual arrangement with our FSA contractor who manages our spares.

Chapter 7 covers this in more detail.

5.4.4. Renew or Dispose[4]

As assets deteriorate, they eventually reach a state where the required maintenance to keep them safe and serviceable becomes ineffective or uneconomic. Further, the condition of an asset may reach a point where it presents an intolerable risk of failure (as described in Section 5.3). Refurbishment and replacement are key activities to manage risks associated with deterioration of asset conditions with impact on safety, network performance, asset obsolescence, and regulatory and legislative compliance.

Safety

We prioritise safety risk management above all other asset lifecycle investment. Our asset risk framework is primarily based on the objective of maximum reduction of the critical risk. In our information systems we set safety zones for our assets based on their estimated exposure to members of public and rated the assets according to the rate of that exposure. This allows us to create safety risk profiles for every fleet in a form of a risk matrix, which in turn is used to determine the renewal programme priorities.

Network Performance

We undertake asset management activities to meet reliability levels for our customers. We are developing a near real-time reliability dashboard and reporting tool, which indicates performance based on network area. In addition, our network needs to be cost-effectively resilient to extreme events, such as storms and earthquakes. While we have updated our current design standards in line with best practice, our legacy asset installations are built to standards that were generally less stringent when they were in force. In some instances where the risk with legacy installations is deemed to be unacceptable, it may be necessary to renew assets to meet today's standards.

Obsolescence

Obsolescence can be the primary driver of renewal of assets, particularly in the secondary systems portfolio. Factors such as incompatibility, unavailability of spares and industry knowledge play a major part in obsolescence.

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[4] We use the term renew to signify either asset replacement or refurbishment.

Renewal Thresholds

The triggers for renewal are asset specific and consider project timelines, asset and resource availability, and integration of work packages to balance network improvement, risk and cost.

Reactive renewals are also required, subject to unplanned or unforeseen asset failure (irrespective of the strategy applied to the asset fleet).

Asset Renewal Forecasting

As assets approach the end of their service life their replacement is triggered by asset condition or our forecasting analysis. In order to forecast the need in asset investment in the future, we project the deterioration of assets in each fleet using the rate that depends on the fleet-specific maximum economic service life. In such, we apply the risk management methodology as described in Section 5.3 to generate the numbers of assets that require renewal per year per fleet. This process is used to project the change in asset fleet risk for the 10-year AMP period. By adjusting the numbers of assets to be renewed each year, the overall risk profile and budget for each forecast scenario is appraised. Forecasts are provided for each asset fleet in Chapter 8.

Options Analysis

Most asset renewal, particularly volumetric work, is like-for-like replacement, and this is not subject to formal, detailed options analysis – the choice of equipment or technology is largely governed by our standards. In some cases, more detailed options analysis is prudent for reasons such as:

- integration of multiple needs or projects, considering other nearby assets and their condition and whether aligning their timing for cost synergies is the lowest whole-of-life cost approach overall, and to avoid returning to the site and disrupting customers in the near future
- technically difficult cases where there is no obvious answer, or there is the opportunity for materially different solutions with different costs/outcomes
- when there is the opportunity for 'betterment' (i.e. not just a like-for-like replacement) while the project is occurring, or the cost to provide extra value to customers is marginal
- where projected costs are large, the investment appears to be required but does not appear economical, or there are opportunities for deferral or use of a non-network solution, such as our non-network alternatives in the Upper Clutha area.

As an alternative to renewal, asset refurbishment or continued maintenance (the latter in most cases being the "Do Nothing" or control scenario) are options that are considered where appropriate.

To help us identify the most appropriate renewal option, we undertake technical studies, economic assessments, and risk analysis, and consider safety implications, likely performance impacts and lifecycle cost, including capital, maintenance and other operational costs.

Prioritisation Across Fleets

As we move towards a quantified risk framework, prioritisation for forecasting asset renewals across fleets will be more accurate and decisions more targeted. In the interim, the following factors have been considered when trading off expenditure to manage resource constraints (E.g. money, human resources, time).

- **inherent risk**: some electrical assets are generally considered to be inherently riskier than others. Considering an overhead network against a cable network, assuming similar design criteria for redundancy, the overhead network is likely to have more faults and more impact on public safety should equipment fail. With limited resources, fleets with inherently higher risk are prioritised.
- **condition**: fleets where the overall fleet health is poor and have a large at-risk proportion in backlog require prioritisation to ensure they are given the attention they require and that the backlog does not grow or remain at an unsustainable level. Our crossarm fleet is aged and in poor condition with a forecast backlog, and the failure rate is rising. Prioritising work here will prevent the failure rate continuing to rise.
- **limited information**: where we have limited information, we must rely on the structured information we have that has been vetted as trustworthy, analyse data that is questionable or has gaps, and, from a 'top down' view, rely on our subject matter experts and their professional judgement and peer review. The WSP review and the CPP independent verifier have provided useful points of reference from external parties.
- **deliverability**: there are some fleets where a significant forecast renewal backlog means, even with the additional resources that could be realistically employed, the risk of this fleet cannot be significantly reduced in the short term. As part of considering deliverability constraints, we are in turn being forced to prioritise across fleets based on limited resources.

Summary of Intervention Strategies

To support our asset management approach, we define a set of strategies for each asset fleet. These form the basis of our day-to-day asset management intervention approaches and investment planning. Table 5.3 below sets out our asset fleet intervention strategies, including the main renewal drivers, primary forecasting method, and primary delivery method.

Table 5.3: Summary of asset fleet intervention strategies

FLEET	INHERENT RISK	MAIN FORECASTING / APPROACHES AND MODELLING	MAIN DELIVERY METHODS
Poles	High	Volumetric/Survivor Curve	Condition, criticality-based bundling
Crossarms	Medium/high	Volumetric/Repex	Condition, criticality-based bundling
Sub-transmission conductor	High	Scheduled or volumetric	Scheduled/proactive
Distribution conductor	High	Volumetric/Repex	Proactive
LV conductor	High	Volumetric/Repex	Proactive
Sub-transmission cables	Low/Medium	Scheduled	Scheduled
Distribution cables	Low	Volumetric/Repex	Hybrid/Criticality-based bundling
LV cables	Low	Volumetric/Repex	Hybrid
Power transformers	Medium/High	Scheduled/Risk-based	Scheduled
Buildings and grounds	Low/Medium	Scheduled	Scheduled
Indoor switchgear	High	Scheduled/Risk-based	Scheduled

FLEET	INHERENT RISK	MAIN FORECASTING / APPROACHES AND MODELLING	MAIN DELIVERY METHODS
Outdoor switchgear	Medium	Scheduled	Scheduled
Ancillary zone substation equipment	Low/Medium	Scheduled	Scheduled
Ground-mounted switchgear	Medium	Volumetric/Repex	Condition/Proactive
Pole mounted fuses	Low	Volumetric/Repex	Proactive/Reactive
Pole mounted switches	Low	Volumetric/Repex	Condition/Proactive
Low voltage enclosures	Medium	Volumetric/Repex	Condition/Proactive/Reactive
Ancillary distribution substation equipment	Low	Targeted/Type-based	Condition/Proactive
Ground-mounted distribution transformers	Medium	Volumetric/Repex	Condition
Pole mounted distribution transformers	Medium	Volumetric/Repex	Condition
Protection	High	Targeted/Type-based	Proactive
Batteries and DC systems	High	Targeted/Type-based	Proactive
Remote terminal units	Medium/High	Targeted/Type-based	Proactive

Chapters 7 and 8 describe our lifecycle management approaches, including maintenance and renewal approaches, for our asset fleets. They provide background on and explain our choice of intervention strategy.

Disposal

Asset disposal follows the decision to remove it from our network, either because it is being replaced or has become redundant. Disposal activities include planning for disposal, decommissioning the asset and site restoration.

Box 5.1: Supporting our sustainability objectives

Ensuring that we employ appropriate disposal options for our assets is important if we are to avoid negative environmental impacts, particularly those assets in close proximity to the communities we serve. Consistent with our sustainability objectives (set out in Chapter 4), we are increasingly focused on minimising the potential negative impact of our assets.

Some assets such as underground cables may be left in situ if removal is not cost-effective and there is no environmental impact. Servicing and repairs may also result in waste products or failed components that require disposal.

Disposal costs and implications, particularly environmental and sustainability related, must be considered in lifecycle planning. As an example, SF_6 gas will become an increasing issue in the future and steps are being taken to utilise equipment that does not use this insulating gas. Our recently signed period supply agreement for indoor zone substation switchgear follows this precept.

Disposal options

Asset disposal works have many similarities with capital projects, including considering cost, safety, environmental impacts, and project management. Additional aspects that are specific to disposal works are site restoration, termination of support activities and removal of asset information.

The options for disposal of an asset are strongly influenced by the particular trigger or driver being addressed but will generally include retaining the asset as a complete spare or as parts for other assets, selling/gifting it as a functioning asset or as scrap, or disposing of it to a waste management facility. The option we select depends on a number of factors, including salvage value, viability of the asset as a spare and the presence or otherwise of hazardous substances. We may choose different disposal options for different components of the asset.

When considering disposal options our preference (in order) is to re-use, recycle or sell or where it is practical and cost efficient to do so. When re-use is not feasible or practical, we dismantle and dispose of redundant assets and where possible, recycle the associated materials. We dispose of surplus assets and waste material in a way that poses minimal risk to employees, contractors, the public and the environment. Opportunities to gift redundant assets with little to no residual value over to communities and not-for-profit organisations that can make use of them are considered.

Waste management

Consistent with our safety and environment objectives, we ensure waste materials are disposed of in a responsible manner. In the majority of cases disposal is a relatively low-cost activity; special disposal requirements, if they exist, are considered at an early stage. Disposal costs are considered as part of the overall lifecycle costing.

Site restoration and reinstatement

When assets are decommissioned and removed, part or all of a site may be able to be re-used or restored. Future use of the site must consider health and safety and environmental considerations, particularly where hazardous wastes are concerned; for example asbestos and lead-based paint. Identifying, managing, and removing contaminated soil can have a significant cost.

Asset Relocations

Our assets are often located alongside other infrastructure such as roads, water pipes, and telecommunications cables. At times, the owners of this infrastructure (for example KiwiRail, NTZA and local councils) may need us to move our assets, generally poles, conductor and cables. Moving poles and lines to accommodate the widening or realignment of a road or development of other infrastructure are examples of this. Relocations may also occur for aesthetic reasons, such as where a customer requests undergrounding of lines that disrupt their views.

Approach to Asset Relocations

Requests to relocate assets for roading and infrastructure development projects generally require significant planning, and coordination with other infrastructure providers. It is necessary for us to be directly involved in the relocation design process. Other requests mainly involve relocation of assets on private land and are usually less complex, allowing authorised contractors to develop a design-build proposal.

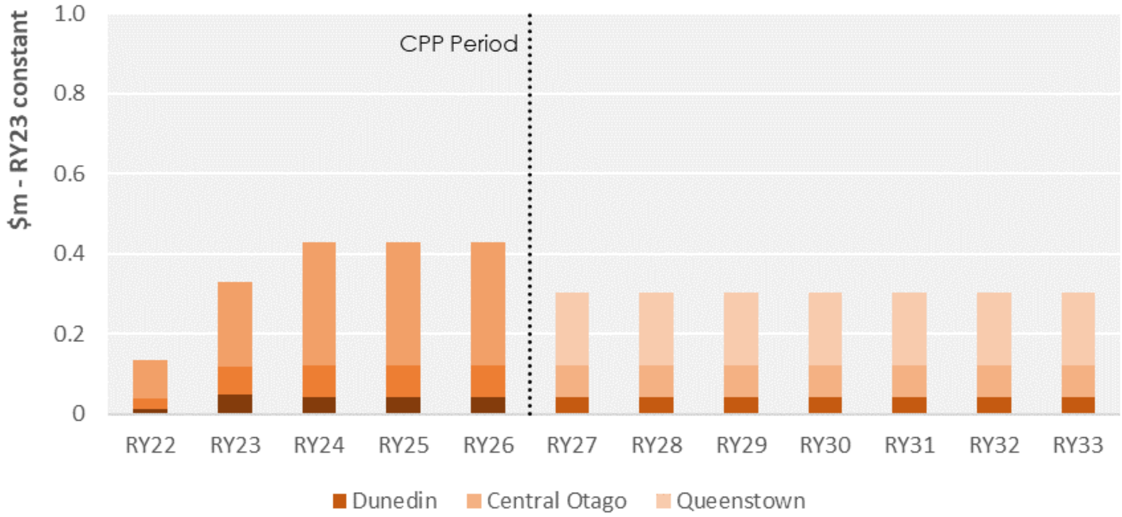
If the relocation involves assets that are in poor condition or defective, we may take the opportunity to upgrade and address defects, utilising planned road closures and reducing the need for planned outages. Where assets are replaced as part of a relocation – usually when in poor condition – expenditure is capitalised. Relocating assets from one location to another without increasing service potential is generally treated as operating expenditure.

In most circumstances we receive contributions from the third party requesting the relocation, reducing the amount of our investment in these projects. For roading and other infrastructure projects, the level of our investment is governed by legislation, which often requires us to fund the materials portion of the project.[5] For other projects, our level of investment is governed by the moving works section of our publicly disclosed capital contributions policy. In general, customers other than roading authorities requesting relocation of existing assets are required to fund the full cost of the works, including the costs of providing or securing easements. An exception may be made when assets are in poor condition and due for replacement.[6]

Forecast Relocations

Our forecast relocations expenditure is our expected investment (net of contributions) during the AMP planning period.

Figure 5.3: Asset relocations Capex (net of capital contributions)



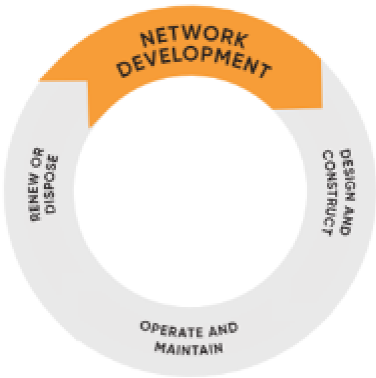
It is difficult to forecast relocations as work is externally driven, often with short lead times. Therefore, we estimate relocation expenditure based on historic average expenditure, adjusted for known projects that are expected to occur for RY24-25.

5 Sections 32, 33 and 35 of the Electricity Act 1992 and Section 54 of the Government Roading Powers Act.

6 Capital contributions are designed to ensure that any uneconomic portion of the incremental cost of supply is paid by the customer requiring the work, and not transferred to existing customers through increased line charges.

6. NETWORK DEVELOPMENT

This chapter sets out our approach to developing our network to meet customer electricity demand and connection requirements using network and non-network solutions. The chapter discusses our approach to decarbonisation and how the future utilisation of distributed energy resources will play a vital role on how we manage development of our network.

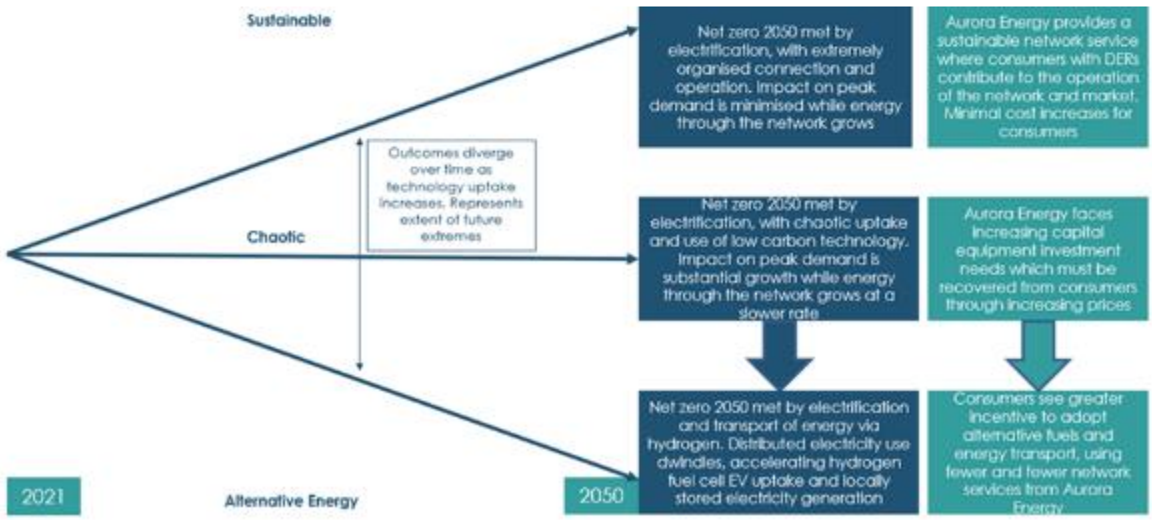


6.1. INTRODUCTION

We use the term 'network development' to describe capital investments that increase the capacity and improve security and reliability to the acceptable levels of network risks. Network development includes four main types of investment:

- **growth and security**: these are investments to ensure we can meet demand on our network while maintaining appropriate security of supply. See Section 6.5
- **network evolution**: these are investments to transform our network to meet our customers' uptake of Distributed Energy Resources and impact of decarbonisation. See Section 6.6
- **reliability-driven**: these investments aim to minimise the impact of a network fault, such as by automatically reducing the number of impacted customers.[1] See Section 6.7
- **consumer connections**: this expenditure facilitates connection of new customers to our network. See Section 6.8

Figure 6.1: Model of decarbonisation scenarios



1 The Commerce Commission defines reliability, safety and environment Capex as spend predominantly associated with improvement of reliability of service, maintaining or improving the safety of the network for consumers, employees and the public, meeting legislative requirements, or reducing the impact of the network on the environment.

Growth and security investments ensure the capacity of our network is adequate to meet the peak demand of our customers, with appropriate supply security, now and into the future. In the following section, we discuss our approach to understanding the impact of decarbonisation on our network and share the potential future scenarios we have developed and modelled.

6.2. IMPACTS OF DECARBONISATION

In last year's AMP, Aurora presented the work we have undertaken to understand the potential impacts of decarbonisation on our two regional networks. Our approach is described in three stages:

Stage 1	To develop scenarios that consider the range of futures with decarbonisation through increased electrification (Completed)
Stage 2	To establish a strategy
Stage 3	To prepare plans and actions to allow Aurora Energy to prepare for these futures

6.2.1. Decarbonisation Scenarios

We have developed three scenarios – Sustainable, Chaotic and Alternative Energy. These scenarios are defined in Figure 6.1 below. While the scenarios are qualitative descriptions of the range of futures, they allowed quantitative results to be derived, specifically providing insight into changes in peak electricity demand and energy delivered through the network. In turn, this gives Aurora Energy an indication of investments of the range of futures and highlights the importance of developing a strategy and action plans to manage these investments (stages two and three of our approach).

The scenarios were developed to represent the range of possible futures that Aurora Energy may experience. These are specifically related to a low carbon future and the transition to more renewable electricity use in the following areas:

- Transport: including residential EV charging, light EV highway charging, heavy EV highway charging, and electric public transport (exclusions are electric planes, ships, boats, etc – we would treat these as step change)
- Residential: including space and water heating, lighting, and cooking
- Commercial & Industrial: including process heat, space heating and lighting (excludes thermal storage)

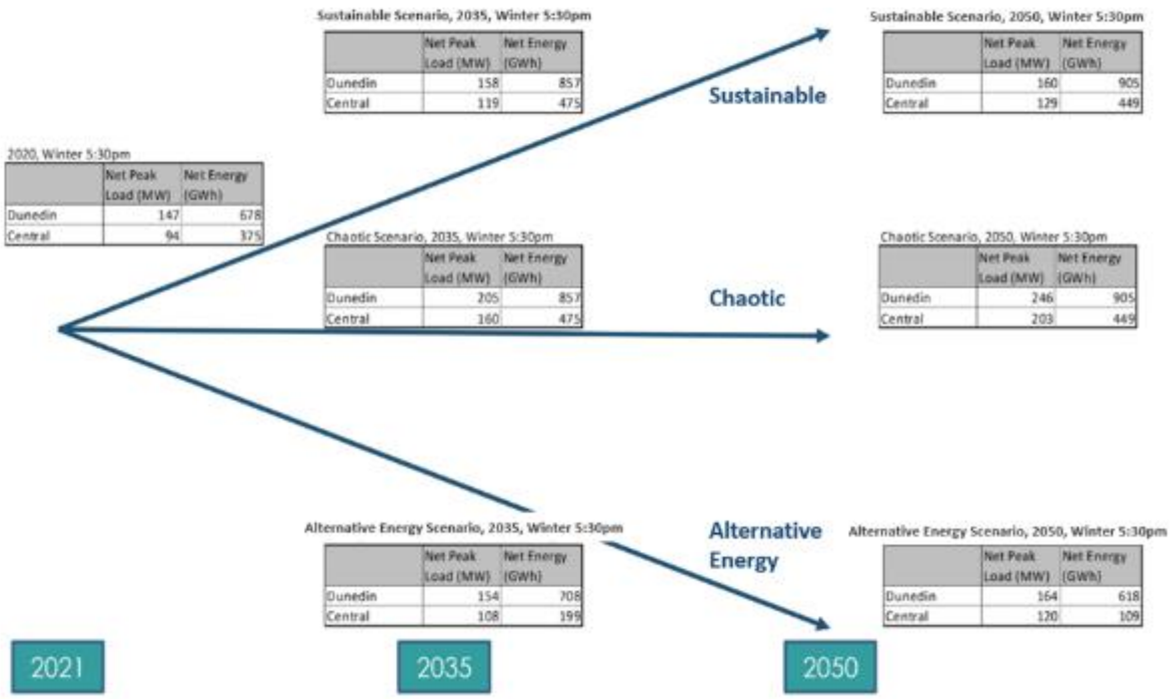
Other changes were also considered, particularly around underlying network growth, which is particularly high in the Central Otago regional network, and around lighting changes in which incandescent and fluorescent lighting will be phased out for more efficient LED technology.

We have modelled the three scenarios across both our Dunedin and Central Otago regional networks for the years 2035 and 2050 on chosen time frames - summer midday, winter 5:30am and winter 5pm.

Figure 6.2 shows the modelling outcomes for both network regions across each scenario and time frame for Year 2035. Evident from these outcomes is that both the Sustainable and Chaotic scenarios present the same increase in net energy consumed across our network due to an equivalent shift from fossil fuels to renewable energy. We see some increase in peak demand in the Sustainable scenario, but there is a significant increase in the Chaotic scenario. Also noteworthy is that under the Alternative Energy scenario, our net peak demand increases slightly, but energy consumed drops markedly for the Central Otago region. The change in consumption derives from alternative forms of energy such as hydrogen displacing renewable electricity to enable decarbonisation of process heat and heavy transport.

This illustrates the divergences identified between each scenario in relation to peak demand. In turn, this will inform the later stages of our project in terms of where to focus our strategies and plans to best address our future management of renewable electricity usage.

Figure 6.2: Summary of decarbonisation results for 2035 and 2050



Figures 6.1 and 6.2 are supported by the following key inputs and outcomes:

- Both the Sustainable and Chaotic scenarios show a significant increase in energy, whereas the Alternative Energy scenario shows little change. These scenarios may present a risk to Aurora Energy given any requirement to invest in network infrastructure to manage potential energy growth in the Sustainable and Chaotic scenarios may become surplus under an Alternative Energy scenario. Investment in network capacity will be minimal under the Sustainable scenario, noting that the network will still need to extend to supply new subdivisions and commercial developments. This would allow us to deliver an increase in energy without specifically needing to invest in additional or upgraded network assets. This scenario requires careful management of peak demand as energy use increases over time.
- Residential electric vehicle (EV) charging could lead to the greatest increase in peak demand, but there is significant scope to manage peak demand from EVs by time-shifting and scheduling charging. Further, this occurs in the low voltage network where significant investment would be required under a Chaotic scenario but can be potentially avoided under

a Sustainable scenario. To date, EDBs do not have visibility of what EV chargers are used and where they are located. The effect could be exacerbated in the event that smart chargers are not adopted as standard.

– Residential batteries can assist to manage peak demand even further in the Sustainable scenario, but solar generation offers no reduction in peak demand at the winter peak. The combination of solar and batteries can be advantageous, with batteries allowing the shift of energy availability from midday to evening in order to reduce peaks on the LV network.
– Highway light vehicles, heavy vehicles and e-buses do not lead to any significant change in peak demand between the Sustainable and Chaotic scenarios because their demand occurs 'on demand'. In other words, these vehicles have no set charging period during daytime hours.
– There is further scope for peak demand reduction through more efficient lighting.

Table 6.1 below shows the peak increase/decrease in Dunedin and Central Otago regional networks for all scenarios forecast for the Year 2035.

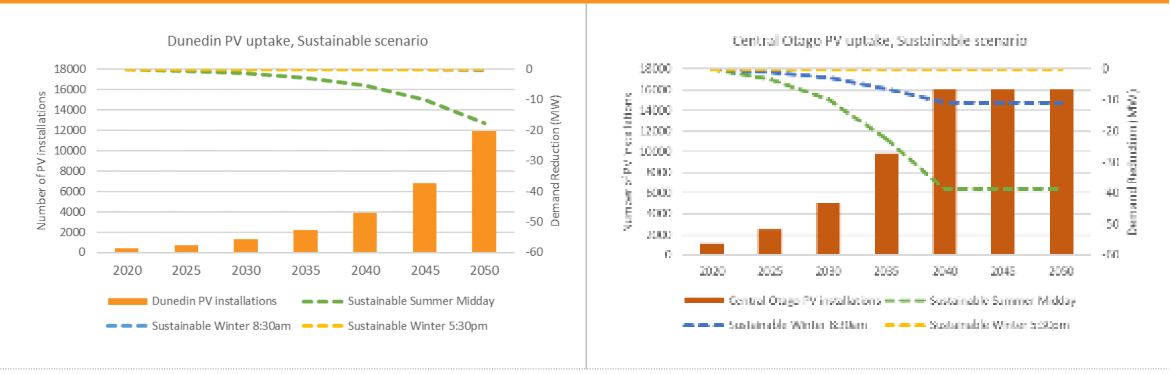
Table 6.1: Impact of each scenario on regional network peak forecast for Year 2035. Values in parentheses indicate a decrease in estimated load

SCENARIO	REGIONAL NETWORK	SUMMER MIDDAY	WINTER 830AM	WINTER 5:30PM
Sustainable	Dunedin	12 MW	15 MW	11 MW
	Central	(2) MW	13 MW	25 MW
Chaotic	Dunedin	19 MW	29 MW	58 MW
	Central	3 MW	37 MW	66 MW
Alternative Energy	Dunedin	(1) MW	1 MW	7 MW
	Central	(85) MW	(12) MW	14 MW

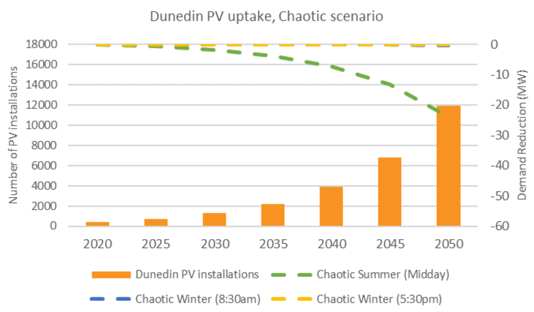
Figure 6.3 and Figure 6.4 are decarbonisation scenario forecasts of EV and PV uptake of both Dunedin and Central Otago regional network with the impact to the peak demand. Note this is a sample on the effect of individual type of DERs – PV provides reduction while EV increases demand.

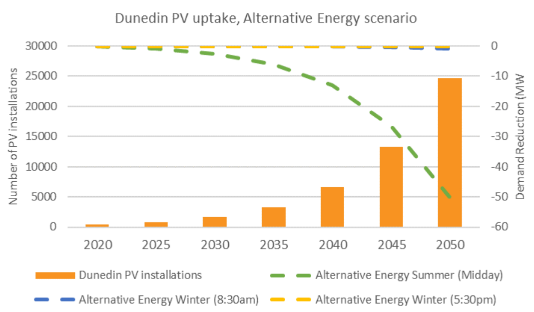
Figure 6.3: PV forecast and impact on demand

DUNEDIN REGIONAL NETWORK	CENTRAL OTAGO REGIONAL NETWORK

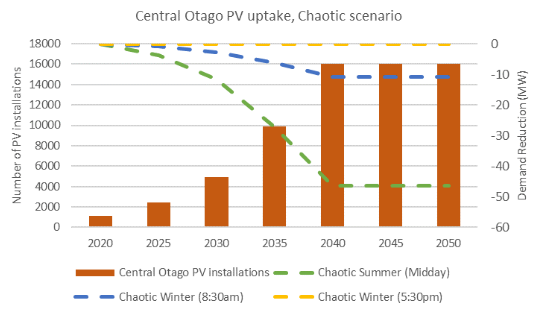


DUNEDIN REGIONAL NETWORK





CENTRAL OTAGO REGIONAL NETWORK



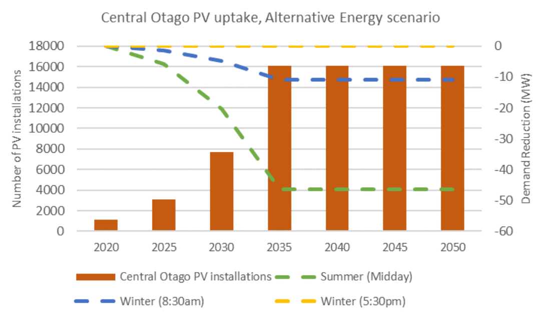
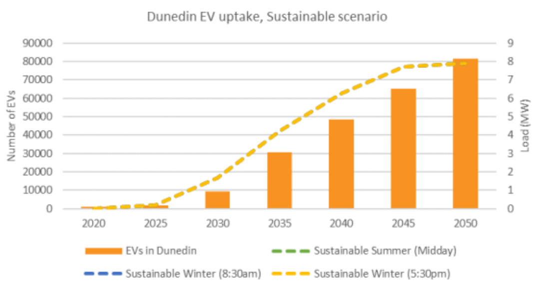
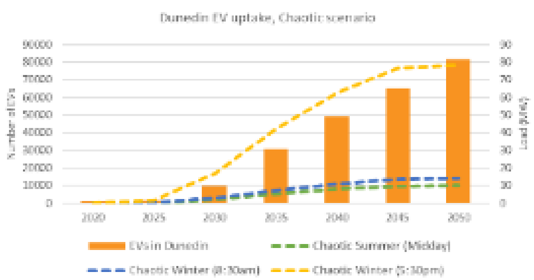


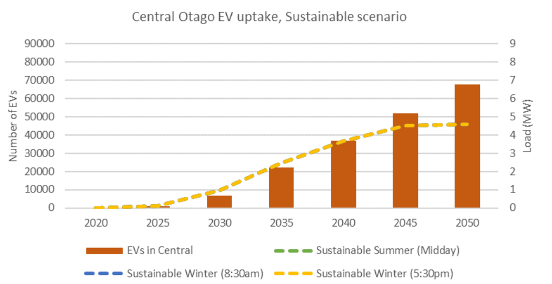
Figure 6.4: EV forecast and impact on demand

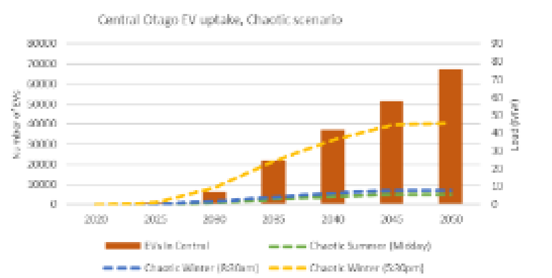
DUNEDIN REGIONAL NETWORK



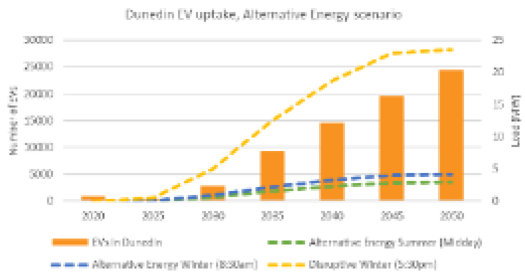


CENTRAL OTAGO REGIONAL NETWORK

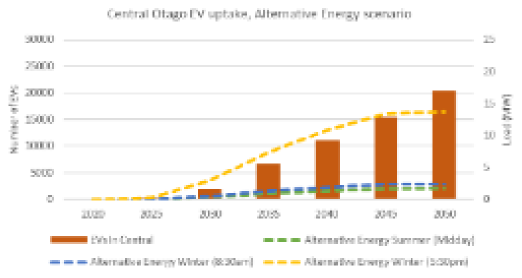




DUNEDIN REGIONAL NETWORK



CENTRAL OTAGO REGIONAL NETWORK



6.2.2. Decarbonisation Demand Forecast

From the regional modelling we used for the study, we have updated our forecasting tool to derive the decarbonisation demand forecast at the GXP, sub-transmission and substation level, which is the same level we used for our expected and prudent forecast. Section 6.3.6 describes our existing demand forecasting tool.

To transition the forecast from regional network, we have made the following update for most residential loads (space heating, water heating, cooking, lighting, EVs, PV) - results are apportioned from region (Central Otago, Dunedin) to zone substation based on the fraction of residential ICPs belonging to each zone substation. For some commercial loads (commercial lighting), this is similarly done using the number of commercial ICPs in each zone substation. For some types of loads (highway EVs, E-buses, commercial and industrial boiler conversion), we directly apply similar methods as used for the regional modelling but apply the methods at the zone substation level.

Hence from the existing demand forecast tool, we have added the following levers: increase due to residential space heating, increase due to residential water heating, reduction due to residential lighting (move to LED), increase to residential cooking (gas to electric), reduction due to commercial lighting and increase from commercial and industrial thermal fuel transition. The existing forecasting tool already includes levers on EVs – light and heavy transport, E-buses, residential EVs.

With the decarbonisation demand forecasting tool, we can now create a more granular forecast, update the scenarios, and create sub-scenarios by adjusting the said levers, which we can use to conduct load flow study using our PowerFactory geographical model to capture potential network gaps. We also intend to create trigger points to when to start planning any network reinforcement or reconfiguration. Further, we intend to integrate these scenarios to the DG hosting capacity study described in Section 6.6.4.

6.3. NETWORK DEVELOPMENT PLANNING

The objective of network development is to expand the network into new areas or increase the capacity or functionality of our existing network to meet the current and future needs of our customers in a cost-effective manner. This definition includes maintaining adequate security of supply, improving reliability, and maintaining power quality, as well as meeting demand.

Network development planning requires that we anticipate potential shortfalls of capacity or breaches of our security criteria, power quality and reliability under forecast demand conditions. We consider both network and non-network options in our planning processes. We plan for efficient and timely investment in additional capacity and security before reliability is adversely affected.

6.3.1. Network Development Planning Process

In this section we describe our approach to planning capital network development investments. This explains how we ensure that our investments prudently support our asset management objectives. The entire process is explained below.

Figure 6.5: Network Development Planning process

Identify Needs

The following are triggers for growth and security investments:

- GXPs/transmission spurs: (commonly at N-1 Security level) triggered by security criteria being exceeded, and to some extent voltage issues
- sub-transmission and zone substation: triggered by security criteria which are effectively a qualified, or switched, N-1 being exceeded, and to some extent voltage issues
- distribution feeders: triggered by feeder forecast, guidelines or planning parameters related to security criteria being exceeded, voltage profile, thermal capacity (of any given section of the feeder), or operational requirement
- LV feeders: our process for determining investment needs has historically been based on new connection information. However, we see this change with decarbonisation and installation of DERs that impacts capacity and regulatory voltage limits. We will utilise the outcome of the DG hosting capacity study to determine potential sites that will have capacity and voltage issues.

The majority of need cases are identified using our demand forecast in reference to our Security of Supply guidelines (see Section 6.3.5). We conduct load flow analysis using PowerFactory geographical model to systematically analyse the network to identify breach of security of supply guidelines and regulatory voltage limits. To some extent, large customer connections, operational requirements, legislative and regulatory compliance, and safety requirements can trigger a need case.

Options Analysis

We carry out options analysis with the level of complexity in proportion to the level of risk associated and the likely cost of a project to meet the need. We also recognise other related works (E.g. renewals, ongoing growth projects) in the Options Analysis stage may create cost-effective and efficient delivery. Network and non-network options are both considered. Options typically include new assets, enhancements to existing assets and operational approaches.

Longlist to shortlist of options

We first prepare a longlist of viable options. To establish whether the options meet the business need we would need to run network studies using our PowerFactory geographical model. Table 6.2 shows the seven assessment criteria to which we filter the longlist to determine the shortlist of options that can be taken through to the economic analysis stage.

Table 6.2: Assessment criteria

ASSESSMENT CRITERIA	DESCRIPTION
Safety	Is the option likely to meet all health and safety requirements and provide a "safety by design" solution?
Meets the business need	Does the option adequately address the business need? (i.e. addresses the identified constraint)
Likely to be cost-effective	Is the option likely to be cost-effective? (i.e. are the costs likely to be commensurate with the risk exposure from not addressing the need?)
Practical to carry out	Is the option practical to carry out? This includes from an engineering perspective as well as the legislative requirements of the option (E.g. consenting difficulty).
In line with good industry practice	Does the option align with good industry practice?
Fit in with other planned work	Does the option fit in with other planned work on the network?
Fit with applicable strategies	Does the option align with any applicable Aurora strategies?

The shortlisting includes assessing whether the "do nothing" case is a viable option. In situations where it is not imperative that we address a constraint, the "do nothing" option is retained as a counterfactual for the shortlist analysis.

Economic Analysis

Once we have a shortlist of options, we compare the options by considering the whole-of-life costs of each. Three main aspects are considered for each option:

Estimate capital expenditure

We use the Project Cost Estimate document for each short-listed option to calculate the capital expenditure. The estimate costs are allocated to the year(s) in which they are expected to be incurred. The Net Present Value (NPV) of the Capex is calculated, using the defined discount rate.

Probabilistic reliability costs

The list of possible outages for each option are created from the standard list of outage inputs for both pre- and post-investment for the entire study period. This information is used to calculate Probability of Failure (PoF) and Consequence of Failure (CoF). For each option, PoF is multiplied by CoF for each year to produce a yearly monetised reliability risk. The NPV of the reliability risk is then calculated per outage and summed to produce a total reliability risk cost for each option.

Operational Expenditure

Operational expenditure (Opex) is considered and the NPV is calculated in the economic evaluation.

Economic evaluation

The capital expenditure, reliability risk and operational expenditure present values are considered for each option to determine a net present value for each investment option. These option costs are then compared with a "Do Nothing" option to determine whether the option has a net benefit or net cost.

The outcome of the economic analysis does not mean that the most economic option is the preferred solution. The resulting NPV net cost of each option is a key component to the selection but not the only component to derive the preferred solution as discussed in the next stage of the process.

Preferred Solution

Selecting a preferred solution is not always straightforward and may require our Network Planning team to apply engineering and economic knowledge. The following factors are taken into consideration to identify the preferred solution:

- result of economic analysis
- extent to which each option addresses the need
- any risk associated with each option
- fit within the context of our wider asset management objectives
- associated intangible benefits
- assessment against the corporate risk matrix

We then produce a Project Option Analysis document to capture the entire process from the need case to the preferred solution identification. The document includes all associated network study files, PowerFactory model and study notes. All medium (3-5 years) and long-term (6-10 years) projects are written in the Project Option Analysis document.

Where projects are to be delivered within the short-term (0-2 years) individual project definition is written for implementation.

Project Definition

The project is defined and scoped in more detailed manner so that project costs can be estimated more accurately and the delivery period is defined either as scheduled within a regulatory year, or dependent on seasonal constraint, or upon customer requirement. This involves an engineering desktop review exercise using drawings, maps, and site views (site visits and aerial views) to confirm the work required to complete the project. This exercise identifies both the equipment required and the quantities/distances.

The details on the Project Option Analysis document are carried through to this document such that the process is recorded. The draft Project Definition is reviewed by internal stakeholder teams (E.g. Engineering, Life Cycle, Programme, Procurement, Project Management, Operations, Customer Connections and Commercial. Feedback and comments are incorporated appropriately, and the final project definition is approved and distributed to the same internal stakeholders for the delivery of the project.

For some major projects that have considerable impact to the community, we seek consultation with the local community, regional and local authorities, iwi, corridor authorities, environmental groups, and local groups (among others) to socialise the project and seek their acceptance of and willingness to actively support the project.

6.3.2. Solution Prioritisation

Network development projects need to fit within the context of our wider asset management activities (E.g. renewal plans, ongoing growth, consumer connection), so that investments are optimised across all business objectives and constraints. As such, there may be some opportunities to coordinate between potential investments. For example, investments may be brought forward from their required date to enable the work to be integrated with related projects. Deferral may also be possible, though this needs to be assessed in each case and may require careful management. Prioritisation of projects are discussed in this section.

This section outlines how we develop proposals for each of our preferred solutions. As the operating environment changes, the investment forecast in the mid to latter part of the planning period may need further refinement. Prioritisation of network development projects is a relatively complex process. In addition to economic benefit and the severity of the need, we consider the following secondary factors when prioritising across a set of network development projects:

- customer expectations: we prioritise the constraints most likely to impact customer service through prolonged and/or frequent outages, or compromise power quality (voltage drop).
- compliance: our aim is to maintain compliance with all relevant legislative, regulatory and industry standards. Priority is given to projects that address any compliance gaps.
- contractor resourcing constraints (deliverability): we aim to schedule work to maintain a steady workflow to contractors. This reduces the risk of our contractors being either over or under resourced.
- coordination with local authorities: We aim to schedule our projects to coincide with the timing of major civil infrastructure projects by local authorities. The most common activity of this type is coordination of planned cable works with road widening or resealing programmes to avoid the need to excavate and then reinstate newly laid road.

After assessing the relative priorities of each proposed project, the knowledge, experience and professional judgement of our asset management team is relied upon to make the final decision regarding the exact timing of an individual project within the 10-year planning window.

When the project selection process is repeated, all projects (including new additions) are reviewed. They may be advanced, deferred, modified, or maintained in the planning schedule, or removed from the programme. Projects that are not included in the plan for the next year but we believe need to proceed during the planning period are provisionally assigned to a future year in the 10-year planning window.

6.3.3. Key Planning Assumptions and Inputs

The key inputs informing our network development planning analyses are:

- historical demand data, by zone substation, sub-transmission and GXP, used for forecasting electricity demand
- information obtained from local councils, developers, irrigators, and other parties reflecting developments expected to impact electricity demand (proxy for economic activity)
- network performance commitments made to customers and stakeholders
- the current configuration of our network
- manufacturer nameplate ratings, equipment thermal ratings and other factors impacting our equipment ratings
- large embedded generations will not be operational following a major power outage.
- voltage requirements and other regulated limits.

Key assumptions informing our planning are that:

- the uptake of new technology such as EVs, batteries and solar generations will accelerate, but will have only modest or clustered network impacts in the planning period. We will review these assumptions based on the DG hosting capacity study (see Section 6.6.4)
- existing levels of hot water load management, through ripple control, are reflected in the historical data and will be reflective of future levels of demand management
- thermal fuel transition of establishments will impact the distribution feeders and the substation capacity; we are working with these customers to understand their transition journey
- industry rules will remain broadly stable and not lead to step changes in security requirements or levels of distributed generation.

6.3.4. Assessing Asset Capability

To determine investment needs arising from demand growth, we assess the capability of our assets to meet forecast demand. This approach relies on asset ratings.

Our asset ratings are based on the manufacturer (nominal) rating for each asset. However, actual safe capacity can vary in real-time, depending on environmental conditions such as temperature and wind speed. We further adjust the ratings of some assets to reflect such factors:

- zone substation transformers and connected assets: we assign a maximum continuous rating and a four-hour rating which applies to post contingent load transfer in an N-1 context. Ratings will be amended from this convention to thermal chain limits to reflect the maximum rating in reference to the limiting components.
- overhead lines: short-term ratings (E.g. four-hour rating) are not appropriate for overhead lines because of their limited thermal capacity, i.e., the temperature rise occurs very quickly. We use nominal continuous winter/summer ratings to systematically identify potential future overloads. We use summer ratings, taking account of known maximum temperatures and minimum wind speeds.

- underground cables: we use standard manufacturer-based ratings for underground cables. Local conditions (E.g. ambient air temperature and soil thermal resistivity) are considered. Generally, ratings are determined per zone substation, taking account the specific cable route conditions, etc.

6.3.5. Security of Supply (SOS)

Security of supply is the ability of a network to meet the demand for electricity when electrical equipment fails. The more secure an electricity network, the greater its ability to continue to perform and/or the quicker it can recover from a fault.

Managing system security is a key driver of growth and security investments. We establish appropriate SOS criteria and apply these in our network modelling to identify investment needs.

Security criteria establish a required level of network redundancy. The degree of redundancy determines the ability of the network to maintain supply following the failure of an asset component. We specify our security criteria to support our performance objectives and the reliability performance sought by our customers and stakeholders (see Chapter 4). Security criteria generally drive the larger investments related to the sub-transmission system and zone substations, which directly impact reliability experienced by large numbers of customers.

Security guidelines are normally defined in terms of N-X, where x is the number of coincident outages that can occur during high demand times without extended loss of supply to customers. At the levels of load encountered at most of our zone substations, N-1 is the optimal consideration (i.e. an outage on the single largest circuit or transformer can occur without resulting in supply interruption).

Our SOS criteria (for GXPs, sub-transmission and distribution networks) is set out in Table 6.3 below.

Zone substation security levels can also be specified by the time allowed to restore supply by network reconfiguration after an asset fails. Security levels for some security classes are qualified by the allowable switching time before all loads can be restored.

Feeder classifications provide information on the type of loads supplied by each zone substation, and these influence its security classification. Our security guidelines also consider the size of load at risk. Higher levels of redundancy or backfeed capacity are required where more customers could be affected by an outage.

Effective tailoring of security guidelines for individual customers, especially in the mass-market, or at lower voltage levels, is impractical. Our security criteria are therefore defined at HV feeder level and above only.

It is important to distinguish between reliability of supply – the actual performance of the network in terms of the amount and duration of interruptions – and security of supply – the innate ability of the network to meet the customer demand for energy delivery without interruption. When planning for load growth, we aim to optimise the level of security and fault tolerance acceptable to our customers. This necessitates a balance between infrastructure investment and operational cost. Infrastructure investment is driven by security of supply requirements, while the reliability of supply that is achieved depends on a combination of security of supply and operational performance.

Table 6.3: Security of supply guidelines

Class	Description	Load (MW)	Cable, Line or Transformer Fault	Double Cable, Line, or Transformer Fault	Bus or switchgear fault
GXPs					
CBD/Urban	GXPs supplying predominantly metropolitan areas, CBDs and commercial or industrial customers	15-200	No interruption	Restore within 2 hours	No interruption for 50% and restore remainder within 2 hours
Rural/Semi-Rural	GXPs supplying predominantly rural and semi-rural areas	15-60	No interruption	Restore within 4 hours	No interruption for 50% and restore remainder within 4 hours
66 kV and 33 kV Subtransmission Networks					
Category Z1	Predominantly metropolitan areas, CBDs and commercial or industrial customers	15 - 24	No interruption	Restore within 2 hours	No interruption for 50% and restore remainder within 2 hours
Category Z2	Predominantly metropolitan areas, CBDs and commercial or industrial customers	0-15	Restore within 2 hours (may include use of the mobile substation)	Restore 75% within 2 hours and remainder in repair time	Restore within 2 hours
Category Z3	Predominantly rural and semi-rural areas	0-15	Restore within 4 hours (may include use of mobile substation)	Restore in repair time	Restore in repair time
6.6 kV and 11 kV Network					
Category F1	Predominantly metropolitan areas, CBDs and commercial or industrial customers	1-4	Restore all but 1 MVA within 2 hours, remainder in repair time[1]	Restore in repair time	Restore all but 1 MVA within 2 hours, remainder in 4 hours (using a generator)
Category F2	Predominantly metropolitan areas, CBDs and commercial or industrial customers	0-1	Restore in repair time[1]	Restore in repair time[1]	Restore in repair time[1]
Category F3	Predominantly rural and semi-rural areas	1-4	Restore all but 1 MVA within 4 hours, remainder in repair time[1]	Restore in repair time[1]	Restore all but 1 MVA within 4 hours, remainder in repair time[1]
Category F4	Predominantly rural and semi-rural areas	0-1	Restore in repair time[1]	Restore in repair time[1]	Restore in repair time[1]

Note 1: Generators to be used where feasible to enable restoration of power before the fault is repaired.

6.3.6. Demand Forecasting

To effectively plan for growth, we need to forecast future peak demands. Our focus is on peak demand (rather than energy) as this primarily drives the need for network development.

The long lead time for major projects to reinforce or upgrade our larger capacity assets, such as sub-transmission circuits, requires that we foresee increased demand some years before it eventuates. However, we must equally consider factors that may depress growth in order to avoid investing too early.

While many factors affect demand, the two main drivers of growth are population growth and economic activity. To an extent, these two factors are related. Demand is also impacted – albeit to a much lesser degree – by changes in behaviour and usage. Improved energy efficiency is one such example. Looking forward, uptake of new technologies (for example photovoltaic generation, battery storage, combined PV-battery systems, EV charging) will likely be the major cause of changing demand patterns.

Decarbonisation will certainly impact electricity supply, although at this stage it is uncertain how this will evolve. We have worked with Deta Consulting (in a shared project funded by Transpower, EECA and Aurora Energy) to ascertain and provide insight on the thermal fuel transition of companies with boilers. As with other EDBs, we do not have visibility of this load and this project is a significant step to understand where the boilers are (which is mostly in the Dunedin network). The project outcome indicates that Aurora will not have considerable increase in demand, but the thermal fuel transition will have significant impact to our distribution feeders and to a moderate degree the substations. We use the data from the thermal fuel transition project as a lever in the demand forecasting. We will coordinate with the boiler owners to understand their transition plans. To help us understand this uncertainty, we have modelled a series of potential future decarbonisation scenarios as described in Section 6.2.

We forecast demand on an annual basis, looking at 10 years into the future at the GXP, sub-transmission and zone substation levels. But we also consider future load on HV feeders, if needed, by adjusting for any known step changes, (E.g. new subdivisions, council plan changes). However, we plan to implement a system of triggers for individual feeder analysis to ensure potential issues are not missed. For example, feeder analysis would be triggered when peak load reaches a specified percentage of nominal feeder capacity, number of customers or N-1 capacity.

Demand forecasting is a key input to determining investment needs. Changes in the forecast from one year to the next may result in planned projects being brought forward or deferred.

Demand Forecast Model

Key to the success of the model is the improvement of our data gathering and obtaining more analogue information from field assets. As a starting point, the network load data is normalised by assessing changes in load patterns to exclude peaks caused by load shifts on interconnected feeders and uncharacteristic behaviour (E.g. sudden increase in short period of time). We also apply a small amount of smoothing to reduce noise, E.g. switching of load control channels.

We then add elements that will contribute to the peak demand as follows:

- Population growth (converted into numbers of new residential connections)
- Step changes from known planned developments (new or expansion)
- Irrigation load
- Residential EV chargers
- Transient EV (Public EV Chargers)
- Light and heavy EV (Buses, Trucks, Couriers etc)
- Boiler conversions (process and building heating).

We also subtract the reduction in load from the following:

- PV generation (not part of non-network capacity solutions)
- Non-network capacity support (if any).

Although, EV charging has been added in our forecasting model we have not included other forms of transportation E.g. planes, ferries, cruise ships, boats, etc or any electrification of port facilities (maritime, land or air) and they will be treated as step change. Further, these type of EVs may potentially impact the network beyond the 10-year planning horizon but we are watching this space in coordination and collaboration with the individual port management - Port of Otago, Dunedin International Airport and Queenstown Airport.

We produced two sets of 10-year demand forecast as our baseline – expected and prudent. The demand forecast is prepared for: total system, GXP, sub-transmission and substation. Section 6.4.1 shows the total system (expected and prudent) forecast, while Section 6.4.2 to 6.4.4 presents the (expected) forecast for sub-transmission and substations.

Additional forecasting for Information Disclosure requirements

The following methods are used to forecast information required for Information Disclosure and which help inform commercial and planning aspects of the business:

- **customer connections**: we use a rolling average method to reflect trends in the number of new customer connections. Using this method, we have observed a minor slowing in the growth rate of new connections.
- **distributed generation (DG)**: we have assumed that the growth in new DG connections observed over the past year will continue for the next six years.
- **electricity volumes**: we have normalised the growth rate over the past five-years for the effects of the COVID-19 pandemic and applied this rate to forecast electricity volumes for the next six years.

We have not conducted sensitivity analysis of these forecasts, nor have we adjusted for weather effects. The effect of weather is generally damped out over the course of the year; however, as more data becomes available, the impact of changing climate may need to be factored into our forecasting.

The data produced is not used directly for investment forecasting as forecasts of final consumer connections do not correlate well to consumer connection Capex due to variability in the work required to connect larger installations, and the fact that subdivisions take several years to be fully built out, depending on property market conditions.

Forecasting Uncertainty

Inherent to demand forecast is the level of uncertainty in the 10-year planning horizon and is amplified from the medium term (3-5 years) and more so long-term (6-10 years). The uncertainty increases over longer forecast periods. This is influenced by a lot of factors including but not limited to - drive for decarbonisation, uptake of emerging/new technologies and potential change of the power system landscape.

6.3.7. Network Modelling

We have created our own two geographical network models in PowerFactory modelling software representing Dunedin and Central Otago network regions. The geographical model comprises of the GXP, sub-transmission, zone substation, distribution feeder, distribution transformer, other line assets (E.g. recloser, RMU), embedded large generations and embedded network (defined as load only). This has given us the opportunity to study to have a better understanding of the network.

We use the geographical model with the demand forecast as input to methodically analyse the network against breaches in our Security of Supply and regulatory voltage limits in the 10-year planning horizon. Managing system security is a key driver of growth and security investments. Identified network gaps or needs are recorded and will go through the network development planning process for resolution. As part of this process, a detailed network study, using the same geographical model is performed to ascertain that options listed are electrically viable to meet the identified need.

We also conduct network studies to assimilate load transfer (within the voltage limits) between substations or offloading a distribution feeder to adjoining feeder(s). The model is further used to resolve localised voltage issues and to reconfigure the network as an immediate operational mitigation. We also use the network model to run other studies such as contingency, fault analysis and protection studies, among others.

6.3.8. Non-network Solution

When the network becomes constrained, investing in new infrastructure may not be the best option to relieve the constraint. Non-network solutions can enable deferral of much larger capital expenditure that is usually associated with network solutions. This provides value in terms of lower lifecycle cost, as well as enabling us to defer a decision when there is considerable uncertainty (such as regarding future load growth). Other alternatives to network solutions include:

- Distributed Energy Resources (DER)
- Demand Side Management (DSM), which includes energy and demand management systems and/or
- Cost-reflective pricing leading to changes of user behaviour.

Distributed Energy Resources

DER is a collective term given to both traditional solutions such as distributed hydro, wind, or diesel generation but also new technologies such as solar generation, battery storage and potentially EVs.[1] We consider that DERs will play a major role in providing benefits to the consumer, and a significant supporting role to the distribution network and the National Grid and the decarbonisation of the electricity generation and transport systems.

However, DERs can also cause constraints in the LV network, and, in some cases, the HV network. We discussed our approach to mitigating potential voltage constraints in Section 6.6.3. It is important that these constraints are understood and mitigated, in order to make certain that the full benefits of DER can be realised. As this is a relatively new solution, the power system and the distribution network need to adjust to the impact of these technologies.

Demand Side Management

Demand side management (DSM) provides an alternative to network reinforcement. Generally, DSM is an alteration of customer behaviour that occurs in response to incentives provided by the distribution business (or retailer). Incentives include peak pricing or payments for load interruption. Traditional examples of DSM include hot water cylinders with centralised ripple control and building energy management systems being utilised to modify demand in response to signal.

We assume no change in the level of DSM activity, i.e. a base level of demand-based initiatives is included in our load forecasts, primarily hot water ripple control, but also some demand response. With the change in the Transmission Pricing Methodology,[2] by removing the Regional Coincident Peak Demand (RCPD), we would continue to operate the hot water channels as if there is RCPD but having more emphasis on the GXP peak.

The key difference between DSM and DERs is the greater flexibility of the latter. DERs also have the ability to export or manage energy in both directions, whereas DSM cannot reverse the flow of energy.

Cost Reflective Pricing

It is anticipated that many different types of customer devices, including DG and battery storage, will be connected to electricity networks in the future. These new devices will be able to respond to price incentives facilitated by time of use smart metering. Cost reflective pricing will be a key enabler, providing financial benefits to the households and businesses that purchase DERs.

Further deployment of smart meters that provide half-hourly metering will facilitate benefits to customers who own smart appliances that can move load away from peak pricing periods. Carefully constructed pricing will enable us to maximise the potential gain from smart metering and the future uptake of DERs and smart appliances.

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1 Distributed energy resources (DER) and distributed generation (DG) are treated as functionally equivalent in this document.

2 In April 2022 Transpower announced its decision to adopt a new Transmission Pricing Methodology (TPM) which takes effect on 01 April 2023.

6.3.9. Value Stacking

DERs in the community provide value stacked benefits for consumers, electricity distribution businesses and Transpower. Value stacking provides the most benefit as it maximises the value of DERs to multiple benefactors. This is the model we used for Upper Clutha capacity support.

The example below illustrates how value stacking works and how the benefit is translated from one customer to NZ. In this example a customer installs a PV-Battery system:

- Lowers electricity bills by utilising PV generation or discharging the battery during peak times to supply home load thereby avoiding high electricity prices and charges the battery through PV or the grid when the prices are low. Can also export excess generation
- Provides back-up power supply to home during network outages
- Working with Flexibility Traders (Suppliers) who aggregate these small scale DERs and provide services to EDBs like Aurora Energy or Transpower through provision of capacity or reactive support during periods of constraint:

  The main benefit to the EDBs is deferral or potential avoidance of major capital investment. It also provides residual benefits such as reduction of everyday peak, supports network restoration during major outage and increase asset utilisation among others.

  The benefit to Transpower, as grid owner, is also capital investment deferral. While as System Operator, assists in managing system stability in terms of voltage and frequency.
- Encourages increase uptake and acceptance of the technology
- Ultimately, supports the nation's decarbonisation goal.

6.4. INVESTMENT DRIVERS

With further development of our risk-based network development, we will be working on comparative analysis of the need to invest. Safety, reliability, environment, customer satisfaction and other risk categories are being assessed and higher relative criticality is being established in order to prioritise the solutions. We give consideration of how the network will perform and operate under various scenarios of risk development and we consider the impact of decarbonisation for sustainable long-term investment. Demand growth, technology, climate, and regulations contribute to the development of these scenarios.

The need for network development investments is driven by a number of factors including:

- **system demand**: the peak demands for power and energy at GXP, zone substation and 11 kV distribution feeder levels compared to the capability of our networks. In Section 6.2 we discussed the three decarbonisation scenarios which will impact demand
- **security of supply**: our ability to meet defined supply security guidelines (see Section 6.3.5)
- **power quality**: our ability to meet power quality regulatory and industry standards.

The following sections provide more detail on these key drivers.

6.4.1. System Demand

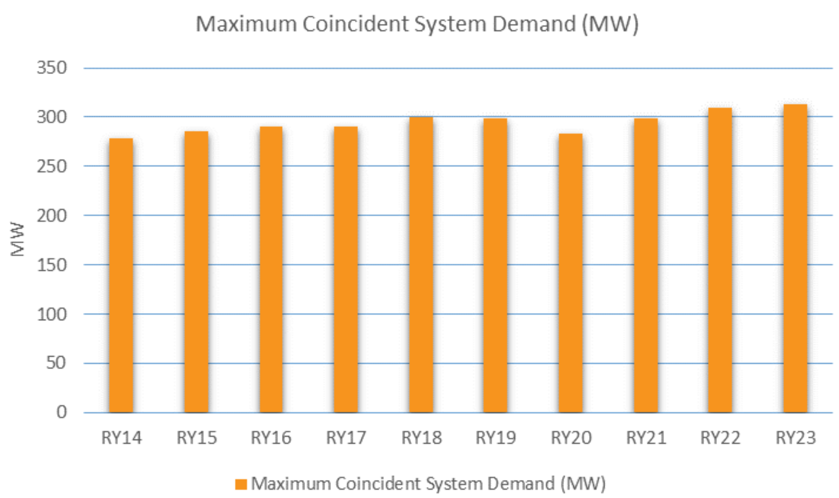
Electricity demand varies over time, on a daily and seasonal basis, as well as longer term, as a result of changes in population, economic activity, and customer behaviour. It can vary significantly from one part of the network to another. With the emerging theme of decarbonisation, we expect that increased adoption of new technologies such as EVs, PVs, and PV-battery systems will impact network capacity at all levels from midterm and beyond the AMP period.

Aurora Energy's network has two regional networks – Dunedin and Central Otago. The regional networks are split into:

1) Dunedin regional network comprise of the Dunedin sub-network, which is supplied by Halfway Bush and South Dunedin GXPs,
2) Central Otago regional network comprises of:
    2.1 Central Otago and Wānaka sub-network, supplied by Clyde and Cromwell GXPs respectively
    2.2 Queenstown sub-network which is supplied by Frankton GXP.

The system maximum demand is the sum of the two regional network coincident peak demand of the GXPs and generation supplying our network. Figure 6.6 shows the 10-year historical maximum system demand. In RY23, the peak demand reached 313 MW, the highest in the last 10 years. The five GXPs supplied 273 MW (87%) and 40 MW (13%) was supplied by generation.

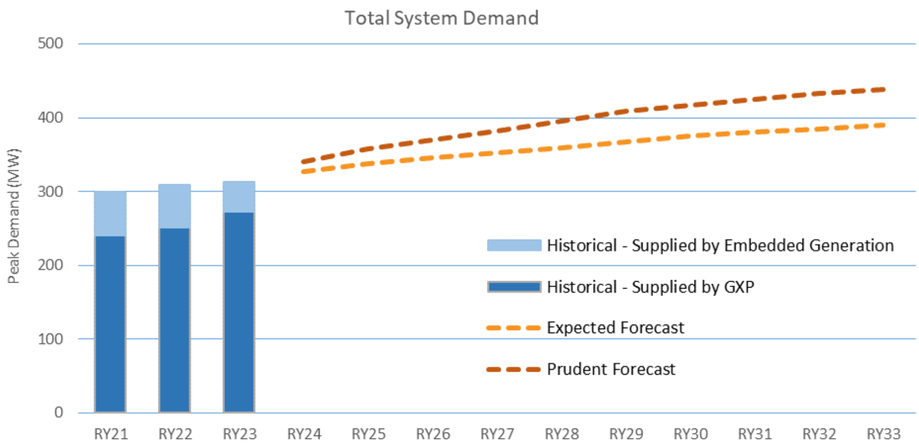
Figure 6.6: Maximum demand in the last ten years



The peak demand has increased steadily since RY20 (COVID-19 pandemic), and we forecast the continued growth in the next 10 years as shown in Figure 6.7. We anticipate that decarbonisation, uptake of DERs and the potential change in the power system landscape will play a vital role from midterm and beyond the 10-year AMP period.

Capacity constraints caused by growth in peak demand is a key driver of investment needs.[3] We have seen significant demand growth in Wānaka and Queenstown sub-network during COVID- 19 pandemic and the forecast indicates continued growth. The Frankton and Cromwell GXPs have experienced increased demand which is causing capacity constraints in both areas. Short-term tactical solutions to resolve the constraint are described in Section 6.4.3 and 6.4.4. Clyde GXP demand increased slightly this year and we expect the data centre would be operational next year hence a step change increase in demand. The forecast indicates the demand to increase due to large new loads currently in different development phases. Halfway Bush GXP has increased slightly, and South Dunedin has held stable for the past three years. We forecast that both GXPs will increase peak demand with new developments including thermal fuel transition within the latter part of the 10-year horizon.

Figure 6.7: Total system peak demand forecast (MW)



The following Sections 6.4.2, 6.4.3 and 6.4.4 will show the forecast peak demand from GXPs, their respective critical sub-transmission circuits and zone substations. The sections will also describe the network gaps and actions we are undertaking.

Note: The winter forecast data is from May to September 2022 and the summer forecast data is from Nov 2021 to March 2022.

6.4.2. Dunedin Sub-Network Forecast and Gaps

Our Dunedin network consists of GXPs at the Halfway Bush and South Dunedin networks. Figure 6.8 and Figure 6.9 shows their historical and forecast peak demand.

Both GXPs have shown steady modest demand increase over recent years and the forecast indicates that this will continue throughout the AMP period. Noticeable step change in the Halfway Bush network is the New Dunedin Hospital Inpatient Building which potentially will be operational by RY28. We anticipate that thermal fuel transition, uptake of EVs, change in heating, some commercial

[3] Note that capacity constraints do not reflect total instantaneous capacity, as they take security of supply requirements into consideration.

developments and population growth will drive the modest demand increase in the 10-year AMP period. We note that the EV uptake is greater in the Dunedin sub-network compared to the whole system. Solar generation, however, has a moderate uptake compared to the other sub-network. The forecast indicates that growth would continue throughout the AMP period and potentially beyond through our decarbonisation journey.

Dunedin Sub-Network Forecast

Figure 6.8: Halfway Bush GXP demand forecast

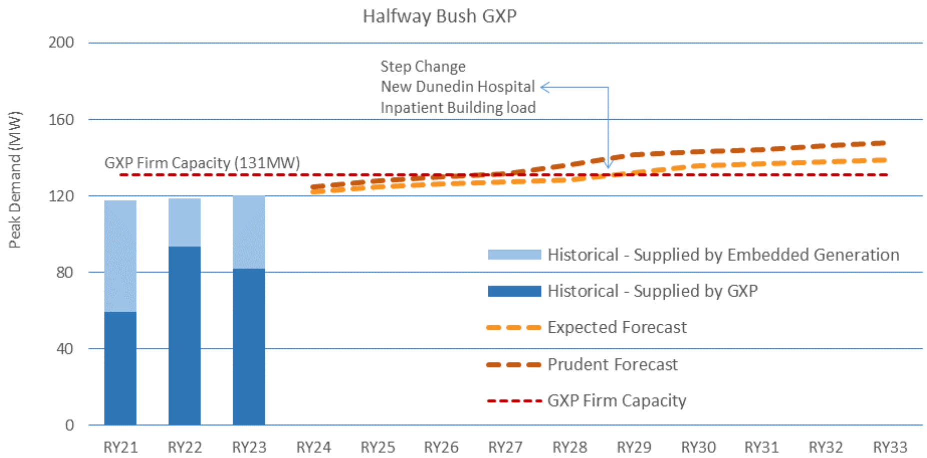


Figure 6.8 shows the Halfway Bush GXP peak demand forecast in steady pace of growth. The forecast implies that the demand will reach the firm capacity midterm of the AMP period. However, the demand is offset by generation (mostly Waipori). The increase in demand starting RY28 is from the anticipated operation of the New Dunedin Hospital Inpatient Building.

As of winter 2023, HWB GXP peak demand is 121 MW of which 82MW (68%) was supplied by the GXP and 39 MW (32%) was supplied by generation. The total installed generation capacity in the network is 95 MW of which, Waipori contributes 89 MW (94%) and the remaining generations are >4 MW.

Table 6.4: Halfway Bush Network critical sub-transmission demand forecast

				Historical			Forecast										
Sub-transmission	Security Class	Firm Capacity MVA	Security Level	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Peak Period
North East Valley-Port Chalmers	Z1	29	N-1	17.0	17.4	17.7	17.9	18.7	19.5	19.6	19.7	19.9	20.0	20.1	20.3	20.4	Winter

All of Halfway Bush sub-transmission circuits are radial with the exception of North East Valley-Port Chalmers and Waipori sub-transmission. Table 6.4 shows the expected forecast for the North East Valley-Port Chalmers sub-transmission. We only included the said sub-transmission in the demand forecast as its capacity potentially will be constrained with the electrification of its largest connected customer.

We expect that the largest customer of Port Chalmers will electrify their operations to meet their decarbonisation goals. The electrification plan is not yet confirmed but we anticipate electrification will progressively drive the increase in demand from midterm of the AMP period. The electrification, depending on the supply requirement, will impact the capacity of Port Chalmers substation, the North East Valley-Port Chalmers sub-transmission circuit and HWB GXP.

The Waipori ABC sub-transmission lines connects the Waipori generation, Berwick, Outram and Mosgiel substation to the HWB GXP. The sub-transmission capacity is constrained by the combined Waipori generation (hydro and wind) at 60 MW.

Table 6.5: Halfway Bush Network zone substation demand forecast

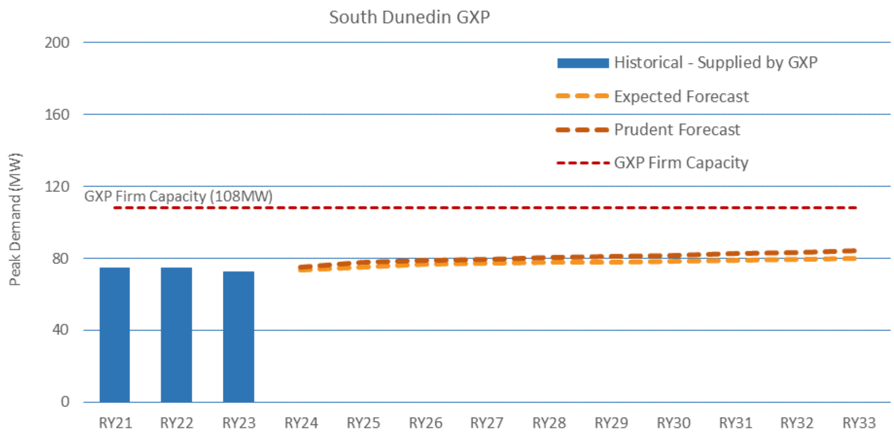
Zone Substation	Security Class	Firm Capacity MVA	Security level	Historical			Forecast										Peak Period
				2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Berwick	Z3	3.6	N	1.4	1.4	**1.6**	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.7	Summer
East Taieri	Z1	24	N-1	17.3	18.7	**18.0**	18.6	19.0	19.2	19.4	19.6	19.8	19.9	20.1	20.3	20.5	Winter
Green Island	Z2	18	N-1	14.0	14.5	**14.6**	14.8	14.9	15.1	15.2	15.3	15.4	15.5	15.6	15.7	15.8	Winter
Halfway Bush	Z2	18	N-1	13.0	13.4	**13.6**	13.8	13.9	14.0	14.1	14.2	14.3	14.4	14.5	14.8	15.0	Winter
Kaikorai Valley	Z2	23	N-1	9.9	10.5	**10.0**	10.1	10.3	10.5	10.6	10.7	10.7	10.8	10.9	10.9	11.0	Winter
Mosgiel	Z2	12	N-1	6.7	7.2	**7.1**	7.2	7.5	7.8	7.9	8.0	8.0	8.1	8.2	8.3	8.4	Winter
North East Valley	Z2	18	N-1	10.2	10.4	**10.4**	10.5	10.6	10.7	10.8	10.8	10.9	10.9	11.0	11.1	11.1	Winter
Outram	Z2	7.5	N	2.9	3.2	**3.3**	3.3	3.3	3.4	3.4	3.4	3.5	3.5	3.5	3.6	3.6	Winter
Port Chalmers	Z2	10	N-1	7.2	7.3	**7.6**	7.7	8.4	9.0	9.1	9.2	9.3	9.4	9.4	9.5	9.6	Winter
Smith Street	Z1	18	N-1	13.9	12.9	**13.2**	13.3	13.4	13.5	13.6	13.7	13.7	13.8	13.9	14.0	14.1	Winter
Ward Street	Z2	23	N-1	9.2	9.3	**9.6**	9.6	9.6	9.6	9.7	11.8	14.4	15.8	15.8	15.9	16.0	Winter
Willowbank	Z2	18	N-1	11.7	11.8	**12.5**	12.7	12.7	12.8	12.9	12.9	13.0	13.0	13.1	13.1	13.2	Winter

- In the 10-year AMP period, we forecast that the zone substations have adequate capacity to meet the demand requirement. The modest uplift in demand includes thermal fuel transition. We anticipate that this will drive the increase in the demand on some substations from midterm of the ten-year plan.
- Ward Street zone substation forecast includes the 7 MVA load of the Inpatient Building of the New Dunedin Hospital.
- Mosgiel zone substation forecast includes a moderate upturn in demand on potential electrification of one of its customers. We are at present collaborating with the customer to understand their decarbonisation journey.
- Port Chalmers zone substation forecast includes a potential electrification project of one of its largest customer but at modest growth. We are presently working with the customer to establish their medium-term supply requirement as well as understanding their long-term plans.
- Forecast also includes the education and health precinct plan.

Table 6.6 shows the existing and potential constraint in the network and provide actions we are undertaking and plans we are developing to resolve this gaps.

South Dunedin GXP has seen relatively stable peak demand over the last three years, but we forecast an increase beginning midterm, driven by decarbonisation goals of our customers such as electrification and move to assets with more efficient energy.

Figure 6.9: South Dunedin GXP demand forecast



South Dunedin network's sub-transmission are all radial architecture. The Dunedin 33 kV sub-transmission project provides interconnection in the sub-transmission with other CBD zone substations.

Table 6.6: South Dunedin zone substation demand forecast

Zone Substation	Security Class	Firm Capacity MVA	Security Level	Historical			Forecast										Peak Period
				2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Andersons Bay	Z1	18	N-1	15.1	15.5	**14.2**	14.4	14.6	14.8	15.0	15.1	15.2	15.3	15.4	15.5	15.6	Winter
Carisbrook	Z2	18	N-1	12.1	12.1	**9.5**	9.5	10.1	10.7	10.8	10.9	11.0	11.1	11.3	11.4	11.6	Winter
Corstorphine	Z2	23	N-1	12.6	12.9	**12.0**	12.1	12.2	12.3	12.4	12.5	12.6	12.7	12.8	12.9	13.0	Winter
North City	Z1	28	N-1	15.5	15.3	**15.4**	15.4	16.2	16.9	16.9	16.9	16.9	16.9	17.0	17.0	17.0	Winter
South City	Z1	18	N-1	14.5	15.1	**14.8**	14.9	14.9	15.0	15.0	15.0	15.1	15.1	15.2	15.3	15.4	Winter
St Kilda	Z1	23	N-1	14.2	14.6	**14.6**	14.8	14.9	15.1	15.2	15.3	15.4	15.5	15.5	15.6	15.7	Winter

- North City zone substation demand forecast includes the 2 MVA Outpatient Building of the new Dunedin hospital.
- Forecast includes the education and health precinct plan.

Dunedin Sub-Network Gaps

The table below shows the existing and potential constraint in the network and provide status of actions we are undertaking and plans we are developing to resolve these gaps.

Table 6.7: Dunedin Sub-Network Gaps

AREA	CONSTRAINT	STATUS
Halfway Bush GXP	The forecast indicates that in the latter part of the AMP period the demand would be above firm capacity of the GXP. However, generation offsets some of the substation loads.	– Aurora will conduct a study to understand the contribution of the generation and implication when the whole/part of generation is out of service. – Investigate (with Transpower) increasing the rating of HWB T5. The transformer rating limits the firm capacity to 131 MVA. – Explore transfer of substation to SDN GXP.

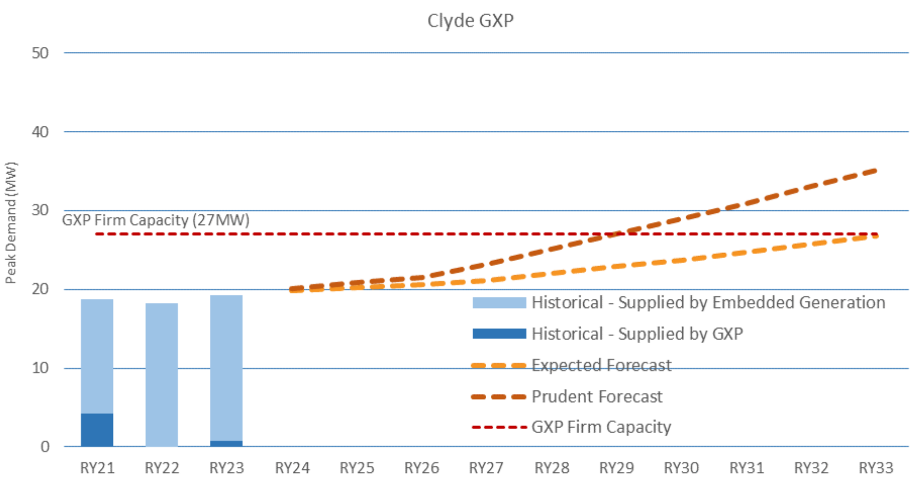
AREA	CONSTRAINT	STATUS
Dunedin Sub-Network	Customers' thermal fuel transition would impact capacity of zone substations and distribution feeders.	– Aurora will work closely with customers to support their decarbonisation goal and to understand their power supply requirement and associated timing.
Dunedin 33 kV Sub-transmission	Halfway Bush and South Dunedin GXPs both supply the CBD but have a very limited transfer capacity between GXPs. Most of the sub-transmission circuits are in radial configuration and at risk of loss of supply in a double circuit outage as the two cables are installed in close proximity.	– Aurora has developed a plan to create a sub-transmission ring configuration in the Dunedin CBD. This will increase security and reliability as zone substations can be transferred between GXPs. Our preferred plan is combining the sub-transmission cable renewal schedule with the creation of the sub-transmission ring. – The Smith St to Willowbank 33 kV cable is currently underway and is projected to be completed in RY24. This allows deferral of Willowbank gas cable renewal. – The other projects scheduled at the later part of the 10-year plan are North City to Ward Street, Smith Street to Carisbrook and Ward Street to South City.
Port Chalmers Substation and North East Valley-Port Chalmers 33kV Sub-transmission	The largest customer of Port Chalmers potentially would electrify its operations to meet their decarbonisation goals. This will have an impact on the capacity of Port Chalmer substation, its sub-transmission and HWB GXP.	– Aurora will work closely with the customer to support their decarbonisation goal and to understand their power supply requirement and associated timing. – Aurora will prepare a plan to resolve capacity constraint.
Berwick zone substation	Berwick zone substation is an N-security level with limited backfeed supply from Outram. For contingent events such as zone transformer failure, restoration of power supply is dependent on repair time.	– Aurora has created a backfeed project to be completed in RY24 to provide backup supply from Outram. This would limit the outage duration to only switching time.
Outram zone substation	Outram zone substation is an N-security level but has transfer capability to adjacent zone substations.	– Aurora will prepare a contingency plan for the loss of power supply.

6.4.3. Central Otago and Wānaka Sub-Network Forecast and Gaps

Central Otago and Wānaka network are supplied by Clyde and Cromwell GXPs respectively. The two networks are not contiguous and there is no interconnection. Figure 6.10 and Figure 6.10 6.11 shows the GXP historical and demand forecast. Clyde network has an aggregated 32MW of generation capacity which more often supplies all its load requirements. Wānaka network has the most active and substantial developments which drives the demand growth. The forecast indicates that growth would continue throughout the AMP period and potentially beyond through our decarbonisation journey.

Central Otago Sub-Network Forecast

Figure 6.10: Clyde GXP demand forecast



In Figure 6.10, the forecast indicates steady growth through the 10-year AMP period. Growth in peak load is expected from a combination of irrigation load and population growth. The GXP currently has almost the same load in summer and winter. The load peak is expected to move to the early spring shoulder season where domestic heating load may combine with early irrigation load or orchard frost fighting load. Exactly how these loads will combine will depend on how much of the new irrigation load will be used in early spring, which makes prediction of this load difficult. The future load may exceed the firm capacity of the Clyde GXP, but the actual GXP throughput will remain well below this due to the large amount of embedded generation. There is 32 MW of generation in the area which most of the time exceeds the substation demand, including at peak times as illustrated.

Table 6.8: Clyde Network critical sub-transmission demand forecast

				Historical			Forecast										
Sub-transmission	Security Class	Firm Capacity MVA	Security Level	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Peak Period
Alexandra - Omakau	Z2	6	N	4.0	4.0	4.2	4.4	4.6	4.8	5.1	5.4	5.7	6.0	6.3	6.5	6.7	Summer
Roxburgh - Alexandra	Z1	16	N-1	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	Winter
Alexandra - Clyde	Z1	13	N-1	11.8	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	Winter

The Clyde sub-transmission is mostly constrained by the generation. In this part of Aurora's network, generation normally supplies the zone substation load. The Alexandra-Omakau single circuit sub-transmission supplies Omakau and Lauder Flat zone substations. The forecast indicates growth in the latter part of the AMP on these two substations. This sub-transmission circuit has some length of squirrel conductor.

Table 6.9: Clyde Network zone substation demand forecast

Zone Substation	Security Class	Firm Capacity MVA	Security Level	Historical			Forecast										Peak Period
				2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Alexandra	Z2	15	N-1	10.9	10.8	**11.5**	11.8	12.1	12.4	12.6	12.9	13.1	13.3	13.6	13.8	14.0	Winter
Dunstan	Z3	24	N			**0.0**	8.0	8.0	8.0	10.3	12.8	12.8	12.8	12.8	12.7	12.8	new substation
Clyde/Earnscleugh	Z3	4.8	N	3.9	3.9	**4.1**	4.1	4.5	4.8	4.3	0.0	0.0	0.0	0.0	0.0	0.0	Summer
Ettrick	Z3	3.6	N	1.8	1.9	**2.2**	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	Summer
Lauder Flat	Z3	3	N	1.3	1.0	**1.2**	1.2	1.3	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.7	Summer
Omakau	Z3	7.5	N	3.4	4.4	**3.2**	3.4	3.6	3.7	4.0	4.3	4.5	4.8	5.0	5.3	5.6	Summer
Roxburgh	Z2	6	N	2.0	2.0	**1.7**	1.7	1.8	1.8	1.9	2.0	2.1	2.1	2.2	2.4	2.5	Summer
Earnscleugh		2															

Zone Substation	Security Class	Firm Capacity MVA	Security Level	Historical			Forecast										Peak Period
				2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Alexandra	Z2	15	N-1	10.9	10.8	**11.5**	11.8	12.1	12.4	12.6	12.9	13.1	13.3	13.6	13.8	14.0	Winter
Dunstan	Z3	24	N			**0.0**	0.0	0.0	0.0	2.3	4.8	4.8	4.8	4.8	4.7	4.8	new substation
Clyde/Earnscleugh	Z3	4.8	N	3.9	3.9	**4.1**	4.1	4.5	4.8	4.3	0.0	0.0	0.0	0.0	0.0	0.0	Summer
Ettrick	Z3	3.6	N	1.8	1.9	**2.2**	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	Summer
Lauder Flat	Z3	3	N	1.3	1.0	**1.2**	1.2	1.3	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.7	Summer
Omakau	Z3	7.5	N	3.4	4.4	**3.2**	3.4	3.6	3.7	4.0	4.3	4.5	4.8	5.0	5.3	5.6	Summer
Roxburgh	Z2	6	N	2.0	2.0	**1.7**	1.7	1.8	1.8	1.9	2.0	2.1	2.1	2.2	2.4	2.5	Summer
Earnscleugh		2															

- The new Dunstan zone substation site is currently in progress and we will progressively transfer Clyde/Earnscleugh load from RY25 to RY27. We plan to decommission Clyde/Earnscleugh zone substation in RY27-28.
- Rebuild of the Omakau zone substation with a 7.5 MVA zone transformer (ex-Cromwell zone transformer) is underway at a new site and is scheduled for completion in RY24. The project includes reconfiguration of the distribution feeders to improve reliability and voltage issues. The zone substation will also include a 2 MVA distributed generation site to provide emergency power supply until a mobile substation is connected or repair is completed.
- Earnscleugh zone substation is the backup of Clyde/Earnscleugh zone substation and is scheduled to be decommissioned after the Clyde/Earnscleugh load has been transferred to Dunstan.

Central Otago Sub-Network Gaps

Table 6.10 below shows the existing and potential constraint in the network and provide actions we are undertaking and plans we are developing to resolve these gaps.

Table 6.10: Central Otago Network Gaps

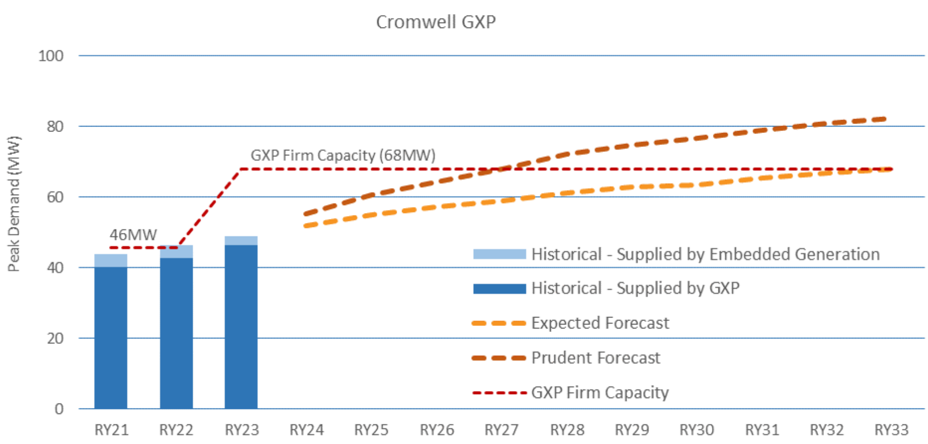
AREAS	CONSTRAINT	STATUS
33 kV sub-transmission	– Generation mostly supplies the network. The current state is that new generation will constrain the sub-transmission. – Alexandra-Omakau-Lauder Flat sub-transmission is forecast to be capacity constrained in the latter part of the AMP period.	– Generation hosting capacity will be conducted to determine space for new generations. Further, additional generations would need to have a runback scheme. – Aurora is investigating replacing the squirrel conductor and other ways to resolve the capacity constraint.
Omakau zone substation	– Omakau is an N-security level with very limited backfeed supply from adjacent zone substations. For contingency event such as zone transformer failure,	– Part of the Omakau substation rebuild is to install a generator to provide emergency backup until the mobile

AREAS	CONSTRAINT	STATUS
	restoration of power supply is dependent on repair time. – The Ida Valley area is supplied from one feeder which introduces security, reliability, and voltage issues.	substation is connected or repair is completed. – Aurora has created a project in RY24 to provide backfeed supply from Lauder Flat and the other way around. – Aurora is investigating options to increase security, reliability and resolve the voltage issue in the Ida Valley area.
Lauder Flat zone substation	Lauder Flat zone substation is an N-security level with limited backfeed supply from Omakau. For contingent event such as zone transformer failure, restoration of power supply is dependent on repair time.	Aurora has created a backfeed project to be completed in RY24 to provide backup supply from Omakau. This would limit the outage duration to only switching time.
Roxburgh zone substation	Roxburgh zone substation is an N-security level with limited backfeed supply from adjacent zone substations. For contingent event such as zone transformer failure, restoration of power supply is dependent on repair time.	Aurora has created a backfeed project to be completed in RY24 will provide backfeed supply from Ettrick. This would limit the outage duration to only switching time.
Ettrick zone substation	Ettrick zone substation an N-security level with limited backfeed supply from adjacent zone substations. For contingent event such as zone transformer failure, restoration of power supply is dependent on repair time.	Aurora has created a backfeed project to be completed in RY24 that will provide backfeed supply from Roxburgh. This would limit the outage duration to only switching time.

Wānaka Sub-Network Forecast

Strong demand growth continues throughout the Wānaka network. The forecast indicates it will carry on throughout and beyond the 10-year AMP period. The demand could potentially exceed the GXP firm capacity mid-term of the AMP period if the demand growth is at prudent forecast rate.

Figure 6.11: Cromwell GXP demand forecast



The Aurora and Transpower project to replace the two 33kV incomer circuit breakers was completed in May 2022, increasing the GXP's firm capacity to 65/68 MVA (summer/winter rating) from 46/46 MVA. The timely completion resolved the expected firm capacity constraint in winter 2022 as the peak demand rose to 49 MVA which is 3 MVA above the old firm capacity.

Small scale DG installations (mostly solar) are increasing, in RY22 the solar generation capacity grew by almost 1 MW from RY21. As of 31 March 2022, the total small-scale solar generation installed capacity is 3.9 MW (44% of the whole network) and majority is in Wānaka. However, we haven't seen the impact in terms of summer peak reduction or power quality issues.

Table 6.11: Cromwell Network critical sub-transmission demand forecast

Sub-transmission	Security Class	Firm Capacity MVA	Security Level	Historical			Forecast										Peak Period
					2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Upper Clutha	Z1	32	N-1		30.5	34.5	36.2	38.1	39.1	40.1	41.7	42.6	42.7	43.9	44.7	44.8	Winter
		30			25.0	27.8	28.4	29.1	29.0	29.1	29.1	29.1	29.5	29.3	30.1	30.5	Summer

Table 6.12: Cromwell Network zone substation demand forecast

Zone Substation	Security Class	Firm Capacity MVA	Security Level	Historical			Forecast										Peak Period
				2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Camp Hill	Z2	7.5	N	5.3	5.5	5.7	5.8	6.0	6.0	5.9	5.9	5.9	5.9	5.8	5.9	6.0	Summer
Cardrona	Z3	6.7	N	3.7	3.7	3.9	5.2	6.2	6.7	7.3	8.7	9.3	9.6	9.8	9.8	9.8	Winter
Cromwell	Z2	24	N-1	12.7	13.8	14.4	15.6	16.7	17.8	18.3	18.9	19.5	20.1	20.8	21.4	21.8	Winter
Lindis Crossing	Z3	10	N	6.8	6.6	7.0	7.4	8.5	8.6	8.6	8.7	8.7	8.8	8.8	8.9	8.9	Summer
Queensberry	Z3	4	N	3.1	3.4	3.8	3.9	3.2	3.3	3.3	3.3	3.4	3.4	3.4	3.4	3.5	Summer
Wanaka	Z1	24	N-1	24.9	25.0	27.2	27.5	28.2	28.7	21.0	20.9	20.9	19.9	20.5	20.9	21.3	Winter
Riverbank	Z3	24	N							8.2	8.5	8.9	9.8	10.1	10.3	10.5	new substation

- Cardrona zone substation capacity will increase with the replacement of the 5MVA transformer with a new 24 MVA zone transformer which is expected to be completed in RY24.
- Lindis Crossing zone transformer was fitted with fans to uprate its capacity to 10MVA from 7.5 MVA last November 2022.
- A portion of Queensberry distribution network was transferred to Lindis Crossing zone substation in November 2022 to supply an orchard development.
- At Camp Hill zone substation, a 2 MVA distributed generation will be installed in RY24 to provide alternate power supply in the event of the loss of the single sub-transmission circuit/zone transformer and associated assets being out of service.

The Upper Clutha network is subjected to considerable demand growth. Developments such as the ski field expansion, film studio, commercial developments at Three Parks, residential developments in Wānaka, Cardrona, Luggate and Hāwea among others are driving the increase in demand. The table below shows the existing and potential constraint in the network and provide actions we are undertaking and plans we are developing to resolve these gaps.

Table 6.13 enumerates our plan to resolve capacity and voltage constraint of the Upper Clutha circuits.

Wānaka Sub-Network Gaps

The table below shows the existing and potential constraint in the network and provide actions we are undertaking and plans we are developing to resolve these gaps.

Table 6.13: Wānaka Sub-Network Gaps

AREAS	CONSTRAINT	STATUS
Cromwell GXP	The 220 kV Clyde-Cromwell-Twizel circuits supplies the GXP's 2x 3-winding transformers. There is no 220 kV bus. The 110 kV side supplies the FKN GXP through the CML-FKN transmission line. The 33 kV side supplies Aurora's Cromwell network. – The 33 kV firm capacity is now 65/68MVA (summer/winter). – The next limiting component is the 33 kV cable (from the GXP Transformer) to the 33 kV outdoor bus. – Additional capacity potentially may be required in the latter part of the AMP period. – The 33 kV outdoor switchgear is scheduled for replacement by Transpower.	– Transpower has completed the replacement of the two 33 kV incomer CB in May 2022 that increased the CML 33 kV GXP capacity to 65/ 68MVA. – Aurora is waiting decision of Transpower on progressing the 33 kV outdoor switchgear replacement. – Aurora is waiting for the plan of Transpower on the replacement of the 33 kV cable to increase capacity which potentially be required in the latter part of the AMP period.
Upper Clutha 66 kV Sub-transmission	The two Upper Clutha circuits takes it supply from the Cromwell 33 kV GXP through Aurora's 33/66 kV auto-transformers. For winter rating: – The winter rating was elevated to 36MVA which is limited by the 33kV bushing. – However, the voltage constraints the firm capacity to 32MVA. This is the maximum load where the voltage is within the regulatory limits when one circuit is out-of-service. – The line winter rating is 43 MVA. Forecast indicates that demand would breach the line rating at the end of the AMP period. For summer rating: – The summer rating is limited by the autotransformer rating of 30 MVA. – The line summer rating is limited to 40MVA. Forecast indicates that demand would breach the line rating at the end of the AMP period.	– To mitigate the voltage constraint, Aurora is currently Installing capacitors at Wānaka, Cardrona and Lindis Crossing zone substations which is expected to be completed by RY24. – Aurora will commission a Special Protection Scheme before Winter 2023 to allow demand above 32 MVA pre-contingent. – Aurora will employ non-network capacity support to augment the capacity constraint. Aurora has partnered non-exclusively with solarZero to provide capacity support during contingency events. This is part of the CPP approved Upper Clutha DER solution. – Aurora plans to commission a new autotransformer of a higher rating and parallel the existing autotransformer by RY24 to increase the capacity of the Upper Clutha circuits to 40/43 MVA (summer/winter). – Aurora will seek additional non-network capacity support through an Open Call process describe in Section 6.6.2
Wānaka zone substation	The peak demand of Wānaka in winter 2023 was 27 MVA which is 3 MVA above its firm capacity. With a number of large developments, our forecast shows that the demand will be 5 MVA above the firm capacity limit in the next three years.	– Aurora has completed the load transfer project last year to provide capability to transfer >1.5 MVA between Wānaka and Camp Hill. – Aurora has started the project to install a 24 MVA zone transformer at Riverbank which is planned to be completed by RY25 to offload Wānaka zone substation.
New Riverbank Substation	The substation is planned to support the load growth n Wānaka. The substation would	– This substation is planned to be commissioned by RY25 with offloading

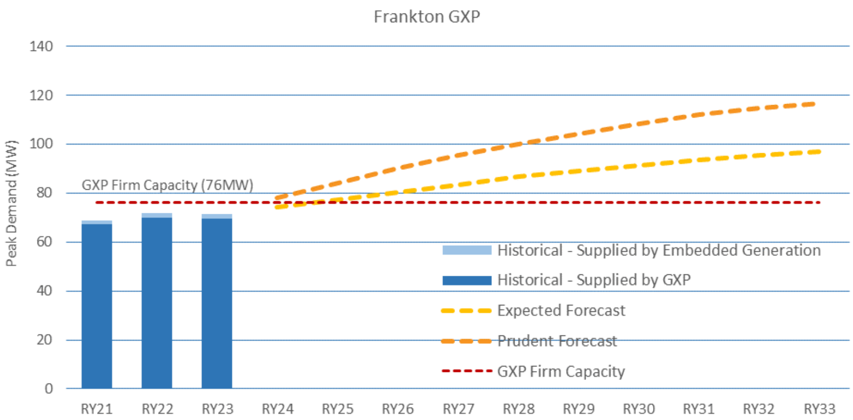
AREAS	CONSTRAINT	STATUS
	provide additional capacity to cater for load growth from Riverbank Rd towards Luggate. Developments such as Three Parks, Silverlight film studio, Luggate residential development among others	Wānaka commencing RY26. This would also result in reconfiguration of the Wānaka distribution feeders and to provide better interconnection with adjacent substations. – In the long term, we plan to install a second 24 MVA transformer at Riverbank to cater for expected growth within the planning horizon.
Cardrona zone substation	We expect that the peak demand in RY23 will be more than the pre-COVID peak and will be above the firm capacity of the single zone transformer. Cardrona ski field has indicated that their load will increase by 8 MVA in the next 10 years with an initial 4 MVA in the next three years. This load increase is well above the firm capacity. Furthermore, there are other large developments in the Cardrona area.	– Installation of a new 24 MVA zone transformer to replace the existing 5 MVA zone transformer is on-going. The new transformer is expected to be commissioned by RY24.
Lindis Crossing and Queensberry zone substation	Both zone substations are N-security level. We expect that developments in the area would increase the demand which impacts the capacity of both substations.	– We have increased the capacity of the zone transformer from 7.5 MVA to 10 MVA with the addition of fans in November 2022. – In the medium term, we plan to increase the capacity of Lindis Crossing to cater for demand growth. However, we are conducting a study to cater for increased capacity in the area.
Camp Hill zone substation	Camp Hill is an N-security zone substation that takes 33 kV supply from the single sub-transmission circuit from Wānaka. Outage on the sub-transmission circuit or zone transformer would result to in loss of power supply.	– Aurora has completed the load transfer project last year to provide capability to transfer >1.5 MVA between Wānaka and Camp Hill. – We are currently installing a 2 MVA generator to be utilised during emergency situations. The project is expected to be commissioned in RY24. – With the Wānaka distribution network reconfiguration, it provides an opportunity to provide additional distribution feeder interconnections with adjacent substations.

6.4.4. Queenstown Sub-Network Forecast and Gaps

Queenstown sub-network is experiencing increasing demand growth, as indicated over the past years, in line with commercial and residential growth in the wider Frankton and Queenstown area. The COVID-19 pandemic has not affected the demand growth. The forecast indicates that growth would continue throughout the AMP period and potentially beyond through our decarbonisation journey.

Queenstown Sub-Network Forecast

Figure 6.12: Frankton GXP demand forecast



The Frankton GXP is expected to see strong growth due to population increase and a return of foreign tourism. Many commercial development projects in the area that had been conceived prior to the COVID-19 pandemic, now appear to be moving ahead with new vigour. The forecast indicates that in the next 2- 3 years the demand will be above the GXP (76MW) and the transmission line (77MW) firm capacity limit.

In collaboration with Transpower and Powernet, tactical upgrade solutions have been developed for implementation over the next 10 years as required to meet peak demand growth. A transformer upgrade at Frankton GXP is planned as the first step in the next 2-3 years. We anticipate that an upgrade to the 110 kV line will also be required over the next 3-5 years to provide a firm capacity of approximately 90 MVA. Further tactical upgrades to the Frankton supply point will enable circa 100 MVA of capacity to be provided from the existing grid supply configuration. Growth beyond 100 MVA will require additional investigation into a range of supply upgrade options. In parallel with the above traditional supply side solutions we will continue to identify and implement emerging demand-side solutions to shape peak demand and enable sustainable and affordable electricity supply to the region.

Table 6.14: Frankton Network sub-transmission demand forecast

Sub-transmission	Security Class	Firm Capacity MVA	Security Level	Historical 2020	2021	2022	Forecast 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Peak Period
Arrowtown Ring	Z1	13	N-1	17.0	17.5	17.9	18.1	18.7	19.2	19.8	20.4	20.7	21.1	21.4	21.7	22.0	Winter
Queenstown	Z1	35	N-1	29.9	29.4	30.9	31.9	33.3	34.5	35.8	37.1	38.0	38.8	39.5	40.2	40.5	Winter

- The Arrowtown 33 kV Ring upgrade is in progress and is expected to be completed by RY24. The project increases the capacity and improves reliability of the sub-transmission ring.
- Growth on the Queenstown sub-transmission will be closely monitored. Running above N-1 capacity for a few hours per year may be appropriate, but we are exploring options to resolve this constraint. This is further discussed in Table 6.16.

Table 6.15: Frankton Network zone substation demand forecast

Zone Substation	Security Class	Firm Capacity MVA	Security Level	Historical			Forecast										Peak Period
				2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Arrowtown	Z2	10	N-1	10.1	9.4	9.7	10.0	10.3	10.6	11.0	11.3	11.7	12.1	12.5	12.8	13.1	Winter
Commonage	Z2	17	N-1	10.7	11.2	11.6	11.7	11.7	11.8	12.0	12.1	12.2	12.4	12.5	12.7	12.9	Winter
Coronet Peak	NA	6	N	5.3	5.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	Winter
Dalefield	Z3	3.6	N	1.9	1.7	1.7	2.2	2.5	2.8	3.0	3.3	3.3	3.4	3.4	3.4	3.4	Winter
Fernhill	Z2	10	N-1	5.9	5.9	6.3	6.6	6.9	7.2	7.5	7.8	7.9	8.1	8.2	8.4	8.4	Winter
Frankton	Z1	15	N-1	16.6	17.1	18.0	19.0	19.8	20.7	21.6	22.5	23.4	24.2	25.0	25.7	26.4	Winter
Queenstown	Z2	20	N-1	13.3	12.2	12.4	12.9	13.9	14.9	15.7	16.6	17.3	17.7	18.2	18.6	18.6	Winter
Remarkables	NA	3.6	N	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	Winter

– The replacement of the 15 MVA zone transformer with 24 MVA at Frankton zone substation will increase its capacity upon completion in RY24.

Queenstown Sub-Network Gaps

The table below shows the existing and potential constraint in the network and provide actions we are undertaking and plans we are developing to resolve these gaps.

Table 6.16: Queenstown Sub-Network Gaps

AREAS	CONSTRAINT	STATUS
Frankton GXP	Frankton GXP is supplied by the 110 kV CML-FKN line. There is no 110 kV bus at FKN. The following were advised by Transpower Grid Owner: – The GXP capacity has a capacity limit of 76 MW. The forecast indicates that the next 2-3 years the load will be above the limit. – The next constraint is the 110kV transmission line which is limited by line loading at 77 MW. The forecast indicates that in the next 2-3 years the demand will be above the GXP and the transmission line firm capacity limit.	– Aurora, PowerNet and Transpower are progressing the replacement of the existing GXP transformers with 120 MVA transformers (2023-26). – Next action is to uprate the transmission line to increase capacity to 90 MW (2026- 30). – Further action is to install a 110kV bus at FKN GXP and/or upgrade the second transformer which will increase capacity to 101 MW (2030). – Aurora will seek non-network solution through an Open Call process described in Section 6.6.2 to provide capacity support.
Queenstown sub-transmission	The forecast shows that the peak demand will be above the firm capacity from midterm of the AMP period.	– We will investigate options to increase capacity of the sub-transmission through network and non-network solutions. – We are reviewing the use of Special Protection Scheme to allow the demand to be above the firm capacity pre-contingent. – We will seek non-network support through an Open Call for non-network capacity.

Aurora Driven Frankton GXP Projects

Table 6.17: Aurora Energy Frankton GXP projects

PROJECT	STATUS
The Arrowtown 33 kV ring upgrade project involves the following works at Frankton GXP: – Protection setting change on FKN2752 and FKN2842 (RY21) – New 33 kV feeder CB (RY23) – New line differential protection relay (RY23) – Upgrade existing feeder tails of FKN2752 and FKN2842 to Aurora's take-off point (RY23)	The Transpower Works Agreement has been signed for Transpower to install the new 33 kV circuit breaker. The project is scheduled for RY23-24 as part of CPP approved projects Aurora will install new protection relays on FKN2752, FKN2842 and the new 33 kV CB. New cable tails will be installed on FKN2752 and FKN2842.

6.4.5. Power Quality

Power quality relates to the voltage delivered to the customer's point of supply for the specified load. It covers voltage magnitude, distortion, and interference of the waveform. Targets for voltage levels are specified in Part 3 of the Electricity (Safety) Regulations 2010 and industry standards. We aim to provide a regulatory-compliant quality of supply to all customers at all times. We do this through effective planning and good network design.

Power quality is generally managed by ensuring that network capacity is adequate. Undersized reticulation or high impedance transformers (where required to manage fault levels) will increase the risk of power quality issues. Some projects provide for the connection of equipment (for example variable speed drives), which can create high levels of harmonic distortion, and it may be necessary to install harmonic filtering equipment to reduce the distortion to acceptable levels.

At this stage, work to address power quality issues is reactive, in that we respond to customer complaints. We have installed Distribution Transformer Monitoring (DTM) devices from RY22 on strategic locations to provide us baseline power quality information of the network. These DTMs provide real-time data and alarms to the engineers' desktop. We have procured additional equipment for power quality, and we have a Power BI reporting tool to monitor complaints and their resolution. We are looking to access customer smart meter data or LV circuit monitoring, so we can progress to a more proactive approach in addressing power quality issues. This is further discussed in Section 6.6.3.

With the level of DG penetration in our network at this stage, we have not experienced any power quality issues relating to solar generation. However, if left unmanaged, DG penetration will cause power quality issues. With our SSDG connection process, we aim to limit the potential impact upon the network.

Voltage Magnitude

Regulations require voltage to be maintained between ±6% at the point of supply except for momentary fluctuations.

Harmonics – distortion and interference

Harmonic voltages and currents in an electric power system are typically a result of non-linear electric loads. Non-linear loads include variable speed drives, switch mode power supplies, and electronic ballasts for fluorescent lamps and welders injecting harmonic currents into the network. These harmonic currents couple with the system impedances, creating voltage distortion at various points on the network. This can cause malfunction or complete failure of equipment such as computers, digital clocks, transformers, motors, cables, capacitors, and electronic controls, which are connected at the same point.

The limits below are used to gauge harmonic voltage distortion lasting longer than one hour. For shorter periods, during start-ups or unusual conditions, these limits may be exceeded by 50%.

Table 6.18: Maximum voltage distortion limits in % of Nominal fundamental frequency voltage

INDIVIDUAL VOLTAGE DISTORTION (%)	TOTAL VOLTAGE DISTORTION THDv (%)
3.0	5.0

6.5. GROWTH AND SECURITY INVESTMENT

We classify our growth and security investments into the following types of projects:

- **major projects**: apply to zone substations, sub-transmission or GXP related works
- **distribution and LV reinforcement**: works to ensure adequacy of our distribution feeder and LV network.

6.5.1. Major Projects

Major projects typically involve zone substation, sub-transmission or GXP related work driven by network security considerations. Major projects are forecast on an individual, project-by-project basis. They are identified through assessing the performance and capacity of our sub-transmission network and zone substations in both a normal configuration and under various contingency scenarios, as specified in our security of supply guidelines.

Examples include growth or security-driven zone substation upgrades and the addition or upgrade of sub-transmission lines driven by growth. An important part of meeting growth and security needs is providing alternative capacity (redundancy) that can be used when a primary asset is out of service. This is particularly important for sub-transmission and zone substation assets due to the number of customers and/or size of the load served by them.

6.5.2. Distribution and LV Reinforcement

The reinforcement projects ensure that capacity and security requirements in the distribution and LV networks are met. The following paragraphs describe the reinforcement project types in detail.

Distribution reinforcements

Distribution growth and security planning aims to ensure that the capacity and voltage profile of 6.6 kV and 11 kV distribution feeders are adequate to meet the current and future needs of our customers.

Distribution reinforcement works allow us to add capacity to existing parts of the feeder network, create additional feeders or backfeed ties, upgrade from 6.6 kV to 11 kV, and install or upgrade voltage regulators.[4]

We classify distribution feeders in our Security of Supply guidelines (refer to Table 6.3), into four categories based on the predominant type of load (or customer) served by that feeder. The load type provides a proxy for the expected economic impact of loss of supply to that load (or customer). The reliability performance of a feeder is significantly influenced by network configuration. Security of supply guidelines are established for each feeder type, and these guidelines are used in our planning process to assist in determining distribution network configuration needs.

Distribution growth and security planning typically results in the following types of projects:

- line upgrades and new sections of line (tie lines or new feeders)
- new cables, usually of larger capacity
- network reconfiguration
- specific backfeed initiatives (increased capacity or new tie lines)
- feeder voltage support (i.e. voltage regulators or capacitor banks)

LV reinforcement

Planning for LV reinforcement is a relatively reactive process, reflecting the lower value and higher volume of assets (compared to the distribution level). The addition of new load is managed through our customer connection process.[5] We assess available capacity on a case-by-case basis and undertake reinforcement work if required. Historically, this process has largely captured the material changes in load. Occasionally, power quality issues have emerged as a result of unknown changes in load.

This reactive process works well in an environment where the underlying electricity usage behaviour is stable. It works similarly well where new distributed generation is connected to our network, as this requires a connection application outlining the type and quantity of generation, allowing us to develop a solution in advance. However, in an environment where customers materially change their electricity usage behaviour (E.g. emerging technologies including heat pumps displacing wood fires, EV chargers, energy efficiency initiatives, retailer promotions, or battery storage) and there is no requirement to notify us, we will not be able to rely entirely on our connection application process to capture the changes in load.

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4 Occasionally the upgrade of a distribution transformer will occur as part of the above works but more generally such work is delivered as part of our customer connections work, which is described in Section 6.8.

5 Note that LV reinforcement is concerned with the LV network impacts of new customer connections, rather than the actual connections. Investments for the consumer connections themselves are discussed in Section 6.8.

In the short term, with relatively low levels of customer behaviour change, we will manage the LV network capacity using improved high-level analysis, modelling tools such as DG hosting capacity (see Section 6.6.4), and analysis of DTM data that enables an annual review of the utilisation of all our LV feeders and uptake of DERs.

Distribution and LV reinforcement forecasting

Distribution reinforcement covers projects that are individually identified through the planning process. We forecast distribution reinforcement in two ways:

- **scheduled projects**: these are individually identified and planned through the network development planning process.
- **non-scheduled projects**: cannot be scheduled because of the time horizon. These projects are similar to the scheduled projects but have not yet been identified and therefore cannot be scoped individually. A trend approach is used to forecast the non-scheduled expenditure; we applied the average of the RY21-22 years' forecast expenditure to trend forward. We also included 2.5% per year to address reactive power constraints in the network caused by the adoption of EVs and PVs by our consumers.

LV reinforcement covers projects that are usually carried out on a reactive basis. We have forecast LV reinforcement Capex of approximately $500k per annum for the AMP planning period using a trend approach based on historical works. As one of the use cases of the DG hosting capacity study (see Section 6.6.4) we shall understand future investment planning on LV network. Hence, the trending approach will be revisited.

6.5.3. Key Planned Growth and Security Projects

This section presents the key projects of both major projects and distribution and LV reinforcement projects. These are shown in accordance with their respective sub-network.

Major Projects

The succeeding tables presents the different types of major growth projects. Table 6.19 shows the approved growth and security major projects within the CPP Period (2022-2026). Table 6.20 displays the capacity event major projects within the CPP Period. Table 6.21 presents the major projects from 2027 onwards completing the latter part of the 10-year plan. The complete list of the projects is shown in Appendix F.

Table 6.19: Summary of key major projects within the CPP Period

Dunedin Sub-Network

MAJOR PROJECT IN CPP PERIOD	FROM	TO	CAPEX($M)
Smith Street to Willowbank 33 kV intertie The Dunedin sub-transmission network is configured as a radial network and has limited capability to transfer load between substations and GXPs, particularly in the CBD. The Dunedin sub-transmission project will create a ring configuration to have the capability to transfer between CBD substations and between GXPs. This will increase security at the CBD. The Dunedin sub-transmission project	2023	2025	4.1

MAJOR PROJECT IN CPP PERIOD	FROM	TO	CAPEX($M)
comprises 33 kV intertie projects and is planned in consideration of 33 kV renewal projects that fall into our 10-year plan. – This project increases resiliency of having the sub-transmission capable of supplying either Willowbank or Smith Street substations. The intertie also includes provision for connecting the North City zone substation and moving it to Halfway Bush GXP. The project increases our security of supply at the CBD while deferring the Willowbank 33 kV gas filled cable renewal project out to RY27. – The project is expected to be completed in RY25			

Table 6.20: Summary of capacity event major projects within the CPP Period

Queenstown Sub-Network

CAPACITY EVENT MAJOR PROJECTS	FROM	TO	CAPEX($M)
Frankton substation transformer replacement Frankton substation is going through a significant demand growth. In the last three years, the demand was above its firm capacity, last year was up by 3 MVA. The project will replace the 15 MVA zone transformer with 24 MVA.	2023	2024	1

Central Otago and Wānaka Sub-Network

CAPACITY EVENT MAJOR PROJECTS	FROM	TO	CAPEX($M)
Riverbank transformer and 11kV switchgear Wānaka zone substation demand grew by 5 MVA in 2020 and 2021 from the year before, which was 1 MVA above its firm capacity. This year the demand was 3 MVA above its firm capacity, the forecast shows the demand will continue to rise by 0.8 MVA yearly in the 10-year planning horizon. – We have brought forward the installation of a 24 MVA zone transformer and 11 kV switchgear at Riverbank to RY23 from RY27. We are planning to offload at least 5 MVA of Wānaka load to Riverbank by RY26. – In the latter part of the AMP period, we plan to install a second 24 MVA transformer to cater to increasing the level of security In the Wānaka area. (See Table 6.21 regarding Riverbank zone substation second transformer)	2023	2025	4.4
Cardrona substation transformer replacement The peak demand of the Cardrona zone substation is nearing the firm capacity limit. This project is to meet the planned growth of Cardrona ski field and other developments. – We expect the completion of the installation of a 24 MVA transformer to increase the substation capacity by RY24.	2023	2024	1.3
Upper Clutha new autotransformer The demand in Upper Clutha region is considerably growing following the increase load of all substations in its network. Installing a new Autotransformer is one of our plans to meet the rising demand in the region. We will parallel the two existing to supply one circuit and the new one to supply the other circuit. This project will add capacity to the Upper Clutha sub-transmission.	2023	2024	3.6

Table 6.21: Summary of key major projects from RY27 onwards

Dunedin Network

MAJOR PROJECTS FROM RY27	FROM	TO	CAPEX($M)
The Dunedin sub-transmission is configured as a radial network and has limited capability to transfer load between substations and GXPs, particularly in the CBD. The Dunedin sub-transmission project will create a ring configuration to have the capability to transfer between CBD substations and between GXPs. This will increase security at the CBD. The Dunedin sub-transmission project comprises of 33 kV intertie projects and is planned in consideration of 33kV cable renewal projects that assist in renewal projects in the 10-year plan. The following projects are part of the Dunedin sub-transmission project:			
North City to Ward Street 33kV intertie Part of the Dunedin sub-transmission project to create a ring configuration to increase capability to transfer CBD load between the Halfway Bush and South Dunedin GXPs.	2028	2030	6.9
Smith Street to Carisbrook 33kV intertie Part of the Dunedin sub-transmission project to create a ring configuration to increase capability to transfer CBD load between the Halfway Bush and South Dunedin GXPs.	2031	2033	4.7
Ward Street to South City 33kV intertie Part of the Dunedin sub-transmission project to create a ring configuration to increase capability to transfer CBD load between the Halfway Bush and South Dunedin GXPs.	2032	2034	1.5

Central Otago and Wānaka Sub-Network

MAJOR PROJECTS FROM RY27	FROM	TO	CAPEX($M)
Second transformer at Lindis Crossing At Lindis Crossing zone substation, our forecast indicates the firm capacity will be exceeded during RY24. – We will install a second transformer and extend the 11 kV switchgear which will cater for load growth, provide backfeed capability to Queensberry zone substation, and allow additional 11 kV feeders into the Bendigo area.	2027	2028	1.4
Riverbank zone substation second transformer For Wānaka zone substation, the forecast shows the demand will continue to rise by 0.8 MVA yearly in the 10-year planning horizon. – In the latter part of the AMP period, we plan to install a second 24 MVA transformer at the Riverbank substation to increase the level of security of supply in the Wānaka area.	2031	2032	1.4
Upper Clutha new 66 kV line The demand in the Upper Clutha region is growing considerably, following the increased load of all substations in its network. – A new 66 kV line (or alternative solution) from Cromwell to Upper Clutha will be built to alleviate anticipated thermal and voltage constraints on the existing lines between Cromwell and Riverbank. This will significantly increase transmission capacity to the Upper Clutha region.	2031	2034	18.3

Queenstown Sub-Network

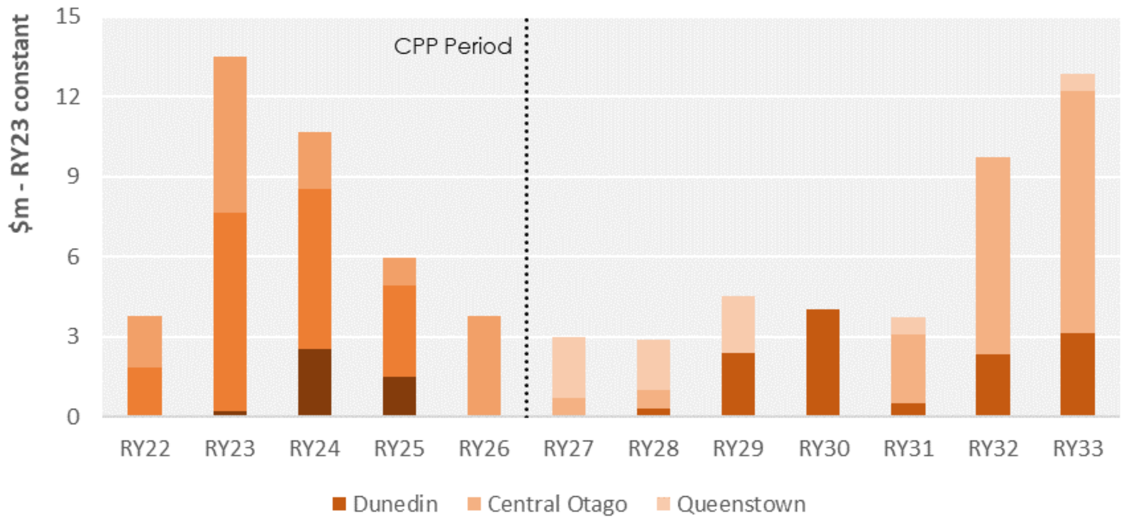
MAJOR PROJECTS FROM RY27	FROM	TO	CAPEX($M)
The Wakatipu area contains the Arrowtown ring which carries loads to Dalefield, Coronet Peak and Arrowtown zone substations. The Arrowtown 33 kV ring upgrade and the Arrowtown 33 kV indoor switchboard improvements mean the ring can be closed at the Arrowtown zone substation open point. To ensure the sub-transmission capacity can meet forecast demand, and to ensure network voltage can be improved, conductor upgrades to overhead lines and underground cables will take place. The following projects are part of the Wakatipu sub-transmission conductor upgrades:			
Wakatipu sub-transmission conductor upgrades The 33 kV overhead lines along Malaghans Road are presently undersized: – Upgrade 33 kV conductor from Malaghans Road to Arrowtown zone substation to meet forecast capacity needs. There are 33 kV cables on the ring, and these will be upgraded to meet future capacity needs: – Upgrade 33 kV cable portions on Dalefield 33 kV entering Arrowtown zone substation, and Arrowtown 33 kV by Lake Hayes.	2032	2034	1.3

Major Projects Capital Expenditure Forecast

Our forecast major projects expenditure during the AMP planning period is shown in Figure 6.13 below. This includes the approved major projects and capacity event major projects within the CPP Period and beyond to RY33.

Wānaka and Queenstown sub-network have shown significant growth in the last three years in spite of the COVID-19 pandemic. New developments are progressing in the region which indicates that this strong growth will continue throughout the planning period. Such substantial growth increase requires additional investment in network capacity. Within the CPP Period, we included capacity event projects that aim to meet customers' power supply requirements. These capacity projects are additional projects within the CPP Period and will be subject to the approval mechanism set by the Commerce Commission.

Figure 6.13: Major projects Capex forecast



Distribution and LV Reinforcement Projects

The following tables presents the key distribution and LV reinforcement projects within the AMP 10-year period. The key distribution projects include backfeed for N-security substations, distribution feeder reconfigurations and feeder reinforcements.

Dunedin Sub-Network

Table 6.22: Summary of Distribution and LV Projects

DISTRIBUTION AND LV REINFORCEMENT PROJECT	FROM	TO	CAPEX($M)
Berwick-Outram backfeed Berwick zone substation is an N-security level with limited backfeed supply from Outram. For contingency events such as zone transformer failure, restoration of power supply is dependent on repair time. This backfeed project is to be completed in RY24 to provide backup supply from Outram. This would limit the outage duration to only switching time.	2024	2024	0.4

Central Otago and Wānaka Sub-Network

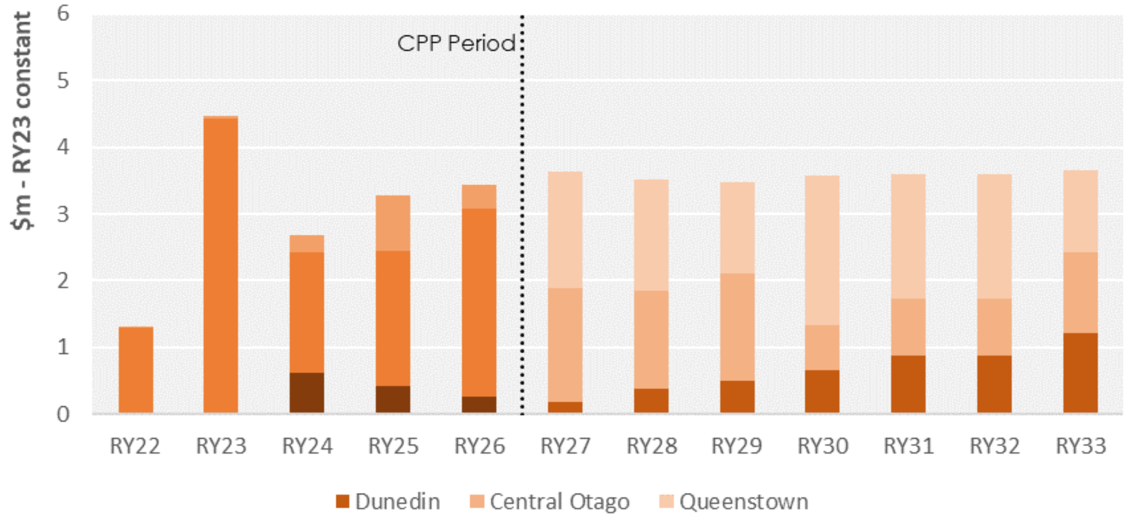
DISTRIBUTION AND LV REINFORCEMENT PROJECT	FROM	TO	CAPEX($M)
Ettrick-Roxburgh backfeed stage 1 Roxburgh and Ettrick zone substation are N-security level with limited backfeed supply from adjacent zone substations. For contingency events such as zone transformer failure, restoration of power supply is dependent on repair time. This backfeed project is to be completed in RY24 and will provide backfeed supply for both Ettrick and Roxburgh. This would limit the outage duration to only switching time.	2024	2024	0.5
Omakau-Lauder Flat backfeed Omakau-Lauder Flat zone substations are N-security level with limited backfeed supply from each substation. For contingency events such as zone transformer failure, restoration of power supply is dependent on repair time.	2024	2025	1.1

The backfeed project is to be completed in RY25 and will provide backfeed supply from Omakau. This would limit the outage duration to only switching time			

Distribution and LV Reinforcement Projects Capital Expenditure Forecast

Forecast distribution and LV reinforcement Capex during the AMP period is shown below.

Figure 6.14: Distribution and LV reinforcement Capex forecast



6.5.4. Themed and strategic budgets beyond RY27

Electrification Growth

Increased load demand due to decarbonisation-related growth may necessitate upgrades across the spectrum of assets, from sub-transmission to low-voltage networks. The total expenditure estimated to meet this additional electrification need is $25.3 million from 2027 to 2033. This may be brought forward, depending on the pace of the transition to electrification.

Wānaka Growth

Due to high load growth in the Wānaka area, additional expenditure worth $22.3 million from 2031 to 2033 is expected, which will cover the establishment of future assets to meet that anticipated need.

6.6. NETWORK EVOLUTION PLAN

Our network evolution plan seeks to prepare Aurora Energy for the future where electricity plays a key role in decarbonisation. We expect and will support more EVs, PVs, battery storage, PV-battery or other forms of future DERs installed on our network and the thermal fuel transition of boilers to electric. We consider DERs an important tool kit to manage the distribution network. We do, however, also recognise that DER solutions will contribute to network constraints including power quality issues if left unmanaged. We have developed three scenarios of decarbonisation and each scenario has different impacts on-peak demand (see Section 6.2)

Solar Generation Uptake

Figure 6.15 shows the 10-year uptake of solar generation in our network. Total solar generation capacity is 8.8 MW which equates to 3% of the system maximum demand with over 1800 connections. In the last five years, solar generation has grown 1.2 MW annually. In RY22, Wānaka sub-network solar generation climbed by 1 MW in capacity from the previous year.

The small-scale solar DG (<10 kW) capacity (see Figure 6.16) accounts for 89% of the total solar generation capacity. The majority of these are located in the Wānaka and Frankton sub-network area with 3.6 MW and 1.6 MW capacity respectively. In Section 6.2.2, we showed the PV uptake forecast which drives decrease in demand based on the three decarbonisation scenarios.

Figure 6.15: Ten-year solar generation uptake in our network

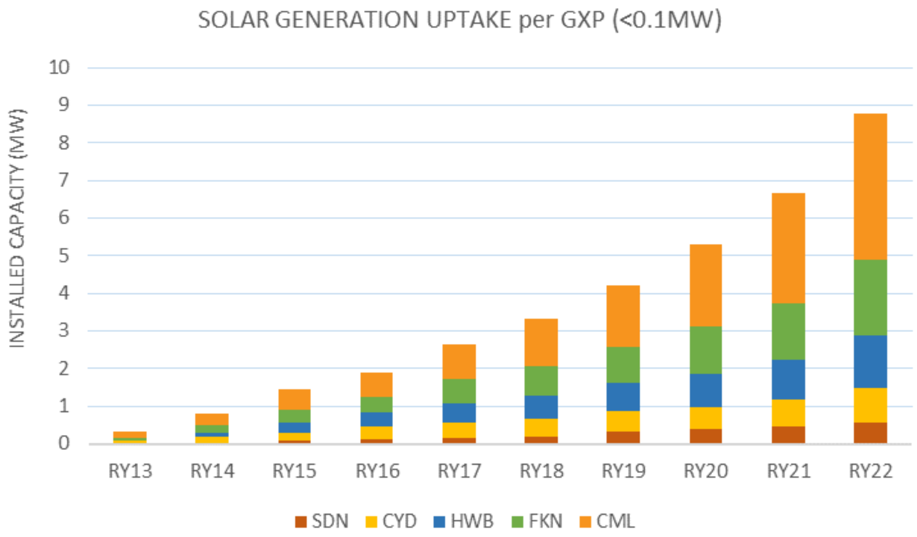
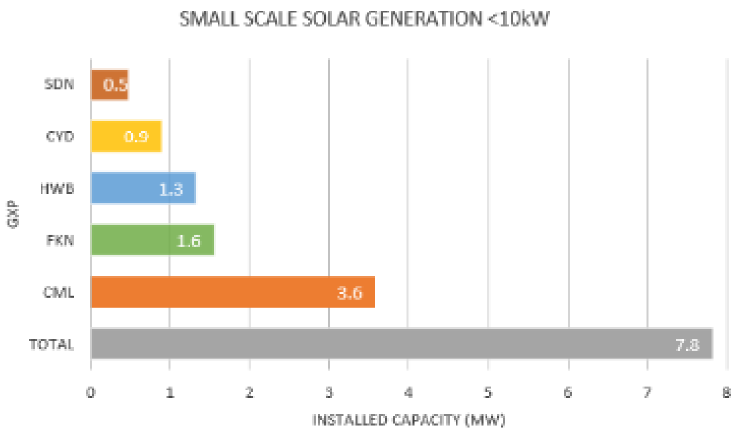


Figure 6.16: Small scale solar generation as of 31 March 2022

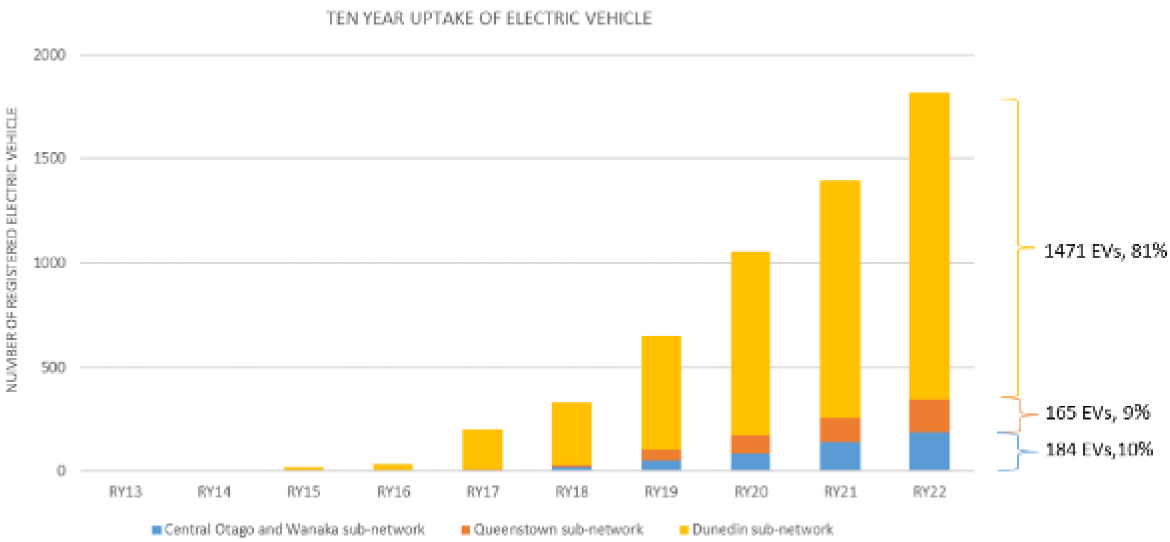


We are monitoring the PV and PV-Battery uptake with a Power BI reporting tool (which we are working to automate) to give us information where these systems are located in the LV network (and see clustering if any), generation capacity over distribution transformer capacity and to assist in the DG hosting capacity study (see Section6.6.4) and PowerFactory load flow studies. This also gives us an opportunity to place DTM devices at sites where there is clustering. So far, we have not experienced any impact of PV uptake on LV capacity constraint nor on power quality.

Electric Vehicle Uptake

Unlike solar generation installation that goes to our connection process (SSDG or LSDG), residential EV chargers do not. Commercial EV charges (E.g. Charge Net) goes to our connection process, hence we have visibility. To date, all EDBs do not have visibility on residential EVs and their chargers – NZTA EV registration is the only available source data but is of limited use. There are about 1820 EVs in our network according to NZTA. Figure 6.17 shows the 10-year uptake of EVs and the number and proportion of EVs in our sub-network as of RY22. Most of these are in our Dunedin sub-network where the daily commute is a short distance compared to Central Otago and Wānaka sub-network. In Section 6.2.2, we showed the EV uptake forecast which drives increase in demand based on the three decarbonisation scenarios. We envisaged that, in the next few years, there will be more smart EV chargers as these can assist in mitigating increases in demand of the household and the distribution network.

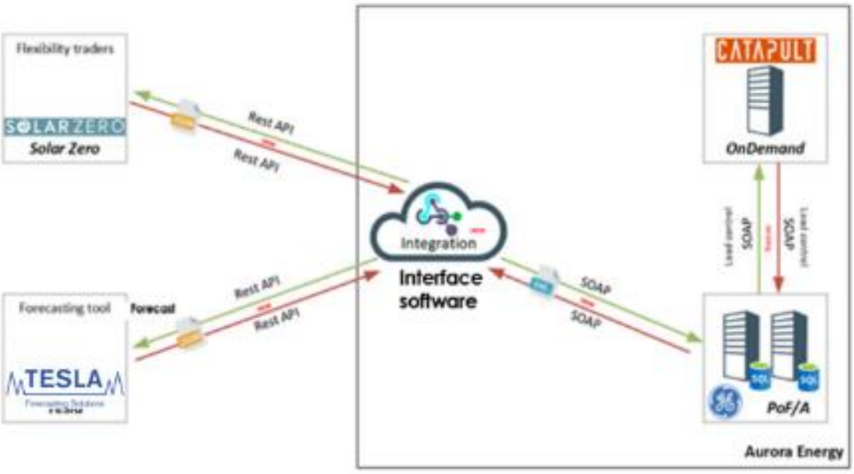
Figure 6.17: Ten Year Uptake of Registered Electric Vehicle



6.6.1. Flexibility Management

Aurora Energy, together with solarZero, Catapult and Tesla have developed a Flexibility Management system that we utilise to operate the hot water load management and send signal to solarZero for them to operate their batteries to manage the peak demand of the Upper Clutha sub-transmission circuits. Figure 6.18 shows the system architecture of the Flexibility Management. The management system uses existing systems' ADMS and OnDemand load management. The system uses Rest API for communication between Aurora's integration, solarZero and Tesla. Aurora's integration is the gateway to PowerOn ADMS and OnDemand load management and uses SOAP interface to communicate between them. We operated the Flexibility Management last year during the two-week July school holidays and it performed as designed. As part of continuing improvements, we will fine-tune the logic of the operation.

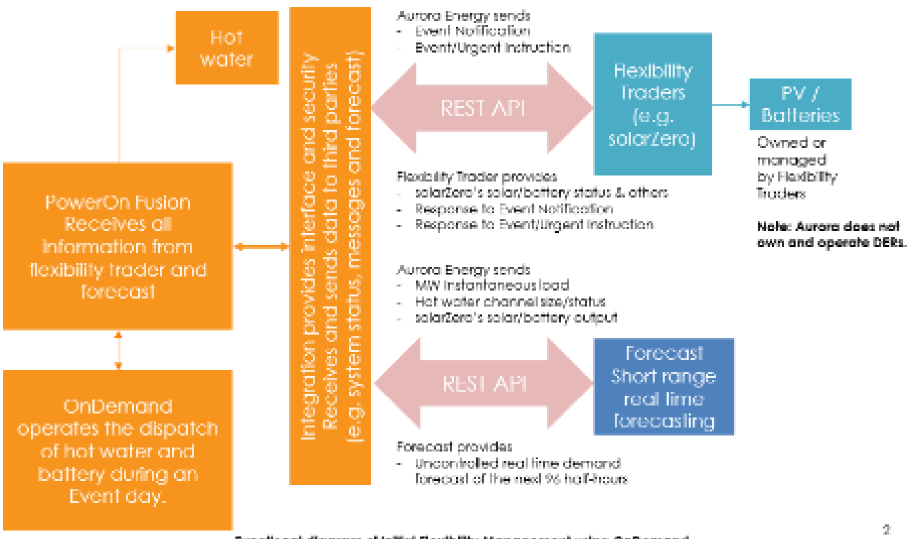
Figure 6.18: System Architecture of Flexibility Management



System architecture diagram of Initial Flexibility Management using OnDemand

There is a lot of information flowing between systems as shown in Figure 6.19. The external data is stored in PowerOn Fusion in which OnDemand uses to operate the Flexibility Management. Tesla provides the short-range uncontrolled demand forecast for which the OnDemand when Event Day Target setpoint is triggered; a notification is then issued to solarZero to indicate that the next day is an Event Day.[6]

Figure 6.19: Functional diagram of Flexibility Management



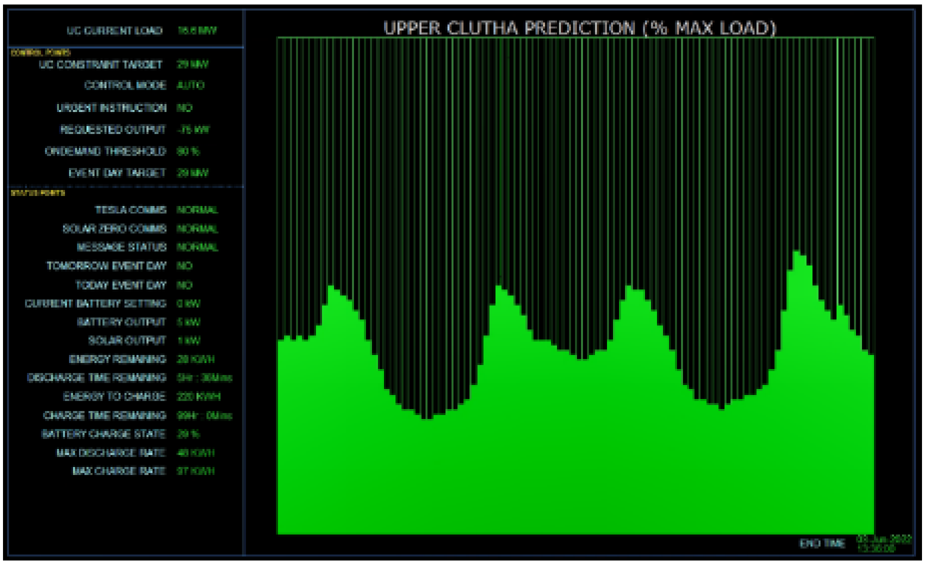
Functional diagram of Initial Flexibility Management using OnDemand

6 Event Day means that the Event is occurring. Event means a time where forecast demand is approaching the secure capacity limit of the Upper Clutha sub-transmission system, or a planned maintenance or unplanned contingency event where only a single sub-transmission circuit is in service in the Upper Clutha Area.

During the Event Day when the Constraint Target setpoint is reached, OnDemand triggers the operation of the Flexibility Management. OnDemand sheds the water channels first to lower the demand and at a certain threshold, when the load is still above the Constraint Target setpoint, OnDemand sends a message to solarZero's front end office for them to operate their battery at a certain level based on the calculations in OnDemand. This combination of hot water channels and solarZero's battery manages the load below the Constraint Target.

Figure 6.20 shows the load control world SCADA points for the non-network capacity support.

Figure 6.20: PowerOn load control world



6.6.2. Open Call for network support

The Open Call is a two-stage process – Stage 1 is an abridged version of ROI and Stage 2 is the RFP process. Open Call is not limited by time, it will remain open until Aurora Energy has contracted the required combined service level.[7] It is open to any respondent who can provide us with suitable demand response capacity at an acceptable cost, while meeting our technical requirements.

Registration of interest is through an online form. Respondents are required to reply to essential requirements. Those who meet our evaluation criteria will receive a letter of invitation to Stage 2 with the RFP documents detailing capacity support, technical and operational requirements and seek commercial offer. We will enter into an agreement to those that meet our requirements.

Both the ROI and RFP will be evaluated on a first-come first-serve basis. We will attend to each stage as they come. The Open Call will only close when Aurora Energy has contracted the required combined service level.

In March 2022, we published our first Open Call which is for the Upper Clutha area, to provide additional capacity support for the sub-transmission and to provide capacity support for summer peaking N-security level substations (Lindis Crossing, Queensberry and Camp Hill). We have received

[7] Combined Firm Service Level is the total of firm service levels from all aggregators/flexibility traders that Aurora Energy has contracted to provide firm service level of non-network capacity support.

a lot of respondents with developed systems which translates that the flexibility services market is maturing. As of this writing, we are evaluating the proposals from Stage 2 respondents.

6.6.3. LV Visibility

With NZ decarbonisation goals encouraging electrification of process heat and transport, distributed energy resources adoption is expected to increase. Pages 144-45 show the uptake of solar generation per GXP in the last 10 years, and the 10-year EV uptake. In Section 6.2.2, we illustrated the uptake of EV and PV in our decarbonisation scenarios. We understand that the LV network will be most impacted with customers moving towards the use of DERs. However, the LV network has been a passive network historically and investment after installation has been reactive in nature.

Our preferred way to achieve LV visibility is from smart meter data, or potentially LV feeder measurement. We aim to develop data analytics that we can use to improve network performance (faster fault response), take initiative in low/high voltages occurrences and power quality issues, understand the existing capability of the LV network, take a proactive approach in safety (identify broken neutral), and optimise asset capability and transition to an active network, by integrating real-time data with analytics. We plan to engage metering equipment providers for the provision of the data.

As we are working towards getting access to smart meter data, in parallel we are investing and installing DTMs at strategic locations to have a baseline information of power quality data on the LV network. DTM measurements provides other data that we can use such as power (use for distribution transformer utilisation) among others. We have also updated our process in capturing MDIs although the data is static it still provides us with loading information of distribution transformers. We are also looking at getting data from flexibility traders which can provide a granular set of measurements. Further, in the succeeding Section 6.6.4, we are presently undertaking a DG hosting capacity study to understand the capacity of the LV network to host PVs and EV chargers.

6.6.4. LV DG Hosting Capacity Study

We are currently undertaking a DG hosting capacity study for the whole LV network. The study provides a snapshot in time on the ability of the LV network to host (connect) PVs and EV chargers. Hence, the DG hosting capacity study is recurring at a determined interval with updated data sets.

The study requires good data quality on:

- GIS network connectivity and topology
- GIS information (distribution transformer, LV line/cable, ICP)
- Asset capability (distribution transformer, LV line/cable)
- LV Network load data (distribution transformer thru MDIs/DTMs, ICP from smart meter, or other data source)
- Location and size of existing PV installation (based on SSDG/LSDG) and EV charger (if any)
- Distribution transformer tap information (boost/buck)
- Exclusions to the study – customer owned assets (distribution transformer, LV circuit).

The study provides understanding on:

- Level of penetration and size of PV system and EV chargers that can be connected prior to occurrence of constraint.
- Determine constraints (existing and likely to occur) on distribution transformer loading, LV feeder loading or voltage incursions outside the regulatory limit.
- Locate the LV feeder or part of it where constraint can potentially occur.

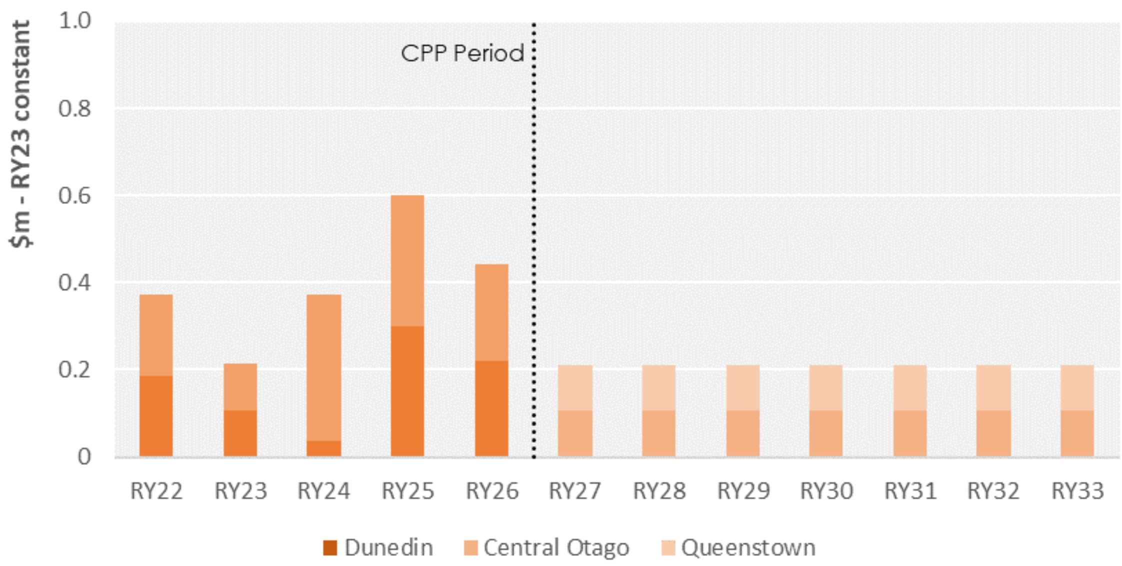
The following are user cases we have identified, at this stage, which we will incorporate in our Growth and Security investment approach.

- **Investment planning** - where and how much we should invest in the LV network over the AMP period based on the type of constraint
- **Managing constraint** - existing or likely to occur, confirmation of the constraint and identify power quality issues to create new LV reinforcement/reconfiguration projects (in coordination with planned works)
- **Input to the SSDG and LSDG connection process –** adopt new traffic light system and visual representation of the study output that can be incorporated in GIS and use in DG connection process.

6.6.5. Network Evolution Capex

The network evolution Capex forecast includes installation of DTMs, updating load management and data warehousing, exploration and development of flexibility management systems, and development of data analytics.

Figure 6.21: Network evolution Capex forecast



During the CPP Period, our initial focus for LV visibility will be on general power quality monitoring at strategic locations across the network to get a baseline understanding of network power quality performance. We will also explore and develop flexibility management systems to manage the operations of the flexibility traders. We will develop data analytics using DTM and smart meter data (when access is available).

6.7. RELIABILITY-DRIVEN INVESTMENTS

Reliability-driven investments aim to improve reliability of service, maintain, or improve the safety of the network for consumers, employees, and the public, meet legislative requirements, or reduce the impact of the network on the environment.

6.7.1. Reliability-Driven Investment Planning

Reliability-driven investments go through the same network development planning process as described in Section 6.3.1.

Investment Drivers

The key driver for reliability-driven investments is the performance and quality of service received by customers on different parts of our networks. Reliability investments support our objective to improve overall network reliability to acceptable levels, while minimising the associated costs. This reflects our understanding of our customers' preferences. The main drivers for undertaking these investments are:

- **reduce impact of outages**: by reducing the severity (extent and duration) of outages. This is particularly effective on heavily loaded or older circuits where the impact on customers may otherwise be unacceptable.
- **increase network control**: automation increases the level of central oversight and control we have on our network. This increases our operational flexibility and improves the real-time control of our assets.
- **address poor performance**: investments target feeders with relatively poor performance in terms of reliability (worst-performing feeders).
- **cost reduction**: automation devices are a cost-effective way to address reliability performance and allow the prudent deferral of more expensive investments.

Within the CPP Period (RY22-26), we only allocated a spend for RY24 and none on the remaining years for Reliability, Safety and Environment (RSE), as our plan is focused on mitigating safety risk and meeting required growth needs of the network rather than investing to directly improve reliability.

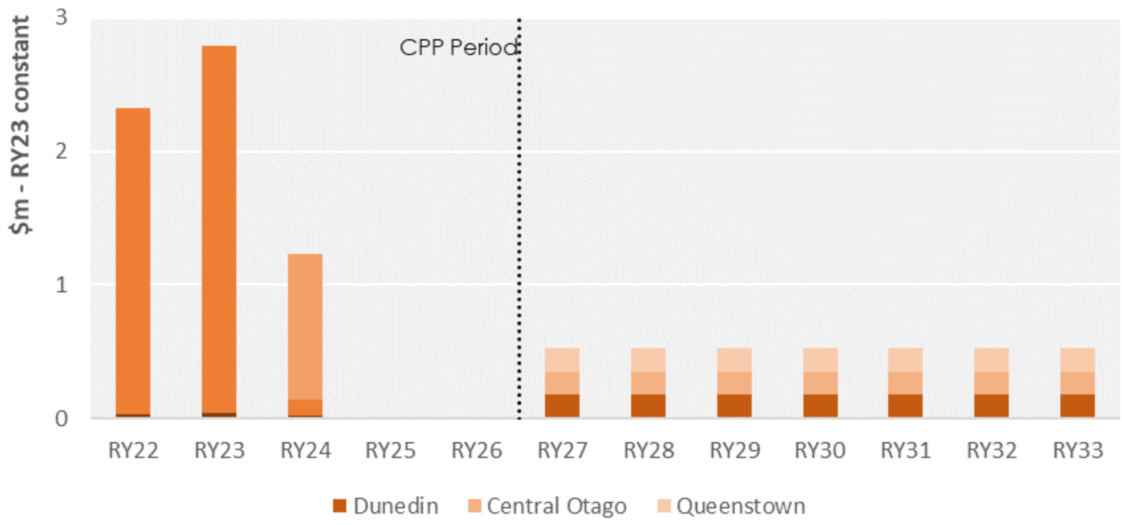
Network safety risk is covered by our renewal workplan and there are no dedicated safety-specific investments (E.g. retrofitting of arc-flash protection) during the CPP Period. It should be noted that our general renewals investments target all the drivers within the RSE category.

Investments proposed for later in the period are dedicated quality of supply projects focused on improving reliability by adding reclosers, remote controlled switches and fault passage indicators. Subject to further consultation, we plan to install many of these starting in RY27.

Reliability-Driven Capex

Our forecast reliability-driven Capex during the AMP planning period is shown below.

Figure 6.22: Reliability-driven Capex forecast



We have identified reliability projects in RY24 in localised areas where it's prudent to action these issues in the short term. We have no projects lined up for the remainder of the CPP Period. Subject to further consultation, our plan is to step up investment in RY27 to RY32 and carry out targeted reliability improvements on our network by installing auto reclosers, remote control and fault passage indicators.

6.8. CONSUMER CONNECTIONS

Consumer connection Capex is expenditure to facilitate the connection of new customers to our network. On average, we connect around 1,200 homes and businesses to our network every year.

New connections range from a single new house through to a range of businesses and infrastructure. The latter may involve small connections like water pumps and telecommunications cabinets, or large connections where the network upgrade is directly related to the connection site. Although a new connection may drive the need for upstream upgrades to the distribution or sub-transmission network, the cost of this work is outside the scope of this portfolio.

6.8.1. Forecasting Approach

Customer connection Capex is externally driven with short lead times. It is difficult to accurately forecast medium-term customer connection Capex requirements. We forecast the number of new connections, and the amount of customer connection Capex and capital contributions from historical data. This data tends to indicate a moderate positive correlation between the number of new connections and customer connection Capex. Historically, we have seen significant year-on-year variation in both customer connection Capex and capital contributions.

Investment in customer connections is largely driven by:

- population growth: the number of new residential properties is driven by population growth, land supply and Government policy (for example, special housing areas). These impact both small connection requests, and large subdivision developments.
- economic activity: growth in commercial activity increases the number of commercial and industrial premises that require electricity supply.

Approach to expenditure forecasting

We have adopted a trend-based approach that takes account of known large connections when forecasting consumer connection Capex. This involves:

- **historical Capex trending:** identifying a level of expenditure that is appropriate to trend forward
- **trending changes**: reflect expected year on year changes that may affect the derived Capex trend, for example, changes in population growth rates
- **identified loads:** these are large known connections we expect to occur. An example would be the construction of a tourism development that would require significant investment.

Historical Capex Trending

Due to the unpredictable nature of (third-party driven) consumer connection volumes, we determined that it would be appropriate to use an averaged figure for trending. We chose the average of the previous six years expenditure (RY17-RY22); this is appropriate as there have been no step changes (large connections) or significant changes in economic activity or population growth during this period. The chart below shows historical gross consumer connection expenditure from RY17-21 with the dashed line showing average expenditure.

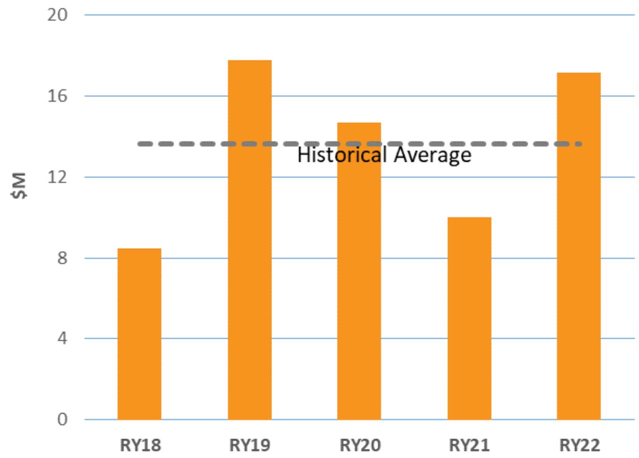
Trend Changes

Consumer connection is heavily influenced by population growth and economic conditions. Historical Capex trending accounts for a certain rate of growth in population and economic activity – higher or lower rates of growth in these factors will affect consumer connection Capex.

Identified Loads

The identified loads applied to our forecast are large known connections. The RY17-22 historical expenditure did not include any equivalent large connections and therefore these are not accommodated in the trended approach. These are connections that the customer has indicated are required (but which are not yet confirmed) which will require significant expenditure. A high-level cost estimate for each identified project is added to the trended expenditure with appropriate timing. We have only identified one known large connection that will be carried out within the AMP period.

Figure 6.23: Average historical expenditure level (Gross)



6.8.2. Consumer Connection Capital Expenditure

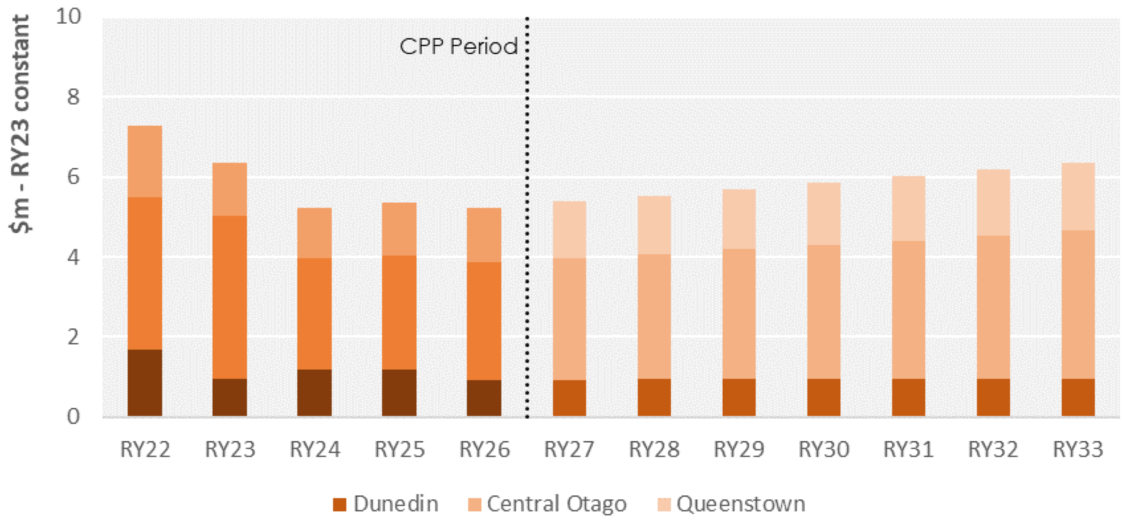
In developing our forecast, we considered the following inputs and made the following assumptions:

- average historical customer connection volumes are a reasonable predictor of future volumes, provided population GDP growth remains broadly in line with historical growth
- assumptions around large customer projects, including timing and cost, reflect our current best estimates and discussions with customers
- no contingencies have been included.

Capital Contributions

A refreshed Capital Contributions Policy was published on 01 July 2021. The refreshed policy results in an average customer contribution of 60% for new and upgraded connections. This is the basis for calculating the net forecast for consumer connections.

Figure 6.24: Consumer connection forecast Capex (net of capital contributions)



6.9. NETWORK PERFORMANCE MEASURES

Our network performance measures focus on the following:

Load Factor at GXPs measures the efficiency of assets we contract from Transpower at GXPs. Low values indicate the provision of excess capacity and cost while higher values can also cause concern due to not having sufficient capacity available.

Table 6.23: Load Factor

Load Factor (%)	Historical		Forecast									
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Dunedin	49%	48%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%
Central Otago and Wanaka	58%	55%	55%	55%	54%	54%	54%	53%	53%	53%	52%	52%
Queenstown	45%	44%	44%	44%	44%	44%	44%	43%	43%	43%	43%	43%
System	53%	51%	52%	50%	49%	49%	49%	49%	49%	49%	49%	49%

Loss Ratio is the ratio of losses (electricity entering the system less energy delivered to ICP) over electricity entering the system.

Table 6.24: Loss Ratio

Loss Ratio (%)	Historical		Forecast									
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Dunedin	5.5%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%
Central Otago and Wanaka	7.4%	7.1%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
Queenstown	4.8%	5.6%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%
System	5.8%	5.4%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%

Total Transformer Capacity Utilisation is the maximum coincident demand divided by total distribution transformer capacity.

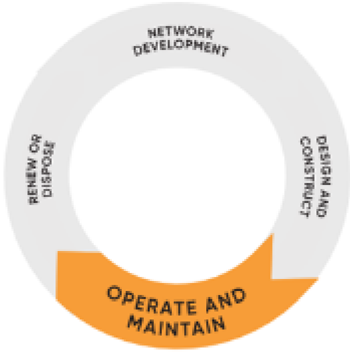
Table 6.25: Transformer Utilisation

Transformer Utilisation (%)	Historical		Forecast									
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Dunedin	37%	37%	37%	37%	37%	37%	38%	38%	38%	38%	38%	38%
Central Otago and Wanaka	20%	21%	21%	21%	21%	22%	22%	22%	23%	23%	23%	23%
Queenstown	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
System	30%	31%	30%	30%	30%	31%	31%	31%	32%	32%	32%	32%

7. OPERATE AND MAINTAIN

This chapter describes how we operate and maintain our assets over their lifecycle.

As discussed in Chapter 5, we manage our network fleets using an asset lifecycle approach. The figure (right) depicts the four life cycle stages within our asset management system.



Operate and maintain is a key stage in this cycle. It lasts for the duration of the asset's life and impacts the timing and scope of other stages, such as the need for renewal.

7.1. OVERVIEW

We use a staged approach to lifecycle management that governs the activities we adopt to manage assets over their lifetime. This includes activities such as network operations, maintenance, vegetation management and spares management. This chapter sets out forecasts for these activities over the AMP planning period (operations spend is covered in Chapter 9). This chapter also outlines the inspection and maintenance programmes that we use across each of our asset fleets.

Appropriate levels of network Opex ensures our assets are operated and maintained effectively, and that asset information is made available to support effective expenditure in other areas, such as renewals. We plan to increase network Opex-related activity in the short term during the AMP planning period to address key issues, including:

- a backlog of asset inspections and condition assessments, to identify defects for remediation and to gather quality asset information
- ensuring that we progress to a steady state of corrective maintenance where asset defects are addressed before expensive capital works are required
- pivoting our vegetation strategy from reactive to proactive and going beyond compliance requirements to improve the long-term efficiency of vegetation management.

7.2. OUR APPROACH TO NETWORK OPERATIONS AND MAINTENANCE

The lifecycle approach requires us to make trade-offs between maintaining our assets in service (Opex) and replacing or refurbishing them (Capex). For example, we may increase the frequency of maintenance for a particular asset type to increase asset life and defer the need for renewal.

Key operations and maintenance-based asset management considerations are:

- **asset management system:** we need to gather information on assets to make cost-effective, prudent decisions
- **legislative or regulatory requirements:** these include minimum frequencies for inspecting overhead line assets, or safety requirements

- **maintenance standards:** documents that outline set requirements regarding inspection tasks, servicing intervals and reporting
- **manufacturers' recommendations:** around inspection tasks and servicing intervals
- **asset condition:** as identified by preventive maintenance activities
- **fault numbers:** leading to reactive maintenance or corrective maintenance.

The table below explains how effective operations and maintenance are important in ensuring our asset management objectives are met. Separate objectives have been created for each of the maintenance portfolios and are covered later in this chapter (see section 7.7: Maintenance by Portfolio).

Table 7.1: Asset management objectives relevance to operations and maintenance

OBJECTIVE AREA	DESCRIPTION
Safety first	The risk of our workforce and the public being exposed to injury, and of damage to the environment, are reduced by undertaking operations and maintenance work in accordance with our safety, maintenance, and operational standards. Many of our new initiatives aim to find and remediate defects earlier, reducing safety risk.
Reliability to defined levels	Scheduled work is generally less inconvenient to customers and landowners than unplanned outages. Reducing unplanned outages will improve reliability as experienced by customers. Increased preventive work will help reduce unplanned outages in the longer-term by informing our renewal work. This will improve reliability as experienced by customers. Reducing the duration of unplanned outages through improved reactive maintenance will improve the network reliability experienced by our customers. Timely rectification of outages supports our compliance with regulatory quality standards.
Affordability through cost management	Planned servicing is generally cost-effective relative to unplanned remediation work. Lifecycle costs should be reduced by undertaking an optimal volume of preventive work, supporting achievement of expected asset lives. Likewise, by undertaking an optimal amount of corrective work, supported by optimal Opex/Capex trade-offs. Enhancing our asset data will enable us to make well informed asset management decisions, including more effective management of whole-of-life costs.
Responsive to a changing landscape	New technology is continually pushing the boundaries of efficiency and information gathering in the operations and maintenance space. We will integrate new technology into our approaches, but generally not aim to be early adopters based on our network state and priorities.
Sustainability by taking a long-term view	Historically low preventive maintenance means some of our asset condition information is inconsistent. Our uplift in inspections over the last three years has enabled improved condition information, which will allow us to make earlier, more informed asset management decisions. We will continue to improve our asset data including some asset characteristic/attribute information, which is absent; preventive maintenance provides a means to confirm or gather this data. As we complete our inspection backlog, we will take steps to transition to a steady-state, long-term, sustainable rate of work.

7.2.1. Overview of Maintenance

Maintenance is the care of assets to ensure they provide required capability in a safe and reliable manner throughout their service life. Maintenance involves monitoring and managing the deterioration of assets and, in the event of a defect or failure, restoring the condition of the asset should replacement not be the optimum course of action. Feedback from maintenance activities is used to improve our asset standards and planning processes, as well as to inform our Capex renewals programme.

Maintenance Portfolios

We manage and organise our maintenance work into three network Opex portfolios:

- **preventive maintenance:** routine maintenance activities including testing, inspections, condition assessments and servicing
- **corrective maintenance:** primarily involves remediating defects by replacing components or minor assets, or undertaking repairs
- **reactive maintenance:** responding to faults and other network incidents; this may involve making a situation safe until a full repair is scheduled or undertaking the repair.

This chapter describes the three maintenance portfolios, together with vegetation management.

Maintenance Planning

Below we explain our approach to planning our maintenance activities.

Planning and prioritisation

We use a preventive maintenance strategy where asset condition is generally assessed on a scheduled time interval basis. Our maintenance standards define preventive maintenance activities to assess the condition of assets and identify any defects; the standards also define the frequency at which these tasks are to be undertaken. In some cases, assets inspections are driven based on number of operations or fault events, to acquire specific asset data, or if our records indicate that the asset is at risk of failure. Our inspection programme is not yet in steady state as we continue to address a backlog of asset inspections. To prioritise the backlog, we use asset age, type, location and other factors to identify the most critical assets. Once the 'first pass' of all network asset inspections are completed for each fleet, and as we get on top of backlog, in a risk prioritised way, we will transition to steady-state preventive maintenance programmes.

We use information obtained from preventive maintenance activities, and occasionally reactive maintenance activities, to plan our corrective maintenance programme and inform renewal decisions. For all identified defects, we have begun to use criticality to prioritise assets for rectification under the corrective maintenance programme. Using a criticality-based approach allows us to allocate our corrective maintenance funds and resources more effectively to reduce risk and to address poor performance. At present, we only have a public safety criticality framework; with the safety of the network as our primary objective, we consider this is an appropriate first step. Expanding our criticality framework in future will enable us to deliver a more risk-based approach to maintenance.

Our maintenance work programme is informed by:

- **preventive maintenance:** records of preventive maintenance on assets, comparison of these to our specified frequency of these activities, analysis of criticality in some fleets based on inherent risk, and where applicable we use an operations/duty basis

- **corrective maintenance:** preventive maintenance records, defects logged using our mobile defect application, historical defect databases, SME knowledge, site visits, risk reviews, follow up to reactive maintenance, and follow up to safety incidents
- **reactive maintenance:** our network operations team which issues urgent reactive maintenance fault work on an individual job basis to our maintenance contractor
- **vegetation management:** our three-year vegetation management plan and ad-hoc requests.

Forecasting and budgeting

Our maintenance budgets are based on the forecasts set out in our AMP. These forecasts consider historical costs as a baseline, which are then updated to reflect:

- targeted changes in strategy
- known emerging issues with our asset fleets
- top-down step changes or trends that are non-asset specific (E.g. anticipating less faults as the condition of the network improves).

The process we use to set network Opex budgets each year includes assessing the previous 10-year portfolio forecasts and updating them based on the approach above. We then review preventive and corrective maintenance plans using a bottom-up approach, identifying work completed. The budgets are reviewed by the General Manager for Asset Management and the General Manager for Works Programming and Delivery.

Maintenance Delivery

Below we explain our approach to managing the delivery of our maintenance activities.

Scheduling

Once an annual maintenance plan has been developed, we schedule maintenance works according to contractor availability. We aim to keep a smooth resource profile across the year while prioritising works that need immediate action.

Outsourced model

As for capital work delivery, all network Opex activities in the field are outsourced. Our maintenance activities are completed by our service providers under field service agreements.

Our service providers are responsible for ensuring they have sufficient resources to undertake the assigned works in line with the required timeframes. They are also responsible for ensuring that their staff are trained and qualified to undertake the assigned works according to our requirements. We monitor their compliance with these requirements, and we retain all specifications and asset information records inhouse to ensure that core asset knowledge is retained within the business.

Quality management

Whilst we have quality assurance staff who review many technical aspects of capital work, we do not yet have an equivalent framework for quality management of Opex works. This is an improvement initiative that we have committed to in our CPP Development Plan for 2023 and 2024.

Feedback and monitoring

Our FSA provides a mechanism for feedback both from and to our service providers. Types of feedback include:

- **technical feedback:** such as ways we can improve our maintenance documents, or highlighting a specific issue with an asset
- **work planning feedback: suggestions** on how we can plan/programme work more efficiently, feedback on commitments and ability to do different types of work or resource restraints.

7.2.2. Overview of Network Operations

Network operations refers to the range of activities necessary to ensure the day-to-day safe and reliable control and management of our distribution network. The primary role of network operations is to provide a reliable supply of electricity to our customers by operating the network in a way that ensures we meet network, operational, safety, and asset performance objectives on a 24/7 basis. This is achieved through system monitoring, switching and load control, risk management, fault response coordination, and providing contractors safe access to the network for works required to develop and maintain the assets.

Our Network Operations Centre (NOC) and contact centre are in constant communication with contractors, generators, retailers and electricity consumers to ensure the continual operation of the network. Our control rooms in Dunedin and Cromwell undertake the operational functions for both the Dunedin and Central Otago networks. Both control rooms can control either network via a common Distribution Management System (DMS). During standard operation, the Cromwell control room is staffed during the day and hands over to the Dunedin control room at night. The ability to control both networks from either Dunedin or Cromwell provides resilience of operation control.

Our contact centre function provides a point of contact for customers and the community to report network outages or incidents, which are then dispatched to our contractors. Crews then respond to network events in the field and liaise with our control room to seek any work authorities or switching instructions as required to restore supply and/or make the network safe.

Our network operators and planners consider factors such as how loading and operation frequency affects asset life and performance, and how to safely remove assets from service for maintenance without compromising performance. Planned electricity outages are necessary to maintain and renew our network assets and ensure long-term safety and reliability. During the planning process to deenergise the network for maintenance or renewal works, outage planners consider all available means to minimise the impact upon our customers.

Network operations is one of the focus areas of our business strategy, and there are several key initiatives that have been identified, which will enable us to continually improve the way in which we operate the network and prepare us for future challenges. These focus areas are addressed briefly below.

Structural Refinement of the Operations Team

In early 2022, we identified several areas of targeted improvement in the Operations team, and have made refinements to the team structure to implement and sustain our improvement opportunities. The key benefits of the changes are:

- **clear management accountability for network operations:** providing variation in work whilst reducing handovers and complexity, and improving cooperation
- **functional separation:** focusing on the functions and ensuring we can be flexible and adapt to the needs of the business but have clarity on task responsibility whilst using our resources effectively
- **making the most out of our planned outage stage gate management and Outage Management System implementation:** embedding the improved ways of working to improve efficiency and quality of service
- **process control and management:** ensuring that there is capability to manage and improve the critical processes within the NOC to ensure safe outcomes
- **contingency readiness:** expanding the team's capability to look beyond the right now; to prepare for and manage the unexpected.

Advanced Distribution Management System (ADMS)

Our ADMS is embedded into operational practice and provides a common system, controlling the Dunedin and Central networks from either Dunedin or Cromwell. The ADMS provides a schematic representation of the sub-transmission and HV elements of the network, and enables network controllers real-time access to the status of the network via data derived from the SCADA system. Network controllers use the ADMS to remotely switch the network, to authorise work on the network, and to manage switching instructions that provide access to our contractors.

We are progressing through standardisation of ADMS symbols and alarms. These changes will help to reduce the likelihood of human error in switching instruction development and increase the speed at which our controllers can identify and respond to network events. These improvements will be felt by our customers through improved restoration times and an overall reduction in outage frequency.

We have upgraded from our existing PowerOn Fusion platform to a next generation PowerOn Advantage system to ensure that our systems remain up-to-date and supported by providers. We are also preparing for the adoption of additional functionality within the ADMS.

In the medium-term future, we are intending to implement real-time distribution power flow analysis into our ADMS. With the changing state of electricity networks, which are increasing in distributed generation capacity, the historic norms which were dominated by one-way power flow, are changing. Distribution power flow analysis will enable our controllers to run pre-emptive or real-time power flow analysis when we detect an anomaly that will restrict or alter the normal flow of energy through our network. Enabling this functionality will support power flow analysis by our planning team, and provide assurance that we can continue to meet current and future load demands or provide early warning that contingency plans are required.

Outage Management System (OMS)

The OMS collates all network status data from the SCADA system and provides a direct real-time system link between the status of the network and the supply of electricity to end point customers. We are currently progressing through a project to better utilise the capability of the OMS. The OMS is now being used to manage calls and outage restoration efforts, track planned and unplanned interruptions to customers, and plan outages. Future enhancements will enable us to provide relevant near real-time information to customers through retailers, our website, or an interactive voice recording system. This system improves fault responsiveness and enables greater communication and visibility of outage status to customers.

Operational Procedures

We are building new process control and management into the Operations team to ensure there is the capability to manage and improve operational switching and the associated critical safety-related processes.

Operational switching refers to disconnecting sections of the network for safety isolation; it is used to enable maintenance or to restore electrical supply in the event of a fault. There are two principal switching methods – remote switching, which is done by the NOC via SCADA, and field switching, which is undertaken by our service provider under the direction of the NOC. Switching is planned and managed through our ADMS.

Network Access / Outage Planning

Our operations and network performance team includes the network access team, who plan for the release of our sub-transmission and HV network for scheduled work. They ensure that planned work can be clearly understood by all concerned and that all recognised measures are in place to ensure safety of personnel and the public during access to the network.

We have introduced, and continue to improve, a new stage gate process to ensure personnel have sufficient time to safely consider permits and switching instructions necessary for work to occur.

Addressing safety concerns is still our highest business priority. Going forward, and while maintaining our safety focus, we will increase our focus on customer experience. This includes providing adequate notice of an outage, explaining why the outage is needed, and responding to queries and concerns. The process also considers the impact on critical customers, such as schools, hospitals, transportation, and industry.

We have introduced new business processes that put greater emphasis on reducing the impact on customers for planned work by identification of customer impact early in the planning phase. We can then ensure that both we and our contractors have adequately explored alternatives to outages, such as live line work, work bundling, generation support, out of hours or weekend outages, to minimise the impact of the outage. The key improvement initiatives are summarised in chapter 9, and a full description of each initiative is outlined in our CPP Development Plan.

Operational Performance Investigation

The Operational Performance team takes a tactical approach to improving operational performance through improved information capture and the investigation of network events. Such improvements will help to identify root causes and causal factors that contribute to network events, which in turn allows for better asset lifecycle and strategy decision-making. We have implemented an investigations and review process for network events. Information capture will be enhanced by future work to improve the data retrieved from contractors by implementing mobility systems that will communicate with our ADMS/OMS.

Compliance to Reliability and Public Safety Obligations / Commitments

Our rapid response process and mobile reporting application has improved our ability to respond to public safety issues and compliance obligations. This fast-track delivery process ensures that we respond promptly to issues on our network that can impact on public safety. We are looking at opportunities to improve the functionality of the application and any associated process, so that we can deliver the best outcomes for our customers. Full implementation of our asset management software solution will support this initiative.

Operational Resilience and Emergency Management

As a lifeline utility, under our Civil Defence Emergency Management obligations we must be prepared to maintain delivery of services during civil emergencies. We have the number of staff members who are trained to operate under New Zealand's Coordinated Incident Management System (CIMS) protocol. CIMS establishes a framework of consistent principles, structures, functions, processes and terminology for response and the transition to recovery. Greater organisational coverage of CIMS training enables us to respond more effectively to a significant civil emergency. We will provide additional training for new staff and refresher training for existing staff as required.

Enabling Future Technologies

We are aware that the nature of the electricity distribution network is changing, as distributed generation connections via renewable energy sources such as solar and wind continue to grow in volume, as does the uptake of electric vehicles. In the future distribution network, energy will no longer only flow from transmission networks down to customers. We will see power flow travelling both directions between residential households, and even up into the HV network. This change in network utilisation will present many challenges to the industry but we are evolving to be a prudent adopter, rather than being reactive. As part of our enablement, we plan to implement the mapping and management on the LV network into our ADMS and, in time, establish power flow analysis and the ability to manage distributed generation on the LV network. Preparatory phases involve improving the asset attributes and quality of data contained in our GIS, thereby enabling improved accuracy and management of the LV network when it needs to be managed in our real-time operations environment.

People Development

We are committed to the ongoing development of our people to make the best use of our systems and technology so that we can adapt to the changing network and continue to improve the reliability that our customers see. We will achieve this through recruitment and skills development. The priority for skills development is our ADMS and OMS, which we will continue to support by increasing training and internal capability. In chapter 9 we outline our broader approach to training and competency across the business. Network operations internal staff costs are covered in our SONS portfolio.

7.2.3. Overall Network Operations and Maintenance Initiatives

The following network Opex initiatives relate to our asset management objective areas and specific portfolio objectives in each maintenance category. They cover all network Opex portfolios.

Table 7.2: General operate and maintain initiatives

OVERALL OPERATE AND MAINTAIN INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[8]
Network Operations Initiatives	The initiatives support our objectives to:	
Live Line work risk assessment process Implementing a process that identifies opportunities to undertake live line work early in the delivery process to maximise our ability to safely use live line approaches.	**Reliability to defined levels** – Live line work is an effective tool to manage network availability to customers.	Complete Ongoing live line risk assessment applies
Outage notifications to customers Modifying existing business process to improve the communication we provide to customers associated with planned outages.	**Reliability to defined levels** – Proper outage notification process will ensure we are communicating effectively with our customers, and this is a key tool to effective management of planned outages.	In Progress (linked to OMS initiative)
ADMS improvement: symbology and alarms Continued progression of symbology improvement and alarm standardisation in the ADMS to minimise the opportunities for human error and speed up response times.	**Safety first** –Improvements in our SCADA interface reduce opportunities for human error incidents. **Reliability to defined levels** – Faster response times will help manage reliability performance for customers.	Short-term
CIMS training Undertake CIMS training for additional personnel.	**Safety first** – Ensuring structure and process rigour in major incidents is key to ensure safety first is upheld. **Responsive to a changing landscape** – Being prepared as an essential service for unplanned incidents is mandatory.	Complete Ongoing refresher training as required
OMS implementation Implementing OMS, integrating its use into business practices, and exploring opportunities to provide improved information to customers.	**Reliability to defined levels** – Use of OMS will help manage network availability to customers by enabling the impact of faults to be found faster.	In progress
Improvement to field audit process We will develop and implement new health and safety compliance auditing with contractors working on our network.	**Safety first** – Ensuring competent people work on our network, for their own benefit, the benefit of other employees and contractors, and the public.	Complete Enhanced QA to follow
Outage scheduling calendar Developing a community event calendar and Network Access stage gate process that provides an improved ability to avoid planning outages that conflict with community events as well as coordinate outages between contractors to minimise the impact on customers.	**Reliability to defined levels** – Having an outage scheduling calendar will help manage network availability to customers. **Affordability through cost management** – more efficient use of outage windows should reduce costs.	Short-term

[8] When used in this table: short-term (underway), medium-term (within 1-2 years), long-term (within 1-4 years).

OVERALL OPERATE AND MAINTAIN INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[8]
ADMS improvement Transitioning from Poweron Fusion to Poweron Advantage to maintain system currency and support and create opportunity to activate future functionality.	**Responsive to a changing landscape** – Ensuring our systems are up to date.	Complete
Switching Request Management Explore the benefits of a switching request management system that will help the business optimise the outage planning calendar and minimise impact to customers for planned work.	**Affordability through cost management**– Increased efficiency in the outage planning process will reduce costs.	Medium-term
ADMS improvement Implementing distribution power flow. Implement LV network mapping.	**Responsive to a changing landscape** – distribution power flow and LV network modelling and monitoring will help ensure our network is enabled for future technologies.	Medium-term LV - Long-term
General maintenance initiatives	**The initiatives support our objective to:**	
Improved network Opex tracking in SAP SAP, our financial system, is used for tracking network Opex costs. We have created a new WBS structure and new forms for capturing information on work completed from contractors.	**Affordability through cost management**– Increase understanding in unit rates for Opex work and use this information to support any necessary changes in Opex regime.	Complete
Outage zone framework We will create an outage zone framework so that all assets have an associated outage zone for efficient work inspection and maintenance bundling.	**Reliability to defined levels** – Planning and bundling work earlier by outage zone will help us manage forecast availability to customers. **Affordability through cost management** – More efficient use of outage windows should reduce costs.	Complete Ongoing refinement to occur
Criticality frameworks We will build on our public safety criticality framework by creating criticality frameworks in other dimensions, such as service performance, worker safety, and environmental criticality dimensions.	**Safety first** – Ensuring safety critical work is prioritised. **Affordability through cost management** – Most critical risks that can be cost-effectively reduced via investment are attended to with highest priority.	Medium-term

Operational and maintenance initiatives are first identified through a prior business need, or through communications with other EDBs or industry partners. Each of these initiatives align with our key asset management objectives. In cases that require a commercial solution, we conduct limited trials where practical to assess any potential benefits before committing to significant investment.

In some cases, innovation practices can be measured in terms of reliability or safety improvements. These measures allow us to set expectations around improvement levels and to gauge success. We can estimate reliability improvements in terms of value of lost load (VoLL), which measures the inconvenience of an outage to customers as a monetary value. In utilising VoLL as a metric, we can compare the cost of any innovation practices against the real or forecast benefit. In other cases, innovations provide alternative benefits such as improved efficiency or accuracy in business processes.

All operational and maintenance initiatives that require additional resource and investment must be approved by senior management and the relevant GM. For new innovations relating to inspection or maintenance, we will conduct limited trials or case studies within select areas of the network. Once these trials have been conducted, we assess the results and consider whether the benefits justify further investment.

7.3. PREVENTIVE MAINTENANCE

7.3.1. Overview

The preventive maintenance portfolio includes scheduled work to ensure the continued safety and integrity of assets and to compile condition information for subsequent analysis and planning. It is our most regular asset intervention and a key source of information feedback. Activities include:

- **inspections:** checks, patrols and testing to confirm the safety and integrity of assets
- **condition assessment:** monitoring of asset condition to support renewal and corrective works
- **servicing:** regular maintenance tasks performed to maintain the condition of an asset.

We carry out various combinations of preventive maintenance for all our asset fleets. The tasks, intervals and reporting requirements are set out in our maintenance standards and summarised later in the chapter (see section 7.7).

We have made significant progress toward addressing a large backlog of preventive maintenance inspections caused by historic underinvestment. Completing the 'first pass' of network inspections is paramount to identifying defects and to gather or confirm asset information, and this is a key reason for an uplift in preventive maintenance over the last three years and into the planning period.

Preventive maintenance is related to our corrective and reactive maintenance activities. We often identify defects during preventive maintenance, and it provides condition information required for planning renewals. Intensifying our preventive maintenance work has led to a consistent flow of defect identification, leading to corrective work in the short- to medium-term.

The expenditure in this portfolio reflects preventive maintenance works undertaken by our service providers.[9] Note that preventive maintenance Opex excludes internal staff costs associated with managing the work undertaken by our service providers, which is included in our SONS portfolio.

Key Drivers

The key expenditure drivers for this portfolio are:

- **asset management system:** we need to gather timely information on assets to make cost-effective decisions
- **legislative or regulatory requirements:** include minimum frequencies for inspecting overhead line assets

[9] All preventive maintenance expenditure is covered under the Operational Expenditure ID category, line item, Routine and corrective maintenance and inspection (RCI) and is included in Schedule 11b in Appendix B. Note that preventive maintenance expenditure does not directly align with ID categories, but rather makes up part of the RCI category together with corrective maintenance.

- **maintenance standards:** that specify recommended maintenance inspection tasks, servicing intervals and reporting requirements
- **manufacturers recommendations:** around inspections tasks and servicing intervals.

7.3.2. Objectives

Our preventive maintenance objectives and the asset management objectives they contribute to are set out in the following table.

Table 7.3: Preventive maintenance objectives

OBJECTIVE AREA	PREVENTIVE MAINTENANCE PORTFOLIO OBJECTIVES
Safety first	Identify safety risks to our workforce and the public in a timeframe appropriate with the risk.
Reliability to defined levels	Ensure planned outages for preventive maintenance are undertaken considering our planned outage reliability limits. Proactively identify defects where it is cost-effective and safety acceptable to avoid a run to failure approach.
Affordability through cost management	Ensure that high-quality, complete asset data is collected to support well informed asset management decisions.
Responsive to a changing landscape	Lift quality and transparency in preventive maintenance activities, through the use of new technologies where applicable.
Sustainability by taking a long-term view	Environmental risks and issues are identified during preventive maintenance. Minimise landowner disruption as much as reasonably practicable. Preventive maintenance backlogs are cleared, and a steady-state is reached.

7.3.3. Preventive Maintenance Initiatives

As part of our efforts to improve our asset management approach, we have identified initiatives to improve our performance. The more significant of these are set out in the table below.

Table 7.4: Preventive maintenance initiatives

PREVENTIVE MAINTENANCE INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[10]
Asset Specific Initiatives	**The initiatives support our objectives to:**	
Pole-top/crossarm inspections Pole tops and crossarms are currently being inspected from the ground. Higher quality condition information is available when crossarms are viewed from above for two reasons: 1) Water based decay to wood pole heads and crossarms tends to be worse on top where it is difficult to detect from the ground 2) It is harder to get good photos from the ground due to contrast between the pole and sky.	**Safety first** – Aerial inspections may find significant defects that were not visible from the ground, hence allowing this information to be acted on to prevent asset failures. **Responsive to a changing landscape** AND **Affordability through cost management** – The use of different technologies will provide increased data quality and allow for better asset management decisions.	Short-term Trials have been undertaken, with consideration on how to make drones available for pole top inspection if the inspector has concerns about pole top condition but needs greater validation.

[10] When used in this table: short-term (underway), medium-term (within 1-2 years), long-term (within 1-4 years).

PREVENTIVE MAINTENANCE INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[10]
Selective drone inspection is being used to gather enhanced condition information on critical feeders.		
Acoustic/alternative pole testing triage trial Several alternative wooden pole testing techniques have been trialled over the last two years, with the aim of improved testing process (speed, ease of use, associated cost and accuracy). One system (Vonaq) has shown promising results and is being further trialled throughout RY23	**Safety first** – Introducing additional 'triage' testing ensures we are doing all that is reasonably practicable to identify poles with insufficient strength, helping to prevent pole failures. **Responsive to a changing landscape** -The use of different technologies serves as an opportunity to have a more specific and targeted test regime for different test types in the future.	Initial trial complete Further trials to be undertaken in the short-term
Oil Testing programme for Distribution Transformers Introduction of oil testing programme for GMTX 750 kVA and above and/or other critical distribution transformers. This will enable us to make evidence-based decisions regarding maintenance and renewal of critical assets in this fleet, and provide greater levels of confidence in renewal forecasting.	**Reliability to defined levels –** Recent oil test results trigger planned replacements and maintenance which reduce significantly the unnecessary outage time and resource costs to replace these transformers reactively	Ongoing / close monitoring
Power Transformer – Detailed Condition Assessments We will carry out more detailed condition assessments including testing, to enhance our assessment of remaining life of power transformers	**Affordability through cost management** – The use of detailed condition appraisals will provide increased data quality and allow for better asset management	Short-term Commencing in RY24
Increased maintenance on electromechanical and static relays While we have a plan for electromechanical and static relay renewal, in the interim we need to test these relays more regularly to ensure calibration is maintained. We have halved the test interval to two years.	**Safety first** – Finding defective protection relays is paramount to ensure protection will clear faults as designed. **Affordability through cost management** – It is not possible to advance the protection renewal programme further.	Complete/ongoing
Distribution surge arrestor inspections We have identified and are prioritising the replacement of porcelain- and glass-types SA on the network. A coordinated effort is being made to identify and replace any SA's that required up-rating as NER's are being installed on the network.	**Safety first** – Porcelain and glass types pose a safety (public and personnel) risk when operated. This also might cause operational risks (see Reliability section below) **Reliability to defined levels** – Having equipment on the network that is not adequately rated can cause cascading issues/failures to a wider section in the lines. This also might cause operational and reliability issues in terms of *material type* and/or arrester *rating*.	Short-term Ongoing in areas with porcelain/glass sites and/or sites with new NERs
Low voltage enclosure inspections uplift The historical base level of LV enclosure inspections will be completed in RY24. An inspection routine is required to ensure the condition of these enclosures and the public safety risks are managed. Unique asset	**Safety first** – LV enclosures are in the public domain and historically have not been inspected **Sustainability by taking a long-term view** – The inspection backlog will be cleared to achieve steady-state renewals.	Short-term Complete/ ongoing routine inspections

PREVENTIVE MAINTENANCE INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[10]
identifying labels are being attached to the enclosures during inspections.		
Post fault zone substation oil circuit breaker servicing Historically OCBs (Oil Circuit Breakers) have not been maintained systematically after a determined number of faults. We are now undertaking this activity in line with good industry practice.	**Safety first –** Ensuring OCBs are in an operable condition is paramount, as maloperation could lead to explosion and oil fire. **Reliability to defined levels** – A potential maloperation of an OCB at a zone substation could have a significant reliability impact.	Ongoing
Air-break switch inspection and maintenance uplift Historically, routine maintenance has not been undertaken on pole mounted switches. It is prudent to restart inspections and servicing to ensure these assets continue to operate as intended. Programme to start in RY23.	**Reliability to defined levels** – Having operable air-break switches will help us meet our reliability limits.	Short-term
'UnableToTest' pole and Distribution Transformers testing 'UnableToTest' poles/transformers are those flagged through our test regime where a test cannot be completed at the first visit to site. To complete the test requires additional resource to be tested E.g. vegetation management, traffic management requirements, landowner access issues.	**Safety first** – Many of these poles will not have been tested in a long time and therefore are likely to be in a poor condition, presenting a failure risk.	Complete where practical to do so Ongoing programme for new discoveries as vegetation or new buildings restrict access
LiDAR survey LiDAR has been identified as a means of improving visibility on vegetation and lines clearances. Two-yearly surveys are being considered to provide quality data, primarily for vegetation management but with future uses in network design and asset management. LiDAR data will be used for vegetation management in the first instance; supporting a decrease of expenditure in this area. Further investigation and preparation is required to ensure we can utilise the survey results effectively.	**Safety first** – Identify vegetation and under-clearance safety risks in a timeframe appropriate with the risk. **Affordability through cost management** – use of LiDAR should increase vegetation management efficiency in the long-term. **Sustainability by taking a long-term view** – Landowner disruption can be minimised by conducting LiDAR survey and potential fire implications can be better managed.	Medium-term
Survey of distribution conductor We use conductor performance and failure data, including sampling and testing conductor of various types, ages and service history, to assess degradation and evaluate remaining life of conductor. Conductor Ground-Based visual assessments are being integrated with our OH Inspections (including structures) and will be used to inform visual asset health grading, from RY24.	**Safety first –** Identifying condition, workmanship, and type issues before they fail could prevent line down events and the subsequent safety issues. **Reliability to defined levels** – Line down events are increasing and lead to a poor reliability experience, generally in rural areas with smaller conductor. Proactive repairs can be managed via planned outages. **Affordability by cost management** – Proactively finding and subsequently	Short-term

PREVENTIVE MAINTENANCE INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[10]
Of the data collected to date, correlation between visual assessments and degradation assessments is good. From RY24 OH joints are to be thermally inspected as part of our cyclic OH inspections.	remediating conductor issues is more cost-effective than replacing upon failure. Sustainability by taking a long-term view – Confirming the extent of poor workmanship and design choices on the network will help us create a plan to ensure this does not continue to occur going forward.	
Aerial inspections of sub-transmission lines Our current inspection regime includes visual assessments of the crossarms and pole tops (to detect pole-top rot) from the ground. We have developed a new OH Inspection Strategy, which sets out when such inspections should be carried out from above i.e. by drone or helicopter. We are formulating the optimum approach with respect to our routine programme of inspections.	Safety first – Aerial inspections may find significant defects that were not visible from the ground, hence allowing this information to be acted on to prevent asset failures. Reliability to defined levels – Reliability of our sub-transmission network is paramount given its criticality, and these inspections will allow more difficult defects to be captured, E.g. discharging insulators. Responsive to a changing landscape AND Affordability through cost management – The use of different technologies will provide increased data quality and allow for better asset management decisions. Aerial surveys allows for large amounts of data to be gathered quickly, by resource that is mostly 'additional' to our main field service providers.	Short-term
Acoustic Inspections Acoustic inspections have been introduced as an advanced inspection targeting overhead feeders with poorer performance, and feeders where asset failure is not tolerable, such as in fire prohibited zones. The inspections are vehicle based, allowing high coverage in short time periods. The technology detects micro arcing which is an indicator of a failing asset (such as a cracked insulator) allowing early intervention - prior to asset failure.	Safety first – Acoustic inspections may find significant defects that were not visible from the ground, hence allowing this information to be acted on to prevent asset failures. Reliability to defined levels – enables targeted advanced inspection mechanisms, that have capability of identifying defects that are not visible, including failing insulators. Responsive to a changing landscape – actively adapting our approach to ascertain the best possible information by optimising our inspections. Affordability through cost management – The use of different technologies will provide increased data quality and allow for effective asset management decisions.	Complete/ ongoing
Pole mounted distribution transformers inspections We have introduced a 5-year inspection cycle with the first cycle due to be completed in RY24	Affordability through cost management – We may be able to make better asset management decisions once we have a more complete condition dataset for pole mounted distribution transformers.	Complete/ ongoing
SF_6 management improvements	Sustainability by taking a long-term view – We want to lift our SF_6 management to	Medium-term

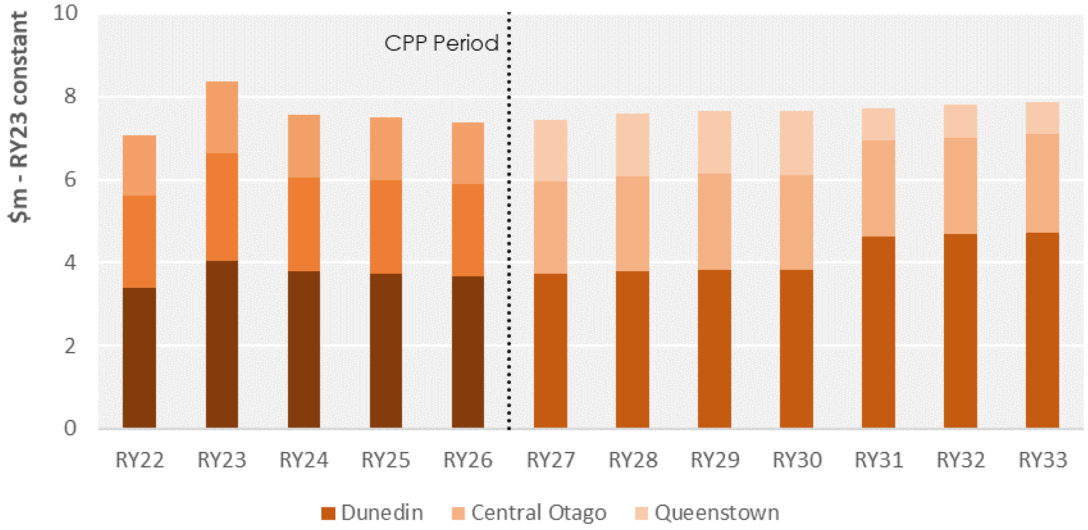
PREVENTIVE MAINTENANCE INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[10]
We do not currently meet regulated reporting requirements for SF_6 as our volumes are below the threshold. Good industry practice is to have a reporting and management regime despite not meeting regulated volumes.	best industry practice, given its long-term impact on the environment.	
Non-asset specific initiatives	The initiatives support our objective to:	
Complete 'first pass' of network asset inspections- - for all fleets Historical under-investment in preventive maintenance has led to a backlog of maintenance and/or inspections in many asset fleets. We will continue to use the data we have combined with criticality information to prioritise assets most in need of inspection, before transitioning to steady-state.	This initiative helps us meet all the preventive maintenance objectives.	Ongoing with introduction of new fleets
Preventive maintenance-controlled documents We continue to develop our suite of preventive maintenance documents. It is paramount that these are completed and created in electronic inspection applications to allow for easier data manipulation.	**Sustainability by taking a long-term view** – we need to be fully supported by our controlled documents through the long-term.	Short-term
Quality assurance and auditing We do not currently have a formal quality assurance or preventive maintenance auditing framework. We will create such frameworks to ensure both site-based assurance and data-based assurance are undertaken, to ensure we are getting the expected value from our preventive maintenance activities.	**Responsive to a changing environment** – our focus is gradually moving from being responsive to the state of the network to being proactive; a focus on quality management will be key to ensure customers are getting the expected value from maintenance.	Medium-term

7.3.4. Preventive Maintenance Forecast

We will continue an elevated level of inspections in future years until we reach steady-state levels.

Figure 7.1 below shows forecast preventive maintenance Opex, which is approximately $7.6m on average per year.

Figure 7.1: Forecast preventive maintenance Opex



Our preventive maintenance forecast budget per asset category is outlined in Table 7.5 below.[11]

Table 7.5: Preventive maintenance Opex forecast by portfolio category (RY23 constant, $,000s)

ASSET PORTFOLIO	RY23	RY24	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33
Overhead Conductor	271	239	237	233	236	487	490	492	495	497	500
Support Structures	2,518	2,495	2,651	2,603	2,624	2,465	2,486	2,417	2,440	2,463	2,485
Secondary Systems	167	136	134	132	134	135	137	138	140	142	143
Zone Substations	1,760	1,427	1,414	1,393	1,408	1,424	1,440	1,456	1,472	1,489	1,505
Distribution Switchgear	2,553	2,155	1,949	1,921	1,943	1,966	1,989	2,011	2,036	2,059	2,084
Distribution Transformers	1,061	1,083	1,070	1,052	1,061	1,070	1,080	1,089	1,099	1,109	1,119
Underground Cables	44	36	36	35	36	36	36	39	37	37	38
Total	8,373	7,571	7,491	7,369	7,442	7,583	7,658	7,643	7,719	7,796	7,874

Expected Benefits

The main expected benefits of preventive maintenance work over the planning period is:

- **management of safety risk**: the risks of our workforce and the public being exposed to injury, and of damage to the environment are reduced by undertaking the work as scheduled
- **improved customer experience/service**: an increase in preventive work will help reduce unplanned outages in the longer-term by helping to identify assets that require renewal

[11] The relationship between our asset portfolios and Information Disclosure categories is explained in Table 8.1 of Chapter 8.

- **reduced cost of works**: planned servicing is generally a cost-effective practice relative to unplanned remediation work. Lifecycle costs should be reduced by optimising the balance between preventive maintenance and asset renewals
- **asset and condition information gathering**: an historical lack of preventive maintenance activities means some of our overall asset condition information is inconsistent. Uplift in inspections will provide us with improved condition information on which to make better informed asset management decisions. Furthermore, some asset attribute information is absent and preventive maintenance can confirm this data or gather it as required
- **improved decision-making**: by gathering better asset information, we are maturing our evidenced based approach to investment, leading to well informed asset management decisions and, thus, least whole-of-life costs.

7.4. CORRECTIVE MAINTENANCE

7.4.1. Overview

The corrective maintenance portfolio incorporates planned work triggered by defects identified during preventive maintenance work or as follow-up to a fault (after service restoration). Where defects do not require urgent remediation, the work can be prioritised and scheduled, which is generally more cost-effective than reactive response. Corrective maintenance includes:

- **defect work:** remediation of issues usually identified from inspections and servicing. This includes repairs and replacement of low-cost assets or asset components
- **second response**: following the initial (first) fault or emergency response, further work may be required to return an asset to service or make the site safe (refer to reactive maintenance). Second response work returns the asset to normal working condition
- **other corrective work**, including:
  - stand overs to ensure the integrity of the network during third-party works, i.e. excavations near an underground cable or cranes and other heavy machinery operating in the vicinity of overhead lines
  - graffiti removal from network assets
  - customer-driven costs not covered by customer contributions, such as safety isolation of an installation, and replacement of consumer service lines and poles.

The expenditure in this portfolio reflects the cost of corrective maintenance undertaken by our service providers.[12] It includes defect rectification, repairs and replacement of minor components to restore assets to operational condition. Failure to undertake this work increases reliability and safety risks due to asset defects and deteriorating condition.

Note that the expenditure excludes internal staff costs associated with managing the work undertaken by our service providers, which is included in our SONS portfolio.

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[12] All corrective maintenance expenditure is covered under the Operational Expenditure ID category, line item, Routine and corrective maintenance and inspection (RCI), and is included in Schedule 11b in Appendix B. Note that corrective maintenance expenditure does not directly align with ID categories, but rather makes up part of the RCI category together with preventive maintenance.

Key Drivers

The key expenditure drivers for this portfolio are:

- **asset condition**: as identified by preventive maintenance activities
- **fault numbers**: where assets require second response work
- **legislative or regulatory requirements**.

The volume of work we undertake in other maintenance or renewal portfolios affects corrective maintenance volumes in the longer-term. For example, an increase in planned renewal or preventive maintenance work on the overhead network will tend to decrease corrective maintenance volumes (in the longer-term) because it improves the condition of assets. However, in the short term, an increase in preventive maintenance may result in more defects being identified and requiring correction.

7.4.2. Objectives

Our corrective maintenance objectives and their alignment with asset management objectives are set out in the following table.

Table 7.6: Corrective maintenance objectives

OBJECTIVE AREA	CORRECTIVE MAINTENANCE PORTFOLIO OBJECTIVES
Safety first	Mitigate safety risks to our workforce and the public by remedying defects within an appropriate timeframe.
Reliability to defined levels	Ensure planned outages for corrective maintenance are undertaken with consideration for our reliability performance targets. Ensure that defective or deteriorating components are remediated in an appropriate timeframe to minimise unplanned service interruptions.
Affordability through cost management	Undertake corrective work based on well informed Opex/Capex trade-offs with the aim of minimising whole-of-life costs. Undertake multiple works in a coordinated manner to ensure economies of scale.
Responsive to a changing landscape	Focus on mitigating the rising failure rate of consumer-owned poles via pole replacement, as the Aurora-owned pole fleet improves.
Sustainability by taking a long-term view	Environmental issues are remediated prior to becoming unacceptable to stakeholders. Minimise landowner disruption as much as reasonably practicable. Prevent build-up of an untenable backlog of defects.

7.4.3. Corrective Maintenance Initiatives

As part of our efforts to improve our asset management approach, we have identified initiatives to improve our performance. The more significant of these are set out in the table below.

Table 7.7: Corrective maintenance initiatives

CORRECTIVE MAINTENANCE INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[13]
Asset Specific Initiatives	The initiatives support our objectives to:	
Possum guard and cable guard retrofit programme During inspections on our poles to date, we have found that many poles in regions that have a risk of possum strike are either missing possum guards or the possum guard is in a state that requires replacement. We will install possum guards on all poles; the programme has been prioritised based on known possum fault locations and areas of fire risk. (completed) When required, cable guards will also be retrofitted to poles during the possum guard programme as a safety initiative.	Safety first – Possum strike can lead to pole fires and in turn scrub/bush fires, so retrofitting guards in possum strike prone areas with high fire risk provides a safety benefit. Retrofitting cable guards provides a public safety benefit due to reduced chance of impact, tampering and/or electrocution. Reliability to defined levels – installing possum guards in areas that experience possum strikes is a cost-effective way to address decreasing reliability.	Short-term This programme commenced in RY23 and is planned to run until RY25
Consumer pole remediations Following inspections of consumer poles as discussed in preventive maintenance, remediations need to be undertaken as required on consumer poles and lines installed prior to 1984 to ensure they are in a "reasonable standard of maintenance or repair" prior to formal handover to the consumer, which has historically not occurred. All expenditure, including pole replacements, is treated as Opex, given that consumer assets are not Aurora owned.	Safety first – Many consumer poles will not have been inspected in a long time, if ever, and hence may present a risk due to poor condition. Sustainability by taking a long-term view – It is in the best long-term interests of consumers for us to assess consumer poles and lines and remediate those that are not in a "reasonable standard of maintenance or repair" prior to handing their ownership to consumers.	Short-term A pilot programme is underway
Zone substations transformer painting All transformers older than 20 years in the Dunedin network that are not being replaced have been assessed as requiring corrosion control and painting to ensure they last their expected lives. Painting will be completed in Dunedin in RY23 before we transition to Central Otago.	Affordability through cost management – Painting transformers before they pass the point of disrepair reduces overall cost of ownership.	Short-term
Legacy metal service pillar (LV enclosure) cover replacements The metal lid replacement programme which is based on previous years' inspection data has been completed. However, we expect there may be some (not yet identified) still on the Network that need replacing as identified by ongoing inspections.	Safety first – We must remediate a known failure mode in a legacy LV enclosure that does not meet 'safety by design' requirements.	Short-term Remediation of legacy enclosures is largely complete
Buildings and grounds corrective maintenance uplift We have a backlog of building and grounds maintenance to undertake at our substations. Buildings may require work to ensure they remain in an acceptable state to house electrical assets.	Affordability through cost management – Undertaking remediations on buildings before they pass the point of disrepair reduces overall cost of ownership.	Short-term

[13] When used in this table: short-term (underway), medium-term (within 1-2 years), long-term (within 1-4 years).

CORRECTIVE MAINTENANCE INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[13]
Backlog remediation As we invest in improved preventive programmes we are responding to correct identified issues. We forecast that this will reduce to a steady state in alignment with preventive maintenance.	**Safety First** - preventive maintenance (inspection) programmes are risk prioritised to drive best possible outcomes, while we work through remediating a backlog of corrective maintenance.	Short-term to medium-term
Distribution assets repainting Equipment repainting helps avoid repairs that can become significantly more expensive if left alone. In the worst-case, asset replacement may be required. We have introduced a paint programme across a range of fleets including ground mount switchgear, cable accessories and distribution transformers. The approach is generally corrective, but some preventive painting is undertaken. Graffiti is addressed as required.	**Affordability through cost management** – Undertaking remediations on equipment before it passes the point of disrepair reduces overall cost of ownership.	Ongoing
Non-asset specific initiatives	**The initiatives support our objective to:**	
Defect management improvements We will improve our mobile 'defect' application used to gather ad-hoc defect information and integrate it with other systems. We will expand our existing defect coding to cover all assets and ensure the correct response is issued based on probability of failure and criticality, automated where possible.	This initiative helps us meet all our corrective maintenance portfolio objectives.	Complete Our asset management software solution will provide further improvement

7.4.4. Corrective Maintenance Forecast

The figure below shows forecast corrective maintenance expenditure. Our corrective maintenance expenditure decreases from $5.3m year on year, until a steady state of approximately $2.7m on average, per year, is reached in RY31. We expect to carry out several maintenance initiatives during the initial stages of the planning period, with reduced need for corrective maintenance in the following years.

Our forecast corrective maintenance budget is broken down by asset category in the table below. These forecasts are based on historical trends in expenditure, but we expect some degree of variance across each asset category based upon changes in maintenance work required in any given year.

Figure 7.2: Forecast corrective maintenance Opex

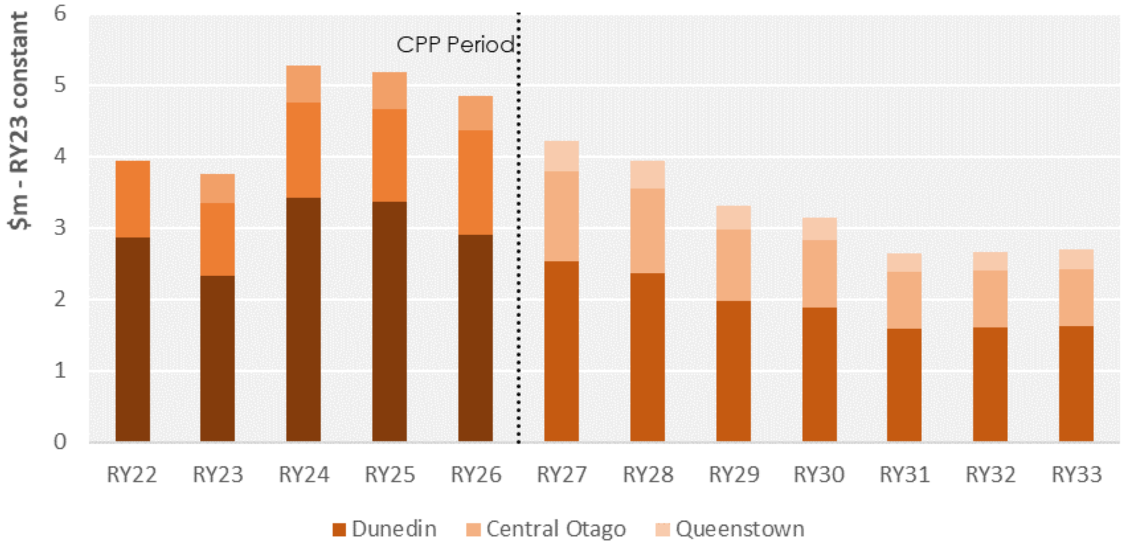


Table 7.8: Corrective maintenance Opex forecast by asset category (RY23 constant, $,000s)

ASSET PORTFOLIO	RY23	RY24	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33
Overhead Conductor	250	286	266	245	214	195	176	178	180	182	184
Support Structures	1,505	2,692	2,771	2,644	2,290	2,183	1,715	1,546	1,016	1,027	1,039
Secondary Systems	123	142	132	121	106	97	88	88	89	90	91
Zone Substations	877	1,008	938	863	753	686	620	627	633	641	648
Distribution Switchgear	464	534	496	457	398	364	328	332	336	340	344
Distribution Transformers	332	381	354	326	284	259	234	237	240	242	245
Underground Cables	205	235	219	202	176	160	145	147	148	150	152
Total	3,756	5,279	5,176	4,858	4,221	3,944	3,307	3,155	2,643	2,672	2,702

Expected Benefits

The main expected benefits of corrective maintenance work over the AMP planning period are:

– **management of safety risk**: the risk of our workforce and the public being exposed to injury, and of damage to the environment, are reduced by undertaking the work in accordance with our safety and operational standards.

- **improved customer experience/service**: addressing defects helps to improve or retain asset condition and reduce the likelihood of unplanned outages. As a result, consumers should experience improvements in network reliability. Scheduled work is generally less inconvenient to customers and landowners than unplanned outages.
- **reduced costs**: planned remediation work is generally more cost-effective than unplanned. Lifecycle costs should be reduced by undertaking an optimal volume of corrective work.
- **statutory obligations**: we will address obligations to remediate customer service lines and poles so that they can be formally returned to customer ownership.

7.5. REACTIVE MAINTENANCE

7.5.1. Overview

The reactive maintenance portfolio includes expenditure related to emergency and fault response, as well as switching in response to an unplanned event or incident that impairs normal network operation. This work is undertaken by external service providers and is dispatched by the control room in response to network incidents.

This work helps maintain network reliability and safety by managing any hazardous or operational conditions that arise through network faults, managing the risk to our service providers and the public, and restoring supply to customers. Activities in this portfolio include:

- **emergency response**: field crews isolate and make safe sections of the network during a fault event, such as where vehicle damage to a pole has resulted in conductor on the ground. Field crews are directed by the control room to undertake switching or isolate damaged network sections by cutting away insecure conductor or undertaking other actions to make the site safe so that supply can be restored.
- **fault (first) response**: undertaken by field crews in a similar way to emergency response, fault response is required where a network component such as an insulator or circuit breaker has failed, resulting in an outage. Fault response also includes 'forced' outages of equipment in distress, where failure has not yet occurred but is imminent.

Events that may require a reactive response include adverse weather/storm damage, asset failure/ imminent failure, vehicle or other third-party damage, network field switching associated with repair work, and dispatched response to alarms. Weather has a significant impact on reactive maintenance volumes.

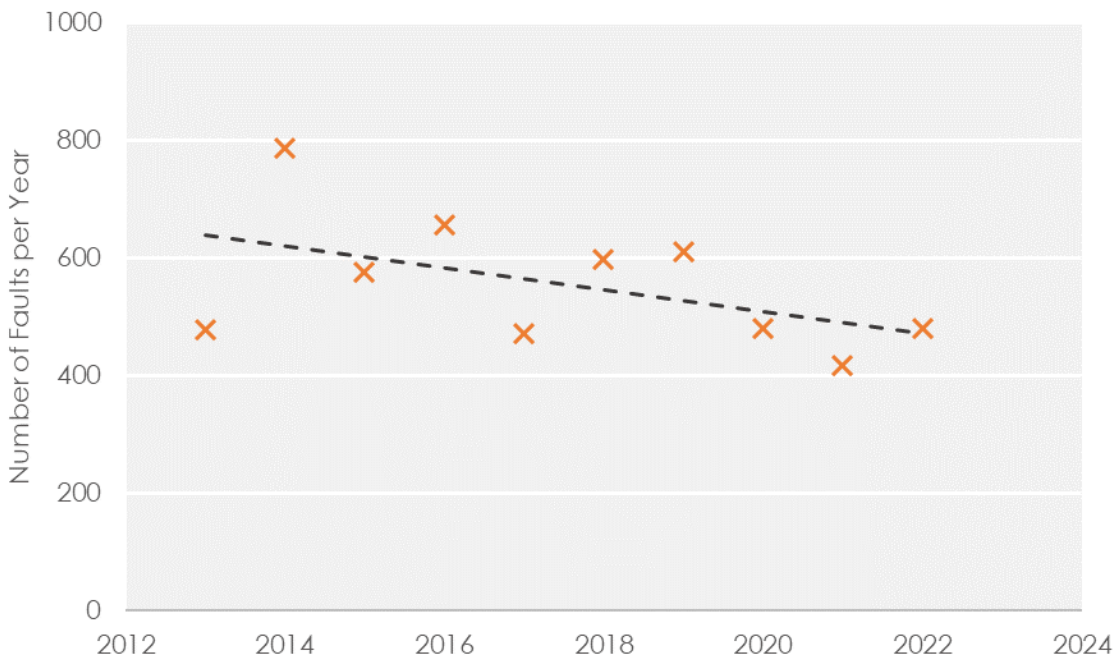
Reactive maintenance work can be challenging due to extreme weather or other severe conditions. Personnel must have a wide range of skills and competencies, and need to be available on standby at strategic locations across the network.

The expenditure in this portfolio reflects reactive maintenance works undertaken by our service providers.[14] It excludes internal staff costs associated with managing the work undertaken by our service providers (included in SONS).

Key Drivers

A key deliverable of this portfolio is to ensure we minimise the impact of outages on customers. Reactive maintenance work volume is primarily driven by the number of faults on our network. The figure below shows the trend in the number of faults on our network over a 10-year period from RY13-22. During the last five years we have dealt with an average of 517 faults per year, which shows an improvement on the five years prior.

Figure 7.3: Historic fault numbers (RY13-22)



The frequency and duration of reactive activities will be driven by factors such as:

- **asset age and condition**: as the ages of our assets increase and condition deteriorates, the volume of faults can be expected to increase
- **asset types**: assets of different types and manufacturers have unique characteristics. Some types fail more often than others, and some types are replaced upon failure (E.g. fuses) while others are replaced proactively
- **number and location of automation devices**: remote devices help reduce event impact, such as by remotely sectionalising the network, thereby speeding up restoration and reducing SAIDI impact

14 All reactive maintenance expenditure is covered under Operational Expenditure ID category, line item, Service Interruptions and Emergencies, and will be included in Schedule 11b in Appendix B. The reactive maintenance portfolio directly aligns with this ID category.

- **location of faults**: rural, remote-rural and mountainous areas require additional travel time to address faults
- **environmental conditions**: overhead assets, in particular, are more prone to failure in corrosive or high wind locations or in adverse weather. Snow and ice can also increase faults, due to additional structural loading on overhead lines
- **third-party**: incidents such as car vs pole and cable strikes caused by third parties lead to outages and potential safety risks.

The amount of work we undertake in other maintenance or renewal portfolios affects reactive maintenance volumes in the longer-term. For example, an increase in renewal work on the overhead network will tend to decrease reactive maintenance volumes as it improves the condition of assets. Similarly, an increase in corrective maintenance will also gradually reduce the amount of reactive maintenance that is required in the longer-term.

7.5.2. Objectives

Our reactive maintenance objectives and the asset management objectives they contribute to are set out in the following table.

Table 7.9: Reactive maintenance objectives

OBJECTIVE AREA	REACTIVE MAINTENANCE PORTFOLIO OBJECTIVES
Safety first	Mitigate safety risks to our workforce and the public by remedying defects within an appropriate timeframe.
Reliability to defined levels	Ensure planned outages for corrective maintenance are undertaken with consideration for our reliability performance targets. Ensure that defective or deteriorating components are remediated in an appropriate timeframe to minimise unplanned service interruptions.
Affordability through cost management	Undertake corrective work based on well informed Opex/Capex trade-offs with the aim of minimising whole-of-life costs. Undertake multiple works in a coordinated manner to ensure economies of scale.
Responsive to a changing landscape	Focus on mitigating the rising failure rate of consumer-owned poles via pole replacement, as the Aurora-owned pole fleet improves.
Sustainability by taking a long-term view	Environmental issues are remediated prior to becoming unacceptable to stakeholders. Minimise landowner disruption as much as reasonably practicable. Prevent build-up of an untenable backlog of defects.

7.5.3. Reactive Maintenance Initiatives

As part of our efforts to improve our asset management approach, we have identified several initiatives to further our performance. The more significant of these initiatives are set out in the table below.

Table 7.10: Reactive maintenance initiatives

REACTIVE MAINTENANCE INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[15]
Asset Specific Initiatives	The initiatives support our objectives to:	
Additional fault response Our faults contractor will establish a 24/7 dispatch service to operate and maintain our service and safety needs. Planning is underway to implement this initiative in RY23.	**Reliability to defined levels** – Ensure fault response times minimise impacts on customers and support achieving our reliability targets.	Short-term
Gathering better data from fault events and subsequent investigation process We will implement a data capture solution (possibly mobile) to enable the collection of information from our contractors and integrate this information with our systems. We will improve our investigations of unplanned outage events.	**Sustainability by taking a long-term view** – By better integrating our systems and having a process to review and learn from events, we will be able to implement further improvements going forward.	Short-term
Enhanced processes around evaluating and capturing root cause of asset failures We are continually improving our process and subsequent understanding of failure causes, and working towards improving how we use that information to target and pre-empt future similar failures. A step change in the process is to share learnings with other networks to identify wider industry systemic issues.	**Safety First** - using actual failure information to prevent future failures. **Reliability to defined levels** - using actual failure information to prevent future failures.	Short-term

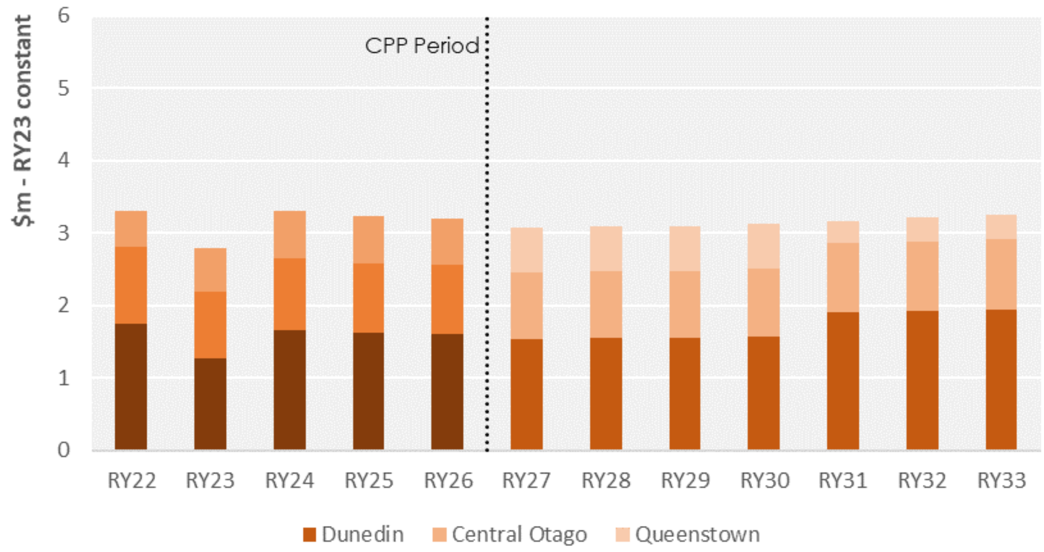
7.5.4. Reactive Maintenance Forecast

The chart below shows our forecast reactive maintenance expenditure. Our reactive maintenance expenditure requirement over the planning period tracks steadily just above $3m across the planning period.

Our forecast expenditure has decreased from previous AMPs based on the expectation that the condition of the network will improve over time, resulting in fewer faults requiring reactive maintenance expenditure. We factor in efficiency improvements as our asset management approach matures. As such, our reactive maintenance budget closely reflects our unplanned reliability forecasts over the planning period.

15 When used in this table: short-term (underway), medium-term (within 1-2 years), long-term (within 1-4 years).

Figure 7.4: Reactive maintenance Opex



Expected Benefits

The main expected benefits of reactive maintenance work over the AMP planning period are:

- **management of safety risk:** the risks of our workforce and the public being exposed to injury, and of damage to the environment, are reduced by undertaking the work in accordance with our safety and operational procedures
- **improved customer experience/service:** reducing the duration of unplanned outages will improve the network reliability experienced by our customers
- **regulatory compliance:** timely rectification of outages supports our efforts to comply with our regulated quality standards.

7.6. VEGETATION MANAGEMENT

7.6.1. Overview

Vegetation management involves monitoring vegetation growing in close proximity to our assets, liaising with landowners, and trimming and removing vegetation to keep it clear of overhead lines. Vegetation management Opex comprises the costs attributed to our vegetation contractor to undertake this work.

Vegetation can have a notable impact on network safety and reliability. Trees growing near live conductor pose a risk of electrocution and fire within our local communities. Further, such events can result in significant damage to network equipment, resulting in network outages. Vegetation is a key contributor to unplanned SAIDI and SAIFI performance across most NZ electricity distribution businesses, including ours.

Effective vegetation management ensures that we adhere to all relevant regulations. In particular, the Electricity (Hazards from Trees) Regulations 2003 establish the rights and responsibilities for network owners regarding inspection and removal of vegetation that encroaches overhead lines.

Our historical approach was largely reactive, whereby crews responded to issues as they were identified by line inspections, third-party reports, or network faults. We have transitioned to a more proactive, cyclical approach, which will give us better visibility of the status of vegetation around lines and enable us to minimise risks before they impact upon network safety and reliability. We completed an initial round of inspection and maintenance across the network in March 2022 and have since moved to a three-year cycle to ensure that vegetation remains in a maintained state.

Key Drivers

The key expenditure drivers for the portfolio are:

- to provide a safe network for the public, our staff and contractors
- to comply with the Tree Regulations
- to reduce the risk of vegetation-related events damaging network equipment
- to provide a reliable network for our customers and meet our agreed service levels.

Tree Regulations

Network operators must meet several compliance obligations in respect to vegetation management. The Tree Regulations prescribe the minimum distance that trees must be kept from overhead lines and set out responsibilities for tree trimming. Our responsibilities are shared with tree owners who, after the initial trim at our cost, assume responsibility for maintaining their trees to the regulated clearances. Our contractor liaison staff patrol the network to identify trees that require trimming and issue appropriate notification to tree owners. If tree owners fail to act with the required time period, we undertake to trim the trees to remove any danger. Where appropriate, we may consider passing on the costs to the tree owner.

Network Performance

Vegetation-related faults are a significant contributor to unplanned SAIDI and SAIFI performance. Adverse weather events such as major storm and snow events increase the frequency and impact of vegetation faults on our network. By adopting a more proactive approach to vegetation management, we aim to reduce the reliability impact that vegetation presents to our overhead assets.

Our three-year inspection programme increases the likelihood of identifying encroaching vegetation before it presents a safety and reliability risk to our network. Where practical, we encourage greater clearances of vegetation to reduce this risk further. We continue to experience faults due to fallen trees and branches that are outside the minimum clearance distances specified in the Tree Regulations. As a proactive measure, we communicate with tree owners where we identify trees outside the regulated distances that present an elevated risk due to their health and potential for damaging our lines.

7.6.2. Objectives

Our vegetation management objectives are set out in the following table.

Table 7.11: Vegetation management objectives

OBJECTIVE AREA	VEGETATION MANAGEMENT PORTFOLIO OBJECTIVES
Safety first	Minimise vegetation-related safety and environmental risks (E.g. electrocution, fires). Improve education around risks associated with vegetation near conductor.
Reliability to defined levels	Reduce the risk of vegetation-related events damaging network equipment to minimise the impact of vegetation on SAIDI and SAIFI. Reduce planned outages by targeting vegetation trimming, and ensuring this work is aligned with other activities.
Affordability through cost management	Improve vegetation management cost efficiency and programme effectiveness. Reduce the occurrence of vegetation related faults and limit related expenditure.
Responsive to a changing landscape	Use technology to assist in vegetation management planning and improve efficiency.
Sustainability by taking a long-term view	Ensure network vegetation is managed effectively, and that vegetation on our network remains in a maintained state. Minimise landowner disruption as much as reasonably practicable.

7.6.3. Vegetation Management Initiatives

As part of our efforts to improve our asset management approach, we have identified initiatives that can usefully improve our vegetation management performance. The more significant of these are set out in the following table.

Table 7.12: Vegetation management initiatives

VEGETATION MANAGEMENT INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[16]
Non-asset Specific Initiatives	The initiatives support our objectives to:	
Refine our cyclic tree trimming approach We introduced a cyclical trimming programme in RY21, and we are now seeing a reduction in vegetation-related outages. Initially, we inspected network feeders on a 5-year cycle, but we have shifted into a more aggressive 3-year maintenance programme. We maintain our overhead sub-transmission circuits annually, and we also include critical distribution feeders as part of this schedule.	**Safety first** – We can minimise our safety risk by ensuring that that vegetation around our network is well managed. This also achieves full compliance with the Tree Regulations. **Reliability to defined levels** – reduces the risk of vegetation-related events and impact on SAIDI and SAIFI by effectively managing our network vegetation.	Short-term
Consideration of a risk-based work programme We will assess the need for a risk-based work programme to manage fire risks, fall zone and hazardous trees (outside of the routine maintenance cycle).	**Safety first** – this will help ensure that that vegetation hazards around higher risk areas are prioritised. **Affordability through cost management** – by targeting vegetation that presents the greatest risk to our network, we can secure the best results from our expenditure.	Medium-term
Improved asset management systems We are planning to identify and record vegetation risks across the network within our GIS system. For each tree site, we will record all relevant details including species, risk and tree	**Reliability to defined levels** – Better programme management and works coordination will reduce planned outages. **Affordability through cost management** – A system will assist in programme effectiveness,	Medium-term

16 When used in this table: short-term (underway), medium-term (within 1-2 years), long-term (within 1-4 years).

VEGETATION MANAGEMENT INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[16]
owner details. This information will help us to monitor vegetation risks across the network and to develop targeted maintenance plans.	and in ensuring that work is completed to schedule. **Responsive to a changing landscape** – through greater information capture, we can adapt our programme based on changing performance trends. **Sustainability by taking a long-term view** – Better works coordination will reduce landowner disruption.	
Develop and deliver an improved communications programme We are refining the coverage and quality of information that we present to tree owners to highlight safety issues and responsibilities.	**Safety first** – improves education around risks associated with vegetation near conductor. **Affordability through cost management** – reduces expenditure as landowners are more aware of their responsibilities.	Medium-term
LiDAR survey LiDAR is identified as a means of enhancing visibility on vegetation and line clearances. We are considering a two-yearly lidar programme on the network to provide quality data.	**Safety first**- Identify vegetation and under clearance safety risks in a timeframe appropriate with the risk. **Affordability through cost management** - LiDAR should increase vegetation management efficiency in the long term **Sustainability by taking a long-term view**- Landowner disruption can be minimised, and tree growth modelling will help mitigate environmental risks of trees in lines and potential fire risk.	Medium-term
OH inspection Vegetation encroachments and fall hazard trees are identified and reported through our five-yearly cyclic overhead inspection programme.	**Safety first** – We can minimise our safety risk by ensuring that that vegetation around our network is well managed. This also achieves full compliance with the Tree Regulations. **Reliability to defined levels** – reduces the risk of vegetation-related events and impact on SAIDI and SAIFI by effectively managing our network vegetation.	Short-term

7.6.4. Vegetation Management Forecast

The chart below (Figure 7.5) shows our forecast vegetation management Opex. Our vegetation management expenditure requirement over the planning period is approximately $3.7m on average per year. As we enter into steady-state management programme from RY23, we forecast lower vegetation management expenditure. We expect to trim or remove less vegetation than in previous years, and we also anticipate transferring a greater share of costs towards tree owners for trees requiring a second cut, as per the Tree Regulations.

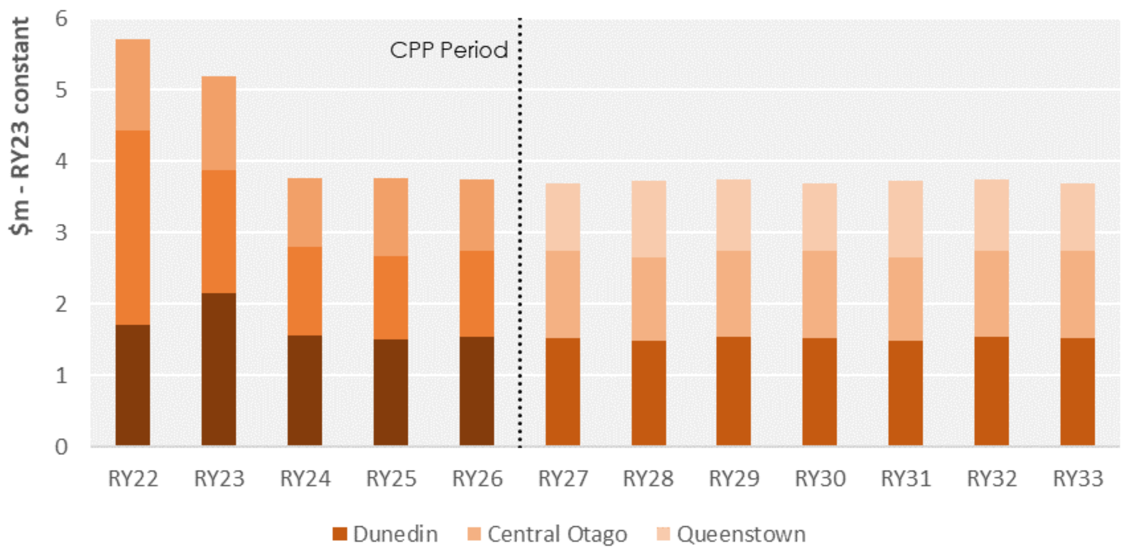
Expected Benefits

The main expected benefits of vegetation management work over the AMP planning period are:

- **management of safety risk**: the risks of our workforce and the public being exposed to injury are reduced by undertaking the work in accordance with our safety and operational procedures

- **improved customer experience/service**: reducing unplanned outages will improve the network reliability experienced by our customers
- **compliance**: ensures that the network is in full compliance with the requirements set out in the Tree Regulations
- **quality standard compliance**: effective trimming supports timely rectification of outages
- **effective engagement**: improved tree owner education and liaison will deliver better community collaboration enabling greater tree owner satisfaction
- **effective engagement**: increased stakeholder awareness around risks associated with vegetation near conductor
- **affordability**: improved efficiency by moving from reactive works to planned cyclic activity. By identifying risks early, we limit the extent of work required to redress the issue.

Figure 7.5: Vegetation Management Opex



7.7. MAINTENANCE BY PORTFOLIO

This section outlines our approach to inspection and maintenance across each of our asset portfolios. The information includes key initiatives, as well as a breakdown of common tasks under preventive, corrective and reactive maintenance.

7.7.1. Support Structures

Preventive maintenance

Poles are durable, static assets and require minimal routine mechanical or electrical maintenance work. We perform pole testing and inspections on a periodic basis, which is essential for identifying degradation, damage, or other compromising factors such as vegetation encroachment, third-party interference, poor ground conditions or land movement.

The detailed inspections regime for each type of pole is set out in our maintenance standards, which also include all relevant regulatory requirements and manufacturer recommendations. The standards also define data capture requirements for service providers when using test forms and mobile applications.

Table 7.13: Overhead line inspection maintenance activity

INSPECTION TASK	FREQUENCY
Pole test and visual condition inspection including crossarms: – For wooden poles, a Deuar test is the default method used to assess structural integrity. If a Deuar test is not feasible due to pole access issues, then a traditional visual inspection is performed – For concrete or steel poles, a visual inspection is undertaken.	Five years

The five-yearly inspection frequency follows the legislated period under NZECP34:2001 for inspecting electricity conductor span clearances. In 2021 we completed a full cycle of pole testing (all poles >10 years old) aside from a small % (0.5%) of harder to reach poles that require specialist access, were tested.

Meeting our portfolio objectives – sustainability by taking a long-term view

We are currently operating within year 1 of a 5-year inspection cycle, having completed a risk focused "once over" fleet inspection between RY18-RY22. In future we will consider introducing more frequent inspections for some sub-populations based on risk and criticality drivers. We are continuously reviewing and updating the process of inspection, condition evaluation, and how we prioritise our intervention strategies.

Our test regime aims to address risks on poles by obtaining information and acting upon it in an appropriate timeframe. For concrete and steel poles, we use a visual assessment (looking for signs of cracking or spalling), while for wood poles the regime is more comprehensive and includes both visual assessment and physical testing for structural integrity.

The nature of wooden poles makes inspections difficult, as areas of deterioration are typically out of sight, i.e., internal and/or below ground. For this reason, we have invested in Deuar Mechanical Pole Testing, which mechanically tests the pole strength. However, Deuar is more expensive to undertake, than other available options. We have trialled three alternative pole testing methodologies over the past three years, with one of these showing promising results (Vonaq). We continue to evaluate emerging condition assessment/testing techniques for wooden poles, verifying our existing test approaches including undertaking forensic activities. We are also in the process of expanding our inspection regime to include pole-top visuals, which will improve the quality of condition data for poles and crossarms.

Box 7.2: Improvement Initiative – Wood forensics and destructive testing

We have forensically inspected poles removed from service to assess actual condition and to improve our understanding of degradation. Poles chosen for this analysis are selected from a range of condition grades, and they have undergone visual and destructive testing. This provides assurance our testing regime and techniques are meeting requirements

To improve our asset management approach, we have identified specific preventive maintenance improvement initiatives for poles and crossarm fleets (see table below).

Meeting our portfolio objectives – responsive to a changing landscape

There are many new or different technologies available today that we can use to improve our poles and crossarms condition assessment data. We have introduced a number of new testing technologies and we continue to investigate additional options that may be embedded in our practices.

Table 7.14: Pole preventive maintenance initiatives

PREVENTIVE MAINTENANCE INITIATIVES	RELATED PORTFOLIO OBJECTIVES	TIME-FRAME
Updated inspection regime / data capture tool We are currently in the process of refreshing our overhead structures inspection regime; this new regime is expected to be delivered in 2023. Key improvements include: • Cross arm health grading • Improved ability to pinpoint & rectify issues (to insulator and cross arm levels) • More efficient and targeted data acquisition • Capture of more safety related data (conductor heights and conditions) • Improved data robustness and industry standardisation	**Safety first -** The new inspection regime will provide higher quality data, allowing us to focus on higher risk asset conditions more effectively **Reliability to defined levels -** The enhanced data will enable us to further develop appropriate intervention strategies which will lead to reliability improvements.	Short-term
Continuous improvement in pole testing Trialling industry available pole testing technology on the AE network. in the form of the Vonaq wood pole inspection system.	**Safety first** – More accurate pole inspections (ability to identify internal rot pockets). **Affordability through cost management** Faster more efficient wooden pole testing technique transferring to cost reductions.	
'Unable To Test' pole testing 'Unable To Test' poles are those flagged through our test regime that cannot be tested as originally planned. We continue to progress testing of these poles through additional focus and resource, E.g. vegetation management, traffic management or landowner access issues to be addressed. These are often poor condition poles and many clearly have not been accessed and tested in some time.	**Safety first** – many of these poles will not have been tested in a long time and therefore are likely to be in a poor condition, presenting a failure risk. **Sustainability by taking a long-term view** – many of these poles have not been accessed in some time – difficult pole testing must be tackled.	Complete where practical to do so. Ongoing programme for new discoveries as vegetation or new buildings restrict access
Targeted Advanced inspections of sub-transmission lines (including pole tops and crossarms) Our primary inspection regime is visual assessments, which can be limited due to height	**Safety first** – aerial inspections may find significant defects not visible from the ground, hence allowing this information to be acted on to prevent asset failures. **Reliability to defined levels** – reliability of our sub-transmission network is paramount given	Short-term

PREVENTIVE MAINTENANCE INITIATIVES	RELATED PORTFOLIO OBJECTIVES	TIME-FRAME
and access or because some issues/emerging issues are not visible. We are utilising aerial technology, including use of infrared cameras to enhance our understanding of things like pole-top condition, crossarm condition and to pick up emerging electrical defects. The use of additional or advanced inspections is targeted due to associated additional cost.	its criticality, and these inspections will allow more difficult defects to be captured, E.g. discharging insulators. **Affordability through cost management** – use of different technologies will provide increased data quality and allow for better asset management decisions.	

Crossarms are inspected at the same time as the poles to which they are attached. Our preventive pole and crossarm inspection procedures were outlined in Table 7.14.

Likewise, many of the preventive maintenance improvement initiatives covered in Table 7.13 will also improve our ability to detect and remediate poor condition crossarms, notably the pole-top inspections (aerial photography) and helicopter inspections of sub-transmission lines.

We have used acoustic testing on an ad-hoc basis to track down leaking pin insulators on sub-transmission crossarms that have caused intermittent faults. This is useful where the defect is not visible from the ground (or at least, not without knowing which pole it is and using a high-definition camera to find the defect).

Corrective maintenance

Pole corrective maintenance options include:

- Cutting the split head off the pole (sometimes lowering the crossarm attachment point if modern clearances can be complied with)
- Fitting a pole cap
- Reinforcement of a pole (nailing)
- Retro fitting possum or cable guards
- Pole straightening

Table 7.15: Corrective maintenance initiatives – poles and crossarms

CORRECTIVE MAINTENANCE INITIATIVES	RELATED PORTFOLIO OBJECTIVES	TIME-FRAME
Possum guard and cable guard retrofit programme During inspections on our poles to date we have found that many poles in regions that have a risk of possum strike are either missing possum guards or the possum guard is in a state that requires replacement. We are installing possum guards, prioritised on known possum fault locations and fire risk. When required, cable guards will also be retrofitted to poles during the possum guard programme as a safety initiative.	**Safety first** – possum strike can lead to pole fires and in turn scrub/bush fires, so retrofitting guards in possum strike prone areas with high fire risk provides a safety benefit. Retrofitting cable guards provides a public safety benefit due to reduced chance of impact, tampering and/or electrocution. **Reliability to defined levels** – installing possum guards in areas that experience possum strikes is a cost-effective way to address decreasing reliability.	Short-term – high risk areas such as Fire Prohibited Zones, have been completed

Corrective maintenance on crossarms is very limited. Proactive work on crossarms typically replaces the entire crossarm, making it Capex. This approach is more efficient from a whole-of-life cost perspective since the opportunity is available to replace other components, such as insulators, in conjunction with the crossarm. Repair is justified in some select cases where there is an obvious workmanship defect such as bolts not tightened adequately or subsequently loosened on a young installation.

Reactive maintenance

Reactive maintenance on poles includes responding to pole failures due to adverse weather or vehicular impact. When reactive maintenance replaces a pole, the cost of the pole replacement itself (excluding first response costs) are capitalised as a new asset is created.

Crossarm fault repairs involve replacement of individual components such as an insulator or binder, or complete crossarm assemblies (complete replacement is subsequently capitalised). Under fault response conditions, it is not always practicable to replace the whole crossarm assembly.

Spares

Poles and crossarms are standard components and stock is kept by our faults contractor at strategic locations to enable fast return to service. Pre-drilled crossarms are kept for contingency purposes.

7.7.2. Overhead Conductor

Preventive Maintenance

We undertake little invasive preventive maintenance work on conductor. Under the NZ Electrical Code of Practice, we are required to check the clearance heights of all overhead electricity lines at least every five years. Currently we coordinate this activity together with our pole inspections. We are also required to inspect our conductor assets in line with good practice. To date we have undertaken inspections on an ad-hoc or limited detail basis. Our new Overhead Inspection regime is a significant improvement – when fully implemented we will have verified conductor type data is correct in our asset management systems and will have a visual condition assessment of conductor supporting repair / renewal decisions. The data will also factor into our conductor fleet asset health model.

This current preventive work on sub-transmission conductor is summarised below.

Table 7.16: Sub-transmission conductor preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Conductor clearance and basic condition observations assessment (in conjunction with pole condition assessments) – moving to new Overhead Inspection regime where conductor condition is assessed more specifically.	Five years
Targeted advanced inspections	Annual

We have identified preventive maintenance initiatives to improve the performance of our overhead conductor fleets. These initiatives primarily support our overhead conductor portfolio objectives in relation to safety and reliability.

Meeting our portfolio objectives – responsive to a changing landscape

There are many new or different technologies available today that we can use to improve our conductor condition assessment data. Given our historical under-investment in maintenance, now is the time to adapt as we progress towards a steady-state maintenance regime. Many of the initiatives use technologies that we have historically trialled but not fully embedded yet in our practices.

Table 7.17: Sub-transmission conductor preventive maintenance initiatives

PREVENTIVE MAINTENANCE INITIATIVES	RELATED PORTFOLIO OBJECTIVES	TIME-FRAME
Visual and thermal inspections of conductor and joints/connections RCA on ACSR conductor drops has revealed the primary cause as workmanship issues with joints. Conductor failures also occur due to visible condition issues E.g. broken strands, signs of clashing and general ageing. A medium-term initiative is to introduce thermal imaging of joints and connections alongside the visual assessment of conductor as part of the 5-year overhead feeder inspection programme.	Safety first – Visual inspections of conductor and thermal inspections of joints and connections will identify defects. This information can be used to drive investment to prevent asset failures. Reliability to defined levels – Reliability of our sub-transmission network is paramount given its criticality. These inspections will allow more difficult defects to be captured, E.g. joints and fittings. Affordability through cost management – The use of different technologies will provide increased data quality and allow for better asset management decisions.	Medium-term
Early Fault Detection System A trial is being initiated to install a continuous high frequency monitoring system on a sub-transmission and 11 kV distribution feeder. The technology will identify and locate micro arcing type events such as broken conductor strands, failing insulators and high resistance connection, enabling mitigation before failure. The feeders identified have poor access N security and reliability concerns.	Safety first – Continuous monitoring of known failure modes will allow identification of assets in the early stages of failure and between cyclic inspection periods. This information can be used to drive investment to prevent asset failures Reliability to defined levels – Reliability of our sub-transmission network is paramount given its criticality. The continuous monitoring will allow more difficult defects to be captured.	Short-term
LiDAR survey LiDAR inspections are identified as an opportunity to enhance data, particularly with vegetation management, but with future uses in network design and asset management. Further investigation and preparation is required to ensure we can utilise the survey results effectively.	Safety first – Identify vegetation and under-clearance safety risks in a timeframe appropriate with the risk. Sustainability by taking a long-term view – Landowner disruption can be minimised by conducting LiDAR survey and tree growth modelling.	Medium-term

Table 7.18: Distribution conductor preventive maintenance initiatives

PREVENTIVE MAINTENANCE INITIATIVES	RELATED PORTFOLIO OBJECTIVES	TIME-FRAME
Survey of distribution conductor We will progress the introduction of a routine survey of distribution conductor condition, with a focus on fittings and joint condition and type issues following a recent increase in failures. This has commenced and is being formalised as part of our new Overhead Inspection strategy. Inspections will be predominantly ground based. Areas not efficiently reached by vehicle	Safety first – Identifying condition, workmanship, and type issues before they fail prevents line down events and the subsequent safety issues. Affordability through cost management – Proactively finding and subsequently remediating conductor issues is more cost-effective than replacing upon failure.	Short-term

PREVENTIVE MAINTENANCE INITIATIVES	RELATED PORTFOLIO OBJECTIVES	TIME-FRAME
or by foot are to be undertaken from helicopter as per sub-transmission inspections.		

Corrective maintenance

Corrective maintenance on overhead conductor consists of activities such as repairs to conductor sections by cutting out damaged sections (where they are short) and adding in new sections with joints, replacing poor condition joints or those with type issues where possible, installing repair rods over defects if applicable, and replacement of other fittings due to condition or type issues. Any entire conductor sections replaced are capitalised.

Reactive maintenance

Reactive maintenance on overhead conductor includes responding to faults when conductor or fittings fail, or due to storms when vegetation falls onto the lines.

One factor to note with reactive maintenance on distribution conductor is that in some cases there is no visibility of this fault in our control room (this assumes the tee off fuse operates properly and there is no circuit breaker or recloser operation). Finding this type of fault relies on information from customers who do not have power, and contractor fault finding. Improvements we are making to our Advanced Distribution Management System (ADMS – our SCADA system) will help to predict fault locations and the fault outage impact based on information received from customers.

The case is similar for LV conductor where, assuming the LV fuse operates correctly and there is no operation of a high voltage circuit breaker or recloser, there is no visibility of this fault in our control room.

Spares

Conductor drums are kept at depots for our most common conductor types. Given that we have over 50 sizes and types of conductor on our network, it is not always possible to quickly obtain the exact conductor in all circumstances. In the event of a particular size not being available, we will put up a similar conductor to ensure continued reliable service. Due to the age and uniqueness of some of our conductor, we may not always be able to source spares of the exact same type and hence a suitable substitute is required. In some cases, a longer-term solution may be required after the initial fault response.

Conductor hardware such as fittings and joints are standard components, and our contractor maintains stock at strategic locations, and limited quantities are kept in fault response vehicles to enable fast return to service.

We are in the process of standardising conductor types for each network region (Central Otago and Dunedin) as each has different characteristics such as wind exposure and corrosion propensity. As non-standard conductor are replaced and phased out, we will require less hardware for fault response.

Standardisation will allow us to better control the number of conductor joints and fittings that we hold. If line crews have all components readily available, they will be able to repair failures more quickly with fewer returns to depots.

We are in the process of standardising joint types to ensure that mid-span joints are not installed unless they can withstand full tension, and to be able to identify and resolve workmanship issues more easily. We will also keep abreast of new products in the industry that are easier to install and last longer. These will be assessed under our New Equipment or Material Assessment (NEMA) process of asset approval before (if successful) being added to our standard material list for approved use on our network.

7.7.3. Underground Cables

Preventive maintenance

We undertake little to no invasive maintenance work on cables. Preventive maintenance involves regular inspections and testing to assess the condition of the asset. Gas and oil-filled cables require additional inspection and testing measures due to the required pressurisation and fluid storage systems. Our preventive maintenance regime for sub-transmission cable assets is summarised below. Detailed testing requirements for each type of asset are set out in our maintenance standards.

Table 7.19: Sub-transmission cable preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Ground based visual inspections of cable terminations (to identify deterioration such as fluid leaks or signs of rust that could lead to future failure)	One year
Oil and gas-filled pressure tests (for early detection of leaks)	Two weeks
Alarm tests to confirm condition of alarms	Six months
Oil and gas-filled outer sheath electrical integrity testing	One year
On line partial discharge testing	Three years

We continuously monitor fluid-filled sub-transmission cable pressures via SCADA alarms.

Outside of zone substations, sections of distribution cable commonly join assets: RMUs to other RMUs; cable network sections to overhead network sections; or supply ground mounted transformers off the overhead network. RMUs may act as switching points in the network or as switching points plus tee off points for distribution transformers. Due to the tight interrelationship between these assets, we group together some of their maintenance and inspection activities.

As per sub-transmission cables, we undertake little-to-no invasive preventive maintenance work on distribution cables. Our preventive maintenance regime for distribution cable is summarised below.

Table 7.20: Distribution cable preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Inspect cable risers for any obvious defects	Five years (during pole inspections)
Clean dry type cable terminations on RMUs and distribution transformers during RMU maintenance (where cable boxes are not fluid/compound filled)	Six years (oil-filled RMUs)
Insulation resistance and polarisation index of distribution cables – during RMU maintenance	Six years (oil-filled RMUs)

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Clean dry type cable terminations on zone substation circuit breakers- during zone substation maintenance (where cable boxes are not fluid/compound filled)	Four years

We do not undertake any material LV cable preventive maintenance. We do, however, assess LV cable terminations when inspecting connected assets. We clean LV terminations when they are disconnected and accessible during maintenance for other equipment.

Our preventive maintenance regime for our LV cable assets is summarised below. The detailed task instructions for each type of asset are set out in our maintenance standards.

Table 7.21: LV cable preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Inspect visible LV cable and terminations	Five years (during pole inspections) During LV enclosure inspections During ground mounted transformer inspections
In addition to visual inspection, clean LV cable terminations	During oil-filled RMU maintenance, where the associated ground mounted transformer is on the same site and is de-energised

Corrective maintenance

Defects works for sub-transmission cables include replacement of joints and terminations. Corrective tasks include sheath or termination repairs to minimise deterioration or in the event of an oil leak, as well as corrosion treatment/painting on terminations and ancillary cable equipment. Components such as gauges and alarm contacts on cable ancillary equipment may also need repair or replacement. We are in the process of implementing a corrective maintenance initiative, as described below.

Table 7.22: Sub-transmission cables corrective maintenance initiatives

CORRECTIVE MAINTENANCE INITIATIVES	RELATED PORTFOLIO OBJECTIVES	TIME-FRAME
Rectify backlog of cable corrective maintenance We have identified a backlog of corrective work on our sub-transmission oil pressurised cables. Terminations require repair in some cases for leaks, and corrosion control/painting at aerial ends including cable stands. An oil leak on one of the Corstorphine cables was repaired in 2022	**Affordability through cost management** –These cables have generally been reliable and investing in maintenance now should ensure that they meet their expected lives. **Reliability to defined levels** – Forced/fault outages from running these types of cables to failure will be very long because the skills required may not be available locally. Hence when defects are found, fixing them proactively is preferred from a reliability and cost perspective.	Short-term

Distribution cable defect works include replacement joints or terminations, which are commonly driven by failed insulation resistance tests.

Reactive maintenance

Reactive maintenance on underground cables includes all work required to return the circuit to service following a fault, whether the fault was unforced (the cable failed because of an inherent issue) or forced (the cable failed due to third-party interference, E.g. digger through cable).

Locating and repairing cable faults can be substantially more expensive and take considerably longer than repairing faults on overhead lines. This is exacerbated by the need for specialist resources, which often must be flown in to assist with fault finding or repairs.

We undertake post-fault root cause analysis for sub-transmission cable failures, which enables us to identify if end-of-life failures are occurring.

For LV cable faults, one notable difference with reactive maintenance is that there is no visibility of the fault in our control room. This is regardless of where the fault occurs on the LV cable and assumes the LV fuse operates properly and no operation of a high voltage circuit breaker or recloser occurs. LV fault finding relies on information from customers who do not have power, and contractor fault finding. Improvements we are making to our Advanced Distribution Management System (ADMS – our SCADA system) will help to determine LV fault locations and the LV fault outage impact based on information received from customers.

Spares

We retain spares to manage the risk associated with our sub-transmission cable fleet. We are experiencing some problems with procuring replacement spares for some of the older cable accessories and terminations on the PILC (solid) sub-transmission cables, as well as the gas- and oil-filled cables. Spares for gas-filled cables are difficult to source; we have supplies in our stores, but their condition is not optimal. Oil-filled cable spares are available for purchase, although they are difficult to source reliably. These issues will be ultimately resolved by replacing aged sub-transmission cable with modern equivalents in coming years.

XLPE cables are current technology and are fully supported. Standardisation of XLPE cable sizes will help to limit the variety of spares and accessories that we are required to store.

For our distribution fleet, standardisation of XLPE cable sizes and the use of cable accessories which can be used across a range of cable sizes, will help limit the different types of spares we need to hold.

7.7.4. Zone Substations

Preventive Maintenance

Our preventive building and grounds works are summarised below. Detailed condition inspections are undertaken by suitably qualified personnel to identify defects, which then support corrective maintenance activity works.

Table 7.23: Buildings and grounds preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Substation grounds maintenance; lawn mowing, weed management, security inspections	Two weeks
Substation monthly inspection; checklist followed to record issues sighted, includes alarm checks, etc.	One month
Ripple injection CO2 system and fire mitigation system checks/tests	One year, pressure test every five years
Fire system checks/tests	One year
Earth grid testing	Five years

Preventive work on our power transformers is summarised below. Detailed inspection regimes are set out in our maintenance documentation.

Table 7.24: Power transformer preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Oil level recordings (most are also reported to SCADA)	One month
Ground level inspection to identify apparent defects in the tank/pipework including oil leaks, check thermometer, ensure pumps and fans are operating correctly and record tap changer cyclometer	One month
Dissolved gas analysis to identify the presence of internal faults	One year
Oil quality and furan analysis to evaluate the rate of transformer ageing	Four years
Transformer out-of-service maintenance; detailed close visual inspection of bushings, pipework, and systems. Electrical insulation and resistance tests. Confirm correct operation of cooling systems.	Four years
Tap changer maintenance; occurrence based on either a time period or a set number of operations, to ensure continuing operation and reliability of tap changer.	Manufacturer recommended, variable according to tap changer type

Table 7.25: Power transformer preventive maintenance initiatives

PREVENTIVE MAINTENANCE INITIATIVES	RELATED PORTFOLIO OBJECTIVES	TIME-FRAME
Enhanced power transformer testing We have implemented an enhanced testing regime to improve the extent of condition and performance information used to inform assessments of remaining useful life. This will be implemented by AH rating and will be a multi-year programme.	**Affordability through cost management** – greater confidence in our assessment of condition and subsequently risk associated with end-of-life assets, that are critical to the network.	Short-term

Preventive work on indoor switchgear is summarised below, with detailed regimes set out in our maintenance standards

Table 7.27: Indoor switchgear preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Visual inspection of circuit breakers including cyclometer readings	One month

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Thermography, partial discharge and acoustic tests	One year
Oil circuit breaker maintenance; restore condition of circuit breaker contacts and insulating oil. Maintain/lubricate operating mechanism. Confirm correct operation of system. Prevent corrosion. Electrical condition assessment is undertaken	Four years
Vacuum/SF_6 circuit breaker maintenance; maintain/lubricate operating mechanism. Confirm correct operation of system. Prevent corrosion. Carry out electrical condition assessment. Contact gap measurements as specified by vendor (may be less often than four yearly)	Four years

Post-fault testing and maintenance are also carried out for oil circuit breakers after three fault operations.

We have identified a preventive maintenance initiative to improve the performance of our indoor switchgear fleet as set out below. This initiative supports our safety and reliability objectives.

Table 7.28: Indoor switchgear preventive maintenance initiatives

PREVENTIVE MAINTENANCE INITIATIVES	RELATED PORTFOLIO OBJECTIVES	TIME-FRAME
Post fault zone substation oil circuit breaker servicing Historically OCBs (Oil Circuit Breakers) have not been maintained systematically after a determined number of faults. We are now undertaking this activity in line with good industry practice.	**Safety first** – Ensuring OCBs are in operable condition is paramount, as maloperation can lead to explosion and oil fire. **Reliability to defined levels** – A potential maloperation of an OCB at a zone substation will have a significant reliability impact. In the worst case, collateral damage to the rest of the switchboard would cause an extended outage to a wide number of customers.	Ongoing

Our preventive outdoor switchgear works are summarised below. The detailed regime for each activity is set out in our maintenance standards.

Table 7.29: Outdoor switchgear preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Visual inspection of circuit breakers including cyclometer readings	One month
Thermography, partial discharge and acoustic tests	One year
Oil circuit breaker maintenance; restore condition of circuit breaker contacts and insulating oil. Maintain/lubricate operating mechanism. Confirm correct operation of system. Prevent corrosion. Electrical condition assessment is undertaken.	Four years
Vacuum/SF_6 circuit breaker maintenance; maintain/lubricate operating mechanism. Confirm correct operation of system. Prevent corrosion. Carry out electrical condition assessment. Contact gap measurements as specified by vendor.	Four years
Air-break switch maintenance; identify visually apparent defects, diagnostic testing, operational checks, check cement (two piece) cleaning, minor repairs.	Four years

Post fault testing and maintenance are also carried out for oil circuit breakers after three fault operations.

We have identified the following initiative to improve the performance of the outdoor switchgear fleet. This initiative supports our safety and reliability objectives.

Table 7.30: Outdoor switchgear preventive maintenance initiatives

PREVENTIVE MAINTENANCE INITIATIVES	RELATED PORTFOLIO OBJECTIVES	TIME-FRAME
Post fault zone substation oil circuit breaker servicing Historically oil circuit breakers have not been maintained systematically after a predetermined number of faults. We are now undertaking this activity in line with good industry practice.	**Safety first** – ensuring OCBs are in an operable condition is paramount, as maloperation could lead to explosion and oil fire. **Reliability to defined levels** – maloperation of an OCB at a zone substation can have a significant reliability impact, from an outage until switching occurs to wider damage causing an extended outage.	Ongoing

The table below sets out preventive maintenance tasks for ancillary equipment.

Table 7.31: Ancillary zone substation equipment preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Outdoor structure and buswork visual inspection (at monthly zone substation inspection)	One month
317 Hz / 1050 Hz ripple plant visual inspection (at monthly zone substation inspection)	One month
Local service system visual inspection (at monthly zone substation inspection)	One month
1050 Hz ripple plant maintenance	Four years
317 Hz ripple plant inspection and maintenance	One years
Mobile substation full maintenance	Four years
Mobile substation checks and roadworthiness	Six months

Corrective Maintenance

Corrective maintenance involves remediating defects such as graffiti, damaged fences, and broken gutters, as well as proactive corrective work such as painting. As part of our effort to improve our asset management approach, we have identified a corrective maintenance initiative in the buildings and grounds fleet. This initiative primarily supports our portfolio objectives regarding affordability.

Table 7.32: Buildings and grounds corrective maintenance initiatives

CORRECTIVE MAINTENANCE INITIATIVES	RELATED PORTFOLIO OBJECTIVES	TIME-FRAME
Buildings and grounds corrective maintenance uplift We have a backlog of building and grounds maintenance to undertake at our substations. Historical surveys by tradesmen have been undertaken. Any issues found are remediated during seismic upgrades or future upgrade or renewal work at the site. Seismic work is complete for sites where there is no major project work planned in the short-term. We have completed outstanding painting in Central Otago and are transitioning to Dunedin.	**Affordability through cost management** – Undertaking remediations on buildings reduces overall cost-of-ownership.	Short-term

Power transformer defects such as rust repairs, oil leak repairs or replacement of seized fans, are dealt with under corrective maintenance. Some minor works may be undertaken while conducting the four-yearly out-of-service maintenance.

To improve fleet performance, we have identified a corrective maintenance initiative. This initiative supports our affordability objective.

Table 7.33: Power transformers corrective maintenance initiatives

CORRECTIVE MAINTENANCE INITIATIVES	RELATED PORTFOLIO OBJECTIVES	TIME-FRAME
Zone substations transformer painting We will paint transformers older than 20 years in the Dunedin network that have been assessed as requiring corrosion control. Painting will be completed in Dunedin in RY23 before we transition to Central Otago.	**Affordability through cost management** – Painting transformers before they pass the point of disrepair can reduce overall cost-of-ownership.	Short-term

Indoor switchgear defects identified during inspections and maintenance are dealt with under corrective maintenance. An example includes replacing insulating washers on current transformers that have failed insulation resistance tests. The fitting of barriers to prevent access to sides and rear of non-arc fault contained switchboards is also a corrective maintenance activity. Outdoor switchgear defects are dealt with under corrective maintenance. An example includes treating corrosion on an outdoor circuit breaker stand.

For ancillary equipment, corrective maintenance requirements include painting and corrosion control work on structures. We have spare 1050 Hz ripple plant equipment from plants already decommissioned. We have redundancy with some of our 317 Hz ripple plant equipment, which mitigates the risk of a fault impacting on performance. We do, however, need to procure additional spares for key 317 Hz ripple plant components.

Reactive Maintenance

Reactive maintenance on buildings is limited. Typical examples include responding to security alarms or reports of intruders. Additionally, reactive first response to any issues such as weather damage or water ingress, broken windows, a burst water pipe, or response to fire alarms.

Reactive maintenance on power transformers may be required due to minor issues or major failures. Minor issues may include attending to alarms where the issue was either a false alarm or the cause of the alarm can be attended to later as corrective maintenance. Major transformer failures may require a contingency response, subject to whether the site is N or N-1 security; if N security, the response depends on the amount of load that can be restored by reconfiguring the network. Our mobile substation may be mobilised and connected, or diesel generation may be required at N security sites. Given the lead time of approximately one year to procure a permanent replacement power transformer, a spare transformer may need to be installed in a semi-permanent arrangement.

Reactive maintenance on indoor and outdoor switchgear occurs in response to switchgear alarms received at the control room, maloperation or failure. On-site inspection is required for all cases, with further action determined, subject to the findings.

Spares

We have a 66-33/11-6.6 kV mobile substation (5 MVA at 11 kV and 3 MVA at 6.6 kV) available to connect to several of our N security zone substations. We also have a spare 33/11 kV, 5 MVA transformer which can provide longer-term coverage should a transformer fail. It can also be used as temporary cover if the mobile substation is in use.

For our larger zone substation transformers, we currently do not have a spare transformer. However, these are usually N-1 capacity, which means that they would not be impacted if only one of the two transformers became unavailable. Once two current renewal projects are completed, we will have four 15 MVA available, and their viability for use as a spare will be determined. We have had two larger, mid-life, zone substation transformers released from other sites (where they are no longer providing the right level of service) that will be redeployed to two nominated sites, resulting in enhanced reliability for those sites. Any transformer that is re-deployed receives a full health check or overhaul, prior to doing so. This includes a detailed assessment of condition, and evaluation of remaining service life under new operating conditions. We plan to create contingency plans for each transformer, and through this analysis we will consider future procurement of a larger strategic spare transformer among other risk mitigation options.

Box 7.3: Improvement Initiative – transformer contingency plans

We will create transformer failure contingency plans for each site so that in the event of a failure, predetermined plans can be followed to ensure a smooth incident response and restoration of service level. This initiative will help us meet our reliability portfolio objective.

The development of contingency plans has progressed, with the completion of our network power flow model. We expect to finalise this contingency analysis work in RY24.

When transformers are decommissioned, spare parts are retained if they can be utilised by other units on the network. Examples are bushings and tap changers. Our standardisation of transformers and major components will make spares holdings simpler going forward.

We have limited spares for our oldest indoor switchboards, although we do have spare circuit breakers for some of our more common middle-aged indoor switchboards. Many bespoke switchboards have no spares, and we are planning to conduct a review once a full stocktake of spares is complete. Once the review is complete, some additional spares may be purchased, and contingency plans developed. When switchgear is decommissioned, some spare parts will be retained if they are applicable to other assets remaining in service.

We have spare 11 kV and 33 kV outdoor circuit breakers. We have no spare 66 kV circuit breaker but are in the process of purchasing two second-hand spares. Similar to indoor switchgear, we plan to undertake a stocktake and review of all spares and develop a contingency plan for purchase and retention.

7.7.5. Distribution Switchgear

Preventive Maintenance

Unlike many of our other assets, oil-filled ground mounted switchgear requires regular invasive maintenance to retain its condition. We have now embedded a full maintenance routine in addition to inspection activities. Our preventive works are summarised below.

Table 7.34: Ground mounted switchgear preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Partial discharge wand checks prior to removal from service. Check fuse carriers/ racks, replace fuse contacts if dislodged/cracked, full oil change/silting, flushing tank with clean oil, test oil dielectric strength, moisture content, and oil acidity.	Six years (oil-filled RMUs/switches)
Partial discharge wand checks, SF_6 gauge checks, visual inspection.	10 years (SF_6)
Testing of protection on RMUs with a circuit breaker, metering, along with visual out of service inspection as per above.	To be determined
DC testing of RMUs with protection/battery.	One year
LV boards inspections.	With associated ground mounted transformer inspection
Indoor high voltage switchboard maintenance.	Four years

Our preventive tasks for pole mounted fuses are summarised below.

Table 7.35: Pole mounted fuse preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Visual inspection of fuses for corrosion, defects and gathering of type information.	Five years (OH Inspections)
Thermography of HV and LV transformer fuses.	During distribution transformer inspections

We are beginning to undertake inspections on pole mounted switches to inform remediation decisions. Once we have gathered sufficient information, we will work to clear the backlog of maintenance and renewals required and form a steady-state maintenance plan. The maintenance interval is likely to vary based on factors such as corrosion zone and number of operations.

Table 7.36: Pole mounted switches preventive maintenance tasks

PREVENTIVE MAINTENANCE INITIATIVES	RELATED PORTFOLIO OBJECTIVES	TIME-FRAME
ABS inspection and maintenance Restart inspections and servicing to ensure these assets continue to operate as intended and remove operating restrictions in the network, remove the risk of switches failing upon operation.	**Safety first** – operable ABS ensures safe operation for our contractors. **Reliability to defined levels** – having operable ABS will help us meet our reliability objectives.	Short-term Programme to start in RY23

Historically, many of our LV enclosures have not been formally inspected. Once we have completed the first round of inspection on all enclosures, we will work to clear the backlog of maintenance and renewals required and form a steady-state maintenance plan. The inspection interval is likely to vary based on factors such as public safety criticality zone.

Table 7.37: LV enclosures preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
LV enclosure inspection and minor repairs as/if required	Six years

Reclosers require material preventive maintenance activities, as summarised below. Much of this maintenance has not been performed historically.

Table 7.38: Recloser preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Visual inspection, thermographic testing.	One year
Maintenance service – test protection, rectifier, SCADA points, bypass checks, check settings, adjust settings if required, replace battery.	Four years

For ancillary distribution substation equipment, our preventive works are summarised below.

Table 7.39: Ancillary distribution substation equipment preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Underground substation electrical equipment inspection/maintenance.	As per individual fleet assets
Underground substation inspection and clean-up including confined space gas checks, equipment inspections, cleaning up of any debris that has passed through the street level grill, alarm checks.	Six months
Distribution earth testing on all assets with earths.	Six years

We are undertaking a new maintenance activity for ancillary equipment as set out below.

Table 7.40: Ancillary distribution substation equipment preventive maintenance initiatives

PREVENTIVE MAINTENANCE INITIATIVES	RELATED PORTFOLIO OBJECTIVES	TIME-FRAME
Distribution surge arrester inspections As NERs have been installed, many surge arresters are now below the required rating, and an increase in failures is being experienced. Inspections are to ensure that no flash overs have occurred, that unventilated types are identified, and that the surge arrester installed is of adequate rating.	**Safety first** – Unvented porcelain surge arresters can explode when operating, causing a safety hazard. **Reliability to defined levels** – Having equipment on the network that is not adequately rated for the voltage may be subject failure, causing cascade faults.	Short-term

Corrective maintenance

We are proactively filling busbar extension boxes with Guroflex on ABB-SD units, and retrofitting un-extended end boxes with a new end box that is Guroflex-filled, to reduce the risk of flashover.

Any workshop-based activity is covered under corrective maintenance, along with other activities such as graffiti removal, padlock replacement, and fibreglass ‘package’ cover repair or replacement.

> **Meeting our portfolio objectives – reliability to defined levels**
> Tilted RMUs of 2.5° or more are classified as Do Not Operate equipment which reduces the operability of our network. Tilted RMUs can generally be remediated via a corrective maintenance procedure rather than replacement, which provides a cost-effective solution to improve the reliability performance of our network.

At present we only undertake simple repairs in-situ on pole mounted switches.

Corrective maintenance on LV enclosures includes activities such as replacing fuses or re-terminating LV cables that show signs of overheating, replacing seals, remounting plastic lids when dislodged, renewing or applying labels, fixing earths, and shrouding exposed live terminals inside the enclosure. We are planning a new maintenance activity as described in the following table.

Table 7.41: LV enclosures corrective maintenance initiatives

CORRECTIVE MAINTENANCE INITIATIVES	RELATED PORTFOLIO OBJECTIVES	TIME-FRAME
Legacy metal service pillar cover replacements A safety risk exists with some types of legacy metal service enclosures where the fuse is close to the metal cover and has a risk of becoming live in a malfunction. For all known sites P160 metal Lids have been replaced with plastic covers. We continue to respond accordingly when inspections identify any existing metal Lids.	**Safety first** – We must remediate a known failure mode in a legacy LV enclosure that does not meet 'safety by design' requirements.	Short-term This programme is largely complete

Recloser corrective maintenance consists of activities such as adjusting settings outside of preventive maintenance activities due to network changes, and fixing communication problems.

Underground substation corrective maintenance consists of work on the transformer and switchgear, plus remediation of issues regarding structural integrity, access, or fire and flooding alarms. Surge arresters are 'maintenance-free' items, but their earthing connections may need remediation if found to be installed with a copper bar that prevents the base from blowing off. Distribution earths will need corrective maintenance remediation if their resistance level is too high or if the earth connection is found to be inadequate.

Reactive maintenance

The most common reactive activity for ground mounted switchgear is replacement of fuses after fault clearance. Other faults may lead to a long outage or reduced network security as it is repaired or swapped for another unit.

Pole mounted fuses are replaced when they blow to clear faults. If the fuse is one of our EETEE types, the entire fuse assembly has to be replaced as no cartridges are available.

If an ABS or HV link fails, the likely course of action to swiftly restore consumer supply is to conduct major maintenance work. The task involves either opening the switch and reconfiguring the network or removing the switch or installing jumpers to short it out, before fixing or replacing the switch under non-fault conditions.

The most common cause of LV enclosure faults is vehicular damage. If this leads to a fault, or a pillar is found in a state that it cannot be safely left as is, work is carried out under reactive maintenance.

Faults may occur in the recloser controller or communication system, or in the primary device itself. Depending on the fault, it may be fixed on site or a spare unit may be used to swap out faulty parts. If the primary device itself faults, a unit swap will always be required.

Faults in underground substations require close management due to the nature of the confined space. Additional failure modes include flooding of the substation and responding to audible alarms called in by the public. Our underground substations are not SCADA connected. Audible alarms sound in the event of fire or elevated water level (E.g. sump pump failure), and the street level grill has contact information and instructions for the public to call should an alarm be heard.

Spares

Our oil-filled ground mounted switchgear types are obsolete and have no original equipment manufacturer spares support. We operate a rotatable spares pool for our oil-filled ground mounted switchgear to help mitigate this spares risk. When units are removed from service, we assess whether they should be reconditioned or scrapped. Refurbished units are returned to the pool. We retain strategic spares for items with long lead times or which are not part of our standard inventory (orphan spares). We hold new spares for our SF_6 RMUs.

Spare fuse cartridges and wires, as applicable, are kept in fault response vehicles. Stores also stock adequate spares or like-for-like modern equivalents. We have no legacy EETEE fuse cartridges in stock. We have spare JW fuses so replacement of the entire assembly on these is reserved for planned works.

We maintain a spares pool of reclosers should a reactive replacement be required.

The electrical equipment in our underground substations is common to above ground substations, so spares are available. We hold stock of spare surge arresters.

7.7.6. Distribution Transformers

Preventive maintenance

We undertake little invasive preventive maintenance on ground mounted distribution transformers. Preventive maintenance primarily involves inspections to verify visible and audible condition issues. We are still gathering data and formulating a steady-state inspection strategy for our ground mounted distribution transformers. Subject to combined analysis of this data, and consideration of integration with other inspection regimes E.g. RMUs, we will formulate our steady-state inspection frequency under the maintenance strategy for this fleet. We will consider introducing tests such as DGA/oil testing on larger ground mounted transformers if the results provide worthwhile information.

Table 7.42: Ground mounted distribution transformer preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Inspection activity / condition assessment – assess corrosion/oil leaks, evaluate enclosure/cover integrity, assess locks/security, consider noise, partial discharge, visual inspection of earths, read MDIs Additionally, we will be creating major maintenance programmes for selected larger rated ground mounted transformers whilst noting their impact on customers served, electrical connectivity i.e. tying feeder-circuits, and public and personnel safety risks.	To be determined subject to analysis. When RMUs co-located with ground mounted transformers are inspected
Air filled cable box inspections and termination cleaning.	When RMUs co-located with ground mounted transformers are inspected
Additional MDI reads.	Ad-hoc as required

Preventive maintenance on pole mounted transformers primarily involves inspections to verify visible, thermography (hotspots), and audible condition (PD) issues. Our current preventive works are summarised below, showing that we currently only do cyclic inspections as part of pole inspections.

Table 7.43: Pole mounted distribution transformers preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Noting of obvious pole mounted transformer defects during pole inspection E.g. significant oil leak, noting hotspots from thermography, corroding pole/platform supports.	Five years

We have identified a preventive maintenance initiative to improve the performance of the fleet. This will primarily support our affordability objectives.

Table 7.44: Pole mounted distribution transformers preventive maintenance initiatives

PREVENTIVE MAINTENANCE INITIATIVES	RELATED PORTFOLIO OBJECTIVES	TIME-FRAME
Pole mounted distribution transformers inspections We plan to commence collection of condition and other relevant data by undertaking specific inspections We have introduced a five-year inspection cycle with the first cycle due to be completed in RY25.	**Affordability through cost management** – better asset management decisions using more complete condition data.	Short-term

Compared to other distribution transformers, voltage regulators require significantly more preventive maintenance. This is because they have moving mechanical parts in the OLTC, plus additional control and communication systems in most cases.

Table 7.45: Voltage regulator preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Visual inspection, thermographic testing, tap changer operation, communications checks.	One year
Maintenance service – to ensure continuing operation and reliability.	Six years, depending on loading, or 100,000-120,000 operations

Mobile distribution substations contain elements of a typical distribution substation and hence their maintenance is multifaceted. Items to note include regular testing of flexible cables and additional requirements of vehicle servicing and roadworthiness.

Table 7.46: Mobile distribution substation and generator preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Mobile substation inspection, testing and maintenance including activities such as cable tests, COF, vehicle servicing	Six months
Mobile substation inspection upon return from service	Whenever returned from service
Mobile generator inspection to confirm operability and condition	Prior to use and after use
Mobile generator full service	Every 500 hours of use
Standby generator inspection to confirm operability and condition	One month
Standby generator oil and coolant testing	Six months

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Standby generator full service (engine heaters keep engine at temperature 24/7)	Four to six years

Corrective maintenance

Corrective maintenance includes clearing of rubbish, debris, and vegetation from the site, replacing locks, addressing security issues as required, graffiti remediation, and on-site transformer repairs.

Generally, it is impractical to carry out significant repair work such as repairing oil leaks on-site. It often requires swapping the transformer out for a similar spare transformer, which may already have been refurbished; both these activities are included in corrective maintenance.

For pole mounted distribution transformers, corrective maintenance is limited. Significant repair work such as repairing oil leaks is impractical on site, therefore we may swap out the unit for a similar spare transformer, which may already have been also refurbished.

Voltage regulators are removed from service based on the number of operations and condition, and replaced with units from the spares pool. Corrective maintenance also covers the costs of servicing/overhaul of removed from service units, where determined economically viable.

Rust treatment and minor repairs have been periodically required on the mobile distribution substations. There are no other significant items to note based on the substation components of these mobile substations.

Reactive maintenance

The most common reactive maintenance activity is replacement of fuses after fault clearance, where the fuses are contained within the transformer cable box(es). Any internal transformer faults or significant vehicular impact will require a new transformer.

Any pole mounted transformer faults will generally necessitate a transformer swap, whether from older like-for-like spares or an as-new spare.

Faults may occur in the voltage regulator controller or communication system, or in the voltage regulator itself. Depending on the fault, it may be fixed on-site or spare units may be used to swap out faulty parts. If the voltage regulator itself faults, a unit swap will always be required.

Spares

We hold spares of new ground mounted transformers based on our standard sizes, and spares of legacy units as required. Units that are swapped out under corrective maintenance are assessed for whether refurbishment is cost-effective and whether existing spares holdings are sufficient.

We hold spares of new pole mounted transformers based on our approved standard sizes, and few spares of legacy units. We assess whether it is cost-effective to refurbish units that are swapped out or decommissioned as part of pole removal, and whether additional spares holdings are needed.

We maintain a rotatable spares pool for voltage regulators. If it is economic to do so, removed units are serviced and returned to the spares pool. Otherwise, they are disposed of, while retaining components as spare parts as needed. This approach requires monitoring and adding to inventory at times so that enough spares are always available.

There are a range of different types and sizes of voltage regulators. We will phase out assets where there is limited stock, which will address the issue of a lack of interchangeability of 'orphan' assets.

Our mobile distribution substations use equipment common to our other network equipment, so spares are available. The cables are a special flexible type and are replaced if they fail testing. We will find it increasingly hard to get parts for the trucks, given their old age. Mobile and standby generator spares are covered by our contractual servicing arrangements.

7.7.7. Secondary Systems

Preventive maintenance

We regularly inspect and test our protection assets to ensure they will operate reliably in response to a fault. Electromechanical relays require detailed inspections and testing. In contrast, numerical relays, though more complex, often self-diagnose outside of inspection intervals. Our approach is summarised below, with detailed regimes set out in our maintenance standards.

Table 7.47: Protection system preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Routine testing of all relays to ensure proper operation of the protection system in entirety including communications (via RTUs)	When associated primary equipment released for servicing; generally four years

We have identified a preventive maintenance initiative to improve the performance of the fleet.

Table 7.48: Protection systems preventive maintenance initiatives

PREVENTIVE MAINTENANCE INITIATIVES	RELATED PORTFOLIO OBJECTIVES	TIME-FRAME
Increased electromechanical and static relay maintenance We will test these relays more regularly to ensure calibration is maintained. We have halved the test interval to two years.	**Safety first** – finding defective relays is paramount to ensure protection will clear faults as designed. **Affordability through cost management** – it is not possible to cost-effectively advance the protection renewal programme further.	Complete/ ongoing

Meeting our portfolio objectives – safety first and affordability through cost management

Our plan for electromechanical relay renewal will run throughout the planning period. To mitigate safety risk in the interim, we have halved the test interval for these relays to ensure calibration is maintained, and defective or deteriorating components are identified in an appropriate timeframe.

Maintenance of our batteries and DC systems is primarily preventive. Battery bank checks help us to maximise the performance and service life of the batteries and ensure we know when our batteries are reaching the end of their useful life. Our preventive maintenance regime is summarised below, and set out in detail in our maintenance standards.

Table 7.49: DC systems preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Battery bank and charger tests	One year
Battery bank and charger visual inspections	One month during zone substation inspections

Maintenance of our RTUs is primarily preventive. Testing of all RTU points is undertaken as part of our zone substation maintenance procedures.

Table 7.50: RTU preventive maintenance activities

MAINTENANCE AND INSPECTION TASK	STEADY-STATE FREQUENCY
Routine testing of all RTU points to ensure proper operation in entirety including communications bearers	When associated primary equipment released for servicing; generally every four years
Visual inspection	One month during zone substation inspection

Corrective maintenance

Corrective maintenance on protection systems is limited. Minor changes to protection relay settings that arise from protection reviews will be undertaken as part of corrective maintenance.

Battery cell failures are usually identified during routine inspections or occur during diagnostic testing. Failed cells are replaced immediately upon discovery.

Corrective maintenance on RTUs is limited. Modules or entire RTUs (if non-modular) are replaced with a spare unit (corrective maintenance) if they are found to be faulty during testing.

We do not undertake specific maintenance on our meters. For check meters, a metering issue would be evident if our set of data deviated from Transpower's.

Reactive maintenance

Reactive maintenance on protection relays consists of activities such as callouts for alarms, gathering data from relays to assist fault analysis, and responding to relays that fail in service.

Reactive maintenance on DC systems involves responding to alarms as required; for example, temperature alarms, or responding to a DC system failure.

Reactive maintenance on RTUs involves responding to alarms as required. For example, loss of power supply or a communications error. Reactive replacement of RTU modules will be required if they fail in service.

Spares

We retain spare relays in three locations around our networks. For each relay type and model, we usually hold two to three spares. When new types or models are introduced, spares are also purchased. We hold some spares for our electromechanical relays, although new spares are difficult to source. As we introduce new relays, we plan to retain the older units as spares. We do not have any spares for our static relays, and they are no longer available. If a static relay fails, our present policy is to replace it with a numerical relay.

We do not maintain spare batteries as their capacity degrades overtime, and our stores do not have the required temperature controls to maintain them in good condition. Our arrangements with suppliers generally enable access to replacement cells at short notice. We do have a standby battery bank, which is used during maintenance and can provide contingency coverage. We have spare charger coverage and plan to keep 48 V, 24 V and 12 V converters in stock.

Where manufacturers notify us that they are going to discontinue support for specific RTU hardware, we manage the risk of unplanned failures through stocking up of spare parts.

We maintain spares for both fixed and modular types of RTUs. We have sufficient input/output modules in stock for various applications. The lead time to order a replacement RTU is usually relatively long, but often a supplier is able to provide one off the shelf. RTUs that are retrieved from renewal projects are disposed of unless they comply with the DNP3 protocol over TCP/IP standard.

8. RENEW OR DISPOSE

As discussed in Chapter 5, we manage our network fleets using an asset lifecycle approach. The figure (right) depicts the four lifecycle stages within our asset management system. The previous chapter outlines the inspection and maintenance activities performed for each asset fleet. This chapter describes how we plan to replace assets as they near the end of their useful life.

This chapter describes each of our asset fleets in terms of age, condition, performance and risk. The information forms the basis of our fleet strategies that inform our planned renewal expenditure over the AMP planning period.

Points to note on the content in this chapter are set out as follows:

- all technical and quantity statistics are accurate as of 31 March 2022 (unless specified otherwise)
- for explanations of modelling approaches, including our definitions of risk and asset health indices (AHI), please see Chapter 5
- when setting out the timing of future initiatives, we use the following periods: short-term (presently underway), medium-term (within 1-2 years), and long-term (within 1-4 years)
- this chapter is structured based on our internal categorisation of renewal portfolios and asset fleets. See Table 8.1 below.

Implementing our asset risk review

For each of our portfolios we have developed a risk model based on the critical network risk of public safety. Where critical risk evaluation is not applicable or unavailable, we continue to rely on existing asset health indices as a proxy to likelihood of failure when evaluating replacement need.

Table 8.1: Our asset portfolios in relation to Information Disclosure categories

PORTFOLIO	ASSET REPLACEMENT AND RENEWAL INFORMATION DISCLOSURE SCHEDULE
Support Structures	Included in 'Sub-transmission' and 'Distribution and LV Lines'
Overhead Conductor	Included in 'Sub-transmission' and 'Distribution and LV Lines'
Underground Cables	Included in 'Sub-transmission' and 'Distribution and LV Cables'
Zone Substations	Included in 'Zone Substations'
Distribution Switchgear	Included in 'Distribution Switchgear', Cf. LV enclosures in 'Distribution and LV Cables', ancillary distribution substation assets in 'Distribution Substations and Transformers'
Distribution Transformers	Included in 'Distribution Substations and Transformers', Cf. mobile generators in 'Other Network Assets'
Secondary Systems	Included in 'Zone Substations'

8.1. SUPPORT STRUCTURES

This section describes our support structures portfolio and summarises how we manage the following two asset fleets:

- poles
- crossarms

Portfolio Summary

We proactively replace poles and crossarms based on condition, with the medium-term work volumes forecast based on survivor curve and Repex modelling respectively.

W expect annual expenditure on support structures to keep relatively stable throughout the planning period, with an overall average of around $23m per annum.

It is critical that we continue to address the backlog of poor condition poles and crossarms to support our safety and reliability objectives. Failure of a support structure (or component of) can significantly impact our performance in these areas.

Poles and crossarms are key components of our network. These assets provide sufficient clearance for our overhead conductor to safely supply electricity to consumer connections. Support structures also support distribution transformers, air-break switches, and third-party assets such as streetlights, communication assets and road signs.

Adequate performance of support structure assets is essential to maintain a safe and reliable network. Asset failure can have significant consequences in terms of network safety and reliability. Most of our overhead network is accessible to the public, so managing our support structures is also critical to ensure public safety, particularly in urban areas.

Box 8.1: Summary of our asset risk review – support structures

Issues: our critical risk associated with support structures includes significant quantities of poles and crossarms beyond their expected life, and incomplete or inadequate inspection records.

Response: We have continued our elevated level of pole replacements, prioritising replacement in terms of asset condition and public safety criticality. We will begin a standalone crossarms replacement programme. We continue to evolve our inspection regimes and use new technologies to increase the quality of our inspection data.

Timing: we expect to reach steady-state pole renewal levels by end of RY32 when we have addressed the backlog of intolerable risks. Crossarm renewals will also continue at elevated rates for the duration of the planning period. We have completed our planned wooden pole (and associated crossarm) inspection milestones in Dunedin and Central, with 95% of network owned poles now within a 5-year inspection cycle.

8.1.1. Support Structures Portfolio Objectives

Portfolio objectives guide our day-to-day asset management activities and are listed below.

Table 8.2: Support structure portfolio objective

OBJECTIVE AREA	PORTFOLIO OBJECTIVES
Safety First	No fatalities from unforced failure of support structures. No fatalities from failure of a support structure during work activities. Downward trend in unforced, condition-driven pole and crossarm failures.

Reliability to defined levels	Downward trend in unforced, condition driven, pole and crossarm related fault outages. Minimise planned interruptions to customers and disturbance to landowners by coordinating all work streams (while achieving established intervention times).
Affordability through cost management	Maximum value is realised for customers by using a risk-based prioritisation approach to pole testing and remediation, with the chosen remediation option being the lowest overall cost. Transition to an efficient feeder-based approach to pole and crossarm inspection/testing following completion of our first full round of inspections.
Responsive to a changing landscape	Adverse weather events and their frequency are considered when planning new support structure design and installation. Alternative technologies are considered to improve reliability or reduce service cost when making renewal decisions, E.g. remote area power systems. New or different technologies are used to improve conductor condition assessment data.
Sustainability by taking a long-term view	Full initial inspection cycle completed for all Aurora-owned poles and crossarms by end RY22. Verify our pole testing methods via forensic inspections and destructive testing, by end RY22. Dispose of poles responsibly and assist communities through their re-use where practical.

8.1.2. Poles Fleet

Poles Fleet Overview

Our support structures carry conductor operating at all our network voltages. We have approximately 53,000 poles across our network regions; these are primarily wood and concrete, with a small number (approximately 1,657) of steel poles. In RY22 we removed our only lattice towers across the Otago Harbour as part of a submarine cable upgrade project.

Concrete poles

We have two main families of concrete pole designs on our networks – pre-stressed and mass reinforced. Pre-stressed poles are manufactured with tensioned steel tendons (cables or rods). They are a mature technology and generally perform reliably over a long period. Most of the new poles we install are pre-stressed concrete, with a design life of 75 years. They are designed and manufactured to meet stringent structural standards.

Mass reinforced concrete poles contain reinforcing steel bars covered by concrete. They were regularly used from the 1960s to 1980s, but infrequently since. These poles were produced by several manufacturers for different areas of our network, which has resulted in differences in design, manufacture and material quality. Relative to pre-stressed concrete, mass reinforced poles crack easily, which allows for water ingress and eventual corrosion of the steel bars. Mass reinforced poles are still relatively robust even with some exposed reinforcing, so replacement is not required unless a key area is affected or there is significant concrete volume loss.

Figure 8.1: Example of a concrete pre-stressed pole

When installing new poles, our preferred type depends on the site and the loads that the pole will carry. However, our preference is to use pre-stressed concrete poles.

Wood poles

Wood poles can be categorised into hardwood and softwood types. The wide natural variances in timber strength result in performance variations. There is no single method to reliably assess all aspects of the condition of wood poles.

Over the last century, a number of hardwood varieties have been installed on our network. Pole performance varies by wood species and by location, but unfortunately the species has not been recorded for some of our poles. Failure or defect modes include loss of cross section due to below ground rot, splitting through the body, and split heads.

In recent years, we have reinforced poles as a risk mitigation strategy. Due to a historical underinvestment in poles, reinforcement was used to limit the risk of failure while the backlog for renewals was cleared.

[1]

Steel poles

We have a relatively small number of steel poles in service. Most of these are modern tubular types though some legacy 'rail iron' poles remain in service. We previously had steel lattice towers on our Dunedin network, but they were removed in RY22 as part of our Harbour Crossing upgrade.

Tubular steel poles can be useful for remote or rugged sites as they are light and can be flown in as sections for on-site assembly. They may also be used in other situations on occasion, such as where certain strength characteristics (i.e. more strength in multiple directions) are needed. The use of steel around other infrastructure must also be taken into consideration due to Earth Potential Rise

[1] Our reinforcement approach involved installation of a steel truss driven deep into the ground next to the pole and secured with metal banding.

(EPR) and transferred voltage issues. It is also difficult to perform condition assessments on steel poles to identify internal or below ground corrosion. Our current approach is to use them only in limited circumstances.

Figure 8.2: Example of a wood pole reinforcement

Population and Age

The table below summarises our population of poles by type. Wood poles currently make up just under half of the pole population. Given the wood pole age profile, we will be making a large investment in replacing them over the planning period.

Table 8.3: Pole population by material type

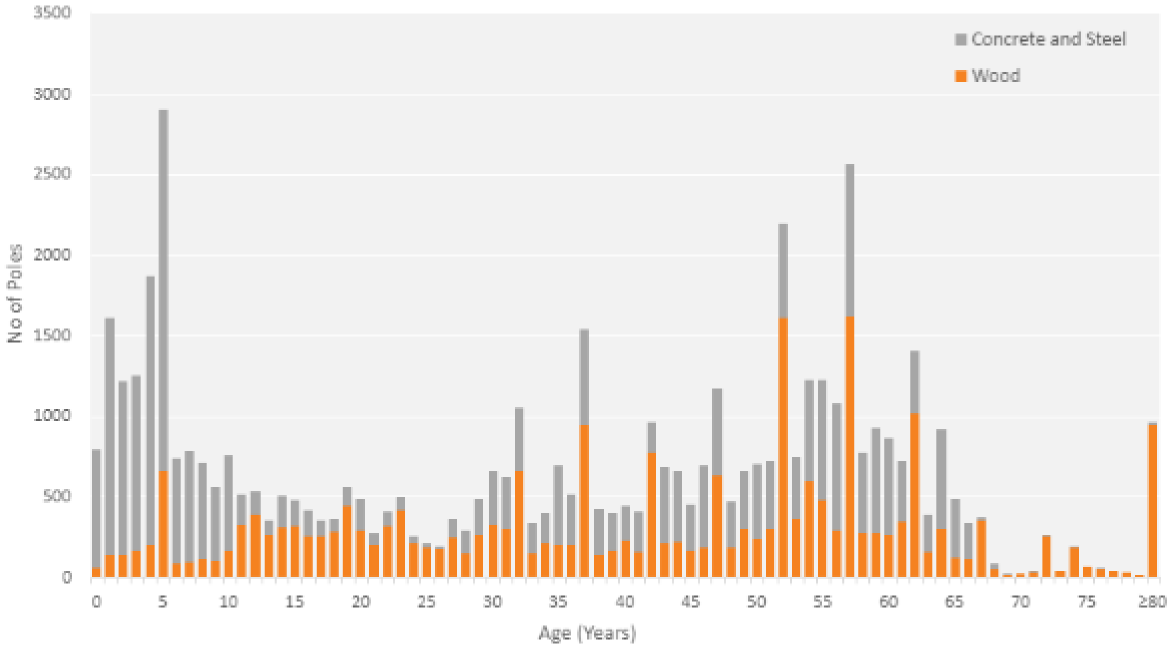
TYPE	POPULATION	PERCENTAGE
Wood	23,647	45%
Concrete	27,793	52%
Steel	1,657	3%
Total	**53,097**	100%

Figure 8.3: Example of a steel pole

The chart below shows that a number of hardwood poles have exceeded, or soon will exceed, their expected life of about 50 years.[2] In contrast, very few concrete and steel poles have yet exceeded their 75 year expected lives. The average age of our concrete poles is approximately 32 years against 41 years for wooden poles. The impact of our Fast Track Pole Programme (FTPP) is also evident. Under this programme we remediated approximately 6,900 poles in the RY17 to RY19 period, and we continue to replace more than 1,000 poles per year.

[2] Estimated from our wood poles survivor curve, which is informed by historical data.

Figure 8.4: Poles age profile



Many of the oldest wood poles on our networks have been identified along our Waipori A, B and C overhead lines in the Dunedin area. In 2021 we replaced over 500 poles on the Waipori B line with steel support structures, and further replacements are expected during upgrades to the A and C lines. The age profile for concrete poles suggests we should have low requirements for age-related end-of-life replacements during the planning period.

Condition, Performance and Risks

Failure of a pole in service is a significant safety issue, potentially exposing the public or field staff to hazards associated with falling equipment and live conductor on the ground (or with reduced ground clearances). It also presents a reliability issue, as a pole failure will generally result in loss of supply or reduced network security. Failure of a structure during maintenance or construction works presents a significant workplace safety hazard.

It is important that pole defects are rectified promptly following identification to avoid pole failures, particularly since the asset may not have adequate strength to withstand added stress due to external forces. For example, a failure may occur during heavy snow or high wind conditions – in such cases the weather cannot be considered the primary cause of failure, as assets are designed to withstand all but the worst environmental conditions. We always aim to replace poles before they fail to minimise safety and reliability risks.

Condition

We undertake periodic condition testing of our pole assets, as covered in the previous chapter.

Based on condition data, as of December 2022 we had a backlog of approximately 2,000 poles awaiting replacement.[3] This figure includes poles that failed our test and/or inspection requirements and warrant replacement within a period of up to 24 months.

> **Meeting our portfolio objectives – safety first**
> Poles are replaced proactively based on condition information, aiming to mitigate safety risks above all other considerations.

In AMP 2018 we noted that addressing overdue red-tagged poles (red tag = not suitable to support everyday duty requirements) in high criticality areas was our urgent priority. At that time, we had approximately 1,000 red-tagged poles on the network. In 2020, that figure was reduced to 157 poles. As of December 2022, we had reduced the number of red tag poles to 19, representing a population of predominantly under control recent find red tag poles.

Our Orange tagged poles (orange tag = Not suitable of supporting design loadings such as high snow/ice event loadings) population as of December 2022 was 674. As such, these poles remain a focus for rectification in RY23-RY24. Rectification options for these poles includes, straightening, reinforcing, replacement, or review via detailed engineering/risk assessment.

> **Meeting our** portfolio **objectives – safety first**
> These targets are key to help us strive towards meeting our safety-first portfolio objectives: no fatalities from unforced support structure failure in either everyday operation or during climbing by our contractors; and a downward trend in unforced, condition-driven pole and crossarm failures.

> **Box 8.3: Improvement Initiative – understanding the true strength of legacy concrete poles**
> We have good data on the strength of newly installed concrete poles, but we are less confident in data on the strength of legacy concrete poles. We have design drawings in some cases, but experience on the network suggests the legacy concrete poles may be stronger than the values stated on our drawings. To address this gap, we plan to undertake destructive testing of legacy concrete poles to determine their true strength. Knowing the true strength of these poles will help us with the following considerations:
>
> – where to replace these poles to ensure resilience E.g. storm prone areas with high load
> – recommencing loading assessment on poles during pole inspections to measure pole fitness for loading, to support visual condition assessment
> – systematic overhead network resilience planning via an overhead network design software package

Asset health

We estimate fleet asset health for wood poles primarily on the basis of age and expected 'survivorship'.[4] (The exception to this is the wood pole backlog, which is assigned an asset health score of H1). We have built a wood pole 'survivor curve' utilising historical failure data – what

[3] We have identified end-of-life poles faster than we have been able to remediate them, resulting in a backlog.

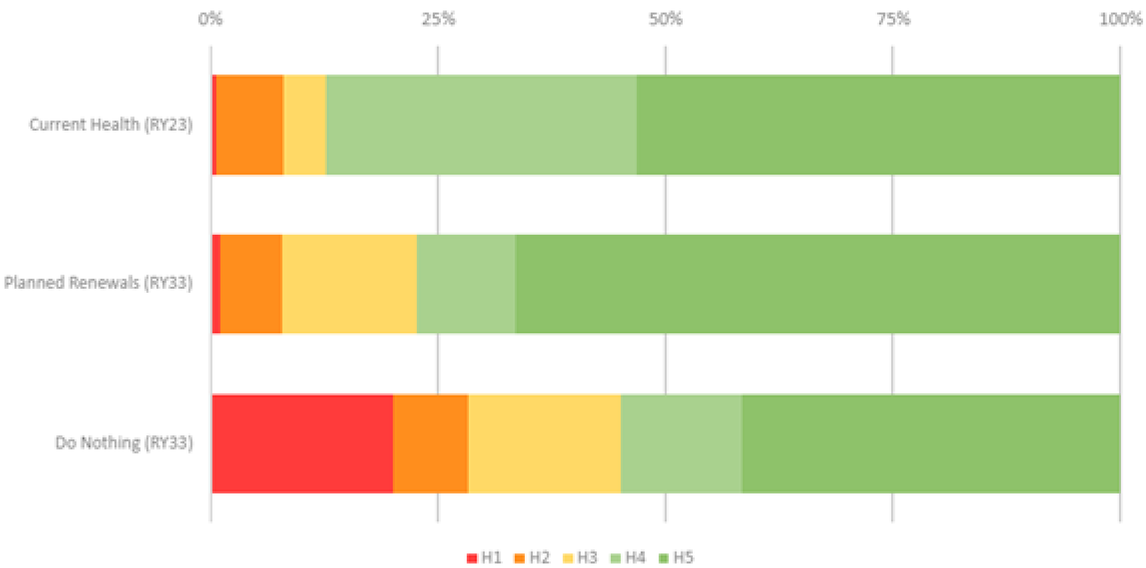
[4] As discussed, the majority of our wood poles have been inspected, however their condition assessment results are not granular enough to be useful for long-term forecast projections. As such, their expected survivorship in relation to age is used instead.

proportion of poles have historically 'failed' by a certain age.[5] Using a statistical failure distribution that incorporates historical data makes this approach more robust than simply assuming that all poles fail when they reach their expected life. Where we reinforce a wood pole, we assume a remaining life of 15 years, so these are classified as H4 until the 15-year life is reached at which point the pole becomes an H1. In some cases, this may overstate the remaining life due to above ground defects requiring early pole renewal, but we do not consider that this will significantly impact our forecasts over the AMP planning period.

For concrete and steel poles we do not have the data to support a statistical/survivor curve type approach. Instead, we estimate the remaining life of each pole using an age-based model (subtracting age from expected life of 75 years). Each pole is then classified as H1-H5 with H1 representing an asset at the end of its expected life, and H5 representing an asset with 20 years or more remaining life. Assets at H3 are within 10 years of their expected life, therefore will need to be considered for replacement within the planning period. Our AHI categories are used consistently across all asset fleets.

As shown below, our wood pole fleet is in poor health compared to our concrete and steel poles. This is mainly due to the wood pole backlog, but also reflects a greater average population age.[6]

Figure 8.5: Projected pole asset health at RY33



Under the proposed work programme, the wood pole backlog will be removed by RY32. We will continue to replace poor condition poles after this date, achieving our steady-state level (corresponding to 500-750 poles replaced per annum) by the end of the planning period. The

5 'Failed' poles comprise poles replaced based on structural end of life or defect as well as the few actual in-service failures that have occurred.

6 The timeframe for addressing the backlog is within 24 months as at 31 March 2019. Poles in the backlog are those that would become H1 by the end of RY20 if not replaced.

proposed work programme aims to reduce the amount of our pole fleet to reach H1 condition by the end of the planning period, which can then be managed on an ongoing basis.

Options Analysis

We undertake options analysis to consider the lowest overall cost approach to managing the risk presented by poles. This includes considering Opex/Capex trade-offs.

Options for poles depend on the condition issue or defect but include:

- **replace**: all condition issues or defects on the pole are remediated
- **undergrounding**: in rare cases replacement above ground may not be technically feasible due to the application of modern clearance standards, or a customer may wish to fund undergrounding
- **repair**: some wooden pole head defects may be repairable (Opex). Crossarms are also replaced on existing poles (Capex)
- **replace pole mounted distribution substation** with ground mounted distribution substation
- **reassess condition and/or strength**: in specific cases, further engineering analysis may mean the pole does not end up needing remediation
- **network alternative**: where significant amounts of pole and conductor replacement is required on lines feeding small customer volumes, consideration is given to whether a remote area power supply is a more cost-effective solution for customers. We have not implemented this solution to date but will continue to consider opportunities.

The forecast presented in this section reflects replacement as the option chosen for forecasting volumetrically. Small quantities of repairs will be covered under Opex and undergrounding or remote area power supply scenarios are covered on a project-by-project basis.

Meeting our portfolio objectives – responsive to a changing landscape and affordability through cost management

We consider the use of alternative technology to improve reliability or reduce service cost when making renewal decisions, E.g. remote area power systems, ensuring we meet our responsiveness objectives.

Undertaking options analysis ensures we meet our affordability objectives by having lowest whole-of-life cost option on each remediation.

Use of criticality in works planning and delivery

Public safety criticality is used to prioritise our pole remediation programme. Public safety zones are established through consideration of factors in the vicinity of a pole such as foot traffic and nearby locations of significance. Poles outside schools, for example, will be prioritised against poles in less accessible areas. Poles in higher public safety criticality zones also tend to serve more customers, so this approach also has an inherent reliability focus.

Disposal

We dispose of poles when they are no longer needed due to asset relocation/undergrounding, asset replacement, or asset failure. When a pole fails, we carry out diagnostic inspection and testing to assess the root cause of failure. As we identify trends from the failure analysis, we incorporate them into our pole fleet asset management approach.

For disposals, CCA treated softwood poles need to be disposed of at an appropriately licensed facility or appropriately repurposed (E.g. farming fences or structures). Hardwood poles may be repurposed for community projects, as in the case of the Cromwell-Clyde cycleway shown in the image below.

Figure 8.6: Repurposing of redundant poles for community benefit

Meeting our portfolio objectives – sustainability by taking a long-term view

Redundant poles are disposed of responsibly and assist wider communities where practical.

Coordination with other works

Pole replacements may be triggered by a need to upgrade the conductor they support. These upgrades put higher mechanical loads on the poles, often forcing an accompanying replacement of the supporting poles.

As part of these upgrade projects, we also identify poles in poor condition and coordinate their replacement alongside the conductor upgrade to ensure efficient delivery and to minimise customer disruption. The detailed requirements for each individual upgrade project are confirmed by a full design study. All the poles replaced on reconductoring projects are covered under the overhead conductor portfolio forecasts.

Meeting our portfolio objectives – reliability to defined levels

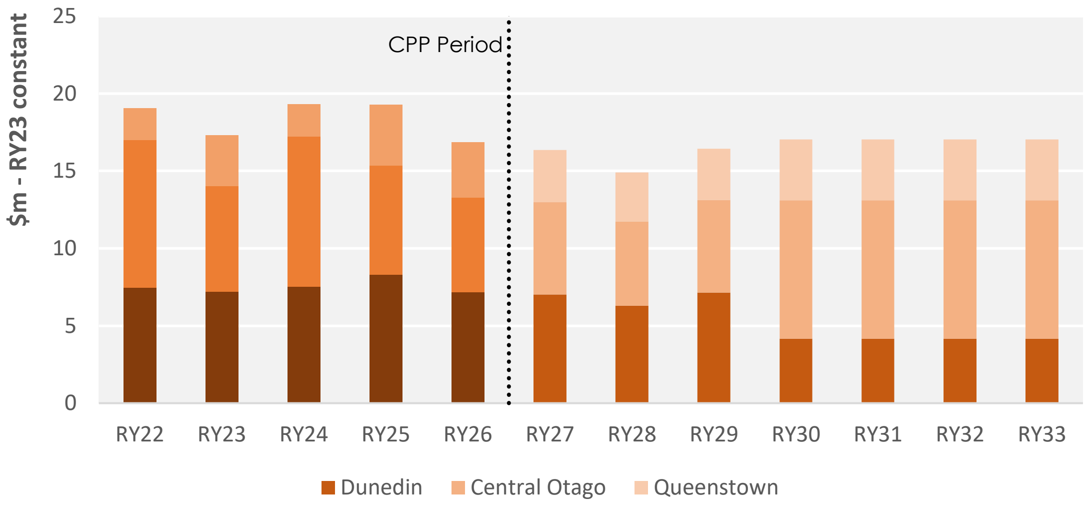
In addition to growth work, renewals work on overhead assets is also coordinated (such as poles, crossarms, distribution transformers and conductor) to ensure we meet our portfolio objectives and planned reliability targets.

Poles Fleet Expenditure Forecast

We have forecast renewal Capex for poles of approximately $171m during the 10-year planning period. This expenditure is significantly higher than forecast during our previous AMP. The change is informed by our improving risk forecasting capability to identify poor condition poles. The additional expenditure also covers the cost of any pole mounted equipment that requires replacement at the same time.

Our forecast investment maintains 'elevated' (relative to future) levels of pole replacement up to RY33. Beyond the planning period, we anticipate steady-state levels of investment as the aggregate health of the pole fleet improves.

Figure 8.7: Forecast poles Capex



Benefits

The major benefits expected from these investments are:

- **improved safety**: reduced risk of unassisted pole failure due to planned renewals with only 1% of poles classified as H1 by RY33. As the backlog is addressed, fleet health will improve relative to recent years. Failing to implement the renewals programme would result in a significant increase in the backlog as more poles reach end-of-life. It would not be consistent with our safety objectives
- **improved asset reliability**: fewer unplanned failures and faults will improve overall network reliability and help us meet our reliability objectives
- **cost-effective**: planned renewal work is generally more cost-effective than unplanned remediation work.

> **Meeting our portfolio objectives – sustainability by taking a long-term view**
> Achieve steady-state pole renewal by RY33; this balances risk mitigation across all assets with sustainability of our business and the wider industry, including our contractors.

8.1.3. Crossarms Fleet

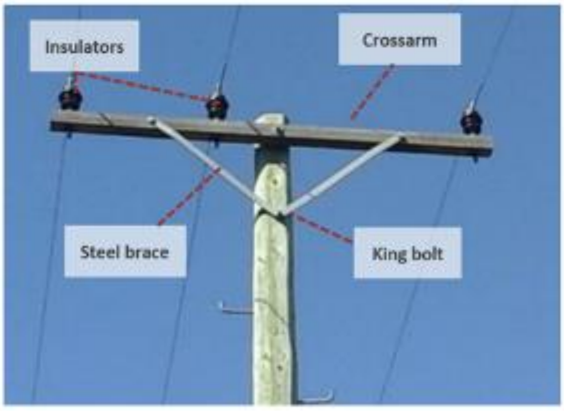
Where information is common to the poles section, it has generally not been repeated.

Crossarms Fleet Overview

Crossarms support overhead conductor. A crossarm assembly (referred to as 'crossarm') comprises the crossarm together with ancillary components such as insulators, binders and jumpers as shown below. Our crossarms fleet consist of a variety of different types and configurations as a result of different equipment suppliers, historical line designs, line voltage levels and historical network owners.

In previous years, there has not been a proactive replacement programme for crossarms outside of our pole replacement programme. We are now managing crossarms as a separate fleet, and there is a clear need for a crossarm (only/retrofit) replacement programme.

Figure 8.8: Typical crossarm arrangement



There are significant safety and performance risks associated with crossarm failure. Crossarms are always replaced when a pole is replaced. Defective crossarms are also replaced separately where the pole itself still has significant remaining life. We expect to include a large number of crossarm replacements as a separate programme of work over the planning period. This need for this programme of work is supported by risk reviews and recent failure events.

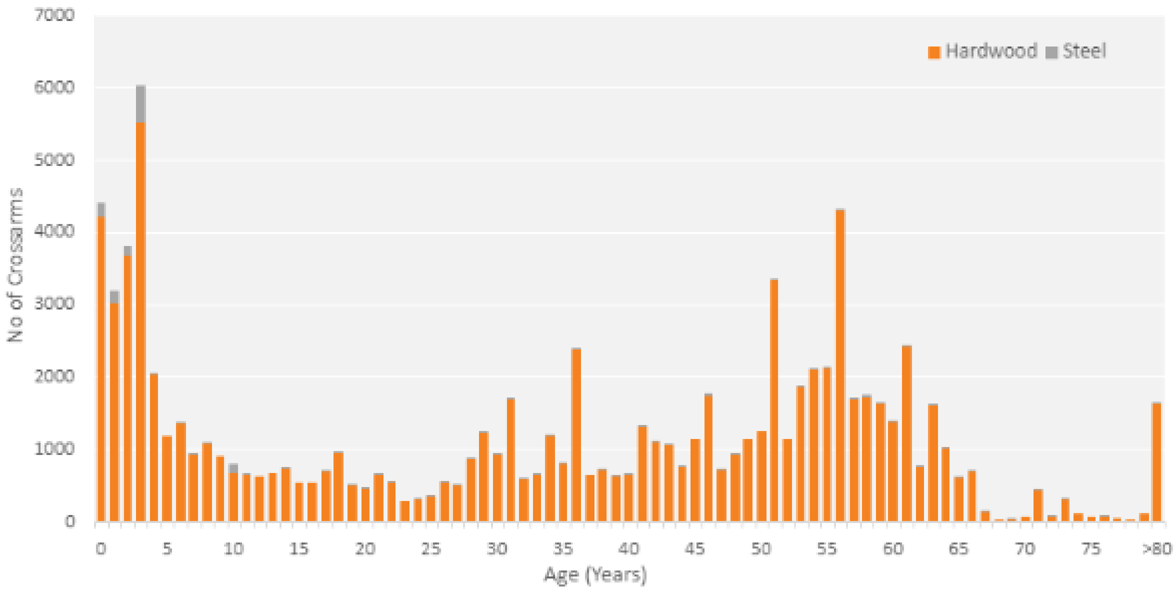
Population and Age

We have approximately 95,000 crossarms, an average of 1.75 crossarms per pole. The majority of these are wooden, with only 1700 steel crossarms.

Our historical data sets do not have age entries for crossarms. In all cases where a pole is replaced, new crossarms are installed. Given there has been no historical crossarm (retrofit) replacement programme, we have assumed all crossarms are the same age as the poles on which they reside. We believe this is a sound assumption, and therefore retrofit crossarm age data will be captured going forward. The estimated average age of our crossarms, using this logic, is 40 years.

We continue to prefer wooden crossarms due to their non-conductive properties, lower upfront cost, and ease of customisation. Additionally, we have recently installed some galvanised steel crossarms on new steel poles. The life expectancies of wooden and steel crossarms are 55 years and 75 years, respectively. Approximately one-quarter of our wooden crossarm fleet has exceeded the expected life of 55 years. This expected life is based on the average age we experience a crossarm defect. This expected life is longer than assumed by other EDBs; however, we are seeing relatively good performance from aged wooden crossarms. In contrast, less than 2% of our steel crossarm fleet has exceeded a 75-year expected life.

Figure 8.9: Crossarms age profile



A significant volume of new crossarms were installed four years ago. These were replaced as part of our FTPP, as each new pole installed includes new crossarms for practicality and cost reasons. We continue to replace crossarms at an elevated level.

Condition, Performance and Risk

Condition

Many of our crossarms are in poor condition as they have exceeded their expected life, and we have not historically had an active crossarm renewal programme. We undertake periodic inspections during pole testing/inspection.

Of the ‘poor condition crossarms’ component, our renewal programme is targeting the D1-classified crossarms first, using a location as a basis for risk prioritisation. The D2 crossarms form the basis of the crossarm replacement programme in the near-term. We are further refining our inspection criteria around cross arms to ensure we are focusing on the highest risk arms, whilst maximising remaining life of existing assets.

Performance

Support structures by their nature may pose risks to public and personnel safety. For example, a crossarm failure can result in a conductor falling which, in turn, could result in an electrocution or fire risk, and will generally cause a loss of supply (except for sub-transmission lines with N-1 security).

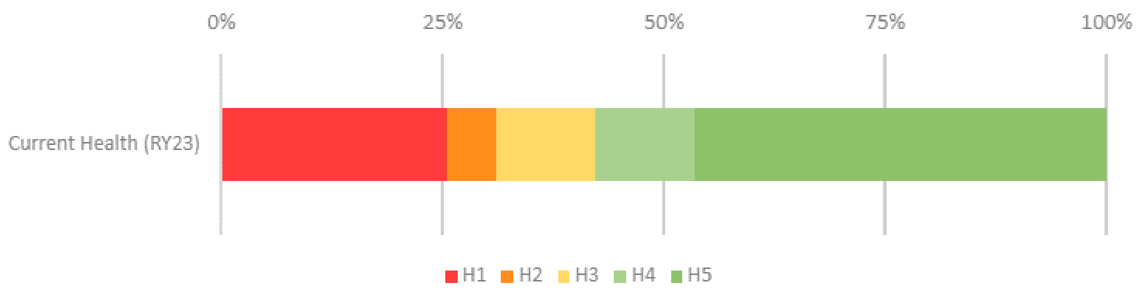
Ideally, we would measure performance based on the number and type of crossarm failures. Until recently, however, we have not recorded this information at a level of detail useful for analysis. We are now collecting this data for all current and future failures. We do know that our conductor drops, or events where conductor have come off the support structure, are increasing, and some of these events are due to crossarm failures.

Asset health

As outlined in Chapter 5, asset health is used to indicate the expected remaining life of an asset and to provide a proxy for likelihood of failure used in renewals forecasting. Our asset health indices (AHI) for crossarms are based on expected remaining life (hardwood crossarms have an expected life of 55 years), where life expectancy is represented by a normal distribution. We have not used condition data due to the large number of crossarms yet to be inspected. We do not consider that using condition data, where it is known, would materially change our assessment of asset health.

Current asset health of our crossarms is shown below. It indicates that almost 25% of our crossarms are at end-of-life (H1), while roughly 50% will move to H1 over the next 10 years. This is primarily due to a large number of crossarms exceeding their expected life (informed by historic data). The majority of crossarms are wooden and because of the natural inherent variability in the material, it is difficult to precisely determine expected life. As we continue to mature our data through evaluating condition through inspection, we will also continually review and update expected remaining life.

Figure 8.10: Crossarm fleet asset health



Risks

The table below sets out the key risks and mitigations we have identified in relation to our crossarms.

Table 8.4: Crossarm risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
Insulator leakage pole fire On wooden poles, leakage current on (generally pin type) insulators tracking along the wooden crossarm, down the crossarm brace to king bolt, starting a pole fire, often breaking the pole and leaving conductor floating above ground (potentially live) or falling to ground.	Ground-based and aerial-based inspection programmes, leading to replacement of visually defective crossarms. New arms (except low voltage) have post insulators. *Future: identification and replacement of any 6.6 kV insulators operating at 11 kV.* *Type based replacement of otherwise non-defective pin insulator crossarms in polluted areas or areas experiencing multiple failures.*	Safety
Intermittent fault caused by leaking pin insulator.	Ground based and aerial based inspection programmes, leading to replacement of visually defective crossarms. New arms (except LV)	Reliability

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
Often the causal condition issue cannot be seen by the naked eye or average camera from the ground.	have post insulators. Ad-hoc use of acoustic discharge test equipment to find intermittent faults.	
Significantly leaning insulator causing leakage/short to crossarm, or failure of leaning insulator (falling off crossarm) causing conductor down or conductor floating event	Ground based and aerial based inspection programmes, leading to replacement of visually defective crossarms (new arms (except LV) have post insulators). Replacement of all pin insulators on reconductoring projects. Installation of vibration dampers on 66 kV circuits with known aeolian vibration problems and failure history.	Safety
Wooden crossarm breakage due to wood ageing/degradation causing conductor down or conductor floating event.	Ground-based and aerial-based inspection programmes, leading to replacement of visually defective crossarms.	Safety
Binder failure causing conductor down or conductor floating event.	Ground-based and aerial-based inspection programmes, leading to corrective maintenance defect repairs.	Safety
Bird strike (particularly NZ native falcon) on steel crossarms.	Falcon guard retrofit programme on steel crossarms near falcon sighting/breeding areas.	Sustainability

Design and Construct

We continue to prefer wooden crossarms due to their non-conductive properties, lower upfront cost, and ease of customisation. Wooden crossarms also prevent the need for fitting of falcon guards to prevent bird strike.

We specify post type insulators rather than pin type insulators to avoid the failure modes of hole elongation caused by conductor vibration, as well as the potential for failure at the cement pin interface. We have approved the use of fibreglass crossarms with a view to introducing their use as a means of achieving longer crossarm fleet life. We are monitoring developments in polymer insulators and considering their wider usage.

The considerations around contractor and design arrangements are the same for crossarms as for poles. Crossarm replacements, however, tend to require significantly less, if any, actual design work.

Our crossarm forecast is ramping up significantly, which could prove a challenge for delivery. As we forecast a ramp up in crossarm volumes, however, we also forecast a ramp down in pole volumes, and the resource requirements are similar. Therefore, we do not foresee any major deliverability issues with this fleet.

Renew or Dispose

Historically, we have taken a predominantly reactive approach to crossarm renewal, other than crossarms replaced during pole replacements. During the planning period, we plan to carry out proactive replacements to mitigate failure-related safety risks and worsening crossarm asset health.

Table 8.5: Summary of crossarms renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Proactive condition-based approach, prioritised by criticality

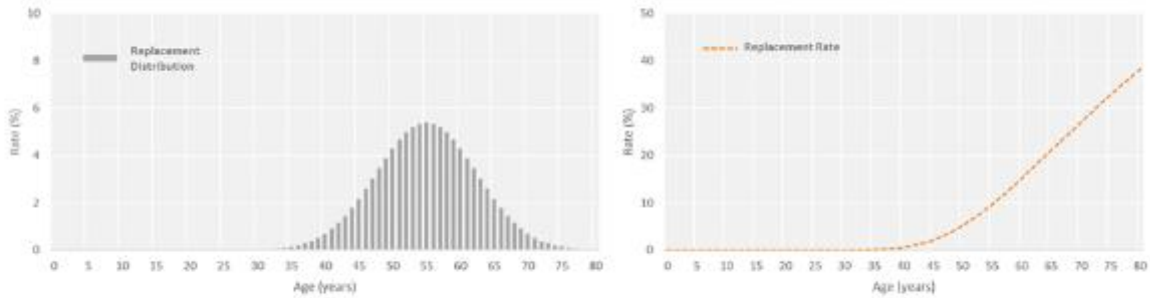
Forecasting approach	Repex model
Cost estimation	Volumetric using historical average unit rate

We will prioritise renewal work programmes of poor condition crossarms based primarily on public safety criticality. Poor condition crossarms will be identified through asset inspections. In the short- to medium-term, our works will focus on replacing crossarms already marked as defective. Where possible, renewals will be delivered as large programmes of work to improve cost-effectiveness.

Renewals forecasting

AHI for crossarms are based on expected remaining life, E.g. 55 years for hardwood crossarms. This expected life represents the average age at which we experience a crossarm defect. This is appropriate given this fleet forecast only includes crossarms replaced onto existing poles (implying the pole is still in a serviceable condition). Life expectancy is represented by a distribution as this approach is more robust than simply assuming that equipment fails at a particular set age. Our methodology uses a normal distribution, with the mean being the life expectancy of the asset and the standard deviation being the square root of the life expectancy. A replacement rate is calculated from the replacement distribution representing the proportion of crossarms that will likely require replacement by a particular age. The wooden crossarm replacement distribution and rate are shown below.

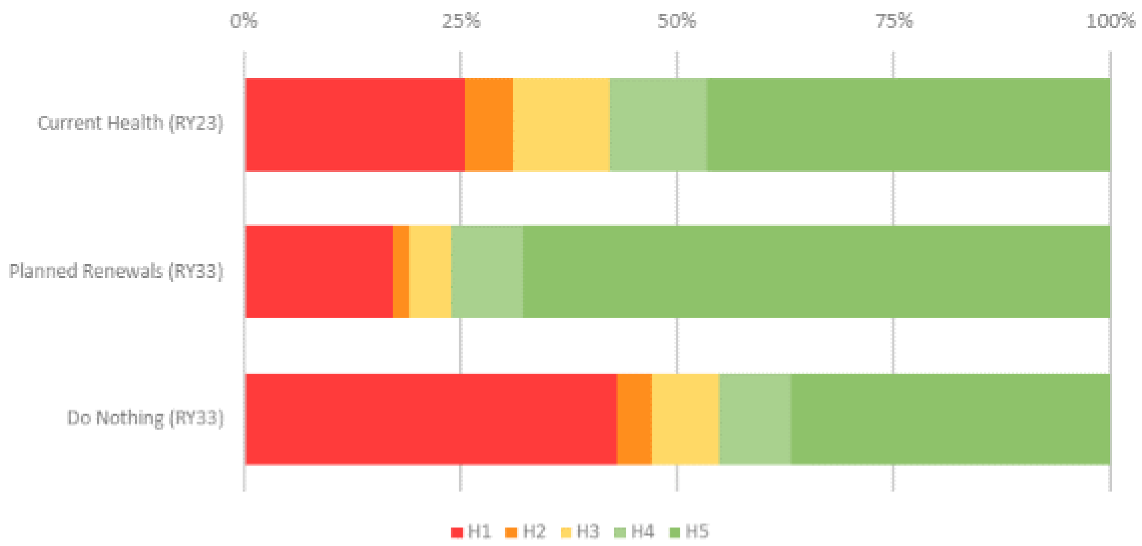
Figure 8.11: Wooden crossarm replacement distribution rate



With improvements in data gathering and management, we will create a wooden crossarm survivor curve later in the planning period.

The volume of renewal needs to increase during the next five years to longer-term sustainable levels, then transition to maintaining fleet health rather than improving it.

Figure 8.12: Projected wooden crossarm asset health at RY33



Our planned investment will lead to an improvement in overall health, particularly in relation to the 'do nothing' counterfactual. A sizeable number of crossarms will still require replacement after 2033, as indicated by the planned renewals portion of the above chart.

Options analysis

Options analysis for crossarm replacements is generally limited to considering the most economical means to replace the crossarms, as opposed to a range of different options in how to mitigate the crossarm failure risk. The following options are considered, depending on pole condition:

1. **Replace crossarm onto existing pole**: where the existing pole has no issues or defects, or the issues/defects are such that the overall cost of retrofitting a new crossarm now is the lowest cost approach.
2. **Replace the pole**: in some cases, it is more cost-effective to replace an entire pole. Examples include occasions where there are high overhead costs such as traffic management, or a large number of individual crossarms on a single pole. As per above, lowest whole-of-life cost approach is taken.

Repair of the crossarm assembly by replacing only a single insulator, for example, is not undertaken except if this is the only sensible course of action in fault or urgent corrective maintenance scenarios.

The forecast presented in this section assumes the option of replacing crossarms onto existing poles is taken, in a volumetric forecast. Small quantities of repairs will be covered under Opex and undergrounding or remote area power supply scenarios are covered on a project-by-project basis.

Use of criticality in works planning and delivery

Public safety criticality is used to prioritise pole testing and remediations for both pole and crossarm fleets. As such, crossarms around high-risk areas such as schools will be prioritised against poles in remote or inaccessible areas. Crossarms in higher public safety criticality zone also tend to serve more customers, so this approach also has an inherent reliability focus.

We have developed a draft risk-based intervention framework for support structures based on public safety criticality and tested condition grades. Once we have addressed our red and orange tag backlogs and are at 'steady-state', we will look to implement graded time interventions for poor condition poles and crossarms. We will be developing criticality frameworks in further dimensions (E.g. service performance) for all assets in the first few years of the planning period.

Disposal

Crossarm assemblies have no specific disposal requirements unless CCA treated whereby the same requirements as poles apply.

Coordination with other works

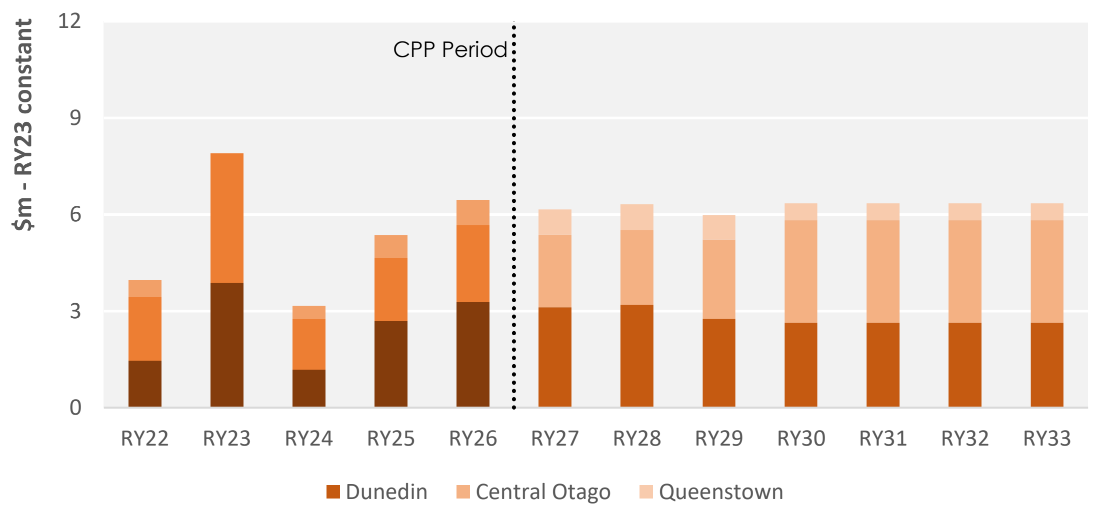
Like poles, crossarms are often replaced as part of overhead line reconstruction projects, such as conductor renewal or conductor upgrades as part of network development works, or via pole replacement work packs which make better use of outage windows.

We have a policy to replace all porcelain pin type insulators during reconductoring projects, given both performance issues and their general condition and age profile. Conductor renewal, where every pole is worked on, provides an efficient time to renew such crossarms; assets replaced as part of reconductoring projects are accounted for in our conductor fleet forecasts.

Crossarm Fleet Expenditure Forecast

We have forecast renewal Capex for standalone crossarm replacements of approximately $58.8m during the planning period, which is materially lower than previously forecast. The reduction is largely related to the efficiency of our support structure replacement programme, where more crossarms are replaced in conjunction with related poles than originally planned.

Figure 8.13: Forecast crossarms Capex



Our historical standalone crossarm replacement levels were low prior to RY20 when we initiated the renewal programme. We intend to increase expenditure for the RY23-26 period as we address the backlog of end-of-life crossarms, while also managing the ability of our contractors to deliver the work. Our plan plateaus somewhat after the CPP Period but remains at an elevated level, aiming to reduce our steady-state levels beyond RY32.

Benefits

The major benefits expected from these investments are:

- **improved safety**: reduced risk of exposing staff/contractors and members of the public to safety risks to help meet our safety objectives. Risks include ageing equipment, potential pole fires, and conductor drops.
- **improved asset reliability**: fewer unplanned failures and faults will improve overall network reliability, helping us meet our reliability objectives.
- **Cost-effective**: planned renewal work is generally more cost-effective than unplanned remediation work.

8.2. OVERHEAD CONDUCTOR

This section describes our overhead conductor portfolio and summarises our management plan. The portfolio includes three asset fleets:

- sub-transmission overhead conductor (33 and 66 kV)
- distribution overhead conductor (6.6 and 11 kV)
- LV overhead conductor (230 and 400 V)

Portfolio Summary

We are proactively replacing overhead conductor based on age vs expected life (expected life varies with conductor type, size, and location), with a focus on the less durable small copper and No. 8 wire types. Medium-term work volume forecasts are based on Repex modelling (with the exception of an identified sub-transmission project) and identified under-clearance violation remediations.

During the planning period we expect to spend an average of $8.5m per annum on overhead conductor renewals. Expenditure peaks at $13.2m in RY29 then falls to around $3.9m by the end of the planning period.

It is critical that we increase the level of investment to support our safety and reliability objectives. Failure of an overhead conductor can significantly impact our performance in these areas.

Overhead conductor is a core component of our network. Combined with support structures and the equipment mounted on them, it makes up our overhead network (63% of total circuit length), which connects our customers to the transmission system and enables the delivery of electricity at various voltages. We use a variety of conductor types across each of the voltage levels mentioned above. The overhead conductor portfolio also includes conductor joints and hardware/fittings but excludes insulators, tie wires, and other crossarm components.

We define our overhead conductor fleets according to the operating voltage of the conductor. Our approach reflects not only the risks faced and the criticality of the asset, both of which vary with voltage, but the inherent nature of each voltage level. These factors, together, can lead to different lifecycle strategies.

Box 8.5: Summary of our asset risk review – conductor

Issues: We have material quantities of conductor with critical risk of failure.

Response: increased volumes of conductor replacements, focusing on small diameter, low tensile strength types that are past expected life and that have experienced failures. We are using criticality, including public safety, to prioritise replacements. We will soon implement a new condition inspection regime, and we continue to undertake representative forensic testing of overhead conductor samples to support our renewal modelling.

Timing: elevated distribution and LV conductor renewal continue until the latter part of the planning period.

Good performance of these assets is essential to maintain a safe and reliable network. Most of our overhead network is in areas that are accessible to the public, and that combined with conductor-drop failure modes, means managing our conductor effectively is critical to public safety.

8.2.1. Overhead Conductor Portfolio Objectives

Portfolio objectives guide our day-to-day asset management activities and are listed below.

Table 8.6: Overhead conductor portfolio objectives

OBJECTIVE AREA	PORTFOLIO OBJECTIVES
Safety first	No fatalities or injuries to workers or public as a result of conductor failure or under-clearance. No third-party or fire damage as a result of conductor failure or under-clearance.
Reliability to defined levels	Downward trend in the unforced failure rate of overhead conductor. Minimise planned interruptions to customers and disturbance to landowners by coordinating all overhead network work streams.
Affordability through cost management	Maximum value is realised for customers using a risk-based prioritisation approach to conductor replacement and retaining existing assets on reconductored circuits that have remaining practical life. Alternative technologies are considered to reduce service cost when making renewal decisions, E.g. remote area power systems.
Responsive to a changing landscape	Adverse weather events and their frequency are considered when planning new overhead conductor design and installation. New or different technologies are used to improve conductor condition assessment data.
Sustainability by taking a long-term view	Systematic analysis of failures and fault data provides reliable feedback to inform asset planning decisions and future performance targets. Expected lives are informed and verified by increased use of conductor sampling and diagnostic testing. A detailed conductor condition assessment procedure is developed and embedded into steady-state preventive maintenance activities.

8.2.2. Sub-transmission Conductor

Sub-transmission conductor connects our supply points at Transpower GXPs to our zone substations, to generator connections and to interconnections between our zone substations. Voltages of 66 kV and 33 kV are used. Our sub-transmission conductor fleet consists of 523 circuit kilometres of conductor, of which the majority is the Aluminium Clad Steel Reinforced (ACSR) type. Given the geographical size of our network across the Central Otago and Queenstown sub-networks, approximately 70% of sub-transmission conductor is located there. The nature of sub-transmission is that the lines often cross private land on direct routes rather than following roadside corridors as commonly used for distribution lines. This can mean that reconductoring involves extensive landowner consultation and consenting. Sub-transmission lines can have 'underbuilt' distribution line and LV lines on the same poles.

Sub-transmission lines are critical assets given the amount of power they carry compared to distribution lines. The impact of sub-transmission line failure is either reduced network security to a large number of customers (if the line is a double circuit or one of two lines feeding an N-1 security substation) or a loss of supply to a large number of customers (if the line is a single circuit to an N security substation). Higher voltage circuits require higher clearances to ground, while higher currents require larger conductor, which has implications on loading and subsequently required pole strength. Higher voltage equipment generally also has a higher cost. Together, these factors mean that sub-transmission line builds tend to have a greater overall cost than distribution line builds. All these factors support managing sub-transmission conductor as a separate fleet to the other voltage brackets.

We have identified three sub-transmission lines that require reconductoring in Dunedin and one and a section of a second in the Central region in the near-term. This is the replacement of the Halfway Bush GXP to Berwick lines, commonly known as the Waipori A/B/C lines in Dunedin and the replacement of the MEG and a section of QT33-1 in Central. These projects can require significant investment and thus it is important that investment options are carefully evaluated, so that opportunity to enhance future network performance and reliability is considered.

Population and Age

The following table summarises our population of sub-transmission conductor by type. ACSR conductor currently makes up about three quarters of circuit kilometres, with most of the rest being copper.

Table 8.7: Sub-transmission conductor by type

POPULATION BY TYPE	POPULATION (CIRCUIT KM)	PERCENTAGE
ACSR	388	~76%
Copper	128	~23%
Aluminium Alloy (ABC/AAC/AAAC)[7]	6	~1%
Total	**523**	**100%**

The preferred material for conductor has changed over time. Up until the 1960s, hard drawn copper was the main type installed because of its conductive characteristics, while also being relatively strong. In the 1960s, however, the price of copper increased significantly, and ACSR stranded conductor became the conductor of choice.[8] It has higher strength characteristics than copper and is much lighter, enabling it to be used to replace conductor sections without needing to replace poles. However, its steel core makes it more vulnerable to corrosion in coastal areas. The majority

[7] AAC: All Aluminium Conductor and AAAC: All Aluminium Alloy Conductor.

[8] ACSR comprises an inner core of solid or stranded steel, and one or more outer layers of aluminium strands.

of conductor installed on our sub-transmission and distribution HV lines over the last five years is all aluminium alloy conductor (AAAC), a lightweight conductor with enhanced strength over all aluminium conductor due to the alloy properties. In general, we use it in areas without snow loading or long spans; it is our preferred conductor in Dunedin. ACSR is still used for projects where AAAC is unsuitable due to site-specific design requirements.

We have a very small amount of the Aerial Bundled Cable (ABC) at sub-transmission level. This was installed as a trial for environmental reasons to minimise the amount of tree cutting required, but it is not a preferred type for general sub-transmission and distribution applications and is planned for replacement in RY24 due to capacity, condition, and maintenance concerns.

Current asset management practice is based primarily on historic data, we know there are limitations in the accuracy of this information and are working (through our inspection regime) to verify our data. All projects identified (based on data; age, type, location) are site-validated prior to initiation. We take every available opportunity to update/correct our data.

According to the best information we have, the average age of our sub-transmission conductor is 50 years. A significant volume of conductor, primarily copper, has already or soon will exceed its expected life. As mentioned above, it is identified that the old copper sub-transmission circuits on the Waipori A/B/C Line are near end of life. Because of the extent of the investment and the complexities associated with it, we have identified a multi-stage, multi-year high level plan for replacement of this line. We have also undertaken testing of a sample of that conductor taken during early stages of the project. Last year, approx. 22km of the Berwick to Outram section of the B line were replaced. The information on conductor condition and strength as well as the current condition and forecast remaining life of the OH structures on this line, have been taken in consideration into planning future stages of this work, currently within the planning period.

Figure 8.14: Sub-transmission conductor age profile

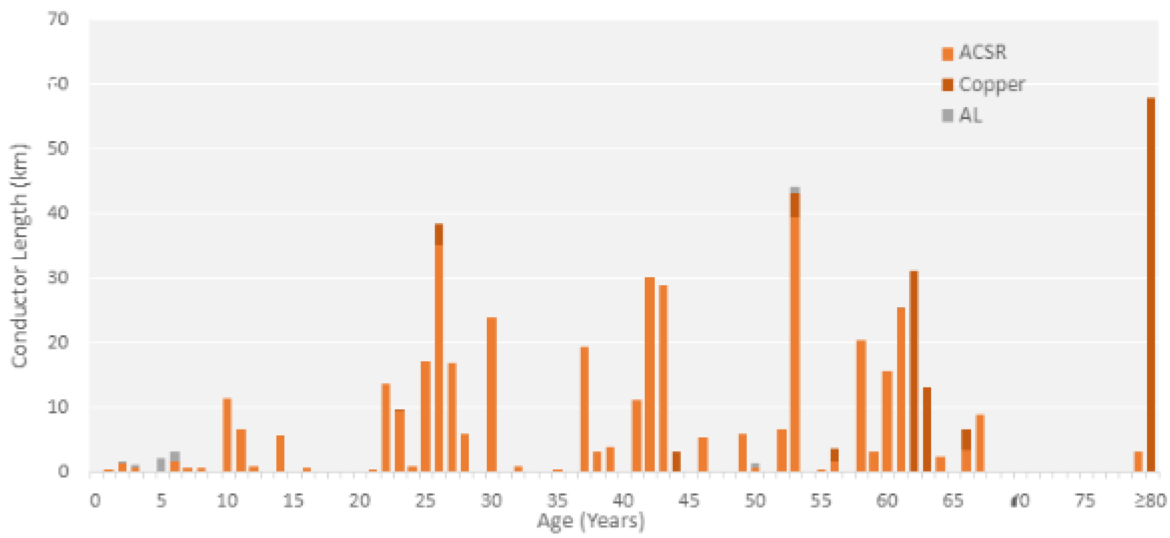


Table 8.8 sets out our conductor expected lives.[9] We have identified that environment plays a significant factor in determining a conductor's average life. Conductor of smaller diameter or located close to the coast has a shorter expected life. ACSR type conductor has a shorter expected life than other types. For example, large diameter ACSR located within 500m of the coast has an expected life of 58 years, while copper conductor of the same diameter and location has a 65-year expected life. Aluminium conductor located more than 5km from the coast has an expected life of over 100 years.

Table 8.7: Overhead conductor expected lives

Type	Conductor Size (mm)	Within 500m of Coast	500m-5km to Coast	> 5km to Coast
Aluminium	<100	77	93	110
Aluminium	≥100	87	103	120
ACSR	<100	48	63	84
ACSR	≥100	58	73	94
Copper	<100	55	67	80
Copper	≥100	65	77	90
No. 8 wire	<100	48	59	75

While the expected lives set out provide a good starting point and are within the bounds of good practice when compared to lives that other NZ electrical asset owners use, we expect to refine these as our knowledge, gained from sampling and condition assessment, increases.[10]

We will be maturing the assessed expected lives to enable us to differentiate between conductor of difference sizes, at a more granular level.

We are also commencing an inspection regime of conductor which will help to verify and improve our confidence in current data on conductor age.

Condition, Performance and Risks

Managing the condition of our overhead conductor assets is critical to meeting our safety objectives. Asset failure can result in live conductor on the ground. Where the ground has high resistance, particularly in the Central Otago area due to the predominant soil type, earth fault protection can have difficulty detecting faults. The issue is present if the conductor has landed on something other than the ground, such as a fence. Manual intervention via circuit breaker operation may be needed to de-energise the conductor, and this requires identification and reporting of the fault.

Conductor failure can also cause loss of supply. At sub-transmission level, faults are not often felt on the customer's side as the circuit will often comprise more than one line for added security. The loss of a single sub-transmission line, however, can have a significant impact on embedded generation, requiring the generator to ramp back its generation to avoid overloading other circuits. A number of our zone substations are supplied by a single sub-transmission circuit and the loss of this line would

9 Note that this table applies across all voltages. There is no No. 8 wire conductor on the sub-transmission network.

10 Conductor sampling and testing is covered in the Distribution Conductor fleet section.

result in loss of supply to all customers supplied from that zone substation (N security).[11] Several substations connect to multiple sub-transmission circuits, but not in a standard configuration (do not have a closed bus) so the loss of a sub-transmission circuit will also cause a loss of supply to the zone substation until manual switching has occurred and the alternative sub-transmission circuit is connected.

To minimise public safety and performance risks, we aim to proactively repair and replace overhead conductor prior to failure.

Condition and performance

Overhead conductor condition assessment typically represents a challenge for the electricity industry. Visual observation, whether from the ground or air, will give an indication of overall asset health and enable identification of defects such as broken strands, corrosion, bird caging and clearance violations.

We have not historically had a routine-based detailed inspection regime for conductor. Inspections have been ad-hoc, such as when surveying a line post-fault to confirm the reason for the fault and ensure safe return to service, 'drive by' type looking only for obvious defects with the line, or commenting on obvious conductor defects during a pole inspection. We have, as discussed in other sections of this document, developed and trialled a new approach to how we inspect overhead assets including poles, cross-arms and conductor. We are well positioned to implement the new inspection in the final quarter of RY23. The expected outcome of the enhanced overhead inspection is to have a full set of condition (visual) data for the network after five years of implementation. We will use this to verify data on conductor type and to take a more comprehensive approach to how we identify and prioritise conductor renewal and repairs.

While our sub-transmission conductor fleet is ageing, line failures are rare, largely due to its heavier, more robust construction. In addition, many sub-transmission circuits have N-1 security, so a fault does not necessarily result in an outage. However, we have had a small number of conductor-related outages on our 33 kV and 66 kV lines in recent years, most of which related to third-party damage (tree trimming, machinery accidental contact) or failed tie wires.[12] In addition, we have had a small number of incidents due to under design and condition on two of our 66 kV lines, that has caused multiple occurrences of floating conductor due to either vibration loosening studs on insulators and causing them to detach from the crossarm, or crossarm failures due to condition and loading.[13] To mitigate this, additional inspections have been carried out this line using drones with defects identified and issued for rectification. The increase in frequency of inspections is to continue until reliability and condition data dictates otherwise.

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[11] Some customers may be able to be switched over to another feeder, reducing loss of supply. This is a manual process which can take some time to undertake.

[12] Tie wires bind the conductor to the insulator. We are replacing tie wires with distribution ties on new installs.

[13] The number of long spans and river crossings require higher tension conductor to avoid sag, which would otherwise cause clearance violations. We sometimes experience smooth laminar wind flow, causing vortex shedding and aeolian vibration.

Figure 8.15: Floating conductor following mechanical insulator failure (left) and re-configured to delta construction with Stockbridge dampers fitted (right)[14]

Aerial Bundled Conductor (ABC) at sub-transmission voltage (33 kV) is aluminium core and 49 years old. It has marginal test results and incurred a recent failure; hence the need for replacement in the medium-term. The solution will require investigation and options analysis due to the trees in proximity. Compared to standard uninsulated conductor using aluminium which has an expected life in this location of 110 years, ABC will experience a much shorter life.

A significant proportion of our conductor faults occur due to failure of fittings or joints, and while our failures from this mode tend to be mostly in the distribution conductor fleet, the sub-transmission conductor fleet is not immune from this failure mode.

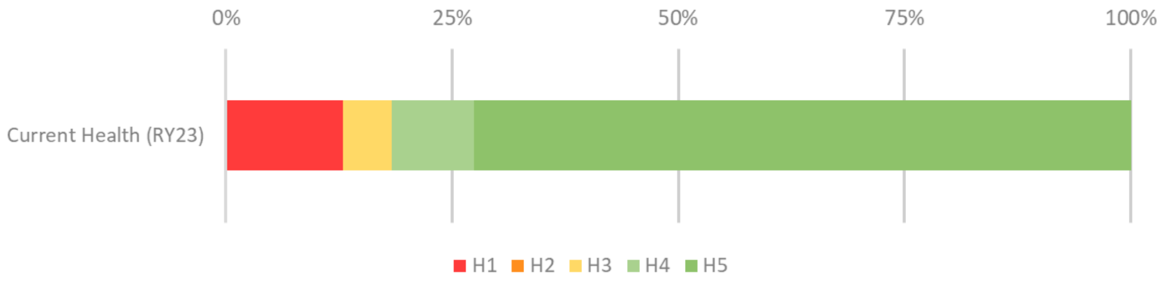
Historically, we have not captured performance statistics where they have not caused losses of supply. As most of our sub-transmission conductor is on N-1 circuits, the number of losses of supply is not a good indicator of asset performance. One of the biggest performance issues on our N-1 sub-transmission circuits in Central Otago is intermittent insulator faults and other line faults. Normally, these faults would not cause customer interruptions due to the N-1 redundancy.

Asset health

Our AHI for sub-transmission conductor is based on expected remaining life considering conductor type, size, and location. Life expectancy is represented by a normal distribution for each expected life grouping, as this approach is more robust than simply assuming that equipment fails at a particular set age. As we mature our approach to assessment of condition, we will be well positioned for further enhance our assessment of current asset health.

[14] Polymer insulators shown in a no crossarm arrangement, but similar insulators are also used in crossarm configuration.

Figure 8.16: Sub-transmission conductor current asset health



Based on asset health, we would expect around 18% of sub-transmission lines to reach H1 condition over the next 10 years. The projects identified above will target the H1-classed assets, with Waipori A/B/C lines making up the majority of the H1-classed sub-transmission conductor. As described above, this project is underway and future stages will be implemented over a number of years.

Risks

The table below sets out key failure modes by type of conductor on our sub-transmission network.

Table 8.8: Sub-transmission conductor failure modes

TYPE	FAILURE MODES
ACSR	The steel core that gives ACSR its strength makes it more vulnerable to corrosion in coastal areas.
Copper	Susceptible to annealing and fretting/chafing. Annealing is a reduction in the minimum tensile strength through heating and slow cooling. Fretting and chafing is caused by conductor swing causing wear and primarily affects homogenous conductor types. Chafing can also occur between the conductor and the binder that connects it to the insulators. Affected by fatigue caused by the flexing of conductor near the insulators, particularly in wind-prone areas, causing brittleness over time. Twisted copper conductor is particularly brittle and failure prone. Small diameter copper conductor is less durable than other types when aged, simply based on its size and how the loss of strength in a small number of strands has a large impact on the strength of the overall conductor.
AAC/AAAC	When exposed to oxygen, a hard and resistant oxide coating forms on aluminium conductor, which reduces conductivity and makes working on it difficult. Some aluminium alloy conductor develop severe pitting and white corrosion products in heavy corrosion areas such as close to the coast or near industrial plants, leading to a reduction in strength. Some aluminium alloy conductor types are more brittle than others, leading to working difficulties and a higher chance of early failure with Aeolian vibration.
ABC	The Poly Vinyl Chloride (PVC) outer covering on Aerial Bundled Cable degrades due to UV exposure. When significant, this leads to exposure of the inner XLPE insulation layer, moisture ingress, XLPE treeing and eventually short circuit faults. Where large trees or branches fall on ABC this can lead to the insulation cracking and breaking.
All types	Clashing of adjacent conductor or foreign object strikes (vegetation, birds, etc) can cause mechanical damage leading to loss of tensile strength.

The table below sets out a high-level summary of the key risks and mitigations we have identified in relation to our conductor fleets. They apply to varying degrees across all voltage levels. We are managing and mitigating these risks to the extent possible, including improving our understanding of condition through sampling and destructive testing, and managing condition through our renewal programme. We are also reducing the risks associated with conductor failures by ramping up a prioritised protection replacement programme to help achieve safe de-energisation of conductor that do fail to ground.

Table 8.9: Conductor failure risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
Conductor failure to ground, due to poor condition or workmanship issue with conductor itself or joints/fittings	New inspection regime and forensic testing regime Proactive replacement of conductor sections Proactive inspection of joints and fittings Standardisation of equipment Training and education of linesmen on joints/fittings usage and installation Protection systems and prioritised electromechanical relay replacement programme RCA on failures, targeted advanced inspections in response to monitored reliability and performance, including on associated assets that may lead to conductor failure to ground incidents	Safety, reliability
Conductor floating, due to failure of hardware such as fittings	New conductor inspection regime includes fittings Pole and crossarm inspection regime Proactive replacement of components where warranted Vibration damper install on lines with known aeolian vibration issues	Safety
Conductor overload causing sag and potential for electrocution, fire	Operating procedures, conductor validation during inspections, MDI reads, network planning and subsequent works	Safety, reliability
Non-compliant conductor clearance causing contact risk to people, property or livestock	Pole and conductor inspections or ‘ring ins’ identifying low spans Historical survey information identifying low spans Under-clearance remediation programme Future: discussions with road owners about road level increases	Safety
Conductor overheating while delivering fault current, leading to sag and clashing	Replace small conductor at risk of insufficient fault handling capability, and replace protection relays	Safety
Conductor flashover due to bird or tree contact	Vegetation management programme – annual inspection/maintenance for all sub-transmission plus those identified as critical distribution feeders Fitting of bird diverters and/or falcon guards onto steel crossarms, in areas of known significant presence/nesting	Reliability, environment
Third-party conductor damage	Permit processes, safety programmes, inspection regime and subsequent remediations of under-clearances and damaged conductor	Safety, reliability
Risk to homeowners undertaking tree trimming accidentally touching a live conductor	Safety programmes, first vegetation cuts, consumer pole and line inspection and remediation programme	Safety

Design and Construct

All sub-transmission renewal projects are designed from first principles, based on AS/NZS 7000 and associated national standards. The design attempts to minimise impacts on landowners and the wider public (such as when working alongside road traffic). Conductor renewal is very dependent on pole design, so we consider these together (as line design), and many poles usually require replacement on reconductoring projects.

Council requirements vary significantly between regions, which may impose limitations on changing or upgrading existing lines and may require us to obtain easements, even where existing use rights occur. In these cases, alternative options such as line rerouting or underground cables are considered.

In choosing the size and type of conductor we consider electrical, mechanical, environmental and economic factors, as well as the network as a whole. AAAC is our preferred conductor in many situations due to its superior conductivity properties and corrosion resistance. However, where we have long spans, or need to consider high snow loading or other higher loading scenarios, ACSR is our preference. We limit installations of ACSR near the coast (across all voltages) as corrosion in these areas can significantly impact the lifetime of ACSR.

In general, we aim to avoid increasing the number of different conductor on the network and we have standardised conductor types for each network region (Central Otago and Dunedin) which satisfy most scenarios. We also intend to limit the number of different conductor fittings we use; the benefit comes from reducing the number of fittings our line crews need to carry, as well as easing our asset lifecycle approaches.

All overhead conductor capital delivery is outsourced to our field service providers. Conductor replacement design is often outsourced to service providers; additionally, we have a design team in-house who fulfil a range of roles from scoping, design, project engineering and contractor design support to standards development. We have in-house quality assurance staff who undertake an audit function of contractor's completed works.

We are early into our conductor renewal programme, and we expect conductor expenditure to ramp up as our pole programme winds down. We are underway with the renewal planning for the A/B/C lines, and this project's construction will be open tendered to any conforming contractors to alleviate any deliverability issues and ensure other work on the overhead network work continues to progress.

Box 8.6: Improvement Initiative – Planned LiDAR survey and overhead network design software

We are considering utilising LiDAR surveys for parts of our overhead network during the planning period. LiDAR is identified as a means of improving conductor information, including identification of areas where conductor does not meet statutory requirements. Additionally, the detailed information can be used on each reconductoring project during line design.

Furthermore, we are planning to investigate the use of an overhead network design software package early in the planning period, with potential implementation in the medium-term. There are software packages available that can load the entire distribution network using sources like our GIS system and LiDAR information. These software packages allow real-world conditions to be entered (E.g. clearances, undulating terrain), and mass sensitivity analysis over the whole network to different conditions such as wind, ice and snow (which could be loaded from other mass data sources including NIWA data), and performance considered against a range of different design standards.

The benefits include better quality and more efficient design, and capability for scenario and sensitivity analysis. These benefits, if realised, would result in indirect benefits of reduced design time and cost.

Meeting our portfolio objectives – safety first

The introduction of conductor inspections and, later, LiDAR technology, will help us meet our safety objectives by identifying under-clearances and by assisting us to predict the effects of adverse weather events when planning reconductor projects and new support structure design and installation.

Renew or Dispose

We renew sub-transmission conductor using primarily asset age, (with expected life as a proxy for condition), asset type, and asset location (exposures and criticality zone). As condition data is obtained, this will be used to verify our assessments and planning. When considering the replacement of conductor circuits on this basis, it is very important to also consider and assess the health of the poles supporting the conductor, as pole renewal comprises a large proportion of the renewal costs. Our conductor forecasts include all replacement poles and pole mounted equipment that are undertaken on the reconductoring project.

Table 8.10: Summary of sub-transmission conductor renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Age (vs expected life remaining)
Forecasting approach	Repex Tailored for Waipori A/B/C lines
Cost estimation	Volumetric: estimated unit rates based on historical conductor projects Tailored for large projects such as Waipori A/B/C lines

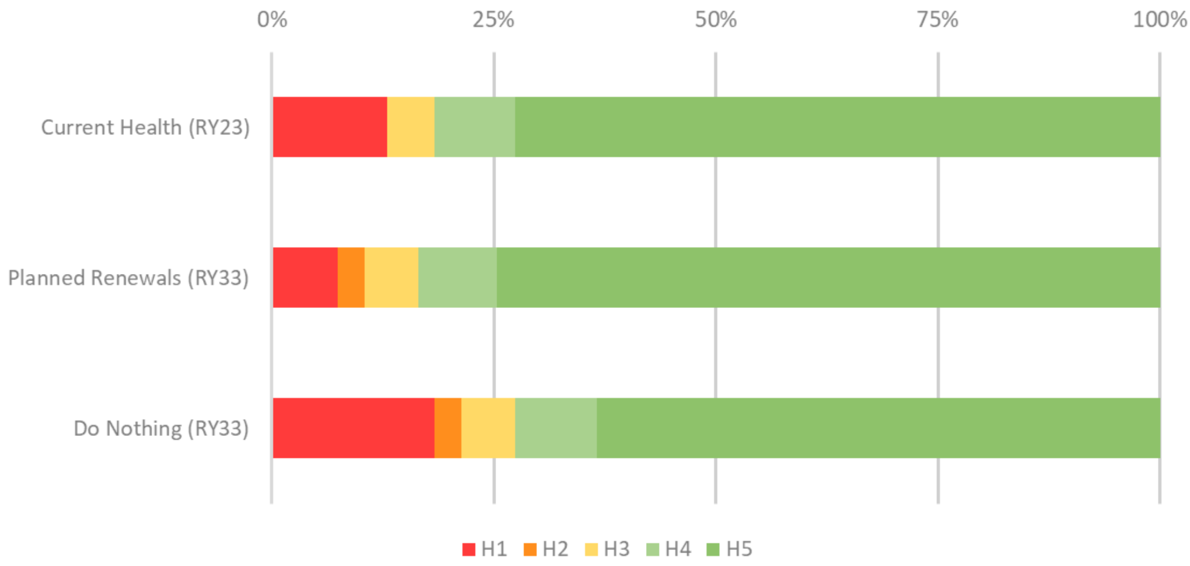
Renewals forecasting

We use a Repex approach for forecasting all sub-transmission conductor renewal volumes, apart from large projects such as the Waipori A/B/C lines. Life expectancy is represented by a set of distributions around the expected life (i.e. a distribution for each type/location/size category). A replacement rate is calculated from the distribution representing the proportion of sub-transmission conductor that will likely require replacement by a set age.

In the case of large projects such as replacement of the Waipori A/B/C lines, we take a tailored approach to determining renewal requirements.

The figure below compares projected asset health in RY23 following our planned programme of renewals, with a counterfactual 'do nothing' scenario. This comparison indicates the benefits provided by our proposed investment programme.

Figure 8.17: Projected sub-transmission conductor asset health at RY33



Waipori A/B/C lines make up the majority of the H1 sub-transmission conductor sections in the top bar. These are forecast to be replaced during the planning period, in addition to further volumetric replacements.

Options analysis

Before making a sub-transmission conductor replacement decision, we undertake a cost benefit analysis to confirm that the proposed intervention is the most robust and cost-effective means to meet the need. The analysis compares the proposed solution with a 'do nothing' and other various intermediate or alternative options. This degree of options analysis is required for sub-transmission conductor, given its high cost and its implications on network design.

When considering renewal of a sub-transmission conductor, we assess the overall condition of the sub-transmission circuit, including pole condition. The cost of pole replacement is a significant part of any renewals work, so if the poles are in poor condition or likely to fail loadings of any proposed new conductor, this broadens the options that we consider.

Options for overhead conductor replacement can depend on whether the associated poles are nearing replacement, and include:

3. proactive repair of the conductor (Opex) where renewal is not yet warranted by condition E.g. proactively replacing joints and other fittings
4. reconductoring along the existing route with modern equivalent conductor asset. Generally, when poles are in good condition, this approach minimises the change in load on the poles and hence minimises the number of poles requiring replacement due to loading increases causing them to be under-designed
5. reconductoring along the existing route with a larger ampacity conductor. If the main driver is renewal, some degree of enhancement can be accompanied, but if the main driver is

rating then the project will be classed as a growth project; this is likely to cause more poles to need replacement due to the load increase

6. partial or full rerouting as part of reconductoring may be considered where poles are in poor condition. It may also be cheaper to reroute the line into public property E.g. road reserve, than refresh consents for the new conductor on an existing private property route
7. undergrounding the line may be considered if the circuit runs through a built-up area or a fault prone area where trees cannot be cleared to fall zone E.g. native forest
8. rebuilding at a different voltage – in the majority of cases this would require a significant growth driver and be classed as a growth project. Lines can be constructed, however, at low marginal cost to enable operation at a higher voltage in the future – the changing of system voltage is generally the significantly more expensive part of such a conversion as it requires new transformers and switchgear
9. network alternative solution – where significant amounts of pole and conductor replacement is required on lines feeding small customer volumes, we consider whether a remote area power supply is a more cost-effective solution for customers. Remote area power supplies may also be used to increase reliability in specific areas. This option is generally not suitable for sub-transmission circuits.

The options considered in each instance will take into account security considerations, future upgrade capability and whole-of-life cost. The Waipori renewal project is an example of where circuits on poor condition poles are being replaced. In this case we are reducing from three low capacity lines on separate poles to two tall pole structures with two 33 kV conductor of higher capacity (one underbuilt with distribution conductor) and the ability to add a third circuit in future at reduced cost.

Underbuilt distribution and LV conductor are considered for renewal with the sub-transmission conductor subject to their age vs expected life and economic efficiency of consolidating works.

Easement considerations are important when considering options, as this can significantly affect project timing and budget. Where possible we aim to use existing use rights. The type of conductor to be used is determined early in the process, once circuit rating requirements are confirmed, as this feeds into pole or tower design.

Use of criticality in works planning and delivery

Sub-transmission projects, if large, generally have detailed studies and site-specific analysis of costs and loads at risk. Criticality in works planning and delivery is more applicable to distribution and LV conductor, which are assessed on a sectional basis within a framework rather than a project specific approach, to ensure prioritisation is effective.

Disposal

Aside from growth projects, conductor replacement is generally based on condition. As such, the conductor is generally sufficiently degraded that reuse is not an option. When replacing conductor assets, we scrap the degraded material. Historically there has been second-hand conductor used on our network, but at present we have no reason or opportunity to continue this practice.

Coordination with other works

Sub-transmission conductor works may be driven by load growth. If a conductor requires replacement in the medium-term (or has already been identified for replacement), forecast growth will be considered, and the preferred solution may be to replace the conductor with a larger size. This decision is supported by analysis of future load growth in the area(s) supplied by the circuit, including both intact and contingency situations (power flow and stability studies). If replacement is not required on the basis of condition, other options to meet demand will be considered.

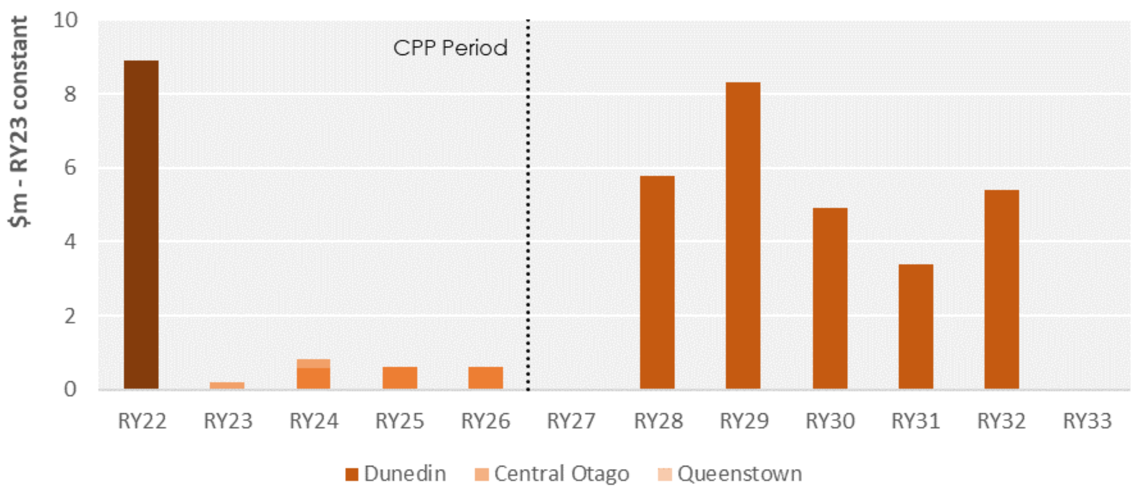
When we need to replace or thermally uprate conductor, the poles that support them may also need to be replaced due to the higher mechanical loads on the poles and application of modern standards. Even a like-for-like ampacity conductor may be larger (E.g. copper is smaller per ampacity than aluminium, so aluminium is lighter but has higher wind loading due to increased surface area). As part of upgrade projects, we may identify poles and other pole mounted equipment in poor condition, which will be replaced in a coordinated manner with the conductor upgrade to ensure efficient delivery and to minimise customer disruption. The detailed requirements for each individual upgrade project are confirmed once the project has been initiated.

Sub-transmission Conductor Fleet Expenditure Forecast

We have forecast sub-transmission conductor renewal Capex of approximately $29.8m during the planning period.

Historically, our expenditure on replacing sub-transmission conductor has been low, driven only by conductor failure/damage, or been growth driven and hence categorised as a growth project. Forecast expenditure primarily relates to staggered replacement of the Halfway Bush to Berwick lines over the period to RY28 to RY32.

Figure 8.18: Forecast sub-transmission conductor Capex



Benefits

The key benefits of our planned sub-transmission conductor renewal are improvements in fleet asset health, and a reduction in public safety risk as we remove poor condition conductor from our network, minimising the risk of fail to ground scenarios This investment is key to meeting our safety and reliability objectives. The Waipori line rebuild also provides an opportunity to implement a more economical solution, both from an operating cost perspective and whole-of-life cost perspective. It provides opportunities for future loads to be connected in a cost-effective manner should they arise.

8.2.3. Distribution Conductor

Where information is common to sub-transmission conductor, it has generally not been repeated.

Distribution Conductor Fleet Overview

Distribution conductor operates at voltages of 6.6 kV and 11 kV, carrying electricity from our zone substations to distribution substations, which convert to LV and supply customers.[15] We own approximately 2,300 circuit kilometres of overhead distribution conductor, comprising of steel (mainly No. 8 wire)[16], ACSR, AAC, AAAC and copper types. Distribution conductor makes up more than half of our total overhead circuit length. 68% of our distribution conductor is located in our Central network and the remaining 32% in Dunedin. Distribution conductor is supported by our overhead structures (poles and crossarms). The same support structures may also support sub-transmission, distribution, and LV conductor, with distribution over LV a common pole/conductor configuration (conductor below others being termed 'underbuild'). Occasionally, multiple distribution voltage circuits may exist on the same poles, side by side or over and under.

Many distribution conductor sections are relatively short and have been built in stages, unlike point-to-point sub-transmission lines. Most conductor sections carry significantly lesser implication on network design and performance compared to sub-transmission conductor. This factor leads us to use a volumetric approach for distribution conductor, with a risk framework approach to prioritisation of work, as described in this section.

Distribution conductor, like our other conductor fleets, has inherent public safety risk from being exposed live wire in public areas that can fail to ground.

Population and Age

The table below summarises our population of distribution conductor by type. ACSR makes up about two-thirds of our distribution network circuit kilometres, with most of the balance being copper.

Table 8.11: Distribution conductor population by type

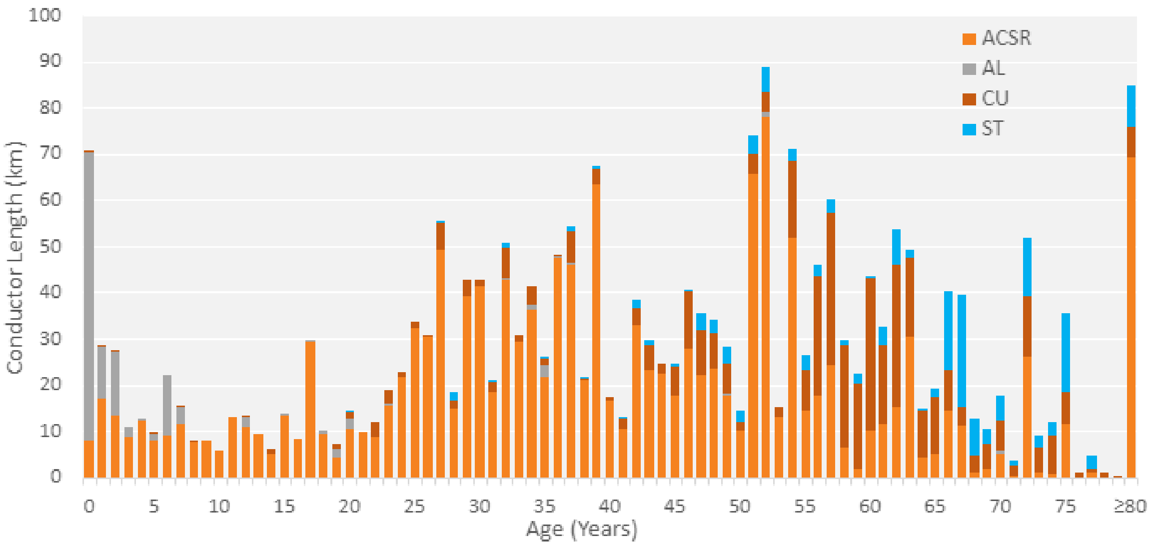
TYPE	POPULATION (CIRCUIT KM)	PERCENTAGE
Aluminium	124	5%
ACSR	1,525	68%
Copper	440	19%
Steel (primarily No 8 wire)	169	7%
Total	**2,264**	**100%**

15 Some customers are directly connected to our network at 6.6 kV and 11 kV.

16 Number 8 steel wire is a 0.16-inch diameter gauge of wire on the British Standard Wire Gauge.

The figure below depicts the age profile of our distribution conductor. No. 8 Wire and copper were the main types used until about the mid-1960s, when AAC and ACSR type conductor became the preferred types. Significant network expansion took place from around the 1960s, much of which is now approaching or has reached end-of-life. Our copper and steel conductor have the highest average ages (56 and 65 years respectively). These types are also less durable than other types, particularly near the coast where corrosion has a significant impact. We have started using AAAC only recently. We have some PVC covered conductor of various conductor core material types, which is primarily used in urban vegetated areas; while not being fully insulated, they do provide a degree of resistance to vegetation-related faults.

Figure 8.19: Distribution conductor age profile



The expected lives of distribution conductor are based on Table 8.8 in the sub-transmission conductor section. We have good examples where investigated failures of distribution conductor support our expected lives as they presently stand for No. 8 and small copper types.

While our historic age data and the expected lives provide a good starting point, (expected lives are within the bounds of good practice when compared to lives used by other New Zealand electrical asset owners), we expect to enhance the basis of informing investment in this fleet. We will do this by validating age and type data through inspections and other means, and by refining assessment of remaining life. We believe, through iterative means, we can use knowledge gained from sampling and testing conductor to continually refine assessment remaining useful life. We are expanding our conductor forensic testing programme and primarily focusing on distribution conductor, given this is where are experiencing the most age-related failures out of the conductor fleets. The same conductor type (E.g. 16 mm^2 copper) may also be used at LV, but LV data quality is less dependable.

Meeting our portfolio objectives – sustainability by taking a long-term view

We will undertake systematic testing and use the results, combined with learnings from analysis on in-service failures, to inform and verify our conductor expected lives. This will ensure we are replacing conductor prudently.

Box 8.7: Improvement Initiative – Expanded conductor forensic sampling

To better understand the strength and expected lives of our conductor, we have been undertaking destructive forensic testing on a variety of conductor across our overhead network – primarily those removed with other works. These were tested to failure and compared with nominal rated tensile strength for their conductor material, along with other observations and tests. This forensic testing is ongoing, and sampling will now become targeted towards capturing a representative selection of the conductor fleet factoring age, design and environmental conditions.

This programme will improve our understanding of conductor expected lives by assessing actual strength and condition in order to improve our understanding of degradation. This information will also enable us to improve our asset health and forecasting models.

Condition, Performance and Risks

The condition, performance and risk considerations of our distribution conductor are similar to those at sub-transmission voltages. Distribution conductor failure, however, will generally also cause loss of supply, because at these voltages the circuit will commonly comprise one line (i.e. N security), or if two lines, then requiring a manual close of air-break switch to restore supply.

Condition

Condition assessment for overhead conductor is relatively challenging. We are implementing an inspection programme across distribution and LV conductor to improve our knowledge of conductor condition and other issues such as poor workmanship.

We have significant evidence from the performance of our No. 8 and 16 mm^2 copper conductor that these conductor are generally past or nearing end-of-life and often in poor condition, and hence these are our renewals focus area for the short- to medium-term. For our 16 mm^2 copper conductor our main issues have been severe corroding within a short distance from the coast. This harsh marine environment, particularly in areas with strong winds, is very corrosive over time. Our older 16 mm^2 copper conductor has fared badly in these conditions and has led to many conductor-down incidents.

Our single strand No. 8 steel wire conductor has become rusty over time as the zinc layer (galvanising) has eroded, causing the steel to corrode. This has been expedited by the use of copper coated wire as binders where the insulators support the conductor. This bimetallic contact between the copper binder and the galvanised steel conductor leads to accelerated sacrificial corrosion of the zinc coating, followed by the steel conductor in preference to the copper tie. This can be seen in the following photos where the corrosion is clear around the binder and limited beyond this contact. This potential failure cause is now specifically checked for and documented under the new OH inspection regime. We are also working with our service providers to ensure that inspectors are aware of and consistently detecting such defects.

Figure 8.20: Mid-span joints on distribution conductor

Figure 8.21: Rusted No. 8 wire at an insulated tie point due to bi-metallic corrosion

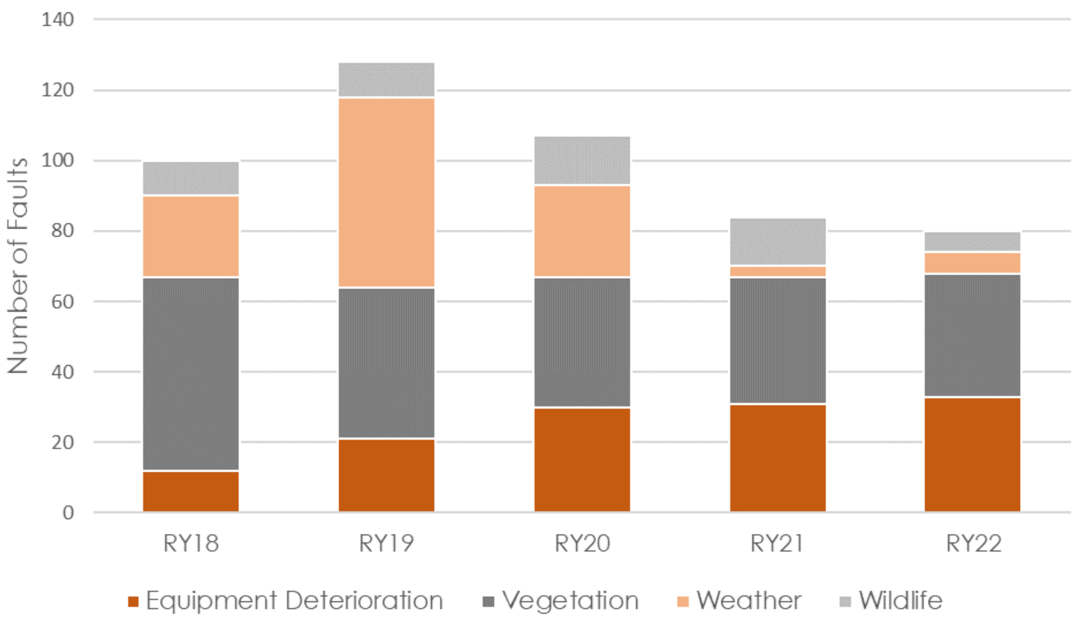
We have identified some type defects in our conductor fleet, which has warranted replacement before expected life is reached. The majority of one example 'Simalec' conductor has been replaced, the remaining is a current project AAAC type conductor, which is manufactured to have high-strength characteristics but has turned out to be very brittle. The conductor cannot be worked on live and has been assessed as being a higher failure risk conductor, warranting prioritised replacement amongst No. 8 and 16 mm^2 copper types.

The ACSR fitting and joint problem (discussed in sub-transmission conductor section) is most applicable to the distribution conductor fleet with its high quantity of ACSR conductor. Our new inspection programme will identify types of joints and ones with poor workmanship, and then a prioritised joint replacement plan under corrective maintenance. In some cases, reconductoring may be applicable if the quantity of joints in one section is very high or other issues are found.

Performance

Our overhead network is designed to cope with defined environmental conditions such as certain wind and snow loadings.[17] Failures, however, do occur and lead to conductor drops. Common causes include external factors such as vegetation and wildlife contact, plus mechanical failures, pole or crossarm failures due to poor condition, wind/snow loading, or failure of conductor joints or fittings. Conductor failure can result in a safety risk to the public and our service providers.

Figure 8.22: Distribution conductor performance – conductor faults



We are working to improve our recording of outage cause data, and we undertake follow up investigations on all conductor incidents to determine the root cause. Knowing the root cause of a conductor down event enables us to take all possible steps to reduce the risk of recurrence.

The chart below shows the frequency of distribution conductor-related faults we have recorded on our network over the past five years.

In spite of a general reduction in conductor-related faults over this period, we have experienced an increase in faults due to deteriorating asset condition. This may reflect poor capture of root cause information in previous years. Our historical performance data is not reported by type or able to be linked to conductor type, so it is difficult to attribute failures to particular conductor types. We have sufficient evidence based on ICAM and other investigations undertaken, that higher failure rates are occurring on No. 8, 16 mm^2 copper, and with ACSR fittings and joints.

We do have instances of high vehicles contacting our distribution conductor, and in most cases the line clearances are compliant. We have a register of under-clearances and often these are located in aged parts of the network. For many overhead sections, design standards have changed since installation. It is now prudent on heavy haulage routes to increase clearances to modern standards, even if the clearances were compliant at the time of installation. Another cause of under-clearances

[17] Note that the design standards that applied to many of our existing assets have changed over time.

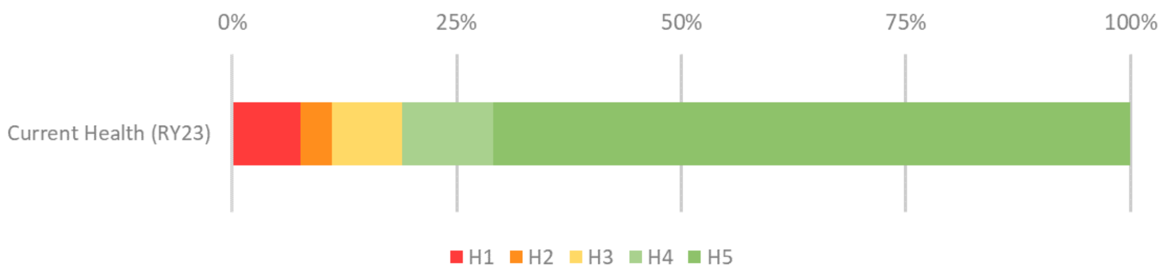
is the inherent raising of road levels as roads get resurfaced, and this is something we will look to manage with stakeholders. We are continuing a programme to address these under-clearances.

> **Meeting our portfolio objectives – sustainability by taking a long-term view**
> We will undertake systematic analysis of failures and fault data to provide detailed feedback to inform asset planning decisions and future performance targets.

Asset health

Our AHI for distribution conductor is based on expected remaining life considering conductor type, size, and location (data quality improvement will come with inspections). The current health of our distribution conductor fleet is shown below.

Figure 8.23: Distribution conductor current asset health



Approximately 17% of our distribution is nearing replacement criteria (H1-H3, replace within 10 years). Most of the replacement will be the aged copper and No. 8 wire conductor types.

Risks

Table 8.9 in the sub-transmission conductor section above sets out the key failure modes of the types of conductor on our network, which also apply to our distribution conductor. We have a significant amount of No. 8 steel wire remaining in service on our distribution networks and this further failure mode is included in the table below.

Table 8.12: Distribution conductor failure modes

TYPE	FAILURE MODE
Steel No. 8 wire	This is No. 8 fencing wire. It is single strand, small diameter galvanised wire. It tends to be less durable than other conductor types and can be prone to sudden failure, especially if overloaded under fault conditions, or when galvanising has degraded and rusted. As noted prior, this is greatly accelerated by the historic use of copper binders creating a galvanic cell.

Table 8.10 in the sub-transmission conductor risk section sets out the key risks we have identified in relation to our conductor fleets. These risks also apply to our distribution conductor fleet.

Design and Construct

In terms of design and construction, each consideration covered for sub-transmission conductor also applies to our distribution conductor fleet. Distribution conductor is generally installed in public areas (unlike sub-transmission) and so consideration to significant line route changes tend to be rare, and consenting requirements are not so often encountered.

Under-clearances are usually remediated by installing two new poles (at either end of the low span) to lift the existing conductor and meet NZECP34:2001 clearance requirements. The conductor will only be replaced if it is past expected life or has noted condition issues justifying replacement (E.g. lots of joints from previous impact repairs).

We are only in the second year of our conductor renewal programme. However, as pole expenditure ramps down conductor expenditure will ramp up, and the resource requirements are similar. We see our programme as deliverable in light of our current contracting arrangements, noting that we have set a realistic timeframe to remove the distributor conductor backlog, taking account of deliverability and risk.

Renew or Dispose

Presently we identify renewal candidates (distribution conductor) using age and expected life as a proxy for condition. As previously mentioned, we will be validating data and visually assessing condition from Q4RY22, and our recovery and testing of samples of conductor will be continually used to adjust or validate remaining useful lives. We prioritise identified renewals by criticality and deliverability at present, due to a backlog of conductor that has exceeded its expected life. Some conductor sections to date have been replaced due to asset failure, and the failure data has supported our estimates for expected lives. Once we have cleared the backlog, we put in place more advanced risk prioritisation processes; this may determine that a conductor in a high criticality zone is replaced prior to end-of-life due to the public safety risk it presents.

When considering the replacement of conductor circuits, it is very important to also consider and assess the health of the poles supporting the conductor, given that pole renewal comprises a significant proportion of the renewal cost. The same consideration applies to pole mounted equipment such as crossarms and distribution transformers, which are only replaced if nearing expected life, economically justified based on economies of scale, or do not meet current design standards. Our conductor forecasts include all replacement poles and pole mounted equipment that are undertaken as part of a reconductoring project.

We have been focusing on replacing smaller conductor past expected life, including No. 8 steel and 16 mm^2 copper, for which there have been confirmed conductor drop incidents. We also address low clearance spans as identified. The table below summarises our renewal approach.

Table 8.13: Summary of distribution conductor renewal approach

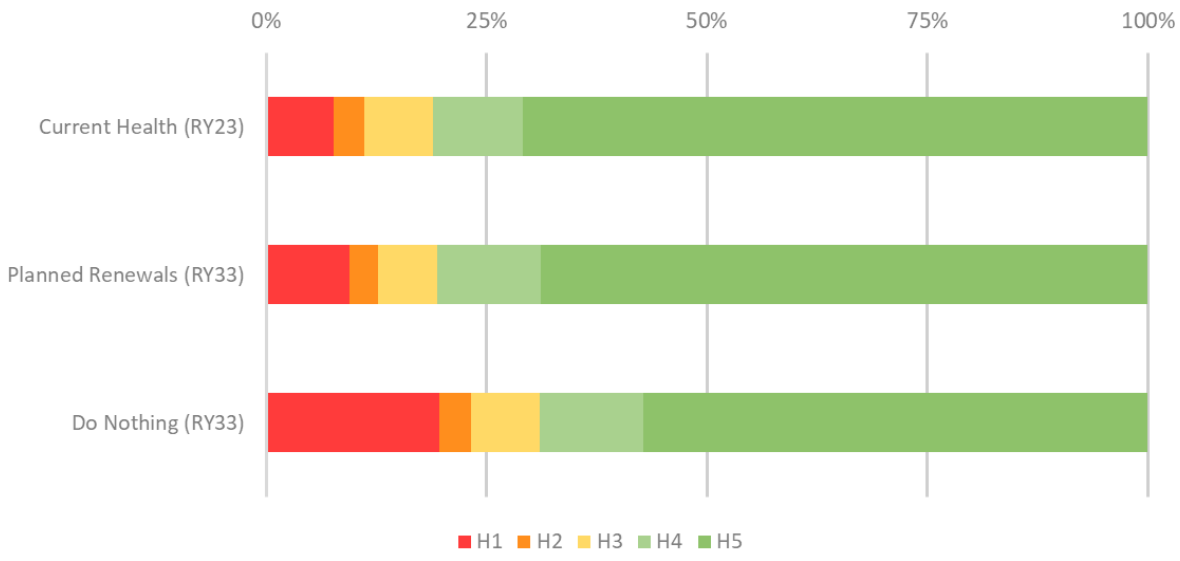
ASPECT	APPROACHES USED
Renewal trigger	Age (vs expected life), with criticality/deliverability/risk prioritisation. Under-clearances, with criticality prioritisation
Forecasting approach	Repex Known under-clearance violations
Cost estimation	Volumetric; historical average unit rates for conductor, and separately per low span (under-clearance)

Renewals forecasting

We are working to refine and verify condition of our overhead conductor fleet; our current forecast and assumptions around condition indicate that even with current investment levels, we will still be in a backlog situation in RY33. Achieving steady-state sooner would be desirable, but we do not believe this to be deliverable, considering SADI and SAFI constraints as well as resourcing constraints, and impact on other works. We are actively managing the risk to public by prioritising renewals in high criticality zones, while we concurrently shift to a condition-based renewal planning model – informed by the OH Inspections which have commenced this year.

The chart below compares projected asset health in 2033 for the entire fleet following our planned programme of renewals, with a counterfactual 'do nothing' scenario.

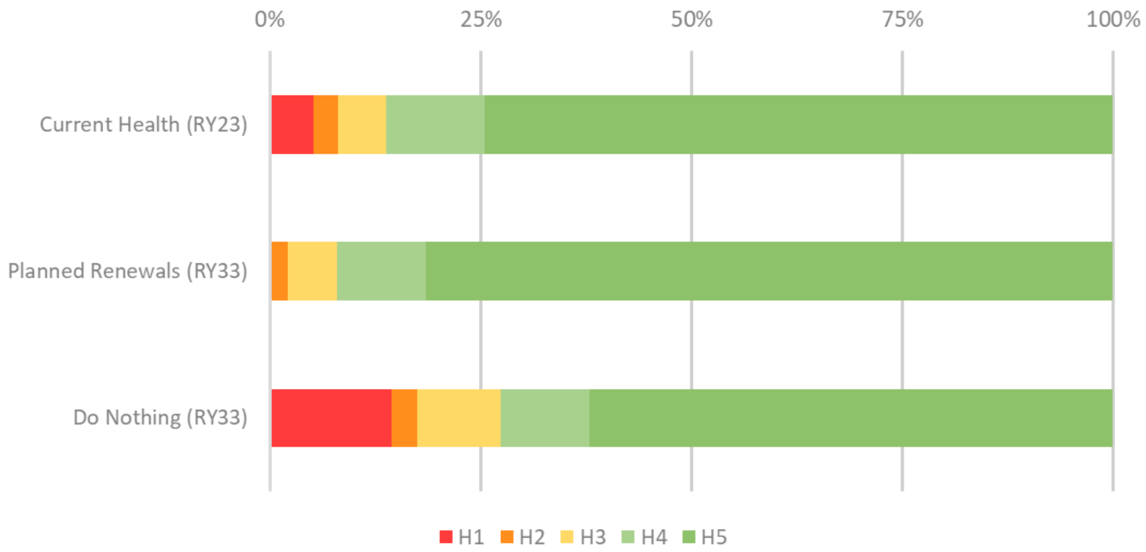
Figure 8.24: Projected distribution conductor asset health at RY33



If we do not invest, then 17% of our fleet will be at risk of failure by RY33, creating intolerable public safety risk. This comparison, however, does not indicate the benefits provided by our proposed investment programme.

Due to the deliverability constraints previously mentioned (labour force, managing planned outage volumes), our proposed level of investment is not sufficient to provide an improvement in the overall fleet health. By taking a risk prioritised approach, focusing on high criticality zones, we will see a significant reduction in H1 assets in Criticality Zones 1 and 2 – as demonstrated in Figure 8.24 below. We will continue this approach of prioritising renewals based on the exposure to the public. The figure below compares the asset health in 2033 for high exposure areas following our planned programme of renewals, with a counterfactual 'do nothing' scenario.

Figure 8.25: Projected distribution conductor asset health for high public exposure areas at RY33



Options analysis

Generally, options analysis is seldom required for distribution conductor. In select cases, such as when the conductor does not feed many customers and the poles are also in poor condition, then it is valuable to consider alternative solutions E.g. non-network solutions.

When managing our distribution conductor fleet, we normally replace line sections rather than whole lines, as generally an entire line or feeder was not built at the same time and hence is not due for replacement at the same time. Furthermore, distribution lines tend to consist of many different conductor serving different loads and with slightly different needs. For example, sections close to towns versus spur sections on the end of radial feeds may be different conductor. Easement considerations tend to be significantly less than sub-transmission conductor, as the majority of distribution conductor is in public property (road reserve).

As such, options analysis is not normally warranted other than verifying that non-network solutions are not more cost-effective where fewer customers are affected. We also consider if, during the renewal any change in ampacity or network configuration is justified. Large network reconfigurations that cause the scope to change significantly are classed as growth projects. As per sub-transmission, Opex/Capex trade-offs are made if the driver to invest in the distribution conductor could be mitigated by either means, and consideration of undergrounding can be applicable in rare cases, E.g. when line passes through a native forest that cannot be trimmed to clear the fall zone.

Underbuilt LV conductor is considered for renewal with the distribution conductor subject to its age vs expected life and economic efficiency of consolidating works.

Use of criticality in works planning and delivery

A criticality score is assigned to each section of distribution conductor, based on the number, size and priority of customers and the public safety zone through which the conductor passes. For instance, conductor supplying higher priority customers such as hospitals and emergency operation centres will be prioritised over those that supply residential premises. In addition, conductor located next to higher public safety zones such as schools will be prioritised over those located in farmland away from roads and other infrastructure.

On an annual basis, we use criticality scores to prioritise renewals in works planning and delivery. We recognise that there is value in enhancing this model and plan to mature it over time. Part of our approach involves sectioning the distribution network into smaller areas to better understand the impacts of an unplanned outage and better reflect the potential outcome of a conductor down incident. Reliability can then form part of the basis for identifying conductor replacement priority.

We also have assigned a deliverability index to each distribution conductor that is past expected life and a potential candidate for our annual delivery. Given we have a backlog of poor condition conductor and are prioritising by criticality, it is efficient to do the most critical jobs that are easier to deliver first, if they have roughly the same degree of risk mitigation. This deliverability index considers practically how difficult the job is to complete, E.g. a project through rough hilly country (which may be alongside State Highway 1 giving it high criticality) will be harder to undertake than a project outside a school on a rural road.

Meeting our portfolio objectives – affordability through cost management

Our criticality and deliverability prioritisation approach ensures that the investments in distribution conductor renewal that reduce the highest risks most easily occur first, ensuring customers and our communities receive maximum value from our projects.

Coordination with other works

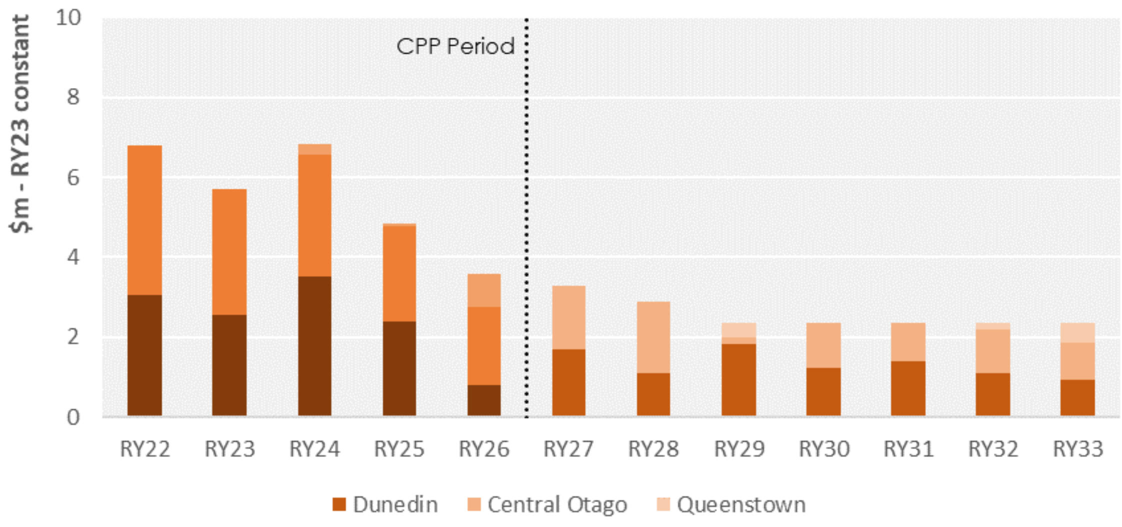
In making distribution conductor replacement decisions we consider whether the investment should be combined with other projects, such as conductor upgrades or new feeders required to supply load growth due to residential infill housing or new subdivisions. We also consider other needs, such as managing low voltages in areas with customer loads supplied by long, 'stringy' lines.

When we need to replace or thermally uprate conductor, the poles that support them may also need to be replaced due to the higher mechanical loads on the poles and application of modern standards. Even a like-for-like ampacity conductor may be larger. For example, copper is smaller per ampacity than aluminium, so aluminium is lighter but has higher wind loading due to increased surface area. As part of upgrade projects, we may identify poles and other pole mounted equipment in poor condition, which would be replaced in a coordinated manner with the conductor upgrade to ensure efficient delivery and to minimise customer disruption. The detailed requirements for each individual upgrade project are confirmed once the project has been initiated.

Distribution Conductor Fleet Expenditure Forecast

We have forecast renewal Capex of approximately $33m during the planning period. We had previously forecast additional expenditure for distribution conductor, but we have decided to prioritise other fleet programmes that present a more significant risk to public safety. Also, we are prioritising conductor replacement in our critical risk zones.

Figure 8.26: Forecast distribution conductor Capex



The programme of work to replace end-of-life distribution conductor started in RY20, prior to which annual distribution conductor replacements were low. We intend to increase our expenditure over the early part of the planning period to address conductor past their expected life and rectify under clearances. In the second part of the period, our focus will be on conductor past expected life and managing any issues found through inspections that did not require immediate intervention. We will replace approximately 212 km (9%) of our distribution conductor over the period to RY33, of which most will be copper and No. 8 wire. Poles and their crossarms often need to be replaced to enable conductor replacement if they are under strength, in poor condition, or unsuitable to meet clearance requirements; these are included in this portfolio forecast.

Benefits

The major benefits expected from our planned distribution conductor renewals are reductions in public safety risk through reduced likelihood of conductor drop or third-party conductor impact, and improved asset reliability via a reduction in faults. This investment is key to meeting our safety and reliability objectives. Asset health for the fleet as a whole will be improved, relative to the current state as the backlog is addressed.

8.2.4. LV Conductor

Where information is also common to the sub-transmission and/or distribution conductor sections, it has generally not been repeated.

LV Conductor Fleet Overview

LV conductor operates at voltages of 230 V and 400 V and carries electricity from our distribution substations to our customers, or it is used to power streetlights. We own approximately 930 circuit kilometres of overhead LV conductor (including streetlighting circuits), which is primarily aluminium and copper types, with a small volume of ACSR. LV conductor is supported by our overhead structures (poles and crossarms).

LV conductor sections tend to be shorter than distribution conductor sections due to the voltage drop. LV can be underneath higher voltages on the same poles (known as 'underbuild'), or on separate pole lines. Many LV lines serve only few customers. We are currently developing a plan to enhance the data we hold on LV lines that serve a single customer. Hence, they are not covered explicitly in any statistics throughout this document. At present, like most other EDBs, we have limited visibility of our LV network, both in terms of asset data and utilisation than our higher voltage networks. This factor, plus the physical characteristics of LV, led us to manage this fleet separately to the other conductor voltages.

LV conductor, like our other conductor fleets, has inherent public safety risk due to exposed live wire in the public domain that can fail to ground. While being lower voltage than other conductor fleets, LV conductor has its own set of safety issues and considerations.

Population and Age

The table below summarises our population of LV conductor by type. Aluminium and copper currently comprise 930 circuit kilometres, with the balance being ACSR and No. 8 wire.

Meeting our portfolio objectives – sustainability by taking a long-term view

For 40% of our LV conductor fleet, we have no master data specifying conductor type. We have prorated the unknown types of LV conductor across the proportions of other types, based on their age. We will use our new conductor inspection regime to identify unknown types over the first half of the planning period to have a better understanding of our LV conductor fleet.

Table 8.14: LV conductor population by type[18]

TYPE	POPULATION (CIRCUIT KM)	PERCENTAGE
Aluminium[19]	302	32%
Copper	616	67%
ACSR	12	1%
No. 8 wire	0.1	0%
Total	**930**	**100%**

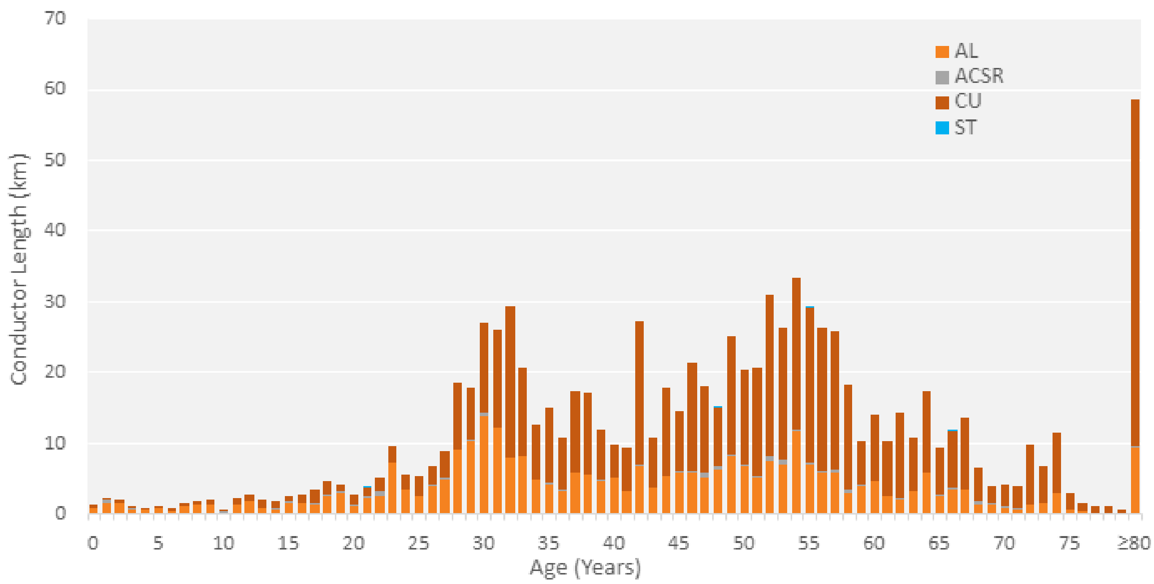
The following chart shows the age profile of our LV conductor. As with our other conductor fleets, significant network expansion took place around the 1960s, resulting in a considerable volume of conductor that is approaching or has reached end-of-life. Our copper conductor has the highest average age at 50 years, and a sizable proportion of this will require renewal in the medium-term. Similar to distribution conductor, we have PVC covered LV conductor to primarily provide increased resistance to vegetation faults, with the added benefit of it making the neutral conductor (which is not covered) more easily identifiable and easier to work on. We also have volumes of ABC LV

[18] This includes prorated types as discussed above.

[19] Includes ABC conductor.

conductor, which is used where clearances are limited, such as when a line runs past a building. The average age of all our LV conductor is 52 years.

Figure 8.27: LV conductor age profile



The expected lives of LV conductor vary with type, size, and location. The expected lives of LV conductor are reflected Table 8.8. The expanded conductor forensic sampling discussed in the distribution conductor section may also apply to LV conductor, subject to our findings.

Condition, Performance and Risks

The condition, performance and risk considerations of our LV conductor correspond to those set for our distribution conductor. However, LV conductor failure will always cause loss of supply, because at these voltages the circuit is always one line (i.e. N security), or if two lines, then requiring a manual close of an open point to restore supply.

Condition

As described in the equivalent section on sub-transmission conductor, condition assessment for overhead conductor is relatively challenging. We have not historically collected condition data for our LV conductor fleet, other than data collected during associated pole inspections. We are implementing an inspection programme to improve our knowledge of conductor condition, to fill data gaps, and to identify other issues such as poor workmanship.

An additional factor for LV conductor relates to the common use of PVC or hessian as an insulating layer on covered conductor. The insulating layer can deteriorate in New Zealand conditions due to the elevated level of UV radiation. The issue is particularly relevant in Otago as it experiences higher UV levels than Dunedin. Fortunately, the covered LV conductor in Otago tends to be newer so the same level of degradation has not occurred. The degraded condition of the PVC does not directly affect the function of the conductor but cracked PVC may trap salt and moisture between the PVC and the conductor itself, and potentially accelerate corrosion above levels that would be experienced without PVC coating. This failure mode will be tested through the conductor forensic sampling programme.

Performance

We have not historically collected LV outage data, so we are unable to assess the reliability performance of LV conductor.

Anecdotal evidence suggests relatively few in-service failures compared to distribution conductor. From ICAM investigation findings to date, we suspect these failures were mainly caused by faulty joints and fittings due to poor workmanship or incorrect product usage. We have seen multiple recent examples (and near misses) of dead-end failures in our Dunedin network, which have been attributed to poor workmanship. We are considering how we can find further cases of these installations prior to their potential failure.

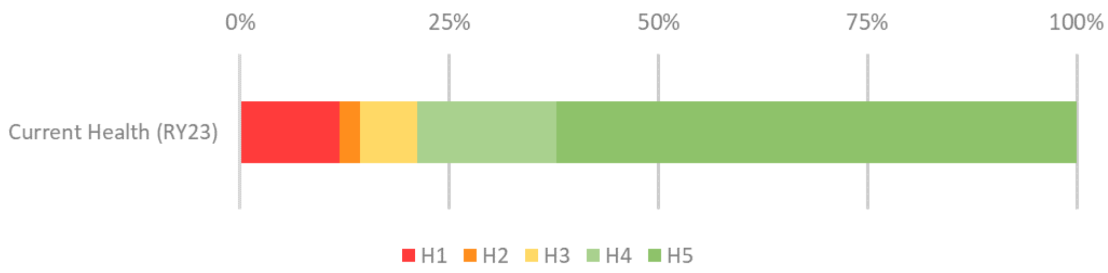
As per distribution conductor, we also have a register of under-clearances on main roads that require remediation.

We are in the process of reviewing our processes and systems to allow for future recording of LV conductor failures, so that we can build a more definitive view of LV conductor performance.

Asset health

LV conductor AHI is based on expected remaining life considering conductor type, size, and location.

Figure 8.28: Low voltage conductor current asset health



Our LV conductor asset health suggests that we need to replace approximately 14% of our LV conductor fleet over the next three years (H1 and H2), and 21% over the planning period (H1 to H3) (to RY33). This predominantly consists of copper conductor that has exceeded its expected life.

Risks

Earlier in Table 8.9 and Table 8.13, we set out the key failure modes of the types of conductor on our network, which also apply to LV conductor. Table 8.10 section sets out the key risks we have identified in relation to our conductor fleets. These risks also apply to our LV conductor fleet. One further risk outlined in Table 8.16 given the specific circumstances of LV conductor faults.

While operating at lower voltages than other conductor, LV conductor faults can be high impedance and difficult to detect and isolate automatically using conventional means such as fuses or protection. As such, the safety risk associated with LV conductor is potentially comparable with that of higher voltage conductor.

The electrocution risk associated with failed LV conductor is partially mitigated by introducing covered conductor. We install covered conductor today, but some legacy conductor is not covered. Degradation of the PVC covering may increase the safety risk compared to new covered conductor. Good PVC insulation may assist with lines remaining live on the ground due to further increasing fault impedance, but it reduces the area of the conductor on the ground which has propensity to electrocute (only the broken end has no insulation on it).

Table 8.15: LV conductor specific failure risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
Conductor failure to ground, due to poor condition or workmanship issue with conductor itself or joints/fittings and potential implications (including electrocution, fire, loss of supply or reduced security). Conductor stays live due to high fault impedances and fuses do not blow to clear the fault.	New inspection regime and forensic testing regime Proactive replacement of conductor sections Proactive replacement of joints and fittings Standardisation of equipment Training and education of linesmen on joints/fittings usage and installation Education of public on lines down events	Safety, reliability

Design and Construct

In terms of design and construction, all the considerations covered in section 8.2.2 for sub-transmission conductor also apply to LV conductor. LV conductor is generally in public areas (unlike sub-transmission) and so consideration to significant line route changes tend to be rare, and consenting requirements are not so often encountered.

Previous LV design standards varied significantly across the Dunedin and Central Otago networks, with different types and sizes of conductor in use. Our preferred LV conductor is now ABC.

At present, our LV conductor renewal programme consists of end-of-life underbuilds being identified during scoping of distribution conductor renewals projects. As they are replaced, the removed conductor are assessed for type and condition to support future renewal decision-making.

Renew or Dispose

Historically there has not been any proactive LV conductor renewals. However, as the population is ageing, it is important that we move to a more proactive approach.

We will renew LV conductor primarily on the basis of age and expected life as a proxy for condition. They are further prioritised by criticality and deliverability at present due to a backlog of conductor past its expected life. Once we have cleared the backlog, we will use full risk prioritisation as opposed to just criticality and deliverability prioritisation; this may entail a conductor in a high criticality zone is replaced shortly prior to end-of-life due to the public safety risk it presents.

When considering the replacement of conductor circuits on this basis it is very important to also consider and assess the health of the poles supporting the conductor as pole renewal comprises a large proportion of the renewal costs. Our conductor forecasts include all replacement poles and pole mounted equipment that are undertaken on the reconductoring project.

We will focus on replacing smaller conductor past expected life, including No. 8 steel and 16 mm^2 copper, for which there have been confirmed conductor drop incidents at distribution voltage level.

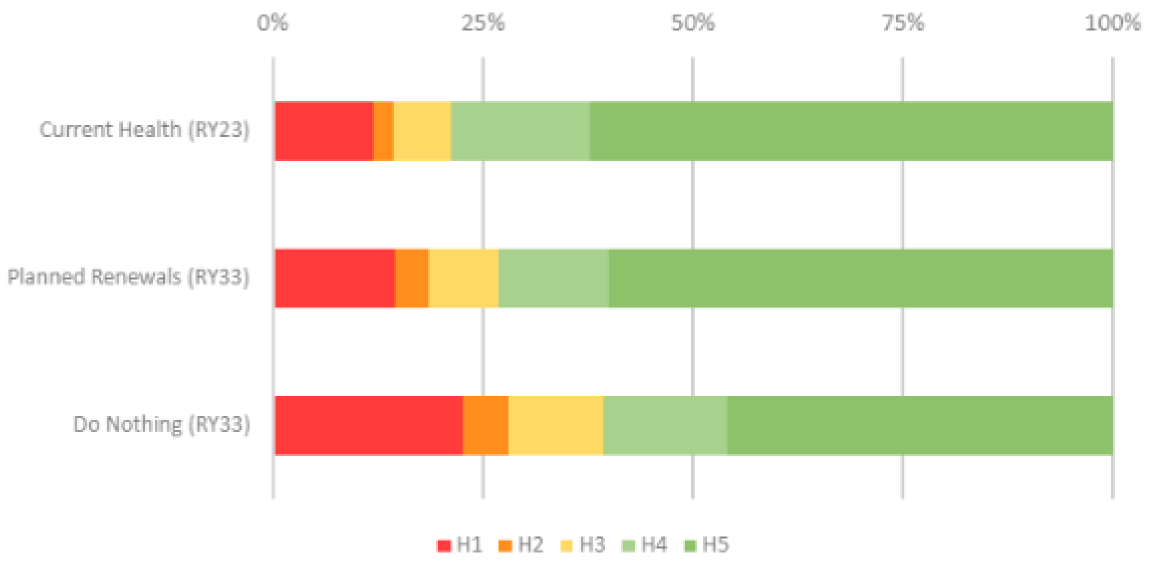
Table 8.16: Summary of LV conductor renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Age (vs expected life) Criticality/deliverability/risk prioritisation Under-clearances, with criticality prioritisation
Forecasting approach	Repex Known under-clearance violations
Cost estimation	Volumetric; estimate of unit rate based on historical distribution conductor projects, and separately per low span (under-clearance violation).

Renewal forecasting

Our plan is to achieve steady-state renewal levels by RY33. Achieving steady state faster would be desirable but we do not consider it deliverable when considering resourcing and impact on other works. The chart below compares projected asset health in RY33 following our planned renewals, with a counterfactual 'do nothing' scenario. This comparison indicates the benefits provided by our proposed investment programme.

Figure 8.29: Projected LV conductor asset health at RY33



Our proposed level of investment will improve overall fleet health, helping manage the risks associated with conductor failure. In the hypothetical 'Do Nothing' scenario, ~23% of our fleet, as depicted by the H1, will be at risk of failure as at RY33, potentially creating intolerable public safety risk.

Options analysis

With LV conductor, more so than the other conductor fleets, we must consider the potential impacts of embedded generation. Increased adoption of solar, battery, and electric vehicle penetration will be felt more readily on our LV network than other parts of the network. In areas where maximum demand indicators (MDIs) signal high loading, it will be prudent to undertake power quality monitoring prior to scoping LV conductor renewals to ensure the right option is chosen.

Use of criticality in works planning and delivery

We are yet to develop a criticality-based prioritisation framework for LV conductor, and we shall develop one as we have for distribution conductor in due course. In our GIS system, consumer connections are often approximated by 'virtual connections', which presents challenges in understanding how our customers are physically connected to our network. Criticality levers such as number and priority of customers supplied, size of demand, and public safety criteria will also be used to build the LV conductor prioritisation model.

Coordination with other works

Planned network development projects focus on sub-transmission and distribution constraints. LV enhancement works are undertaken as an outcome of Customer-Initiated Works (CIW) programmes, as customers request connection and require reinforcement of existing assets, or in response to voltage complaints. Renewals are also instigated by the need to meet our legislated quality of supply obligations. This work affects only a small volume of LV conductor, and is not specifically targeted at LV conductor health, but overlap and consolidation of works for efficiency must be considered.

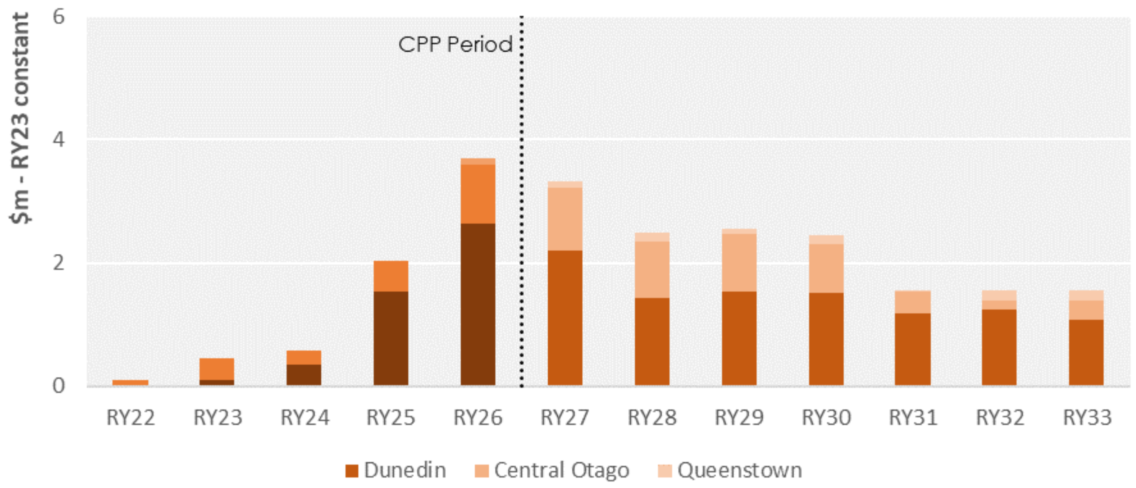
Some LV conductor upgrade work will be carried out as part of associated projects, such as distribution conductor replacement when LV is underbuilt, if the LV is at or past expected life or otherwise justified.

LV Conductor Fleet Expenditure Forecast

We have forecast LV conductor renewal Capex of approximately $21.8m during the planning period to improve the overall condition of the fleet.

We have historically only replaced LV conductor on a reactive basis. The programme of work to replace end-of-life LV conductor started in RY22 but ramps up over the RY24-26 period. In the latter years of the planning period, we will continue replacement at a steady rate. The primary drivers for this renewal programme are management of the safety and reliability risks associated with aged copper conductor. This level of work is warranted by the aggregate health of the LV conductor fleet.

Figure 8.30: Forecast LV conductor Capex



Benefits

The main benefits expected from these investments are improved safety (reduced risk of conductor drop or third-party conductor impact (for low spans)) and improved asset reliability (fewer faults).

8.3. UNDERGROUND CABLES

This section describes our underground cables portfolio which includes three asset fleets:[20]

- sub-transmission cables (33 and 66 kV)
- distribution cables (6.6 and 11 kV)
- LV cables (230 and 400 V).

Portfolio Summary

We replace cable sections or entire sub-transmission cables proactively on the basis of age (compared to expected life) and condition, while most distribution and LV cables renewals, undertaken on a condition-basis, are reactive. In the medium-term we forecast work volumes using individual identified analysis for sub-transmission cables and Repex models for distribution and LV cables. We are also proactively replacing cast iron cable terminations due to safety risk.

During the planning period we expect to spend an average of $3m per annum on cable asset renewals, approximately half of this on sub-transmission renewals.

Our cable works programmes focus on maintaining reliability and addressing safety concerns. The reliability impacts of cable faults, particularly sub-transmission faults, can be greater than for overhead conductor due to the longer repair times requiring specialist resources.

Underground cables, like overhead conductor, convey electricity between the transmission system and zone substations and between different zone substations (sub-transmission cables), between zone substations and distribution substations (distribution cables), or from distribution substations to LV customers (LV cables). They come in a variety of types and sizes, enabling electrical flow at

20 The portfolio forecasts exclude power cables which connect our zone substation transformers to our zone substation switchboards, as these are located wholly in our zone substations and hence are covered under that portfolio.

various voltages. Underground cable makes up approximately 37% of our total circuit length. The underground cables portfolio also includes cable joints, pole terminations, equipment terminations and other ancillary cable equipment.

We define our underground cable fleets according to operating voltage. This is because the approach needs to reflect not only the risks faced and the criticality of the asset, both of which vary with voltage, but the inherent nature of each voltage level. Together, these factors can lead to different lifecycle strategies.

Box 8.8: Summary of our asset risk review – underground cables

Issues: We have identified signs of condition deterioration in some sections of cables above ground. We also have cast iron cable terminations installed on our network, which have a potential explosive failure mode.

Response: removal of all cast iron cable terminations with prioritisation towards those installed in public safety critical areas. We will continue our programme of sub-transmission cable replacements based on condition, obsolescence and resilience drivers.

Timing: we plan to replace all cast iron cable terminations by RY26. Sub-transmission cable replacements will continue over the AMP planning period.

The performance of our cable assets is essential to maintain a safe and reliable network. Cables are better protected from adverse weather than overhead conductor, but are susceptible to insulation, sheath and joint deterioration, particularly if not installed properly. Cables are not readily accessible to the public but may be damaged and exposed by excavation or disturbed by ground movement.

8.3.1. Underground Cables Portfolio Objectives

Our portfolio objectives for underground cables are listed below.

Table 8.17: Underground cable portfolio objectives

OBJECTIVE AREA	PORTFOLIO OBJECTIVES
Safety first	No fatalities or injuries to workers or public from contact with our cables or failure of our cables and terminations.
Reliability to defined levels	Cable failure rates are to be consistent with historical failure rates.
Affordability through cost management	Ensure lowest whole-of-life cost solutions are chosen, while giving regards to network resilience.
Responsive to a changing landscape	Manage obsolescence risk of fluid-filled cables.
Sustainability by taking a long-term view	Minimise oil leaks from pressurised oil-filled cables. Minimise traffic interruptions when undertaking cable repairs or renewals in road reserves and plan consolidated works with other underground utilities. Opportunities to increase cable network resilience are taken, where cost is comparable to like-for-like replacement.

8.3.2. Sub-transmission Cable

Sub-transmission Cable Fleet Overview

Sub-transmission cable connects our supply points at GXPs to our zone substations, and generator connections and interconnections between our zone substations, at voltages of 66 kV and 33 kV. Our sub-transmission cable fleet consists of approximately 87 circuit kilometres of underground cable, around 75% of which is located in our Dunedin network region. The fleet includes any sub-transmission cable ancillary equipment such as surge arresters, and gas and oil pressurisation equipment. The nature of our sub-transmission network is that the cable routes are point to point, unlike distribution cables which generally have many tee-off points at ring main units to supply distribution substations.

Sub-transmission cables are critical on the network given the amount of power they commonly convey compared to distribution cables. To mitigate failure risk, almost all our sub-transmission cables have N-1 security, meaning that the failure of one of the cable circuits does not cause loss of supply, though it will result in reduced network security to a large number of customers. Having N-1 security means that if a cable does fail, we can undertake repairs while continuing to supply power on the parallel circuit. This is important, given specialist resource requirements and the much longer time taken to repair a cable compared to an overhead conductor. These long repair times do leave open a reliability risk of the other cable circuit failing, and failure risk is likely elevated during this time due to the cable carrying double its normal current for an extended period.

Sub-transmission cables are inherently under greater stress than distribution and LV cables, by the nature of the higher operating voltage. This makes them less resilient when defects are present.

Network considerations, in addition to being more complex and higher value equipment, mean that sub-transmission cable projects tend to have a much greater cost than distribution cable projects. All these factors support managing sub-transmission cables as a separate fleet.

Our fluid-filled sub-transmission cables are near obsolete due to procurement of parts and specialist workers. Given that approximately half of our sub-transmission cable is expected to require replacement within the planning period, we plan to reconfigure the Dunedin sub-transmission cable network in a manner which improves resilience to major events such as earthquakes. Some investments involved in the reconfiguration will be classified as sub-transmission cable renewal, while others will be growth/resilience investments covered as major projects in our network development programme. This will depend on the specific project.

Population and Age

Our sub-transmission cable network consists of nitrogen gas-filled and oil-filled paper insulated cables,[21] Paper Insulated Lead Covered (PILC) cables and Cross-Linked Polyethylene (XLPE) cables. The table below summarises their population by type. Fluid-filled cables make up almost 50% of total cable circuit length.

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21 Gas-filled and oil-filled cables are technically a subset of PILC cables; however, given their different characteristics and expected lives we have classified them separately.

Table 8.18: Sub-transmission cable population by type

TYPE	POPULATION (CIRCUIT KM)	PERCENTAGE
Gas-filled	16	18
Oil-filled	25	29
PILC	11	13
XLPE	35	40
Total	**87**	**100%**

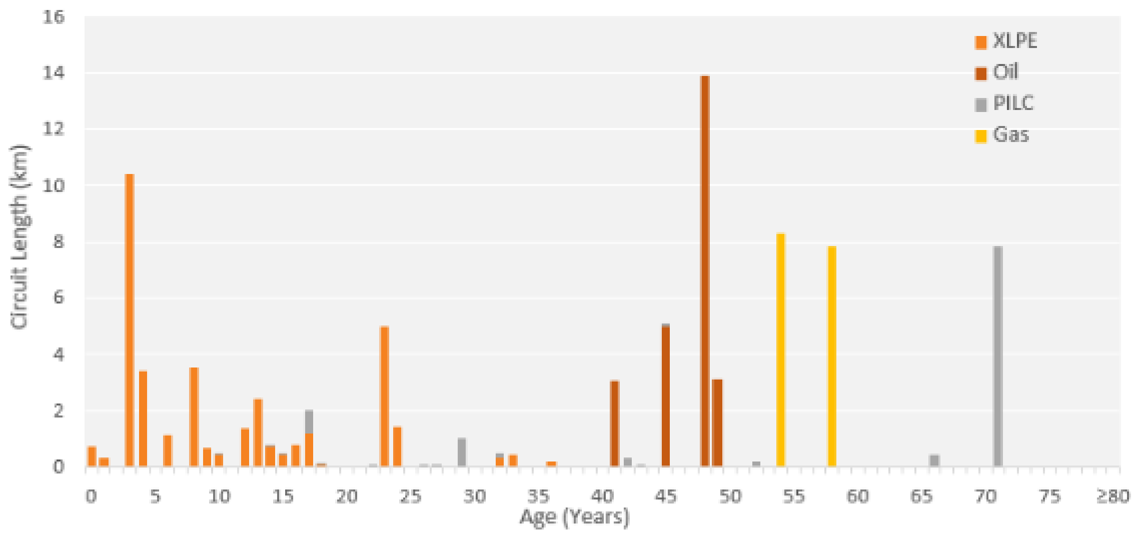
Most of our Dunedin sub-transmission cable was installed during the period 1960-80. Gas- and oil-filled cables, which were the preferred types over that period, have weighted average ages of 57 and 48 years respectively. While they have an expected life of 100 years, both of these cable types are now obsolete.

Our gas cable circuits use a mix of aluminium and copper conductor, while our oil-filled cables use only aluminium conductor. They both have a lead sheath and use paper insulation over the cable conductor. Unlike PILC (solid) cables, however, pressurised gas or oil is used to increase the voltage withstand capacity of the paper insulation. Using the gas or oil allows for less paper insulation to be used, resulting in a smaller cable which costs less. However, these fluid-filled cables do require gas or oil storage vessels, as well as pressure gauges and alarms to provide continuous monitoring for cable containment. They present an inherent risk that other 'passive' cables do not, as their normal cable operation is reliant on the pressurised fluid system containment, and they require more maintenance and monitoring.

Solid PILC cable has been used internationally for over 100 years. It uses paper insulating layers impregnated with non-draining wax or oil/grease, as opposed to pressurised gas or oil. The cable is generally encased in a waterproof lead sheath covered in wrapped tar-impregnated fibre material, PVC or polyethylene. PILC cables have a good performance record in the industry, though obtaining cable jointing expertise for this cable type at the higher voltages (66 and 33 kV) is becoming problematic. We have PILC across all our cable fleets and our oldest sub-transmission cable is PILC type. PILC cables can use aluminium or copper conductor. We have set an expected life of 100 years for our PILC cables, which are an average age of 60 years.

First generation XLPE cable, manufactured in the 1960s and 1970s, is known to fail prematurely due to water-treeing, which causes the insulation to break down. We do not believe we have first generation XLPE in our networks based on age profiles, and if any does exist, they are in limited quantities, and we are not seeing the related failure modes. We are certain that we have no first generation XLPE at sub-transmission voltage. The present generation XLPE has a treeing-retardant added during construction to extend its viable life. XLPE cable is now the industry standard and is generally used for new construction. This cable has an expected life of 60 years. XLPE cables can be purchased with copper or aluminium conductor; aluminium is generally more cost-effective and hence more widely used today.

Figure 8.31: Sub-transmission cable age profile



The gas and older solid PILC cables are nearing or past their expected lives. While the oil cables have not reached expected life, they will likely be replaced in the medium-term due to obsolescence through the scarcity of qualified technicians available to conduct repairs.

Condition, Performance and Risks

Failure of a sub-transmission cable can have significant reliability impacts by leading to a loss of supply or, more likely, reduced network security. The consequences of a failure are potentially high due to the length of time it can take to undertake repairs on specialist cable types; the parallel cable circuit could fail during this time, resulting in loss of supply, and failure risk is likely elevated due to the doubling of normal current flow through the cable for an extended period.

Condition and performance

Managing the condition of sub-transmission cable assets is important for meeting our performance and environmental objectives. The main determinant of sub-transmission cable life is how well the integrity of the cable sheath can be maintained. For fluid filled and solid PILC types, the primary concern is how well the brass tapes/wipes are protected from corrosion; these parts in turn protect the lead sheath underneath, which has reduced life once it becomes directly in contact with the environment. The condition of these parts of the cables are related to the age of the cables and the corrosiveness of the ground in which they were installed.

Our oil and gas-filled pressurised cables, which are the focus of our renewal programme, are obsolete technology. Joints and termination parts are becoming difficult to source, though we do have some stock remaining. The qualified workforce is retiring, and with insufficient ongoing training we are finding it increasingly difficult to find competent jointers to repair our oil and gas cables. Often, we need to rely on specialist contractors from outside our region; as other EDBs also phase out these cables – potentially earlier than we do – our ability to rely on specialist resource from other regions will become limited.

Though little of our remaining oil- and most gas-filled cable has reached its expected life, the condition of much of the older cable is poor. Deterioration has been accelerated by ground movement and corrosivity, installation on slopes, sheath damage, and water ingress. Only one set of our remaining gas-filled cables has intact outer sheaths. We are seeing gas leaks at the joints of gas-filled cables; the leaks are caused by cable movement and corrosion of the bronze tapes which hold the lead sheath in place, allowing moisture ingress. Analysis shows a high failure rate of gas-filled cables over the past 20 years, with incidents occurring almost annually. Gas leaks can be difficult and costly to locate, and we plan to replace all remaining gas-filled cable during the planning period.

The condition of the sheath of our oil-filled cable is generally acceptable, though some minor leaks present a concern. From the perspective of sheath continuity, oil leaks are less of a concern than moisture ingress into the cable. We have scheduled replacement of our oil-filled cables for later in the planning period, primarily due to obsolescence; we will review these replacements on the basis of condition, performance and risk closer to the time, including monitoring the availability of specialist resource and spare parts.

Our older solid PILC sub-transmission cable has suffered accelerated deterioration due to drying out of the paper below leaking joints installed on steep slopes. This has caused several faults, and though it has not quite reached its expected life, we plan to replace affected cable in the near-term.

Overall, our sub-transmission cable performance has been reasonable in the recent past. As most of our circuits have N-1 security, the occasional fault can occur without interrupting supply.

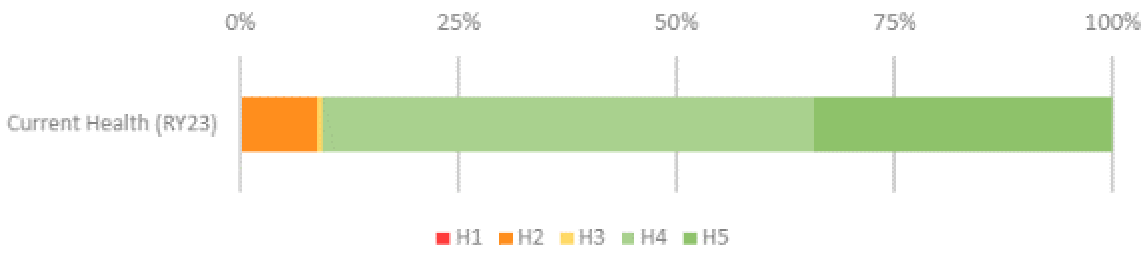
Meeting our portfolio objectives – responsive to a changing landscape

We will continue to monitor the market for skilled cable professionals who can work on our fluid-filled cables, and adjust our plans should the outlook change, including if new condition information comes to hand.

Asset health

We estimate fleet asset health for sub-transmission cables primarily on the basis of age (vs expected life) and condition. Sub-transmission cable asset health is shown below.

Figure 8.32: Sub-transmission cable asset health



Our asset health analysis indicates that approximately 18% of our sub-transmission cable length has already or will reach end-of-life within the next three years (H1-H2), and over 25% within 10 years (H1-H3). Our proposed investment programme will remove all H1 condition sub-transmission cable and reduce the level of H2 and H3 on our network.

Risks

The table below sets out the key risks and mitigations we have identified in relation to our sub-transmission cable fleet.

The instantaneous effects of a sub-transmission cable failure are typically mitigated by the redundancy provided in the network design. However, repairs to sub-transmission cable failures can be lengthy operations, creating significant reliability risk for the duration of the repair.

Table 8.19: Sub-transmission cable risks

RISK/ISSUE	TYPE	RISK MITIGATION	MAIN RISK AREA
Cable strike	All	B4UDIG service Cable depth requirements, mechanical protection requirements Historical practice of both sub-transmission circuits in the same trench now avoided Strategic spare cable joints N-1 redundancy in sub-transmission installations Cable differential protection is fast and limits damage	Safety, reliability
Partial discharge	All	On-line partial discharge monitoring carried out to detect partial discharge, i.e. failing insulation, prior to in service fault	Reliability
Oil-filled cable leaks	Oil-filled	Oil pressure monitoring via SCADA and routine site inspections Type of oil in cables is not considered a hazard by Regional Council	Environment, reliability
Gas-filled cable leaks	Gas-filled	Gas pressure monitoring via SCADA and routine site inspections	Reliability
Lack of resilience to major events E.g. Seismic activity		Some intertie capacity at distribution voltage level and a limited capacity 33 kV link between Ward St and Carisbrook zone substations Dunedin sub-transmission architecture changes will lead to diverse cable routes via a ring architecture, and hence a reduction of common mode failures	Reliability
Fault due to PILC cable drying out	All	Cable differential protection is fast and limits cable damage N-1 redundancy in sub-transmission installations Condition input of known historical failure modes factored into sub-transmission cable replacement programme	Reliability
Oil/grease leakage at joints/pot-heads due to cable laid with high head	PILC (solid)	Routine site inspections Cable differential protection is fast and limits cable Terminations/joints are in secure areas, either buried or high up poles N-1 redundancy in sub-transmission installations	Reliability
Ground level change due to landscaping/erosion	PILC (solid), gas-filled, oil-filled	Regular survey of sub-transmission cable routes	Reliability

RISK/ISSUE	TYPE	RISK MITIGATION	MAIN RISK AREA
Cable or cable termination mechanical damage	All	Routine site inspections Cable differential protection is fast and limits cable damage Terminations are in secure areas or high up poles; cable guards fitted on poles or fitted in retrofit cable guard programme (applies not only to PILC cables) Strategic spare cable and terminations	Reliability
Poor backfill materials can lead to overheating or sheath damage and subsequent cable degradation and/or failure	All	Specifications and site quality assurance	Reliability
Underrated surge arresters protecting sub-transmission cables; potential failure of the surge arrester under fault conditions		One-off inspections to check for correct rating and replace if underrated	Reliability

We have identified that the current network configuration may be vulnerable to high impact low probability events (such as earthquakes or tsunami) as it does not allow for any significant load transfer between zone substations and GXPs. It is also vulnerable to common mode failure, such as a digger putting a bucket through both sets of sub-transmission cables to a zone substation that are located in the same trench area. As significant renewals are required over the next decade, we plan to take this opportunity to reconfigure the Dunedin City cable network to improve resilience to major events.

Design and Construct

We use single-core XLPE cable for new sub-transmission cable circuits. It is the most economic choice available today, and the single-core avoids water blocking issues with three-core cables. Furthermore, many of the cable ratings we require are not available with three-core cables.

The size of the cable to be installed has a small impact on the cost of a cable installation, so we aim to select a size that can be economically justified but considers likely future use in a 'least regrets' manner. While we are standardising on cable sizes, many cable accessories such as joint and terminations can be used across a range of cable sizes. We take this into consideration when procuring spare accessories.

Cable with aluminium conductor is preferred over copper as it is lower cost and lighter to work with. All GXPs feeding our network now have NERs fitted, which in many cases (subject to other connected parties such as embedded generation) means the earth fault level is low enough that significant cost savings can be made by specifying a smaller cable screen size compared to when there were no NERs.

For sub-transmission cable projects, our engineers work with design consultancies to undertake detailed scoping of the project, conceptual design, and detailed design, and to support contractors through delivery.

All underground cable portfolio network Capex delivery is outsourced to field service providers. Cable projects have a high percentage of civil works compared to overhead network projects, and often our contractors will utilise subcontractors for this work. Given the size and value of sub-transmission cable projects, they are expected to be competitively tendered.

We do not foresee significant deliverability issues in relation to sub-transmission cables, as planned expenditure will not peak at materially higher levels than have occurred in the past. In creating the forecast plan, we considered the implications of having multiple, large, concurrent cable projects in construction on our Dunedin network. Given the large size of projects, the expenditure profile will be inherently ‘lumpy’.

Renew or Dispose

We replace sections or entire sub-transmission cables proactively on the basis of age (compared to expected life) and condition. Drivers of obsolescence and growth project opportunities are also considered. The Dunedin architecture reconfiguration is an example of the latter. The table below provides a summary of our approach to sub-transmission cable renewal.

Table 8.20: Summary of sub-transmission cable renewal approach

Aspect	Approaches Used
Renewal Trigger	Age (vs expected life), also taking condition (proactively), obsolescence, and growth/resilience project opportunities into consideration
Forecasting Approach	Identified projects
Cost Estimation	Tailored

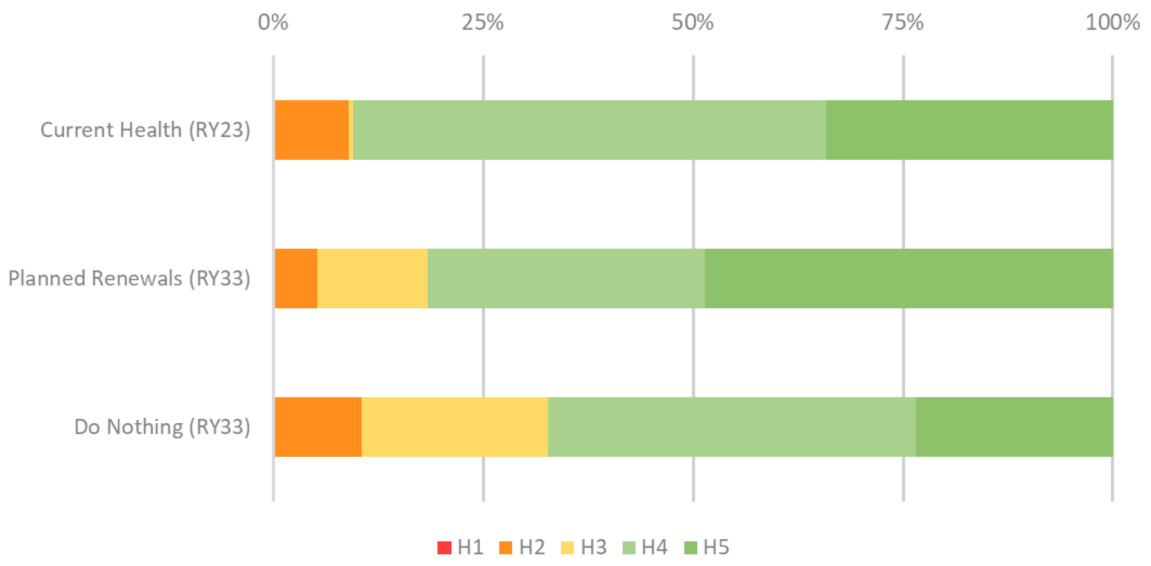
Renewals forecasting

We currently forecast renewals for sub-transmission cable based on age and known condition/performance issues. Our work programme involves replacing sub-transmission cable in the Dunedin area, comprising three renewal and four growth/resilience projects. The planned new 33 kV cable architecture will make some of the existing cables redundant. The chart below indicates the age-based asset health status only, and the improvements provided by our proposed investment programme. The three renewal projects have been identified as priority renewal projects, based on performance, and known degradation modes. These are well understood failure modes. In some cases, the premature degradation is resulting from design limitations i.e. the ability for a specific type of cable to function in the environment that it has been installed in, for the maximum life expectancy.

Effectively, we have identified some cables that are failing prior to reaching the age based H1 criteria. We are in the process of maturing our asset health assessment model for this fleet. These assets are N-1 configuration, meaning that when a failure of one cable occurs, we have sufficient capacity in a parallel cable to carry the load until the issue can be localised and repaired. The above-mentioned architectural improvements will also improve reliability in Dunedin.

Also not captured in the age-based asset health, is the impact of obsolescence on this fleet. This effects our ability to respond and repair defects in cables. As mentioned previously, we are currently working on creating an asset health model that more accurately captures our assessment of asset health and thus renewal needs.

Figure 8.33: Projected sub-transmission cable asset health at RY33



Options analysis

When considering renewal of a sub-transmission cable, given the high cost of any renewal option, and the potential impact and opportunity in terms of network planning, we make sure to consider all reasonable options including Opex/Capex trade-offs. Cable size itself is a small proportion of any cable installation, so we aim to use a size that is economically justified while taking account of future opportunities in a 'least regrets' manner.

Options for sub-transmission cable remediation include:

10. Proactive repair of the cable circuit (Opex), E.g. proactively replacing joints and terminations if these are the only poor condition components of the circuit. This approach relies on jointing skills of legacy cable types remaining available.
1. Replacing a section of sub-transmission cable which has been found to be problematic, E.g. hill sections with joint failures.
2. Like-for-like replacement of the sub-transmission cable along the existing route (electrically, and potentially physically) with a cable of economically justified ampacity.
3. Replacing the sub-transmission cable, creating a different electrical network architecture.
4. Replacing the sub-transmission cable with a different voltage cable – in most cases this would require a substantial growth driver and would be classed as a growth project. Cables suitable for a higher voltage can be installed for a marginally higher cost. In the event of future growth, the cable can then be operated at a higher voltage – changing the system voltage is generally the significantly more expensive part of such a conversion as it requires new transformers and switchgear.

In each instance, considerations would apply for security of supply, future upgrade capability and whole-of-life cost.

Meeting our portfolio objectives – affordability through cost management and Sustainability by taking a long-term view

Our Dunedin architecture proposal is justified based on cost benefit analysis, and further supported by the resilience benefits that it provides should a HILP event such as a major earthquake occur in the Dunedin region.

Use of criticality in works planning and delivery

At present, our criticality framework does not cover cable assets. We will be developing criticality frameworks for all assets in the first few years of the planning period.

Disposal

We generally leave decommissioned sub-transmission cable in the ground due to the high cost of retrieval. Fluid-filled cables are drained of fluid and capped. This retains the cable route for potential future use (at which time the old cable would be removed). There is also the potential to return the cable to service in future, operating it at a distribution voltage instead of sub-transmission voltage should an economic use case arise.

Coordination with other works

As mentioned previously, we closely coordinate planning and design for renewals and growth/resilience-based investments. The Dunedin architecture provides a good example.

As trenching makes up a large proportion of cable replacement cost, we may align renewal works to take place in combination with customer-initiated works, growth projects and/or other underground infrastructure projects to maximise value to our customers and communities.

We also coordinate our works with Transpower planned work at local GXPs. We will continue to work with any third parties who require cable relocation for their projects.

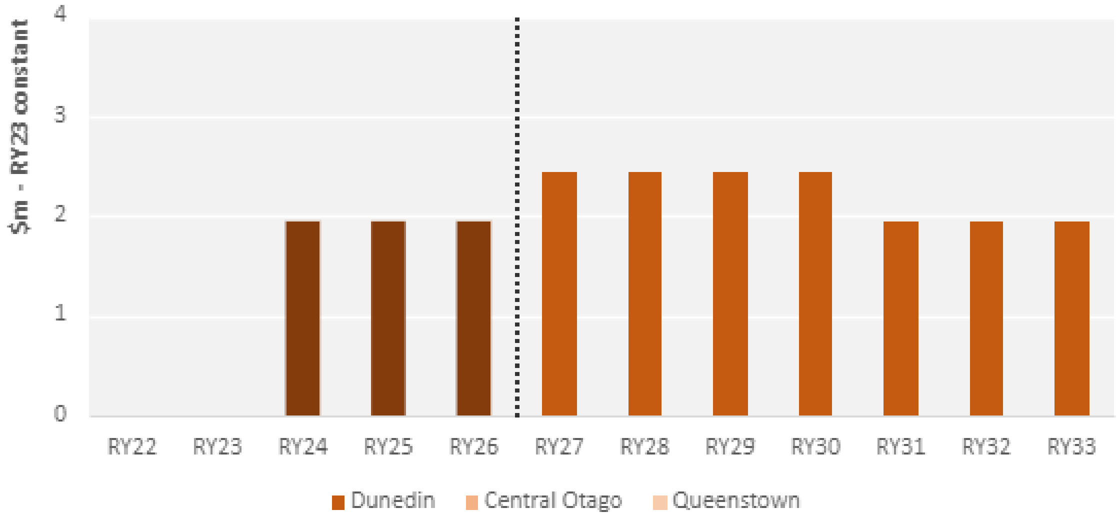
Sub-transmission Cable Fleet Expenditure Forecast

We have forecast renewal Capex of approximately $21m during the planning period. Our focus is on replacing aged, obsolete gas-filled cable with failed sheaths, aged PILC sub-transmission cable with dry-out issues, and obsolete oil cable. Due to its underground location, we have not targeted this fleet as a safety-driven priority.

Benefits

The key benefit of our planned sub-transmission cable renewal is to maintain reliability performance at the current level. The reconfiguration of the Dunedin sub-transmission cables will also provide significant benefits in terms of resilience to major adverse events. The environmental risks associated with some of our oil-filled cables will be managed through our renewals programme.

Figure 8.34: Forecast sub-transmission cables Capex



8.3.3. Distribution Cables

Where information is common with the sub-transmission cable section, it has generally not been repeated.

Distribution Cables Fleet Overview

Distribution cables operate at voltages of 6.6 kV and 11 kV, carrying electricity from our zone substations to distribution substations, which convert the distribution voltage to LV for supply to customers.[22] We own approximately 1,100 circuit kilometres of distribution cable, comprising PILC and XLPE types. The distribution cable fleet includes distribution cable joints and terminations (including those located on poles and inside switchgear).

The distribution network has been expanded significantly since the first sections were constructed more than 87 years ago. In contrast to sub-transmission cable, distribution cable has often been built in relatively short sections. Overall, our distribution cable assets are young relative to their expected lives, which has allowed us to take a reactive approach to managing the health of the fleet without a decline in performance.

The key focus in the distribution cable fleet over the planning period is replacement of all remaining cast iron cable terminations (also known as cast iron potheads), a legacy termination type used on PILC cables. These pose a public safety risk, having an explosive failure mode.

Population and Age

The table below summarises our population of distribution cable by type. The majority of our PILC distribution cable is in our Dunedin network region. PILC cable stopped being the standard cable used in our Dunedin network region in the 2000s, while XLPE was adopted earlier in our Central

22 Some customers are directly connected to our network at 6.6 kV and 11 kV.

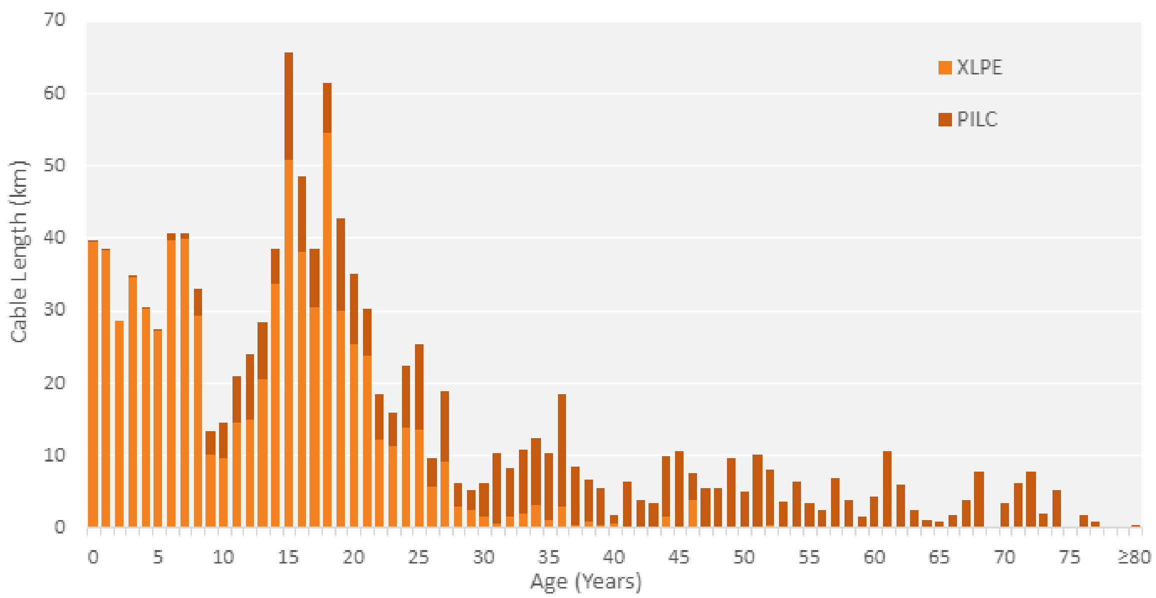
network region by the previous network owners. The majority of our XLPE distribution cable is in our Central Otago network region.

Table 8.21: Distribution cable population by type

TYPE	POPULATION (CIRCUIT KM)	PERCENTAGE
PILC	420	36%
XLPE	742	64%
Total	**1,162**	**100%**

The chart below shows our distribution cable age profile. Our distribution cable fleet is considerably younger than our sub-transmission cable, and the same expected lives of 60 years (XLPE) and 80 years (PILC) apply. The young population of XLPE distribution cable reflects the large growth in new connections in Central Otago over the last 10-17 years.

Figure 8.35: Distribution cable age profile



Condition, Performance and Risks

Condition and performance

Our distribution cable assets are relatively young, and we believe they are in overall good condition. We have had some minor issues affecting performance. With the quality of our historical data, however, we are unable to undertake detailed analysis easily, and hence we are making improvements in fault information capture.

In general, PILC cable does not cope well with being moved, which can occur when replacing poles with cable terminations, or when replacing ring main units or installing new ring main units into existing cable circuits. Due to the fragility of the older PILC, we use XLPE tail-jointed into the existing PILC circuit for alterations that require cable movement and bending.

Prior to the early 1990s, cast iron cable terminations were used to breakout three-core PILC cable terminations up poles. These present a public safety risk in the form of a potential explosive failure mode when re-energising. We believe this is caused by moisture ingress during termination cooling when de-energised, leading to internal insulation breakdown and flashover on re-energisation. The photos below show an exploded cast iron cable termination showing the bitumen (also known as pitch) insulating compound sprayed onto the ground below. We have been proactively replacing these terminations since 2014. We will replace all of the known remaining 165 cast iron cable terminations (a mixture of distribution and LV) during the CPP Period (ending RY26) through a prioritised work plan.

Figure 8.36: Cast iron cable termination (left) and bitumen sprayed after cast iron cable termination failure

In the late 1990s we installed a small batch of PILC cable that used a low viscosity oil within the paper layers rather than grease. Most of the dry type terminations used at that time were not rated for the pressures created by the low viscosity oil, and terminations have wept. We have replaced some of them and are monitoring termination leaks, with a view to initiating replacement when warranted.

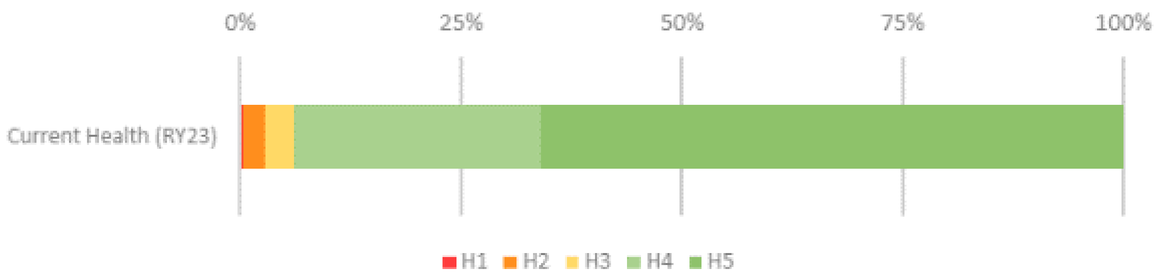
Meeting our portfolio objectives – safety first

Cables are generally inherently safer than overhead electrical assets. However, cast iron cable terminations have a failure mode with significant safety implications. To mitigate this risk, we are proactively replacing all of these terminations with modern types during the planning period.

Asset health

AHI for distribution cable is shown in the figure below.

Figure 8.37: Distribution cable asset health



The analysis indicates that approximately 0.5% of our distribution cable will reach end-of-life within the next 10 years. Our fleet is relatively young and so we expect our distribution cables to be in good health overall. This asset health position does not reflect the cast iron cable termination risk.

Risks

The following sets out the key risks we have identified in relation to our distribution cable fleet.

Table 8.22: Distribution cable risks

RISK/ISSUE	TYPE	RISK MITIGATION	MAIN RISK AREA
Cable strike	All	B4UDIG service Cable depth requirements, mechanical protection requirements Strategic spare cable joints	Safety, reliability
Partial discharge	All	Partial discharge check done with hand-held partial discharge detector, prior to de-energisation of ring main unit (RMU) for maintenance	Reliability
Cable or cable termination mechanical damage	All	Viewed during pole inspections Terminations are in secure areas or high up poles; cable guards fitted on poles Strategic spare cable and terminations	Reliability
Touch potential (due to exposed termination sheath/armour/earth exposed metal on aged PILC cables)	PILC	Cable guard retrofit programme (applies not only to PILC cables)	Safety
Cast iron cable termination explosive failure	PILC	Prioritised replacement programme	Safety, reliability
Poor backfill materials can lead to overheating, or sheath damage and subsequent cable degradation and/or failure	All	Specifications and site quality assurance	Reliability

Design and Construct

With distribution cable, we use single-core XLPE cable for short runs and equipment tails, and three-core XLPE cable for long run new distribution cable circuits. This is the most economic choice available today. Single-core cable allows ease of jointing and termination into switchgear and transformer cable boxes. We generally avoid trifurcating three-core cables in cable boxes due to space constraints. Some distribution transformer cable boxes have adequate room to trifurcate three-core cables, and so an external three-core to single-core transition is not required.

We are standardising on XLPE cable sizes. Many cable accessories, such as joints and terminations, can be used across a range of cable sizes. As with sub-transmission cables, aluminium conductor cable is preferred over copper as it is lower cost and lighter to work with.

On each large zone substation project, such as replacement of indoor switchgear or power transformers, we fit neutral earthing resistors (NERs). This reduces the earth fault level, improving safety and enabling cost savings to be made by specifying a smaller cable screen size compared to when there were no NERs.

Cast iron cable termination replacements are often not straightforward. Sometimes the termination cannot simply be remade with a modern type due to clearances on the pole (E.g. between the distribution voltage level and LV). This can necessitate running new XLPE cable tails down the pole and jointing the XLPE tails to the existing PILC cable below the ground to ensure modern clearances are met on the pole. In some cases, it is required to replace the pole entirely. In the case of some two pole structures, it requires replacement of the entire two pole structure, often with a ground mounted substation solution, as modern clearances simply cannot be achieved on the structure when the cable is re-terminated. If a pole is in poor condition, we replace the pole as part of the cable termination replacement works.[23]

There are some circumstances where we will continue to use PILC rather than XLPE distribution cable. PILC cable has a smaller diameter than XLPE for an equivalent ampacity and conductor material. In certain circumstances we replace degraded with new PILC, for example, where limited size ducts under railways would not allow for XLPE cable of the required ampacity.

We have experienced instances of cable strike where we have subsequently found that the distribution cables were not buried at a depth consistent with good industry practice. Often this is due to third-party works reducing ground levels. This is largely outside our control,[24] and requires us to re-lay significant sections of cable to the right depth. However, this does raise the importance of proper burial depths during construction and quality assurance around this.

All underground cable portfolio network Capex delivery is outsourced to our field service providers. Cable projects have a high percentage of civil works compared to overhead network projects, and often our contractors will employ subcontractors for this work. We often outsource the design of distribution cable renewals to our service providers. We also have a design team in-house, which fulfils a range of roles from scoping, design, project engineering and contractor design support to standards development. We have inhouse quality assurance staff who undertake an audit function of contractors' completed works.

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23 If the pole was already planned for replacement the cost is counted in the support structure portfolio, but if the pole (or structure) requires replacement only because the pothead cannot be remediated while meeting modern clearances it will be in the cable portfolio. If a ground mounted solution is required, the total Capex falls into the distribution transformers portfolio.

24 The situation is similar to drainage ditch clearing activities that can undermine our poles. Good communications with other infrastructure businesses are needed to ensure we work in each other's best interests.

Renew or Dispose

The table below summarises our approach to distribution cable renewal. Expenditure on distribution cable is currently reactive, upon receipt of failed test/inspections or in response to a fault. Cast iron cable terminations are identified and prioritised for replacement by public safety criticality location.

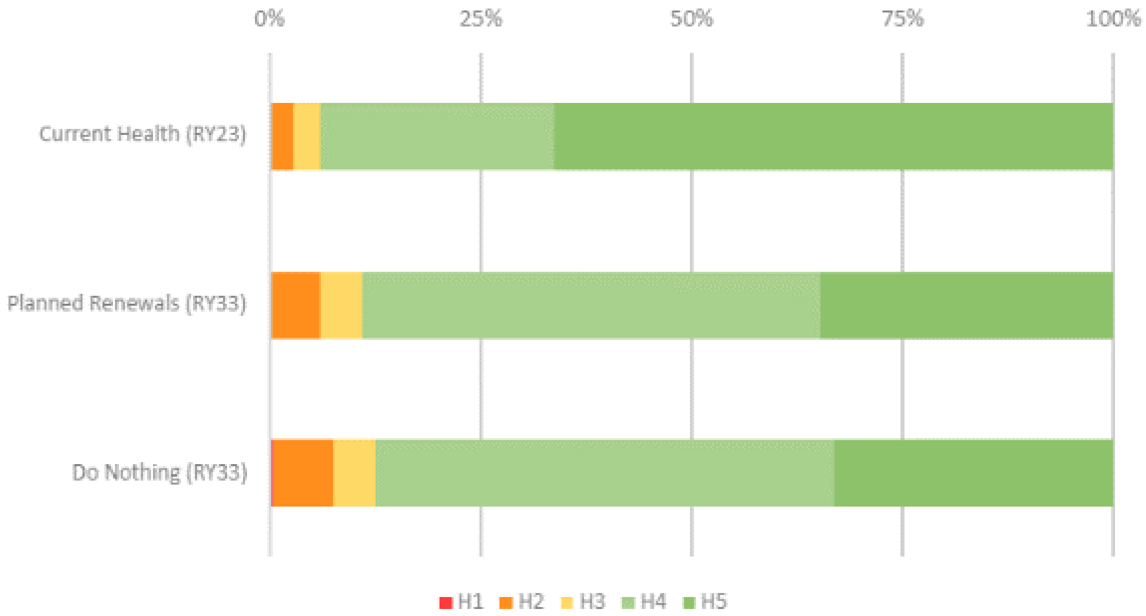
Table 8.23: Summary of distribution cable renewal approach

Aspect	Approaches Used
Renewal trigger	Condition (reactive) (for cable and terminations) Type (for cast iron cable terminations), prioritised by criticality
Forecasting approach	Repex (for cable) Identified (for cast iron cable terminations)
Cost estimation	Volumetric (for both cable and cast iron cable terminations)

Renewals forecasting

The figure below compares projected AHI in 2033 following planned renewals, with a counterfactual 'do nothing' scenario. It demonstrates the benefits of our proposed investment programme.

Figure 8.38: Projected distribution cable asset health at RY33



Currently only about 0.3% of our distribution cable is classified as H1. Under our planned programme of investments, H1 distribution cables will be almost removed by the end of the period. Failure to undertake the forecast level of renewals will increase H1 to about 0.5%. Note that this reflects the health of only the cable, not including the cast iron cable terminations.

Options analysis

As our approach to management of distribution cable is reactive at present, options analysis is limited. Work generally involves replacing sections of damaged cable and/or terminations only.

For cast iron cable terminations, we consider the remaining life of the pole on which it is located. We also adopt the least cost approach (refer to Design and Construct section) to replace the termination.

Use of criticality in works planning and delivery

We generally prioritise replacement of cast iron cable terminations based on public safety criticality zone. Higher criticality areas are defined as locations of significance such as schools, or locations with elevated levels of traffic.

At present our criticality framework covers only the cast iron terminations. We will be developing criticality frameworks for all assets in the first few years of the planning period.

Coordination with other works

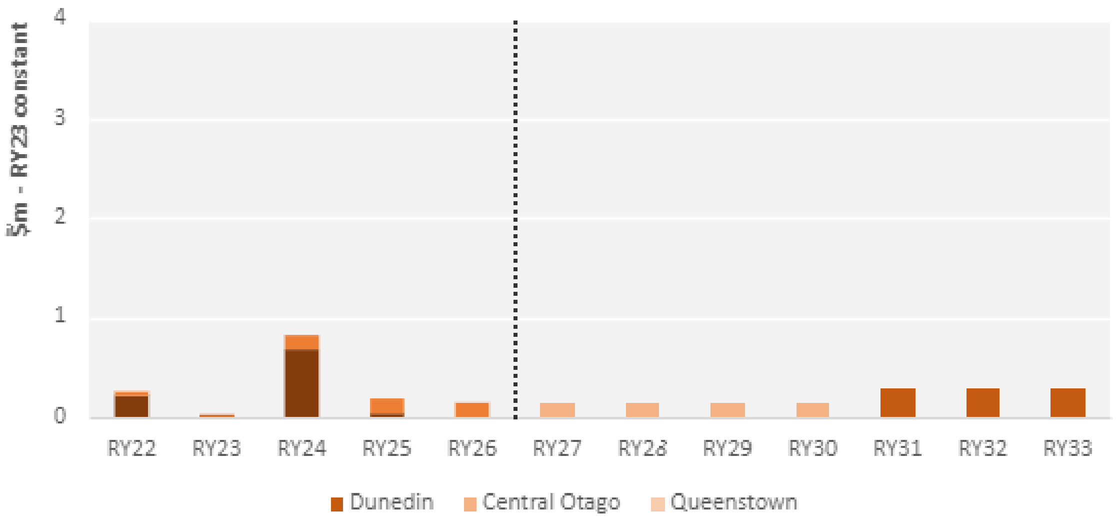
The key focus in the distribution cable fleet over the planning period is replacement of the remaining cast iron cable terminations. In addition to proactively planning the work in the prioritised criticality zones, we will also carry out this work opportunistically when cast iron cable terminations are de-energised for other work such as pole replacements.

> **Meeting our portfolio objectives – sustainability by taking a long-term view**
> We work with other stakeholders and utilities to ensure periods of inconvenience due to underground works are minimised, for the benefit of our communities.

Distribution Cable Fleet Expenditure Forecast

Our forecast distribution cable renewal Capex is approximately $2.6m during the planning period. This forecast excludes distribution cable and termination replacements undertaken as part of other work, such as distribution transformer, pole, or RMU replacement.

Figure 8.39: Forecast distribution cables Capex



Historical expenditure has been relatively low due to the relatively young average age of these assets. Full replacement of cables is only undertaken when it is uneconomic and impractical to maintain the cable in service using repairs and sectional replacements. A low level of reactive cable section replacements is expected in the interim.

Benefits

The key benefit of distribution cable renewal works is the reduction in public safety risk associated with removal of cast iron cable terminations. Reducing this failure risk also reduces the associated reliability risk from the loss of supply caused when a cast iron cable termination fails.

8.3.4. LV Cables

Where information is common to the sub-transmission and/or distribution cable sections, it has generally not been repeated.

LV Cables Fleet Overview

LV cable operates at voltages of 230 V and 400 V, carrying electricity from our distribution substations that convert it from 11 kV or 6.6 kV to 400 V, to our customers, or to power streetlights. We own approximately 1,000 circuit kilometres of LV cable.

LV cable sections tend to be shorter than distribution cable sections as LV cannot be used for long distances due to voltage drop. LV can be located in the same trench as distribution cable (or at least spaced nearby to it). At present we have less visibility of our LV network, both in terms of asset data and utilisation, than our higher voltage networks; this and the physical characteristics of LV lead us to manage this as a separate fleet.

Our approach to LV cable lifecycle management is primarily reactive. We do, however, have cast iron cable terminations operating at LV, which we plan to replace proactively as per our distribution cable cast iron cable terminations.

Population and Age

The table below summarises our population of LV cable by type. XLPE makes up more than 86% of the population with small populations of PILC and PVC cable.

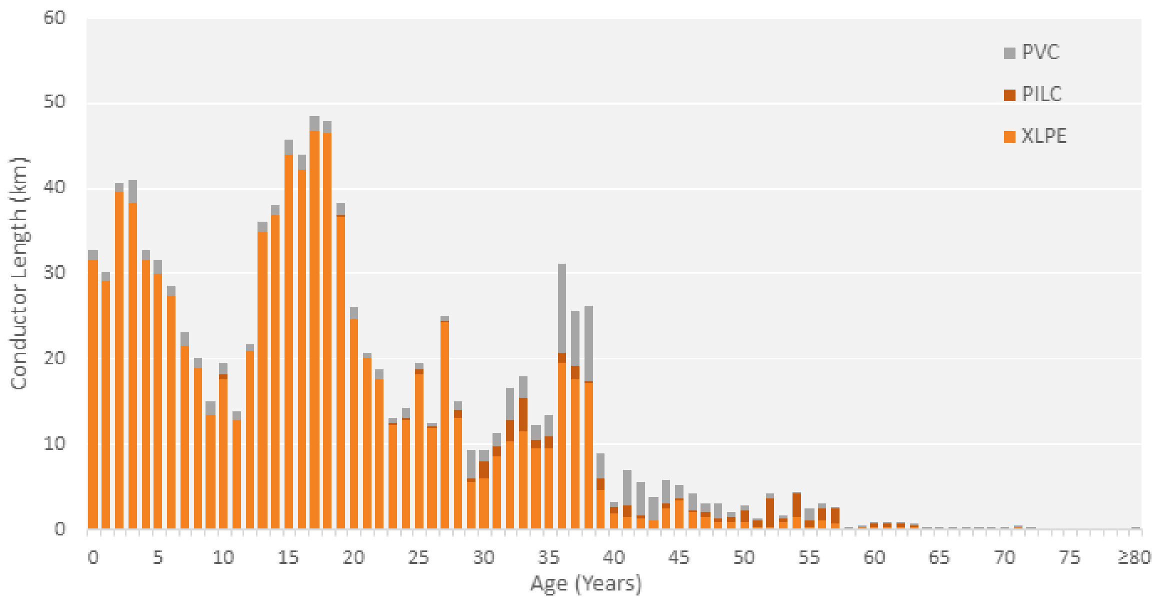
Table 8.24: LV cable population by age

TYPE	POPULATION (CIRCUIT KM)	PERCENTAGE
PILC	38	4%
XLPE	898	86%
PVC	107	10%
	1,044	100%

The chart below depicts our LV cable age profile. The same expected lives apply as per our other cable fleets. PVC cable is only used at low voltage and has an expected life of 60 years.

Our LV cable fleet is relatively young, much of it reflecting network growth over the past 10-17 years. Many councils now require underground cables in preference to overhead lines; this leads to an increased use of cable, particularly in the case of new subdivisions/connections in Central Otago.

Figure 8.40: LV cable age profile



As discussed in the sub-transmission cable section, we may have very small quantities of first generation XLPE on our network. Based on analysis of cable age, material type, and voltage, if we do have any first generation XLPE cable on our networks, it is considered most likely to be LV and in our Dunedin network. Currently, we are not seeing the expected failure modes associated with treeing in first generation XLPE cables.

Condition, Performance and Risks

Condition and performance

In general, our LV cable is in reasonably good condition and presents a low reliability risk. We will need to consider the impact of embedded generation penetration and the uptake of EVs on our LV networks going forward. We have not historically collected LV outage data, so we are unable to assess the reliability performance of LV cable.

We have cast iron cable terminations at LV that present the same risk as distribution terminations.

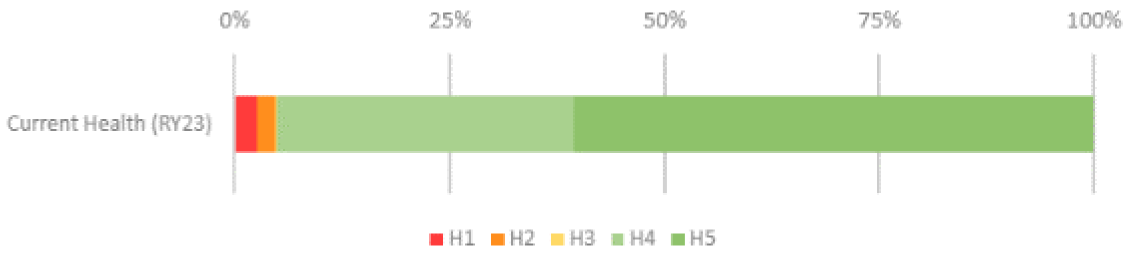
The majority of LV cable failures are attributable to damage from third-party construction and ground movement. As the older PILC cables are fragile, movement is detrimental. We have also seen some issues with crystallisation of the lead sheath in Central Otago, which can lead to cracking of the lead sheath if the cable has force exerted on it (such as during works or a fault). Sheath cracking will quickly reduce the cable’s life expectancy. These cases are rare, and they are managed on a reactive basis.

Historically when LV XLPE cables were terminated to an overhead line, the primary insulation phase coloured covering was left exposed to the environment. This covering was not UV stabilised and over time becomes brittle and develops cracks. This can result in pieces falling off or water ingress, such that at the crutch of the breakout boot phases will short out, resulting in loss of supply. Current practice is to fit a UV stabilised tube.

Asset health

AHI for LV cable is shown in the following chart.

Figure 8.41: LV cable asset health



Our asset health analysis indicates that approximately 5% of our LV cable is within H1-H3 condition and will reach end-of-life within the next 10 years.

Risks

The following table sets out the key risks we have identified in relation to our LV cable fleet.

Table 8.25: LV cable risks

RISK/ISSUE	TYPE	RISK MITIGATION	MAIN RISK AREA
Cable strike	All	B4UDIG service Cable depth requirements, mechanical protection requirements Strategic spare cable joints	Safety, reliability
Cable or cable termination mechanical damage	All	Viewed during pole inspections Terminations are in secure areas or high up poles; cable guards fitted on poles or fitted in retrofit cable guard programme Strategic spare cable and terminations	Reliability
Cable OH-UG termination UV damage	XLPE	Viewed during pole inspections UV stabilised tube fitted	Safety, reliability
Touch potential (due to exposed termination sheath/armour/earth exposed metal on aged PILC cables, or livening of other metal)	PILC	Cable guard retrofit programme (applies not only to PILC cables) Corrective maintenance and cable renewal programmes	Safety
Overloading cable due to embedded generation or general load being too excessive	All	Voltage complaint follow up power quality monitoring MDI reads Growth expenditure projects to upgrade LV cables Future: consider further mitigations in this area as solar PV penetration increases	Reliability
Cast iron cable termination explosive failure	PILC	Prioritised replacement programme	Safety, reliability

Design and Construct

Design and construction considerations are similar to distribution cables.

Our standard replacement LV cable uses XLPE insulation and aluminium conductor, three-core with a neutral screen. Sizes are standardised and the same considerations at distribution voltage apply in that respect apply to LV. There is generally limited need for single-core cables at LV, as LV cable and terminations are smaller. Equipment is generally designed for cables to be broken out internally. Single-core cable may be required in some applications to provide sufficient rating.

Renew or Dispose

The following table summarises our approach to LV cable renewal. Expenditure on LV cable renewals is currently reactive, upon fault. Cast iron cable terminations are identified and prioritised for replacement by public safety criticality location.

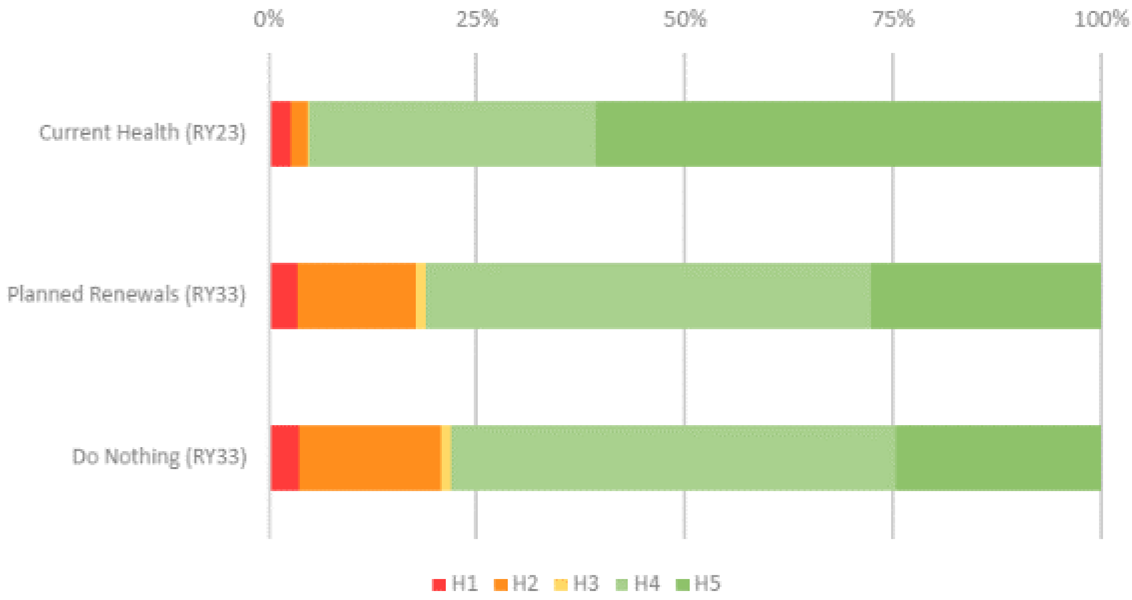
Table 8.26: Summary of LV cable renewals approach

ASPECT	APPROACHES USED
Renewal trigger	Condition (reactive) (for cable and terminations) Type (for cast iron cable terminations), prioritised by criticality
Forecasting approach	Repex (for cable) Identified (for cast iron cable terminations)
Cost estimation	Volumetric (for both cable and cast iron cable terminations)

Renewals forecasting

The following chart compares projected asset health in 2033 following planned renewals, with a 'do-nothing' scenario. It demonstrates the benefits of our proposed investment programme, i.e. we limit the increase of LV cables approaching end-of-life. Note that the proportion of H1-3 classed cables increases under our planned renewal approach, reflecting that the fleet as a whole is getting older, and potentially signalling future increased renewal levels beyond the planning period.

Figure 8.42: Projected LV cable asset health at RY33



Options analysis

As our approach to renewal of LV cable is reactive at present, options analysis is limited. Work generally involves replacing sections of damaged cable and/or terminations only.

Use of criticality in works planning and delivery

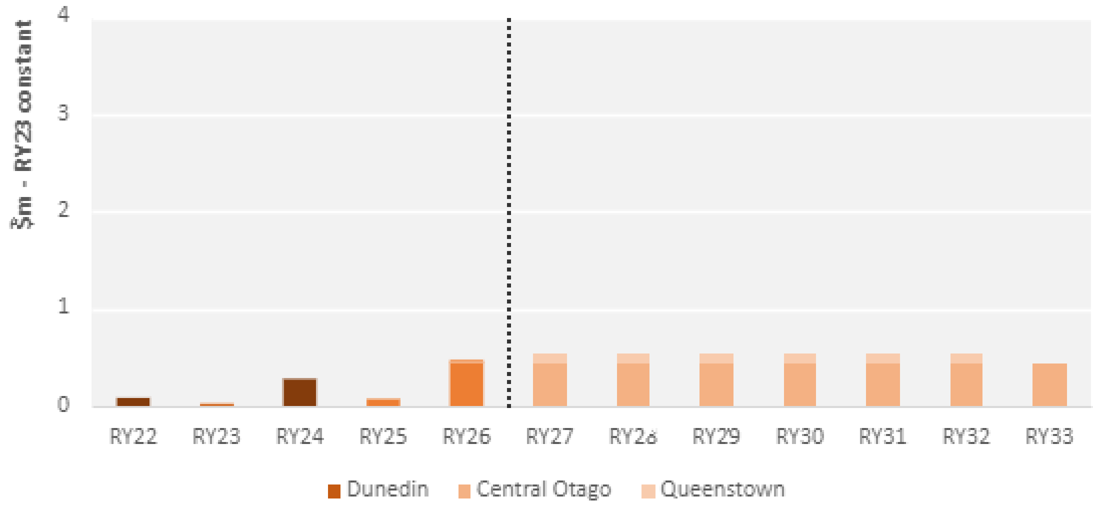
With the exception of opportunistic replacements (such as part of replacing a poor condition pole), we are prioritising replacement of cast iron cable terminations based on public safety criticality zone. Higher criticality areas are highly populated areas such as schools and beside significant roads.

At present, our criticality framework covers only the cast iron terminations. We will be developing criticality frameworks for all assets in the first few years of the planning period.

LV Cable Fleet Expenditure Forecast

Our forecast of LV cables renewal Capex is approximately $4.5m during the planning period. We acknowledge the need to improve our low voltage network beyond the planning period to be capable of handling increased electrification brought on by new technology, such as electric vehicles and solar energy. Our forecast excludes LV cable and termination replacements undertaken as part of other work, such as distribution transformer, pole, and LV enclosure replacement.

Figure 8.43: Forecast LV cables renewal Capex



Historical expenditure on LV cable assets has been relatively low due to the young average age of these assets. We expect to have to ramp up expenditure beyond the CPP Period.

Benefits

The key benefit of distribution cable renewal works is the reduction in public safety risk associated with removal of cast iron cable terminations. Reducing this failure risk also reduces the associated reliability risk from the loss of supply caused when a cast iron cable termination fails.

8.3.5. Cast Iron Post Head Terminations (CIPH) Sub-fleet

CIPH Sub-fleet Fleet Overview

Since we were alerted to the potential of high energy failures of Cast Iron Cable Terminations where insulating medium can melt and seep out of the enclosure, or upon rare occasions fracture the enclosure with possible wall material being ejected, we have taken the decision to remove all these items from our fleet. As such, all CIPH assets are considered an intolerable risk and we have treated them as a separate sub-fleet within our underground cable portfolio.

We have developed a dedicated programme for Cast Iron Cable Termination replacement. Triage undertaken prioritised the removal of units in high criticality locations, such as near schools or high population density areas. Work undertaken on assets with a direct impact upon Cast Iron Cable Terminations will automatically trigger the removal of these items.

Currently 207 units have been replaced or removed and the remaining 165 (this number includes new discoveries) will be removed by RY26.

Population

The following table summarises the total number of CIPH on our network by voltage level.

Table 8.27: CIPH population by voltage

VOLTAGE LEVEL	POPULATION	PERCENTAGE
11 kV	15	9%
6.6 kV	128	78%
LV	22	13%
Total	165	100%

Condition, Performance and Risks

Condition and performance

We have experienced several catastrophic failures of CIPHs (on average 2 per year).

Asset health

We rate the Health Index of every CIPH as H1. Under this approach, CIPH terminations will be phased out of service over the next few years and replaced with safer alternatives. We prioritise replacement by safety criticality, indicating that those CIPH installed in highly populated areas are scheduled for replacement first.

Risks

We consider every CIPH representing an imminent failure risk and must be replaced.

Table 8.28: CIPH fleet by safety criticality

TYPE	C5	C4	C3	C2	C1
11 kV	3	8	9	2	0
6.6 kV	2	43	49	22	12
LV	0	9	4	0	2

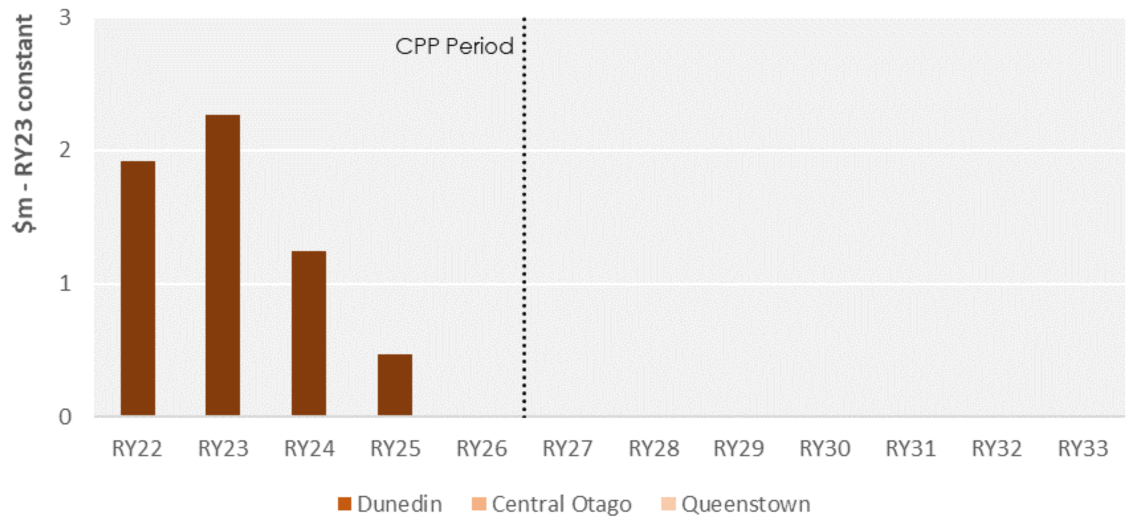
Use of criticality in works planning and delivery

Limited only by deliverability, starting with higher criticality zones and finally removing all CIPH's off our network.

CIPH Expenditure Forecast

We are targeting removal of all 165 units off our network by the end of our current CPP Period in RY26. Our forecast of the related renewal Capex is approximately $1.7m.

Figure 8.44: Forecast CIPH Capex



8.4. ZONE SUBSTATIONS

This section describes our zone substations portfolio and summarises our management plan. The portfolio includes five asset fleets:

- buildings and grounds
- power transformers
- indoor switchgear
- outdoor switchgear
- ancillary equipment

Due to the consolidated approach we take to zone substation forecasting, a different approach is applied to this portfolio section, with all expenditure included in a single section at the end.

Portfolio Summary

During the planning period, we expect to spend an average annual Capex of $5.8m, although expenditure does vary from year to year due to the large size of zone substation projects.

Expenditure on zone substation assets was low prior to RY18. We have since significantly increased expenditure, primarily due to the replacement of the Neville Street zone substation (with the Carisbrook zone substation). We plan to continue a programme of zone substation renewals to support our safety and other portfolio objectives. The higher than historical level of zone substation renewals Capex is driven by the need to:

- Renew assets in poor condition. Most expenditure is driven by renewal programmes for power transformers, indoor switchboards, and outdoor switchgear, which are reaching the end of their expected lives.
- Stabilise asset health. Our renewal models indicate the need for an increased level of asset renewal to bring fleet health to an acceptable level.
- Manage safety risk, particularly for field staff. Some of our 6.6 & 11 kV switchboards have a higher than acceptable arc flash risk. We have prioritised replacement or modification of indoor switchgear to reduce this risk to field staff.

Zone substations take supply from GXPs through sub-transmission feeders (both overhead and cable). The photo below shows one of our modern zone substations. They provide connection points between sub-transmission circuits, step-down voltage through power transformers to distribution voltage levels, and incorporate switching and isolation equipment to enable operation of the network. Supply for many thousands of customers depends on key assets within zone substations. Our zone substations are high-value critical assets within our network, and prudent management is essential to ensure safe and reliable operation. The zone substations portfolio also includes some primary plant equipment installed at GXPs including ripple plants and outdoor switchgear.

We define our zone substation fleets according to the function and location of the equipment. The assets vary significantly between fleets, ranging from buildings to transformers and switchgear, so different lifecycle management approaches are required for each.

Figure 8.45: Camp Hill zone substation

Box 8.9: Summary of our asset risk review – zone substations

Issues: risks associated with zone substations include material quantities of switchgear past expected lives, switchgear with a failure history (including homebuilt enclosures), and incomplete switchgear and tap changer maintenance.

Response: we are addressing the backlog of switchgear and tap changer maintenance through new maintenance standards. We have created an integrated zone substation renewal plan, focusing on types of switchgear that are both past expected life and where failures have been experienced, and transformers that have tap changer and other issues.

Timing: we are forecasting elevated renewal expenditure for the next five years that seeks to address the highlighted risks; after which work will continue at a lower 'steady-state' level.

8.4.1. Zone Substations Portfolio Objectives

Our objectives for the zone substations portfolio are listed below.

Table 8.29: Zone substation portfolio objectives

OBJECTIVE AREAS	PORTFOLIO OBJECTIVES
Safety first	No fatalities or lost time injuries, including from arc flash incidents Any touch or step voltage hazards are mitigated in a timely manner
Reliability to defined levels	Manage HILP failure risks through renewal planning and in conjunction with growth planning
Affordability through cost management	Continue to develop and refine our asset health, criticality, and risk models to support cost-effective renewal decision-making
Responsive to a changing landscape	Ensure the design and aesthetics of zone substations considers the impact on the neighbouring community
Sustainability by taking a long-term view	No uncontained oil spills or SF_6 leaks from zone substation assets Implement good industry practice SF_6 management and reporting Any non-compliant noise pollution is mitigated in a timely manner

8.4.2. Buildings and Grounds Fleet

Buildings and Grounds Fleet Overview

The buildings in the portfolio range from new to over 70 years old. A significant number of them were built between 1950 and 1970. The building types vary widely due to a number of factors, including substation location (i.e. rural vs urban), size and historical construction methodologies.

Our zone substation buildings mainly house protection, communications, indoor switchgear and ripple injection plant. This fleet category also includes fences, driveways, security, and access-ways to substation sites. Buildings and grounds must provide security for the equipment contained within, be well secured for earthquake exposure, and adequately earthed.

We have undertaken a seismic survey of our zone substation buildings. This work identified a list of buildings that require strengthening to meet the NZ Building Code, and we are presently addressing the issues identified. Buildings are also replaced when there is a lack of space to house new equipment during other zone substation renewals.

Population and Age

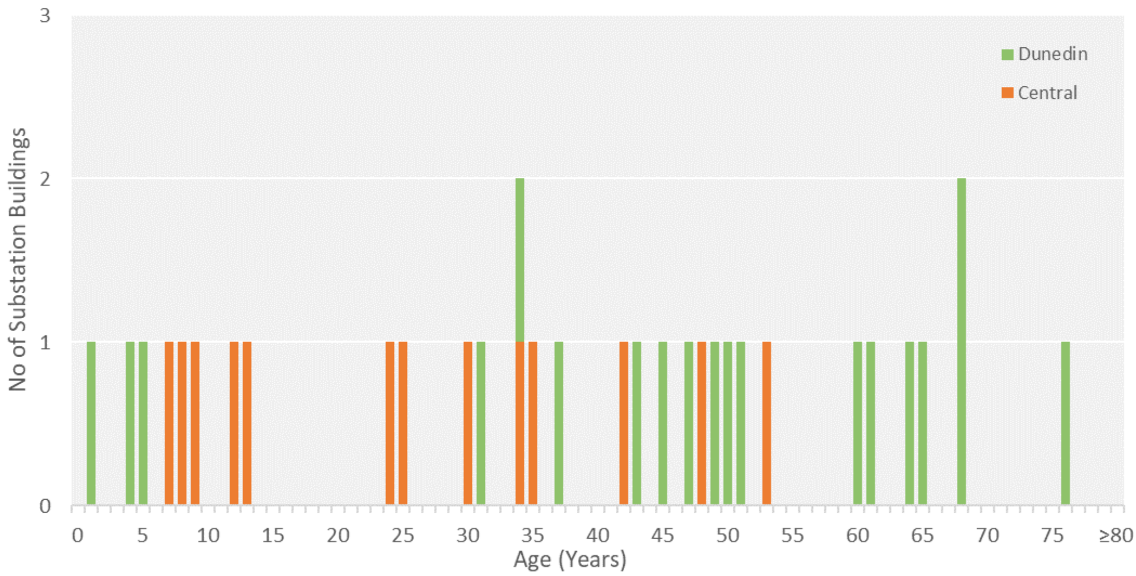
The table below summarises our population of zone substation buildings by network location. Some of our smaller zone substation sites do not have buildings but have fencing and earthing.

Table 8.30: Zone substation buildings by region

REGION	POPULATION
Central Otago	13
Dunedin	19
Total	**32**

The figure below depicts the age profile of our zone substation buildings by region.

Figure 8.46: Zone substation buildings age profile



Overall, the average age of our zone substation buildings is 37 years. The buildings in our Dunedin region have a higher average age (45 years) than those in our Central region (26 years). Our oldest substation building is located at our Ward Street substation in Dunedin.

Condition, Performance and Risks

Condition and performance

Historically, there has been a lack of maintenance of our zone substation buildings. During RY20 we started a programme of remediating building defects by activities, such painting external cladding to prevent degradation of building materials and replacing failed butanol roof coverings to prevent further water ingress. Further corrective work of this type will be required to ensure our buildings do not degrade to the point where more costly remediation is needed. We generally aim to maintain our buildings in perpetuity, the exception being where zone substation asset renewals (E.g. indoor switchgear) require more or different space than the existing building allows.

Asset health and criticality

We do not have AHI or a criticality framework for our buildings and grounds fleet. We will consider whether there would be value in developing these in future. We have developed a criticality framework for indoor switchgear, which we use as a proxy for the building containing the switchgear.

Risks

Many of our buildings did not have air conditioning, and we are nearing the end of a programme to retrofit this where it can be effective. The purpose of air conditioning is to control temperature and prevent condensation in electronics (such as protection) and on high voltage switchgear. In some historic buildings, such as the historic Ward St substation, air conditioning is impractical for mitigating condensation risk due to the size of the building and lack of insulation.

Building standards have evolved over time and seismic performance requirements have changed. Older buildings, particularly those made of brick or unreinforced masonry and concrete, are below today's strength standards. The seismic performance of our zone substation buildings is important for the safety of the people working in them, and to maintain or quickly restore electricity supply following a large earthquake event.

Our objective for our existing buildings is that they meet 100% of the New Building Standard (NBS) for an Importance Level 3 (IL3) standard. As expected, newer buildings generally have better seismic strength and compliance with modern fire and security standards than older buildings, which are much more likely to be understrength and non-compliant. For new zone substation buildings, it is cost-effective to meet an IL4 standard.

In 2015, we carried out a set of comprehensive fire, security and seismic risk assessments for assets at our zone substations. The assessments determined that many of our substation buildings do not fully meet 100% of NBS for the IL3 standard. In general, this is due to the buildings having insufficient structural integrity/strength, which will likely result in the buildings failing during specific earthquake conditions. However, the specific reasons for this vary. Most of the lower rated buildings were built prior to 1970.

For some sites, the structural deficiencies will be addressed as part of other upgrade or renewal work at the substation. For the remainder of the sites, we have developed detailed designs for seismic strength upgrades of the buildings that do not currently meet the 100% of the NBS for IL3 standard, and our implementation plan is underway.

Meeting our portfolio objectives – reliability to defined levels

Bringing our fleet of buildings up to industry standard IL3 increases the resilience of our network to HILP events, ensuring that if these events do occur, our zone substations can be returned to service relatively quickly, thereby minimising the reliability impact.

We have recently completed an asbestos survey at our zone substations, undertaken by a qualified practitioner. The majority of asbestos in our zone substations is in buildings, and is encapsulated or not in generally accessible areas, and hence does not require immediate remediation. The small number of instances that require attention in the short-term are being assessed for remediation options at present. Future upgrade and renewal work on existing buildings that may expose asbestos will include an assessment of any further asbestos remediations required.

Proper earthing ensures the power system delivers quality power, that faults are safely detected, and that the risk of faults leading to secondary harm to the public or workers by step and touch potential are mitigated. We undertake periodic zone substation earth testing to prove our earth grids. Central Otago ground conditions are such that achieving low earth grid resistance is more challenging than in our Dunedin network region, but we have not identified any areas where significant investment is required.

The table below summarises the key risks identified in relation to our buildings and grounds fleet.

Table 8.31: Zone substation buildings and grounds risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA

Seismic event	Programme of structurally strengthening buildings and internal/external equipment hold down upgrades	Safety, reliability
Flooding event	Elevating equipment as it is renewed, above certain flood criteria, managing and upgrading Stormwater Management Systems	Reliability
Security breach	Security alarms and cameras, suitable fencing	Safety
Fire event	Fire detectors, alarms and extinguishers. Fire consequence mitigation in design	Safety, reliability
Poor internal building environment leads to primary asset or electronics failure	Heat pump and insulation retrofits where practical Internal equipment anti-condensation heaters Replacement buildings when unsuitable for new equipment	Reliability
Step or touch potential leading to injury	Earthing of equipment Periodic earth grid testing Equipment inspections	Safety
Asbestos inhalation	Asbestos survey undertaken Asbestos register Hazards identified and labelled Containment or removal Specialist contractors	Safety

Design and Construct

When designing new zone substation buildings and grounds, we integrate the building into its surroundings, in line with council requirements. The designs of our rural substations may include an outdoor switchyard along with a modest switch-room building. In urban locations our substation designs usually include indoor switchboards and the buildings are designed to blend into the surrounding neighbourhood. In some locations, we have urban development encroaching on existing rural substations. During renewal of these substations, we take account of the changing demographics and, as much as practicable, improve the substation appearance and noise containment.

Meeting our portfolio objectives – responsive to a changing landscape

Compared to when most of our substations were built, today there is an expectation that design will integrate new structures into the existing environment. We will ensure that design and aesthetics of our zone substations consider the impact on the neighbouring community and are integrated into the surroundings as much as is practical.

We have adopted an IL3 standard for existing buildings following evaluation of legislative requirements and industry practice, and recommendations from consultants. IL3 implies that the design level earthquake has a return period of 1,000 years for the ultimate limit state and 25 years for the serviceability limit state. We understand that electricity distribution businesses typically ensure that the designs of their existing substation buildings comply with IL3, while Transpower ensures existing building designs comply with IL4. The additional cost to design and construct a new substation in accordance with IL4, as opposed to IL3, is small, while upgrading our existing buildings from IL3 to IL4 is very costly. All our new buildings will be designed to an IL4 standard.

Design for our projects is underway at present, and we will consider introducing a standard building design to drive project and operational efficiencies. Modern building designs incorporate features often not present (or present to a lesser degree) in legacy buildings, including insulation and air conditioning, fire detection and alarms, good cable access, compliant clearances from switchgear to other equipment and safe access and provision for external arc fault venting.

Most zone substation design is undertaken by our engineering design consultants under direction from our internal engineers and project managers. All construction in zone substations is outsourced to our field service providers. Large zone substation projects are generally tendered to ensure that we achieve a competitive construction price. While we are ramping up expenditure in this area, we have considered the specialist resources required for zone substation works, and we have created a steady work plan that is deliverable with our FSA partners and supplementary contractors as required.

Renew or Dispose

Buildings and grounds renewal work is driven by seismic upgrades and space requirements for new equipment. The table summarises our renewals approach.

Table 8.32: Summary of buildings and grounds renewals approach

Aspect	Approaches Used
Renewal trigger	Seismic upgrades Physical space for new equipment
Forecasting approach	Specified seismic upgrades Switchgear renewal projects
Cost Estimation	Tailored estimates

Options analysis

We consider the risks, future proofing requirements and costs associated with re-using existing buildings or land to accommodate new equipment.

Disposal

Buildings that are no longer required for their original purpose may be demolished or kept for storage purposes, dependent on site-specific factors and ongoing maintenance costs.

Asbestos in buildings being demolished must be identified, handled and disposed of appropriately.

8.4.3. Power Transformers Fleet

Power Transformers Fleet Overview

Power transformers are used to transform the electricity supply from one voltage level to another. These units are generally equipped with on-load tap changers to assist with maintaining the required distribution supply voltage. Typically, large zone substations have two transformers, providing N-1 security. Modern designs incorporate interception bunds to contain oil spills and firewalls between the transformers (where necessary), to minimise the risk of fire spreading in the event of catastrophic failure. Power transformers typically comprise the core and windings, tank, bushings, cable boxes, insulating oil, conservator and management systems, breather, cooling systems and tap changing mechanisms.

Power transformers have proven to be generally robust devices, but their internal condition cannot be directly observed, and they can fail quickly without warning. This, combined with the potential wide range of material consequences and high replacement cost, fits well with the risk-based investment approach we have applied.

Population and Age

Our zone substation portfolio includes 67 power transformers.[25] They range from 2 MVA to 30 MVA and typically have winding voltages of 33/6.6 kV, 33/11 kV and 66/11 kV. We previously included auto-transformers as part of our Power Transformer fleet. These accounted for within our Distribution Transformer fleet.

The table below summarises the population by operating voltage and size. We now purchase standard power transformer sizes and configurations, but we have some legacy sizes, and most legacy designs are bespoke. The inclusion of non-standard models presents challenges to interchangeability and operational flexibility.

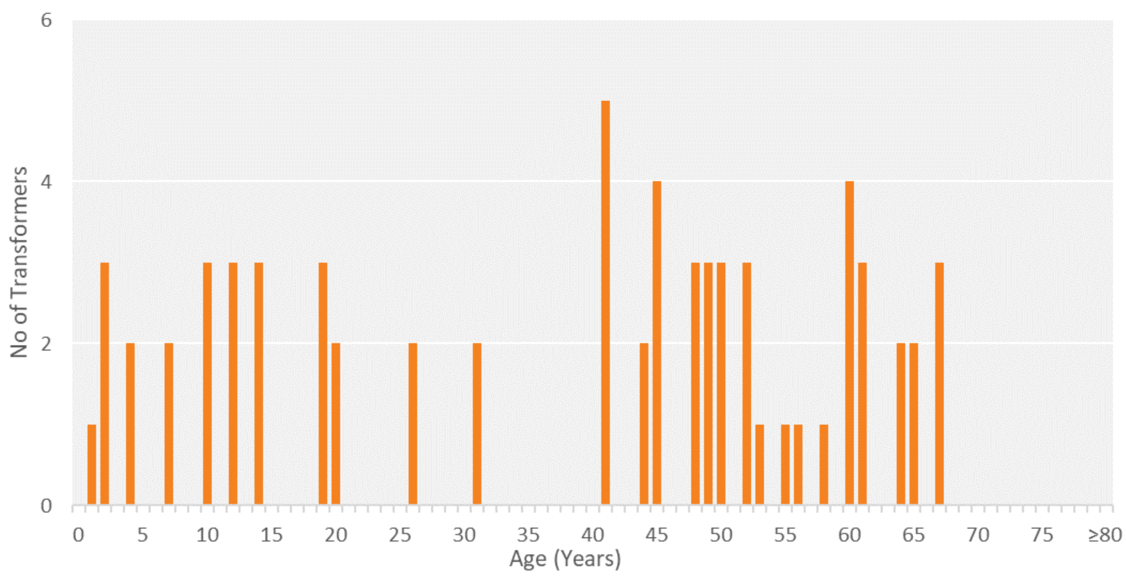
Table 8.33: Power transformers population by size

TRANSFORMER TYPE	HIGHEST OPERATING VOLTAGE	SIZE (MVA)	POPULATION
Power Transformer	33 kV	<10	24
		10-20	36
	66 kV	<10	5
		10-30	2
	Total		67

The figure below shows the age profile of our power transformers.

25 This excludes our mobile substation transformer, which is covered under zone substation ancillary equipment.

Figure 8.47: Power transformers age profile



Recent renewals have reduced the average age of power transformers to 31 years. Five of our power transformers have exceeded the average life expectancy of 60 years of age.

Condition, Performance and Risks

Condition

Our now-ongoing routine testing and inspection helps us understand how our power transformers are ageing, and to indicate any systemic issues. The external condition of the fleet, including degree of rust and oil leaks, is in line with expectations based on the various ages and locations. There are issues that need attending to in this regard, but none that are an imminent failure concern. Examples of transformer defects include oil leaks, corrosion, lack of signage and improper earthing.

Oil testing provides an indirect measure of internal condition, as it is not economic to directly test/observe the internal condition of power transformers. The fleet shows no major signs of significant internal ageing, overheating or arcing. The periodic use of online oil filtration has helped control moisture levels in our remaining ageing, free breathing transformers.

Performance

Major power transformer failures are relatively rare but can have significant consequences. The main causes of major failures are manufacturing defects within the core and windings, and on-load tap changer (OLTC) failures, generally due to mechanical wear.

Over the last 15 years, we have had five major power transformer failures at our substations that led to full replacement of the transformer, as follows:

- Halfway Bush (age 59 at time of failure, failed in 2006): the unit failed from the centre of the coil to the tank, most likely as a result of moisture ingress.
- Roxburgh (age 49 at time of failure, failed in 2011): it is suspected that arcing due to insulation failure led to a high amount of acetylene within the oil.

– Halfway Bush (age 59 at time of failure, failed in 2013): the unit failed due to water ingress.
– Outram (age 61 at time of failure, failed in 2016): the unit experienced a winding fault.
– Clyde-Earnscleugh (age 58 at time of failure, failed in 2017): the internal voltage transformer failed, leading to pollution inside the transformer rendering it unserviceable.

These statistics support our base expected life for a power transformer of 60 years.

We have had a number of OLTC issues at various sites, with the most common cause being malfunctioning contactors. These have been remediated under corrective maintenance when issues have arisen.

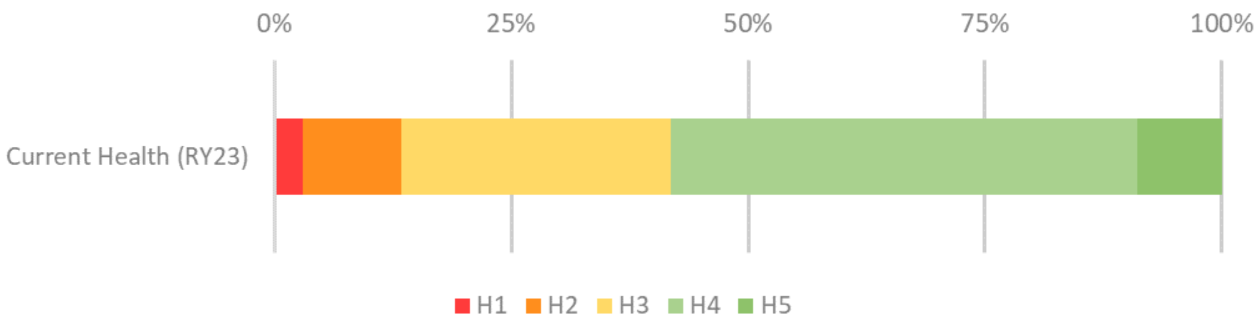
Asset health

We assess the health of our power transformers using a similar approach to that recommended by the EEA's *Asset Health Indicator Guide*.[26] Our power transformer AHI is therefore not purely age-based, but considers the following:

– transformer age
– results of visual inspections of the main tank
– results of visual inspections of the radiators
– results of visual inspections of the tap changer mechanism
– number of tap changer operations
– results of oil tests, including oil condition, dissolved gas analysis and furans.

We determine a score for each measure, and an overall health score for the transformer is determined by using a weighted average.

Figure 8.48: Power transformer asset health



This shows that 3% have a health of H1, suggesting replacement in the near-term is likely required. A further 10% have a health score of H2 and are likely to require replacement early in the planning period.

Criticality

For power transformers, the key criticality dimension is reliability, which is related to the load served and the level of backup supply. In order to prioritise their replacement, we identify risk based upon

[26] "Asset Health Indicator Guide (AHI Guide)", Electricity Engineers' Association, 2016, see https://www.eea.co.nz/

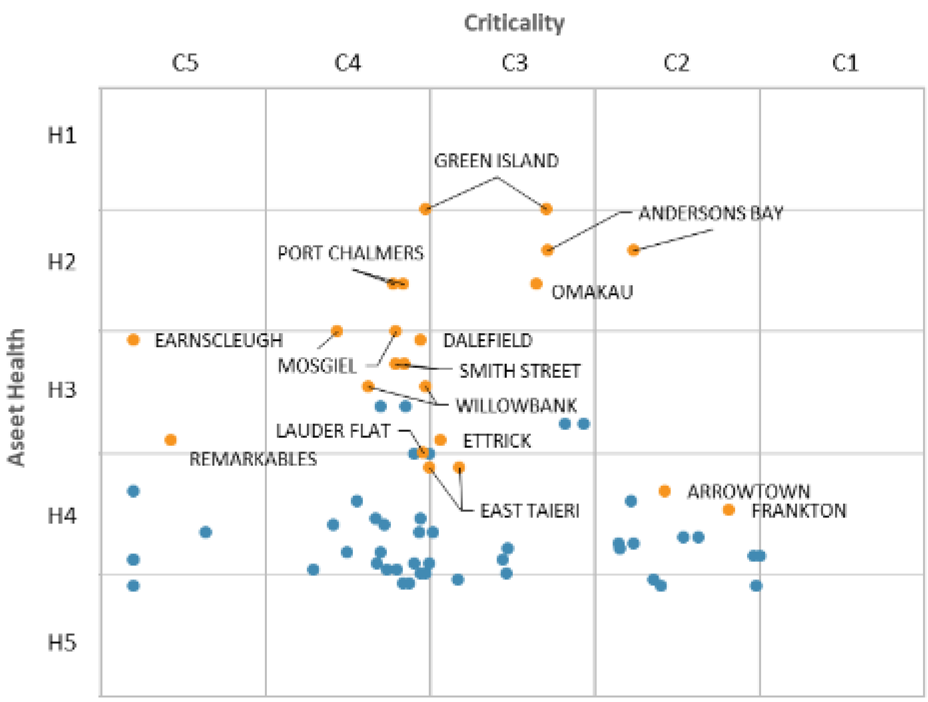
AHI and a criticality index that ranges from one to five (i.e. C1 through C5). The criticality indices have been determined using a weighted average of the following factors:

- magnitude of the load supplied
- security level of the zone substation (i.e. N vs N-1 vs N-1 switched)
- type of load supplied (i.e. CBD vs urban vs rural)
- load transfer capability (i.e. the backup 11 kV or 6.6 kV supply from the adjacent substations).

As an example, units at single-transformer substations with minimal load transfer capability are generally more critical assets, and we have less tolerance for deferring their replacement.

The following figure shows the current understanding of our power transformer criticality. The highlighted dots indicate work during the planning period.

Figure 8.49: Power transformer asset health and criticality graph



Risks

Aside from the risks presented by condition issues and evident through historical performance, we face a number of other power transformer risks for which mitigation must be considered.

The following table summarises the key risks identified in our power transformer fleet.

Table 8.34: Power transformer risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
Oil spill	New transformers have bunding and oil containment	Environmental, reliability

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
	Buchholz alarming to NOC or tripping advises control room of issues. Some units have separate oil level indicators which may be alarmed Inspections check for oil levels, oil leaks and rust which may cause leaks Corrective maintenance remediations	
Fire as a result of transformer failure	Replacement transformers meet standard fire clearance requirements, otherwise a firewall is installed Oil containment and bunding reduces consequence of an oil fire	Reliability, safety
Seismic event	New transformer arrangements are seismically compliant and do not have mercury switches on protective devices Retrofit seismic hold down programme where transformer is not being replaced in near-term	Reliability, safety
Major active part failure or major OLTC failure	N-1 security (two transformers) for larger loads Mobile substation and contingency planning Replacement programme Oil testing Keep unit spare parts once decommissioned, in case of future failures Preventive maintenance of OLTCs	Reliability
Lightning strike or switching surge	HV and LV surge arresters on new transformers as standard practice Retrofit surge arresters onto existing transformers where feasible	Reliability
Excessive transformer noise	Investigate complaints and remediate to council limits if required Acoustic studies and transformer specification Fit vibration pads under new transformers and consider retrofit on a case by case basis Consideration to move to ODAN transformers to avoid issues with noisy fans	Environmental

While we expect them to withstand a moderate seismic event, many of our older power transformers and their foundations have been rated below 100% of the NBS for an IL3 standard and could be vulnerable in the event of a significant earthquake. Also, many older units have legacy Buchholz relays and winding temperature indicators, which contain mercury switches that may trip the transformer inadvertently during a seismic event.

A number of our transformers are not equipped with oil containment. We intend to progressively resolve this issue as part of our power transformer renewal programme, ensuring there is a significantly reduced risk of a large oil spill and also ensuring compliance with modern regulations.

We intend to progressively install NERs during substation renewal projects. NERs lower the phase-to-earth fault level, which reduces the risk of equipment damage and safety risk during phase-to-earth faults, assuming that protection equipment is operating in the expected manner.

Design and Construct

We have a range of controls that ensure we get quality and consistency from our power transformer suppliers, designs, and projects. We have a standard procurement specification, which lists standard major components, standard transformer sizes, and a period supply agreement (PSA) with a small number of transformer manufacturers. Working with a small number of manufacturers and having standard sizes and specifications drives efficiencies through design, procurement, and allows the operational flexibility of moving transformers between sites should the need occur. We conduct design reviews for all new transformers, but where an exact transformer is re-ordered this is not required. Factory visits to inspect the transformer and witness factory acceptance tests are undertaken on every power transformer procurement.

All new transformer installations have full bunding and oil containment, with firewalls installed if we would not otherwise have standard separation distances between equipment. Foundations are built to the seismic withstand requirements of the site, which vary between our two network regions. These design criteria mitigate the consequence of HILP events and are in line with good industry practice.

Our decision to fit NERs with power transformers means that we must undertake insulation coordination studies and inspections across the connected network. Some equipment, commonly underrated surge arresters, will need to be replaced to be rated for the new operating environment.

We undertake acoustic studies before specifying any power transformer where there is likely to be potential noise implications. Understanding the impact of noise on the immediate community allows us to implement necessary measures to ensure compliance with council noise requirements.

> **Meeting our portfolio objectives – sustainability by taking a long-term view**
> We will ensure that any noise complaints are investigated and mitigated, if required, in a timely manner, and the noise of new transformers is compliant with council requirements. All new transformer installations will have oil containment systems, ensuring compliance with environmental requirements.

Renew or Dispose

We renew power transformers on the basis of risk, as informed by asset health and criticality. We group power transformer replacements with other renewal needs at the same zone substation to be delivered together as a single project.

We do not run our power transformers to failure because of the potential network impacts, costly contingency response, long procurement times, and the potential safety risk of fire and explosion should a catastrophic failure occur.

> **Meeting our portfolio objectives – reliability to defined levels**
> Transformer failures are rare but can have significant consequences. We use a risk basis to justify their replacement, with asset health providing a proxy for failure probability, and criticality representing a possible consequence of failure.

The following table summarises our approach to power transformer renewal.

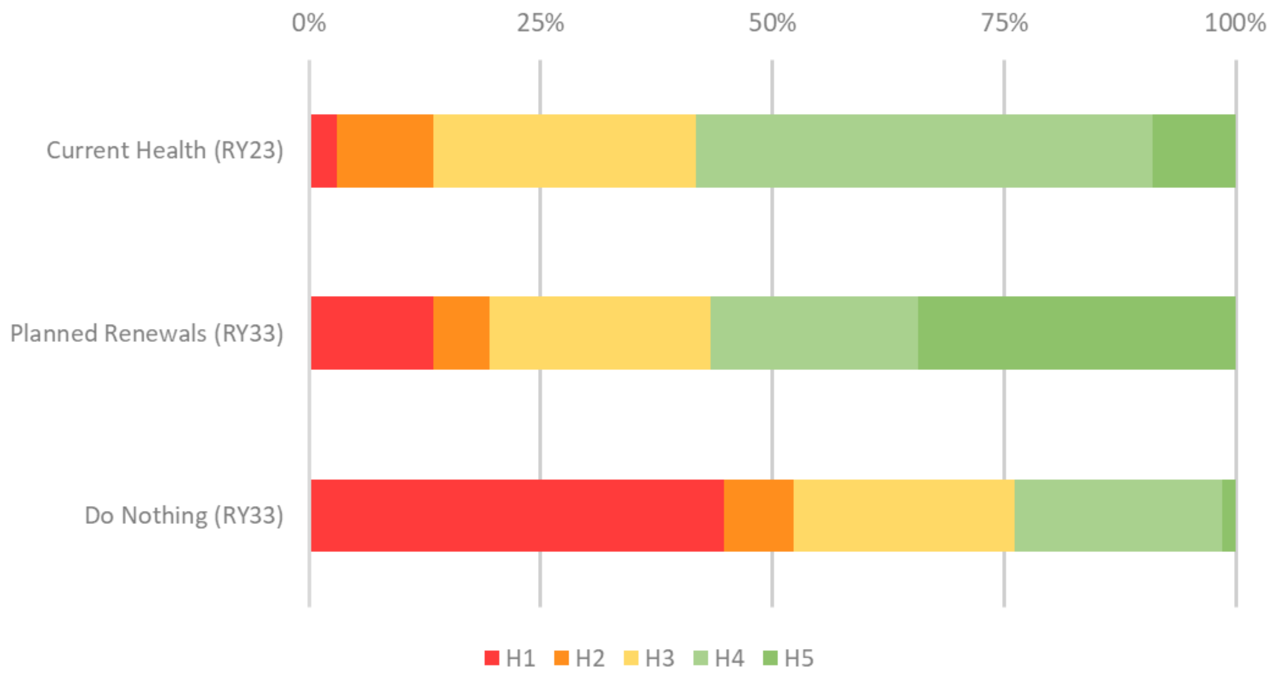
Table 8.35: Summary of power transformer renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Risk-based approach using asset health and criticality
Forecasting approach	Risk-based approach using asset health and criticality Consolidation of zone substation projects
Cost estimation	Tailored estimates

Renewals forecasting

We have developed an asset health versus criticality risk model to help forecast power transformer replacements. The methodology is discussed in more detail at the end of the zone substation section (see 8.4.7). The model enables us to predict changes to asset health, with the risk impact reported as a function of time. The following figure summarises AHI of our power transformer fleet.

Figure 8.50: Projected power transformer asset health at RY32



Our power transformer fleet is ageing, and the likelihood of asset failure is increasing. Even with planned investment, the health of this fleet will continue to decline over the period. This is reflected in our current asset health where approximately 42% (H1-H3) will be considered for replacement in the planning period. Under our planned renewals programme, overall transformer health will continue to decline but not as the same rate as the 'do nothing' scenario. We are putting in place an enhanced condition assessment programme for H1 and H2 power transformers. This will provide us with greater certainty of our assessed health and subsequent assessment of remaining life on an asset by asset basis. Undertaking this work will ensure that we are well positioned to optimise and appropriately prioritise our transformer renewal plans.

Meeting our portfolio objectives – affordability through cost management

We intend to continue to improve and refine asset health and criticality modelling to support better risk-based decision-making.

Options analysis

When a transformer is in poor condition, we consider several options including replacement, refurbishment (off-site), decommissioning or component replacement (on-site). The applicability of refurbishment and component replacement is limited to certain circumstances, as discussed below.

We do not have access to a transformer refurbishment facility within either of our network regions. Our analysis has shown that for common size power transformers on our networks, refurbishment (off-site) is not cost-effective. Key contributing factors are the cost of assembly/disassembly, transport and oil handling; the majority of these costs are also included in new transformer procurement. New transformers also have warranties and significantly longer expected lives.

With little component replacement on transformers to date (E.g. bushings, painting, control systems, Buchholz devices, etc), significant proactive component replacement would be required on site, and therefore is also not cost-effective on transformers that are aged, given it provides no benefit to the active part, and internal failure probability has been proven to increase with age. Component replacement is cost-effective when transformers are at middle age.

Disposal

We dispose of power transformers when they cannot be redeployed and have no use as spare units or for spare parts. The principal components of oil, copper, and steel are recycled.

8.4.4. Indoor Switchgear Fleet

Indoor Switchgear Fleet Overview

The primary function of indoor switchgear is the connection, disconnection, and isolation of network equipment such as 6.6 and 11 kV feeder circuits, bus bar sections or power transformers. Indoor switchgear comprises individual switchgear panels assembled into a switchboard, as shown in the photo below. These panels contain circuit breakers, current and voltage transformers, isolation switches, earth switches and busbars, along with associated insulation and metering. They may also contain protection and control devices, or these may be installed in a separate relay panel, sometimes located in a separate protection/control room.

Figure 8.51: Modern vacuum interrupter indoor switchboard at Carisbrook zone substation

Indoor switchgear has been used extensively for applications at 6.6 kV and 11 kV, and, more recently, it is also preferred for 33 kV applications. It is generally more reliable than outdoor switchgear, due the fact that it is installed indoors and is thus not exposed to pollution, weather, wildlife or foreign interference. Indoor switchgear also has a much smaller footprint, making it useful in urban environments, where it can be housed within a relatively small building. The confined and enclosed nature of indoor switchgear means that if it does fail, there is significant arc flash risk. Legacy switchgear is mostly oil filled, and not arc fault contained. It represents a significant safety risk to the operator and any nearby personnel, should it malfunction. Our approach to indoor switchgear renewal considers this risk and includes a programme of oil-filled switchgear replacements.

Population and Age

Our zone substation portfolio contains a total of 340 indoor circuit breakers (making up 30 switchboards). The table below summarises the population by type and rated voltage.[27]

Table 8.36: Indoor switchgear population by operating voltage

INTERRUPTING MEDIUM	6.6 KV	11 KV	33 KV	TOTAL
Oil	144	18	0	162
SF_6	14	7	7	28
Vacuum	50	84	0	134
Total	208	109	7	324

The figure below shows the age profile of our indoor switchgear by circuit breaker type. Switchgear technology has evolved over time. Prior to the 1990s, the majority of circuit breakers used oil as the insulation medium, and these make up a significant amount of our current population. Oil-based circuit breakers carry additional safety risks compared to their modern equivalents. Modern switchgear uses solid dielectric or SF_6 insulated vacuum or SF_6 circuit breakers. The level of arc flash containment and protection has improved significantly with modern switchboards.

The average age of our indoor circuit breakers is 35 years, with those in our Dunedin network region having a higher average age than those in our Central Otago network region. The circuit breaker life expectancies in the table below are based on standard industry practice. A significant number of our oil circuit breakers have exceeded their expected life. Many of these aged bulk oil circuit breakers are located in the Dunedin region, while all the minimum oil circuit breakers are in Central. In contrast, our vacuum and SF_6 circuit breakers are relatively young with average ages of 11 years and 27 years, respectively. The 33 kV indoor switchgear is relatively young and in good condition.

27 Some of our 11 kV switchboards in Dunedin operate at 6.6 kV.

Figure 8.52: Indoor switchgear age profile

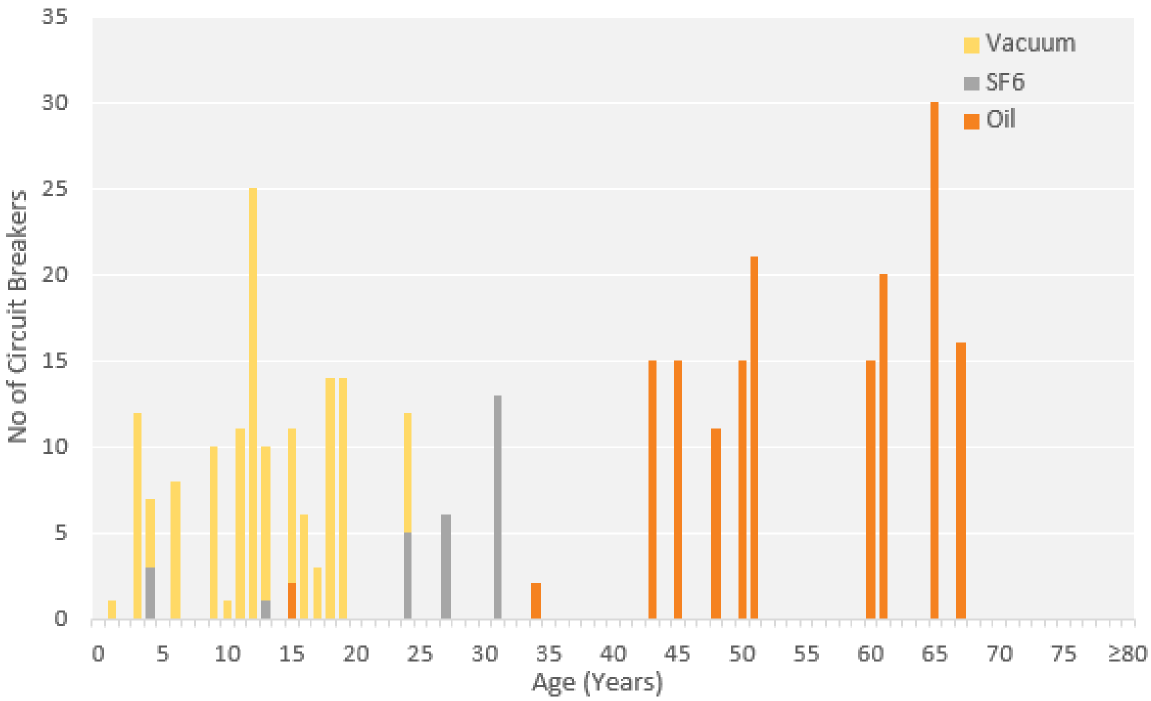


Table 8.37: Indoor switchgear expected lives by insulating medium

CB TYPE	AVERAGE AGE	MAXIMUM LIFE EXPECTANCY
Vacuum	11	45
SF_6	24	45
Oil (bulk and minimum)	53	35-50

Condition, Performance and Risks

Condition

We gather condition information on our indoor switchgear during preventive maintenance. In particular, insulation resistance tests provide a good indication of potential insulation breakdown. Routine testing across the whole fleet enables within site and across site trends to be tracked, enabling early identification of potential failure.

We have identified two 11 kV switchboards of the same type at different zone substations that have insulation resistance lower than expected, indicating that the switchboards are reaching end-of-life.

We identified and remediated poor condition CT insulating washers at two sites, and have repaired an 11 kV SF_6 leak at another. We note also that the slow or disproportionate phase clearance time on some breakers is an indication of deteriorating condition.

Overall, the condition of our switchgear is commensurate with its age profile and supports replacement at selected sites.

Performance

Indoor circuit breakers are generally reliable assets and we do not have any catastrophic failures on record.[28] Our historical data shows most of our switchgear-related unplanned outages are switching errors. Some types of switching errors involving oil insulated indoor circuit breakers can indicate an elevated risk due to the failure mode of these assets. This is increased as none of the switchboards are rated to contain arc faults like modern switchboards.

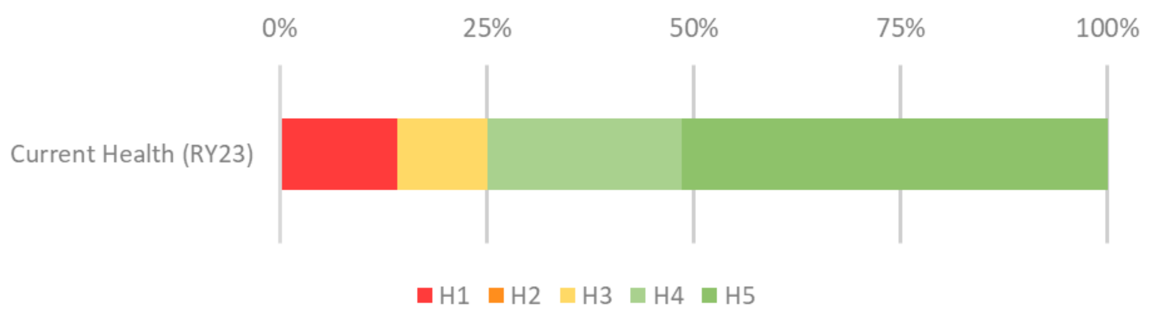
Our field inspections show that several circuit breakers were displaying evidence of deterioration. Observations included slow or phase imbalance with operating times, significant carbon in oil (signifying too many operations prior to maintenance), and minor parts needing replacement.

At one zone substation, 6.6 kV circuit breakers have tripped during the operation of an adjacent circuit breaker (on the same switchboard) in an isolated incident. Our investigation indicated that the inadvertent tripping likely resulted from the mechanical vibrations on the switchgear and subsequently the electromechanical relays installed on it.

Asset health

Equipment age provides a reasonable proxy for switchgear health and thus our AHIs for indoor circuit breakers are based on remaining life, based on age versus switchgear life expectancy. Expected life varies depending on the insulating medium and the rated operating voltage ratio. The figure below summarises AHI for our indoor switchgear fleet.

Figure 8.53: Indoor switchgear asset health



A significant proportion of this fleet (14%) has a health score of H1 and need replacement in the short term. Also, 25% of assets are H3 or less, meaning they will require replacement early in the planning period. This is largely driven by our ageing oil-filled circuit breakers.

Criticality

For indoor switchgear, the key criticality dimensions are safety (of staff and operators) and the load serviced (as a proxy for reliability performance). To prioritise the replacement of indoor switchgear, we have assigned them a criticality index that ranges from one to five (i.e. C1 through C5). The criticality indices have been determined using a weighted average of the following factors:

– magnitude of the load supplied

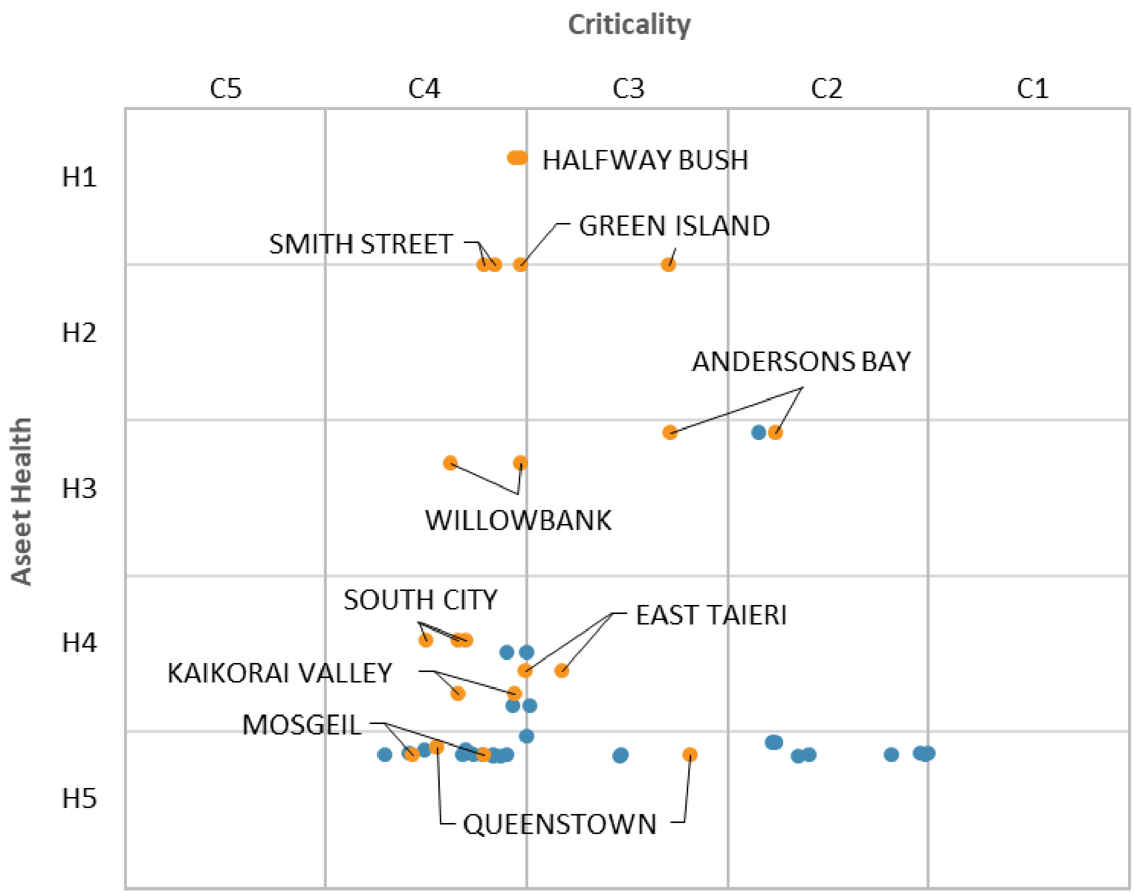
[28] We have had catastrophic failures of indoor switchgear installed in outdoor enclosures, which are covered in our outdoor switchgear fleet.

- load transfer capability (i.e. the backup 11 kV supply from the adjacent substations)
- protection clearing time (safety relevance)
- equipment fault rating capability in comparison to the actual fault levels (safety relevance)
- availability of spare parts (reliability relevance i.e. impacting recall time).

This means that, for example, switchgear that has minimal load transfer capability from adjacent substations is generally more critical, and we have less tolerance for deferring its replacement.

The following figure shows the current understanding of our indoor switchgear criticality. The highlighted dots indicate work during the planning period.

Figure 8.54: Indoor switchgear asset health and criticality graph



Risks

A significant safety issue associated with our indoor switchgear assets is arc flash risk. An arc flash is a type of electrical explosion that can release a large amount of energy. It can cause material damage, and serious injury or even death, and is made worse when switchgear is oil filled, as the oil fuels any explosion. Furthermore, if such a fault does occur it will have a significant reliability impact, as the switchboard will likely be rendered unserviceable and require complete replacement.

New switchgear is oil free, has arc flash detection, arc fault containment, and generally has external venting for toxic arc by-product gases. Therefore, the type of risks we face on historic equipment are reduced to very low levels in new switchgear.

With older indoor switchgear that is oil filled or not arc fault contained, we partially mitigate the risk using the following approaches in addition to normal work practices:

- specific personal protective equipment (PPE) for operators, removing unnecessary personnel from the switch-room when operating, and appropriate signage
- carrying out switching operations via SCADA with personnel outside of the switch room
- installing barriers so that sides and rear of non-arc fault contained switchboards cannot be accessed when the equipment is in service.

Meeting our portfolio objectives – safety first

Arc flash and oil switchgear failure are key risks driving our indoor switchgear renewal programme

Like transformers, switchgear also carries seismic risk. In a recent seismic assessment, the hold-down fixings of some of our switchgear assets were found to be understrength, and we are in the process of rectifying a number of cases where this is feasible and where the renewal of the assets is not planned within the medium-term. The following table summarises the key risks identified in the fleet.

Table 8.38: Indoor switchgear risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
Arc flash	Operational management, PPE, signage in substations, barrier off rear and sides of switchgear Arc flash protection installed or retrofitted to switchboards with material remaining life NERs installed or retrofitted to reduce earth fault levels, which are particularly high in the Dunedin 6.6 kV network	Safety
Compound filled cable box	PPE, signage in substations, barrier off rear and sides of switchgear	Safety
Major oil circuit breaker failure leading to arc flash, fire, and major service disruption	Operational management, PPE, signage in substations Switchboard replacement programme Dunedin network architecture changes Mobile substation and other contingency planning	Safety, reliability
Seismic event	Structural modifications where required Replacement plan	Reliability
Failure to operate during fault conditions	Coordination of protection systems to ensure the provision of backup fault clearing	Safety
SF_6 leaks	Monthly checks of gauges and remediation if required Avoidance of SF_6 in new equipment where possible	Environmental
Lightning strike leads to indoor switchgear failure or damage	Surge arresters on overhead to cable interfaces	Reliability, safety

Design and Construct

We have a PSA with a single manufacturer for 11 kV indoor switchgear. This will drive efficiencies through design, procurement and construction as we ramp up our replacement programme. This switchgear is fully arc fault contained, externally vented, uses vacuum interrupters, and does not contain SF_6. When we need to purchase more 33 kV indoor switchgear, we will investigate options for a similar agreement on 33 kV indoor switchgear.

> **Meeting our portfolio objectives – safety first**
> We procure new indoor switchgear that is arc flash tested, in accordance with IEC 62271-200, and equipped with external arc by-product venting. Also, where appropriate, we are equipping our power transformers with NERs to reduce phase-to-earth fault levels and the energy released during arc flash events to ground.

As discussed in the buildings and grounds section, existing buildings are generally not suitable for new switchgear, and new buildings will be required for most indoor switchgear renewal projects.

Renew or Dispose

We replace indoor switchgear on the basis of risk, as informed by asset health and criticality. We do not run our indoor switchboards to failure because of the potential consequences of a major failure including arc flash, fire and explosion leading to severe harm or death, potential network impacts, costly contingency response and long procurement times.

> **Meeting our portfolio objectives – safety first**
> Indoor switchboard failures are rare but can have significant safety consequences.

The following table summarises our approach to indoor switchgear renewal.

Table 8.39: Summary of indoor switchgear renewals approach

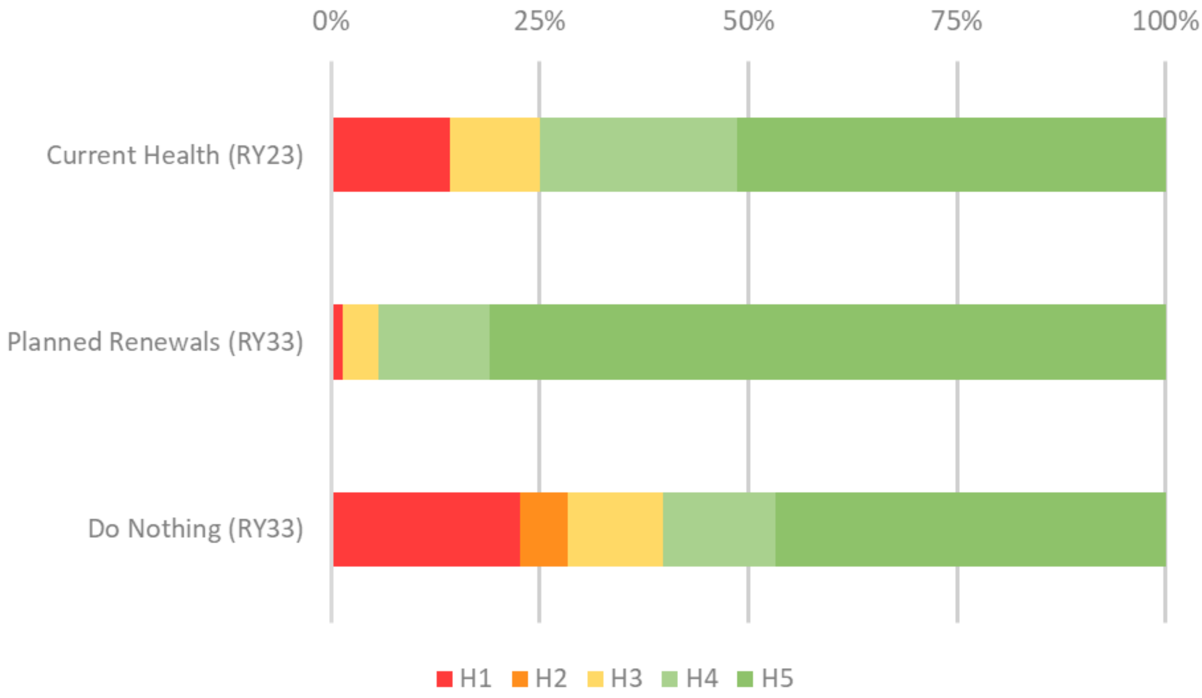
ASPECT	APPROACHES USED
Renewal trigger	Proactive, asset health
Forecasting approach	Risk-based approach using asset health and criticality Consolidation of zone substation projects
Cost estimation	Tailored estimates

Renewals forecasting

We have developed an asset health versus criticality risk matrix model to help forecast indoor switchgear renewals. The methodology employed is discussed in more detail at the end of the zone substation section. The model enables us to predict changes to asset health with the risk impact reported as a function of time. The chart below summarises AHI for our indoor switchboard fleet.

Our indoor switchgear fleet is ageing and its likelihood of failure thus increasing. The planned investment levels will enable us to manage a critical safety and reliability risk., The impact of the planned investment on H1 rated indoor switchgear is indicated below. Currently nearly 25% of our fleet requires replacement over the planning period. Our planned renewals programme will significantly improve overall fleet health.

Figure 8.55: Projected indoor switchgear asset health at RY33



Disposal

We dispose of indoor switchgear when it has reached end-of-life and is removed from service. Where the same make/model switchboard remains in service at another site, we will assess it for retention of spare parts and keep them as required. SF_6 is a greenhouse gas and can be contaminated with toxic arc by-products. It is handled by specialist contractors and disposed of appropriately. Other switchgear components, including oil, copper, aluminium and steel, are recycled.

8.4.5. Outdoor Switchgear Fleet

Outdoor Switchgear Fleet Overview

The zone substation outdoor switchgear fleet comprises several asset types, including outdoor circuit breakers, voltage and current transformers, air-break switches, load break switches, earth switches, fuses, and reclosers.

Outdoor switchgear is primarily used to connect, disconnect or isolate network equipment in the same manner as indoor switchgear. It de-energises equipment and provides isolation points so that our service providers can access equipment to carry out maintenance or repairs.

Circuit breakers and reclosers provide protection and control, while fuses provide protection and isolation only. Non-load break air-break switches can be used to isolate equipment but cannot be used to break significant load current. Load break switches connect, disconnect and isolate and can be used to break load current.

Population and Age

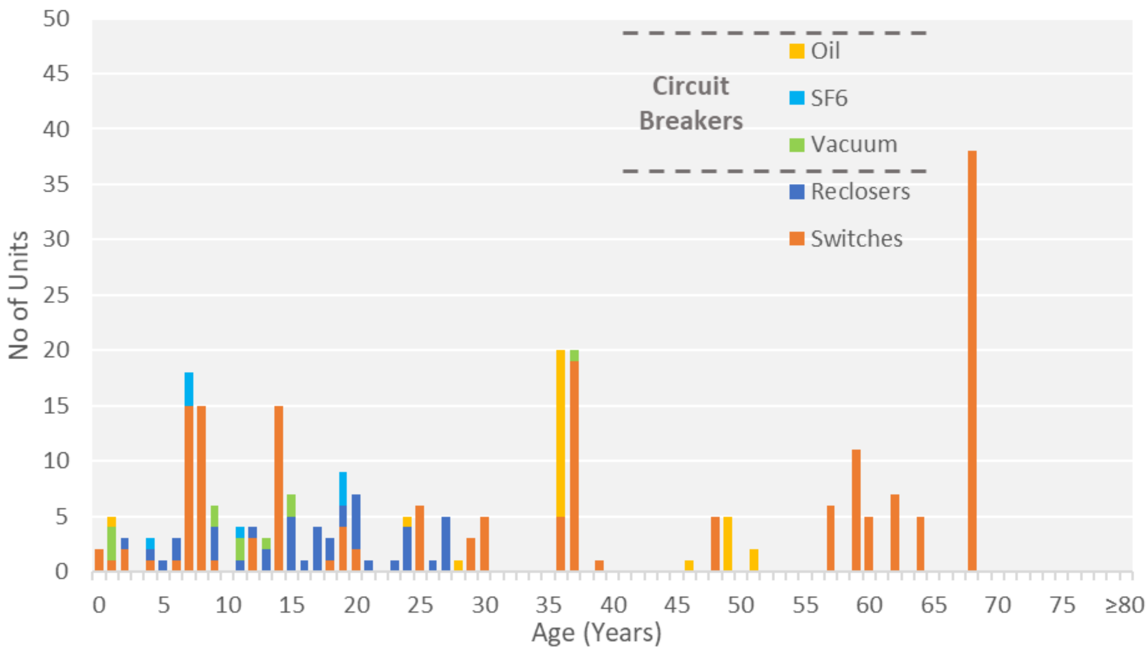
Our zone substation portfolio contains a total of 267 outdoor switchgear units, comprising circuit breakers, reclosers (within zone substations, reclosers provide zone substation circuit breaker functionality), and switches. The table below summarises their population by type.

Table 8.40: Outdoor switchgear population by rated voltage

TYPE	INTERRUPTING MEDIUM	TOTAL	AVERAGE AGE
Outdoor circuit breakers	Oil	26	26
	SF_6	8	8
	Vacuum	11	11
Reclosers		43	17
Air-break switches		179	38
Total		**267**	**33**

As with indoor switchgear, the technology associated with outdoor switchgear has evolved over time. The majority installed prior to the 1990s are oil insulated and these make up a significant portion of the circuit breaker population. The remainder (generally installed after 1990) are vacuum or SF_6 insulated. The figure below shows their age by type.

Figure 8.56: Outdoor switchgear age profile



A small number of our OCB's are beyond life expectancy or Maximum Practical Life (MPL) of 45 years. Our reclosers are relatively young, with none yet exceeding their 45-year life expectancy. The life expectancies used are based on standard industry practice.

Condition, Performance and Risks

Condition

Until 2020 we had not been able to internally access our minimum oil CBs due to unavailability of spares from the manufacturer. We then embarked on dismantling a spare unit to create bespoke parts. We are not in a programme to undertake a full condition assessment of 11 kV circuit breakers. For 33 kV minimum oil circuit breakers, we have not been able to assess contact condition but are able to flush the oil during maintenance. We recognise the need to replace these circuit breakers, and we plan to carry out the works in the next few years.

While not strictly a condition issue, we are modifying the air breathers on a type of oil-immersed interrupter vacuum circuit breaker and improving the bushing seals. They had potential failure mode of moisture ingress through the breathers and seals on the bushings, which had been locally modified to accommodate current transformers. The bushing modification requires changes to the seals for them to be effective.

We have a population of indoor type minimum oil circuit breakers (ABB type HKK) that have been installed in locally made, poorly designed, 'outdoor cubicles' in our switchyards. We have one installation of these circuit breakers that has been created as a switchboard (see below) where the CBs are withdrawable as per a normal indoor switchboard of this type. The others have the interrupter and mechanism installed in a small enclosure on top of a transformer, and these are fixed rather than withdrawable. In the 1980s this type of 'homemade' installation was considered to be cost-effective, but we (and other EDBs) have experienced issues with these installation types – we believe primarily due to water ingress and internal pollution leading to flash overs. The cubicles are lined with Pinex, a wood product, and so in the event of a catastrophic failure they contain further fuel in addition to oil in the circuit breakers.

Figure 8.57: Indoor minimum oil-filled circuit breakers (left) installed in outdoor cubicles (right)

Performance

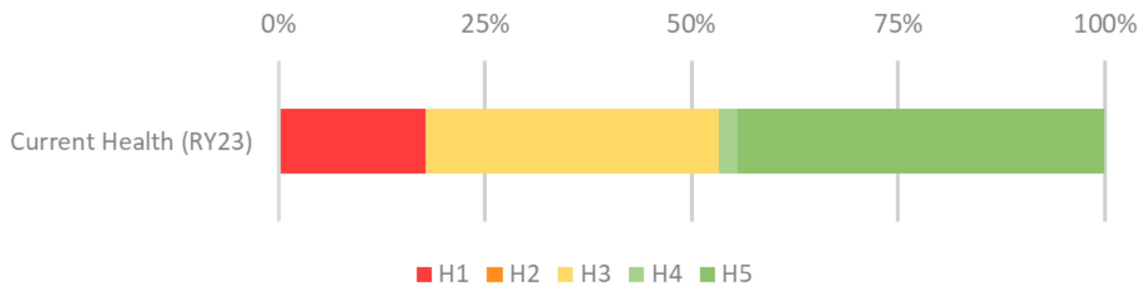
Our ageing population of oil-filled outdoor switchgear poses safety and performance risks. Unlike our indoor switchgear fleet, however, our outdoor switchgear has an elevated track record of poor performance. We have recent experience of outdoor switchgear failures:

- In 2012, an indoor SF_6 11 kV circuit breaker (ABB type HPA) in an outdoor cubicle/switchboard arrangement (similar to the minimum oil example above) failed at a Central Otago zone substation. While the root cause is unknown, this resulted in a switchyard fire.
- During the clearance of an 11 kV feeder fault at a Central Otago zone substation (late 2019), oil was expelled from the breather of one of the minimum oil 11 kV circuit breakers (ABB type HKK) that are installed in outdoor cubicles.
- We have experienced a number of Canterbury Engineering 33 kV air-break switch (ABS) failures due to the breakdown of the cement compound that bonds the two-piece insulators to the steel frame of the ABS. We are intending to replace the insulators on the ABSs that are to be retained, with a one-piece version of the insulator.

Asset Health

While we do have outdoor circuit breaker and ABS condition information, it is not in a form to reliably and systematically translate to AHI. Therefore, our AHIs for outdoor switchgear are based on expected remaining life, calculated by subtracting the current age of each circuit breaker from its life expectancy. The chart below summarises current AHI for the circuit breakers (reclosers and switches are included in their respective fleets).

Figure 8.58: Outdoor switchgear asset health



Criticality

For outdoor switchgear renewals, our assessment criteria does not currently utilise criticality. In the future, we intend to incorporate criticality into our outdoor switchgear renewal models. Presently, outdoor switchgear works that are undertaken as part of other large zone substation projects are inherently prioritised on a risk basis, as criticality is used to prioritise these larger projects.

Risks

The table below summarises the key risks identified in our outdoor switchgear fleet.

Table 8.41: Outdoor switchgear risks

Risk/Issue	Risk Mitigation	Main Risk Area
Seismic event	Structural modifications	Reliability
Failure to operate during fault conditions	Coordination of protection systems to ensure the provision of backup fault clearing	Safety
Arcing fault in oil circuit breaker leading to explosion	Regular maintenance and remote switching of circuit breakers	Safety
Arc flash (homemade switchboard enclosure installations)	Operational management, PPE Maintenance programme Replacement programme	Safety
Lightning strike leads to outdoor switchgear failure or damage	Insulation coordination reviews Surge arresters retrofit, particularly where circuit breakers sit open for long time periods Overhead earth wires	Reliability, safety
Equipment failure	Check cement and replace 33 kV ABS two-piece insulators as required	Reliability
SF_6 leaks	Monthly checks of gauges and remediation if required Avoidance of SF_6 in new equipment where possible	Environmental

Design and Construct

Due to historically low volumes of asset replacement and a relatively small fleet, we have not yet standardised our outdoor switchgear. We will strive to use equipment that does not contain SF_6.

Meeting our portfolio objectives – sustainability by taking a long-term view

SF_6 is classified as a greenhouse gas, so we are endeavouring to limit the purchase of SF_6 switchgear to applications without a viable alternative, thereby minimising our environmental impact. Additionally, we require specialist handling of SF_6 switchgear following an internal switchgear fault with electrical arcing, due to the toxic products that are formed.

The volume of SF_6 on our network does not require us to do regulated reporting. Despite this and due to its propensity as a greenhouse gas, in the medium-term we will implement industry good practice reporting, covering aspects such as volumes and amounts handled, as part of our sustainability efforts.

Designs of new outdoor switchyards are made compliant with best industry practice safety and access clearances. Brownfield renewals work in existing outdoor switchyards must be complaint with good industry practice, which may be slightly more restrictive than a greenfield design.

Renew or Dispose

We replace outdoor switchgear on the basis of asset health. Generally, outdoor switchgear renewals are grouped with other zone substation renewals and delivered as one project.

Meeting our portfolio objectives – safety first

Switchgear with 'homemade' enclosures has a history of failures and presents a safety risk. Those containing minimum OCBs are our highest priority for replacement.

We do not run our outdoor switchgear to failure, as switchgear (with protection operation) removes faults from the network. Investment is required based on the performance we are experiencing and associated safety risks. The table below summarises our approach to outdoor switchgear renewal.

Table 8.42: Summary of outdoor switchgear renewals approach

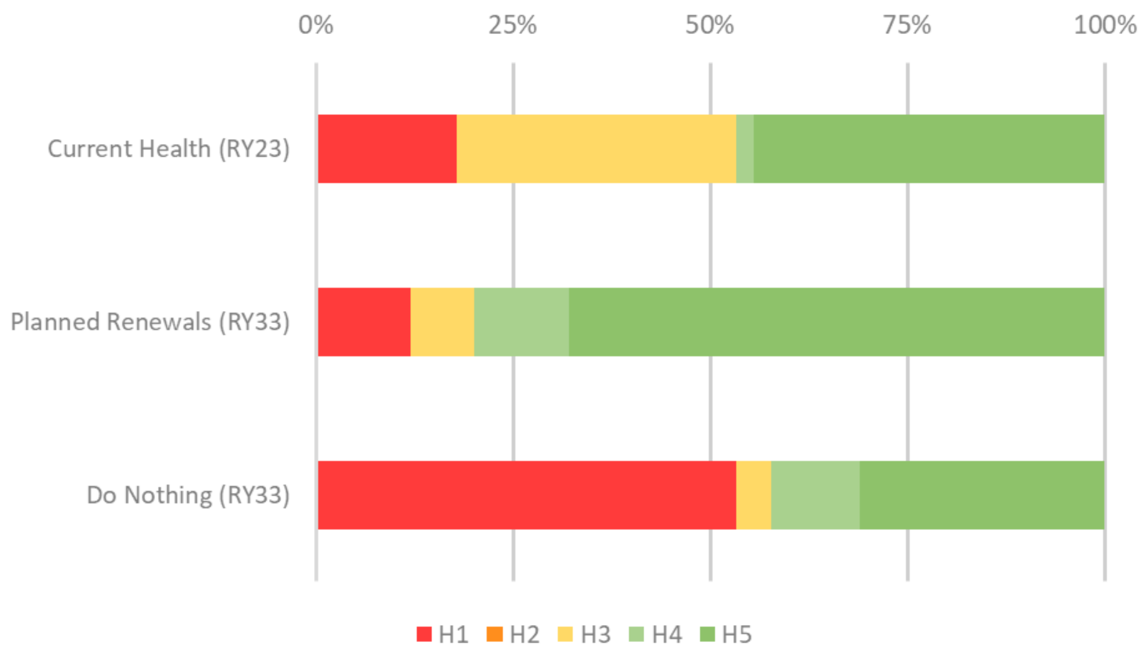
ASPECT	APPROACHES USED
Renewal trigger	Proactive, age vs expected life
Forecasting approach	Remaining life Consolidation of zone substation projects
Cost estimation	Tailored estimates

Renewals forecasting

We use an age-based model to help forecast outdoor switchgear fleet renewal requirements. We intend to further improve these models to include condition-based AHI and criticality.

The figure below summarises AHI for our outdoor switchgear fleet and illustrates that approximately 20% of the fleet has already exceeded its life expectancy (H1). Our planned replacement programme will reduce the number of H1 assets by 2033.

Figure 8.59: Projected outdoor switchgear asset health



Options analysis

Where a significant amount of outdoor switchgear is planned for renewal, we consider conversion to indoor modern equivalent upon assessing the costs and benefits. Indoor options are preferable where safety clearances in the outdoor switchyard do not meet current standards. Indoor options also provide improvements, such as adding a bus section circuit breaker and busbar protection, less vulnerability to weather events, and no exposed high voltage outdoor buswork.

Disposal

We dispose of outdoor switchgear when it has reached end-of-life and is removed from service. Where the same switchgear remains in service at another site, we assess it for retention of spare parts. SF_6 is handled by specialist contractors and disposed of appropriately. Other switchgear components, including oil, copper, aluminium and steel, are recycled.

8.4.6. Ancillary Equipment

Ancillary Equipment Fleet Overview

The ancillary equipment asset fleet refers to equipment in our zone substations that does not fit into one of the previous categories including: load management equipment, outdoor structures and buswork, mobile zone substations, and local service supplies.

We presently use ripple injection equipment to manage load during peak demand periods, which supports deferral of network investment. Ripple plant also controls street lighting. We have 317 Hz and 1050 Hz ripple injection systems.

Outdoor structures support buswork, which transmits power between different circuits at a zone substation. Structures vary in types and arrangements and can be concrete or wooden poles, steel lattice structures, or other steel structures. Many designs are legacy and have varying degrees of non-conformance with modern standards. Structures with material non-conformances that breach current industry practice (and associated primary plant) will be replaced with an equivalent indoor switchboard solution at equipment end-of-life.

A mobile substation can reduce or eliminate the need for lengthy planned outages. It can also provide contingency coverage in the event of a major failure. We purchased a single 5 MVA, 66-33/11-6.6 kV unit 12 years ago, and have made provision for its connection at a number of our single transformer substations.

Population and Age

We have 317 Hz and 1050 Hz ripple injection systems, with the 1050 Hz legacy system being phased out. In Dunedin, we operate two or three ripple injection load control systems in parallel injecting at GXPs using modern solid state 317 Hz systems.[29] These units are controlled via the Dunedin SCADA master station. Two injection units exist at one GXP, and one injection unit with two converters at the other.

[29] If the bus at Transpower's Halfway Bush substation is operationally split, we need to operate three ripple plants.

The aged K22/Decabit 1050 Hz ripple injection system comprising 16 injection plants injects into distribution circuits at each zone substation. We have 15 rotary plants, installed between the 1950s and 1970s, and one static plant installed in the 1990s. We have an additional three Decabit 317 Hz solid state ripple injection plants at each of our Central Otago GXPs. These date to 2009, 2010, and one has a 1984 vintage coupling cell with a 2015 vintage converter.

We have not replaced any significant outdoor structures in zone substations. Unless they are wooden poles, their expected lives tend to be significantly longer than the outdoor switchgear itself.

Local service equipment tends to be the same age as the original substation and is replaced if at end-of-life as part of larger zone substation projects.

Condition, Performance and Risks

Condition and performance

The performance of the ripple systems is dependent on the performance of the controlling systems, communications, and ripple receiver relay installations. We have had issues with electrical control system component failure on our ripple plants and are investigating these with the manufacturer. Some of the bespoke container buildings housing ripple plants have no temperature or humidity control and are being retrofitted with air conditioning plant.

We do not have any significant issues with the condition of our outdoor structures. Some mass reinforced concrete pole support structures in zone substations have minor spalling, which is treated with a rust-kill/sealant product. Given their low loadings compared to concrete poles with long overhead conductor spans, this condition is deemed acceptable at present.

Risks

We have one outdoor switchyard that has relatively low 33 kV buswork. This presents a safety hazard to anybody walking around or working in the switchyard. We are installing barriers to prevent inadvertent breaches of minimum approach distance, and appropriate signage. This switchyard is planned for replacement in the short-term.

Table 8.43: Ancillary zone substation equipment failure risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
Ripple plant inoperable due to component failure	Maintenance programme Spare parts Redundancy of equipment	Reliability
Tight clearances in outdoor structures	Job safety assessments Barriers and signage Replacement programme Bird deterrents if required	Safety, reliability
Local service failure	Redundancy being installed at N-1 sites DC system carry over capacity Portable generators and connection points	Reliability
Local service arc flash and JW fuses	Replacement of legacy LTAC panels as part of zone substation projects	Safety

Design and Construct

The main design consideration in this fleet is the physical layout of each outdoor substation. Designs of new outdoor switchyards are compliant with best industry practice safety and access clearances. Brownfield renewals work into existing outdoor switchyards also needs to be compliant with good industry practice, this can be more restrictive relative to a greenfield design.

Renew or Dispose

Zone substation ancillary equipment is generally renewed or disposed with larger zone substation works. The table below summarises our approach to ancillary equipment renewal.

Table 8.44: Summary of ancillary equipment renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Consolidation of zone substation projects
Forecasting approach	Consolidation of zone substation projects
Cost estimation	Tailored estimates

We do not plan to renew any 317 Hz ripple injection equipment during the planning period. We are progressively removing 1050 Hz ripple plant as we refurbish or renew each zone substation, and are working with metering equipment owners on prioritising and expediting ripple relay replacement to enable this. We own the streetlighting ripple relays (only) and we have replaced them. We have six absorption units for 1050 Hz to prevent the 21st harmonic from the Tiwai smelter interfering with our 1050 Hz load management system. They will be removed once all 1050 Hz plants are decommissioned.

8.4.7. Zone Substations Forecasting Approach

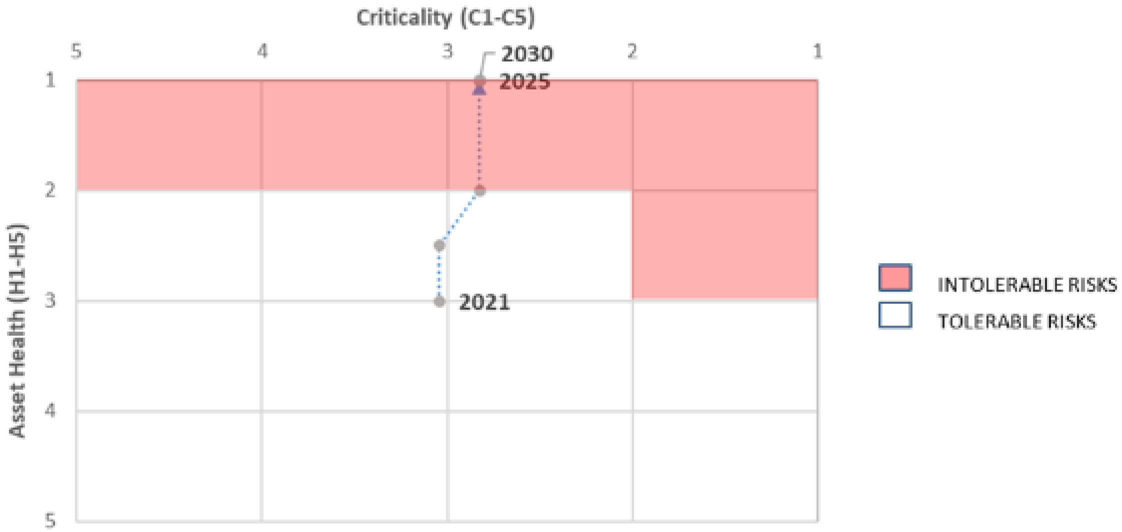
We forecast renewal needs for power transformers, indoor switchgear and outdoor switchgear using models informed by AHI and, where possible, criticality. The models help us to identify and prioritise the replacement of zone substation equipment. We coordinate zone substation and secondary systems renewal works to align these projects and reduce overall costs and equipment downtime.

The figure below shows an example risk matrix as the asset's health degrades from H3 to H1 over a period of time. We consider risk levels in the pink shaded area to be intolerable and, for the example shown, the risk becomes intolerable in RY25 by which time we would expect the asset to be replaced.

We defined the 'intolerable region' based on a number of factors, including:

- as the major hubs of our network, we proactively replace zone substation equipment in poor health (i.e. AHI = H1)
- we have a lower risk tolerance for assets that play a critical role (designated by C1) in our network. Given this, it is considered intolerable to retain assets that have a criticality score of C1 once they have AHI scores of H1 or H2
- we undertake options analysis to identify the lowest cost approach and develop specific customised capital cost estimates for each of the identified asset replacement projects.

Figure 8.60: Example risk matrix used to assess renewal need



We review all zone substation projects and optimise the project timings. This review involves the use of a coordination tool to ensure that equipment is replaced in a coordinated manner. For example, if switchgear and transformer replacements are required at the same zone substation within a 5-year period they are undertaken in parallel. Similarly, all major growth projects that are projected to occur within a similar period as renewal projects (at the same zone substation) are undertaken at the same time to reduce required outages.

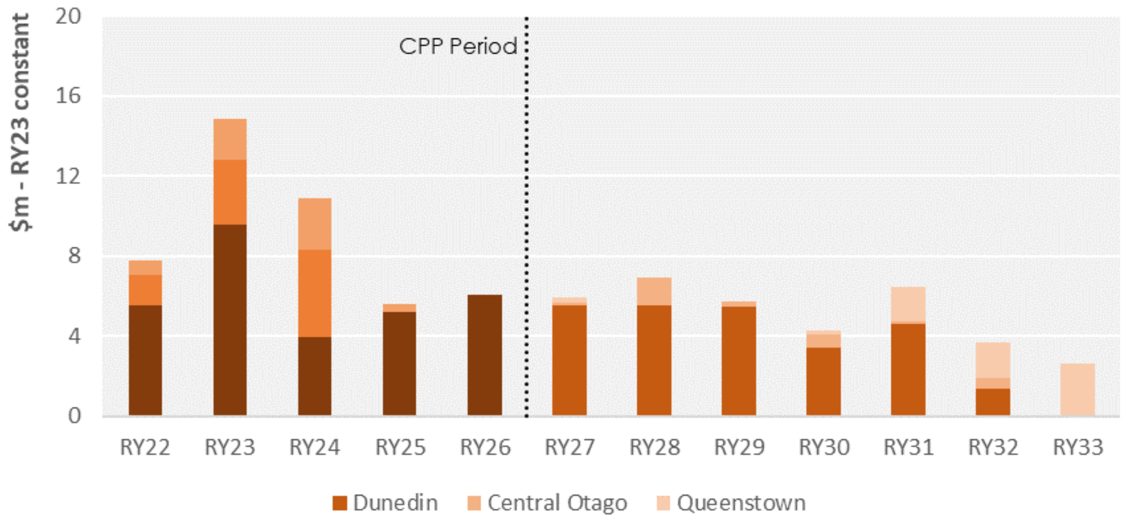
The use of a risk matrix has enabled us, as much as possible, to prioritise zone substation renewal projects. For example, those assets that have the highest priority in terms of renewal are located in the top right corner of the matrix (with a score of H1/C1). Note that the change in criticality shown below is an example of a forecast increase in load supplied by the asset.

Zone Substation Portfolio Expenditure Forecast

The figure below shows forecast Capex for zone substation renewals over the AMP planning period.

We have refined the timing of our zone substation projects to ensure the combined profile of this work is stable and we can manage resourcing levels. The resulting annual expenditure profile varies due to the 'lumpy' nature of zone substation projects. The forecast expenditure includes secondary systems renewals that occur as part of larger zone substation projects where the primary project driver is from a fleet within the zone substations portfolio.

Figure 8.61: Historical and forecast zone substation Capex



Benefits

There are numerous benefits of our planned zone substation renewal programme:

- less safety risk due to aged, inherently unsafe oil-filled or non-arc fault contained switchgear
- improved safety performance from reliable circuit breaker/protection operation during faults
- enhanced safety in design with modern switchyard clearances or indoor equivalents
- enhanced network resilience through reduced downtime and fast protection clearance preventing major equipment damage
- reduced preventive and corrective maintenance
- improved reliability from new busbar configurations and reduced likelihood of failure.

8.5. DISTRIBUTION SWITCHGEAR

This section describes our distribution switchgear portfolio and summarises our management plan. The portfolio includes six asset fleets:

- ground mounted switchgear
- pole mounted fuses
- pole mounted switches
- LV enclosures
- reclosers and sectionalisers
- ancillary distribution substation equipment

Portfolio Summary

During the planning period we expect to spend an average of $8.9m per annum on distribution switchgear renewals with expenditure increasing slightly beyond the CPP Period.

It is critical that we manage distribution switchgear to support our safety and reliability objectives. Failure of distribution switchgear can significantly impact our performance in these areas.

Switchgear is the collective term for equipment used to provide network isolation, protection[30], and switching facilities. This portfolio comprises several diverse asset types, but excludes zone substation switchgear. We define distribution switchgear based on a combination of the equipment's detailed function and where it is located. This is because the specific function and location of these assets can lead to different lifecycle strategies.

The performance of these assets is essential to maintain a safe and reliable network. Equipment mounted on the ground is more accessible by the public which has safety implications, and equipment that is inoperable due to its condition or failure risks reduces reliability of our network.

Box 8.10: Summary of our asset risk review – distribution switchgear

Issues: We have identified material quantities of ground mounted switchgear past expected lives, plus defects such as type issues, oil leaks, or inoperable (also includes fuses).

Response: increased ground mounted switchgear renewal to address switchgear in poor condition, has type issues, or is obsolete. Type issues and obsolete populations to be prioritised. We are addressing inoperable switchgear by undertaking corrective maintenance such as tilt correction, supported by new maintenance standards.

Timing: elevated renewals will continue until the latter half of the planning period, and the programme will continue at a lower steady-state level once the highest risk assets have been replaced.

8.5.1. Distribution Switchgear Objectives

Portfolio objectives (set out below) guide our day-to-day asset management activities.

Table 8.45: Distribution switchgear portfolio objectives

OBJECTIVE AREA	PORTFOLIO OBJECTIVES
Safety first	No fatalities or injuries to the public or service providers from maloperation of switchgear No fatalities or injuries to the public from non-malicious equipment access No step and touch voltage hazards
Reliability to defined levels	Downward trend in unforced, condition driven, distribution switchgear fault related outages Improve network reliability by addressing Do Not Operate (DNO) equipment
Affordability through cost management	Maximum value is realised for our customers using a risk-based prioritisation to ground mounted switchgear renewal and choosing lowest overall cost options
Responsive to a changing landscape	Investigate ground mounted switchgear products that do not use SF_6
Sustainability by taking a long-term view	Implement good industry practice SF_6 management and reporting Ensure sustainable inspection practices are in place

30 This section only covers primary assets that don't require protection relays E.g. fuses, and other equipment that provide a protective function on receipt of a trip signal from a protection relay. Protection relays are in the secondary systems portfolio.

8.5.2. Ground Mounted Switchgear

Ground Mounted Switchgear Fleet Overview

This fleet includes high voltage ground mounted RMUs and other high voltage ground mounted switches, HV ground mounted fuses,[31] indoor HV switchboards located at customer premises, and ground mounted LV switchboards. Ground mounted switchgear is generally associated with our underground cable network; some, however, are connected via short cable tails to our overhead network.

RMUs provide connections, switching and isolation functionality between cable circuits, and provide fuse protection and isolation functionality to distribution transformers. Historically we used oil-filled RMUs and other high voltage ground mounted switches, but these are no longer purchased. Oil-filled switchgear requires intensive maintenance (relative to modern assets) and does not meet modern operational safety requirements. They are no longer supported by manufacturers. We now predominantly install SF_6 insulated switchgear and solid dielectric insulated switchgear. All must be arc fault contained designs.

In our Central Otago network region, we have a population of 150 High Voltage McGraw Edison (ME) boxes that provide a transformer protection/isolation function, usually undertaken by a fuse switch in an RMU. This equipment is no longer installed on our network unless under exceptional circumstances.

We have four indoor HV switchboards in our Dunedin network region that use switchgear similar to the types used in our zone substations. These four switchboards connect HV customers and some of them have shared ownership arrangements. We also have a small number of HV customers fed off RMUs via metering equipment.

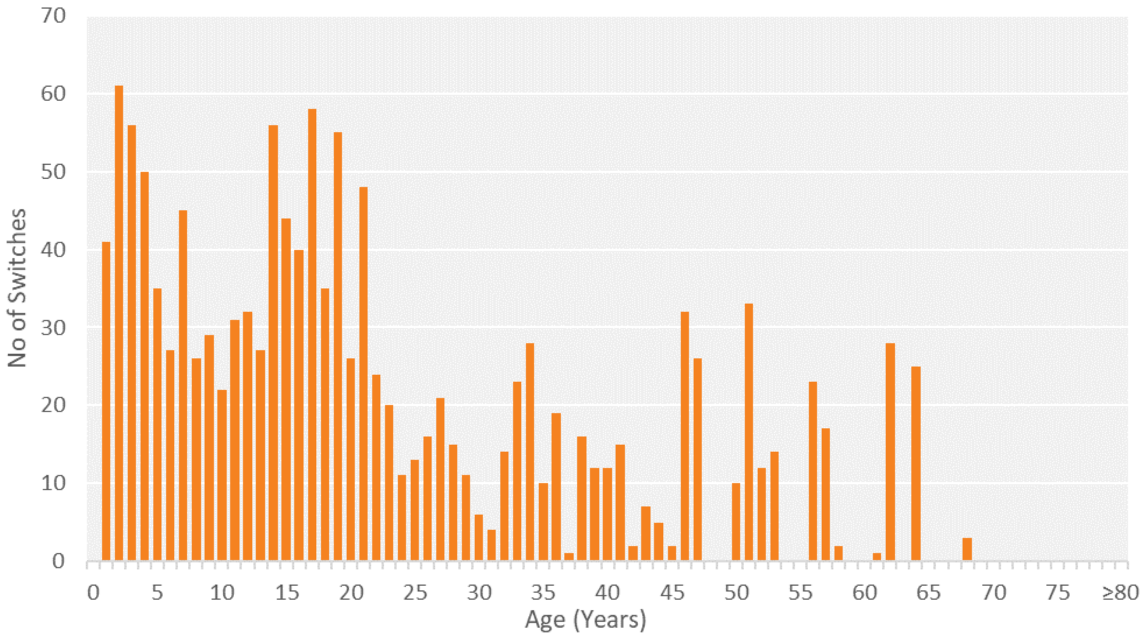
Ground mounted LV switchboards are present at most of our ground mounted distribution substations. They provide segregation of LV loads for protection and isolation purposes.

Population and Age

The fleet profile shown in Figure 8.62 is for high voltage ground mount switchgear only and includes 1,377 units of various models and insulating media as shown below. The chart excludes high voltage ground mount McGraw Edison (ME) Boxes and all ground mount low voltage switchgear.

[31] In this instance, HV represents 11 kV and 6.6 kV voltage levels.

Figure 8.62: Ground mounted switchgear age profile



Our high voltage ground mounted switchgear assets are relatively young (average age 23 years) although some units have already exceeded their life expectancy (40 to 50 years depending on the switchgear type).

Condition, Performance and Risks

In-service failure of high voltage ground mounted switchgear can be a significant safety issue, potentially exposing the public and field staff to hazards including electrocution and arc flash. It also presents a reliability issue as a high voltage ground mounted switchgear failure will generally result in loss of supply to consumers. We always aim to proactively replace high voltage ground mounted switchgear units before they fail, to minimise failure risks.

Condition and performance

Older oil-filled high voltage ground mounted switchgear continues to pose the main safety risk, as their consequences of failure (because they are without arc fault containment and contain oil) are much greater than for modern equivalent assets. We have imposed restrictions on the operation of some of our oil-filled high voltage ground mounted switchgear to reduce safety risk until they can be replaced.

In RY14, we began to remove aged oil-filled high voltage ground mounted switchgear, and this has resulted in an improvement in the health of the asset type, though small populations of specific legacy models still remain in service. We have not historically collected condition data for our high voltage ground mounted switchgear. Recognising the need to better understand their condition, we undertook an inspection of our high voltage ground mounted switchgear in RY17 and RY18 to gather condition data and verify asset specification data.

The table below sets out known type issues with our remaining oil-filled high voltage ground mounted switchgear. Replacement of these units continues to be a priority. The majority of our remaining high voltage ground mount switchgear units are the ABB-SD and Long and Crawford types, although we still have a large population of Statter switches in the Dunedin area.

Table 8.46: Known type issues with ground mounted switchgear

TYPE	RISKS/ISSUES
Reyrolle	**Condition**: These have mechanism issues and often have oil leaks, with Andelect RMUs sometimes leaking through welds and spitting oil when operated **Obsolete**: Lack of manufacturer support; new parts not available
Statter	**Safety**: Non-arc fault contained, but in generally good external condition as covered or inside **Obsolete**: Lack of manufacturer support; new parts not available
ABB 'Small Dimension' (ABB-SD)	**Condition**: Signs of mechanical failure, particularly rusting. Some have tilted due to improperly installed foundations. Once the tilt reaches a certain angle the switches cannot be operated as the fuse carrier will surface out of the oil and into air at the top of the oil chamber. Extended or extendable switch units have issues with the short creepage on the bushing – moisture and dirt ingress can progress under the heat shrink; tracking can occur until discharge causes arcing i.e. a fault.
Magnefix	**Obsolete**: This type of switchgear requires specialist manual operators and due to the small population, we are finding it difficult to maintain operator competency
Long and Crawford	**Obsolete**: Previously thought to be obsolete, manufacturer expertise and spares have become available from the UK. This includes maintenance training for the T4GF3 model. We expect to achieve a life extension for these RMUs, making them our lowest replacement priority of the oil-filled units.
JW HRC fuses	**Safety**: Many older ground mounted LV switchboards use these fuses, which can create arcs on removal/insertion if opened or closed onto high current (such as large load or short circuit). We have not installed these fuses since the mid-1990s, and we are replacing switchboards containing them when the associated transformer is replaced. We plan to start a programme of LV switchboard retrofits onto good condition transformers to address the reliability impact of not being able to undertake live operation.

Note: Operational restrictions (remote switching or not operated live) are imposed for all the above type issues to mitigate operator safety risks until such time as the units can be replaced.

Meeting our portfolio objectives – safety first

We will continue to replace aged, obsolete, oil-filled high voltage ground mounted switchgear to mitigate its inherent safety risk to operators and the public.

We have a large number of 'package' substations in our Dunedin network region that are built into the ground. The equipment is not visible to the public due to fibreglass covers, which also provide protection from general weather and some protection should an internal failure occur. The most common high voltage ground mount switchgear used in package substations are L&C types which are hard bus (rather than cable) connected to transformers. The hard bus connection means that when the high voltage ground mounted switchgear is replaced, the transformer also needs to be replaced (and vice versa) to avoid significant retrofit to change to cable connections.

Not all package substations have a float switch operated sump pump inside to clear out water, and some that do have been found to be inoperable. Groundwater rise through cable penetrations and salt air in South Dunedin has led to significant rusting in some instances, which is now requiring replacement of the 'package' substation with an above ground solution. Finally, while the security of package solutions is generally good, we have had several instances of locks seizing due to inactivity, and (rarely) night latch type locks popping open in strong winds. We replace such faulty locks with a padlock system.

Some high voltage ground mounted switchgear is installed in old Aurora Energy-owned buildings, which are in a poor state and will not be seismically compliant. This switchgear will generally be replaced outside of the building where applicable, and the building demolished or sold.

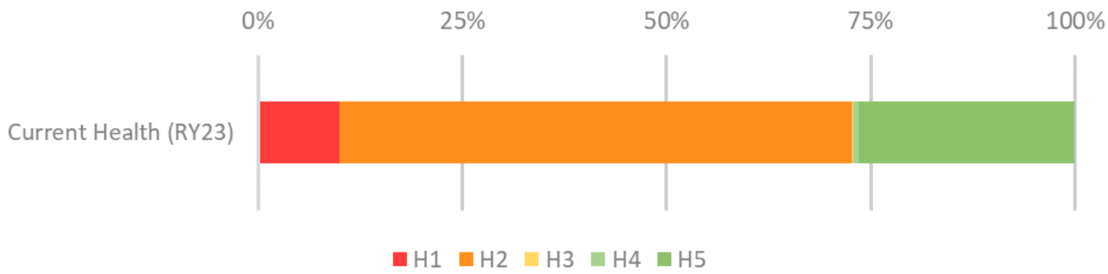
ME boxes have not been inspected to date and are generally considered maintenance free. We are unlikely to start detailed inspections of these – in the same way we do not carry out detailed pole fuse inspections – unless supported by failure evidence.

Our historical records on high voltage ground mounted switches show no failures recorded since 2013. The main performance issues in the ground mounted switchgear fleet relate to inoperable equipment. Oil filled high voltage ground mount units past their allowable tilt limit and low voltage JW fuses reduce the operability of the network, meaning that under fault and outage scenarios, outage zones are often bigger than they would otherwise need to be.

Asset health

Our AHI for high voltage ground mounted switchgear is based on expected remaining life. This AHI covers high voltage ground mounted switch gear and indoor high voltage switchboards. ME boxes and LV switchboards do not have an AHI at present; we will look to develop this in the future when we decide to proactively undertake renewals in these areas. The asset health of high voltage ground mounted switch gear is shown below.

Figure 8.63: Ground mounted switchgear asset health



The predominant driver for end-of-life (H1) is ageing oil-filled switchgear.

Risks

The table below summarises the key risks in our ground mounted switchgear fleet.

Table 8.47: Ground mounted switchgear risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
Reyrolle – These oil-filled RMUs suffer safety and performance risks due to design and installation/tilt issues	Operating procedures Programmed replacement	Safety
Magnefix requires specialist operators and has a small orphan population	Operating personnel with specialist training Operating procedures Replacement programme	Safety
Arc flash event with potential to harm operator or public (with all non- arc fault contained switchgear)	Remote operation via actuator or lanyard for older switchgear where at all possible Any maintenance on an RMU is only undertaken when it is fully de-energised with remote isolation in place Replacement switchgear is arc fault contained	Safety
RMUs past tilt limit cannot be operated	Measurement before operation to control safety risk Corrective maintenance programme	Reliability, safety
Third-party damage or access	Installation of visible warning signs Inspections and replacement of locks Design choice of location 'Package covers'; repair and replacement	Safety
Live operation of JW fuses has an arc flash risk	Safety risks controlled by DNO order which creates reliability issue Future: prioritised LV switchboard replacement plan	Reliability, safety
SF_6 release to atmosphere	Periodic checking of pressure gauges Specialist SF_6 handling	Environmental

Design and Construct

Given the safety risk that high voltage ground mounted switchgear failure presents to both operators and the public, we aim to purchase new switchgear rated for either class A or class B internal arc flash containment (IAC). IAC class B is equipment that is accessible by the public, and IAC class A is equipment in locations accessible only by authorised personnel wearing appropriate PPE. IAC rated switches and enclosures have been type tested to ensure that in the event of internal failure, arc flash heat and blast energies are diverted or dissipated to such a level that any people near the switch are safe. Most of our new high voltage ground mount switchgear units are an SF_6 model that have an IAC rating that meets class A and B requirements up to 16 kA fault level.

New installed high voltage ground mounted switchgear may be specified to enable future automation and remote operation capability. Remote operation has the potential to reduce switching/restoration times and provide greater safety for our service providers in the field. As remote operation may allow equipment to be operated without an observer, to ensure the area around the switch is clear from members of the public, this type of automation is only proposed for new installations with enclosures that are designed with full arc fault containment.

> **Meeting our portfolio objectives – sustainability by taking a long-term view**
> SF_6 is classified as a greenhouse gas, so we are endeavouring to limit the purchase of SF_6 high voltage ground mount switchgear to applications without a viable alternative thereby minimising our environmental impact. We continue to assess new market offers on high voltage ground mount switchgear units that do not contain SF_6.

We have many instances of high voltage ground mount oil fuse switches installed in our network in a configuration known as 'tee switches'. These reduce network reliability and operability by requiring increased outage zones during maintenance. If applicable when these are renewed, a full three terminal high voltage ground mount switchgear unit is installed given the cost differential is marginal at time of replacement.

'Group fusing' installations, where multiple ground mounted transformers are fused from a single point, result in a large area of lost supply from a single fault. We also have reservations about the protection adequacy of group fusing. These are investigated when renewal, growth, or customer-initiated work occurs in their vicinity, with an aim to remove this arrangement where practicable and cost-effective by installing high voltage ground mount switchgear to provide standard protective and switching functionality.

When ground mounted transformers in 'package' distribution substations with busbar connections to their associated high voltage ground mount switchgear require replacement, we replace the high voltage ground mount switchgear at the same time for feasibility and cost reasons.

We have a LV switchboard design suitable for retrofit into our 'package' substations, the elements of which can be used on LV switchboards in other locations. This replaces the JW type (currently DNO) fuses in the switchboards with modern DIN or high rupture current (HRC) fuses.

All Capex delivery is outsourced to our field service providers, most of whom will be covered by an FSA. Design is often outsourced to these service providers.

Renew or Dispose

We replace units of high voltage ground mount switchgear on the basis of asset condition, defect data captured during inspections and obsolescence. Repair or replace decisions depend on the specific make and model of the unit and the defect(s) found. We are progressively replacing our fleet of old and obsolete oil-filled high voltage ground mount switchgear units. We are focusing on Reyrolle units, followed by Statter models, then Long and Crawford and ABB SD Series.

Table 8.48: Summary of ground mounted switchgear renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Proactive condition-based Obsolescence
Forecasting approach	Repex
Cost estimation	Volumetric based on historical average unit rates

Meeting our portfolio objectives – affordability by cost management

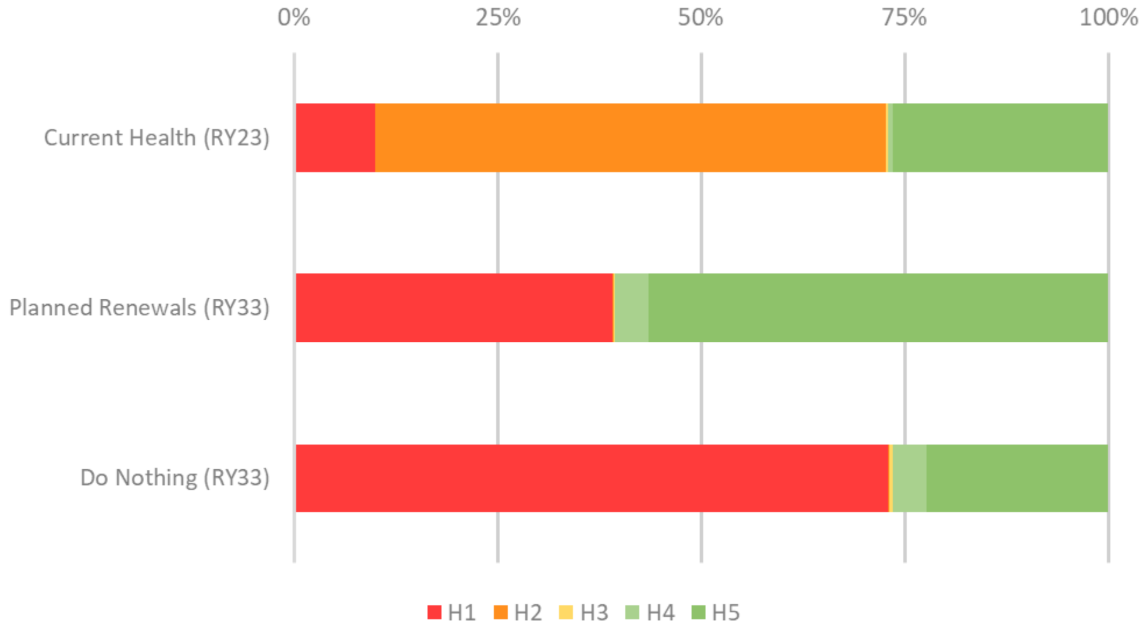
We are working to create a risk prioritisation framework for high voltage ground mount switchgear unit replacements that will consider an asset health score and criticality factors based on safety and load characteristics. This will drive repeatability and consistency in decision-making and ensure the highest risk high voltage ground mount switchgear units are addressed.

Renewals forecasting

AHI for high voltage ground mounted switchgear is informed by expected remaining life, with expected life ranging from 30 to 50 years, depending on type. While our overall fleet of high voltage ground mounted switchgear assets are relatively young (average age 16 years), there are many oil-filled units that are considered to be obsolescent. In previous years we have forecast asset health based on age only which infers a favourable Asset Health profile. The profile below has been updated to consider determined end of life due to obsolescence (parts, components, or skills no longer available or easily accessible). This is depicted in current health view by the significant H2 scores. The model is set up to transition H2 to H1 over time, which is a limitation in forecasting for obsolescence. We are currently working on maturing our model for assessing asset health to specifically deal with obsolescence. We are also reviewing our strategic approach to how we manage this fleet and the risks associated with obsolescence. As we replace assets that are determined to be obsolescent, we are actively recovering and storing strategic spares.

The chart below compares projected AHI in RY33 following our planned renewals, with a counterfactual 'do nothing' scenario.

Figure 8.64: Projected ground mounted switchgear asset health



Options analysis

We undertake options analysis to consider the lowest overall cost approach to managing our ground mounted switchgear. Options for renewal depend on the condition or defect, but include:

- replace: install a new unit which means that all condition issues or defects are remediated
- repair: remove the unit from site, swap for another in our spares pool. We refurbish the removed unit (if suitable) before returning it to our pool of RMUs for re-deployment
- alternative solution: we may consider whether there is a more cost-effective solution that might involve rationalising network assets.

Disposal

We dispose of ground mounted switchgear when decommissioned and there is no justification to keep the unit or parts of it as spares. The principal components of steel, copper, and oil are recycled. RMUs that contain SF_6 are either returned to the manufacturer or we employ the services of a specialist for safe handling of SF_6 gasses before we dispose of them.

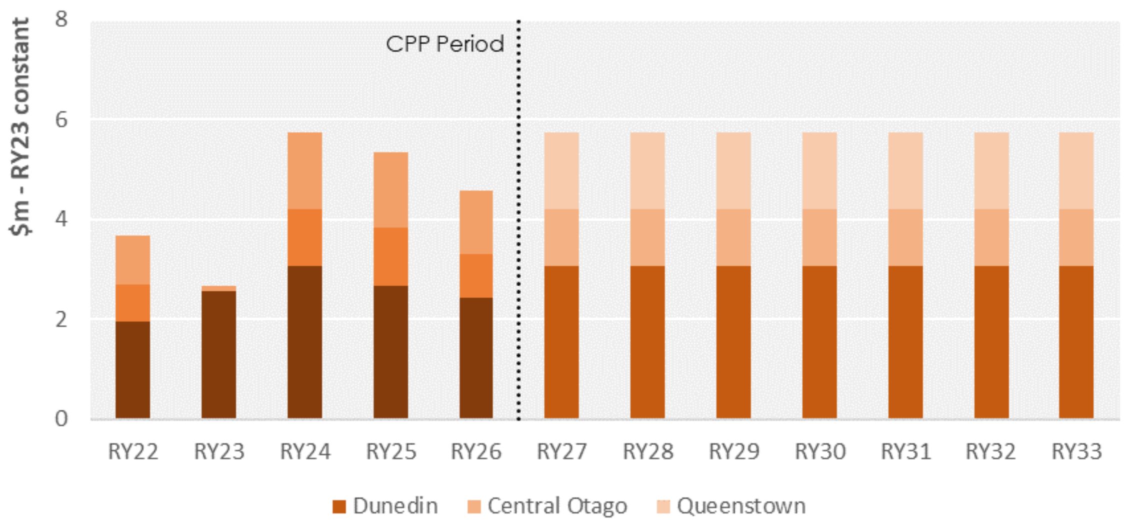
Coordination with other works

We coordinate replacements with other network asset replacements, including poles and cast iron cable terminations. Where customer or growth-related jobs are undertaking enhancement work, we look to coordinate works to reduce required outages.

Ground Mounted Switchgear Fleet Expenditure Forecast

Our forecast renewal Capex is approximately $55.8m during the planning period, as shown below.

Figure 8.65: Forecast ground mounted switchgear Capex



Historically, our expenditure for replacing oil filled high voltage ground mounted switchgear has been relatively low, and was largely driven by overhead to underground conversions, network switching improvements and third-party damage. The replacement programme has been ramped up to address a backlog of switchgear that has reached end-of-life, including management of investment required over an extended period to replace all obsolescent assets. As discussed above, we are currently reviewing our strategic approach to managing this fleet and how we manage the risk associated with obsolescence. Our current programme indicates an elevated and steady investment over the period of the plan, which reflects the intent to replace end of life assets over a sustained period until the backlog is addressed. At this level of investment, we anticipate that it will take 20 years to complete.

Benefits

The key benefits of our planned ground mounted switchgear renewal programme are reducing the safety and operability issues associated with obsolete equipment.

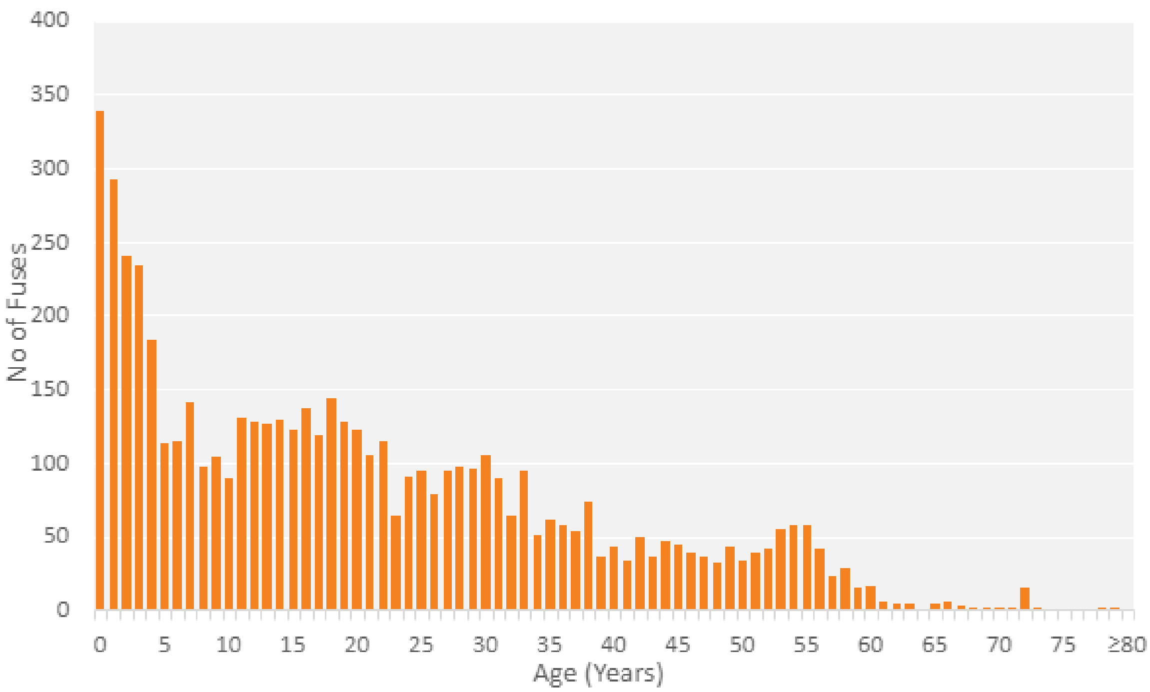
8.5.3. Pole Mounted Fuses

Pole Mounted Fuses Fleet Overview

Pole mounted fuses are simple devices that provide protection and isolation functionality. HV fuses primarily isolate and protect distribution transformers and HV cables (terminating on poles). In rural areas HV units also provide fault isolation for network tee-offs that supply low customer density spur lines or cables. The fleet includes expulsion drop out (EDO) and high rupturing capacity (HRC) fuses. We have a large proportion of HRC HV fuses due to high fault currents in our Dunedin 6.6 kV network.

Our LV pole fuses consist of rewireable and HRC types, and JW type fuses housed in aluminium enclosures that often also have MDIs (maximum demand indicators) inside.

Figure 8.66: Pole mounted HV fuses age profile



Population and Age

Our fleet consists of 5,619 HV fuse units that are all very similar in design and function but comprise a wide range of makes and models.

Our pole mounted fuses are relatively young (average age 20 years), although some units have exceeded their life expectancy of 50 years.

Condition, Performance and Risks

Fuses are designed to blow to provide protection to other equipment, so concerns exist when they fail outside of normal operation, or when they are not operable for their intended isolation purpose, as this has a direct reliability impact. In-service failure of fuses results in loss of supply.

Condition

We visually inspect fuses when we do pole inspections, but we do not undertake detailed assessments of condition. Fuses may be replaced in response to visual inspection or as part of a pole replacement. At times, only the fuse cartridges will need to be replaced.

We are phasing out one type of fuse known as 'EETEE' fuses present in our Dunedin network (shown in the photo below) due to potential failure of the stand-off insulators on the fuse mounts when the fuse is operated. These fuses are subject to operational restrictions; they are not operated live. We also have no spares of these EETEE fuses, so any time a fuse blows or an operation is required, the whole fuse assembly, including mounts, must be replaced with a modern equivalent HRC fuse assembly. These factors have material reliability implications because it reduces our ability to isolate and manage the network, and a larger outage footprint is required when replacing these types of fuses.

Figure 8.67: EETEE HRC fuses (left), and 'homemade' aluminium box containing LV JW fuses and MDIs (right)

We also have small quantities of old glass EDO fuses, which are prone to breaking when pulled for isolation, and these are programmed for replacement when they are identified.

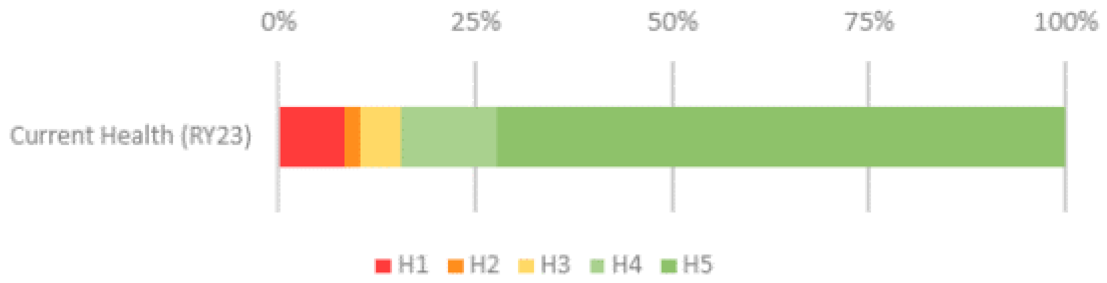
Performance

Our records indicate that the average failure rate for pole mounted fuses (that results in consumer outages) is five per annum. This count correctly excludes when the fuse has operated for downstream faults. Reliability performance on our Dunedin network is reduced due to the inoperable EETEE (HV) and JW (LV) fuse types.

Asset health

AHI for pole mounted fuses is based on expected remaining life and is shown below.

Figure 8.68: Pole mounted fuse asset health



Based on asset health, 8% of our pole mounted fuses have already reached end-of-life (classified as H1) and we expect that up to 16% (H1 to H3) of them will be considered for replacement in the planning period.

Risks

The table below summarises the key risks in our pole mounted fuse fleet.

Table 8.49: Pole mounted fuse risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
EETEE HRC fuses in Dunedin network have faulty insulator fuse mounts such that the mounts may break when operated	Operating restrictions – DNO Programmed and reactive replacement	Reliability, safety
EETEE HRC fuse cartridges no longer available	Programmed and reactive replacement	Reliability
EDO fuse assembly corrosion	Programmed replacement	Reliability
Glass EDO fuses	Programmed replacement	Safety
JW HRC fuses are not operated live due to arc flash risk	Safety risks controlled by DNO order which creates reliability issue Future: prioritised LV switchboard replacement plan	Reliability, safety

Design and Construct

The selection of pole mounted fuses is based on the specific protection and operating needs of the network. The fuses used on our network must comply with industry standards and withstand corrosion factors. Before a new type of fuse can be used on the network it must be evaluated to ensure the equipment is fit for purpose.

Renew or Dispose

We replace pole mounted fuses on the basis of condition during inspections, obsolescence, other associated renewals, and reactively in response to faults. The table below summarises our approach.

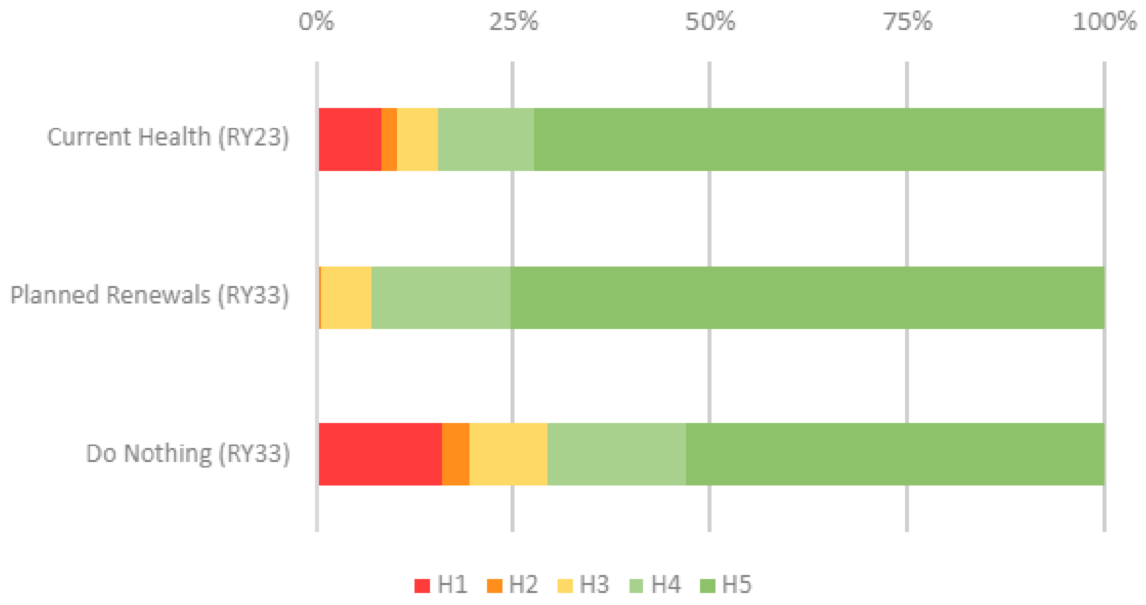
Table 8.50: Summary of pole mounted fuse renewal approach

Aspect	Approaches Used
Renewal trigger	Proactive condition-based Obsolescence/type based Associated renewals (E.g. pole) Reactive
Forecasting approach	Repex
Cost estimation	Volumetric

Renewals forecasting

The chart below compares projected AHI in RY33 following our programme of renewals, with a counterfactual 'do nothing' scenario. This year, we have adjusted the MPL (maximum practical life) up from 35 years to 50 years, which has been informed by a maturing view of survival data of this fleet.

Figure 8.69: Projected pole mounted fuse asset health at RY32



This comparison indicates the benefits provided by our proposed investment programme. At current investment levels, we anticipate a significant reduction in H1 assets over the period.

Options analysis

The only options analysis generally applicable is the decision to replace fuses with type issues as a standalone project, or wait until other underlying assets in the same outage zone also need work and consolidate this. We use a combination of both options to create our rolling annual plan, undertaking options to achieve lowest overall cost at the time of decision-making.

Disposal

Pole mounted fuses have no specific disposal requirements.

Coordination with other works

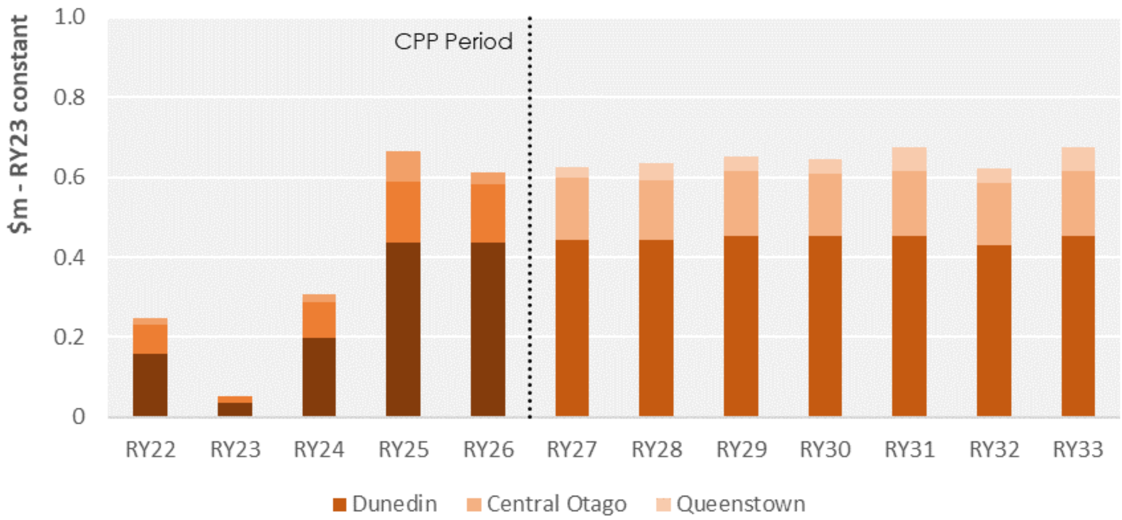
Obsolete fuse type replacements are coordinated with the renewal of the poles they reside on, and the equipment they protect. They are also coordinated with other works that may require their operability to ensure network reliability risks are managed.

> **Meeting our portfolio objectives – reliability to defined levels and affordability by cost management**
> DNO equipment such as inoperable EETEE and JW fuses reduce the operability of our network. Replacing this equipment in conjunction with other equipment is a cost-efficient way to increase reliability.

Pole Mounted Fuse Fleet Expenditure Forecast

We have forecast pole mounted fuse renewal Capex of approximately $6.1m during the planning period, as shown below. We have increased our spend significantly from previous AMPs due to the poor health and risk profile of the LV fleet in particular. This excludes pole mounted fuses replaced during pole replacements.

Figure 8.70: Forecast pole mounted fuse Capex



Historical annual expenditure in this fleet is broadly in line with the forecast. During RY15-19, we focused on type-issue replacements. Moving beyond the CPP Period, we will focus heavily on renewing this fleet due to its poor condition.

Benefits

The key benefit of our planned renewal programme is appropriate reliability performance by removing operating restrictions put in place to allow safe switching. Renewals will thereby deliver a safety in design solution, removing the reliance on operational risk control measures.

8.5.4. Pole Mounted Switches

Pole Mounted Switches Fleet Overview

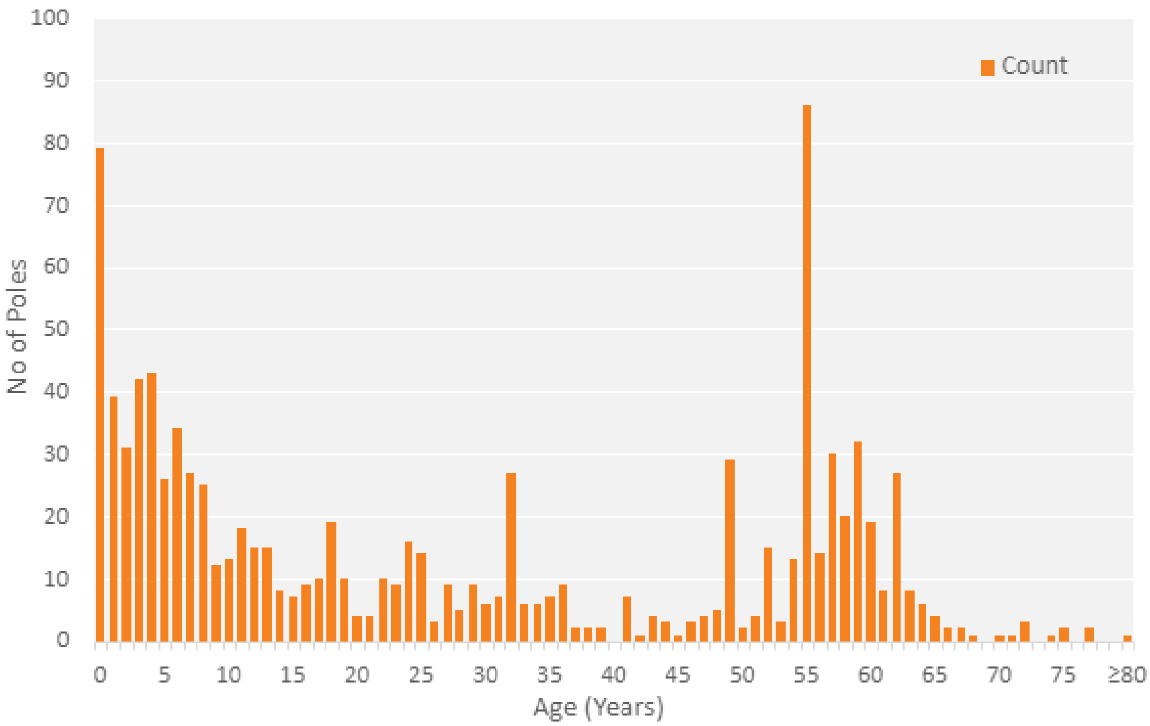
This portfolio incorporates switches and links that are mounted on poles outside of zone substations. Pole mounted switches come in a wide variety of configurations and insulating mediums (SF_6 and air). For switches, we most commonly utilise ABSs, which use air as the dielectric and can be operated using a handle mounted on a pole. ABSs are used for sectionalising feeders to isolate faults and facilitate maintenance, and as open points between feeders. A standard ABS has limited load break capability, so we have added this capability to some units to improve operability. We only have one SF_6 switch fulfilling the same function as an ABS.

Links provide lesser functionality than ABSs. They are operated one phase at a time and cannot break or make load current, but they are useful for minimising outage zones. They are currently treated as maintenance-free devices in a similar way to drop out fuses.

Population and Age

We have 1,003 pole mounted switches in our distribution network. There is significant diversity in the switches fleet with many different manufacturers. The figure below depicts the fleet's age profile.

Figure 8.71: Pole mounted switches age profile



These assets have an average age of 28 years. In our review of this fleet, given its diverse nature we have updated the expected life profile, to allow for the range of life expectancy. Previously an average MPL of 50 years was applied across the entire fleet. Our updated view, informed by a range of expected lives, is from 45-65 years.

Condition, Performance and Risks

Condition

Historically, there has been low levels of maintenance on our ABSs. Many of our ABSs are not required to be operated for long periods of time, and only after a fault occurs or outages are required for other work are they needed to sectionalise our network. Under these circumstances we may find that the ABS mechanisms have seized and require maintenance/renewal. This, combined with other condition issues such as bowing operating rods or flickers not engaging, means in some cases we do not consider they can be safely operated and so they are tagged Do Not Operate (DNO).

We are experiencing corrosion issues with some of our older pole mounted switches, particularly in coastal areas. We have multiple types of ABSs and links that may suffer insulator failures.

We are increasing inspections and maintenance to address issues and gather information to support the renewal programme, with an initial focus on aged ABSs located in severe corrosion zones.

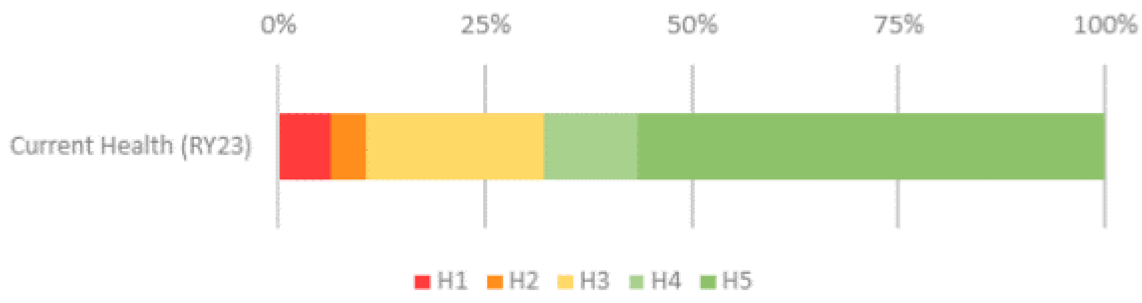
Performance

Our historical outage records indicate that we experience relatively few outages due to faulty pole mounted switches. We do, however, currently have a number of poor condition switches that are inoperable. Issues with aged assets often relate to historical maintenance practice; for example, operating handles jam as a result of not being operated and maintained regularly. The state of some of our older pole mounted switches has led to some performance issues. Our service providers will not operate switches that are found to be in poor condition. Limited switching functionality reduces our ability to reduce the impact of outages, and in some cases, it prevents service providers from carrying out planned works. We have introduced an inspection and maintenance regime for pole mounted switches to retain them in operating condition (see Chapter 7).

Asset health

AHI for pole mounted switches is based on expected remaining life, as shown below.

Figure 8.72: Pole mounted switch asset health



A new inspection programme is enabling us to verify our asset type and condition data. That as well as the adjustment of life expectancy across this fleet has resulted in a significant improvement in our assessed AHI for the fleet. The AHI model does indicate a significant portion of the fleet at H3. According to the model these H3 assets will transition to H1 over the period, as depicted below.

Risks

The table below summarises the key risks identified in our pole mounted switch fleet.

Table 8.51: Pole mounted switch risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
Canterbury Engineering type two-piece 33 kV insulator ABSs; cement failure between the shields	Replacement of the ABS insulator with 4944 or replacement ABS	Reliability, safety
Mahanga Holdings ETE ABS insulator failure at top casting	Reactive replacement of ABS	Reliability
1985 era 11 kV insulator ABSs; insulator failure due to sulphur cement failure on top casting	Largely resolved with historical replacements	Reliability
A type of legacy HV link is prone to breaking on opening	Operating restriction Type based replacements	Safety, reliability
Inoperable / DNO ABSs	Maintenance and replacement programmes	Reliability

Design and Construct

We are aware that some EDBs are introducing vacuum and SF_6 puffer switches in place of an ABS. This change is being driven by the fact that manually operated SF_6 or vacuum switch costs are approximately the same as an ABS to purchase and install, but the lifecycle costs are less. There are also potential automation benefits. The risk associated with these new vacuum and SF_6 switches is the absence of a visual break during isolation and the need for surge arresters either side with appropriate earthing. Therefore, these types have not received widespread acceptance by EDBs.

We prefer to install load break head fitted air insulated switches, while monitoring the performance of new vacuum and SF_6 puffer switches used by other EDBs. We would prefer not to introduce more SF_6 on our network unless necessary, but we will continue to monitor new equipment options.

Renew or Dispose

We replace our pole mounted switches on the basis of as-found condition or with associated renewal work, with information gathered during switching operation, inspections, or maintenance. Repair or replace decisions depend on the specific make and model of enclosure and the defect(s) found.

Table 8.52: Summary of pole mounted switch renewal approach

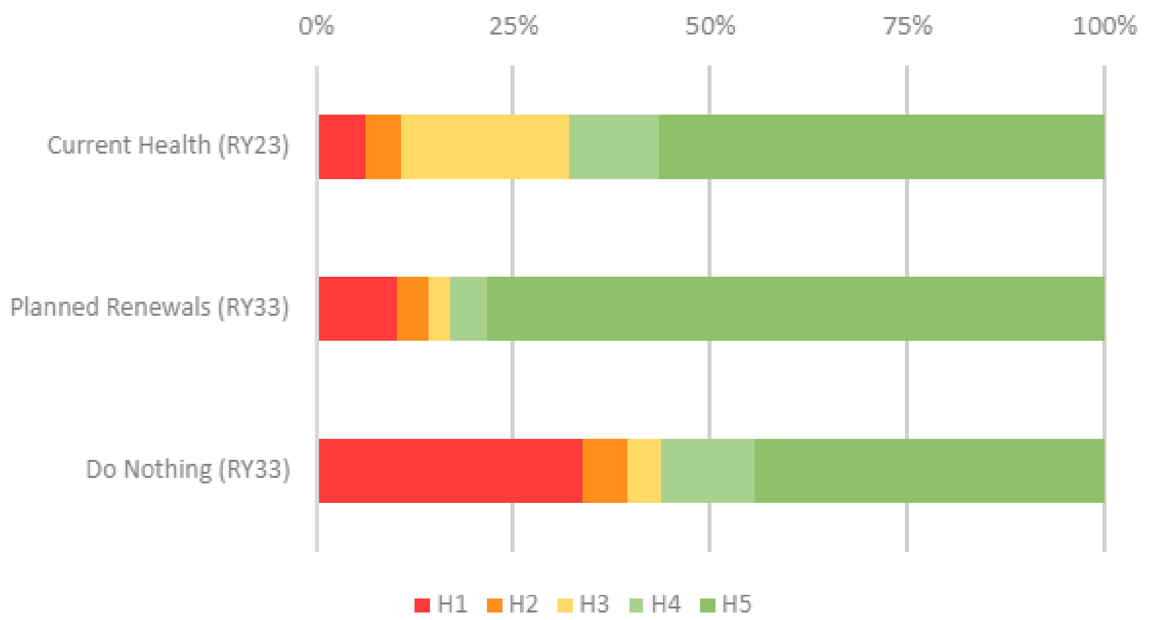
ASPECT	APPROACHES USED
Renewal trigger	Proactive condition-based Associated renewal work (E.g. pole renewal) Type based

ASPECT	APPROACHES USED
Forecasting approach	Repex
Cost estimation	Volumetric

Renewals forecasting

The figure below compares projected AHI in RY33 following planned renewals, with a counterfactual 'do nothing' scenario. This comparison indicates the benefits provided by our proposed investments.

Figure 8.73: Projected pole mounted switch asset health at RY33



If we undertook no replacements, we would expect the proportion of end-of-life pole mounted switches to be over 30% by RY33. Based on our proposed replacement programme, we will have a slight increase in H1 assets by the end of the period; this reflects the high numbers of H3 assets in the current view. Overall, we will have made significant progress in addressing this backlog. The current programme of inspection and data verification is enabling a more mature approach to risk management; we will target and prioritise renewal of higher risk assets.

Options analysis

At present, we do not have an ABS refurbishment programme. If an ABS cannot be maintained on-site to restore it to a satisfactory condition, it is replaced with a new unit. We will consider the viability and benefit of a refurbishment programme in the medium-term.

Disposal

Pole mounted switches have no specific disposal requirements.

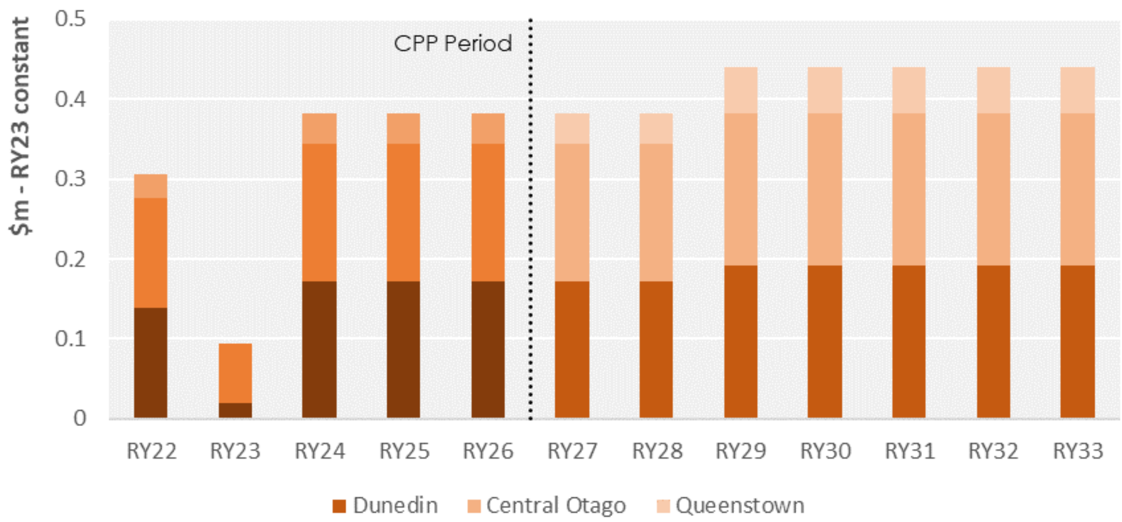
Coordination with other works

Pole mounted switches works are coordinated with other overhead asset renewal works such as pole replacements. Some pole mounted switches supply cable fed areas, so some coordination with ground-based equipment may also occur. Work on switches may also be coordinated with customer or growth works, particularly when looking at required outages for the work.

Pole Mounted Switch Fleet Expenditure Forecast

We have forecast pole mounted switch renewal Capex of approximately $4.1m during the planning period. This Capex excludes pole mounted switches replaced during pole replacements.

Figure 8.74: Pole mounted switch expenditure



To address a backlog of required switch replacements, we will increase expenditure over the RY24-RY26 period. Expenditure and replacement rates will maintain at a steady pace until the end of the forecasting period.

Benefits

The key benefit of our planned renewal programme is ensuring appropriate reliability performance by removing inoperability and associated safety risks. Renewals will therefore deliver a safety in design solution, removing the reliance on operational risk control measures.

8.5.5. LV Enclosures Fleet

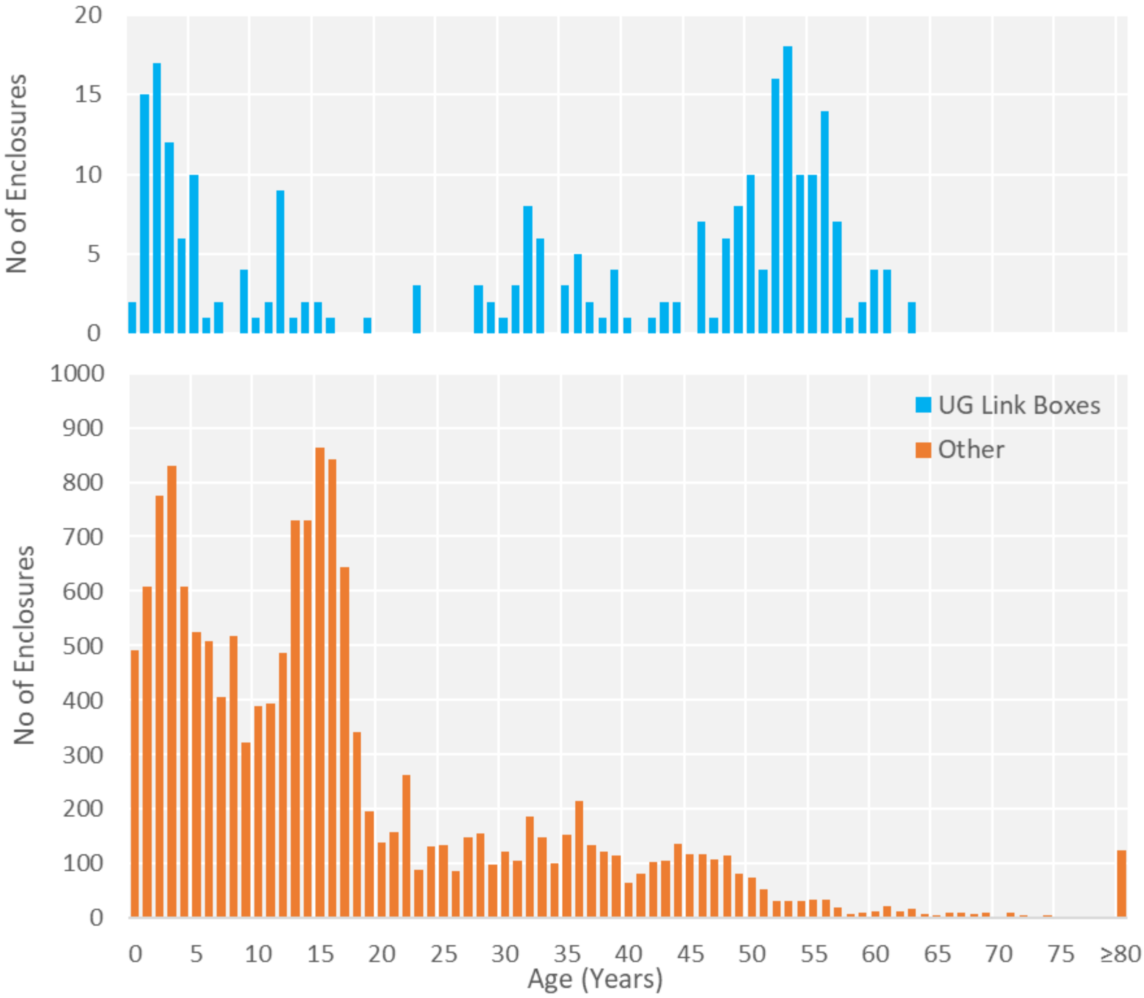
LV Enclosures Fleet Overview

LV enclosures are used in our LV network to supply domestic/small installations and provide LV switching functionality. We have a large variety of makes and types of enclosures. A relatively small number of our LV enclosures are underground link boxes installed in Dunedin CBD. As opposed to above ground pillars, we refer to these enclosures as link boxes. The remainder are service pillars/boxes used to terminate consumer connections.

Population and Age

We have approximately 16,000 LV enclosures. Of these, only 266 are the underground link box type. The figure below depicts age profiles of our two categories of LV enclosure.

Figure 8.75: LV enclosures age profile



The underground link boxes are an older population in general, with an average age (useful life) of 33 years. In comparison, the average age of 'other LV enclosures' is 17 years. This is because use of LV enclosures has increased substantially in recent years as new customers are increasingly supplied via underground cables in new subdivisions.

Condition, Performance and Risks

Condition and performance

Following an inspection of all underground link boxes, we know that many are in poor condition. The Henley underground link boxes, in particular, are often more than 45 years of age and are in poor condition, having water ingress issues leading to corrosion and possible short circuit faults. An example of an underground link box removed from service is shown below. We do not allow live operation due to the nature of their exposed terminals and arc flash risk. While this manages the safety aspect of live operation, it impacts on reliability performance, especially when isolation may require the operation of JW fuses, which also have live operation restrictions. These assets tend to be located near CBD areas, so unplanned failures and inoperability live have a higher outage impact on customers than other LV enclosures.

Figure 8.76: Decommissioned Henley underground link box

We are now at the stage where these LV enclosures are getting better site information through inspections. Since we started in RY19 to assess the condition of these enclosures, this inspection cycle will be completed in RY24 and will head on to the next inspection cycle in RY25. We have identified some for immediate replacement but since it is in the LV space, we would maintain/repair these as we find it.

Frequent failure modes of our other LV enclosures include vehicle collisions and vandalism, which generally cannot be predicted on an individual asset basis. Failures can present some public safety risk due to their accessibility, and involve the risk of electrocution. Legacy design LV enclosures that have metallic covers can inadvertently become live when wiring insulation or fuses within the enclosure fail to perform their normal function.

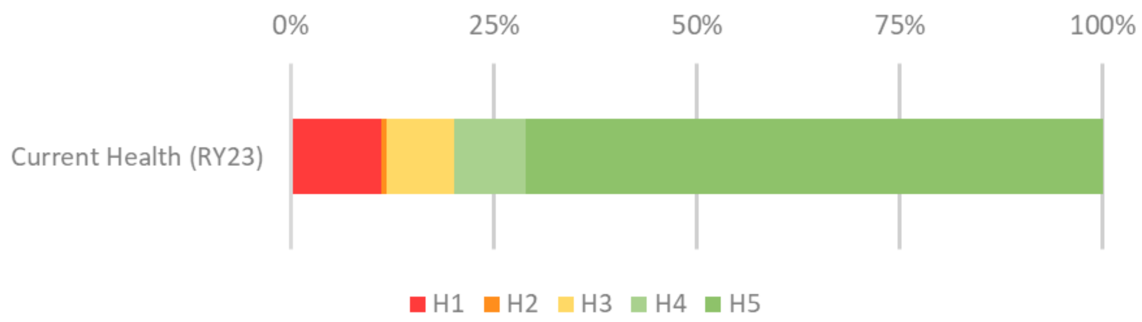
Through inspection results to date, we are finding large numbers of pillars in unsuitable locations. Many have had retaining walls or fences built around or over them, and some have been buried in gardens. These pillars require relocation to be accessible.

We have not historically collected LV outage data, so we do not have reliability performance information for LV enclosures as of yet. However, we are presently gathering this fault information and collaborating with the Operations team to build a database.

Asset health

The figure below shows asset health of our LV enclosures.

Figure 8.77: LV enclosures asset health



Based on asset health, 11% of our LV enclosures have reached end-of-life (classified as H1). Most end-of-life enclosures are in the Dunedin network, including our underground link boxes. These aged and inoperable assets present an unacceptable reliability and safety issue in the Dunedin CBD. The asset health of other LV enclosures appears relatively good, but there is a high reactive renewal component for these assets due to third-party damage.

Risks

The table below summarises the key risks identified in relation to our LV enclosures fleet.

Table 8.53: LV enclosure risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
Henley underground link boxes are degrading due to water ingress. These have safety issues including high arc flash potential, and exposed terminals	Safety risks controlled by DNO Replacement programme	Safety, reliability
JW fuses are not operated due to safety issues (arc flash)	Safety risks controlled by DNO Future replacement programme	Safety, reliability
Steel pillars can be live due to high impedance faults E.g. retaining screw from fuse loosening and touching cover	Test before touch Inspection programme Corrective maintenance to retrofit plastic lids Replacement programme	Safety
Third-party damage/vandalism leaves pillars compromised	Inspection programme Public reporting Corrective maintenance Replacement programme	Safety

Design and Construct

For underground link boxes, our historical preferred solution was a 'quad-link' type, which was manufactured overseas and is now no longer available. We have some residual stock of these items and are beginning an assessment to find an alternative product. Where we can meet stakeholder requirements, our preference is to use an above ground solution as they are less vulnerable to moisture ingress and easier to fix. Where this is not possible, simpler underground products are available, but we lose the four-way switching flexibility of the 'quad link'.

Our standard for other LV enclosures are above ground pillars with plastic shells, removing the ability of an internal fault livening the box (unlike legacy design metal LV enclosures). Safety in design is paramount in choosing the best LV enclosure location. Consideration has to be given to the likelihood of vehicular impact and choice of a location that will not obstruct potential landowner activities, such as fencing.

Meeting our portfolio objectives – sustainability by taking a long-term view

We will work with stakeholders to ensure that our preferred solution of above ground pillars can be accommodated and provide acceptable visual amenity to our communities.

Renew or Dispose

We are replacing our LV enclosures using condition and defect data collected during asset inspection surveys. Repair or replace decisions depend on the specific make and model of enclosure and the defect(s) found. We also replace LV enclosures reactively in the event of vehicle damage or vandalism. The table below provides a summary of our approach renewal of LV enclosures.

Table 8.54: Summary of LV enclosure renewals approach

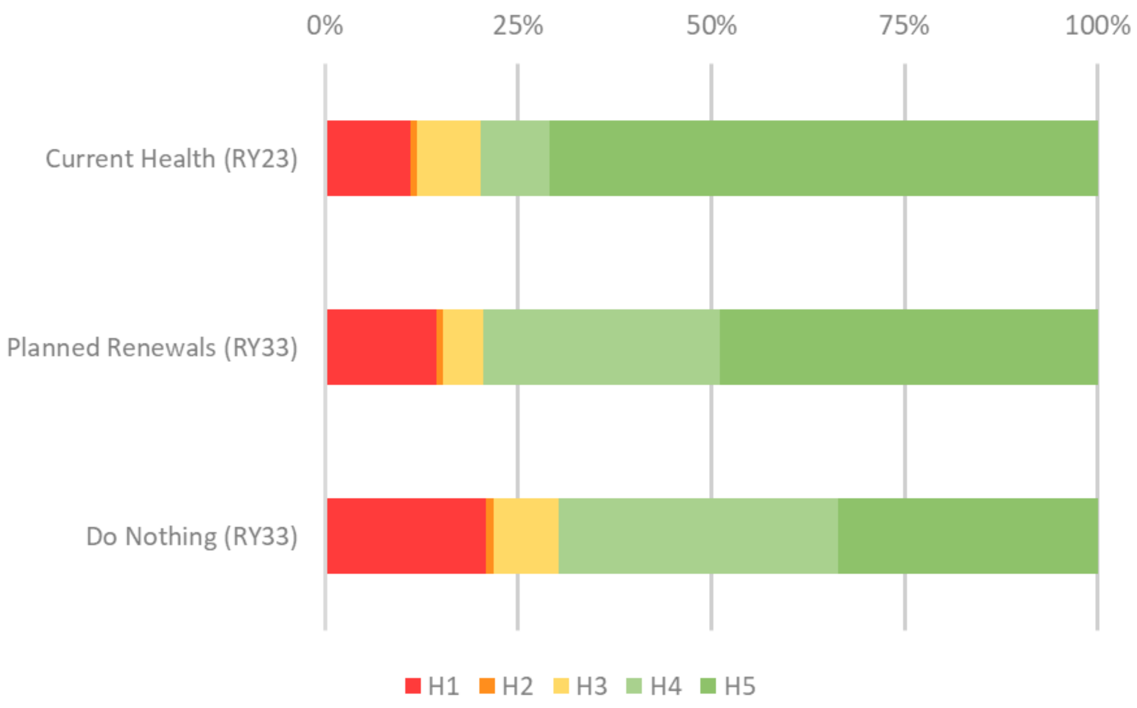
ASPECT	APPROACHES USED
Renewal trigger	Proactive and reactive condition-based
Forecasting approach	Repex
Cost estimation	Volumetric based on historical unit rates

Renewals forecasting

The figure below compares projected asset health in RY33 following our planned programme of renewals, with a counterfactual 'do nothing' scenario.

The following chart indicates the need for investment within our fleet replacement programme. Our proposed replacements maintain the health of the fleet, whereas a 'do nothing' approach would increase the number of H1 enclosures from 11% to 21%.

Figure 8.78: Projected LV enclosures asset health



Options analysis

Options analysis on LV enclosures is relatively limited. It is technically preferable to replace underground link boxes with above ground solutions, provided it is not cost prohibitive (in which case an underground replacement will be undertaken). For our other LV enclosures, if the enclosure cannot have its defects remediated on-site, it will be replaced with a new like-for-like or equivalent unit.

Disposal

LV enclosures have no special disposal requirements.

Coordination with other works

We coordinate LV enclosure replacements with stakeholders; in particular, roading works with underground link box replacements. Coordination may also occur with customer works that require relocation of LV enclosures. The majority of LV enclosure works are not coordinated with other works as they need to be addressed promptly given their location at ground level in the public domain. Underground link box replacements will be coordinated with underground substation replacements in the Dunedin CBD.

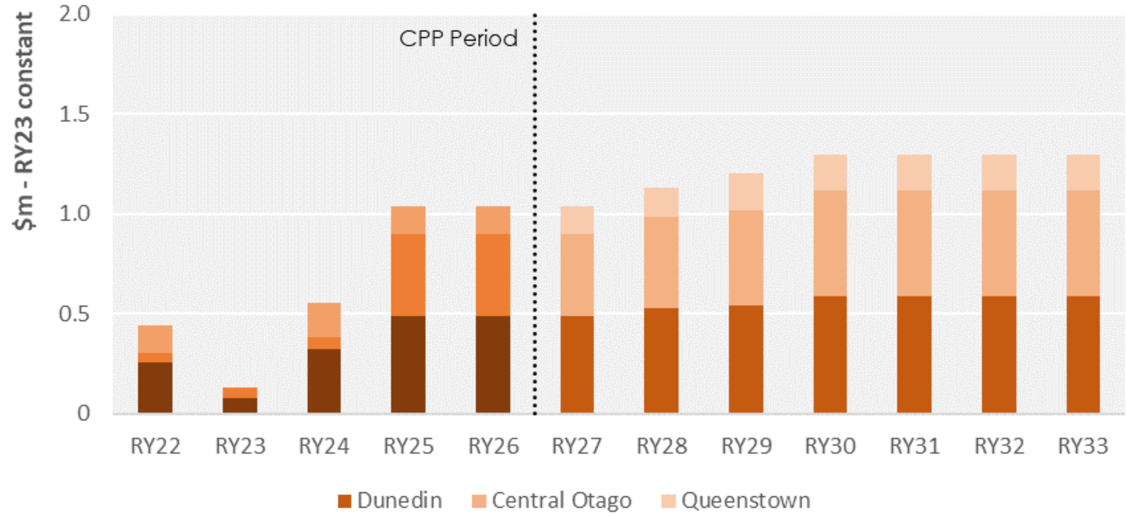
Meeting our portfolio objectives – safety first

We are actively inspecting our LV enclosures and replacing or repairing those in poor condition to minimise the electrocution risk to our contractors and the public. Our rapid response process is a key workstream to remediate LV pillar defects promptly.

LV Enclosure Fleet Expenditure Forecast

We have forecast LV enclosures renewal Capex of approximately $11.1m during the planning period, as shown below. This expenditure includes any cable costs required to relocate enclosures for condition-based reasons (not customer driven).

Figure 8.79: Forecast LV enclosure Capex



Prior to RY20, our LV enclosure replacement levels were very low. In RY20 we initiated a programme of replacements; we plan to increase expenditure from RY24 to address the backlog of LV enclosure renewals, within deliverability constraints.

Benefits

The key benefits of our planned LV enclosure renewal programme are reduced safety risk to public and contractors and ensuring appropriate reliability performance by removing operating restrictions.

8.5.6. Reclosers and Sectionalisers Fleet

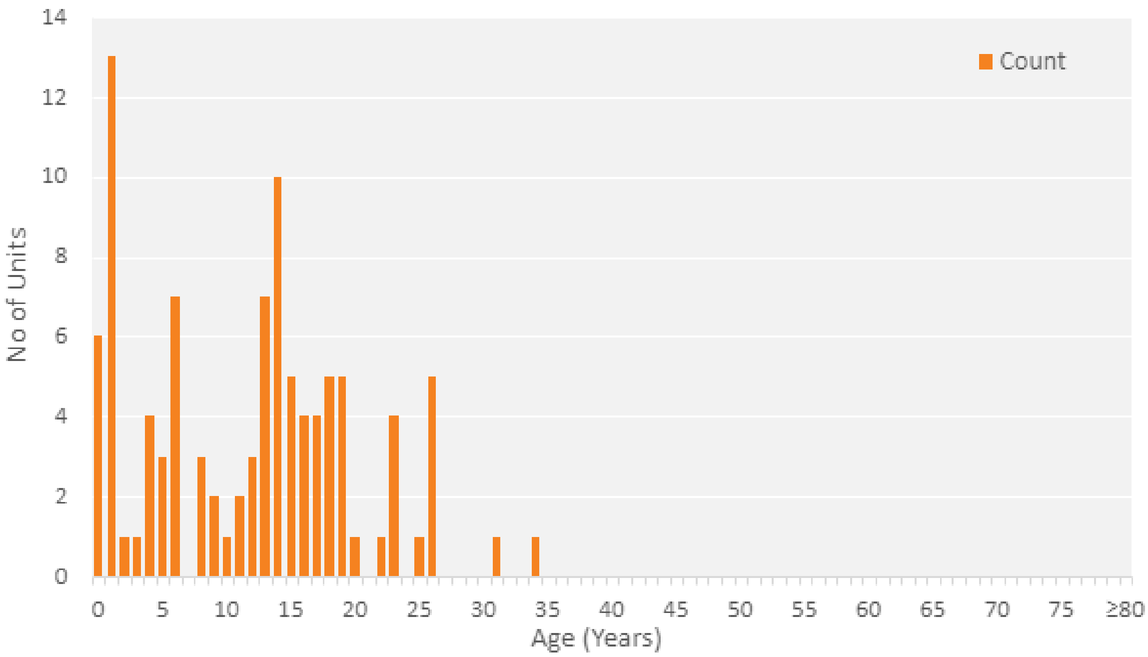
Reclosers and Sectionalisers Fleet Overview

Reclosers and sectionalisers are devices that improve the reliability of our network by limiting the area impacted by faults. Reclosers contain a protection device that detects fault current and trips to minimise the outage zone and clear the fault off the rest of the network. The majority of the reclosers are on poles in our distribution network. We currently do not have any sectionalisers that automatically sectionalise faults after a certain number of fault passages. These reclosers acting as sectionalisers do not have protective devices installed and are used as remote switches only, to help speed up restoration post fault, by allowing the control room to sectionalise off the area of the fault.

Population and Age

We have a fleet of 100 HV reclosers, the chart below shows their age profile.

Figure 8.80: Reclosers and sectionalisers age profile



The majority are Nova three phase vacuum interrupter reclosers, installed in the last 15 years. The most common controller paired with the Nova reclosers is a Cooper Form 6 microprocessor. There are still a few older vacuum interrupter reclosers of various makes and models.

Condition, Performance and Risks

Condition and performance

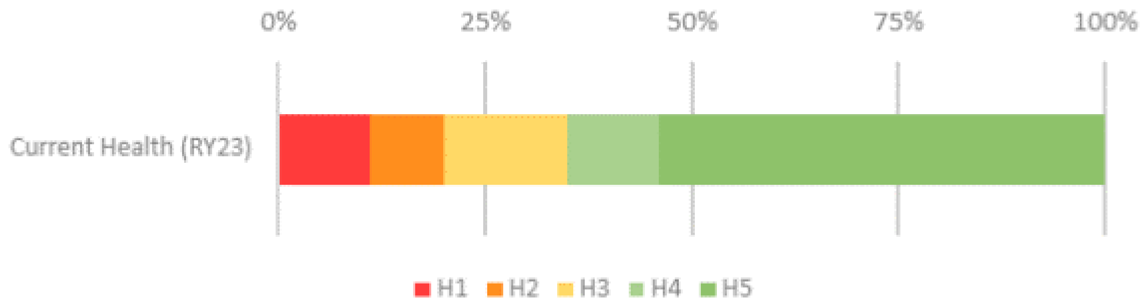
The majority of our reclosers are in good condition. The performance of reclosers has generally been satisfactory. Our outage records indicate that on average we experience one faulty recloser every 2 years. This outage rate includes when a recloser has failed to operate subsequent to a line fault.

We have had one instance with a bird strike, leading to a phase-to-phase fault and destructive failure of the recloser. To mitigate this risk, we are retrofitting wildlife guards to the Nova model as they have tight pole clearances. We have had isolated problems with some controllers from our recloser fleet.

Asset health

The figure below indicates the current health of our recloser fleet on the basis of age:

Figure 8.81: Reclosers and sectionalisers asset health



Given the small size of the fleet, only 11 reclosers are nearing the end of their expected service life (H1).

Risks

The table below sets out the key risks identified in our recloser and sectionaliser fleet.

Table 8.55: Summary of recloser risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
Recloser cannot easily be removed from service for maintenance	Installation of bypass facilities	Reliability
Auto-reclosing leads to fire	Operational procedures – block auto-reclose in high fire risk seasons/regions	Safety, environmental
Controller failure means recloser does not operate	Inspection and maintenance Replacement programme	Reliability
Bird strike at recloser terminals	Presently considering risk mitigations E.g. insulating droppers Standard equipment choice to have adequate pole spacing	Reliability
Lack of easement on site (most sites installed post-1992 existing use rights consideration)	Gain easement New site chosen when renewing or adding bypassing if easement cannot be gained on existing site	Environmental

Design and Construct

We have a standard design to be used on all new recloser installations/replacements, which includes isolation links and an ABS bypassing facility to minimise disruption when taking the recloser out of service for maintenance. Where sites do not have a bypass at present and are in private property, an easement will have to be gained when the recloser is replaced due to changing the configuration.

Some retrofit work with isolation links and an ABS bypassing facility is being undertaken; more than 250 ICPs must be downstream and no mesh feed ability for the recloser to qualify. In other cases, live line techniques are used for maintenance.

Renew or Dispose

When a recloser reaches its operation-count limit, or is found to be significantly degraded or malfunctioning, it will be replaced. The table below summarises our approach.

Table 8.56: Summary of recloser renewals approach

ASPECT	APPROACHES USED
Renewal trigger	Proactive condition-based
Forecasting approach	Individual sites
Cost estimation	Volumetric

Reclosers and Sectionalisers Fleet Expenditure Forecast

Given the small quantities of renewals, our replacement rate for reclosers is minimal through the planning period.

8.5.7. Ancillary Distribution Substation Equipment Fleet

Ancillary Distribution Substation Equipment Fleet Overview

This portfolio comprises ancillary distribution substation equipment including distribution surge arresters, underground distribution substations and distribution earths. Surge arresters are installed to protect network equipment against voltage surges and are typically installed on underground cables, reclosers, and some pole mounted transformers.

Underground distribution substations are confined spaces below the street or footpath level of Dunedin CBD, accessible by ladder. Each underground distribution substation contains the usual distribution substation components of a (ground mounted) distribution transformer, a RMU, and LV switchgear. While they contain all the usual distribution substation components, which could be managed in their respective fleets, we have chosen to manage underground substations separately, given their unique location leading to high cost, bespoke solutions for their renewal. Where possible, we will replace these substations with above ground equipment to remove the risks associated with the confined space.

All accessible metal equipment on the distribution network must be earthed. Earth points are tested periodically for resistance to ensure equipment remains safe in the case of faults or induced voltage.

Population and Age

We have 17 underground substations located in the Dunedin CBD and they are all older than 60 years. We are currently in the process of verifying distribution surge arrestor location, type, age and condition data, through an inspection programme. While we have some data (from inspections already complete), we do not currently have enough data to present reliable age or type profiles.

Condition, Performance and Risks

Condition and performance

Our underground substations have been assessed by an engineering design consultant for condition as well as fire, seismic and reliability risk. The consultant concluded that all of the substations need to be replaced due to structural, water ingress/flooding, confined space and poor asset condition issues. The photo below shows an example of corrosion to structural members and water ingress.

Figure 8.82: Example underground distribution substation condition

The electrical performance of our underground substations is similar to above ground substations.

We are experiencing high failure rates of 33 kV surge arresters installed in locations where the supplying GXP has NERs. As we now install NERs at HV when doing major zone substation works, we are using inspection data to identify surge arrestors that no longer meet rating and material (i.e., porcelain/glass), and technology (i.e., gapped/non-gapped/vented/unvented) requirements, and progressing plans to proactively replace surge arrestors as part of the NER installations. We have a population of unvented porcelain surge arresters, which have a propensity to explode upon operation (arresting surges), spraying porcelain shards, which creates a safety hazard. We are actively identifying and targeting the renewal of all porcelain and glass type surge arrestors on the network.

Asset health

We have not developed AHI for the assets within our ancillary distribution substation fleet.

Risks

The table below summarises the key risks identified in our ancillary distribution substation fleet.

Table 8.57: Ancillary distribution substation equipment risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
Underground substations are confined spaces	Operational procedures	Safety
Flooding of underground substation	Sump pumps Audible float level alarms	Reliability
Risks common to ground mounted switchgear and distribution transformers E.g. arc flash, inoperable JW fuses, etc	As identified in individual fleets	Safety, reliability

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
Unvented porcelain surge arrester failure	Inspection and replacement programmes	Safety, reliability
Underrated surge arrester failure	Inspection and replacement programmes prior to NER install	Reliability
High earth resistance or poor earth connection can lead to unsafe equipment in the event of a fault or induced voltage	Corrective maintenance repair	Safety

Design and Construct

We have identified 10 underground substations that are suitable for removal and relocation above ground into a standard ground mounted distribution substation. For the remaining seven, an above ground relocation is challenging due to the lack of an obvious location to site a replacement substation above ground.

We have standard surge arresters that will be used on all replacements, which are rated for an ineffectively earthed system.

Renew or Dispose

We forecast our surge arrester renewal Capex based on an estimate of the population quantity and expectation that a proportion of them will be underrated, unvented or in poor condition, warranting replacement. Our forecast renewal expenditure for underground substations is based on the replacement of a small number per annum due to their inherent confined space risk and their end-of-life equipment, to create a steady programme of work. Undertaking more than a few replacements per annum will likely lead to significant disruption to the CBD power supply and/or a loss of security of supply during construction of more than one site at a time.

The table below summarises our approach to ancillary distribution substation equipment renewal.

Table 8.58: Summary of ancillary distribution substation equipment renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Type based (underground substations, unvented and underrated surge arresters) Proactive condition-based
Forecasting approach	Individual sites (underground substations) Engineering estimate (surge arresters)
Cost estimation	Engineering consultant estimates (underground substations) Volumetric (surge arresters)

Options analysis

If there is no obvious replacement site for an underground substation above ground near to the existing underground site, we will assess additional options. These include a new above ground site further from the existing site or decommissioning the existing site (potentially requiring material network reconfiguration), or installation of a new transformer into the existing underground substation, with switchgear above ground and structural refurbishment of the 'bunker' as required. Costs and the degree of risk mitigation provided by each option will be assessed.

> **Meeting our portfolio objectives – safety first**
> Confined spaces that exist in our underground distribution substations are inherently hazardous. Replacing confined space underground substations where possible with above ground solutions when renewing aged equipment is a safety by design solution.

Disposal

Special consideration will have to be given to decommissioned underground substation sites as to whether they will be retained as sites or filled in. Discussion with council and other asset owners in the Dunedin CBD will be required. Surge arresters generally have no special disposal requirement, but some very old types may have explosive actuators that require investigation prior to disposal.

Coordination with other works

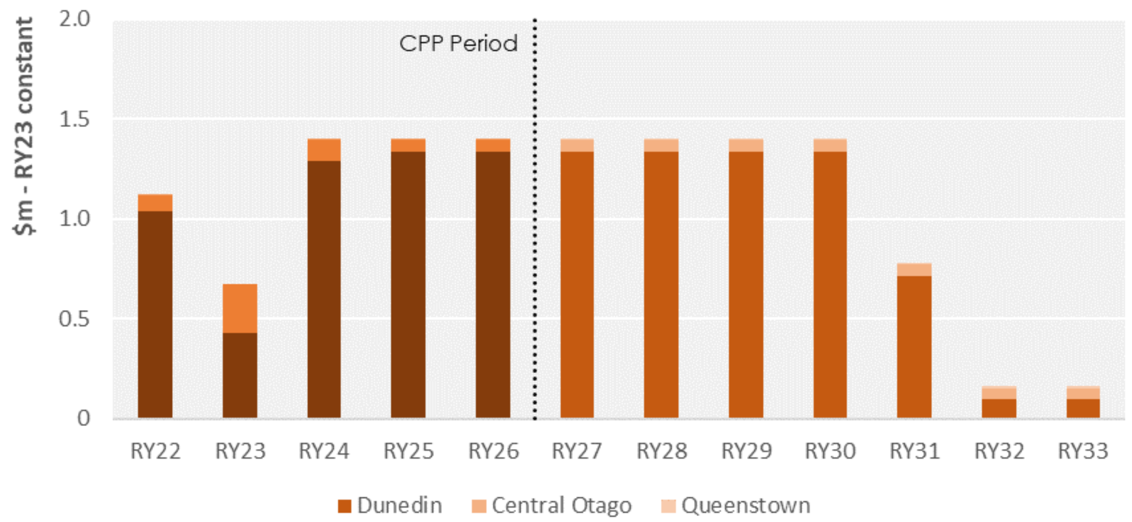
Underground substation replacements will be coordinated with underground link box replacements in the Dunedin CBD. We will also coordinate underground substation replacements with works to be undertaken by council and other asset owners in the Dunedin CBD. Surge arrester replacements may be coordinated with other works.

> **Meeting our portfolio objectives – sustainability by taking a long-term view**
> We will work with stakeholders to ensure visual amenity, and that movement of people and vehicles are not negatively impacted by above ground solutions.

Ancillary Distribution Substation Equipment Fleet Expenditure Forecast

We have forecast ancillary distribution substation equipment renewal Capex of approximately $10.9m during the planning period.

Figure 8.83: Ancillary distribution substation equipment expenditure



Our plan is to replace the 17 underground substations over the later years of the planning period, either with above ground solutions or in-situ. We plan to replace surge arresters throughout the period.

Benefits

The key benefits of our planned ancillary distribution substation equipment renewal programme are reducing or eliminating the specific safety risks associated with our underground substations, and reducing the safety and reliability risks of surge arrester failure. Replacement with above ground assets will also reduce the reliability/resiliency risk associated with flooding in the CBD area, and the safety risks associated with working in confined spaces.

8.6. DISTRIBUTION TRANSFORMERS

This section describes our distribution transformers portfolio and summarises how we manage these assets. The portfolio includes four asset fleets:

- ground mounted distribution transformers
- pole mounted distribution transformers
- voltage regulators
- mobile distribution substations and generators

Portfolio Summary

We replace distribution transformers based on condition, with the medium-term work volumes forecast based on Repex modelling. During the planning period, we expect to spend an average of $1.8m per annum on distribution transformer renewals.

Our renewal forecast reflects the large number of pole mounted distribution transformers installed during the 1960s and 1970s that have or will become due for replacement. Distribution transformer failures can have a material impact on our safety and reliability objectives.

Distribution transformers are devices used in electrical circuits to transform the voltage of electricity to a suitable level for customer connections, for example, from 11 kV down to 400 V/230 V. We also use auto-transformers in parts of the network to enable interconnection of 6.6 kV to 11 kV circuits. Transformers come in a variety of sizes with various manufacturers and models. They can be single or three phase and either ground or pole mounted (crossarm or platform) installations. They are all oil-filled and come with associated environmental, seismic and fire risks. We have a large number of legacy assets across our Dunedin and Central Otago networks.

Box 8.11: Summary of our asset risk review – distribution transformers

Issues: key risks include small quantities of distribution transformers past expected lives.

Response: increased pole mounted transformer renewal to address assets which are in poor condition, installed with unsafe clearances to ground, or are seismically vulnerable two pole substations. We will continue to replace small quantities of ground mounted transformers.

Timing: increasing renewal up to steady-state levels, which will continue for the remainder of the planning period.

Voltage regulators are designed to automatically maintain voltage to a set level. The length of some of our 11 kV distribution lines necessitates the installation of voltage regulators partway along the feeders to maintain the correct voltage at the end of the feeder.

Mobile substations and mobile generators enable us to bypass permanent distribution substations to enable and support both planned and fault work.

8.6.1. Distribution Transformers Portfolio Objectives

Portfolio objectives (set out below) guide our day-to-day asset management activities.

Table 8.59: Distribution transformers portfolio objectives

OBJECTIVE AREA	PORTFOLIO OBJECTIVES
Safety first	Reduce public safety risks arising from unauthorised access to transformers, and step and touch potential No explosive failures or fires caused by distribution transformers
Reliability to defined levels	No failures of distribution transformers due to overloading Downward trend in condition-based distribution transformer failures
Affordability through cost management	Improve forecasting approaches by incorporating improved condition assessment data
Responsive to a changing landscape	Better understand distribution transformer loadings by trialling the use of distribution transformer monitoring systems
Sustainability by taking a long-term view	No significant oil spills from distribution transformers Transformer noise complaints are investigated and mitigated (if required) in a timely manner Increase resilience by managing seismic risks posed by larger pole mounted transformers

8.6.2. Ground Mounted Distribution Transformers Fleet

Ground Mounted Distribution Transformers Fleet Overview

Ground mounted distribution transformers are ground mounted devices used to transform the voltage of electricity to a suitable level for customer connections, which is generally 400 V or 230 V. They are generally located in suburban areas and CBDs with underground cable networks. Ground mounted transformers range in size from smaller than 100 kVA to larger than 1 MVA. Pole mounted transformers on our network do not exceed 400 kVA capacity, and so larger loads must be fed by ground mounted transformers. We have a small number of ground mounted 11/6.6 kV auto-transformers to interconnect our distribution system. They do not have on-load tap changers.

Older ground mounted transformers commonly have oil- or pitch-filled cable boxes with no integral fuses at either voltage. Modern ground mounted distribution transformers may contain high voltage fuses in the high voltage cable box/end, and LV fuses or switchgear in the LV cable box/end. Modern ground mounted transformers do not contain fluid-filled cable boxes. If a ground mounted transformer with integral fuses and LV switchgear needs to be replaced, these integral components are also replaced. Some older ground mounted transformers are not cable connected on the high voltage side, instead using solid busbars to connect to their respective RMU in a condensed 'package' distribution substation that has a very small footprint.

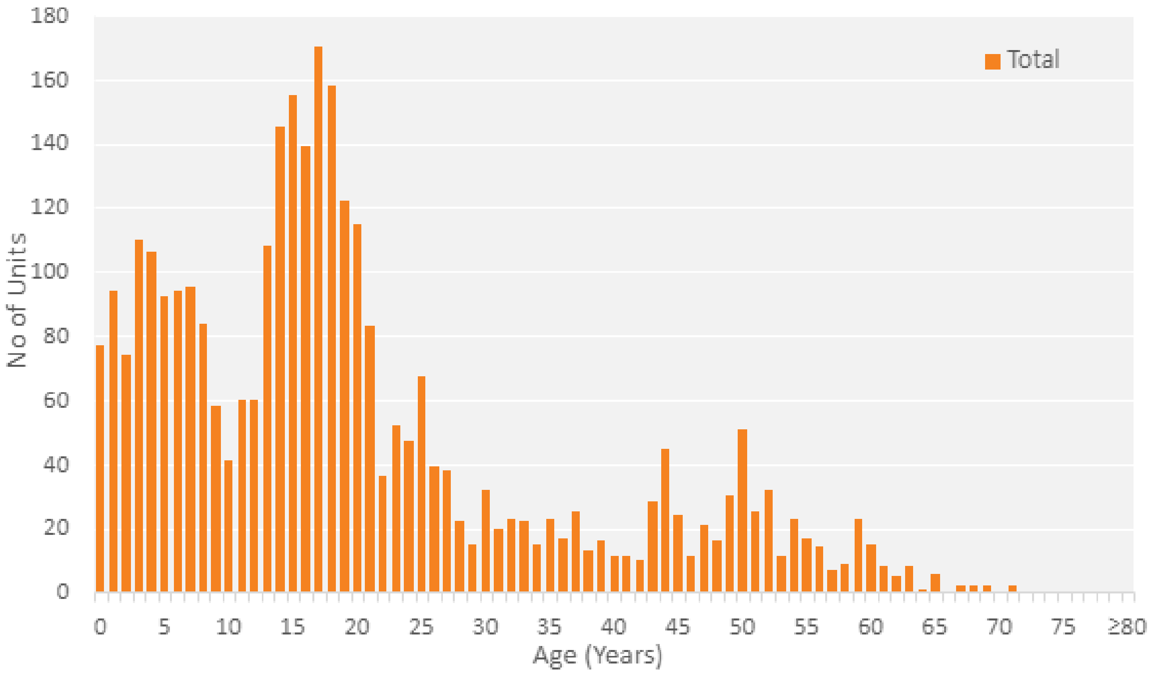
Ground mounted distribution transformers are inherently more seismically robust than pole mounted transformers but still require seismic restraint. They are also vulnerable to vehicular impact and flooding.

Ground mounted transformers can be installed in various locations: on public property, inside an Aurora-owned distribution substation building, or in customer premises (private, industrial, commercial).

Population and Age

We have 3,179 ground mounted distribution transformers.

Figure 8.84: Ground mounted distribution transformers age profile



Most are less than 25 years old, making this a relatively young fleet, with the oldest units only just beginning to reach their expected life of 70 years.

Table 8.60: Ground mounted distribution transformer ratings

RATING (KVA)	POPULATION	PERCENTAGE
0 to 100	1,138	35%
100 to 200	498	15%
200 to 300	495	15%
>300	1,101	35%
Total	**3,232**	**100%**

The table above summarises population by rating (kVA). Ground mounted units tend to be higher rated than pole mounted as they serve more customers or are used for higher capacity installations.

Condition, Performance and Risks

Failure of a distribution transformer can lead to safety issues, though explosive failure modes are rare. Environmental issues can also occur if a transformer spills oil upon failure. Reliability impact can be significant for larger units; contingency measures, such as a mobile substation, are used to restore supply until the transformer is replaced.

Condition

The most common defects on ground mounted transformers are vegetation growing around the transformer, earthing issues, and issues relating to access, signage, labels, and security. On the transformer itself, the most common defect is corrosion of some form, followed by oil leaks – either due to degraded seals/gaskets or corrosion. Other causes of degradation are third-party damage, moisture and other contaminants in the oil, mechanical failure due to internal ageing and corresponding lack of fault current withstand, or thermal failure due to overloading. Some ground mounted distribution transformers are installed in old Aurora Energy-owned buildings, which are in a poor state and will not meet today's seismic standards.

Performance

The performance of our ground mounted transformers has been generally good over the past decade, with minimal failures and no systemic issues. We have some legacy installations in Central Otago where several small ground mounted distribution transformers are 'daisy chained' together off a single HV fuse, also known as 'group fusing'. This causes the loss of multiple transformer supplies for a single fault, and historical protection coverage may be inadequate in some cases.

We are experiencing increasing numbers of overloaded distribution transformers, primarily due to retailer pricing incentives (not reflecting our own pricing signals), with many consumers making use of an incentive (free power) at the same time of the day.

Box 8.12: Improvement Initiative – distribution transformer monitoring systems

To better understand transformer overloading events and to prepare for the potential of more customer behaviour change with new technologies and new retailer offerings, we are trialling online distribution transformer monitoring systems. MDIs, the traditional way to check transformer peak loading, do not provide a daily demand profile, nor any information on voltage or power quality at the time of peak demand. Distribution transformer monitoring systems can capture and communicate this information in real-time, so it is available to our control room and engineers. We are also exploring the use of modern metering time use data to identify transformers that may be at risk of overload.

This expenditure is covered under network evolution Capex – outlined in Chapter 6.

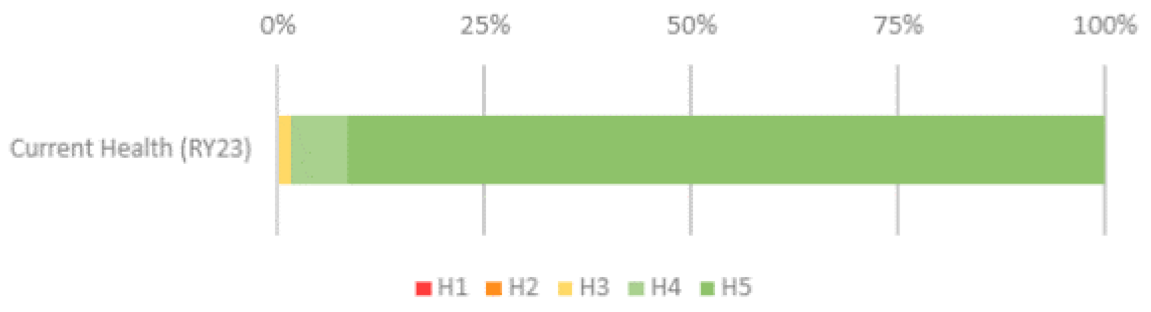
Meeting our portfolio objectives – responsive to a changing landscape

Trialling the use of distribution transformer monitoring systems will help us prepare for further changes in the way our distribution network operates, including increased electric vehicle and embedded renewable generation penetration, and changes to retailer offerings.

Asset health

AHI for ground mounted distribution transformers is shown below.

Figure 8.85: Ground mounted distribution transformer asset health



The overall health of this fleet is good, but a small number of renewals will be required each year to address issues with specific assets. Our asset health analysis indicates that we need to replace a small number of ground mounted transformers within the planning period.

Risks

The table below sets out the key risks identified in the fleet.

Table 8.61: Ground mounted distribution transformer risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
Overloading of distribution transformers leads to distribution transformer failure	Inspections and MDI reads Voltage complaint and follow up actions Upgrade plan – see network reinforcement	Reliability
Oil leakage into environment	Maintenance and replacements	Environmental
Third-party damage or access	Installation of visible warning signs Locks and inspections Design choice of location	Safety
Distribution transformer failure due to age-related internal failure	Strategic spares Replacement plan	Reliability
Distribution transformer noise complaints	Inspections and follow up actions Replacement plan	Environmental
Distribution transformer explosion, either due to active part failure, bushing failure, or cable box failure	Maintenance and replacements Safety in design solutions E.g. consider location and whether dry type or non-flammable oil is appropriate	Reliability, safety, environmental
Vegetation restricting access to transformer	Inspections and corrective maintenance	Reliability
Poor or missing earth connections	Periodic earth testing Corrective maintenance	Safety

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
Potentially inadequate ground mounted distribution transformer protection due to 'group fusing'	Review protection requirements during asset renewal, enhancement, or customer work in their vicinity, with a view to remove this arrangement where practicable and cost-effective	Safety, reliability
Ground mounted transformers installed inside 'homemade' cubicles ('pig pens')	Replacement of 'pig pen' arrangements	Safety, reliability
Some transformers are located in buildings that are in poor condition or do not meet current seismic and fire standard requirements	When the transformer is due for renewal it is replaced outside the building and the building demolished or sold	Safety, reliability
Some ground mounted transformers have poor lock mechanism ('night locks') which fall open unexpectedly	Identify and replace these locks with the Aurora approved padlock mechanism	Safety

Design and Construct

In most circumstances, our preferred design is a 'mini' type solution, which has a high voltage air-filled cable box, a transformer in the middle and a LV cable box and switchboard on the other end. The connected RMU or pole supplying the 'mini' contains the protective fuses. We use 'micro' ground mounted distribution substations at smaller capacities (<100 kVA); these are either fused off the overhead network or have drywell fuses installed inside the transformer cable box.

We have standard sizes for ground mounted transformers allowing for efficiency in design, procurement, and spares management. When renewing a distribution transformer, we assess the electrical load to ensure the rating for the new transformer is appropriate as per our standards.

Through our safety in design process, we consider aspects, such as transformer location and the potential impact on risks of different solutions, at potentially different cost points. Risks, including vehicular impact, fire, confined space (E.g. if located in a building basement), and third-party access are considered before a final decision on location is made. Outdoor installations are generally preferred as this avoids confined space or internal fire risk considerations. We consider the use of inflammable insulating oils such as Midel or Ester as/if required on indoor installations.

If a transformer is located inside our distribution substation building deemed to be in poor condition, it will be replaced outside of the building and the building demolished or sold. This outcome is preferred over seismically reinforcing the poor condition legacy design building, which in many cases will not accommodate the new equipment, would lead to constructability issues, or be uneconomical.

When ground mounted transformers in 'package' distribution substations with busbar connections to their associated RMU require replacement, we replace the RMU at the same time for economic and constructability reasons.

All Capex delivery is outsourced to our field service providers. Distribution transformer replacement design is often outsourced to these service providers; however, we also have a design team inhouse, which fulfils a range of roles. Deliverable quantities remain small, and so we do not foresee any deliverability issues in this portfolio.

Renew or Dispose

The table below summarise our renewal approach for ground mounted transformers.

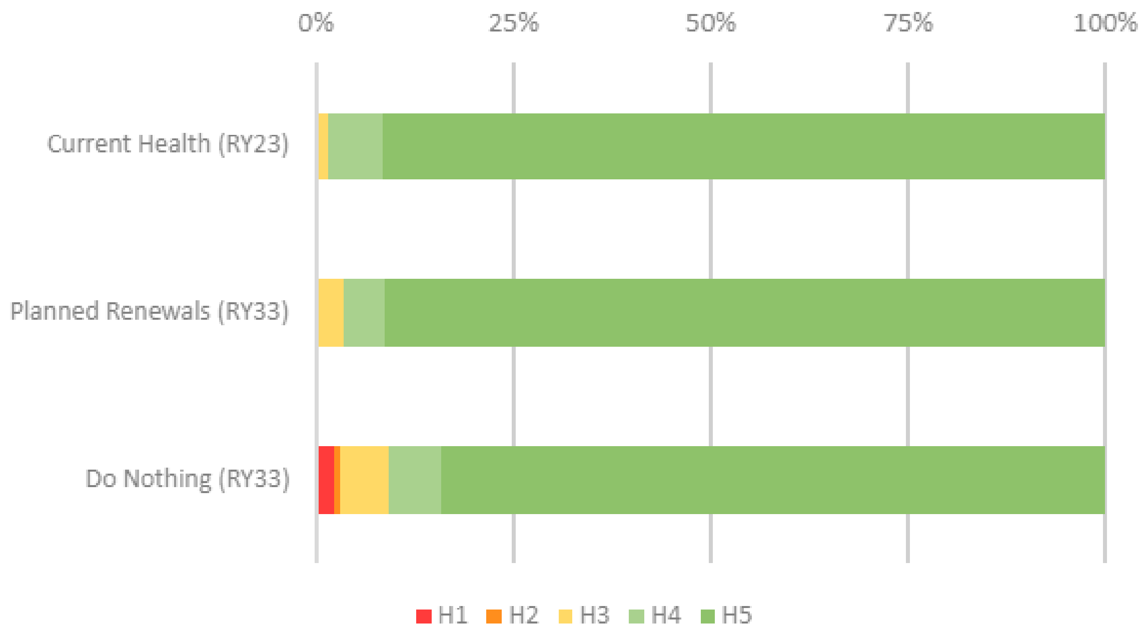
Table 8.62: Summary of ground mounted distribution transformer renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Proactive condition-based
Forecasting approach	Repex
Cost estimation	Volumetric based on historical average unit rate

Renewals forecasting

We use a Repex approach for forecasting ground mounted distribution transformers renewals. The chart below compares projected AHI in 2033 following our programme of renewals, with a counterfactual 'do nothing' scenario. This indicates the benefits of our programme.

Figure 8.86: Projected ground mounted transformer asset health at RY32



Our planned work programme will enable us to maintain our H1-classified transformers at a low level. However, H3 assets – those for which replacement within 10 years is required – will grow over the period as the fleet ages. Replacement of these units will largely occur beyond the AMP period.

Options analysis

When units have oil leaks that can be repaired in a workshop, a corrective maintenance task of swapping the existing transformer with a like-for-like spare replacement is often cost-effective. Alternately, a new transformer may be installed. Consideration must be given to factors such as the transformer's loading (whether its capacity is still sufficient for the expected remaining life), and the condition of any co-located equipment such as RMUs, which, if also in a poor condition or of certain type, may justify a total replacement solution.

Consideration is also given as to whether the ground mounted distribution transformer can be offloaded to other nearby substations and decommissioned.

Use of criticality in works planning and delivery

Due to low renewal requirements, we have not focused on developing further criticality dimensions or applying the framework at this stage. We will be developing criticality frameworks in further dimensions (E.g. service performance) for all assets in the first few years of the planning period.

Disposal

We dispose of ground mounted distribution transformers when decommissioned. The principal components – steel, copper, and oil – are recycled.

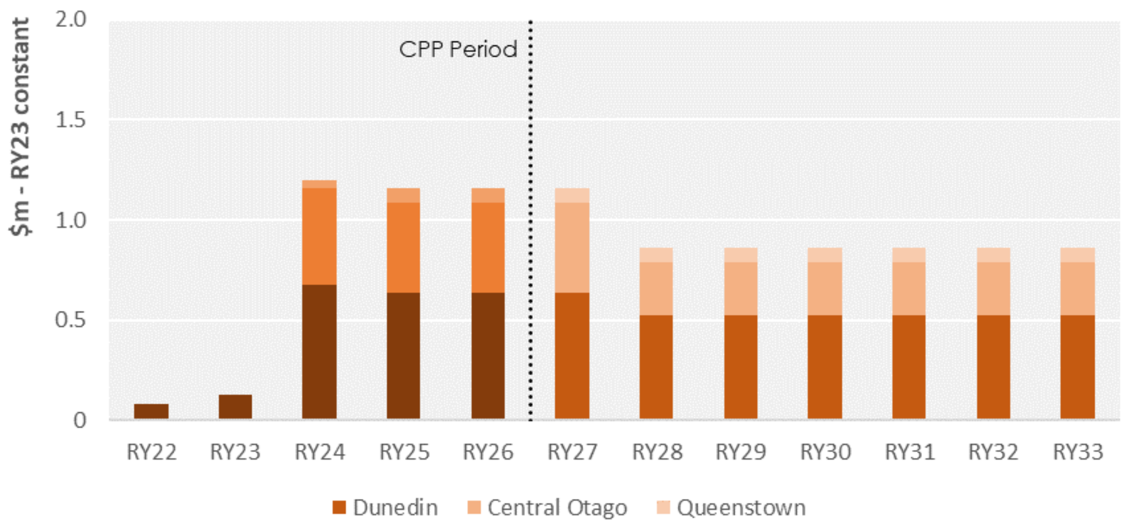
Coordination with other works

We coordinate ground mounted transformer replacements with ground mounted switchgear replacements. In many instances, short cable runs connect ground mounted transformers to overhead networks (via RMUs or directly onto cables up poles and pole fuses), and so overhead network work also is coordinated with ground mounted transformer replacements.

Ground Mounted Distribution Transformers Fleet Expenditure Forecast

Our forecast ground mounted distribution transformer renewal Capex is shown below. The total forecast expenditure over the planning period is $9.8m.

Figure 8.87: Ground mounted distribution transformers forecast Capex



Due to the age of the fleet, we have not replaced many ground mounted distribution transformers in recent years. We expect an increasing level of renewals as our fleet ages, and have increased our renewal quantities to target specific assets relating primarily to obsolescence, age, and condition.

Benefits

The key benefit of our planned renewal programme is ensuring continued reliability of service to customers. Secondary benefits are mitigating low probability safety incidents during transformer failure and mitigating environmental risk of oil spill from aged or failed transformers.

8.6.3. Pole Mounted Distribution Transformers

Where information is common to the ground mounted distribution transformers section, it has generally not been repeated.

Pole Mounted Distribution Transformers Fleet Overview

Pole mounted distribution transformers, like ground mounted transformer units, are used to transform the voltage of electricity to a suitable level for consumer connections. Pole mounted units are smaller on average, with the majority of the population being smaller than 100 kVA. They are usually located in rural or suburban areas with lower customer density and smaller loads. We have a small quantity of single wire earth return (SWER) transformers supplying a SWER system in our Dunedin network region. We have a small number of pole mounted 11/6.6 kV auto-transformers to interconnect our distribution system. They do not have on load tap changers.

In recent years, we have replaced a considerable number of pole mounted transformers as part of pole renewals. Over the planning period we will maintain the health of the fleet by continuing to replace aged units during pole replacements as well as undertaking standalone replacements based on condition. Large transformer substations mounted on two-pole structures are generally replaced with ground mounted units to mitigate seismic risk.

Population and Age

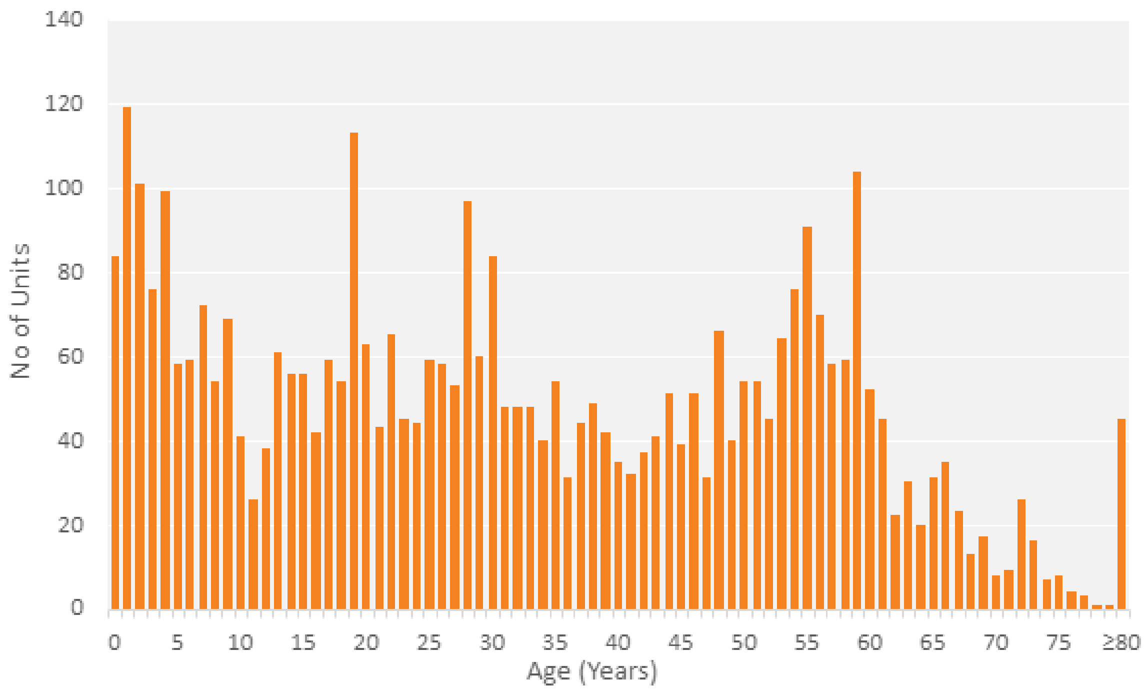
We have approximately 4,000 pole mounted distribution transformers across our network, 90% of which are below 120 kVA.

Table 8.63: Pole mounted distribution transformer ratings

RATING (KVA)	POPULATION	PERCENTAGE
≤15	376	10%
15 to 30	1,181	30%
30 to 120	1,999	50%
120 to 200	26	1%
> 200	344	9%
Total	**3,926**	**100%**

The chart below shows the age profile of our pole mounted distribution transformers.

Figure 8.88: Pole mounted distribution transformer age profile



Given their 60-year expected life, 9% of pole mounted transformers have already exceeded their expected life and we expect to replace a considerable number of them during the AMP planning period.

Condition, Performance and Risks

Condition and performance

We do not currently inspect pole mounted transformers except as a component of our visual pole inspections, from which only significant and obvious defects are identified. As a result, we do not currently have condition data that is adequate to assess either overall fleet or individual asset condition.

However, in RY23 we will be commencing detailed inspections of our larger pole mounted transformers, specifically, with the objective of collecting condition and other asset data.

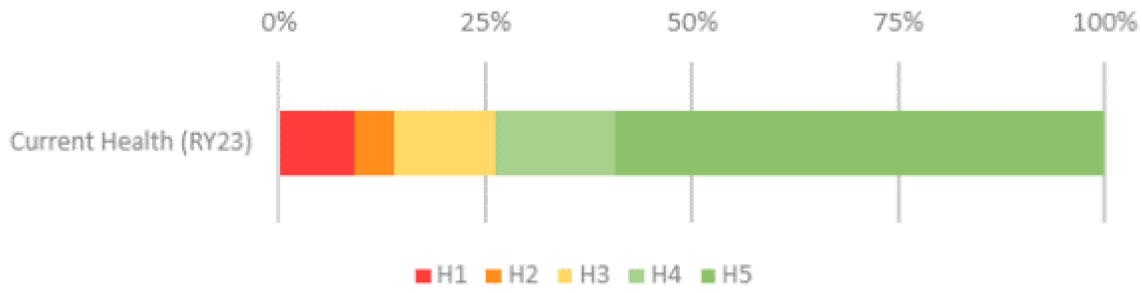
In Central Otago we have many pole substations that are installed unacceptably low to the ground. These will be replaced with new pole mounted or ground mounted substations as applicable.

> **Meeting our portfolio objectives – safety first and sustainability by taking a long-term view**
> We will replace transformers that are installed unacceptably low to the ground to help reduce public safety risk. The replacement will be a seismic resilient solution, whether a pole or ground mounted transformer.

Asset health

AHI for our pole mounted transformers is shown below.

Figure 8.89: Pole mounted distribution transformer asset health



The analysis indicates that we need to replace 9% (H1) of our pole mounted transformers within the next year, and approximately 26% (H1 – H3) will be considered for replacement over the AMP planning period.

Risks

Table 8.65 (below) sets out the key failure modes of ground mounted transformers. Transformer specific risks (i.e. regardless of mounting arrangement) also apply here to pole mounted transformers. The table below sets out additional risks identified in relation to our pole mounted transformer fleet.

Table 8.64: Pole mounted distribution transformer risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
Third-party damage (car vs pole)	High visibility reflectors on poles Design choice of pole location	Safety
Seismic risk – older pole mounted units, especially two pole substations, are not compliant with modern seismic standards	Replacement plan Pole mount to ground mount conversions	Safety
Electrocution risk from public accessing or contacting low mounted distribution transformers E.g. via orchard equipment	Identifying locations of low mounted transformers through inspections Replacement of low sites Signage and discussion with landowners in interim	Safety

Design and Construct

We have standard, seismically compliant designs for pole mounted substations between 100 and 200 kVA in our Central Otago network region and up to 300 kVA in Dunedin. The differences in each network region are due to seismic potential based on geographic location. Pole mounted units were historically installed by default due to their cost-effectiveness over ground mount solutions. Larger capacity pole mounted substations must be replaced with ground mounted substations (when renewal is warranted) to ensure seismic compliance.

Furthermore, some legacy pole substations have air-break switches and distribution voltage cables terminated on them (often cast iron cable terminations), and often these legacy designs cannot be replicated on a modern pole substation due to modern safety standards (clearances). A ground mounted solution is therefore required at additional cost. The photos below shows a legacy 'pole-and-a-half' substation with an ABS and two cast iron cable termination. This is a rather 'busy' structure that cannot be replicated with a modern pole mounted substation. A ground mounted substation with an RMU is required and a new termination pole.

Figure 8.90: Legacy pole-and-a-half substation with an ABS and two cast iron pot head terminations

Any pole mounted transformers installed at a height such that does not comply with its clearance standards at install will be replaced with a new pole substation as applicable.

Renew or Dispose

In the case of small transformers, we generally replace these reactively upon failure. This is cost-effective as the impact on customers is limited. Recently we have replaced a large number during pole replacements, and this will continue, albeit at a lower rate. The AHI profile of the fleet is declining, with multiple units having already exceeded their expected lives. As such, it is essential that we take a more proactive approach. This will involve proactive replacement of larger, aged pole mounted units (which present a specific public and worker safety risk) with ground mounted units, together with condition-based replacement of other pole mounted transformers.

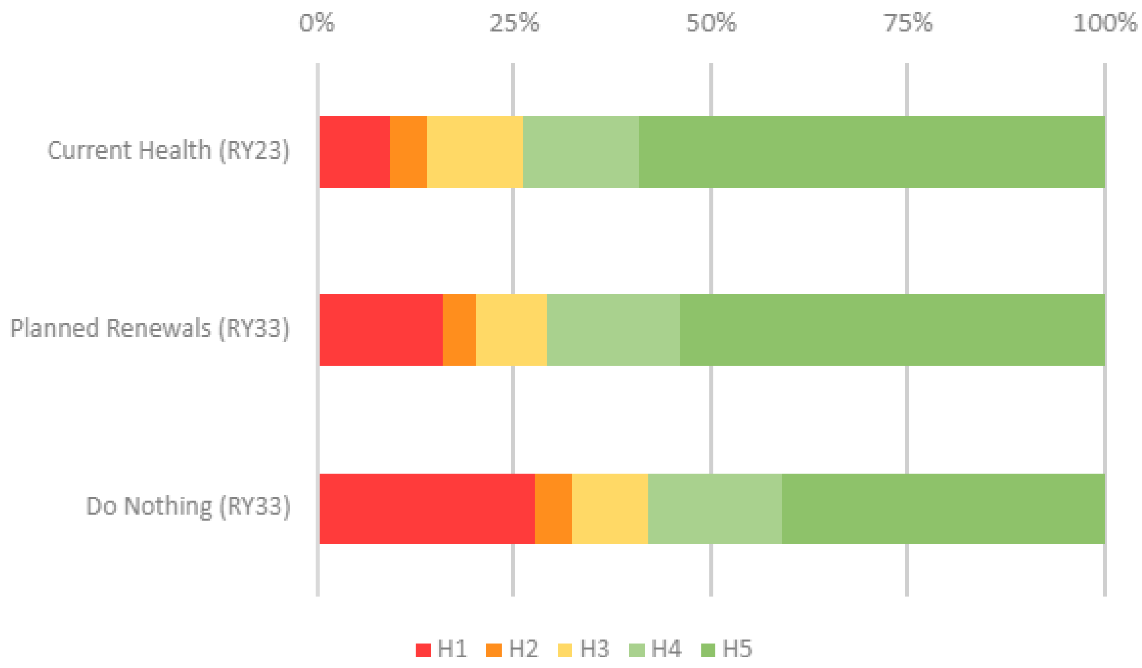
Table 8.65: Summary of pole mounted distribution transformer renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Reactive (replace upon failure)
Forecasting approach	Repex
Cost estimation	Volumetric

Renewals forecasting

The following chart shows the current and projected AHI of the fleet, together with the expected health under a 'do nothing' scenario. Currently, 9% of the fleet is classified as H1 (replace within one year). The current overall health profile depicts a backlog situation, which is based on a model largely driven by age and criticality of condition. While the asset health degrades over the period (assets continue to age/degrade), even with proposed investment level – it is significantly better than the 'do nothing' scenario where the proportion of H1s would increase to 28%. The ongoing progress in maturing and refining our inspection programme will provide us with the information we need to continue to progress towards a more condition-based approach. We will use this data to continually refine our assessment of health and risk, including how we plan and prioritise renewals

Figure 8.91: Projected pole mounted distribution transformer asset health



Options analysis

Our preferred replacement option, where feasible with modern equivalent functionality, is to retain pole mounted transformers where possible under our design standards. This is supported by consultation with communities on the price implications of underground conversions for visual amenity reasons. Offloading and decommissioning are applicable to pole mounted distribution transformers.

Use of criticality in works planning and delivery

Our public safety criticality framework is locational, so is applicable to distribution transformers (and the poles on which they are located). We use this framework to help prioritise replacements of pole transformer substations in highly populated areas or areas of significance. We will be developing criticality frameworks in further dimensions (E.g. service performance) for all assets in the first few years of the planning period.

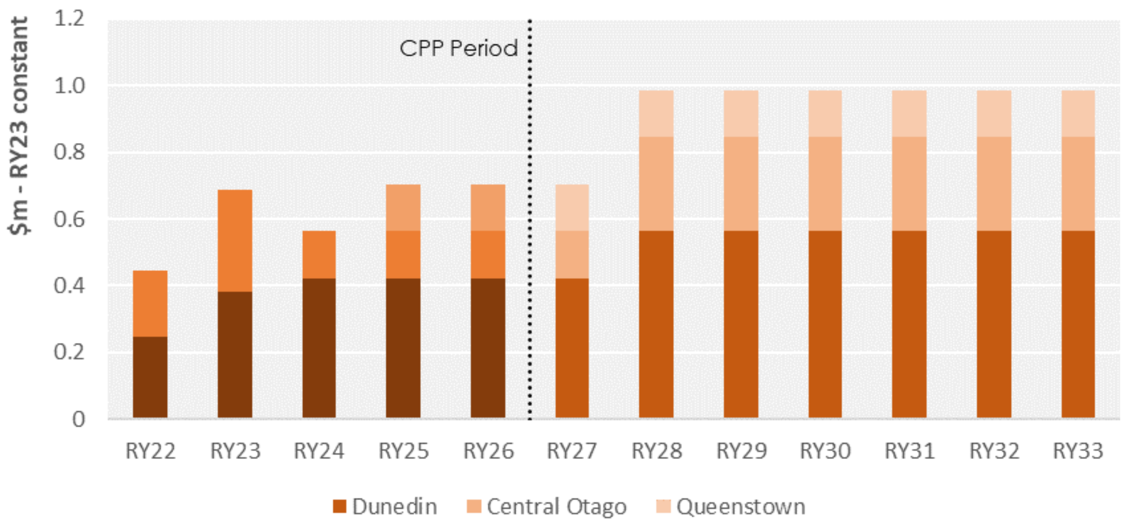
Coordination with other works

We coordinate replacements with other overhead asset replacements including poles, crossarms, conductor, and cast iron cable terminations. Where customer or growth-related jobs are planned, we look to coordinate renewal work that is required in the outage zone.

Pole Mounted Distribution Transformers Fleet Expenditure Forecast

We have forecast renewal Capex of approximately $8.6m during the planning period. We are limited in our capability to deliver greater replacement numbers. As such, we are targeting assets in this fleet with the highest safety criticality. Expenditure excludes units replaced onto new poles during pole replacements, where the driver is pole replacement.

Figure 8.92: Pole mounted distribution transformers forecast expenditure



Standalone historical expenditure on pole mounted distribution transformers was low because a large number of renewals have been undertaken as part of the pole renewal programme. While pole mounted transformers continue to be renewed as part of the pole renewal programme (associated assets), we are taking a more proactive approach to this fleet. We are building data through inspections and thus our understanding of asset condition and performance. We have adjusted the expenditure to reflect our updated view of asset health, which we expect will continue to mature over the period. We will continue to review and refine as our approach and data mature.

Benefits

The key benefits of our planned renewal programme are mitigating the potential decline in associated reliability due to the forecast decline in asset health, and reduction in safety risk associated with larger pole mounted units.

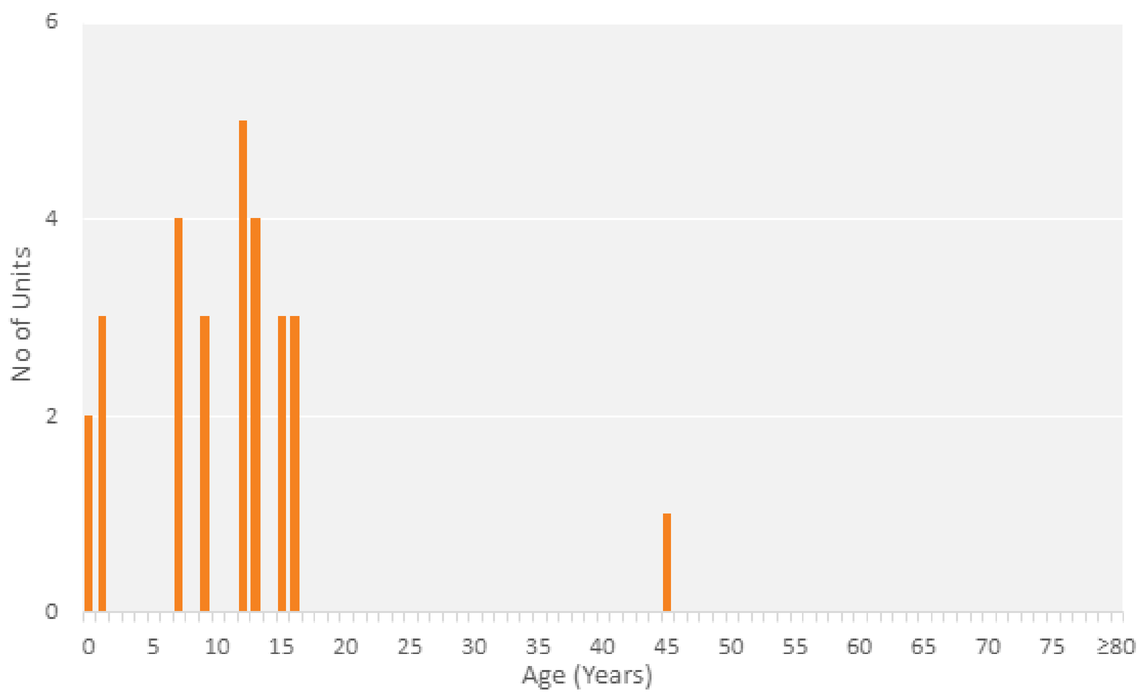
8.6.4. Voltage Regulators Fleet

Voltage Regulators Fleet Overview

Voltage regulators automatically maintain a set voltage level on our 11 kV or 6.6 kV network. The length and lightness of some of our HV distribution lines necessitates the installation of voltage regulators partway along the feeders to compensate for undersized and/or long rural lines feeding isolated loads, which would otherwise experience non-compliant voltage. In some cases, using a voltage regulator enables reconductoring to be deferred, which would otherwise be required to ensure voltage compliance.

Voltage regulators are made up of an auto-transformer and a control device, and some with basic Remote Terminal Units (RTU) functionality and communications to our SCADA system. While our fleet of voltage regulators are primarily controlled by digital controllers, a few older controllers with ad-hoc setups and limited visibility of settings remain in service.

Figure 8.93: Voltage regulators age profile



Population and Age

We have a total of 31 voltage regulators, either three phase units or single phase 'cans' making a three-phase voltage regulation site.

The majority of our voltage regulators are recently installed. They have an average age of 11 years, while as a fleet they have an expected life of 55 years. We do expect, however, that those in higher corrosion areas will deteriorate more quickly. In future, we will incorporate corrosion zones into our criticality framework.

Condition, Performance and Risks

Condition and performance

We have a backlog of voltage regulator maintenance and repairs due to insufficient historical work. We have corrosion issues at sites near the coast, which have not been adequately and regularly maintained. In addition, there are sites where the regulators have not been set up correctly, or different voltage regulators from the same 'set' were used across different sites. We have a plan to 'rematch' these sites up to ensure each site is operating correctly and has equal impedance.

Asset health

Given the low average overall age of this fleet, we estimate little need for replacement over the planning period. Most of our assets are within the H4-H5 range, which indicates that the fleet will remain in good health in RY33.

Risks

The table below sets out sets out the key risks identified in relation to our voltage regulators fleet.

Table 8.66: Voltage regulator failure risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
In service failure or forced outages leads to uncompliant voltage	Inspection, preventive maintenance, and replacement plan	Reliability
Lack of easement on-site (most sites installed post 1992 existing use rights consideration)	Gain easement New site chosen when renewing, or add a bypass if an easement cannot be gained on the existing site	Environmental
Mismatched sites losing synchronism leading to uncompliant voltage	Overall plan to 'rematch' up sites across the network and revisit settings to ensure voltages are compliant	Reliability

Design and Construct

Our fleet ranges from a single 1 MVA pole mount voltage regulator site to a 3 MVA ground mount voltage regulator site. We have purchased a standard design for our most common two 'can' and three 'can' pole mounted voltage regulator sites, which will include an ABS bypass for use away from roads and footpaths. A simple design is usually all that is required when undertaking individual unit like-for-like swaps.

Renew or Dispose

Voltage regulators have an expected life of 55 years, but we expect those in higher corrosion areas will deteriorate more quickly. Achieving expected life assumes regular maintenance, which has not typically occurred in the past. Units running abnormally will likely not achieve expected life, such as sites running at high loading or with units performing additional tapping. As a result, some may be replaced based on adjusted expected lives.

When a voltage regulator reaches its operation-count limit, or is found to be significantly degraded or malfunctioning, it is removed from service and replaced with a unit from the pool of refurbished units or a new unit, as best applicable.

Table 8.67: Summary of voltage regulator renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Condition (proactive)
Forecasting approach	Individual sites
Cost estimation	Volumetric

Renewals forecasting

Given the small quantities of likely renewals and the rotating nature of voltage regulator 'cans' (meaning it is likely many will be refurbished under corrective maintenance), we have not created a long-term Capex forecast at this time.

Options analysis

When reviewing a site for maintenance or replacement, the voltage regulator unit is assessed to determine how much life it has remaining. Indices, such as the number of taps, the repair cost of any work required, and the adequacy of the existing size, are used to determine if the asset should be refurbished or replaced.

Use of criticality in works planning and delivery

Criticality has not influenced our voltage regulator planning to date, given the low quantities of assets in poor condition. All our voltage regulators are in areas of low population density.

Disposal

We dispose of voltage regulators when it is no longer economic to refurbish them. We retain components as spares. The principal components – steel, copper, oil, and the battery – are recycled.

Coordination with other works

The majority of our voltage regulators are pole mounted and so works are coordinated with overhead asset works. Outages have to be taken during low load seasons and (sometimes) certain times of day, so that service compliant voltages can be maintained with the voltage regulator out of service.

Voltage Regulator Fleet Expenditure Forecast

We expect to replace a small quantity of voltage regulator sets over the next few years, and will determine the solution (Opex or Capex) nearer to the time of each project. Some existing sites have been identified for bypass installation to enable maintenance to be carried out safely. This is categorised as reliability, safety and environmental Capex.

8.6.5. Mobile Distribution Substations and Generators Fleet

Mobile Distribution Substations and Generators Fleet Overview

Mobile distribution substations are used to bypass permanent 11 kV or 6.6 kV distribution substations to enable planned work to proceed without significant loss of supply to consumers. They are also used as backup transformers in the event of a distribution transformer failure. Our mobile distribution substations consist of HV and LV cables, an RMU, a transformer, an LV switchboard, and the truck and body housing all these components.

The purpose of mobile diesel generators is to reduce the impact of planned outages on customers.

We have standby generators supplying our Dunedin and Central Otago control rooms in the event of a loss of network supply.

Population and Age

We have three mobile distribution substations, with transformer capacities of 1 x 300 kVA and 2 x 500 kVA. They are ageing, having been purchased in the 1980s, but are in acceptable working order.

Our mobile generator fleet consists of three 100 kVA generators and one 300 kVA generator, all of which were purchased in 2019.

We have a nine-year-old standby generator at Glenorchy. Our standby generators supporting our Dunedin and Central Otago control rooms were installed in 2017 and 2019, respectively.

Condition, Performance and Risks

Condition and performance

All three distribution substations are truck mounted and are of different legacy designs. The 500 kVA units require working on top of the enclosure, a risk for contractors during a fault. There is a requirement to operate the RMUs at a distance with a lanyard system due to arc flash levels. With the old age of the trucks, we have had rust issues that require ongoing repairs to obtain a certificate of fitness (COF).

The mobile generators and standby generators are young assets and are in good condition.

Risks

The table below sets out risks identified in our mobile distribution substations and generators fleet.

Table 8.68: Mobile distribution substation and generator fleet failure risks

Risk/Issue	Risk Mitigation	Main Risk Area
Arc flash from failure of Statter RMU in mobile distribution substations	Lanyard operating system	Safety
Injury from falling off mobile substation	Edge protection system installed on top during usage	Safety

Design and Construct

When we plan to replace our mobile substations, we will define requirements to ensure we build to a modern specification that is consistent with our safety in design standards.

Renew or Dispose

We will replace our mobile distribution substations and mobile generators when their condition becomes poor, they become uneconomic to maintain, too unreliable to operate, or begin to present a significant safety risk. We plan to investigate options around replacing the mobile distribution substations in the medium-term.

Table 8.69: Summary of mobile distribution substation and generators renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Condition (proactive)
Forecasting approach	Individual sites
Cost estimation	Volumetric

Mobile Distribution Substation and Generator Fleet Expenditure Forecast

At this point, no renewal Capex is planned for our mobile assets during the period to RY33.

8.7. SECONDARY SYSTEMS

This section describes our secondary systems portfolio, which includes four asset fleets:

- Protection systems
- DC systems
- Remote Terminal Units (RTUs)
- Metering and power quality monitoring.

Portfolio Summary

We proactively replace secondary systems equipment based on age and type, with the medium-term work volumes forecast via the same approach. During the planning period, we expect to spend $17.3m on replacing secondary system assets. Some of our protection fleet will be replaced as part of growth projects, and so will be accounted for separately.

A significant proportion of our protection relays are obsolete and have ongoing reliability issues, which result in intolerable safety risks. This is a key investment driver for this portfolio.

Secondary systems are critical for the safe and reliable operation of our network. The portfolio encompasses assets that range from relatively simple to technically complex. They are generally relatively low cost compared to the assets they control or monitor, but also have shorter useful lives.

Box 8.13: Summary of our asset risk review – secondary systems

Issues: key risks identified include significant quantities of electromechanical relays and static relays past expected life, losing calibration, obsolete, and at times not operating as expected. Absence of DC system redundancy was also identified, and some battery banks required replacement.

Response: we have increased our electromechanical and static relay renewal programme, and plan to replace all these relays as a priority in the planning period. We are addressing calibration drift by undertaking testing at half the previous test interval (2-yearly vs 4-yearly). Later in the planning period, a steady-state renewal level for protection will be reached and other relay types past expected life will also be replaced. We have introduced an annual battery test programme and increased DC system replacement and redundancy where practical to reach good practice steady-state levels.

Timing: We will replace all electromechanical and static relays that are past end-of-life by the end of RY29.

Protection systems are required to rapidly detect network faults and initiate the opening of circuit breakers to isolate the fault from the rest of the network and prevent harm to people and our assets. Automatic voltage regulator systems located at zone substations are included in our protection fleet.

DC systems provide a reliable and efficient power supply to vital elements within our zone substations and our assets at GXPs and ensure continued operation of these devices when AC supply is lost. The system consists of two main elements: batteries and chargers.

RTUs are electronic devices used for monitoring, control and data acquisition in real-time. They capture signals received in zone substations from protection, DC, and metering equipment as well as other on site monitoring systems, and transmit it to our control rooms for action.

Metering assets comprise check metering at GXPs and zone substation power quality meters. Check meters provide verification against Transpower's revenue meters, while power quality meters provide data, such as harmonic levels, that cannot be obtained from normal protection relays.

8.7.1. Secondary Systems Objectives

Portfolio objectives for secondary systems are listed in the following table.

Table 8.70: Secondary systems portfolio objectives

OBJECTIVE AREA	PORTFOLIO OBJECTIVES
Safety first	No injuries resulting from maloperation of protection systems In a 'line down' event, no protection maloperation leaves live lines on the ground
Reliability to defined levels	No protection maloperations cause a loss of supply No protection maloperation renders primary equipment unserviceable where it could have been saved from end-of-life damage DC systems meet specified carry over times in the event of a loss of AC supply ADMS (Advanced Distribution Management System i.e. our SCADA system) and RTUs provide uninterrupted control and monitoring of our network at all times
Affordability through cost management	Protection scheme replacement is consolidated with other zone substation works where possible, using a risk prioritisation basis
Responsive to a changing landscape	Better fault information is gathered from modern relays now installed, and processed to assist with fault analysis
Sustainability by taking a long-term view	Secondary system asset data including protection settings is comprehensive, up-to-date, and readily accessible through an effective and controlled asset information system

8.7.2. Protection Systems Fleet

Protection Systems Fleet Overview

Protection systems rapidly detect network faults and initiate the opening of circuit breakers required to isolate the fault from the rest of the network, preventing harm to people and our assets. Protection systems must be capable of discriminating between faults occurring on adjacent parts of the system and faults occurring on the parts they are deployed to protect. Reliable performance is critical to the safe operation of our network. Protection systems comprise protection relays and their associated cabinets and cabling. Our protection fleet includes protection assets inside zone substations, at GXPs, and at high voltage customer sites where an indoor switchboard is present.

Protection relays have evolved over time. A percentage of our protection fleet comprises legacy type relays, which provide basic protection functionality. These static and electromechanical relay types are at an age where we have concerns about their ongoing reliability, and we are incurring increased maintenance costs to keep them in service. Lack of spare parts and manufacturer support are also driving their obsolescence. We are facing a lack of technicians with the skills to service electromechanical relays, and other electricity distribution businesses are also removing them from their networks.

Types of relays

We have three protection relay types on our networks:

- **electromechanical:** a legacy technology that converts electrical signals (such as current and voltage) into mechanical forces, which operate primary plant secondary circuits. They are simple devices with limited functionality.
- **static:** analogue, semiconductor-based relays that are also a legacy technology. Spares can be difficult to source, and repairs are not generally economical.
- **numerical:** an electronic device and our preferred relay type, these can be programmed and configured to provide a wide range of protection applications. They have less complex wiring, provide more sophisticated protection, indication and control, and allow remote management of the relays directly from our SCADA system.

Population and Age

The table below summarises our population of protection relays by type. In the table, the protection functions represent the primary plant the relays are protecting. The complexity (and hence cost) of protection varies by protection function.

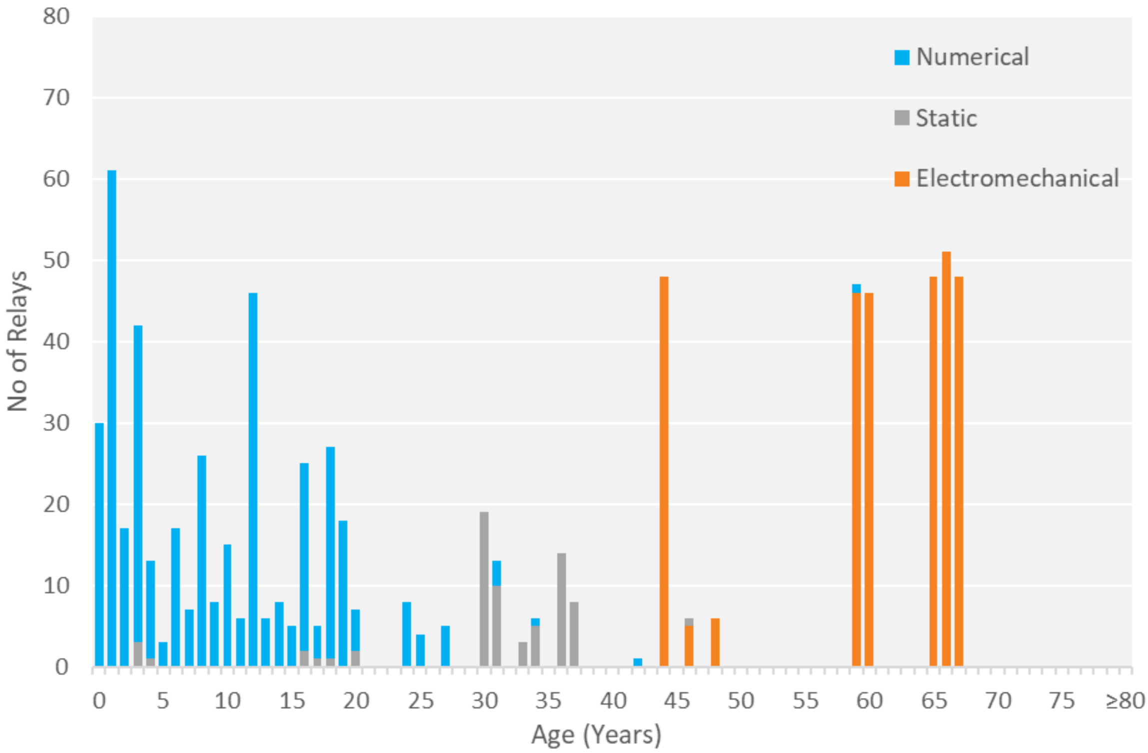
A protection scheme may consist of multiple relays (E.g. a feeder relay may consist of earth fault and three overcurrent relays). Numerical schemes make around 52% of our raw population of protection relays, and approximately 73% of protection schemes. A circuit breaker bay with an electromechanical protection scheme will typically have four separate relays, each providing a single protection function; while a circuit breaker bay with a numerical protection scheme will typically have a single numerical protection relay providing several protection functions.

Table 8.71: Protection asset population by type

RELAY TYPE	TOTAL	PERCENTAGE
Electromechanical	298	39%
Static	70	9%
Numerical	405	52%
Total	**773**	**100%**

The figure below depicts the age profile of individual relays (not schemes). It shows that relays have been installed in phases, generally when substations were established, or switchboards replaced.

Figure 8.94: Protection relay age profile



Relay end-of-life is generally driven by obsolescence, lack of spares, and cost to maintain. The expected life of electromechanical relays is 40 years, while for the numerical and static types, a 20-year life is expected. Approximately 39% of our relays are electromechanical. Nearly all have exceeded life expectancy, and spares for them can no longer be purchased.

Many of our static relays have exceeded their expected life and we only have spares for some. Many numerical relays will reach their expected life during the AMP period.

Condition, Performance and Risks

Condition and performance

Our fleet includes a significant number of legacy electromechanical relays, which only provide basic functionality. Their age means we have concerns about their ongoing reliability, and we are incurring higher maintenance costs to keep them in service. Lack of spare parts and manufacturer support are also driving their obsolescence and there is a lack of technicians with the skills to service them.

Electromechanical relays have moving mechanical parts, such as rotating discs and springs, and they lose calibration over time. We generally recalibrate them during scheduled maintenance and replace parts when calibration issues are found. However, given their age, replacement parts are becoming scarce, and most are now obsolete.

Static relays may have a number of analogue electronic components with properties that can drift with age, such as capacitors, leading to drift of the protection set-points, and potential maloperation. We test during scheduled maintenance and re-set or replace where calibration issues are found.

Many electromechanical and static earth fault and over-current detection relays are consistently losing calibration between maintenance cycles. Loss of calibration may cause a protection relay to fail to clear a fault, which presents a significant safety risk. We identified our electromechanical relays as the highest risk protection assets on our network, with static relays also identified as high risk. Other relay types do not face the same calibration issues as electromechanical and static types.

There is clear evidence that we are experiencing an increasing number of relay failures or maloperations. If relays fail to operate as intended, this can result in live conductor on the ground not being detected and remaining energised.

Electromechanical and static relays are old technology with functionality usually limited to a single protection function, so multiple relays are required for each protection scheme. They also have limited performance in comparison to numerical relays which have significant additional functionality (i.e. fault recording and remote interrogation).

Meeting our portfolio objectives – safety first and reliability to defined levels

Our safety and obsolescence driven electromechanical and static relay replacement plan will provide reliability benefits due to higher performance relays with extensive functionality.

Risks

The following table sets out the key risks and mitigations we have identified in our protection fleet.

Table 8.72: Protection system risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
Failure to detect conductor to ground	Increased preventive maintenance on electromechanical and static relays to manage calibration Replacement programme	Safety
Obsolete relay failure (whether in service or when tested) with no spares available resulting in prolonged equipment out of service	Spares purchased where available Contingency planning to use a different model	Reliability, safety
CT open circuited resulting in equipment failure due to overvoltage (potential fire risk)	Modern relays equipped with alarming	Safety
Incorrect CT polarity, ratio, or other connection resulting in maloperation	Preventive testing, commissioning procedures	Reliability, safety
Incorrect protection settings applied resulting in maloperation	Controlled settings database and procedures for revising settings	Reliability, safety
Seismic event leads to maloperation of electromechanical relay and loss of supply	Replacement programme	Reliability

Design and Construct

Design of protection systems requires balancing many competing requirements to ensure the system is effective. The system must operate correctly when needed, for all relevant faults, despite being called upon very rarely. It must also not operate incorrectly for out of zone faults, and it must remain stable when events that look like faults (but are not) occur, for example, power swings. It must operate with the required speed and coverage as part of an overall protection scheme, and the overall scheme should be simple so that it can be easily maintained. Lifecycle cost is an important consideration.

Our sub-transmission and zone substation protection standard is a key document supporting our standard protection scheme designs and philosophies and will drive consistency through the network going forward. We have also begun to use a specialised protection asset management software package. This software enables us to manage equipment in terms of device types and location, and can also cater for workflow (i.e. maintenance, commissioning, cyclic protection tests, ad-hoc settings changes, and arc-flash label creation).

> **Meeting our portfolio objectives – sustainability by taking a long-term view**
> Our new protection software allows us to comprehensively manage our secondary system asset data in an effective and controlled system. The workflow enforced by this system also helps mitigate the safety risk of incorrect protection settings being applied.

All secondary systems network Capex delivery is outsourced to field service providers, either covered by an FSA or approved contractors who win tendered projects. Detailed protection design is outsourced to engineering design consultants with significant involvement from our internal protection team.

Protection technicians are specialised staff who have undergone years of training and work experience. We have based our work programme on a steady ramp up and flow of projects to best support the resources available in the market.

Renew or Dispose

The main drivers for renewal of protection schemes are:

- **public and operator safety criticality**: protection schemes are critical to the safe operation of our network and failure of protection to clear a fault poses a significant safety risk.
- **obsolescence:** relays with limited or no manufacturer support. The technology employed in electromechanical and static relays is outdated and our service providers are finding it difficult to sustain the skills necessary to maintain these relays.
- **performance:** we are experiencing an increasing number of protection relay maloperations, primarily due to the settings 'drifting' on electromechanical and static relays.
- **functionality:** modern numerical relays provide significant additional functionality that enables us, among other things, to improve management and operation of our network by easy access to detailed fault information.

Some of our existing schemes contain areas where there is inadequate protection, i.e. they do not meet our sub-transmission and zone substation protection philosophy/standard. Most of these will be brought up to standard when they are replaced. Some lower priority protection gaps will remain, and we will further investigate the appropriate timing to address these gaps following completion of the more immediate priorities.

Note that in most cases, multiple electromechanical relays can be replaced by a single modern equivalent numerical relay. When these modern relays are employed, our protection engineers are able to swiftly download/review event data and remotely modify protection logic/settings. This results in a much better understanding of network events, and significantly improves our ability to refine our protection systems and take measures to reduce safety risks and prevent consumer outages. We replace a considerable number of protection assets as part of zone substation projects.

Table 8.73: Summary of protection renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Obsolescence, age Zone substation projects (forecast under zone substation portfolio)
Forecasting approach	Obsolescence (age/type based)
Cost estimation	Volumetric based on estimated costs

Renewals forecasting

We forecast renewal need based on our strategy to remove from service (during the planning period) all electromechanical relays and all other relays that are obsolete/have reached end-of-life.

We have scheduled the total annual number of renewals to match our capability to deliver in an efficient manner. This is necessary due to the large number of overdue protection relay renewals.

Once we have replaced all our electromechanical relays, we will begin replacing static relays, followed by numerical relays that have reached end-of-life. Some protection scheme renewals will be brought forward or deferred to fit in with zone substation upgrades or renewals.

Options analysis

Options analysis for protection renewals is generally limited. Running protection to failure is intolerable. We have a large volume of aged and obsolete relays in the fleet and are seeing some failures occurring. We have considered seeking ‘life extensions’ by rotating in service equipment with refurbished or spare units. However, this has proven unsuccessful for other network operators, as rotated equipment often fails soon after it is put into service. Therefore, despite gaining spares as we renew the fleet, we will not employ this refurbishment approach.

Use of criticality in works planning and delivery

Protection works undertaken as part of zone substation projects are inherently prioritised on a risk basis, via the criticality framework used to prioritise zone substation work. Developing a criticality framework specific to protection systems is a future improvement. Given protection isolates assets in public areas when a fault occurs, the criticality framework will include consideration of public safety risk.

We will prioritise protection replacements based on the principles of what our future criticality framework will include (public safety, worker safety, load characteristics).

Disposal

Relays with potential use as spares will be retained. Disposal requirements are minor and similar to other electromechanical or electronic devices. Some of our existing Buchholz devices contain mercury and we will use appropriate disposal methods when these are replaced.

Coordination with other works

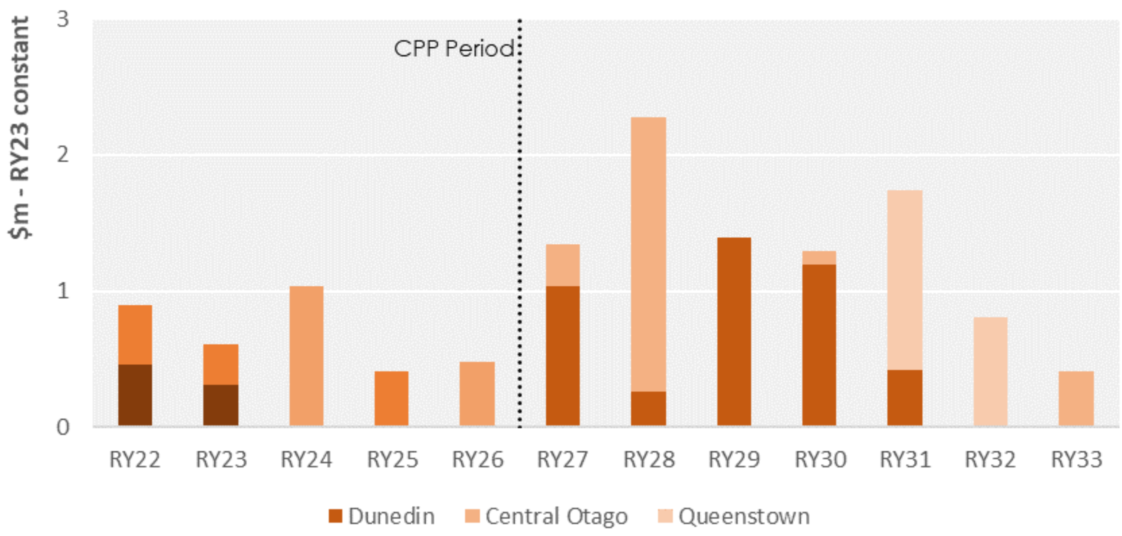
Where possible, we coordinate replacement of protection relays with other project works, such as zone substation upgrades – whether renewals or growth driven – or Transpower projects at GXPs.

Protection Fleet Expenditure Forecast

We take a volumetric approach to protection renewal forecasts. Unit rates vary with the function of the relay, with bus zone or sub-transmission protection relays having higher unit costs.

We have forecast protection renewal Capex of approximately $11.2m during the planning period. This expenditure excludes protection replaced under zone substation projects.

Figure 8.95: Forecast protection Capex



Up until RY18, expenditure on protection systems was low. We increased renewals during RY19, and we will remain at an elevated level through the CPP Period. There is a further uplift post CPP Period as we move from replacement during zone substation renewal to renewing our older numeric protection schemes on zone substations that are mid-life.

Benefits

The key benefit of our planned renewal programme is mitigation of relay failure or maloperation risk. Other benefits are reduced maintenance costs, increased functionality, increased standardisation (reducing human errors), and improved reliability performance.

8.7.3. DC Systems

DC Systems Fleet Overview

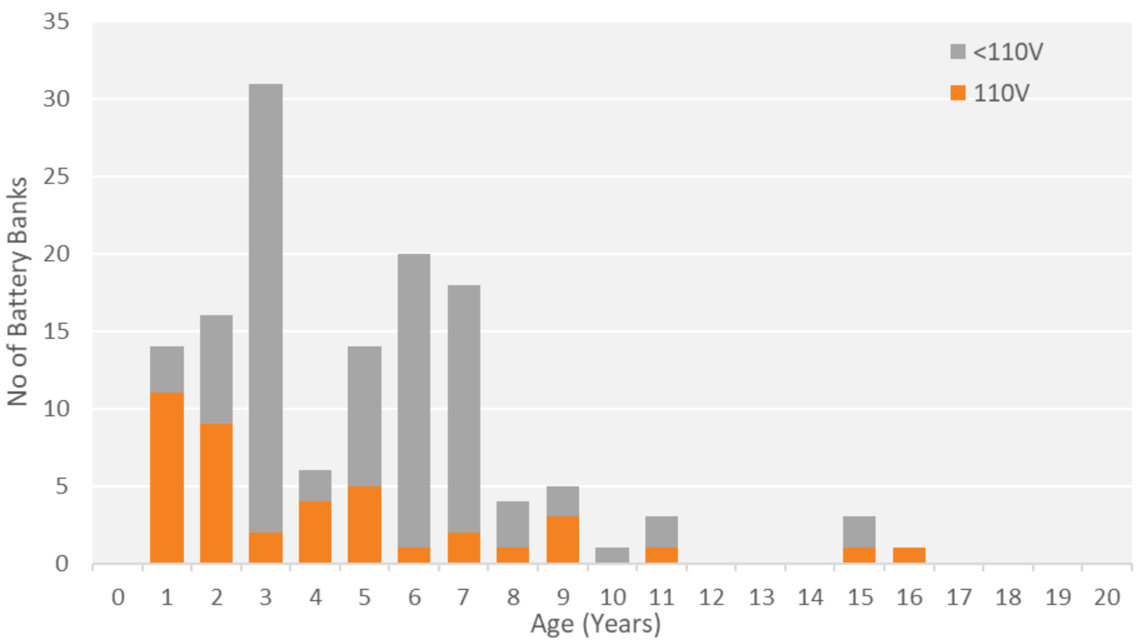
DC systems provide a reliable and efficient power supply to vital elements within our zone substations and our areas at GXPs. They ensure continued operation of these devices when AC supply is lost. Protection equipment, SCADA equipment such as RTUs, metering, communications and security alarms, are all powered by DC systems so that they can continue to operate should the AC supply be lost, such as during a fault – the exact time protection needs to operate. The system consists of two main elements: batteries and chargers, together with DC distribution panels. Chargers are also known as rectifiers, as they convert AC into DC to charge the battery.

Our batteries are predominantly sealed lead acid and provide DC supply at voltages from 12 V to 110 V. Our high voltage batteries mainly serve protection equipment, while lower voltages are mainly used for SCADA and communications.

DC systems at a small number of our higher criticality substations have N-1 redundancy. Most of our battery banks have no redundancy. This means that the failure of a single cell would result in loss of substation control and protection. This is not good industry practice, so when they are replaced, we look to convert them to redundant (duplicated) systems. Many of our battery banks are not in temperature-controlled environments – large temperature variations cause reduction in battery life.

Population and Age

Figure 8.96: Battery bank age profile



Generally, we aim to replace batteries once they reach eight years of age, otherwise they are replaced based on condition (i.e. failing test). A number of the 110 V batteries exceed eight years of age and have a higher risk of failure than younger units. Some DC supplies will be replaced as part of zone substation projects.

The majority of our zone substations have a 110 V battery for protection supply. However, some of the smaller single power transformer zone substations use lower voltages for this purpose. Most zone substations use 12 V, 24 V, or 48 V for communications equipment supplies only.

The following table summarises our population of DC systems.

Table 8.74: DC system asset population by voltage

VOLTAGE LEVEL	POPULATION
110 V	41
48 V	11
12/24 V	84
Total	136

Condition, Performance and Risks

Condition and performance

The condition of our DC systems is not acceptable, based on the age profile against good industry practice expected lives. This is especially the case given the lack of redundancy in our DC systems; this poses safety and reliability risks from potential protection maloperation. Many batteries are exposed to large temperature variations due to their locations; this has a significant impact on their condition and life expectancy. Batteries are replaced into temperature-controlled environments where possible, which may not be until a project occurs at the site to provide a suitable location.

Risks

The following table sets out the key risks identified in relation to our DC systems.

Table 8.75: Protection system risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
DC system fails in service leading to protection maloperation, no visibility or no network control	Inspection and test regime. Alarms and monitoring Age-based replacement N-1 battery systems installed where applicable/possible	Safety, reliability
Catastrophic battery failure (i.e. thermal runaway) leading to fire	Alarms and monitoring	Safety, reliability

Design and Construct

We have standardised our valve regulated lead acid batteries and chargers. The capacity of battery banks is determined in accordance with the requirements of IEEE485. We have defined battery carryover times, which vary by battery location based on likely response times. Batteries are installed on seismically rated stands, and the connections between cells are to be fully insulated.

At zone substations that serve as a communications hub for other sites, a separate DC system is installed for the communication equipment to allow for different standby times. At substations where communications infrastructure is in place to solely serve that substation, the communications equipment will be supplied from the substation supply by means of AC-DC converters.

Renew or Dispose

Key drivers of expenditure for renewal of DC systems:

- **condition:** if battery banks fail discharge testing, then we replace the entire bank. If a charger is tested and found to be faulty it is replaced (i.e. higher voltage ripple than specified limit).
- **age:** batteries have an expected life of 8-10 years (depending on system redundancy and the environment in which they are installed) and we replace them at this time in line with good industry practice or earlier due to condition. Chargers are replaced with every second battery replacement if they are our standard type. If not, they are replaced with the first battery bank replacement.

Table 8.76: Summary of DC systems renewals approach

ASPECT	APPROACHES USED
Renewal trigger	Age based Reactive condition-based Type (non-standard chargers only)
Forecasting approach	Age based
Cost estimation	Volumetric based upon historical average unit rates

Disposal

Lead acid batteries are recycled at end of life. Chargers are disposed of as per other electronic equipment.

Options analysis

In our DC standard we have adopted good industry practice of duplicating DC systems where possible. In the case of batteries, other than the main protection battery bank or batteries with space constraints, we undertake like-for-like replacements.

Longer-term, at N-1 battery bank sites, we may consider staggering replacements, such that one bank is replaced at a later time and off-cycle with the second bank. Given the redundancy and assuming batteries still pass test results, this approach may help smooth the expenditure profile and corresponding workload while maintaining an acceptable risk level.

Use of criticality in works planning and delivery

Criticality is not currently taken into consideration when planning battery replacements.

Coordination with other works

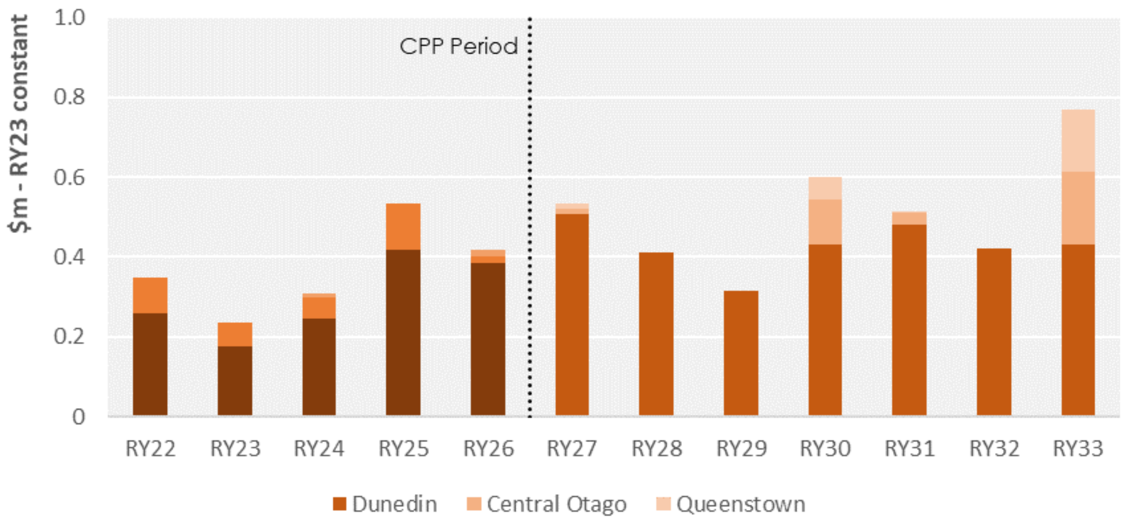
We undertake battery replacements in conjunction with zone substation renewal or protection upgrades where possible due to the synergies of combining the works. Given their importance, however, if DC systems have exceeded their expected life, they must be replaced as soon as possible rather than waiting for future project consolidation.

DC Systems Fleet Expenditure Forecast

We take a volumetric approach to DC systems renewal forecasting. We use unit rates for different voltage battery banks, chargers and distribution panels.

We have forecast battery and DC systems Capex of approximately $4.8m during the planning period. This expenditure excludes DC systems replaced under zone substation projects.

Figure 8.97: Forecast DC supplies Capex



Capex was low prior to RY20, mainly as work was bundled up or classified as zone substation renewals. However, as a large volume of batteries already meet renewal criteria, a standalone renewal programme is required. We plan to increase renewals to supplement the zone substation renewal-based DC works.

Benefits

DC systems ensure a constant power supply to other vital secondary systems equipment in the event of equipment failure. Ensuring that our DC supplies are in satisfactory health is critical to maintaining a safe and reliable network.

8.7.4. RTU Fleet

RTU Fleet Overview

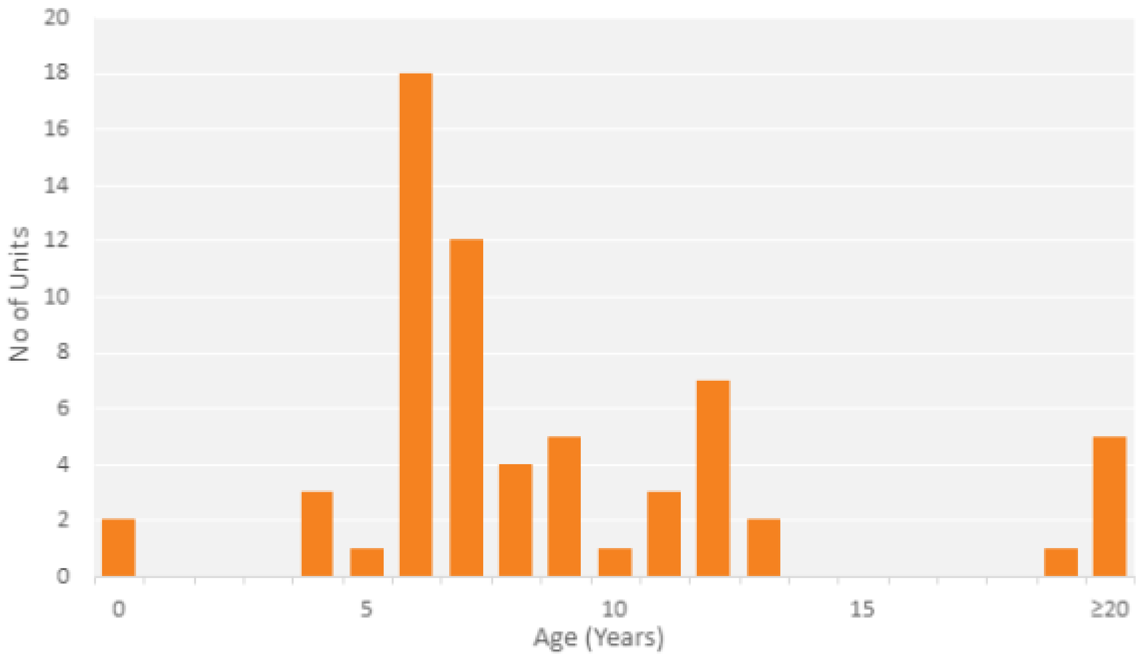
RTUs are an integral component of our SCADA and telemetry system. RTUs communicate with intelligent electronic devices (IEDs) in a zone substation. IEDs include protection relays, transducers, and human machine interface displays. The RTUs provide information to our network operation personnel and our control centre. We use various communication mediums with our RTUs that include 4G, fibre, microwave, and UHF radios to cater for the higher bandwidth and polling requirements.

RTUs are located in zone substations and also at GXPs. Our SCADA system and RTUs recently went through a major upgrade, so the fleet is generally in good condition. As such, we are now in steady-state and do not have much work planned in this portfolio over the planning period. Going forward, some RTU replacements will be undertaken as part of larger zone substation works.

Population and Age

We have 64 total RTUs across our network.

Figure 8.98: RTUs age profile



Most of our RTUs are less than 20 years old, though some have exceeded their expected life of 15 years. RTUs replaced 6-7 years ago as part of our SCADA upgrade are evident in the profile. The majority of our RTUs are modern and provide an adequate level of operational performance. We have adapted good industry practice and our devices use standard DNP3 protocol over TCP/IP communication to our SCADA master station. We refurbished a few of our older RTUs to enhance their operational performance, and also to extend their support for TCP/IP communication. We have a few legacy RTUs that are planned to be replaced or decommissioned.

Condition, Performance and Risks

Condition and performance

It is not practical to obtain condition information on RTUs, due to their electronic nature. Instead, we use age as a proxy for condition. Based on this, our RTU fleet is in generally good condition.

The key driver of expenditure for RTUs is technological obsolescence. Where manufacturers notify us that they are going to discontinue support for specific RTU hardware, we manage the risk of unplanned failures through stocking of spare parts.

The performance of our RTUs is satisfactory and we have not identified any issues. Our standard design includes dual communication paths, which means that it is rare for us to lose communication between our master station and zone substation RTUs. Some of the RTUs in the Central network region are limited, having serial communication and a fixed number of input and output contacts.

Risks

The following sets out the key risks identified in relation to our RTU fleet.

Table 8.77: RTU system risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
RTU malfunction or failure in service leads to lack of remote control or indication	Inspection and test regime. Alarms and monitoring. Age-based replacement	Safety, reliability

Design and Construct

We have standardised on one make/model of RTU for new installations or replacements. We are standardising our naming conventions and alarm strategy to drive consistency across our SCADA network.

Detailed SCADA design is outsourced to engineering design consultants with significant involvement from our secondary systems engineers. The SCADA input/output mapping is prepared during detailed design and is used as the input to programme new RTUs and also to update our SCADA master station prior to pre-commissioning activities taking place on-site.

Renew or Dispose

During the planning period, we will primarily replace RTUs as part of wider zone substation works. We also replace RTUs as they become technologically obsolete, using age (versus expected life) as a forecasting proxy for obsolescence. The table below summarises our renewals approach.

Table 8.78: Summary of RTU renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Obsolescence and age vs expected life
Forecasting approach	Age based
Cost estimation	Volumetric based on historical average unit rates

Options analysis

Alternatives to complete renewal of RTUs when they meet their expected life are limited. A firmware upgrade programme was undertaken to extend the life of older RTUs where applicable. Firmware updates are a path which can delay obsolescence in limited circumstances.

Use of criticality in works planning and delivery

RTU works that are undertaken as part of zone substation projects are inherently prioritised on a risk basis. RTU replacements outside the zone substation programme are relatively limited at present, and criticality has not yet been factored into planning of these works.

Disposal

Any RTU module that can be used as a spare is retained. Disposal requirements are minor and follow the same manner of dispose as other electromechanical or electronic devices.

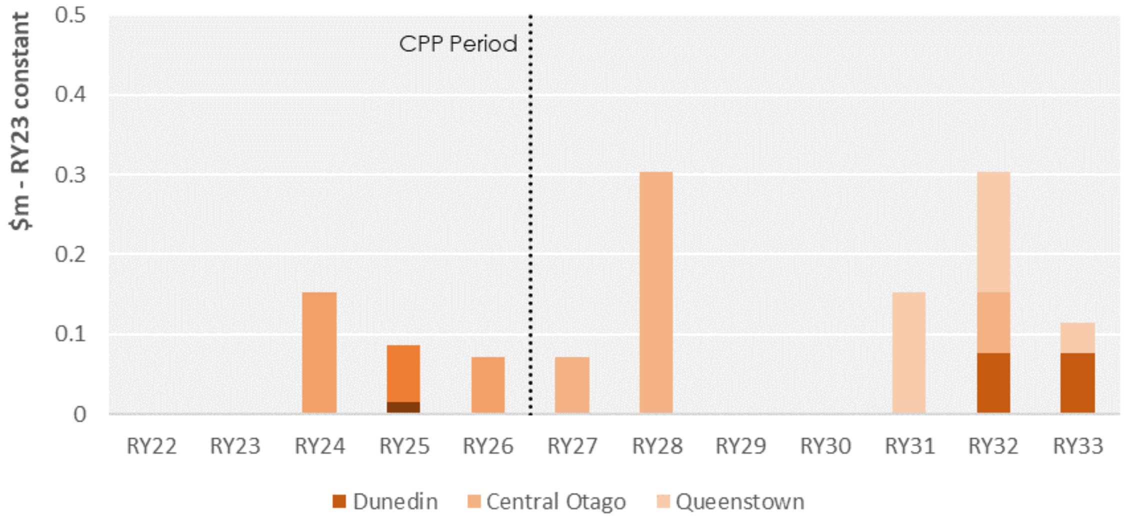
Coordination with other works

Where possible we coordinate the replacement of RTUs with other project works, such as zone substation and protection renewals, due to the synergies of combining these types of works.

RTU Fleet Expenditure Forecast

We take a volumetric approach to RTU renewal forecasting. We have forecast Capex of approximately $1.3m during the planning period. This excludes RTUs replaced under zone substation projects.

Figure 8.99: Forecast RTU Capex



We undertook a large SCADA upgrade project from RY17 to RY19. During this programme, we replaced a large portion of our RTU fleet as well as our network operations control system. Our forecast for the planning period comprises a low volume of replacements during the CPP Period, rising in later years where units reach end-of-life or obsolescence. These are in addition to units replaced as part of larger zone substation works, which are covered in the zone substations forecast.

Benefits

The key benefit of planned RTU renewals is ensuring the assets remain reliable and age-based failures and obsolescence issues are minimised.

8.7.5. Metering Fleet

Metering Fleet Overview

Our metering fleet includes check metering at GXPs and a small number of power quality units at some zone substations. The check meters are installed to provide 'check metering' of power supplied from GXPs. We have replaced older and unsupported meters at three of our GXPs, but we still have legacy check meters in the Central Otago region. Modern GXP check meters are able to communicate via a modern protocol (i.e. DNP3), and provide remote access functionality. Our meters are capable of recording additional parameters, such as peak and average MVA, and power factor.

We installed power quality meters on 11/6.6 kV incomer circuit breaker CTs at newly built zone substations and protection renewals. The output parameters from power quality meters (E.g. harmonic levels) are monitored via our SCADA system, and are configured to alarm our control room if the measured values exceed specific threshold limits. Detailed data is also available to be analysed by our planning and engineering teams. These parameters are not available from our standard specification protection relays.

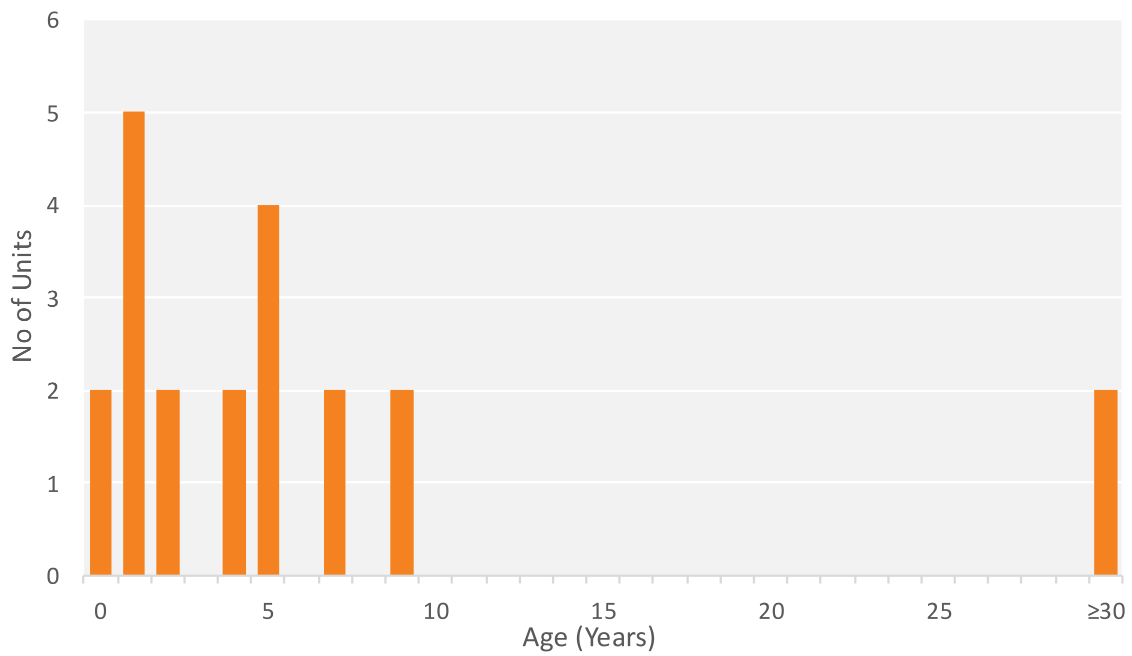
Population and Age

We have 10 check meters across our networks. All but two check meters are currently 9 years old or less; two are near end of life, one of which is to be replaced in RY24.

Our 11 power quality meters are all less than 7 years old.

The life expectancy of a modern numerical meter is 25 years.

Figure 8.100: Metering age profile



Condition, Performance and Risks

Condition and performance

We are not experiencing any condition or performance issues with our metering fleet.

Risks

The table below sets out the key risks identified in our metering fleet.

Table 8.79: Metering risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK AREA
GXP revenue metering failure	Reconciliation of data Transpower metering calibrations	Financial

Loss of load control	Load control system uses ours and Transpower's revenue metering, together with SCADA MW measurements, so has redundant inputs	Financial

Renew or Dispose

Renewal of meters is usually undertaken with other works such as GXP and protection upgrades.

Table 8.80: Summary of metering renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Age, linked to GXP substation renewals
Forecasting approach	Tailored
Cost estimation	Tailored

Disposal

Disposal requirements are minor, similar to other electromechanical or electronic devices.

Coordination with other works

Metering replacements are coordinated with GXP upgrades and protection upgrades due to the synergies of combining such work.

Metering Fleet Expenditure Forecast

No renewal expenditure is planned under this portfolio during the planning period.

9. ASSET MANAGEMENT ENABLERS

This chapter discusses the business functions and non-network assets that support our electricity network. We use the term 'asset management enablers' to describe the following:

- **asset management capability**: includes the competency and capacity of staff and the processes that support our day-to-day asset management activities
- **business support**: includes the capacity of supporting processes (E.g. human resources and finance) and the staff that directly support our day-to-day asset management activities. Facilities and motor vehicles are also included in this category
- **information communications and technology (ICT)**: sets out our approach to delivering our ICT strategy and how this function provides continuous support for the wider business.

9.1. ASSET MANAGEMENT CAPABILITY

Below we discuss our asset management capability including how improving our current capability is required if we are to achieve our asset management objectives and deliver a safe, valued service to customers. We explain the results of our latest Asset Management Maturity Assessment Tool (AMMAT) and set out our asset management improvement plans.

9.1.1. Current Asset Management Capability

As discussed in earlier chapters, several issues on our network need to be addressed through focused asset interventions. To increase our effectiveness and reduce price impacts on customers, we plan to enhance our asset management analysis capabilities. This extends to improving the way we work with our service providers to efficiently deliver our investments. As our work programmes broaden, we will need expanded work management and delivery capabilities, including continued improvements in the management of our service provider model. These improvements will support the future efficiency gains we are targeting from improved work processes and optimised investment and operational decision-making.

There are other areas where we need to increase our capability, for example, to be able to understand and respond to likely changes in the wider electricity market (such as the increasing uptake of EVs and residential PV installations as a result of decarbonisation). Gaps in our asset management capability are reflected in our most recent self-assessment of asset management maturity (AMMAT), which is discussed in the next section.

People play a central role in asset management. To effectively deliver our asset management objectives we need to make sure our people have the right capabilities. This means the people working for us, directly or through our service providers, need to have the right capabilities (including in emerging areas such as asset analytics) and be willing to learn and adapt as the electricity sector evolves. The increasing use of small-scale distributed generation, the availability of energy storage applications, and the increasing use of intelligent network devices will have far-reaching implications for the way we operate. Our current progress regarding the DER solution in

Upper Clutha (see Section 6.6) is an example of the type of innovation that improving capability will allow.

One of our key capability initiatives is developing an asset management competency framework to ensure there is a direct link between our objectives and the skills of our people. A well-performing asset management business has lines of sight that link its strategies and objectives with the roles and responsibilities of staff. Linking what staff do day-to-day to our objectives is critical if we are to deliver an efficient service to customers and effectively manage long-life assets. Some examples of asset management competency include:

- developing planning and design guidelines
- drafting technical standards
- setting out effective maintenance and renewal strategies and plans
- network analytics including fault trending and asset survivor analysis
- specifying materials and equipment standards
- retaining and communicating specialist knowledge (E.g. for SCADA, protection).

Other success factors for effective asset management organisations include staff engagement, clarity of direction and effective collaboration between different teams and functions. We aim to create a shared understanding around required capability which we can communicate to our team. Implementing this framework will be an important tool for achieving our asset management objectives.

We continue to invest to improve our asset management maturity and approach. We have made good progress, and the analysis set out in this AMP illustrates some of our advances. Our asset management analysis and supporting models were tested by the Independent Verifier during the 2020 CPP application and deemed appropriate given the existing asset management system maturity and data availability. Since 2020, we have continued to improve upon the availability and quality of the data that supports our analysis, and we have improved our ability to quantify safety risks on our network.

We are cognisant of both where we have come from in our asset management journey, and where we are headed. We see value in an Asset Management System that is aligned to ISO55001 and we recognise that achieving this will take time and continuous improvement. As we continue to use the AMMAT to understand where on our maturity journey we are, we are not losing sight of our goal to have an ISO55001 aligned Asset Management System.

As outlined in both our Development Plan and here in the AMP, we have identified targeted and priority improvement initiatives that will enable continuous improvement while prioritising the value add and still ensure that we are progressing towards our goal of having an ISO55001 aligned Asset Management System. Looking forward, we are committed to further developing our overall asset management capability to meet the internationally accepted best practice standards. The investments in capability and systems outlined in this AMP are important enablers of that goal.

Box 9.1: Asset Management Maturity Journey

We will identify and prioritise asset management improvement initiatives that enable us to achieve our business and asset management objectives, while keeping sight of our goal to have an ISO55001 aligned Asset Management System and being able to demonstrate leading practice asset management capability.

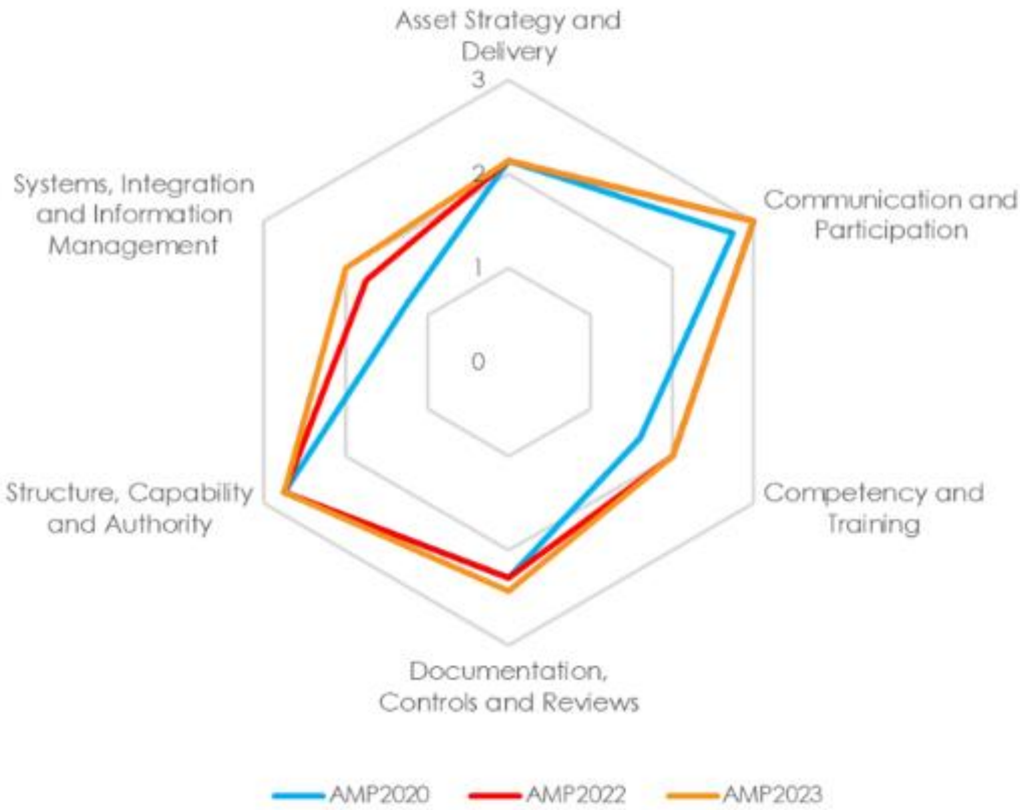
9.1.2. AMMAT Assessment

We undertake periodic reviews of our asset management maturity using the AMMAT assessment tool.

[1] This consists of a self-assessment of our maturity compared to good asset management practices. The tool is based on PAS 55:2008, which has been succeeded by ISO55001:2014.

Our assessment in 2020, was reviewed externally by AMCL against ISO 55001 as part of our evidence to support our CPP application. Subsequent assessments have, as per the Commerce Commission guidelines, been undertaken internally.

Figure 9.1: Comparison of our historical AMMAT scores



The three most recent assessments covering the AMP2020, AMP2022 and AMP2023 indicate a steady improvement.

1 As a regulated Electricity Distribution Business we are required to undertake the AMMAT self-assessment and publicly disclose the results (this is reproduced in Schedule 13 of Appendix B. Disclosure Schedules)

Table 9.1: Previous AMMAT scores

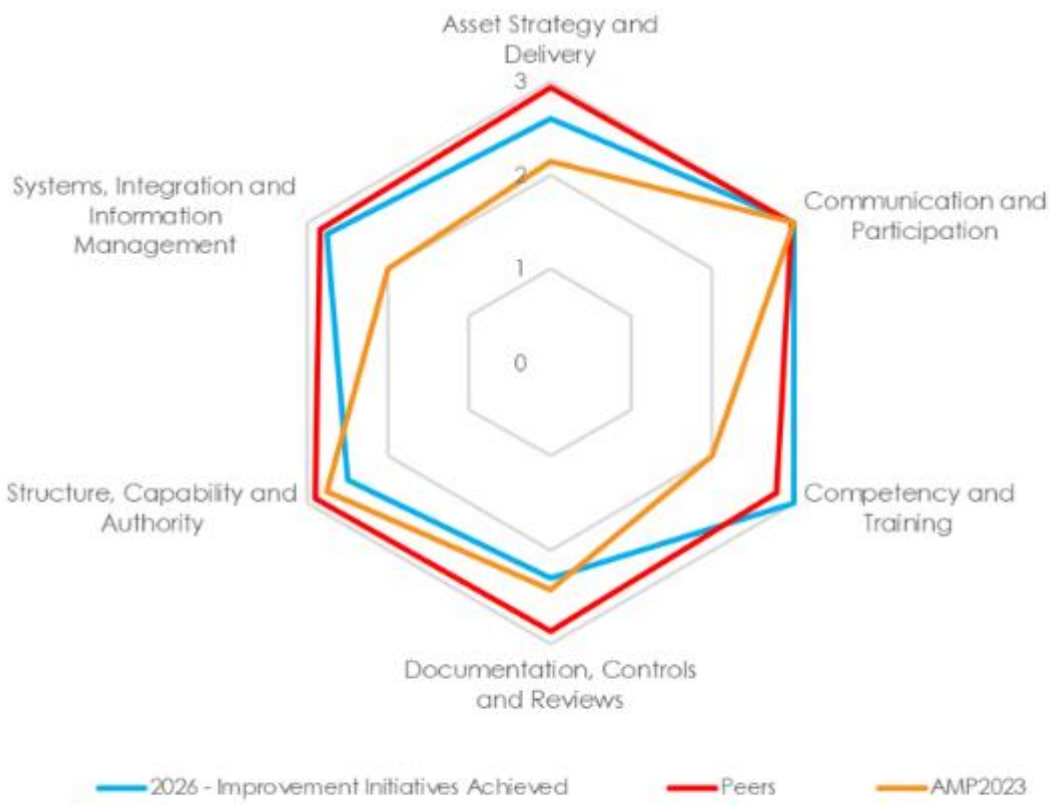
AMP YEAR	AMMAT SCORE
2020	2.13
2022	2.29
2023	2.35

AMMAT questions have been grouped and presented in six key assessment areas that generate the overall score (Table 9.1).

The results for each of the key areas is an average rating in several assessment questions. Figure 9.1 below, illustrates our asset management maturity journey from 2020-2023 in each of the key assessment areas.

Figure 9.2 below, Illustrates our AMMAT scores for 2022 in comparison to industry peers (EDBs of a similar size). We also give our assessment of what our progress, relative to each specific AMMAT question, will look like, when we have achieved all our improvement initiatives. These projects are set out in the Development Plan alongside the specific Competency and Training improvement initiatives, defined in this AMP.

Figure 9.2: Comparison of our current and target AMMAT scores against select EDB peers



We have strategically identified that Systems Integration and Information Management investment will be a priority and have subsequently detailed a plan to take us to where we believe we need to be. This is set out in our Asset Management Development Plan.

Previously, the 2022 AMMAT review enabled us to take a holistic view of our asset management practices and, in turn, check that we were taking a systems approach in identifying and prioritising improvement initiatives. The review of asset management maturity and the focus areas identified by the Commerce Commission in the CPP Determination were used as important inputs to the development of our asset management development plan.

As discussed above, there were several identified improvement opportunities that we have committed to in the short-term, specifically over the CPP Period. These improvements will enable an asset management maturity step change that we will build on to achieve our goal of having an ISO55001 aligned Asset Management System.

The 2021 AMMAT has indicated that we are progressing on our maturity journey. Areas such as health and safety, contract management and IT systems are showing improvement where it would be expected that a step to the next level could be made in time for the following AMMAT review. Aurora Energy applies the integer vale for step levels per question, this means that progress within a step is not reflected in the overall scoring.

9.1.3. Asset Management Development Plans

Our AMMAT score is a frank assessment of our current capabilities, processes and practices. Our review indicated a good understanding of the core principles of asset management, but the results fall short of the standard expected from a mature asset management system. We do not consider this sufficient and accordingly, have put in place a plan to improve our asset management capability. As part of our asset management journey, we have established an Asset Management Development Plan (AMDP) which outlines key areas of improvement.

Our overall AMDP therefore consists of two closely related sets of plans:

- An update of the initiatives included within our 2020 AMDP
- CPP Development Plan initiatives to address the focus areas raised by the Commerce Commission in the CPP reporting disclosure requirements.

The following sections of this chapter provide an overview of the CPP Development Plan initiatives and additional content to outline our broader AMDP initiatives, including Training and Competency development which is a key focus at the present time.

To ensure that these plans are effectively communicated to customers and other stakeholders, we have regular regional engagement information sessions to summarise the improvement initiatives that we will be implementing, including the key outcomes for Aurora Energy, stakeholders and consumers.

9.1.4. CPP Development Plan

As part of our CPP information disclosure requirements,[2] we have prepared a publicly available standalone Development Plan, which contains several business improvement initiatives. These initiatives are directed towards key business areas, including our asset management practices, data systems, and approaches to cost estimation. In these areas, we believe that improvements will bring genuine benefit to consumers.

The plan has been made publicly available to all customers and other interested parties.

Aurora Energy's CPP Development Plan outlines our processes to improve our performance capability, and includes the following key areas:

Asset Data Collection and Asset Data Quality

Accurate and reliable asset data is a prerequisite for effective asset management decision-making. Good quality data enables us to improve our budgeting, risk assessment and forecasting abilities. In order to ensure that we are meeting our business objectives and to optimise our future investments, Aurora Energy has an increasing need for reliable and comprehensive information. In particular, we require good quality asset condition data to support timely investment decisions relating to asset renewals.

We have identified the following improvement initiatives that will enable us to develop and improve our asset data collection and data quality practices:

- Define and document key requirements for asset data to support decision-making, including master data and condition data
- Implement the systems and processes to facilitate the collection of asset data in a timely manner
- Implement the systems required to ensure robust storage and integration of our asset data
- Improve our internal data management practices by clarifying the roles of data owners and stewards
- Implement reporting tools and enhance our reporting practices

Asset Management Practices

Asset management capability forms a key area of improvement to ensure long-term efficient care of network assets. Further asset management development is required to continually meet customers' expectations, manage network risks, and address changes in network demand and technology.

Public safety is a paramount objective for Aurora Energy, and it plays a fundamental role in our asset management decision-making. Many of our assets have an elevated safety risk in the event of failure, and many of our assets are also in close proximity to public areas.

Part of our asset management improvement involves refining our risk framework to better understand the likelihood of particular assets failing, and to identify the potential outcomes of that failure. Our key initiatives include further development of our modelling for understanding asset

[2] See Electricity Distribution Information Disclosure (Aurora Energy Limited) Amendment Determination 2021 available here.

health and criticality. Refined health modelling will help us to better identify the likelihood of asset failure and to implement appropriate preventive measures.

Criticality helps us to understand the potential consequences of asset failure so that we might introduce appropriate controls. In regard to consequence of failures, we have already established Safety Criticality Zones in our GIS. We have used these safety zones to guide our pole replacement programme where we prioritised replacements in areas of high traffic or public density such as main roads, schools and tertiary institutions.

During the CPP Period, we will develop failures modes, effects and criticality analysis (FMECA) across all asset fleets to support a standardised approach to managing asset risks across different areas, including Safety, Reliability, Environment and High Impact Low Probability (HILP) events.

As part of our CPP disclosure requirements we have produced a publicly available Safety Delivery Plan, which demonstrates how we have used our improved safety risk assessment to report and track our safety risk reduction over the CPP Period. We aim to refine our risk management framework further so that we can optimise our investment in renewals to replace assets with the greatest impact upon safety. Further, we will continue to develop alternative methods of control such as design standards and maintenance programmes as cost-effective alternatives to replacement.

We also plan to introduce fleet strategies/plans which define our decision-making processes for each asset type based on their risk profiles. The individual fleet strategies will be guided by an overall strategic asset management plan (SAMP), which will govern asset management activity to align with our overall business objectives.

Cost Estimation Practices

Improved cost estimation practices can help the business to identify and deliver upon cost-effective solutions for network improvement. The plan will cover both capital and operational expenditure projects and programmes.

Areas of development include the following initiatives:

- **Enhanced unit rate estimation**: we will enhance our processes for the capture of as-built costs. Also, we will put in place an annual unit rate review process to ensure that our budgets and forecasts are informed by the most up-to-date market rates.
- **Enhanced project cost estimation tool**: for zone substation growth and renewal projects, and other large projects we will enhance our cost estimation tool.
- **Improvements to our network Opex models**: we will improve the data that informs our 'Base-Step-Trend' forecasting models.
- **Review the vegetation forecasting model**: improved vegetation status data and input costs for vegetation-related works (E.g. customer liaison and second-cut costs) will enable us to develop a more comprehensive model for forecasting vegetation management costs.

Quality Assurance Processes

The purpose of Aurora Energy's quality assurance processes is to ensure that capital expenditure and operational expenditure programmes are effectively delivered to meet applicable industry standards. Appropriate quality assurance processes and resources must be in place to ensure that the escalated level of planned works during the CPP Period are delivered to all applicable standards.

In our approach to improving quality assurance, we plan to implement two separate focus areas: works management capability and construction works quality assurance. Within works management, we are introducing robust frameworks to identify and monitor quality risks during key project stages. We have rolled out continuous staff development in alignment with PRINCE2 methodology to drive efficient delivery of capital and maintenance projects. We also aim to roll out improvements to processes and systems to enable better reporting, risk monitoring, and visualisation of project health, leading to more successful delivery.

We aim to improve our works quality assurance by introducing internal standards and quality assurance metrics that guide the review of constructed works. We also plan to extend the scope of our quality assurance review process to include inspection and maintenance tasks, connection services, and zone substation works. We will review the required resourcing and internal development to meet the requirements of our upgraded quality assurance process.

Voltage Quality Development Plan

This plan outlines how we plan to monitor and upgrade our network to ensure that customers receive a consistent and predictable supply. While power quality disturbances can occur for various reasons, some beyond our control, we take responsibility for ensuring that their frequency and impact are reduced where possible. We have implemented a plan to help us transition from a reactive stage where we respond to issues when notified, to a predictive approach where we can identify and understand issues before they are experienced by consumers.

To aid our improvement journey, we have defined four broad maturity stages:

1. **Reacting**: our ability to model and predict PQ problems is still developing; issues are often resolved following receipt of enquiries from customers.
2. **Monitoring**: we can observe PQ problems by using monitoring devices such as distribution transformer monitors and/or by analysing smart meter data. Network modelling together with improved monitoring, will help us to resolve PQ issues before they materially impact customers, therefore improving the level of service they receive.
3. **Anticipating**: PQ problems are anticipated to avoid material issues on the network. Actions may include network upgrades, installation of capacitor banks or harmonic filters to avoid PQ problems before they start to affect network performance. Active monitoring will help us to better anticipate upcoming PQ concerns.
4. **Predicting**: PQ problems can be predicted over the longer-term and can help to avoid potential issues from increased DER on our network. Network policies, strategies, standards, and processes will be updated to avoid PQ problems before they start to appear on the network. Future scenarios will be tested in high voltage and low voltage models to forecast the PQ concerns.

From a customer service perspective, we have introduced changes to our complaints process to reduce response times and provide real-time data to our customer services teams.

Customer Charter and Compensation Arrangement Development Plan

Aurora Energy published its current customer charter and compensation arrangement in 2017. We are committed to reviewing the existing charter, seeking public feedback on any changes, and bettering our promotion and communication of our customer commitments. Additionally, we are focused on developing a customer-centric internal culture within Aurora Energy.

We aim to launch our revised customer charter and compensation arrangement by April 2023 after a period of internal review and public consultation. We will then promote and celebrate our commitment to customer experience by ensuring that our customer charter is available at Aurora Energy events and public forums, by executing a public campaign to promote awareness of the charter, and by providing annual reporting around our performance in relation to the charter. Finally, we will conduct a further review of our customer charter and compensation arrangement in RY26 to ensure that it is fit for purpose and widely understood by our customers.

Management of Planned Interruptions

Aurora Energy's elevated network investment during the CPP Period requires additional planned outages in order to renew and maintain network assets. As a result, our customers will experience more interruptions to their supply than has historically been the norm. Our internal research, and feedback received during the Commission's CPP consultation, indicates that customers can become frustrated not only by the frequency of outages, but also their timing. Outages during particular seasons and particular times of day can significantly affect their impact on customers. As part of our improvement initiatives, we will look to increase the use of bundled works to carry out multiple tasks during a single outage, therefore limiting the number of outages required to perform our work programmes.

Additionally, we have improved our communications with consumers regarding network outages and transitioned to a new service provider to provide after-hours customer service. We are currently working on further improvements to our website to improve the way customers can interact with both planned and unplanned outage information. We also communicate all planned outages via social media and in local newspapers.

9.1.5. Additional AMDP Improvement Areas

The improvement plans outlined in Section 9.1.4 have been developed as part of our programme to deliver upon our CPP commitments. The improvement initiatives identified in this section capture the additional actions we are taking to improve our broader asset management practices and complete our Asset Management Development Plan. We note that there is a degree of overlap in this section with our CPP Development Plan, but we consider this overlap helps to provide context and alignment between our AMDP workstreams.

Continuous improvement around the areas outlined below will be critical if we are to operate successfully in a changing environment. To keep up with our customers' evolving requirements and expectations, and to maintain good practice asset management, many of our practices need to improve. We have identified several areas of improvement to achieve our goal of good industry practice.

The shortcomings that we want to address as part of an asset management improvement journey are consolidated in our existing AMDP and are summarised below.

- strategy and planning: we plan to develop fleet strategy documents and plans for each of our asset fleets, to support optimisation of asset interventions across the asset lifecycle. This will be guided by a standalone asset management strategy
- reliability management: we are developing an overarching network performance strategy to improve our overall reliability performance with a greater focus on underperforming areas (further detail is set out in Appendix C)
- risk and review: we are establishing effective feedback and review mechanisms to provide assurance that objectives are being achieved, this will support continual improvement of our activities
- asset management decision-making: we continue to make improvements to the tools and analysis approaches used to support our asset intervention decisions.

These improvements are directed towards aspects of our asset management systems, processes and culture where improvement is most needed but also where the benefits are likely to be material. In many cases, the initiatives implement recommendations from independent reviews, and reflect knowledge and experience of approaches adopted in leading distribution companies.

Ultimately, our objective in undertaking these initiatives is to ensure customers receive a safe and reliable service that they value, while minimising the whole-of-life cost of managing our assets. We note that, while many of the initiatives will underpin our current CPP investment plans, others will take a number of years to fully implement.

We have started to develop the relevant documentation, systems and processes to support these efforts. An asset management engagement plan will lift the profile of our asset management system across the company. It will set out how we communicate with stakeholders that inform our strategies, objectives and plans. Our competency framework to strengthen capability across the functions of our asset management system. An asset information strategy will be used to improve our asset management information practices.

Summary of Asset Management Improvement Initiatives

We have developed a set of focused initiatives to achieve the required improvements in capability. These initiatives are reflected in our planned expenditure on asset management capability through our SONS portfolio (refer to Chapter 10). Implementing these initiatives will drive an uplift in SONS expenditure relative to historical levels but is an essential component of delivering our AMP investment plans and ensuring we have sufficient capability and capacity to meet the needs of our stakeholders. Table 9.2 presents the main improvement initiatives, by topic area and progress to date.

Table 9.2: Asset management improvement initiatives

AREA	INITIATIVE	SUMMARY	PROGRESS
Competency and training	Various	We will identify and address the necessary steps to achieve ISO 55001 certification.	Gap analysis to ISO 55001 has been carried out by AMCL.
Competency and training	Competency and Training Plan	Identifying competencies required to deliver our improvements to asset management maturity. Enact training and recruitment to address gaps.	Defining our competency requirements under the Institute of Asset Management Competencies Framework.
Reliability management plan	Various	This will focus on ensuring we can effectively meet our future quality standards and deliver a reliable service to customers (see Appendix C).	Reliability forecasting model created.
Reliability management plan	Post-event analysis	Implement post event analysis 'protocol' and lessons learned framework to drive improvements.	ICAM investigations expanded to include network only events.
Strategy and planning	Fleet management plans	Develop a suite of dedicated fleet management plans that will set out planned improvements in asset information, condition assessments, forecasting tools, cost estimation, and solution options.	Fleet management plans in development.
Risk and review	Improve review and feedback processes	Establish effective feedback and review mechanisms to provide assurance that objectives are being achieved and to support continual improvement.	Ongoing
Risk and review	Review practices	Establish regular self-reviews that will assess the continuing suitability of our asset management policy, strategy, objectives, plans and delivery.	Ongoing
Risk management	Business continuity planning	Undertake a strategic review of contingency preparedness and emergency response capability.	Review complete and tested under several scenarios.
AM decision-making	Asset criticality	Extend the application of our pole and overhead lines asset criticality framework to a wider group of assets. Criticality may incorporate a number of dimensions depending on relevance to the asset type.	Ongoing
AM decision-making	Network planning	Our demand forecasting methodology and load flow models will need to be updated and expanded to model future load scenarios. These innovations are important if we are to pursue 'least-regret' investments.	We have developed a new fit-for-purpose demand forecasting model.
AM decision-making	Improve lifecycle analysis	Improve approaches used for decision-making across the stages of an asset's life through new analysis and tools.	Ongoing
AM decision-making	Asset health	Refine asset health models for major asset types, including introducing multi-factor models for the higher value or higher risk asset types.	As part of our CPP application we have developed a refined set of asset health models,

AREA	INITIATIVE	SUMMARY	PROGRESS
			including multi-factor models for power transformers.
AM decision-making	Asset failure risk	Formalise and expand the use of asset health measures and integrate this with our evolving criticality framework to capture asset-failure risk.	Ongoing
Works delivery	Process development	Develop and implement improved works management capability for capital projects delivery, maintenance, and vegetation management, including necessary information system improvements.	Sentient works management system commissioned to monitor and report on contracts and projects.
Works delivery	Multi-party process development	Develop and implement a new contracts management capability to manage multiple service providers and increased tendering of works.	Field Services Agreements completed and operational with three contractors.
Works delivery	Improve delivery and planning interfaces	Review the internal communications required to deliver the works plan, including information handovers from planning to delivery, and the feedback required from delivery.	Ongoing
Asset knowledge	Asset information strategy	Develop and implement an asset data quality strategy that will ensure our asset managers and operations staff are provided with comprehensive and accurate asset and network performance data.	Ongoing

9.1.6. Competency and Training Development Plan

Aurora Energy recognises the importance of ensuring we have competency growth plans in place to match our development plans and our asset management outlook. As such, we have introduced our own Competency and Training Development Plan which will support the business in meeting the improvements set out in Section 9.1.3, as well as developing a target area in our AMMAT assessment.

During 2018, the Asset Management and Planning team was reshaped to strengthen our capability to forecast, plan and scope our network related capital and operational expenditure. The current asset management team roles are well defined; however, it is acknowledged that, at a time when we have plans to improve our asset management maturity, we have a need to better understand the full suite of competencies required to deliver. We also require the ability to identify in a timely manner areas in which we need to grow.

The retention and attraction of skills that are critical to our business, as well as the investment and development of our people, are a key strategic focus for our business. Aurora Energy has initiated a People and Culture Plan, which is currently being advanced.

Key Initiatives/Planned Improvements

The following stages form the basis of our Competency and Training Plan:

1. Define the competencies required to deliver our AMP and Development Plans

Using the Institute of Asset Management Competencies Framework – one which aligns with the principles and requirements of both BSI PAS-55:2008 and ISO 55000 suite of Standards – we will define a complete set of competencies required to ensure the success of our AMP and associated development initiatives, and we will assess the need for adjustment based on specific needs and priorities of our business. We will assemble a small working group to customise the framework.

2. Develop a competency matrix for all staff

We will develop a competency matrix to assess the level of competency against the set of competencies defined above. Employees will self-assess in the first instance, and identify improvement opportunities for themselves. The aim of the competency matrix will be to assess if, as a business, we have the capacity and depth in our team to deliver both now and into the future. This includes both core business-as-usual tasks and the more exceptional improvement projects. This oversight will be used to inform resource planning, including succession planning, development plans, recruitment and outsourcing.

3. Resource Planning Tool

To understand the capacity element of the challenge, we will set up a resource planning tool. This will enable the team to plan and programme work, and provide visibility to managers who can adjust priorities on a basis of need. This will give us enhanced visibility regarding how we are progressing in our transition from being largely reactive into a more preventive form of asset management. It will also enable us to better understand where our business can best use external resources to support the delivery of our AMP and Development Plan.

4. Use the Competency Matrix to inform training and recruitment plans

Once we have established a coherent view around the suite of competencies needed within the business against those that we already have, we will be well positioned to identify how we address those gaps. We will use this information to inform a plan on closing any identified competency and capacity gaps or constraints.

Expected Benefits

The initiatives outlined above will realise a number of benefits for Aurora Energy and our customers, including:

- Transparency on competency gaps and the ability to prioritise training
- The ability to tailor recruitment to meet our business needs
- Enhanced performance, and confidence that we can deliver upon our plans
- Clearly defined training needs that are informed by business needs
- Maturing our Asset Management System in line with industry standards.

Milestones

We expect this programme to be completed by the end of RY26.

Table 9.3: Competency and training milestones

KEY ACTIVITIES / MILESTONES	TIMEFRAME FOR COMPLETION
Define the competencies required to deliver our AMP and Development Plans	RY23-24
Develop a competency matrix for all staff	RY23-24
Develop a Resource Planning Tool	RY24-25
Use the competency matrix to inform training and recruitment plans	RY25-26

9.2. BUSINESS SUPPORT

Business support includes the business functions that support our network distribution operations. This includes corporate functions, such as finance and human resources, that directly support our day-to-day asset management activities. It also includes ICT-related Opex.

9.2.1. Business Functions

Business support Opex covers expenditure on direct and indirect staffing costs and external support, as well as advice we use to complement our internal resource. The key functions supported by this expenditure include:

- health and safety: providing leadership and coordination of safety policies and approaches in support of our operational teams, including contractors
- finance: includes managing our working capital and debt, purchasing and transaction functions, financial analysis, corporate reporting, and advice
- commercial and regulatory: supports compliance with statutory requirements, including regulatory and environmental obligations. This function is responsible for contract management for large customers
- human resources: responsible for attracting and retaining capable and effective people, managing skills and competency development, and fostering a positive working environment. This will be increasingly important as we grow our capability and competency levels over the planning period
- external relations: manages our day-to-day customer interactions, stakeholder engagement, consultation, and general communications
- insurance: consists of a suite of general insurances appropriate for a business of our type and size, with the main policies providing coverage for material damage and business interruption, various forms of liability, and policies to cover vehicles and corporate travel
- corporate governance: costs associated with corporate governance and supporting the activities of our Board, including fees and associated costs. This ensures that our business is governed by a team of knowledgeable and experienced directors
- compliance activities: there are a range of fees we incur in order to meet legal and regulatory requirements, including audit fees related to statutory and regulatory audits.

These functions all support our electricity asset management activities. Opex related to these activities is classified as non-network Opex. Below we discuss some of the key drivers for this expenditure over the planning period:

- **staff numbers**: this directly impacts business support costs. As our activity levels grow, we will require increasing numbers of capable staff. Salary and indirect costs (E.g. consumables) are driven by overall staffing levels
- **external labour market**: staff salaries and other benefits are influenced by the general employment market. Demand for skilled staff, particularly regionally, will impact the level of competitive salaries
- **business support requirements**: as our network work programme expands, work volumes for areas of support functions will increase
- **regulatory and compliance requirements**: we incur a range of costs to meet statutory obligations. This includes regulatory obligations under the Commerce Act (for example, auditing Information Disclosure statements and price-path compliance statements) and auditing of financial statements
- **ICT capability requirements**: our staff numbers will increase as we deliver increased work volumes. As a result, the number of people using our ICT systems will increase. Licence agreements and costs for third-party support and hardware are impacted by headcount.

Our business support Opex forecast is set out in Chapter 10.

9.2.2. ICT Opex

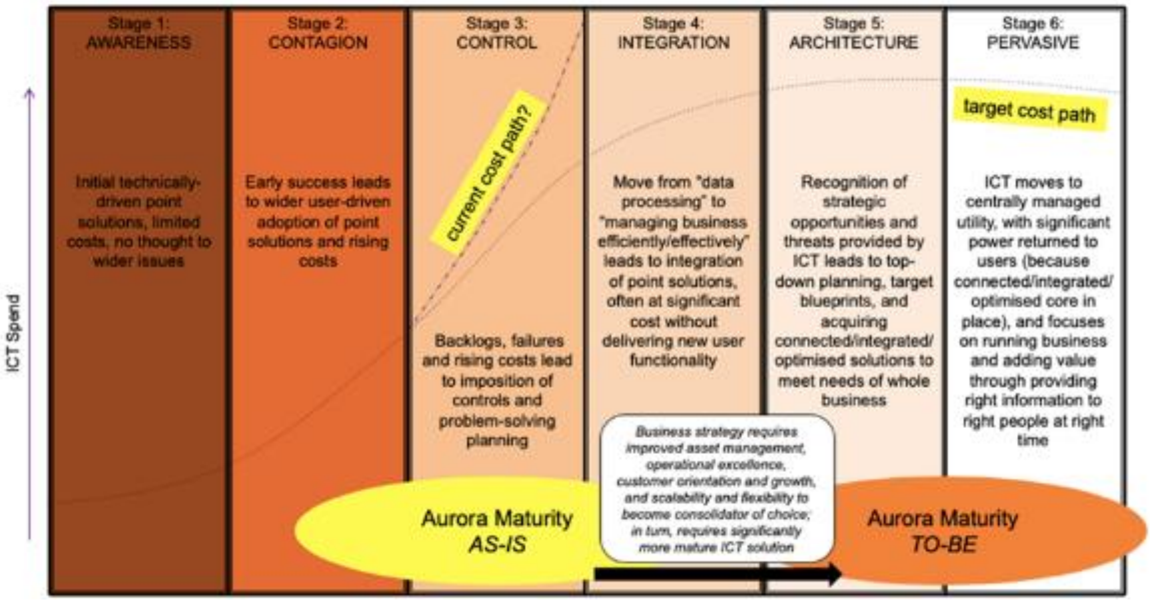
ICT-related Opex is included in business support for Information Disclosure purposes (note our ICT Capex is included in the non-network Capex forecast).

ICT-related Opex includes expenditure related to software licensing, as well as ongoing support such as bug fixes and service packs. It also includes internet, network, and data communications, customer contact technology and the hosting, server and storage, backup and disaster recovery infrastructure, on which our business applications run. Our systems engineers and third-party supplier agreements with appropriate service levels support all business-critical 24/7 and real-time systems.

A major change during this AMP period will be the transition to standardised and cloud-provisioned ICT services, which will allow us to remove local customisations and so manage the cost and complexity of maintaining ICT service components so that they can be supported by vendors on standard commercial terms, over time. In time this will result in a shift between our ICT costs being predominantly Capex to Opex. Once the transition is complete, we expect to provide more and better ICT services to the business at no greater total cost than with the current on-premise solutions.

The diagram shows how the cost of our legacy ICT environment would have escalated without the introduction of cloud services to bring about lower costs and increased ICT maturity.

Figure 9.3: Current ICT maturity assessment[3]



The current model is our enterprise systems are supported by the ICT Operations team with supplier agreements in place for more complex support and subject matter expertise. The need for an in-house service model will decrease as more cloud services are introduced.

All costs are actively managed. Historically, most solutions were purchased to run on site, but they are increasingly moving to subscription-based costs, as discussed in the next section.

We outsource our data centre requirements and core communications network. This service includes resolving incidents that affect our operations. The data centres are tier 3 or tier 2.5 and are managed as such, including independent compliance audit and review.

Our service management ensures that proper procedures and controls are in place for the delivery, distribution and tracking of ICT services, along with monthly service level monitoring and reporting against agreed levels. We record and track all ICT incidents and fix minor or high-priority incidents within agreed service levels. Incidents that require significant analysis or investment are prioritised into the annual capital programme.

9.3. INFORMATION, COMMUNICATIONS AND TECHNOLOGY

This section sets out our approach to delivering our ICT strategy. It explains our current and planned ICT capabilities and how we manage our ICT assets. ICT Capex is classified as non-network Capex (along with assets such as facilities and motor vehicles owned by the business).

9.3.1. Overview

Our ICT team delivers the infrastructure, servers, communications technologies, applications, and data that support our distribution-network operations. The group's responsibilities include:

[3] Adapted from Nolan, Norton and Co.

- ensuring required technology, communications and information is provided and operated efficiently to assist in meeting customer requirements for reliable and safe energy delivery
- storing and providing current and accurate information about the extent and performance of the network and assets
- providing cyber security capability to safeguard the network and its assets
- monitoring technology, customer, and industry trends, assessing their effectiveness, and determining the optimum time to implement those best suited to meet business needs
- ensuring technology and information plans provide effective direction to network performance and asset management planning and delivery.

To date, our focus has been on establishing working systems to support our day-to-day asset and information management activities. As we embed these systems, we turn our focus to additional capability and lifecycle management of our systems.

Increasingly, and also reflecting the rapid rate of change in the technology industry, ICT solutions are being sought and provided as cloud services. Current ICT infrastructure services are already provided this way. Over the next five years we will seek to purchase an increasing portion of required applications and capabilities in the cloud and likely move from private to public cloud hosting. Where efficient, this will effectively replace Capex with Opex but at similar or lower total expenditure over a the medium-term. This may have an impact on our actual Capex and Opex expenditures in the latter years of this plan. The rationale for moving to the cloud where possible includes:

- increasing our evergreen footprint (where upgrades are factored in as they are available)
- increasing the opportunity to take advantage of new technologies and services
- decreasing the upgrade overhead and consequent business impact
- increasing the standardisation of services provided to business and customers.

To help plan our ICT requirements we have identified the following five business service categories.

Table 9.4: Business service categories

BUSINESS SERVICE	DESCRIPTION
Asset Management	Support the creation, management and operation of assets and asset management. Support the forecasting and planning of distribution asset maintenance and our data collection systems.
Operational Technology	Includes SCADA and associated systems to support the core distribution services, and the management of substations through the provision of real-time and time-series information.
Customer and Commercial	Systems and technology used to support customer care and management, billing, regulatory compliance and commercial activities.
Corporate	Systems used to support our corporate operations through human resource, finance, risk, audit and compliance, legal and property services.
Enterprise Technology and Infrastructure	Support ICT services and infrastructure (servers, operating systems, data centres, storage, backup), identity and access management, telecommunications, network, security, end-user device, and business continuity and disaster recovery capability.

ICT solutions change frequently, as an increasingly large number of devices and processes depend on digital technologies and communication. Most of our capitalised ICT assets have a depreciation life of less than five years, reflecting the rapid rate of innovation and change in the technology industry.

9.3.2. ICT Governance

All ICT development starts with a business need. These needs are assessed, and our response guided by our executive team. This ensures that ICT has a whole of business overview and undertakes ICT-related governance for all initiatives. Initiatives are informed by technology and information principles which encompass business, information, data and technical architecture, as shown below.

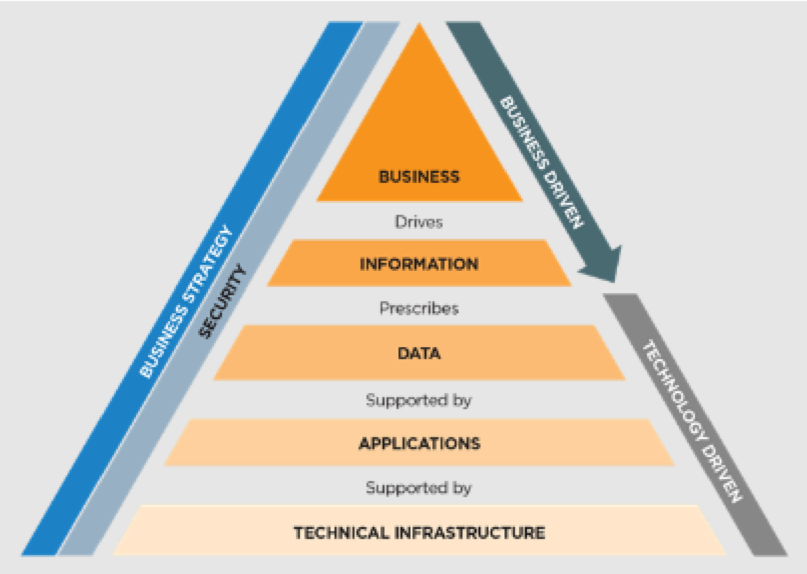
The following principles help govern our overall technology environment. Though these principles are not new to us, they will increasingly drive our selection, implementation and operation of technologies.

Box 9.2: Technology and Information Principles

The following principles govern our technology environment

- decisions related to architecture should provide the maximum benefit to the enterprise and not a particular organisation unit within the enterprise
- development of data, application, and technology architectures should consider the use of existing systems first
- we have a managed/architected technology environment (data, applications, services, integration, ICT, Operational Technology, communications, security, structure / organisation)
- data is an asset and must be treated as such. This includes planning for it, creating it, and safeguarding, trusting, maintaining and retiring/disposing of it
- we complete our programmes of change, especially those involving technology, over reasonable and finite timeframes
- we use third-party hosted, service-based solutions where possible. There is no need for us to 'reinvent the wheel' and we can re-engineer business processes to fit
- where no suitable hosted solutions exist, we will buy solutions (E.g. software) supported by third parties. We will avoid building and supporting solutions ourselves, where possible
- a technology solution is not required for every issue. We will not modify or customise technology or technology solutions to meet 100% of requirements and requests
- we acquire and implement solutions and services where integration is pre-built by third parties wherever possible, and which is already configured (or is easily configurable) and readily provides data for reporting, analysis and presentation. Where no pre-built integration exists, we will use a standard integration framework when connecting our applications and services
- new technologies will be required from time-to-time whether sought by users or through identified business or customer need. All new technology is reviewed against these principles
- introduction / implementation of technology will include its effective roll-out to users. This comprises communication and user training and measuring user satisfaction with the business outcome.

Figure 9.4: Enterprise architecture framework[4]



9.3.3. ICT Strategy and Planning

ICT strategy and planning over the AMP planning period is undertaken over three horizons.

- Horizon 1: covering the current period up to 2024
- Horizon 2: covering the years 2025 to 2026
- Horizon 3: covering a period from 2027 onwards

The tables below set out the summary objectives for each of the five technology portfolios across each horizon. Given the rapid changing nature of ICT solutions, Horizon 3 only includes our current investment plans and is subject to change.

All ICT investment is informed by the enterprise technology and information principles and governed as set out in Box 9.2.

Table 9.5: Horizon 1 investment focus (RY22 to RY24)

BUSINESS SERVICE	INVESTMENT FOCUS
Asset Management	– Ongoing implementation of our new asset management software solution to consolidate data through systems integration, and to support capital and operations work planning and delivery. – Complete the development of an automated process to create and refresh our network power flow model. Further enhancements to our asset inspection applications to better inform asset condition data and asset management decision-making.
Operational Technology	– Upgrading the capability of the Advanced Distribution Management and Outage Management Systems to fully supported versions allowing improved cyber security and external support. Improved management, customer communication and reporting of planned and unplanned outages on the network. – Review the Digital Mobile Radio operational voice network lease.

4 This is a variant of a typical enterprise architecture framework.

BUSINESS SERVICE	INVESTMENT FOCUS
Customer and Commercial	– Maintaining billing systems, planning increased customer care and service capability.
Corporate	– Continued support of existing systems while improving operational efficiency. Data preparation and support for the development of business information dashboards.
Enterprise Technology and Infrastructure	– Implementation of a business system integration platform to enable systems to support 'end to end' business processes and ensuring one source of data. – Completion of separating Aurora Energy infrastructure and services from Delta. – Optimising our communications network by improving redundancy and ensuring a higher level of resilience.

Table 9.6: Horizon 2 investment focus (RY25 to RY26)

BUSINESS SERVICE	INVESTMENT FOCUS
Asset Management	– Extending our asset management software solution to embed or integrate with advanced analytics capability to support condition-based risk assessment and use of near real-time asset health indicators. – Continuing integration with other core systems and embedding and supporting the development of new capability such low voltage network modelling incorporating smart meter data and other third-party information.
Operational Technology	– Extending distribution management capability further into the LV network. – Implementation of real-time distribution power flow into our ADMS – Increasing capability for management of Flexibility Traders and large-scale distributed energy resources. Improving customer case management and customer services.
Customer and Commercial	– Improving customer case management and customer services.
Corporate	– Reviewing core financial systems and employee management and payroll systems.
Enterprise Technology and Infrastructure	– Standardising our communications network.

Table 9.7: Horizon 3 investment focus (RY27 onwards)

BUSINESS SERVICE	INVESTMENT FOCUS
Asset Management	– Adding/improving capability to support external data sets. – Increasing process work automation. – Potentially undertaking a lifecycle replacement of one or more parts of systems used – GIS, Asset Management, analytics toolsets. Adding/improving capability to support external data sets.
Operational Technology	– Potentially moving parts of these technologies to cloud services. This may drive a major lifecycle replacement.
Customer and Commercial	– Increasing distributed systems capability. – Improving operational efficiency.
Corporate	– Enhancing new financial tools.
Enterprise Technology and Infrastructure	– Exploring opportunities for sensors, machine learning and use of artificial intelligence to drive enhanced analytics.

ICT Assets

Historically we have maintained our ICT systems to achieve business outcomes, investing in the ICT assets as necessary to support them and replacing only at end-of-life. Changes in business needs and an increasingly rapid rate of technological change have driven the need for a more responsive ICT approach. For example, increased investment in our electricity network is driving an increased demand for data, field-based applications, and more efficient back-office transactions. We are also seeing increasing demands from safety and network operational requirements.

Cloud, agile and digitised platforms, applications, infrastructure and services will represent an increasing part of the ICT asset portfolio over the next five years as we work to meet our customers' needs, add value to our business, improve our operating model and optimise our technology portfolio.

We monitor all ICT systems continuously for performance and capacity, and report our overall performance monthly. Key performance measurements for our major systems including availability, service outages (number and duration) and service level achievement are tracked and monitored.

ICT Portfolios Initiatives

The portfolio initiatives for each business service have been determined by assessing the gap between our current capability and the anticipated future needs of our business. Our technology and information principles regarding procurement approach help us manage investment and ongoing costs by subscribing to third-party hosted services where possible, buying third-party supported solutions where not, and avoiding developing solutions uniquely for ourselves. Our cost estimates for future investment are based on historical spend on similar initiatives (where available), market intelligence and vendor advice.

Over time, we expect the market to make more numerous and attractive subscription services available – including for geographic information systems, work and asset management services, and real-time operational technology tools such as SCADA, distribution management and outage management systems. We prefer to utilise these options if they prove efficient – effectively replacing Capex with Opex – but at similar or lower Totex over a 5 to 10-year period. This may have an impact on our actual Capex and Opex expenditures in the later years of this plan.

The following sub-sections discuss the portfolios initiatives expected to be required for each business service.

Asset Management

Asset management services relate to capabilities that support our core activities including asset inspections, work planning, job issuance, job management and recording, as well long-term asset management strategy.

Substantial ICT investment is required in asset management service areas, reflecting the need to commission new tools for work and job management, and to improve the collection of, and quality and accuracy of, asset data. This is needed to assist in lifting capability in risk and condition assessment and improving our asset management maturity.

Between RY22 and RY26 – covering Horizons 1 and 2 – we will focus on implementing and utilising the full capability of our new asset management system software. We will scope, select and implement new work, job and works management tools to improve the efficiency of our field work and the quality of the data we maintain about our assets. This will improve our ability to plan how and when to maintain and replace assets in order to efficiently meet the evolving needs of customers.

Asset Management System Software (AMSS)

This new system will provide us with an underlying and consolidated view of all asset data within the business. Our AMS project has been run across several phases; phase 1a included releasing a live version of the software in October 2022 which includes a snapshot of information relating to over 500,000 assets. Phase 1b is on track to be complete in early 2023 and takes in additional data attributes and asset condition data across all asset fleets, including location information and parent/child relationships.

Operational Technology

Operational technologies are the real-time tools that we use to run our network – SCADA, and distribution and outage management systems. These systems are critical to the safe and reliable operation of the network and must achieve exceptionally high reliability.

We have carried out extensive work on this portfolio over the last five years for the HV network. Over the next 2-3 years, we will begin to extend this capability to the LV network and increase mobile capability. A significant upgrade of our core supervisory control SCADA tool and underlying infrastructure was completed in 2022, and further enhancements to outage management planning are planned for the 2023 period. Although cloud-provisioned SCADA is not yet commercially available, it is possible that this may be an efficient implementation option for us – this would allow us to transition away from expensive and disruptive upgrades to smaller, more frequent updates that would occur automatically.

Outage Management System (OMS)

We are in the process of completing an outage management system due to be complete in early 2023. The OMS enables us to manage and communicate all outage incidents on our network, and provides the ability to manage outage incidents more efficiently and to provide up-to-date information to our customers by feeding outage data directly to our website and call centre.

Customers and Commercial

Our customer and commercial portfolio includes billing, case management and regulatory compliance services. We plan to commission new case management capability in parallel with exploiting the ability of our new operational technology platforms to offer improved notifications to our customers around outages and likely restoration times.

Corporate

Our corporate services cover all non-network activities including finance, human resources (HR), legal and property.

However, there is a need for intervention with respect to the financial management system within the planning period because of an expected obsolescence/cessation of product support in 2027. The final decision about the most appropriate intervention will depend on whether transitioning to a subscription service (with lower Capex and higher ongoing Opex) is efficient and practical, compared with capital investment.

Enterprise Technology and Infrastructure Requirements

This covers the enabling technology and generic technology frameworks and platforms that allow us to provide digital access to our business services, integrate standalone data sources and analyse information, as well as support the processing, storage and exchange of digital information around the company.

Investments include completion of the overhaul of our voice and digital communications to support operational technologies. Many of the services provided in this portfolio are delivered through cloud services, with the result that Capex is relatively low. Investments in these business services are included in our non-network asset Capex and in business support Opex.

Appendix E provides further detail on our ICT assets and how these are managed.

Customer Benefits

Ultimately the objective of our ICT work is to improve service standards and lower costs for customers, in particular, we expect the current ICT workplan to enable the following benefits:

- improved productivity of asset planning and operational teams
- deferral of asset spend
- improved customer service – especially communications around outages
- improved productivity of our customer facing team
- self-service access to timely and relevant information regarding planned maintenance
- integration of DERs like solar panels and batteries at least cost
- energy sustainability reporting.

9.4. OTHER NON-NETWORK ASSETS

In addition to our ICT assets, we own or lease a range of other non-network assets that are used to support our day-to-day asset management activities.

9.4.1. Facilities

We own or lease a number of facilities including office buildings and storage sites in Dunedin, Christchurch and Central Otago. Our facilities management programme aims to ensure that our offices and stores are safe and secure for our employees and contractors, are functional and fit for purpose, support improved productivity and efficiency, and are cost-effective to procure and operate. They must also be sized to support future staff growth and materials storage requirements.

The table below summarises the location of our offices and storage sites and their ownership arrangements. The facilities are strategically located throughout our network footprint. This has many advantages, including having employees with local knowledge close to customers and service providers. The new Christchurch office enables us to collaborate with industry counterparts and assists with our recruitment and retention strategies

Table 9.8: Facilities assets

REGION	BUILDING LOCATION		
Dunedin	Halsey Street	Leased	Main office and storage
	Fryatt Street	Leased	Control room
Central Otago	Ellis Street (Alexandra)	Owned	Storage, part leased to third party
	Barry Avenue (Cromwell)	Owned	Storage
	McNulty Road (Cromwell)	Leased	Main office and control room
	Success Street (Alexandra)	Leased	Storage
Christchurch	Sir Gil Simpson Drive	Leased	Christchurch office

Our network operations team has continued to provide an essential service by managing our network 24/7. Due to the potential impacts of COVID-19, our control rooms have been isolated from other staff to minimise any spread of COVID-19. To ensure that this team is able to work with minimal disruption in future, we have leased an office space for our Dunedin control room.

Technology Assets

The office facilities we operate are fitted out with workstations to accommodate our employees. The standard setup of a workstation includes a desk, chair, storage, laptop and mobile phones. Our offices also host meeting spaces and relevant office equipment required to operate effectively, such as printers, storage and meeting room technology. These assets include:

- desktop hardware
- laptop hardware
- monitors
- video conferencing equipment
- other peripherals (scanners, digital cameras).

The key driver of expenditure on these assets is the number of employees, which determines the volumes of desktop computers / laptops and related peripherals required to service their ICT needs.

9.4.2. Motor Vehicles

We have a fully maintained fleet of 38 vehicles that are leased over a range of terms. We lease all of our vehicles, apart from one or two speciality vehicles and six trailers, which cannot be leased cost-effectively.

Our fleet includes vehicles that fit defined criteria, including that vehicles must have a five-star ANCAP safety rating, low emissions and be fit for purpose i.e. all-wheel-drive and with suitable ground clearance. Our approach to managing our vehicles fleet is documented in a company standard[5] that sets out how we procure and permit the utilisation of company motor vehicles.

We periodically undertake lease versus ownership analysis for our vehicle fleet, including comparing the relative cost-effectiveness of fully maintained or company-maintained leases. Lease costs for selected vehicle types were sought from a range of leading fleet providers in New Zealand, with selection of a provider based on best fit, considering pricing, servicing and location of support.

[5] AE-SG03-S Company Motor Vehicles Standard.

10. SUMMARY OF EXPENDITURE FORECASTS

This chapter sets out a summary of our expenditure forecasts over the AMP planning period. It provides further commentary and context for our forecasts, including key assumptions. It should be read in conjunction with the relevant expenditure chapter.

It discusses our cost estimation methodology and how this has been used to develop our forecasts.

10.1. INTRODUCTION

The expenditure forecast categories presented here align with our internal expenditure categories and those used in our CPP proposal. The information presented here summarises the investments discussed in earlier chapters.

Our AMP includes our current best forecasts based on our asset management strategies and using available network information. In subsequent updates, we expect the profiles, particularly later in the period, to be further refined as we collect improved asset information and enhance our modelling approaches.

Box 10.1: Note on our expenditure charts

The charts in this chapter show our forecast for RY23 (01 April 2022 to 31 March 2023) as published in our 2022 AMP, plus our forecasts for the remainder of the planning period. Our CPP Period RY22-26 is indicated by the darker bars.

Expenditure is presented according to our internal categories. It is also provided in Information Disclosure categories in Schedules 11a and 11b in Appendix B.

Unless stated otherwise, all dollars are denominated in constant price terms using RY23 New Zealand dollars.

Below we summarise our Capex and Opex forecasts for the AMP planning period, together with cross-references to chapters where more detailed information is provided.

10.1.1. Total Capex

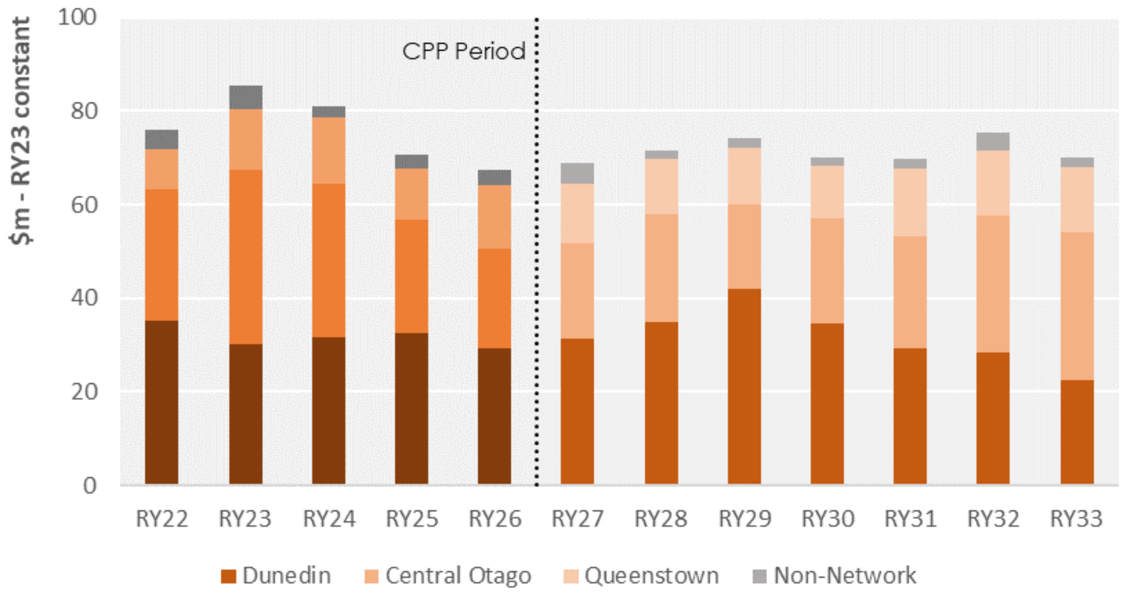
Total Capex includes the following three expenditure categories:

- **network development Capex:** investments related to growth and security, reliability-focused projects, and new connections to our network, and are discussed in Chapter 6
- **asset lifecycle management Capex:** used to renew (replace or refurbish) existing assets on our networks. We also relocate assets of behalf of third parties. These investments are discussed in Chapter 8
- **non-network Capex:** includes expenditure on IT assets and facilities. These investments are discussed in Chapter 9.

The majority of Capex during the AMP planning period lies within the asset lifecycle management category. The uplift in Capex during the CPP Period relates almost entirely to network expenditure.

There is an initial increase in non-network Capex arising from our investments in systems and capability to better enable delivery of our work programmes. Over time this will reduce as we migrate to service-based IT solutions.

Figure 10.1: Forecast total Capex (net of contributions)



Considering the various pressures outlined in this AMP, our current Capex forecast tracks above the CPP Determination 2020 for the period RY22-RY26 as approved by the Board. It continues to represent a significant increase on historical levels beyond the CPP Period. This level of expenditure is needed due to our ageing asset base and is important to ensure a long-term safe and reliable supply for customers. We intend to focus on a number of key fleets and initiatives over the next decade.

The main drivers for the overall spend profile include:

- prioritisation of asset replacement for fleets with high safety impact such as support structures and OH conductor
- ongoing pole replacement programme, declining slightly after the CPP Period until the end of the AMP planning period
- replacement of poor condition assets in other fleets that present safety risks, particularly ring main units and indoor switchgear
- addressing the accelerated increase in network demand by initiating new and bringing some existing network growth projects forward
- supporting strong growth in new connections to our network
- implementing new ICT systems, and supporting processes, in the early part of the CPP Period, including an Asset Management System Software
- replacement of obsolete protection relays, particularly electromechanical. We will replace most of them, with modern numerical types during the planning period.

Our forecast Capex for the AMP planning period remains relatively high as we address work deferred as part of the CPP Determination, and we meet strong growth associated with electrification to support decarbonisation. This is offset to some extent to take account of efficiency gains we expect to make as we increase our asset management maturity and improve our underlying processes and systems. This is discussed in Section 10.1.3.

10.1.2. Total Opex

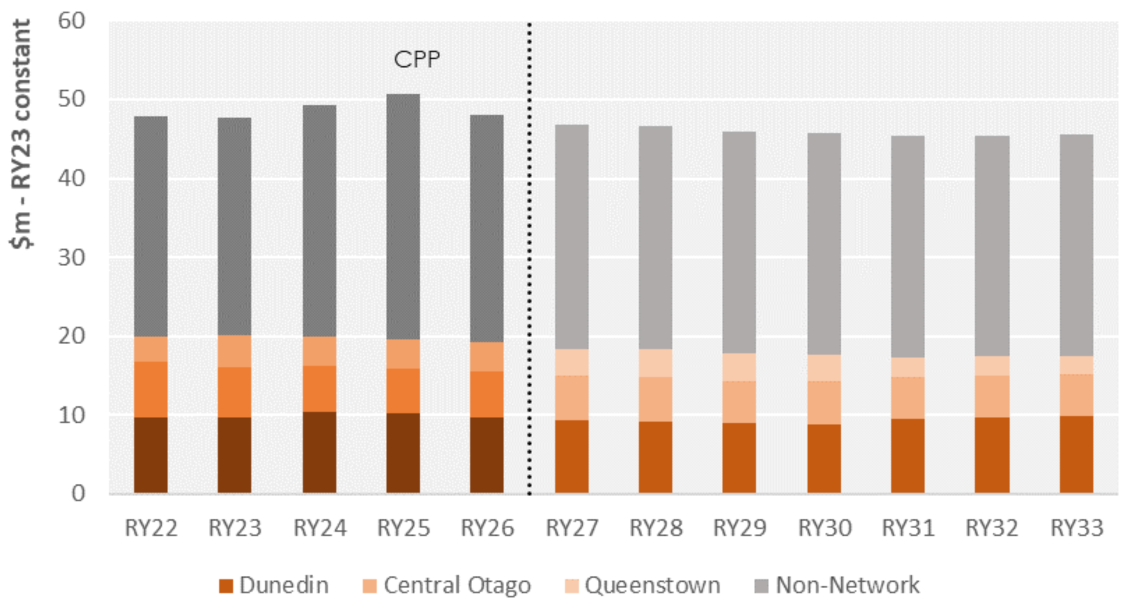
Our total Opex forecast is relatively stable but increasing slightly during the early part of the planning period. Our expenditure profile flattens (in constant dollar terms) following the CPP Period as we refine our asset management approaches and modelling and begin to see improved levels of efficiency across our network activities.

Total Opex includes the following:

- **maintenance**: relates to activities to inspect and repair our assets. Improvements in our inspection regimes will allow us to optimise our asset lifecycle investments (see Chapter 7)
- **vegetation management**: relates to the management of vegetation in close proximity to our assets (see Chapter 7)
- **non-network Opex**: includes our SONS and Business Support expenditure, and relates to activities that support the day-to-day asset management of our assets (see Chapter 9).

Our total Opex increases relative to recent historical levels. This increase is mainly driven by increased maintenance activities and initiatives to improve our asset management capability. The increases are in areas where we believe they will provide material medium- and long-term benefits to network performance and reduced (real) costs to customers. Increased capability will allow us to optimise total Capex required over the period. We expect productivity and efficiency improvements to offset upward cost pressures in the latter part of the AMP period.

Figure 10.2: Forecast total Opex



Following an uplift during the CPP Period, our overall Opex is expected to flatten over the AMP planning period. In the coming 2-3 years, we expect to incur costs related to our continuing improvement journey and to help develop a further CPP application. Our Opex targets an improvement in asset inspections, reduction of our defect backlog, better vegetation management, and investments to improve our future productivity and efficiency. The main drivers for our overall Opex spend profile include:

- adopting improved inspection and assessment techniques so we can better understand asset condition and network risks
- completing deferred maintenance on assets to ensure they operate as intended, and continue to maintain them at appropriate intervals thereafter
- bringing our vegetation management practices up to good industry practice
- pursuing improvements in our asset management practices, to achieve industry good practice and to realise efficiencies. This requires us to bolster our capabilities and skills
- increasing our project delivery capacity to ensure we effectively deliver required investments
- using additional business support resources to finalise our transition to a standalone business and support the delivery of improvements to our IT systems and capabilities.

Our forecast Opex for the AMP planning period has been reduced in later years to take account of efficiency gains we expect to make as we increase our asset management maturity and improve our underlying processes and systems. This is discussed in Section 10.1.3.

10.1.3. Future Efficiencies

We are committed to further developing our asset management capability to meet internationally accepted good practice. In addition, we continue to make improvements in business support activities, including improved IT capability. These improvements will support future efficiency gains from improved work coordination, increased delivery productivity, and better operational decision-making. We aim to work hard to drive efficiency into our design, procurement, and delivery to make sure that we maximise the value we provide to customers.

We note that COVID-19 and the Russian global events have created supply shortages and upward pressure on the cost of equipment procurement. COVID-19 has also impacted the availability of staff, creating work delivery and cost pressure for our contractors. We also note very recent commodity/equipment price increases from our suppliers, and these have not been incorporated into the RY22 constant dollar assumptions in this AMP.

Given the uncertainty associated with these factors they are not adequately addressed in our cost escalation processes, and we have therefore removed the forecast Capex efficiencies included in our CPP Application and the resulting Determination. However, this does not mean that we will not achieve underlying efficiency gains in our Capex programme, it simply means we are of the view that these will be offset by other global factors not foreseen in our CPP Application.

Opex efficiencies continue to be included in our forecasts as we consider these to be less impacted by global events. Achieving our forecast Opex efficiencies is ambitious but achievable if we are not materially impacted by external factors.

Box 10.2: Our approach to future efficiency adjustments

We plan to make material capability and capacity improvements over the AMP planning period. We expect that efficiencies will result from these planned business improvements. Reflecting this, we have applied specific efficiency adjustment factors to relevant portfolios. The efficiencies are based on a composite of potential efficiency sources that are discussed below:

- **contractor productivity**: reflecting increased competitive tension and scale efficiencies that could be realised by the uplift in work, noting that these are offset by rising procurement costs associated with recent and ongoing global events
- **works coordination**: medium-term as we move from addressing spot risks to fleet-wide risks
- **improved decision-making**: driven by improved asset management, including expanded network analytics using better data; investment optimisation; and condition-based risk management
- **improving capability**: improvements as we mature our systems and processes, aligned with our ISO 55001 initiative. ICT investments (E.g. EAMS) will enhance renewals through improved information and simplify the as-building process, leading to some SONS efficiencies.

Reflecting the above, we have applied efficiency targets to our forecasts across the relevant expenditure portfolios. The Opex efficiencies are essentially 'baked in' to our forecasts which are aligned to the CPP Determination, including the associated efficiency assumptions.

10.1.4. Approach to Escalation

There are a number of inputs and assumptions underpinning our forecasts for the planning period. These include our approach to escalating our forecasts to nominal dollars, (note Section 10.4 discusses inputs and assumptions relating to our underlying forecasting approaches).

Over the AMP period we expect to face different input price pressures to those captured by a general measure of inflation like CPI.

[1] We expect that the input price increases we face over the planning period will be greater than CPI due to factors such as the need to attract and retain skilled staff and the global demand for commodities used in our assets.

To reflect this, we have conducted analysis of the available inflationary trends and applied different cost escalators to our constant (RY23) price expenditure forecasts from those specified in CPP Determination 2020. Our new escalators have been developed using forecasts of input price indices that reflect the various costs that we face, including material, labour and overhead components sourced from an economic consultancy firm. These are applied using weighting factors for cost categories, such as conductor that are impacted by the inputs. These were applied to our constant (RY23) forecasts to produce the nominal dollar forecasts for the Information Disclosure schedules in Appendix B.

The consultancy advice we received included commentary outlining a higher level of uncertainty in the escalation forecasts due to recent and ongoing global events. We also note that the very recent price increases from our suppliers are not incorporated into the RY23 constant dollar assumptions.

[1] All groups Consumer Price Index.

10.2. CAPEX FORECAST

As discussed in Chapter 5, we have adopted a lifecycle-based approach to asset management. We reflect these stages in the categories we use to explain our investments in network assets.[2] In addition, we use non-network Capex as a category.

Overall Capex includes the following three main categories:

- **network development Capex**: relates to capital investments that increase the capacity, functionality, or size of our network. These are described in Chapter 6
- **lifecycle management Capex**: is expenditure used to replace or refurbish existing assets on our networks. Our approach for identifying these investments is set out in Chapter 8. This also includes the cost of relocating our assets to facilitate developments by third parties. Our approach to asset relocations is discussed in Chapter 5
- **non-network Capex**: is our investment in those assets that support and enable our asset management activities. The drivers for these investments are discussed in Chapter 9.

10.2.1. Network Development Capex

We use the term 'network development' to describe capital investments that increase the capacity, functionality, or size of our network.

Network development includes the following types of investment:

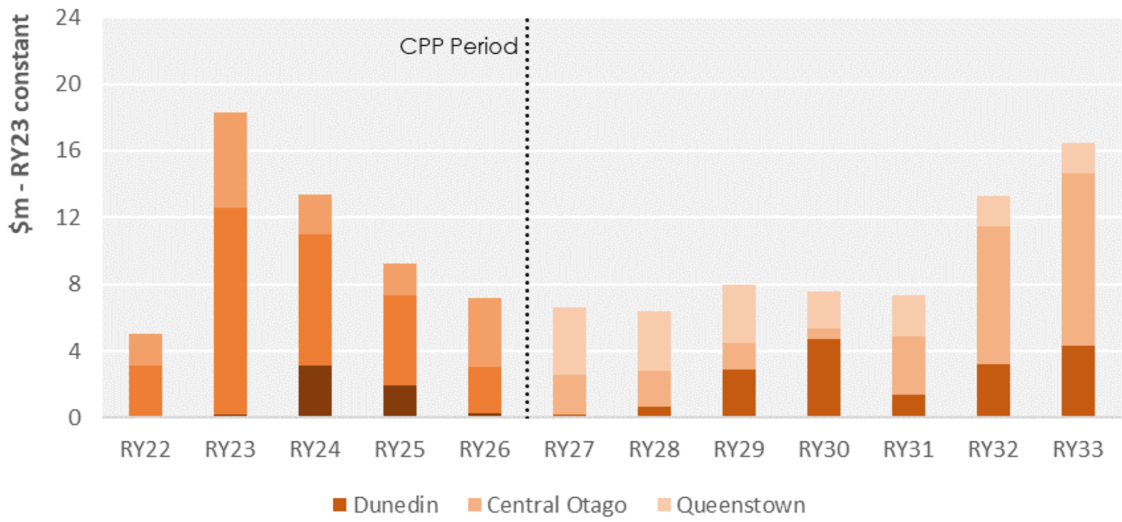
- **growth and security Capex**: is used for investments that increase the capacity of our networks in response to increasing demand or to meet our security of supply guidelines
- **reliability-driven**: these investments aim to minimise the impact of an event, for example by automatically reducing the number of customers impacted by it
- **consumer connections**: reflects the investments we make to facilitate the connection of new customers to our network. Expenditure presented here is net of capital contributions
- **network evolution**: these are investments to transform our network to meet future needs with the advent of DERs.

Growth and Security Capex

Growth and security investments ensure the capacity of our network is adequate to meet the peak demand of our customers, with appropriate supply security, now and into the future. Growth and security Capex includes two expenditure portfolios: major projects, and distribution and LV reinforcements.

[2] Information Disclosure specifies six Capex categories. We use these categories, with some adjustments to reflect our internal approaches. Our expenditure, aligned with Information Disclosure categories, is set out in Appendix B.

Figure 10.3: Growth and security Capex



We plan to undertake a number of major growth and security Capex projects over the planning period. The majority of expenditure falls within the major projects Capex category, comprising works such as new substation builds, transformer upgrades and sub-transmission capacity upgrades.

In addition to our major projects, distribution and LV reinforcement spend amounts to approximately $3.5m per annum on average with a relatively consistent profile over the period. We originally anticipated reduction in this expenditure in RY22 and RY23 due to the impact on demand from COVID- 19. However, we are experiencing significant growth in demand in Central Otago and a steady growth in Dunedin.

The overall profile is relatively lumpy, with expenditure spikes reflecting overlapping spend on two or more large projects. The large step up into RY23 and RY24 is due to the Arrowtown 33 kV ring upgrade and Smith St to Willowbank 33 kV intertie projects. The overall forecast increase is also due to the combined cost of four projects – New Riverbank substation, Lindis Crossing substation new transformer, Frankton substation transformer upgrade, and the North Street to Ward Street 33 kV intertie.

Reliability (Network Upgrade)[3]

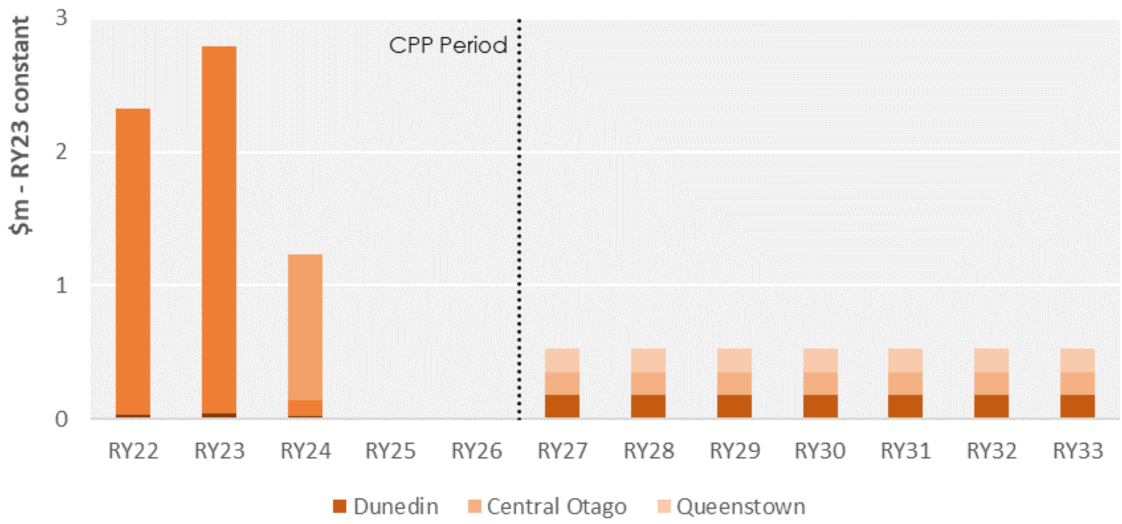
Reliability-driven investments aim to maintain or improve reliability of service at appropriate levels, reflecting the preferences of customers.

Capex in this category relates to installing new reclosers on problematic and unreliable feeders, installing fault passage indicators, and other assets and methods to improve reliability. For RY23, we made provisions for the installation of back-up generators at Camp Hill (Hāwea) and Omakau zone substations, which are supplied by single sub-transmission circuit. We also plan to undertake the following initiatives starting later in the AMP planning period:

[3] We include these investments within the Reliability, Safety and Environment (RSE) category under Information Disclosure.

- installing strategically placed auto-reclosers on the network to reduce the number of consumers affected by planned/unplanned interruptions
- Installing remote controlled switches on feeders to reduce the average time that consumers are affected by unplanned interruptions
- installing fault passage indicators to reduce the time taken to find faults, reducing the average time consumers are affected by unplanned interruptions.

Figure 10.4: Reliability Capex



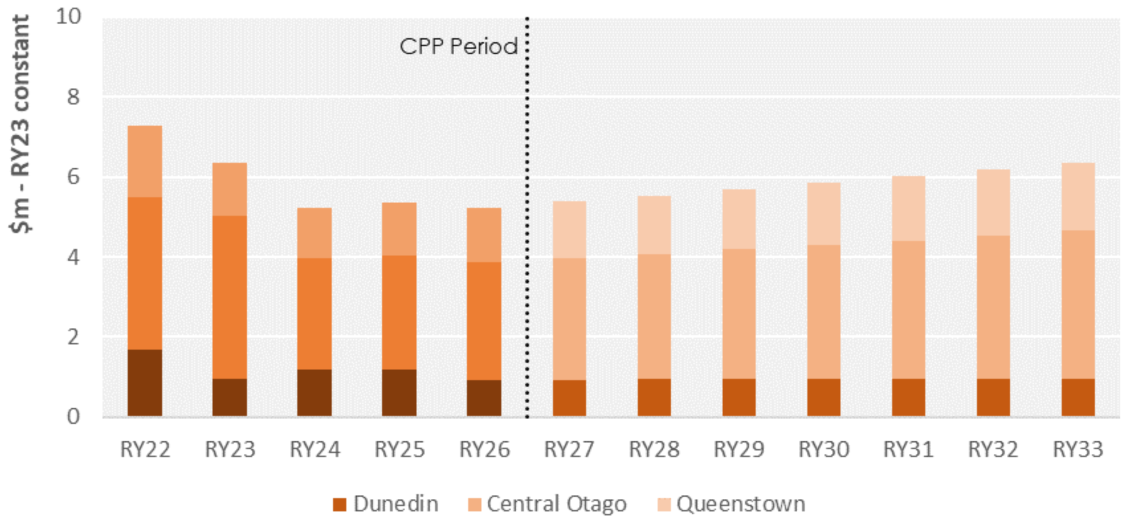
Consumer Connection Capex

Consumer connection Capex is externally driven with short lead times, which compromises our ability to accurately forecast medium-term requirements. We forecast connection numbers, customer connection Capex and capital contributions by trending historical data and including known large developments.

Historically, we have seen significant year-on-year variation in both customer connection Capex and capital contributions. We forecast future investment levels based on the average of recent years. This forecast is then adjusted where we know of significant new connections that are larger than typical, and that are unlikely to be accommodated within the average.

We have retained this broad approach for the AMP planning period with the exception of the next 2-3 years. As has been stated earlier we have experienced a higher-than-average trend in new connection growth contrary to what was expected to be the impact of the COVID-19 pandemic. We will be making a 'capacity event' application to the Commerce Commission for the forecast expenditure in this portfolio that exceeds the provision in the CPP Determination.

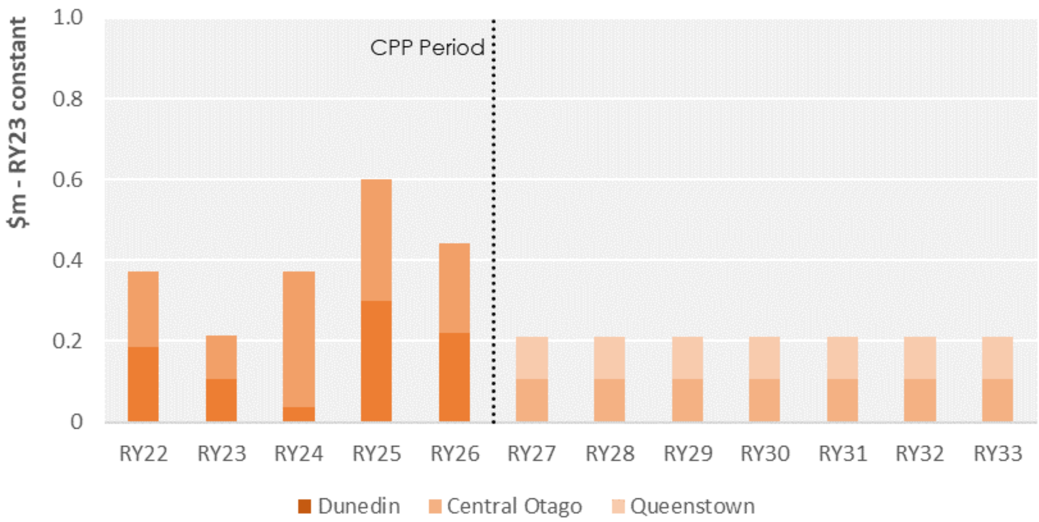
Figure 10.5: Consumer connections Capex (net of capital contributions)



Network Evolution

Our network evolution investments prepares us for the wider, future adoption of DERs as part of the NZ decarbonisation goal. Over the AMP period, we expect to see more EVs, photovoltaic installations and battery storage systems installed on our network.

Figure 10.6: Network evolution Capex



The network evolution expenditure includes an initial set of investments for the installation of LV monitoring systems to give greater visibility of our LV networks. In recent years, we have not invested in these assets due to a focus on network renewal. We will continue to deploy LV monitoring to support our ability to monitor and predict power quality performance and emerging trends. Our SONS Opex forecast makes provision for the acquisition of smart meter data to increase LV visibility and to further improve our ability to anticipate and predict future power quality issues/performance.

10.2.2. Lifecycle Management Capex

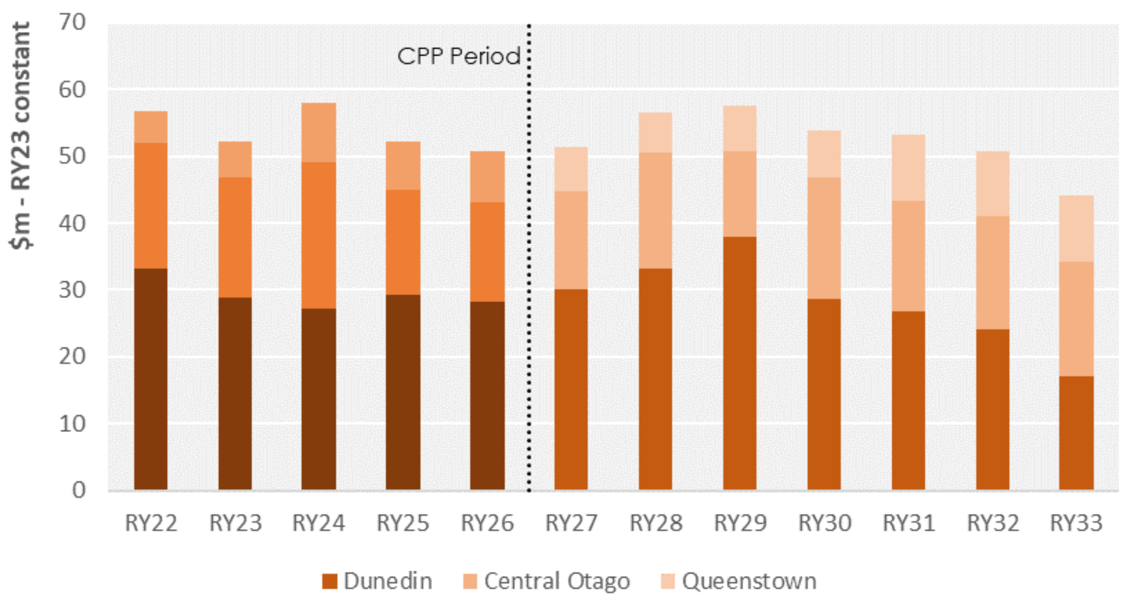
The lifecycle management Capex category includes seven expenditure portfolios that are used for budgeting purposes. These seven portfolios, in turn, include 28 asset fleets. Our day-to-day asset management is at the fleet level. Fleets are also the basis for medium-term forecasts. We also include asset relocation investments in this category.

The particular drivers for our investment in renewing our asset fleets over the planning period have been discussed in Chapter 8. The primary driver for optimisation and adjustment of our asset renewal investment is reduction of our critical risk to public health and safety from ageing assets. We have also begun to implement reliability risk for our assets that don't present a direct public safety risk, such as Zone Substation fleets.

We have been addressing backlogs in required renewals since our 2018 AMP, and will continue to do so over the CPP Period. Reducing the volumes of these 'at-risk' assets is a key driver for our CPP investment plans. To achieve this when a large part of our asset population is approaching end-of-life requires increased investment.

The combined forecast expenditure in our seven renewal portfolios is shown below.

Figure 10.7: Total renewal Capex

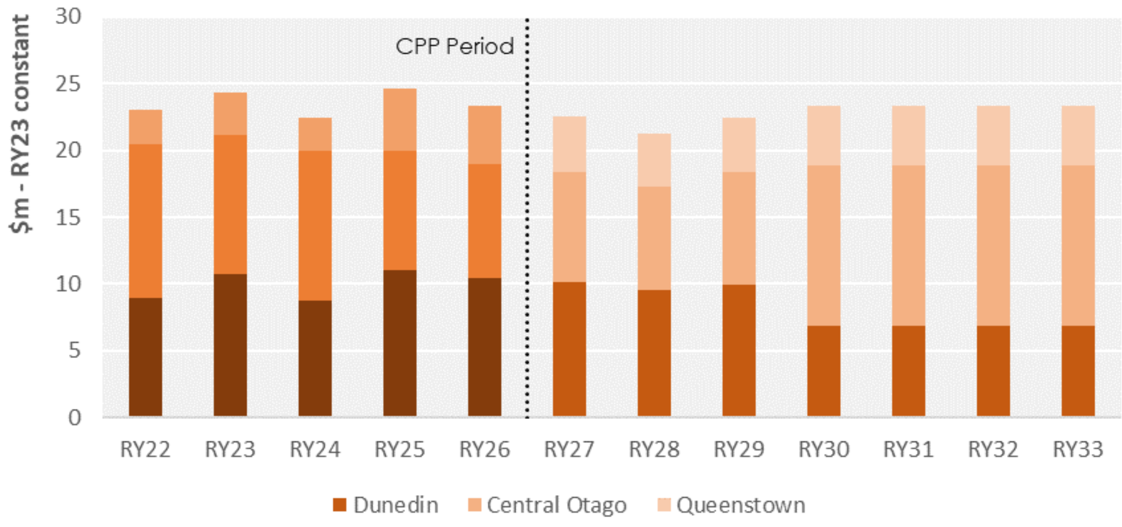


The following sections set out our planned renewals Capex for each of the seven portfolios. Appendix B sets out this expenditure using Information Disclosure categories.

Support Structures

Chapter 8 explained that our support structures portfolio includes our pole and crossarm fleets.

Figure 10.8: Support structures renewal Capex



Our planned renewals Capex for support structures over the next two years focuses on our ongoing work to replace our worst condition poles, and the expansion of a separate programme to replace poor condition crossarms. Our pole renewal programme reflects our expectations of pole asset condition results as we continue with our mechanical and traditional inspection tests. Previously, we were planning during the CPP Period to gradually reduce the level of pole investment. However, we now forecast stabilised levels of replacement rates beyond RY24 to ensure sustainable management of this critical asset fleet.

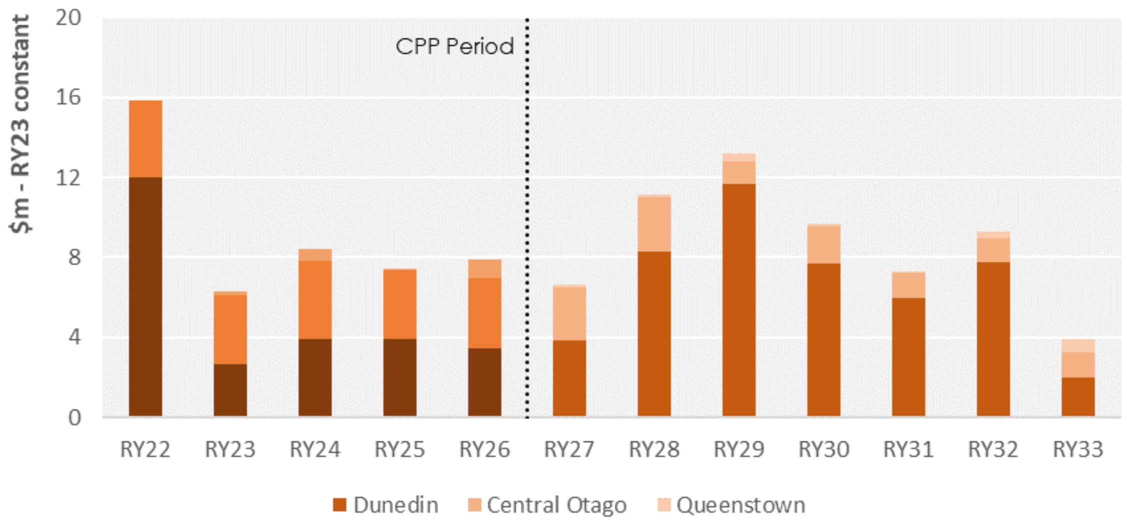
Our proactive crossarm replacement programme will continue to ramp up as we compile improved data on this fleet. A sizable crossarm replacement programme will continue through to the end of the planning period.

Overhead Conductor

The chart below shows our forecast investment over the planning period in our three conductor fleets: sub-transmission; distribution; and LV.

As discussed in Chapter 8, we have a relatively large volume of aged conductor. To address this, we began a renewal programme in RY20 to progressively replace distribution and LV conductor deemed to pose the greatest safety risk. Based on age and location of our various types of conductor, we have estimated likely replacement volumes over the planning period.

Figure 10.9: Overhead conductor renewal Capex

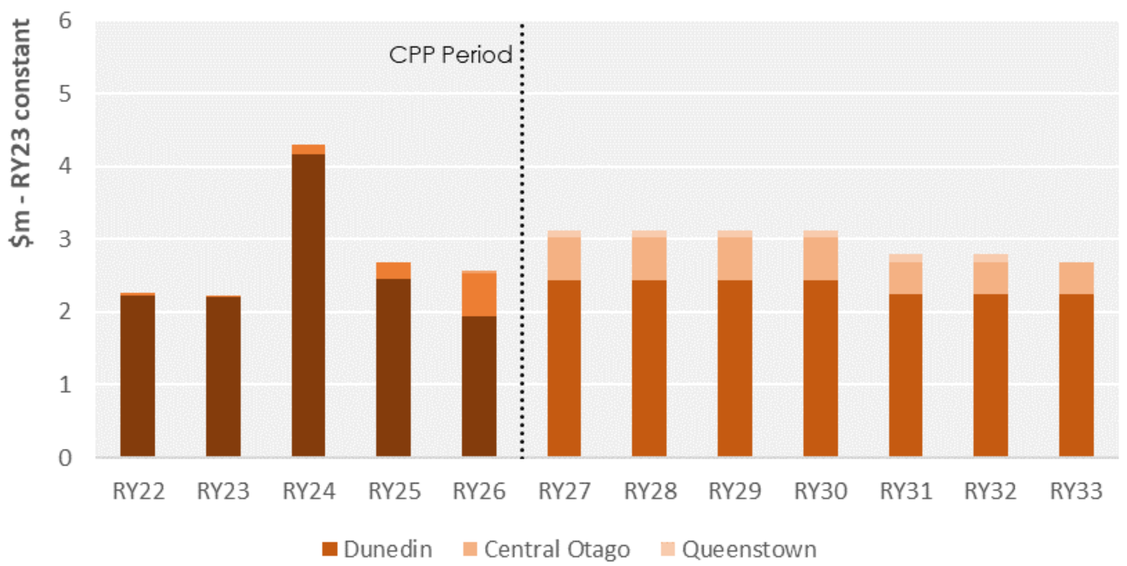


Early in the period, we have scheduled a large reconductoring project on part of our sub-transmission network (Waipori lines) to manage the risk associated with these ageing assets (parts of these lines are over 80 years old). This project leads to a temporary uplift in work during RY22 and post CPP Period. The rest of the period will see us undertake relatively low volumes of additional sub-transmission renewal.

Underground Cables

The chart below shows our forecast investment in our underground cable fleets.

Figure 10.10: Cables renewal Capex

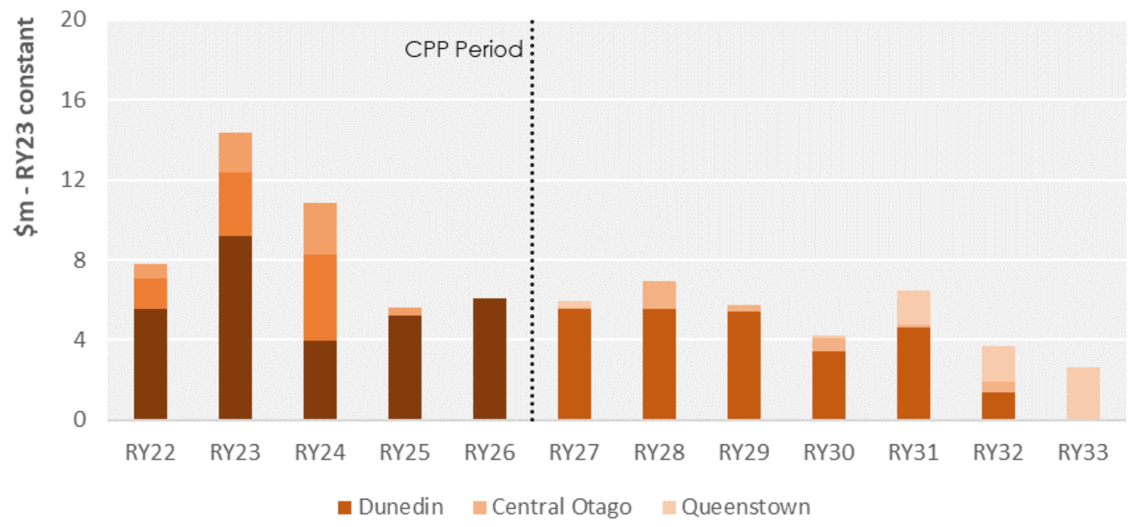


The condition of our sub-transmission cable, and the risk associated with a significant failure, means that many need to be replaced during the planning period. We plan to replace a large number of cast iron potheads and some poor condition PILC distribution and LV cable.

Zone Substations

The chart below shows our planned renewal investment in our zone substation assets.

Figure 10.11: Zone substations renewal Capex

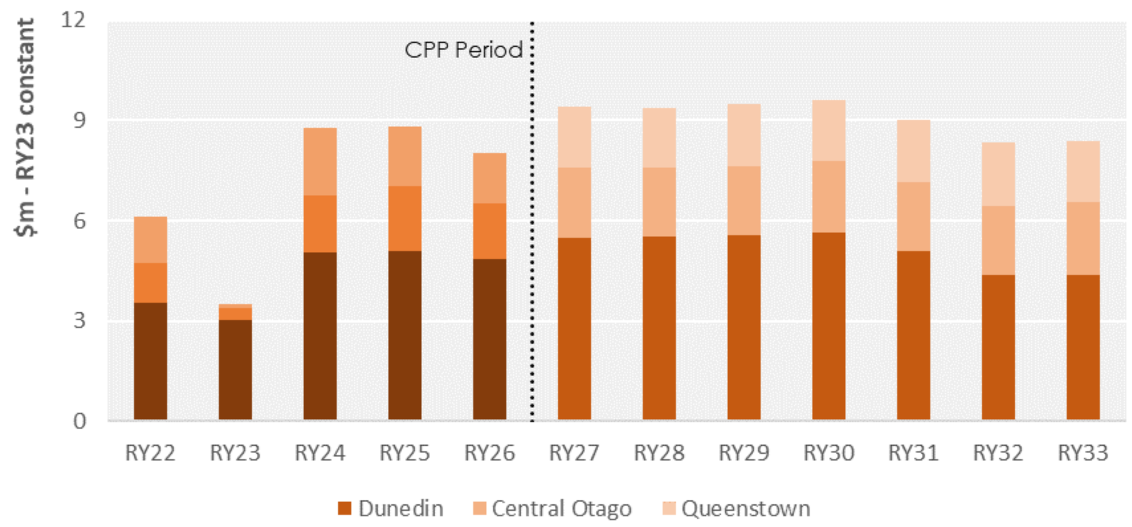


Chapter 8 explains the need to replace zone substation assets due to drivers such as asset health, criticality, and safety/environmental risk. Most zone substation works are large projects, which leads to a relatively 'lumpy' investment profile over the planning period.

Distribution Switchgear

The chart below shows our forecast investment on our distribution switchgear fleets.

Figure 10.12: Distribution switchgear renewal Capex

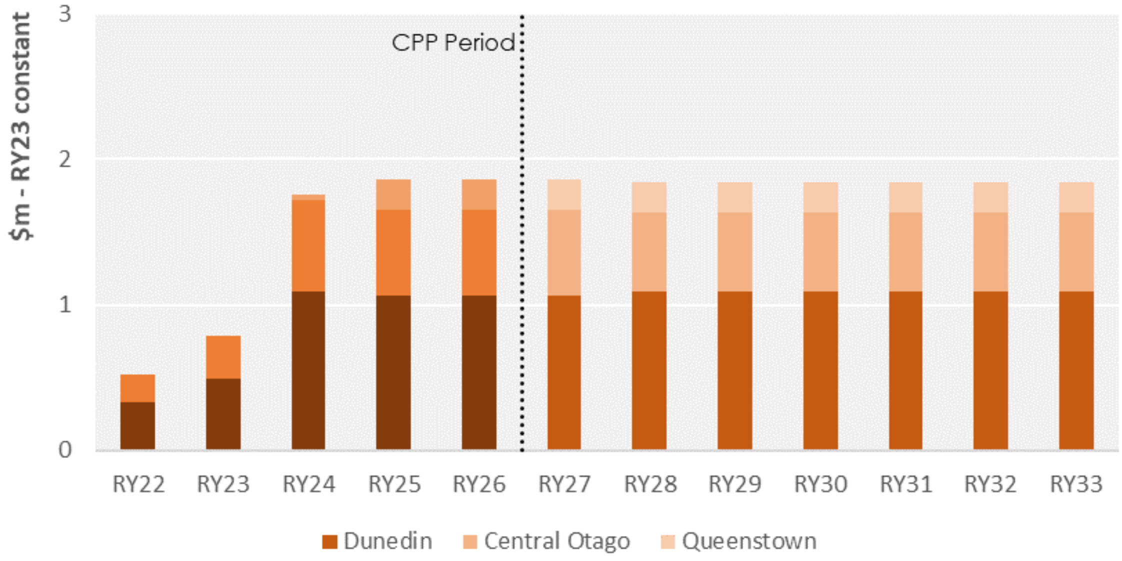


Capex on distribution switchgear, such as fuses and pole mounted switches, are often undertaken reactively, so our renewal forecasts are partially based on historical failures. However, we also plan to increase proactive replacement of ground-mounted switchgear with known type issues, and LV enclosures with known safety 'type' issues.

Distribution Transformers

The chart below shows our forecast investment in our distribution transformer fleets.

Figure 10.13: Distribution transformers renewal Capex

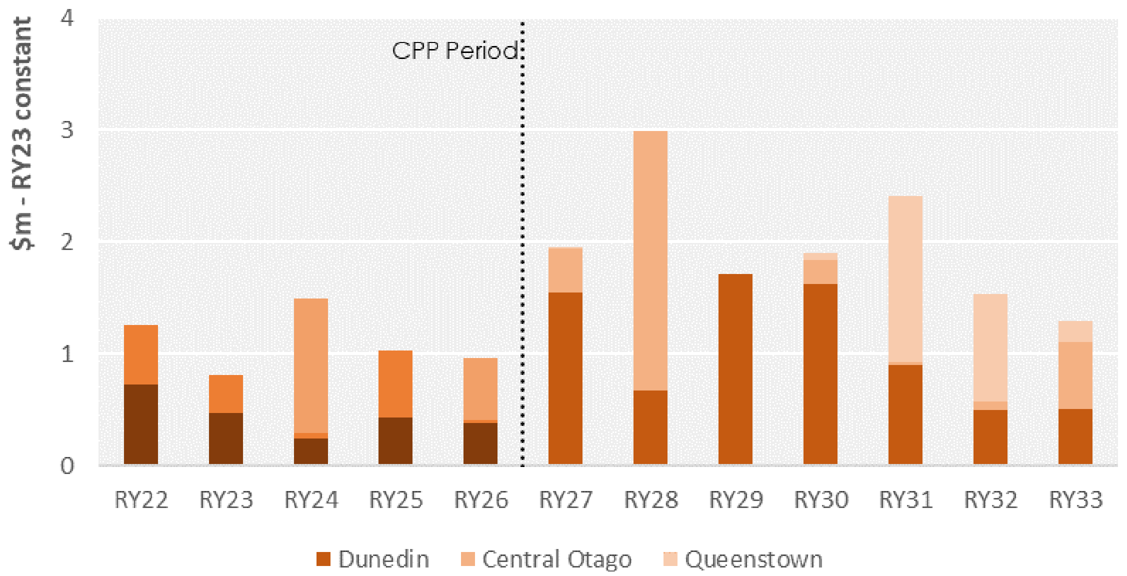


Our distribution transformer renewals forecast ramps up until the end of the CPP Period, after which we will have reached steady-state. A key driver is the conversion of large pole mounted transformers to ground-mounted units to reduce safety risk.

Secondary Systems

The chart below shows our forecast investment on secondary system assets.

Figure 10.14: Secondary systems renewal Capex

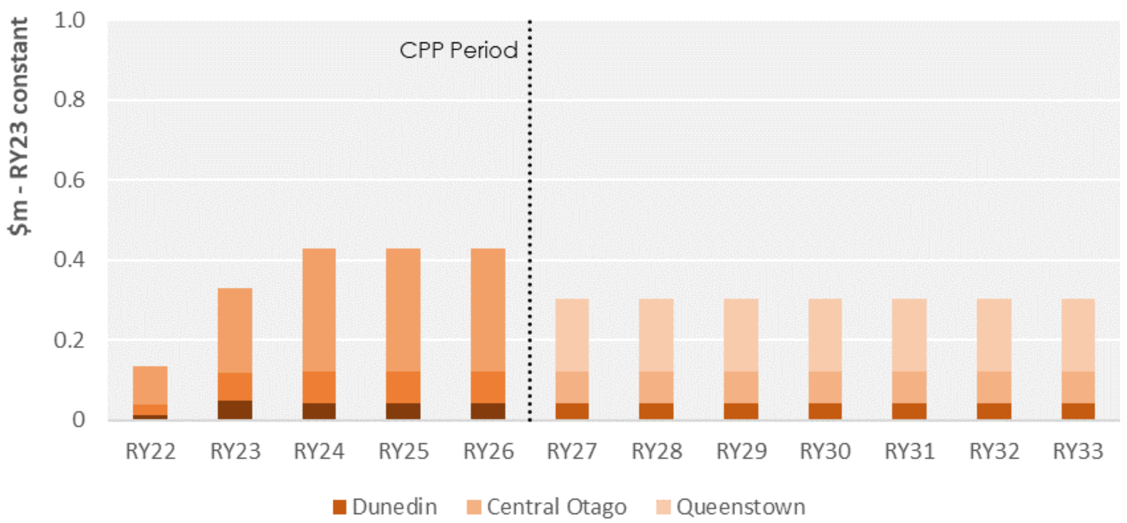


We are planning to replace most of our old electromechanical relays (by RY26) and DC systems during the AMP period. We align these replacements with zone substation projects where practical.

Asset Relocations

The chart below shows our forecast asset relocation Capex.

Figure 10.15: Asset relocation Capex (net of capital contributions)



We estimate relocation expenditure based on historic average expenditure, adjusted for known projects that are expected to occur within the next three years. This Capex is associated with moving our assets to enable other parties to undertake projects. We have experienced a significant growth in asset relocation requests but anticipate this expenditure to stabilise closer to the historic averages over the next few years. Most commonly this relates to roading projects but works may also be undertaken for other parties such as property developers. This is discussed in Chapter 5.

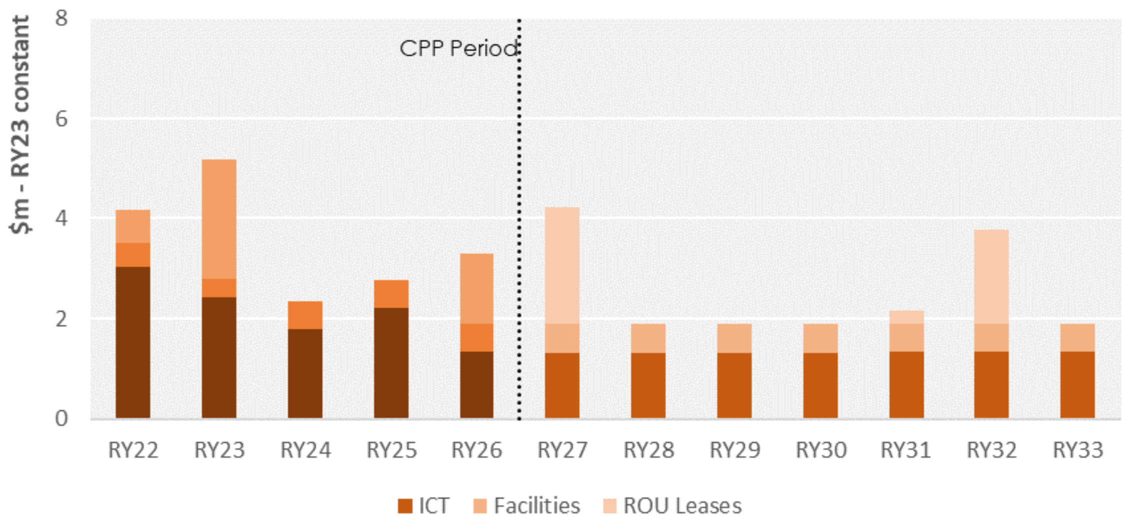
10.2.3. Non-network Capex

As discussed in Chapter 9, our non-network Capex is split into the following portfolios:

– **ICT**: investments in capital items to provide corporate and operational IT solutions
– **facilities**: includes the capital costs of office equipment and renovation of our corporate sites.

The combined expenditure in these portfolios is shown below.

Figure 10.16: Non-network Capex[4]



Our main non-network investments in the planning period focus on renewing existing systems and improving our IT capability. We expect that these investments will support the effective delivery of our work programmes. An initial focus is on developing a purpose-built asset management system to consolidate current systems into a more effective platform. They will also improve system resilience and facilitate improved operating processes.

Capital expenditure reduces from RY23 as we migrate towards service-based solutions. Given the rapidly changing nature of ICT solutions, the exact investments we will make and their associated costs are less certain later in the period.

Right of use (ROU) lease forecasts reflect our best estimate of lease renewal dates in relation to office premises, our motor fleet and IT communications equipment.

4 Note: the amounts presented here (and non-network Capex amounts in the body of the AMP) may differ from related disclosed amounts in Schedule 11a. This is due to adjustments made to reflect the accounting treatment of Right of Use assets, that have been applied to the amounts in Schedule 11a.

10.3. OPEX SUMMARY

Our Opex forecast includes our forecast expenditure in the following six portfolios. Further information on the forecasts can be found in Chapters 7 and 9. Note: our approach to categorising maintenance activities (discussed in Chapter 5) differs from the Information Disclosure definitions. An explanation of our maintenance categories is included in Chapter 7.

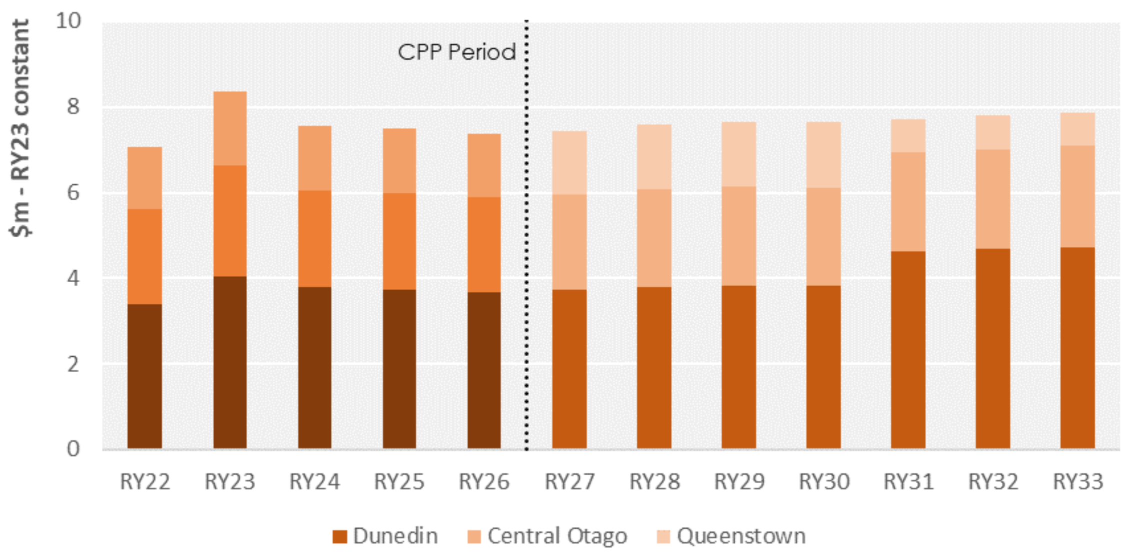
- **preventive maintenance**: this encompasses inspections, condition assessments, and servicing. These are typically activities that are carried out on a regular basis (for example, every three months, annually, every six years) in accordance with our maintenance standards
- **corrective maintenance**: this is planned work arising from preventive maintenance work or as a follow-up to a fault (following service restoration, also known as 'second response'). It includes defect rectification, repairs and replacement of minor components to restore the condition of an asset
- **reactive maintenance**: this is reactive work, including fault response and emergency switching, carried out in response to an unplanned event or incident that impairs normal network operation
- **vegetation management**: relates to expenditure on tree trimming, inspection and liaison with tree owners
- **business support**: includes the costs associated with support functions such as HR and Finance, as well as ICT-related Opex
- **SONS**: is Opex where the primary driver is the management of the network, and includes expenditure relating to engineering staff, control centre and system operations.

Appendix B sets out this expenditure using Information Disclosure categories.

10.3.1. Preventive Maintenance

The chart below shows our forecast preventive maintenance Opex during the AMP planning period.

Figure 10.17: Preventive maintenance Opex



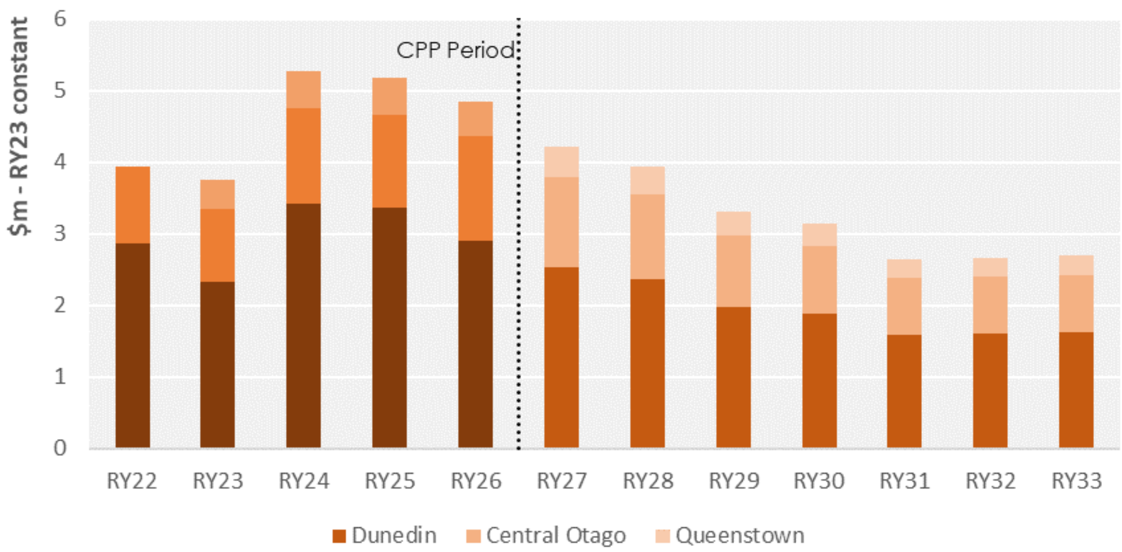
Increased expenditure in coming years is due to additional and expanded activities, some of which are listed below. Some of these (E.g. consumer pole inspections) will be temporary, leading to a slight reduction in expenditure towards the end of the period. Key drivers include:

- improved condition inspections: we have begun to introduce initiatives to improve our knowledge of asset condition and to pre-empt potential failures. Specific initiatives include forensic testing of overhead line components (conductor, insulators, terminations) to better understand overall fleet condition
- consumer pole inspections: we will begin inspecting consumer-owned poles to support our planned programme to ensure pre-1984 poles can be handed back to customers
- new inspection techniques: we plan to implement new inspection techniques for pole-top assemblies and aerial photography of overhead lines. This will deliver a better understanding of asset health and associated risk.

10.3.2. Corrective Maintenance

Corrective maintenance includes activities that restore assets that have aged, been damaged, or do not meet their intended condition. This helps to ensure that assets are safe and provide reliable service.

Figure 10.18: Corrective maintenance Opex



Increased expenditure in coming years is due to the additional activities listed below. Some of these will be temporary, leading to an eventual reduction in expenditure towards steady-state levels.

- defect numbers: likely to increase due to improved inspections and condition assessments. We expect this will stabilise midway through the AMP planning period
- consumer poles: we will begin remediating defects on consumer-owned poles in a planned programme to ensure pre-1984 poles can be handed back to customers.

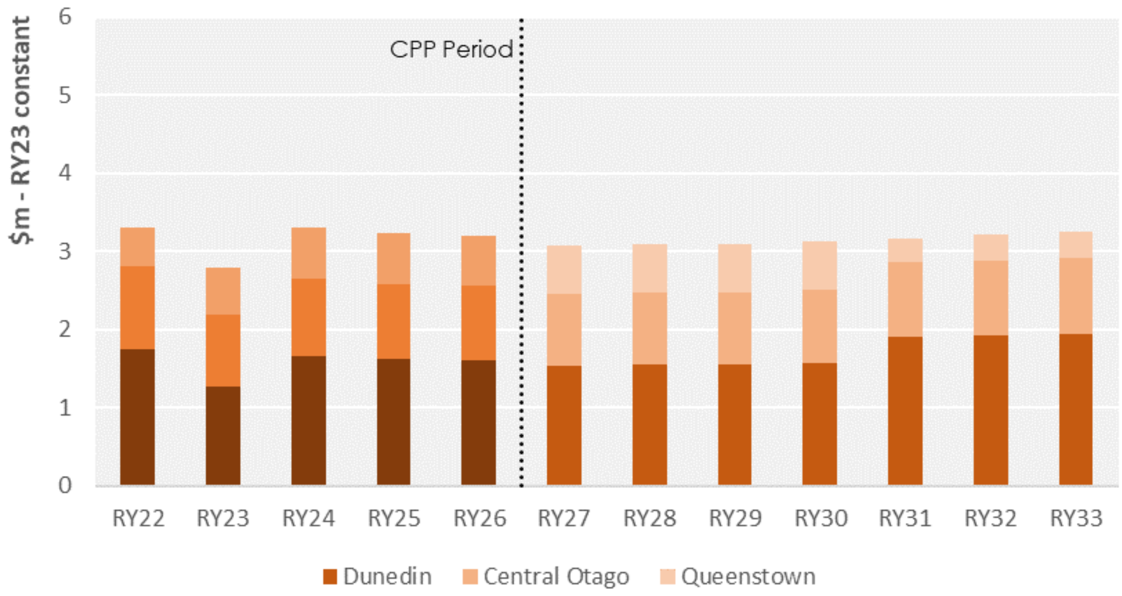
10.3.3. Reactive Maintenance

Reactive maintenance involves interventions in response to network faults and other incidents. There is no advanced scheduling of this work other than ensuring that there are sufficient resources on standby to respond to network faults. Reactive maintenance is about safely switching and restoring the supply to customers. It is impacted by large events such as major storms.

By its nature, reactive maintenance requirements cannot be accurately predicted for any particular year. Annual reactive work is driven by the frequency and severity of network faults. Other than from poor asset condition, network faults are mainly influenced by external, often random, events.

Towards the end of the period, we expect to achieve efficiencies (resulting in lower cost to manage faults) resulting from improved asset management practices. In addition, we expect to see a lower number of faults towards the end of the period due to our ongoing asset renewal programmes.

Figure 10.19: Reactive maintenance Opex

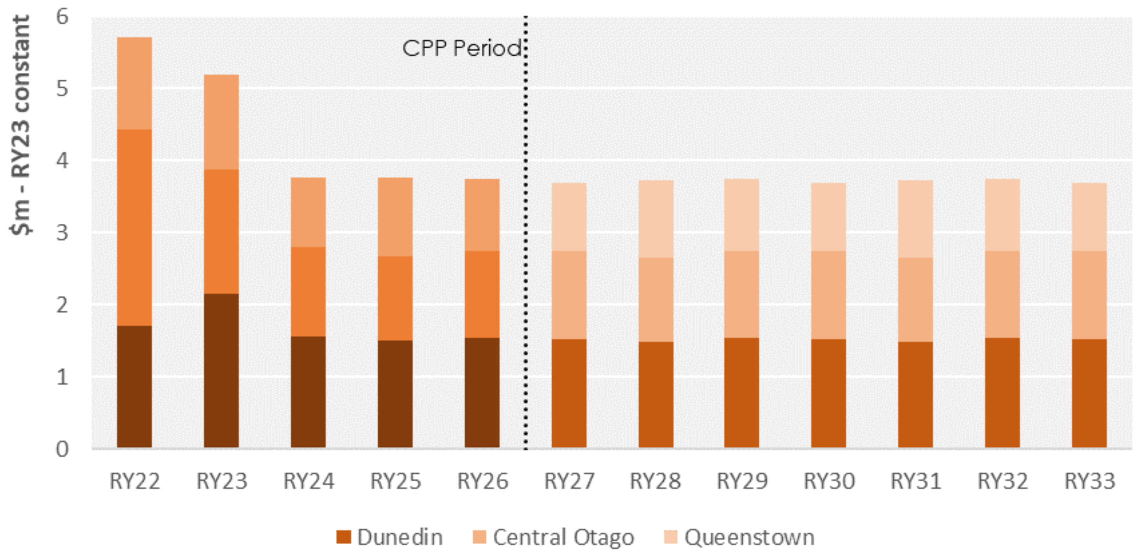


10.3.4. Vegetation Management

We are moving to a more proactive approach to managing vegetation, which over time has significant savings compared with our historical, mainly reactive, approach. The overall number of trees to be inspected and trimmed will reduce as more of the network is under a fully cyclical approach. We expect to reach a materially lower steady-state expenditure level during the CPP Period once we have completed an initial series of vegetation inspections across the entire overhead network. Once in a managed state, we expect vegetation management Opex to reduce while delivering an improved level of compliance with the Tree Regulations.

The following chart shows our forecast vegetation management Opex during the AMP planning period.

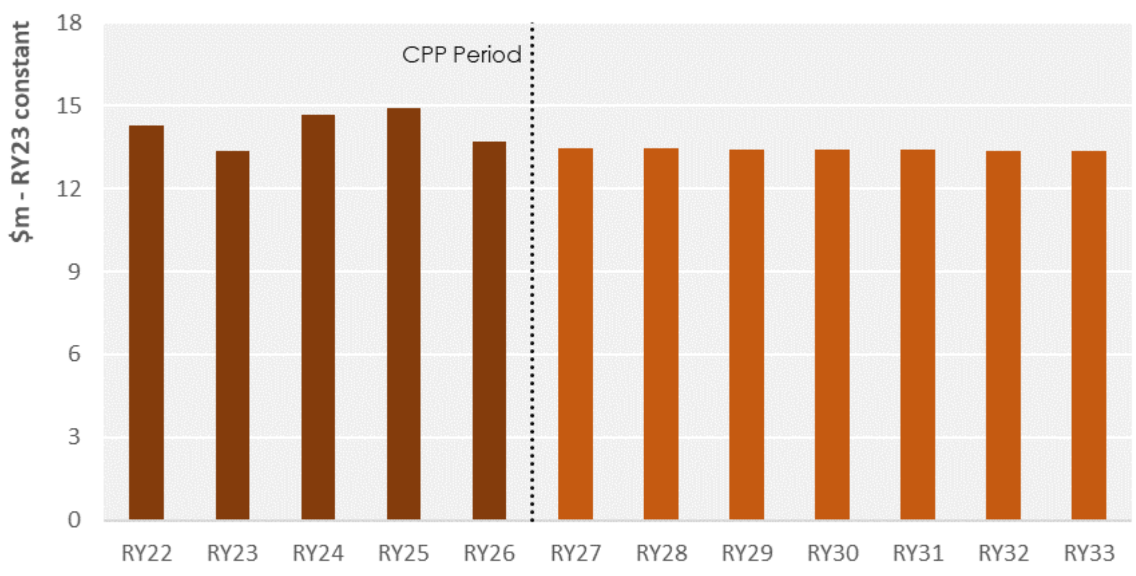
Figure 10.20: Vegetation Management Opex



10.3.5. Business Support

The chart below shows our forecast business support Opex during the AMP planning period.

Figure 10.21: Business support Opex[5]



Business support Opex includes spend that supports our day-to-day asset management activities. It includes direct staff costs and external specialist advice. The other material elements are office accommodation costs, legal, audit and governance fees, and insurance costs.

5 Note: the amounts presented here (and business support Opex amounts in the body of the AMP) may differ from related disclosed amounts in Schedule 11b. This is due to adjustments made to reflect the accounting treatment of Right of Use assets that have been applied to the amounts in Schedule 11b.

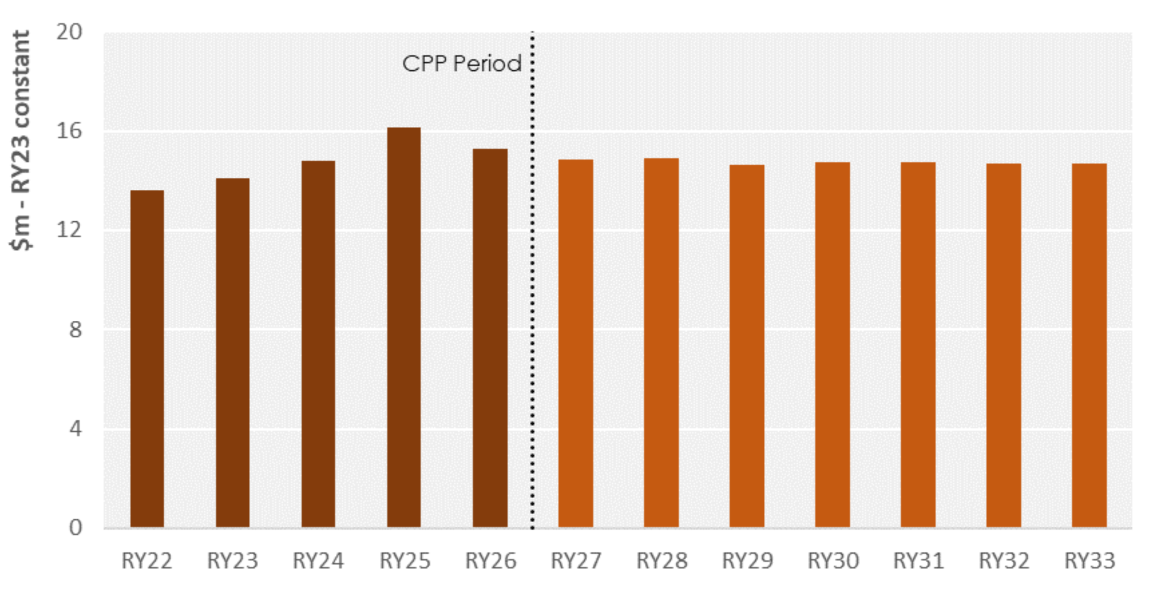
Our forecast expenditure is largely constant over the planning period, although slightly elevated toward the middle of the CPP Period as we focus on business improvement initiatives and the ICT transition to subscription-based services. While we have an ongoing focus on improving our efficiency and are confident that improvements can be made, we also recognise that there will be additional demands and requirements that may offset these savings.

ICT-related Opex will increase from historical levels as we move towards subscription-based services. However, the resulting new capabilities and improved functionality will allow us to achieve savings in other areas of the business. We have reflected these potential savings in our forecast for the AMP planning period.

10.3.6. System Operations and Network Support (SONS)

SONS is Opex where the primary driver is the management of the network, and includes expenditure relating to control centre and office-based system operations.

Figure 10.22: SONS Opex[6]



Our SONS forecast reflects our need to continue developing our people and their capabilities. It includes increased engineering capacity to effectively support additional work volumes, and to enable us to accommodate new techniques and processes.

Specific drivers for expenditure over the AMP planning period include:

- capacity increases: efficiently delivering increased capital and maintenance works requires additional internal resources for planning, design, project and contract management. The majority of this capacity is already in place, though we expect to make further additions on key specialist roles

6 Note: the amounts presented here (and business support Opex amounts in the body of the AMP) may differ from related disclosed amounts in Schedule 11b. This is due to adjustments made to reflect the accounting treatment of Right of Use assets that have been applied to the amounts in Schedule 11b.

- **capability increases**: we will continue to invest in improved capability to support our goal of reaching good industry practice asset management (as we plan to demonstrate by showing alignment to ISO 55001) and responding to changing customer needs
- **investment optimisation**: we need to ensure we can effectively account for a range of factors – lifecycle cost, asset risks, safety and environment, customer preferences, compliance, and commercial implications – in our long-term investment planning. We will invest in our skills in areas underpinning this analysis including quantified risk assessment, lifecycle costing studies, and cost-benefit analysis
- **improved asset information**: improving data quality, information management and analysis capability is necessary to underpin asset management and operational improvements.

10.4. COST ESTIMATION

In general, our expenditure forecasts are developed using predictive forecasting techniques that estimate necessary work volumes and apply associated unit rates to them. This bottom-up approach uses cost estimates and unit rates that are linked to outturn costs (where available). We have initiated a business project to improve the quality of our estimation processes and, consequently, the accuracy of our expenditure forecasts. This initiative is documented as a part of our Annual Delivery Reports under the CPP regime.

10.4.1. Overview

Good practice cost estimation utilises a range of qualitative and quantitative methods to establish the most likely expenditure at project or programme level, depending on the nature of the work. Our forecasts for works beyond two years into the future use a combination of the following approaches:

- **volumetric estimates**: used for smaller, high-volume works that are reasonably routine and uniform. These are generally related to scheduled repairs, small renewals, and scheduled maintenance. These are used in both Capex and Opex portfolios
- **tailored estimates**: used for large single Capex projects (>$500k) that require individual tailored investigation
- **trending**: is used to forecast maintenance and non-network Opex (based on a base-step-trend approach). It is also used for some Capex forecasts where expenditure is consistent over time and is driven by external factors (E.g. third-party connection requests).

These estimate types are discussed below.

10.4.2. Volumetric Estimates

Programmes with relatively large volumes of similar works are categorised as volumetric works for estimation purposes. The key determinant of accurate cost estimates for volumetric projects is the use of historical costs from completed equivalent projects. This feedback is used to derive average unit rates to be applied to future work volumes. The resulting unit rates are often combined to form building block costs that include the main components of typical works.

Using this approach, we consider that our volumetric works will have appropriate estimates, given the following assumptions:

- project scope is reasonably consistent and well defined
- unit rates based on historical outturns effectively capture the impact of past risks, and that the aggregate impact of these risks across portfolios is unlikely to vary materially over time
- a large number of future projects are likely to be undertaken, so that the net impact of variances will tend to diminish given the greater number of projects
- the volume of historical works is sufficiently large to provide a representative average cost.

For investment in non-network assets and systems (E.g. IT hardware), we have used expected volumes and unit rates informed by a number of factors including discussions with vendors and historical outturns.

10.4.3. Tailored Estimates

This approach involves developing cost estimates based on project scopes. Project scopes are determined from desktop reviews of asset information such as aerial photographs, site layout drawings, underground services drawings, and available cable ducts. These assessments provide reasonably accurate estimates for materials and work quantities; for example, building extensions and cabling.

Activity costs are based on historical costs, service provider rates, quotes, and external reviews. Material costs are determined with reference to supply contracts and historical costs. Installation costs are informed by similar previous projects and updated with current prices or quotes.

For investment in large non-network systems, we have based our forecasts on a combination of tender responses and desktop estimates for those later in the period. These desktop estimates are mainly informed by historical tenders and discussions with vendors.

As part of our AMDP programme, we will introduce a risk-based estimation approach for large projects that involves assessing and pricing project risks. Over time, we will report on the expected risks, identifying whether they eventuated, to what extent, and whether the risk funding was adequate. Feedback of this information will enable our planning team to better include risk in future forecasts.

10.4.4. Trending

We have used a trend-based approach to forecast part of our expenditure. The approach is used by many utilities for forecasting recurring expenditure. This is mainly used for forecasting reactive maintenance and certain trend-based Capex forecasts, such as asset relocations.

The approach starts with selecting a representative year. The aim is to identify a recent year that is representative of recurring expenditure we expect in future years. If there are significant events (E.g. major storms) an adjustment is made to remove its impact.

Expenditure in this typical year is then projected forward. To produce our forecasts, we adjust the resulting series for anticipated significant, non-recurring expenditure, permanent step changes, trends due to ongoing drivers, and any expected cost efficiencies.

10.4.5. Inputs and Assumptions

The following inputs and assumptions have informed our overall forecasting approaches.

Demand Forecasts

Historical relationships between proxy drivers (such as GDP) and demand load growth continue to apply in the short-term. We expect our demand forecasting approach (discussed in Chapter 6) to evolve over the next few years. In the medium-term, the increasing adoption of new technologies may alter these underlying relationships, and we will monitor these trends carefully. Our investment planning approach is designed to ensure that we do not invest in new capacity until we are sure it is required, which moderates the risk of over-investment.

We will refine our approach to demand forecasting as part of our AMDP, and will adapt our approach as our understanding evolves.

Embedded Generation

Embedded generation will not have a material impact on network investment in the planning period. We have assumed that the installation of PV and energy storage will not materially affect peak load growth or related investment requirements over the planning period (refer to Chapter 3). The requirement for network reinforcement, which is largely driven by peak load, is therefore not anticipated to increase noticeably as a result of embedded generation.

Historical Unit Rates

Historical unit rates for volumetric works reflect likely future scopes and risks, at an aggregate or portfolio level. While we continue to target efficiency in all aspects of our work delivery, our experience has shown that increased efficiency tends to be offset by enhanced safety related costs (such as traffic management) and increased costs associated with accessing the road corridor and private land.

APPENDICES

Aurora
ENERGY

Appendix A. GLOSSARY

ACRONYM	MEANING
AAC	All aluminium conductor
AAAC	All aluminium alloy conductor
ABC	Aerial bundled cable
ABS	Air break switch
ACSR	Aluminium conductor steel reinforced (cable)
ADMD	After diversity maximum demand
ADMS	Advanced distribution management system
AHI	Asset health indices
ALARP	As low as reasonably practicable
AMDP	Asset management development plan
AMMAT	Asset management maturity assessment tool
AMP	Asset management plan
BCP	Business continuity plan
CAIDI	Consumer average interruption duration index
CAPEX	Capital expenditure
CB	Circuit breaker
CDS	Controlled documentation system
CIMS	Coordinated incident management system
CIW	Customer initiated works
CODC	Central Otago District Council
CoF	Consequence of failure
CPI	Consumer price index
CPP	Customised price-quality path
CT	Current transformer
DC	Direct current
DCC	Dunedin City Council
DCHL	Dunedin City Holdings Limited
DER	Distributed energy resource
DGA	Dissolved gas analysis
DNO	Do not operate
DPP	Default price-quality path
DSM	Demand side management
EAMS	Enterprise asset management system
EDB	Electricity distribution business
ENA	Electricity Networks Association

ACRONYM	MEANING
ERT	Emergency response team
EV	Electric vehicle
FSA	Field service agreement
FTPP	Fast tracked pole programme
GIS	Geospatial information system
GWh	Gigawatt hour
GXP	Grid exit point
HILP	High impact low probability (events)
HRC	High rupture current fuse
HV	High voltage
HWB	Halfway Bush
ICAM	Incident cause analysis method
ICP	Installation control point
ICT	Information communication technology
IEDs	Intelligent electronic devices
IEEE	Institute of Electrical and Electronics Engineers
kV	Kilovolt
kVA	Kilovolt ampere
kVAr	Kilovolt ampere reactive
kW	Kilowatt
LiDAR	Light detection and ranging
LV	Low voltage
LVAC	Low voltage alternate current
MDI	Maximum demand indicator
MPL	Maximum practical life
MVA	Mega volt-ampere
MVAr	Mega volt-ampere reactive
MW	Megawatt (one million watts)
N-1	Indication of power supply security. In the event of a failure, a back-up supply will ensure that power is uninterrupted
NBS	New Building Standard
NEMA	New equipment or material assessment
NOC	Network Operations Centre
NZECP34	The New Zealand Electrical Code of Practice for Electrical Safe Distances
NZTA	New Zealand Transport Agency (Waka Kotahi)
OLTC	On-load tap changer
OMS	Outage management system

ACRONYM	MEANING
OPEX	Operational expenditure
ORC	Otago Regional Council
PILC	Paper insulated lead cable
PoF	Probability of failure
PSMP	Public safety management plan
PV	Photo voltaic (solar)
QLDC	Queenstown Lakes District Council
RC	Replacement cost
RMA	Resource Management Act 1991
RMP	Reliability management plan
RMU	Ring main unit (distribution switchgear)
RSE	Reliability, safety and environment (Capex)
RTU	Remote terminal unit
RY	Regulatory year (starting 1 April)
SAIDI	System average interruption duration index (minutes)
SAIFI	System average interruption frequency index
SAMP	Strategic asset management plan
SCADA	Supervisory control and data acquisition system
SF_6	Sulphur hexafluoride
SOI	Statement of intent
SOS	Security of supply
SWER	Single wire earth return
TRIFR	Total recordable injury frequency rate
VoLL	Value of lost load
VT	Voltage transformer
XLPE	Cross linked polyethylene cable

Appendix B. DISCLOSURE SCHEDULES

This appendix includes the following Information Disclosure schedules:

- Schedule 11a: report on forecast Capital Expenditure
- Schedule 11b: report on forecast Operational Expenditure
- Schedule 12a: report on asset condition
- Schedule 12b: report on forecast capacity
- Schedule 12c: report on forecast network demand
- Schedule 12d: report on forecast interruptions and duration
- Schedule 13: report on asset management maturity
- Schedule 14a: commentary on differences between forecast Capex (schedule 11a) and Opex (schedule 11b) in nominal and constant prices
- Schedule 15: voluntary explanatory notes

Schedule 11a: report on forecast Capital Expenditure

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1April 2023 - 31 March 2033**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref

			Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8		for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10		Consumer connection	15,903	13,670	14,510	14,527	15,267	16,039	16,843	17,682	18,556	19,468	20,419
11		System growth	18,282	13,499	9,622	7,659	7,126	7,016	8,974	8,827	8,765	16,107	20,507
12		Asset replacement and renewal	52,296	59,277	55,267	54,680	56,307	63,017	65,204	62,237	62,058	60,560	53,448
13		Asset relocations	3,757	4,484	4,662	4,768	3,425	3,500	3,575	3,649	3,724	3,799	3,874
14		Reliability, safety and environment:											
15		Quality of supply	3,000	1,682	653	492	839	857	875	894	912	930	948
16		Legislative and regulatory		-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment		-	-	-	-	-	-	-	-	-	-
18		**Total reliability, safety and environment**	3,000	1,682	653	492	839	857	875	894	912	930	948
19		**Expenditure on network assets**	93,238	92,612	84,714	82,127	82,964	90,429	95,470	93,289	94,015	100,864	99,195
20		Expenditure on non-network assets	5,191	2,456	3,002	3,651	4,804	2,191	2,242	2,292	2,650	4,757	2,436
21		**Expenditure on assets**	98,429	95,068	87,716	85,778	87,769	92,619	97,712	95,581	96,666	105,621	101,631
22													
23	*plus*	Cost of financing	400	476	430	418	434	459	485	469	472	520	494
24	*less*	Value of capital contributions	12,923	12,238	12,902	13,008	12,243	12,773	13,323	13,894	14,485	15,100	15,737
25	*plus*	Value of vested assets											
26													
27		**Capital expenditure forecast**	85,906	83,306	75,244	73,189	75,960	80,305	84,874	82,157	82,653	91,041	86,388
28													
29		Assets commissioned	68,085	90,740	84,588	73,531	75,498	79,581	84,113	82,610	82,570	89,643	87,163
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 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
32			**$000 (in constant prices)**										
33		Consumer connection	15,903	13,085	13,359	13,076	13,443	13,821	14,211	14,614	15,028	15,457	15,899
34		System growth	18,282	13,376	9,213	7,204	6,608	6,395	7,984	7,581	7,311	13,329	16,497
35		Asset replacement and renewal	52,296	58,085	52,131	50,703	51,443	56,630	57,535	53,793	53,165	50,839	44,123
36		Asset relocations	3,757	4,292	4,292	4,292	3,016	3,016	3,016	3,016	3,016	3,016	3,016
37		Reliability, safety and environment:											
38		Quality of supply	3,000	1,610	601	443	738	738	738	738	738	738	738
39		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
41		**Total reliability, safety and environment**	3,000	1,610	601	443	738	738	738	738	738	738	738
42		**Expenditure on network assets**	93,238	90,448	79,596	75,719	75,248	80,600	83,483	79,742	79,259	83,379	80,274
43		Expenditure on non-network assets	5,191	2,351	2,764	3,287	4,230	1,888	1,892	1,894	2,147	3,777	1,897
44		**Expenditure on assets**	98,429	92,799	82,360	79,006	79,479	82,488	85,375	81,637	81,405	87,156	82,171
45													
46	**Subcomponents of expenditure on assets (where known)**												
	**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*												
47		Energy efficiency and demand side management, reduction of energy losses											
48		Overhead to underground conversion											
49		Research and development											
50		Cybersecurity (Commission only)											
51													

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
Difference between nominal and constant price forecasts	**$000**										
Consumer connection	-	585	1,151	1,451	1,824	2,218	2,632	3,069	3,528	4,011	4,520
System growth	-	122	409	455	518	621	990	1,246	1,454	2,778	4,010
Asset replacement and renewal	-	1,193	3,136	3,977	4,865	6,387	7,669	8,444	8,893	9,721	9,324
Asset relocations	-	192	370	476	409	484	559	633	708	783	857
Reliability, safety and environment:											
Quality of supply	-	72	52	49	100	118	137	155	173	192	210
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
Total reliability, safety and environment	-	72	52	49	100	118	137	155	173	192	210
Expenditure on network assets	-	2,164	5,118	6,408	7,716	9,828	11,987	13,546	14,757	17,485	18,921
Expenditure on non-network assets	-	105	238	365	574	303	350	398	504	980	539
Expenditure on assets	-	2,269	5,356	6,772	8,290	10,131	12,337	13,944	15,261	18,465	19,460

Commentary on options and considerations made in the assessment of forecast expenditure

EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**

11a(ii): Consumer Connection

*Consumer types defined by EDB**	**$000 (in constant prices)**					
Consumer Connection	15,903	13,085	13,359	13,076	13,443	13,821
**include additional rows if needed*						
Consumer connection expenditure	15,903	13,085	13,359	13,076	13,443	13,821
less Capital contributions funding consumer connection	12,923	7,851	8,015	7,846	8,066	8,293
Consumer connection less capital contributions	2,980	5,234	5,343	5,231	5,377	5,528

11a(iii): System Growth

Subtransmission	5,792	3,033	1,514	-	-	303
Zone substations	8,180	7,660	4,429	3,775	2,984	2,575
Distribution and LV lines	2,843	959	1,360	2,553	1,532	1,289
Distribution and LV cables	1,329	331	913	95	1,568	1,704
Distribution substations and transformers	44	-	-	-	-	-
Distribution switchgear	43	869	-	-	-	-
Other network assets	51	524	998	781	524	524
System growth expenditure	18,282	13,376	9,213	7,204	6,608	6,395
less Capital contributions funding system growth						
System growth less capital contributions	18,282	13,376	9,213	7,204	6,608	6,395

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11a(iv): Asset Replacement and Renewal

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
$000 (in constant prices)						
Subtransmission	193	2,787	2,550	2,553	2,435	8,224
Zone substations	14,355	10,873	5,629	6,061	5,954	6,914
Distribution and LV lines	30,443	30,034	31,493	30,618	29,125	26,592
Distribution and LV cables	2,209	2,352	727	626	692	692
Distribution substations and transformers	785	1,760	1,864	1,864	1,864	1,847
Distribution switchgear	3,499	8,783	8,835	8,018	9,424	9,366
Other network assets	812	1,495	1,033	963	1,949	2,995
Asset replacement and renewal expenditure	52,296	58,085	52,131	50,703	51,443	56,630
less Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
Asset replacement and renewal less capital contributions	52,296	58,085	52,131	50,703	51,443	56,630

11a(v): Asset Relocations

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
*Project or programme**	**$000 (in constant prices)**					
Asset Relocations	3,757	4,292	4,292	4,292	3,016	3,016
**include additional rows if needed*						
All other project or programmes - asset relocations						
Asset relocations expenditure	3,757	4,292	4,292	4,292	3,016	3,016
less Capital contributions funding asset relocations	3,381	3,863	3,863	3,863	2,715	2,715
Asset relocations less capital contributions	376	429	429	429	302	302

11a(vi): Quality of Supply

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
*Project or programme**	**$000 (in constant prices)**					
Future Networks	213	373	601	443	211	211
RSE	2,787	1,236	-	-	527	527
**include additional rows if needed*						
All other projects or programmes - quality of supply						
Quality of supply expenditure	3,000	1,610	601	443	738	738
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	3,000	1,610	601	443	738	738

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**

11a(vii): Legislative and Regulatory

*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		-	-	-	-	-	-

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**

11a(viii): Other Reliability, Safety and Environmen

*Project or programme**		**$000 (in constant prices)**					
**include additional rows if needed*							
All other projects or programmes - other reliability, safety and environment							
Other reliability, safety and environment expenditure		-	-	-	-	-	-
less Capital contributions funding other reliability, safety and environment							
Other reliability, safety and environment less capital contributions		-	-	-	-	-	-

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**

11a(ix): Non-Network Assets

Routine expenditure							
*Project or programme**		**$000 (in constant prices)**					
Non-network assets		5,191	2,351	2,764	3,287	4,230	1,888
**include additional rows if needed*							
All other projects or programmes - routine expenditure							
Routine expenditure		5,191	2,351	2,764	3,287	4,230	1,888
Atypical expenditure							
*Project or programme**							
**include additional rows if needed*							
All other projects or programmes - atypical expenditure							
Atypical expenditure		-	-	-	-	-	-
Expenditure on non-network assets		5,191	2,351	2,764	3,287	4,230	1,888

Schedule 11b: report on forecast Operational Expenditure

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2023 - 31 March 2033**

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).

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	2,800	3,447	3,493	3,546	3,486	3,571	3,658	3,779	3,903	4,029	4,157
11	Vegetation management	5,256	3,927	4,081	4,152	4,174	4,318	4,430	4,447	4,595	4,708	4,720
12	Routine and corrective maintenance and inspection	12,130	13,387	13,652	13,487	13,160	13,298	12,927	13,003	12,740	13,136	13,539
13	Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
14	**Network Opex**	20,186	20,761	21,225	21,185	20,819	21,188	21,015	21,229	21,238	21,873	22,416
15	System operations and network support	14,111	15,506	17,656	17,043	16,928	17,327	17,367	17,831	18,163	18,476	18,822
16	Business support	13,348	15,324	16,147	15,150	15,236	15,558	15,871	16,177	16,476	16,766	17,095
17	**Non-network opex**	27,459	30,830	33,803	32,193	32,165	32,885	33,239	34,008	34,638	35,241	35,917
18	**Operational expenditure**	47,645	51,591	55,028	53,378	52,984	54,073	54,253	55,238	55,876	57,114	58,333

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 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	2,800	3,301	3,226	3,202	3,079	3,087	3,096	3,133	3,170	3,208	3,247
23	Vegetation management	5,256	3,760	3,769	3,749	3,687	3,733	3,749	3,687	3,733	3,749	3,687
24	Routine and corrective maintenance and inspection	12,130	12,850	12,667	12,227	11,663	11,528	10,965	10,798	10,362	10,469	10,576
25	Asset replacement and renewal		-	-	-	-	-	-	-	-	-	-
26	**Network Opex**	20,186	19,911	19,662	19,179	18,429	18,348	17,810	17,618	17,266	17,426	17,509
27	System operations and network support	14,111	14,770	16,158	15,268	14,852	14,894	14,633	14,731	14,719	14,693	14,693
28	Business support	13,348	14,661	14,896	13,676	13,456	13,447	13,431	13,410	13,384	13,352	13,352
29	**Non-network opex**	27,459	29,432	31,054	28,943	28,308	28,341	28,064	28,142	28,103	28,044	28,044
30	**Operational expenditure**	47,645	49,343	50,716	48,122	46,736	46,689	45,874	45,760	45,368	45,470	45,554

31 **Subcomponents of operational expenditure (where known)**

**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*

32	Energy efficiency and demand side management,											
33	reduction of energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance											
37	Cybersecurity (Commission only)											

38 ** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

39

40		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
41	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
42	**Difference between nominal and real forecasts**	**$000**										
43	Service interruptions and emergencies	-	147	267	344	407	484	562	646	732	820	910
44	Vegetation management	-	167	312	403	487	585	681	760	862	959	1,034
45	Routine and corrective maintenance and inspection	-	536	985	1,260	1,497	1,771	1,962	2,205	2,378	2,667	2,962
46	Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
47	**Network Opex**	-	850	1,563	2,006	2,391	2,840	3,204	3,612	3,973	4,446	4,906
48	System operations and network support	-	736	1,498	1,775	2,076	2,433	2,735	3,100	3,444	3,783	4,129
49	Business support	-	663	1,251	1,474	1,781	2,111	2,440	2,767	3,092	3,414	3,744
50	**Non-network opex**	-	1,398	2,749	3,249	3,857	4,544	5,175	5,867	6,535	7,197	7,873
51	**Operational expenditure**	-	2,248	4,312	5,256	6,247	7,384	8,379	9,478	10,508	11,643	12,779

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Schedule 12a: report on asset condition

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref												
7					**Asset condition at start of planning period (percentage of units by grade)**							
8												
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	No.	0.07%	0.95%	0.44%	29.92%	68.63%	-	3	2.17%
11	All	Overhead Line	Wood poles	No.	1.37%	16.59%	9.59%	39.46%	32.99%	-	3	25.09%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-		N/A	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	12.59%	0.85%	4.52%	9.07%	72.97%		3	3.51%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	21.14%	78.86%	-	2	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	100.00%	-	-	2	20.00%
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	100.00%	-	-	2	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	68.69%	3.81%	16.07%	11.43%	-	2	48.82%
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.	28.13%	6.25%	9.38%	18.75%	37.50%	-	2	6.25%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	100.00%		3	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	20.83%	-	33.33%	-	45.83%	-	2	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	32.53%	-	6.02%	8.43%	53.01%	-	2	24.10%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	100.00%	-	2	-
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%	-	2	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	18.05%	-	29.65%	6.16%	46.14%	-	3	15.38%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	27.69%	-	38.50%	9.22%	24.59%	-	2	25.19%
35												

					Asset condition at start of planning period (percentage of units by grade)							
36												
37	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	4.48%	8.96%	28.36%	44.78%	13.43%	-	3	13.43%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	4.89%	2.59%	7.55%	11.62%	73.35%	-	3	5.66%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	23.73%	19.32%	16.49%	10.10%	20.42%	9.94%	2	100.00%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.74%	0.12%	-	21.70%	77.44%	-	2	0.64%
44	HV	Distribution Cable	Distribution UG PILC	km	-	6.05%	9.43%	46.23%	38.30%	-	2	1.20%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	30.55%	-	-	69.45%	-	3	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	11.00%	9.00%	15.00%	11.00%	54.00%	-	3	5.00%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	14.51%	1.58%	4.73%	24.92%	54.26%		2	19.24%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	8.21%	2.37%	7.69%	12.80%	68.92%	-	3	11.30%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	66.46%	32.73%	0.20%	-	0.61%	-	2	13.74%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	27.01%	27.92%	-	1.02%	44.04%	-	2	16.91%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	11.16%	4.25%	12.07%	14.42%	58.10%	-	3	6.24%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.09%	0.12%	1.95%	7.11%	90.72%	-	3	4.67%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	3.57%	-	96.43%	-	2	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	50.00%	50.00%	-	-	2	-
55	LV	LV Line	LV OH Conductor	km	12.36%	2.41%	7.54%	16.66%	61.03%	-	3	8.40%
56	LV	LV Cable	LV UG Cable	km	3.06%	2.26%	0.15%	36.85%	57.68%	-	3	1.23%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	3.95%	0.67%	9.03%	25.91%	60.44%	-	2	-
58	LV	Connections	OH/UG consumer service connections	No.	11.10%	0.75%	8.29%	8.87%	70.99%	-	3	6.21%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	52.52%	7.37%	12.16%	27.94%	-	-	3	36.09%
60	All	SCADA and communications	SCADA and communications equipment operating as a single syster	Lot	7.81%	-	17.19%	64.06%	10.94%	-	2	35.94%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	100.00%	-	3	-
62	All	Load Control	Centralised plant	Lot	-	-	-	66.67%	33.33%	-	2	-
63	All	Load Control	Relays	No.	0.35%	1.58%	4.30%	67.52%	26.25%	-	2	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

Aurora ENERGY

Schedule 12b: report on forecast capacity

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**

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	Alexandra	12	15	N-1 switched	4	77%	15	86%	No constraint within +5 years	
10	Clyde/Earnscleugh	4	-	N	4	-		-	No constraint within +5 years	To address aging assets, the Clyde Earnscleugh substation will be decommissioned following the transfer of load to the new Dunstan substation in RY26. We have also reinforced the network to provide better back-up supply from Alexandra to Clyde/Earnscleugh.
11	Dunstan	-	-	N		-		-	No constraint within +5 years	A new substation is to be completed in RY23. Supply to a new data centre is no longer required. Clyde/Earnscleugh load will be transferred to this substation in RY26.
12	Ettrick	2	-	N	1	-		-	No constraint within +5 years	
13	Lauder Flat	1	-	N	-	-		-	No constraint within +5 years	
14	Omakau	3	-	N	2	-		-	Transformer	Rebuilt of the substation at a new location and increase capacity will be completed in RY24.
15	Roxburgh	2	-	N	1	-		-	No constraint within +5 years	
16	Camp Hill	6	-	N	2	-		-	No constraint within +5 years	
17	Cardrona	4	-	N	1	-		-	Transformer	Existing transformer will be replaced with a new 24MVA transformer in RY24 to cater for the forecast load growth.
18	Cromwell	14	24	N-1	-	58%	24	79%	No constraint within +5 years	
19	Lindis Crossing	7	-	N	1	-		-	No constraint within +5 years	In the short term, we have increased the capacity by adding fans to cater for modest load growth. The medium term plan is to increase capacity but we will monitor load growth and plan accordingly.
20	Queensberry	4	-	N	1	-		-	No constraint within +5 years	
21	Wanaka	27	24	N-1	2	113%	24	87%	Transformer	Operationally we have the capability to move >1MVA load to Camp Hill substation. We are installing a transformer at Riverbank switching station to offload Wanaka substation.
22	Riverbank	-	-	N		-		-	No constraint within +5 years	We are installing a new transformer at Riverbank and expect operation by RY25 to offload Wanaka substation.
23	Arrowtown	10	10	N-1 switched	1	97%	10	113%	Transformer	Initial plan is to rebuild the substation to cater for load growth. However, we see other developments in the Wakatipu area as such we are conducting a network study to develop a plan for Wakatipu area.
24	Commonage	12	17	N-1 switched	10	69%	17	71%	No constraint within +5 years	
25	Coronet Peak	5	-	N	-	-		-	No constraint within +5 years	
26	Dalefield	2	-	N	2	-		-	No constraint within +5 years	
27	Earnscleugh	-		N	-	-		-	No constraint within +5 years	Earnscleugh provides short term partial back up to Clyde/Earnscleugh. We have reinforced the network to provide back-up supply from Alexandra to Clyde/Earnscleugh. The substation will be decomissioned when the distribution feeders have been transferred to the new Dunstan substation.

	Fernhill	6	10	N-1 switched	5	63%	10	78%	No constraint within +5 years	
	Frankton	18	15	N-1	3	120%	24	94%	Transformer	We have moved the replacement of the smaller size transformer with 24MVA transformer to RY24 from RY29 due to significant demand growth.
	Queenstown	12	20	N-1 switched	6	62%	20	83%	No constraint within +5 years	
	Remarkables	2	-	N	-	-		-	No constraint within +5 years	
	Berwick	2	-	N	1	-		-	No constraint within +5 years	
	East Taieri	18	24	N-1 switched	10	75%	24	82%	No constraint within +5 years	
	Green Island	15	18	N-1	7	81%	24	64%	No constraint within +5 years	
	Halfway Bush	14	18	N-1	9	76%	24	59%	No constraint within +5 years	
	Kaikorai Valley	10	23	N-1	9	43%	23	47%	No constraint within +5 years	
	Mosgiel	7	12	N-1 switched	3	59%	12	67%	No constraint within +5 years	
	North East Valley	10	18	N-1	4	58%	18	60%	No constraint within +5 years	
	Outram	3	-	N	3	-		-	No constraint within +5 years	
	Port Chalmers	8	10	N-1	3	76%	10	92%	No constraint within +5 years	
	Smith Street	13	18	N-1	13	73%	18	76%	No constraint within +5 years	
	Ward Street	10	23	N-1	11	42%	23	51%	No constraint within +5 years	Includes the new hospital connection. North City and Ward Street substation will provide supply to the new hospital.
	Willowbank	13	18	N-1	11	69%	18	72%	No constraint within +5 years	
	Andersons Bay	14	18	N-1	6	79%	24	63%	No constraint within +5 years	
	Carisbrook	10	24	N-1	10	40%	24	45%	No constraint within +5 years	
	Corstorphine	12	23	N-1	9	52%	23	54%	No constraint within +5 years	
	North City	15	28	N-1	14	55%	28	60%	No constraint within +5 years	Includes the new hospital connection. North City and Ward Street substation will provide supply to the new hospital. The cost to relocate North City zone substation (if required by the MoH) has not been included in our financial forecasts.
	South City	15	18	N-1	13	82%	18	83%	No constraint within +5 years	
28	St Kilda	15	23	N-1	13	63%	23	67%	No constraint within +5 years	

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Schedule 12c: report on forecast network demand

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**

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

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
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 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
11	*Consumer types defined by EDB**						
12	Residential	1,391	1,140	1,140	1,140	1,140	1,140
13	Load Group 0	(2)	2	4	5	6	6
14	Load Group 0A	3	10	14	16	17	17
15	Load Group 1A	14	15	16	16	16	16
	Load Group 1	7	50	72	83	88	91
	Load Group 2	269	198	162	144	135	131
	Load Group 3	11	8	6	5	5	5
	Load Group 3A	6	5	4	4	4	4
	Load Group 4	10	7	5	4	4	4
	Load Group 5	-	-	-	-	-	-
16	Street Lighting & DUML	-	-	-	-	-	-
17	**Connections total**	1,709	1,435	1,423	1,417	1,415	1,414
18	**include additional rows if needed*						
19							
20							
21							
22	**Distributed generation**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
23	Number of connections made in year	448	372	372	681	681	681
24	Capacity of distributed generation installed in year (MVA)	1.8	1.9	1.9	3.5	3.5	3.5
25	**12c(ii) System Demand**						
26		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
27	**Maximum coincident system demand (MW)** — for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
28	GXP demand	273	275	285	293	299	305
29	*plus* Distributed generation output at HV and above	40	52	53	53	54	54
30	**Maximum coincident system demand**	313	327	338	346	353	359
31	*less* Net transfers to (from) other EDBs at HV and above	0	0	0	0	0	0
32	**Demand on system for supply to consumers' connection points**	312	327	337	346	352	359
33	**Electricity volumes carried (GWh)**						
34	Electricity supplied from GXPs	1,152	1,216	1,260	1,296	1,319	1,346
35	*less* Electricity exports to GXPs	51	51	51	51	51	51
36	*plus* Electricity supplied from distributed generation	302	304	306	309	313	316
37	*less* Net electricity supplied to (from) other EDBs	2	2	2	2	2	2
38	**Electricity entering system for supply to ICPs**	1,401	1,467	1,513	1,552	1,580	1,609
39	*less* Total energy delivered to ICPs	1,322	1,384	1,427	1,464	1,490	1,518
40	**Losses**	79	83	86	88	90	91
41							
42	**Load factor**	51%	51%	51%	51%	51%	51%
43	**Loss ratio**	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%
44							

Schedule 12d: Report on forecast interruptions and duration

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Network / Sub-network Name	**Total Network**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	185.3	159.1	158.0	137.1	145.8	137.8
12	Class C (unplanned interruptions on the network)	140.5	121.5	119.9	117.8	116.8	119.8
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.72	0.77	0.77	0.67	0.71	0.68
15	Class C (unplanned interruptions on the network)	2.35	1.63	1.62	1.59	1.57	1.58

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Network / Sub-network Name	**Dunedin Sub-Network**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	117.7	114.7	121.1	99.9	113.1	106.5
12	Class C (unplanned interruptions on the network)	55.3	75.0	75.8	75.4	74.8	76.6
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.50	0.58	0.61	0.51	0.57	0.53
15	Class C (unplanned interruptions on the network)	0.85	1.04	1.06	1.05	1.04	1.05

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Network / Sub-network Name	**Central Otago and Wanaka Sub-network**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	303.9	278.2	230.6	199.1	206.8	197.8
12	Class C (unplanned interruptions on the network)	277.6	203.4	196.6	190.9	188.1	194.4
13	**SAIFI**						
14	Class B (planned interruptions on the network)	1.09	1.36	1.13	0.99	1.03	0.98
15	Class C (unplanned interruptions on the network)	5.33	2.47	2.40	2.33	2.29	2.33

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Network / Sub-network Name	**Queenstown Sub-network**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	267.6	146.9	188.5	185.6	178.4	166.5
12	Class C (unplanned interruptions on the network)	262.8	174.8	172.3	169.1	169.3	172.1
13	**SAIFI**						
14	Class B (planned interruptions on the network)	1.01	0.65	0.85	0.83	0.80	0.75
15	Class C (unplanned interruptions on the network)	3.61	2.60	2.58	2.75	2.52	2.58

Aurora ENERGY

Schedule 13: Report on asset management maturity

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Asset Management Standard Applied	**ISO 55001**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	Asset Management Policy is authorised by Chair and CEO and published within Controlled Document System. The Asset Management Policy is part of the suite of governance documents Reviewed November 2022		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 are some linkages between the asset management strategy and other appropriate organisational policies and strategies such as the Business KPIs but they are not yet fully and consistently aligned		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	Aurrora has identified the various asset classes it owns, operates and maintains and each class has been assigned to an Asset Specialist manage to the lifecycle of thise assets. The full lifecycle of each asset class is not yet defined and documented		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2	Aurora has developed a structure and hierarchy of the asset class strategies but have not completed documenting the lifecycle plans in its fleet strategies		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Asset Management Standard Applied	**ISO 55001**

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	A significant amount of communication is undertaken digitally and in person during teams meetings, one one one discussions and governance groups		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	Processes documented within Promapp include roles and responsibilities. Internal position descriptions for our staff, and our contracts for outsourcing designate responsibilities for the delivery of our actions set out in our AMP.		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2	Our present capability for contract and job management, work scoping, including resource requirements (and cost estimating) will be improved to see us consistently achieve efficient and cost effective implementation.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Incident management and business continuity plan documents have been updated and revised since the last assessment. Emergency management and communication plans are regularly tested and any improvement opportunities are identified and addressed.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

		Company Name	Aurora Energy Limited
		AMP Planning Period	1 April 2023 – 31 March 2033
		Asset Management Standard Applied	ISO 55001

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	Manager roles have been developed with responsibilities for delivery of asset management policy, strategy, objectives and plans. Position descriptions for roles are broadly aligned with asset management strategy and objectives.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	Substantial changes are taking place in our arrangements for works delivery, with implications for works delivery planning and management of outsourcing. Sufficient resources are not consistently available in some key areas.		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	GM of Asset Management and Planning emphasises the need to meet asset management requirements, including the commitment to ISO 55000 alignment. There are regular team briefings and newsletters from top		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	Process for Contract Management inplace and operational. Contractor selection process documented. Field Service Agreements are actively reviewed and ammended where appropriate. Alignment with asset management objectives and policies in development.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2023 – 31 March 2033
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2	Aurora has established an organisation chart with identification for the resources required for activities associated with an AMS. A software solution has been identified and is in the process of being implimented		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	Position descriptions for asset management roles include requirements based on our understanding of good industry practice. Development plans for staff are updated annually and progress reviewed at 3-6 month interval		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2	Competency registers are held for staff undertaking construction and Maintenance work. Training requirements for Asset Management staff are recorded in a Company register but a review system against competencies has not yet been implemented		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2023 – 31 March 2033
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	Regular (typically quarterly) engagement sessions are held with Staff, Territorial Authorities, Contractors and the Community. An Annual Delivery Report is prepared focussing on Asset Management issues and outcomes		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3	All main processes and the interactions between them have been documented in the Promapp system		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	Asset classifications have been developed for 12 Asset Fleet Categories as part of the asset managment system implementation. The high level design for asset data migration has been developed to migrate asset condition data from external sources to Maximo.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2	The data teams have implemented 8 different controls focussed on completeness, accuracy & timeliness (reviewed by KPMG). There are further controls in development to publish to a Data Quality dashboard		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2023 – 31 March 2033
Asset Management Standard Applied	ISO 55001

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 Asset managment system implementation is governed by a Steering Group made up of Executives representing all impacted stakeholders inside the business. This group meets regularly and ensures the implementation project delivers to plan		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 applied within Fleet Management Stategies. The resulting inspection, testing and maintenance requirements are managed within the Controlled Documents System. Development of risk identification is continuing. Aurora holds an extensive set of technical standards across four platforms and these are being updated and consolidated into the new		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	New risks identified as part of incident investigations (ICAM) are added to the Corporate Risk Register. Regular reassessment of of the existing risk register occurs.		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	Aurora uses Comply Watch to monitor the regulatory environment. The Comply With system is used for internal compliance identification purposes		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

Aurora ENERGY

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2023 – 31 March 2023
Asset Management Standard Applied	ISO 55001

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	Works delivery planning and management is a key area of focus and the recent implementation of the Sentient system for monitoring and reporting of projects at each stage of the process has improved visibility and quality. Aurora holds an extensive set of technical standards within its controlled documents system although the regular		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2	Preventive maintenance policies and procedures have been developed for most asset types. The lack of an enterprise asset management system makes the consistent application of these difficult achieve and monitor. The latest outsourcing contracts include key result areas to enable high level monitoring.		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 preventive maintenance and inspection regimes are being adjusted based on the insight from the fault analysis. Condition assessment methodologies are improving and the initial asset health models are in use. Use of leading indicators is limited to a few asset classes.		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3	Dedicated roles have been established to monitor network performance and carry out root cause analysis of outages. Asset failures are investigated by ICAM trained staff and the results reported to the wider business. Function now decentralised, systems and responsabilities are being realigned		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.

Aurora ENERGY

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Asset Management Standard Applied	**ISO 55001**

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	A number of major external reviews of our asset management systems and practises have been recently carried out. WSP-Opus and Sapere reviewing the overall Asset Management cpability of the busines and AMCL assessing against ISO55001. An internal audit system has yet to be established.		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	Triggers set and understood for implementation of formal investigations of failures. Systematic instigation of actions stemming from ICAM is still immature and requires documenting to ensure consistency		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	Fleet strategies taking account of cost/risk/performance over the lifecycle of the relevant assets are not yet complete but artefacts supporting decisions exist in most cases. Regular meetings are held to review operational incidents, to improve the understanding and classification of causes and identify systemic issues with asset classes.		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?	2	Regular engagement with suppliers and consultants. The organisation sponsors staff membership of industry and professional bodies, and ensures attendance at industry conferences and trade shows. A Distribution Engineering team has been established with a key function being the monitoring of new development in th industry. There is an established formal change control system for evaluating technologies and practises.		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.

   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)

2. 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
Differences between constant and nominal forecasts are a direct output of out escalation approach. Our expenditure forecasts were determined in constant 2023 dollars and escalated to nominal dollars using forecast price indices. Each expenditure category is escalated separately using price indices specific to that category. Price indices for each expenditure category reflect a combination of labour and materials prices. Forecast labour and materials prices are sourced from a variety of sources.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

3. 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
Our approach for operational expenditure is equivalent to the approach for capital expenditure, described above.

Schedule 15: Voluntary Explanatory Notes

This Schedule enables an EDB to provide, should it wish to-

1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.6.6;

1.2 information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of any final wash-ups.

2. Information in this schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.
3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanation comment on disclosed information

Our forecast asset expenditure over the planning period takes into account the output from our previous investment plans, as well as several new and emerging investment drivers. While we continue to focus on safety through asset renewals, we also look to address the following in our forecasting:

- changes to our network in order to support decarbonisation through electrification,
- network resiliency in the event of climate change and extreme weather events,
- larger than anticipated growth,
- increasing costs due to inflation,
- targeted reliability improvements based on consumer preferences.

See the Executive Summary of our Asset Management Plan for further information.

Appendix C. RELIABILITY MANAGEMENT

Context

We recognise the need to maintain the reliability of our network to ensure customers receive an appropriate level of service, and that we meet our regulatory quality standards. Throughout the CPP Period, our network investments are primarily targeted towards mitigating safety risks via replacement of ageing or poor condition assets. We have targeted asset fleets that present the greatest risk of harm and sit within our most densely populated areas (See Section 5.3). As we remove poor condition assets from our network, we expect to see a minor improvement in reliability performance.

We exceeded our quality standards on several occasions from 2016-20 as a result of long-term underinvestment. Due to the deteriorating condition of our network, we experienced an increase in interruptions, both planned and unplanned, driven by failure of end-of-life assets, and by an accelerated asset renewal programme.

Changes in operational practice also contributed to the deteriorating trend in reliability performance. In order to mitigate the risk of fires during the summer months, we have reduced the use of auto-reclosers in order to conduct thorough line inspections prior to re-energising lines. We have also limited the extent of live-line work to ensure a greater level of safety for our crews. As a result, some faults take much longer to restore than in the past.

We are currently undertaking a large scale, multi-year programme of asset renewals. In many cases, the work requires interruptions of supply so that the maintenance and renewals can be performed safely. In addition, there have been changes in safe work practice across the electricity industry that have significantly reduced the extent of work that can be carried out live.

We have seen better unplanned reliability performance in recent years, partly due to planned replacements of ageing assets across our network. Although our investment focus throughout the remainder of the CPP Period will focus on safety risk, we plan to identify actions for reliability improvement, particularly in areas of poor performance, when developing our Network Performance Strategy.

Network Performance Strategy

We have observed positive network performance trending in previous years, and we successfully met the regulatory limits set for our business. We acknowledge, however, that customers in select areas of the network are unsatisfied with our network performance. In 2023 we will introduce a Network Performance Strategy to help us identify reliability targets across individual network areas, and to ensure that our future investment plans are sufficient to meet those targets. We anticipate that this strategic approach will bring greater balance to network performance across our network, to the benefit of our worst served customers.

Objectives

Our key objectives for improving our approach to reliability management are to:

- Identify drivers that define localised network performance
- Benchmark and identify an appropriate level of performance across network areas
- Establish anticipated performance levels by local customer groups
- Define optimum balance between anticipated reliability performance and its cost to Aurora
- Set effective communication with local communities about what can be sustainably achieved in relation to expectations
- Assess the effectiveness of investment plans by continuous monitoring of network performance
- Implement continuous improvement in our approach to managing network reliability.

The following sections of this plan set out the main steps we will take to optimise reliability performance.

Reliability Management Improvement

We are working on delivery of a number of strategic improvements, which will be part of our overall Network Performance Strategy:

Asset Management

- Development of a comprehensive network performance framework
- Analysis of the relationship between asset condition information and reliability
- Location-specific SAIDI/SAIFI analysis and forecasting
- Location-specific unplanned outage forecasting and quoting
- Review of customer outage impact (i.e. value of lost load) and incorporation into network performance framework

Works Delivery

- Work packaging by outage zone
- Prioritisation of investment by reliability criticality
- Development of backup generation policy

Data management

- Increased granularity in outage data by location, root cause and information about the affected asset
- Incorporating LV outages into the overall reliability framework
- Improvement of fault-finding and documentation of outages
- Improvement and integration of Outage Management System

Network operations

- Development of selective seasonal recloser disablement policy
- Prioritisation of vegetation management to reliability zoning
- Planning for more reclosers
- Establishment of reliability forum within the business
- Analysis of feasible restoration times for specific circumstances
- Optimisation of switching to reduce of planned and unplanned outages
- Service provider metrics and incentives
- Management of cancellation cases
- Investigation of outage overruns

Customer service and communication

- Standardisation and stabilisation of outage notification
- Improvement of Customer Charter
- Development of Service Standards
- Improvement of management of customer complaints and enquiries
- Review and improvement of outage compensation

We have established a multi-departmental focus group where we discuss all aspects of our network performance in relation to our customer experience in order to:

- Identify and understand the latest network performance trends
- Analyse any major network events or risks
- Communicate accurate information about our network performance to communities
- Monitor the progress in delivery of the improvement initiatives outlined above.

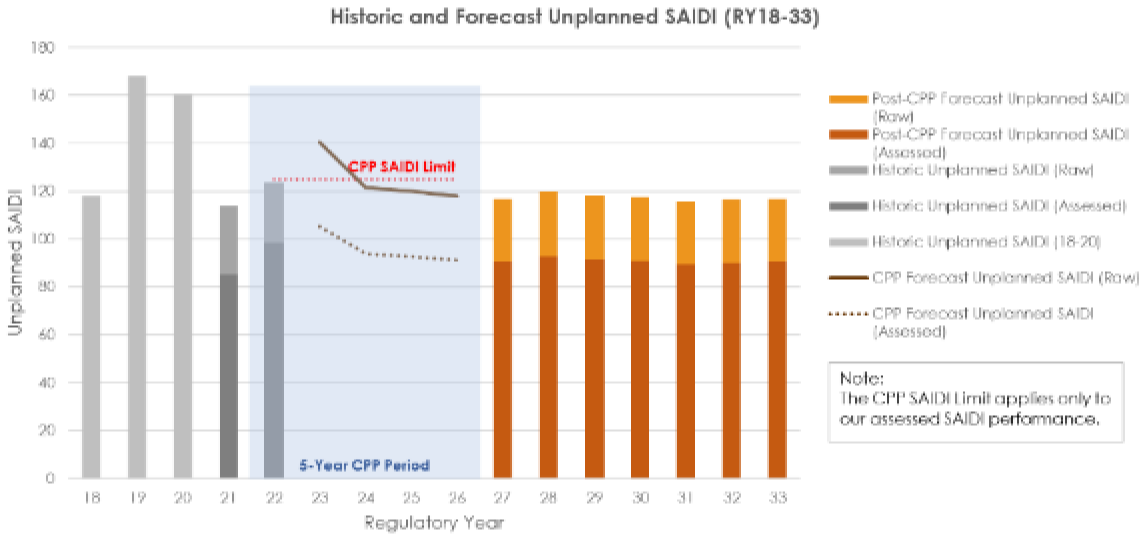
We plan to further refine these initiatives and incorporate them into our day-to-day work plans. We have started several working groups where the initiatives will be managed.

Reliability Forecasts

We have developed forecasts of our reliability performance in terms of SAIDI and SAIFI. This will support more accurate forecasting of quality measures, which is important to gauge the potential benefits of various initiatives that we are considering. For our CPP submission, we developed simple models for forecasting planned and unplanned SAIDI and SAIFI, with consideration for our asset renewals programmes across the planning period. We have updated these models for the 2024 – 2033 period to reflect the results of the CPP decision, including the transition to a five-year CPP Period and the subsequent changes to our investment allowances. We have also refined the models to take into consideration additional inputs that may influence planned and unplanned outages.

Below we set out our forecast unplanned reliability (SAIDI and SAIFI) for the AMP period, highlighting the reliability performance we expect during the remainder of the CPP Period.

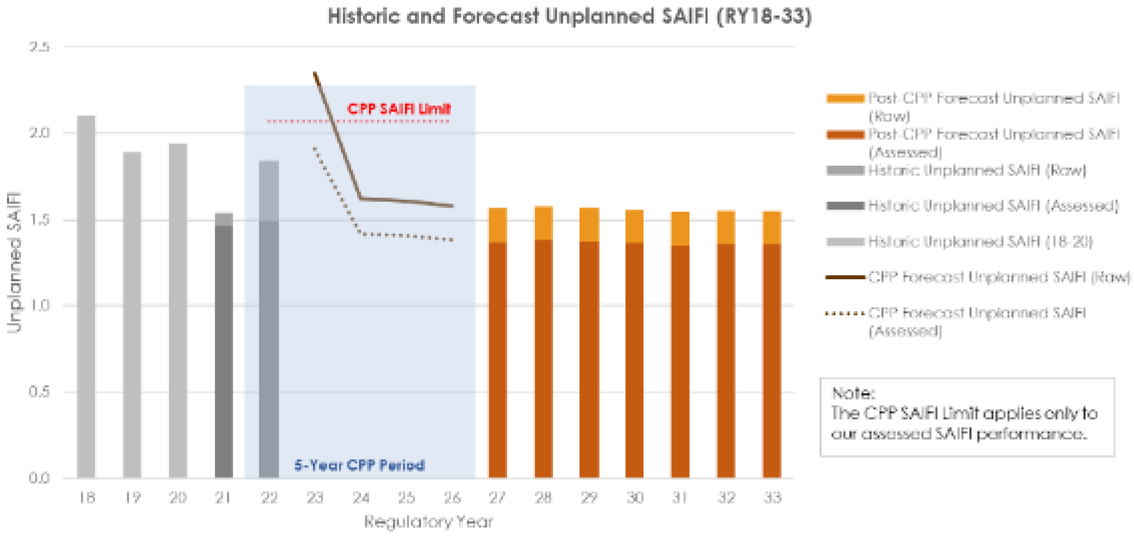
Figure C.1: Forecast unplanned SAIDI



In RY21-22, we experienced notable improvement to our unplanned reliability performance as a result of network investment. While our RY23 performance was below expectations, we expect unplanned outages to stabilise across the remainder of the planning period. This forecast is based on our improved reliability modelling capability, which incorporates projected changes in asset health, modelling of non-asset-related outages, and the impact of our vegetation management plans. The forecast modelling for unplanned reliability indicates that we should remain within our compliance limit throughout the CPP Period.

The charts above include our longer-term forecasts from RY27 onwards, which are subject to change depending on our investment focus beyond the CPP Period. We will utilise our ongoing customer surveys to inform our understanding of the reliability preferences of our communities. We anticipate that our continued investment in safety beyond the CPP Period will have a further positive effect on reliability performance. Additional reliability improvement could be achieved through targeted investment if customers prefer this outcome. Future forecasting for unplanned reliability will account for targeted initiatives as part of our Network Performance Strategy.

Figure C.2: Forecast unplanned SAIFI



We are confident of managing our asset maintenance and renewal programmes to meet our planned reliability targets during the remainder of the CPP Period.

Reliability forecasts

Reflecting the discussion above the following table sets out our reliability forecast for the next five years.

Table C.1: Forecast SAIDI and SAIFI (raw, by regulatory year)

RELIABILITY MEASURE	2024	2025	2026	2027	2028
SAIDI – Planned	159.07	157.98	137.13	145.84	137.79
SAIDI – Unplanned	121.48	119.94	117.79	116.76	119.80
SAIFI – Planned	0.77	0.77	0.67	0.71	0.68
SAIFI – Unplanned	1.63	1.62	1.59	1.57	1.58

Appendix D. WORK PROGRAMME UPDATE

This appendix provides information on our progress against physical and financial plans set out in our previous AMP.

Financial Progress Against Plan

Total direct expenditure on our distribution network was on average more than the 2022 AMP forecast. There are however some categories which are under our forecast amount. These variances are shown in the figure below.

Figure D.1: Capex variance RY22

The growth in new customer connections in the Queenstown Lakes and Central Otago region remained strong through RY22 and we are yet to see evidence of the forecast slowdown following the pandemic. This resulted in RY22 customer connection capex being 46% higher than forecast. System growth was lower than our forecast by 12% mainly due to design issues for a spare transformer project resulting in expenditure deferral. Asset replacement and renewal is 10% above forecast. This variance is largely attributable to increased cost of materials and labour. Asset relocations expenditure was less than forecast by 52%. This reduction was due to NZTA driven Queenstown projects being deferred.

Figure D.2: Opex variance RY19

Service interruptions and emergencies expenditure was lower than forecast by 34% as our network experienced fewer fault events. Trees are a major cause of service interruptions and we looked to prioritise vegetation management activity to address this. Our planned new maintenance activities did not progress as much as expected, leading to a reduction in routine and corrective maintenance and inspection.

Overall AMP Forecast Comparison

The following table explains variances in our overall expenditure forecasts since our last full AMP in 2022. These reflect changes in forecast expenditure (by Information Disclosure sub-categories) during the overlapping period i.e. RY23 to RY32 inclusive. All amounts are in constant RY23 dollars.

Table D.1: Expenditure profile comparion (RY23 constant, 000's)

	AMP22	AMP23	% CHANGE	COMMENTS
Capex				
Consumer connection	140,136	141,996	1%	Higher than expected consumer connection requests, inclusion of expected large connections
System growth	76,341	97,285	27%	Greater than expected demand growth. Impact of COVID-19 was minimal
Asset replacement and renewal	508,573	536,618	6%	Updated renewals modelling, identifying additional safety-driven needs in crossarms, conductor, and zone substations fleets
Asset relocations	18,275	34,730	90%	Updated for known Waka Kotahi projects
Quality of supply	6,542	10,085	54%	Category introduced after AMP20
Legislative and regulatory			0%	No applicable projects
Other reliability, safety and environment			0%	No applicable projects

Expenditure on non-network assets	23,600	29,419	25%	Shift towards SaaS based capability has reduced ICT Capex
Opex				
Service interruptions and emergencies	44,854	31,303	-30%	Refined base-step-trend model, updated with more recent information
Vegetation management	38,295	38,872	2%	New cyclical strategy expected to reduce future clearance requirements
Routine, corrective maintenance and inspection	88,513	115,659	31%	Several new maintenance initiatives are planned to improve and expand inspection regimes and to address defect backlogs
Asset replacement and renewal			0%	Category no longer used
System operations and network support	146,702	148,829	1%	Refined base-step-trend model
Business support	141,803	137,060	-3%	Refined base-step-trend model has been updated with more recent information

Appendix E. ICT ASSET INFORMATION

This appendix provides further information on the ICT systems that support asset management activity within our business.

Information Systems

Currently, we use the following information systems, described below, as our primary asset management ICT systems and requirements:

- Geospatial Information System (GIS)
- network operations systems
- customer and commercial systems
- corporate systems
- enterprise technology and infrastructure requirements

In addition, we are also in the process of rolling a new asset management system (AMS) to improve our business capability.

GIS

We use GIS to visualise our network assets. GIS is the master record for geospatial data, and works with other systems to present the asset spatial information as a key input into renewal and outage scheduling where geographical and network hierarchy factors are considered in the planning, monitoring and improvement of the asset base.

Network operations

Our network operations rely on real-time information systems including SCADA, distribution and outage management systems. These systems are critical to the safe and reliable operation of the network and must achieve exceptionally high reliability.

Over the next 2-3 years, we plan to extend our remote monitoring and control capability into the LV network and increase the ability to access real-time systems from mobile devices.

Our main operational platform is the SCADA system. It requires significant lifecycle replacement investment throughout the planning period.

Customers and commercial systems

Our customer and commercial business services include billing, case management and regulatory compliance.

Our business requirements include new case management capability to work in parallel with our new operational technology platforms, so that we can offer improved notifications to our customers about outages and likely restoration times.

Corporate

Our corporate services cover business support and customer related activities including finance, HR, legal and property. Our current financial management technology service is relatively mature, however, there is a need for intervention with respect to the financial management system within the planning period because the software version that we currently run will cease to be supported by the vendor.

Implementations about the most appropriate intervention will depend on whether transitioning to subscription services (with lower Capex and higher ongoing Opex) is efficient and practical, and the capability to integrate with the asset management system.

Enterprise technology and infrastructure requirements

Our core ICT infrastructure also requires ongoing renewals and some improvements in capability.

This portfolio covers the enabling technology and generic technology frameworks and platforms that enable digital integration of business services and standalone data sources. This new integration technology will enable us to access reliable information as well as support the processing, storage and exchange of information across the company and with our business partners.

Expenditure in this portfolio early in the planning period reflects completion of the overhaul of our digital communications to support operational technologies. Many of the services provided in this portfolio are delivered through the cloud, with the result that Capex is relatively low.

Asset Management System (AMS)

AMS will be the comprehensive single source of truth that identifies asset specific information about our network. It will include physical asset data (type, age, condition, etc.), and also provide visibility regarding performance histories, maintenance schedules and network operations.

During the initial phases, we have migrated the various databases containing our asset data and data from field inspections databases into the AMS. This information has been mapped into the newly developed set of asset attributes that will be used for future asset management decision-making. The next phase of work focuses on implementing work orders to manage all work requests related to capital, corrective and preventative maintenance plans. The work orders will align asset management data with the corresponding financial data mastered in SAP, allowing staff to have greater visibility over planning, monitoring and execution of work and enhanced capability to report on progress against plan.

Outage Management System (OMS)

The outage management system is software used to identify outages, provide instant alerts, and to create efficiencies for restoring power to customers after a fault. Working in tandem with GIS mapping systems, an OMS enables us to prioritise response based upon customer impact. It can also support communication with customers by enabling real-time alerts around outages and the status of repairs. The OMS has automations to keep the website, our call centre and our regulatory databases up to date in near real-time.

Control and Integration

We need to protect the integrity of asset information held in our systems. The system and processes we deploy have security controls in place to restrict access to them, and a change management process to ensure that system changes do not create problems in the wider operation of our ICT services, and that all systems are fully backed up on- and off-site.

Limitations and initiatives to improve data

We are continually working to improve the asset data we maintain in our systems. Challenges with inconsistent recording of information in the field and changing information requirements makes it difficult ensure the quality of information to support our asset management activities. We are currently constrained by shortcomings in the current systems' ability to share information and limited integration options. Our planned implementation of an enterprise integration tool along with a fit-for-purpose asset management system will address these constraints.

Our current asset management information systems do not yet fully meet our needs. We are improving our capability in our information systems that will allow us to:

- apply data standards and templates within the information systems, to improve the quality of asset information
- improve the quality of asset attribute, transactional, and condition assessment data by enabling input directly from mobile devices, with validation at the point of entry
- more effectively manage work on assets, including defining and planning work, managing jobs and work orders, and recording the work carried out.

For the purposes of asset planning in particular, we require improved capability to:

- visualise asset condition, work order and defect history
- visualise selected asset performance data from real-time systems
- undertake predictive analysis and develop forecasts of risk and intervention needs
- define and manage plans and programmes of interventions
- apply reference cost tables to forecast interventions, particularly for the costs of high volume, standard types of work
- understand financial implications of decisions
- link capital expenditure and operating expenditure forecasts to company financial models
- access multiple data sources, both internal and external, for scenario modelling.

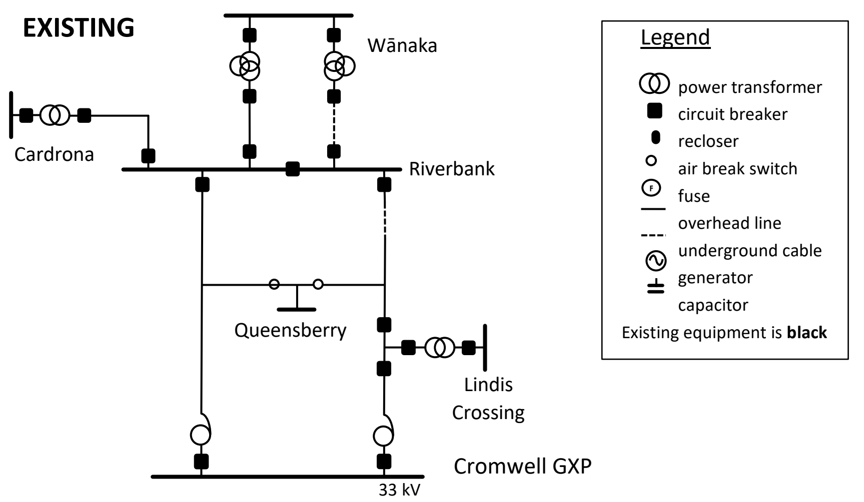
This chapter outlines the enabling ICT initiatives that will support these capabilities. Our current priorities are improving the way we manage and use information across the company and establishing an EAMS system capability. Work is underway on this and will be completed in stages during the CPP Period.

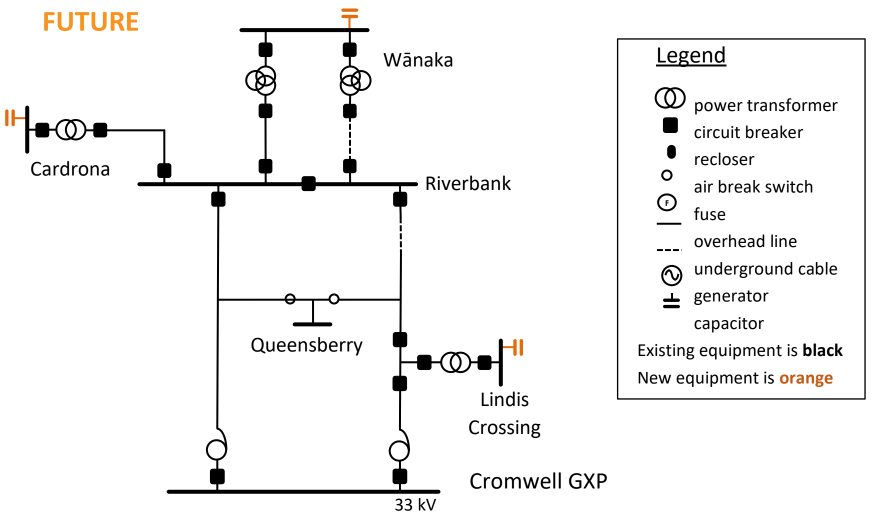
As part of our CPP requirements, we are required to publish a development plan that outlines our approach to improving processes and practices across several business areas. As part of this development plan, we include our approach around data collection and data quality. See Chapter 9 for more detail.

Appendix F. GROWTH PROJECT DETAILS

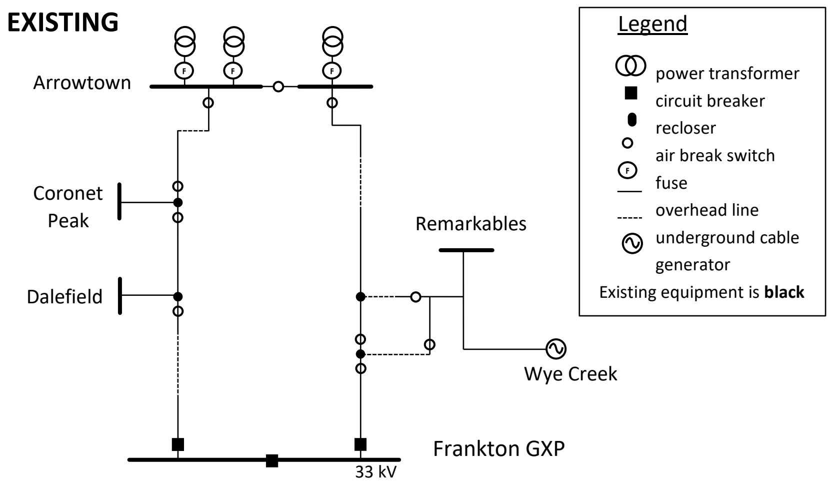
The following tables set out our main planned major network development projects for the AMP planning period.

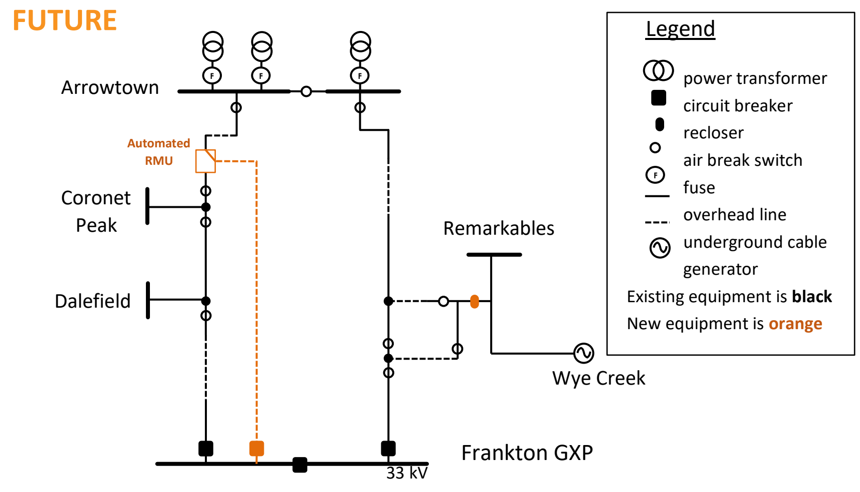
PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Upper Clutha Voltage Support	During peak load, the voltage drops below 66 kV particularly when one of the two circuits is out of service.	– Do Nothing – Install 10MVAr of voltage support at Riverbank substation – Install a total of 10 MVAr of voltage support on the 11 kV bus of Wānaka, Cardrona and Lindis Crossing substation.	**Install a total of 10 MVAr of voltage support on the 11 kV bus of Wānaka, Cardrona and Lindis Crossing zone substations** This solution provides the following benefits: – Significantly improves the network voltages on the Upper Clutha 66 kV network. – Reduces network losses. – Removes the risk to shed consumer load in the event of the loss of one of the Cromwell–Riverbank circuits.	2021-24	6



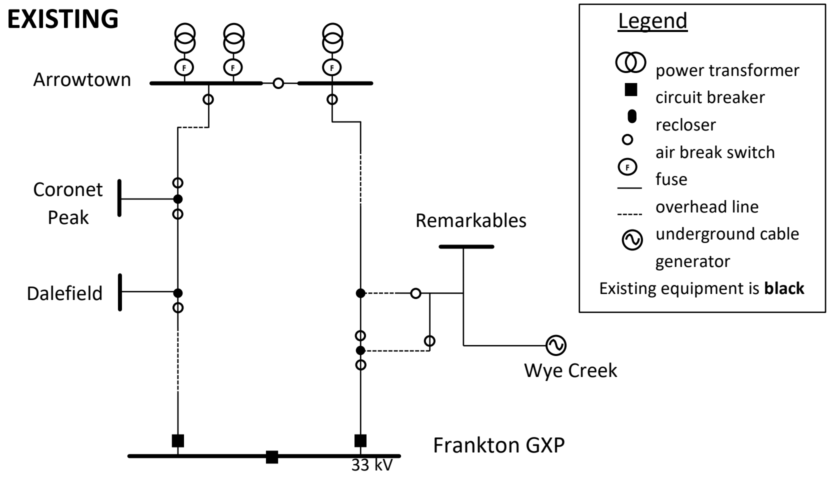


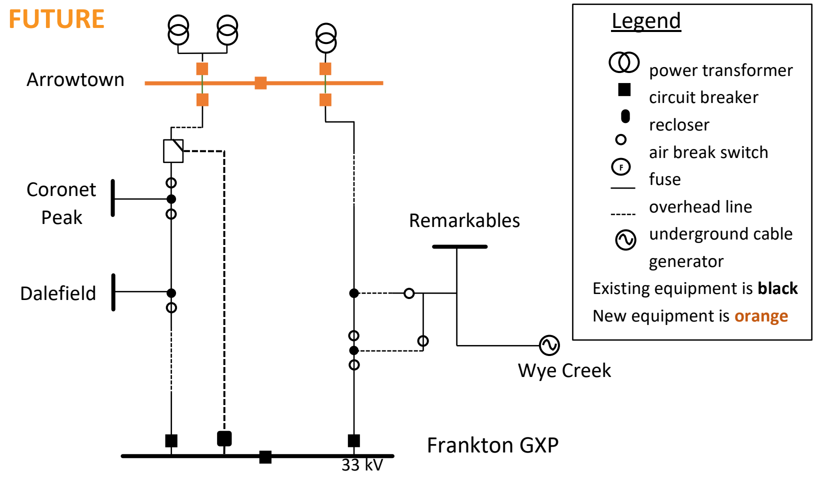
PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Arrowtown 33 kV Ring Upgrade	The demand of the Arrowtown ring has exceeded its firm capacity and security level in the last six years.	– Do Nothing – Replace existing conductor – Arrowtown 33kV ring upgrade	Arrowtown 33 kV ring upgrade This solution provides the following benefits: – Significantly improves the security of supply to the Dalefield, Coronet Peak and Arrowtown areas. – Provides a firm capacity of 34 MVA on the Arrowtown 33 kV Ring. – Reduces the risk of a HILP event that would see significant outages in the Dalefield, Coronet Peak and Arrowtown areas.	2021-24	6



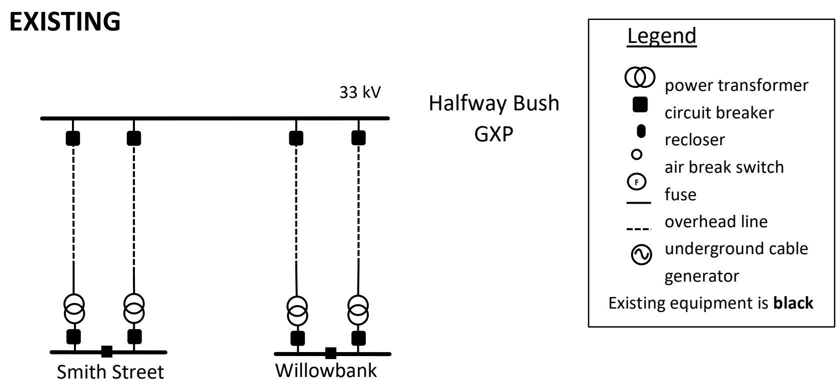


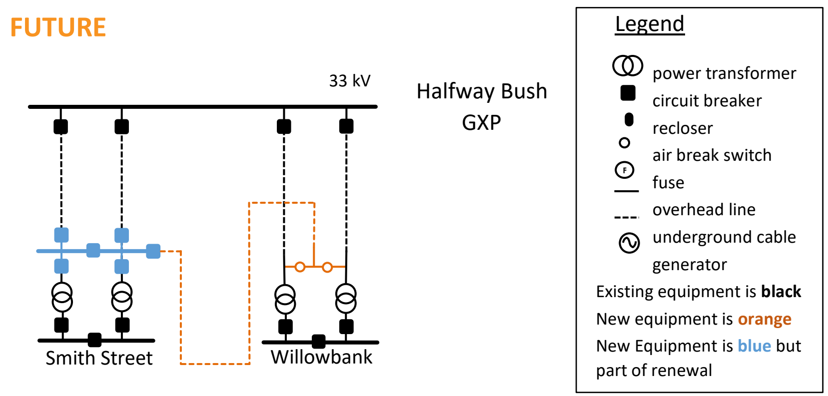
PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Arrowtown 33 kV indoor switchboard	The security level of the Arrowtown ring requires no break in electricity supply. This is not currently achieved as the ring is operated as an open ring. The open point is at the Arrowtown zone substation using a normally open, manually operated, 33 kV ABS bus coupler.	– Do Nothing – 33 kV outdoor switchyard – 33 kV indoor switchboard	**33 kV indoor switchboard** This solution provides the following benefits: – Significantly improved security of supply to class Z1 to the Dalefield/Coronet Peak/Arrowtown region – Reduced risk of a HILP event that would result in significant outages in the Dalefield, Coronet Peak and Arrowtown areas. – Enables improvement in protection for the transformers.	2024-25	2.7



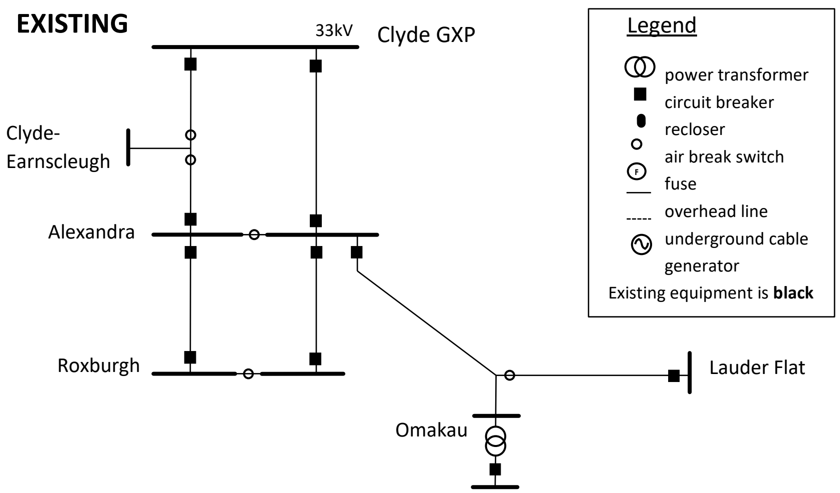


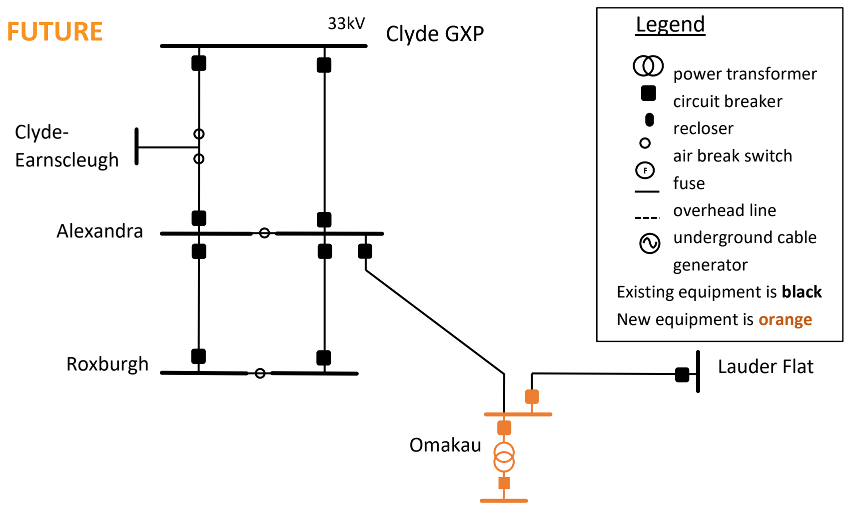
PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Smith Street to Willowbank Zone Substation 33 kV Intertie	The sub-transmission circuits in Dunedin are all radially fed, with two cables in the same trench. This risk is pertinent during earthquakes as highlighted in the Christchurch earthquake. The network architecture is not resilient – no ability to transfer load to between GXPs. The two 33 kV gas-filled sub-transmission cable to Willowbank is 57 years old and in relatively poor condition.	– Like-for-like replacement – Ring Architecture version 1 –first project is the Smith Street to Willowbank zone substation intertie – Ring Architecture version 2 same as above but different staging.	**Ring architecture version 1 - first project is the Smith Street to Willowbank zone substation intertie** This solution provides the following benefits: – Willowbank zone substations on the sub-transmission circuit. – Enables the cable route to be close to the proposed new North City zone substation. – Delays the timing of other 33 kV cable replacements – Addresses the common-mode failure issues associated with dual 33 kV cables in the same trench.	2021-24	6



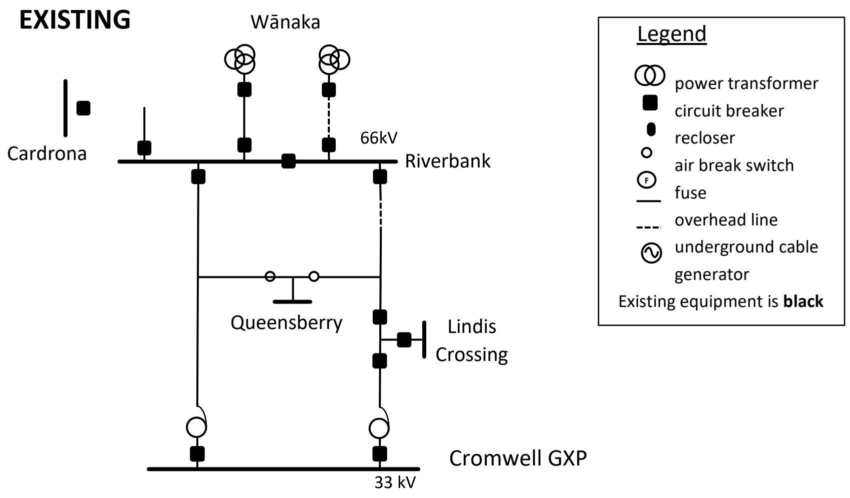


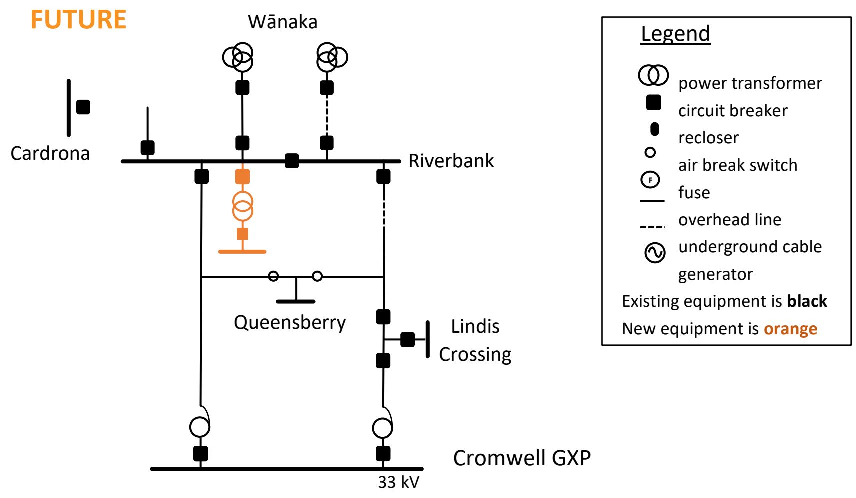
PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Omakau New Zone Substation	The load of the single power transformer has reached its capacity. The substation has limited backfeed from adjacent substations and does not have a mobile parking area. These limit the offload options during maintenance and unplanned outages. The substation is located on a road reserve with no space to expand. The substation has a flood risk being located very close to the river.	– Offload to Lauder Flat zone substation with mobile substation parking bay – As above, without mobile substation parking bay – New zone substation with mobile substation parking bay – As above, includes strengthening 11 kV interties.	New zone substation with mobile substation parking bay This solution provides the following benefits: – Improves the reliability of supply to Omakau zone substation – Significantly increases the capacity of Omakau zone substation enabling us to meet projected future growth in electricity load – Reduces the risk of equipment failure due to replacement of equipment that is at or close to end-of-life. – Fits in with our long-term strategy to have the Omakau and Lauder Flat provide backup to one another.	2021-24	3.1





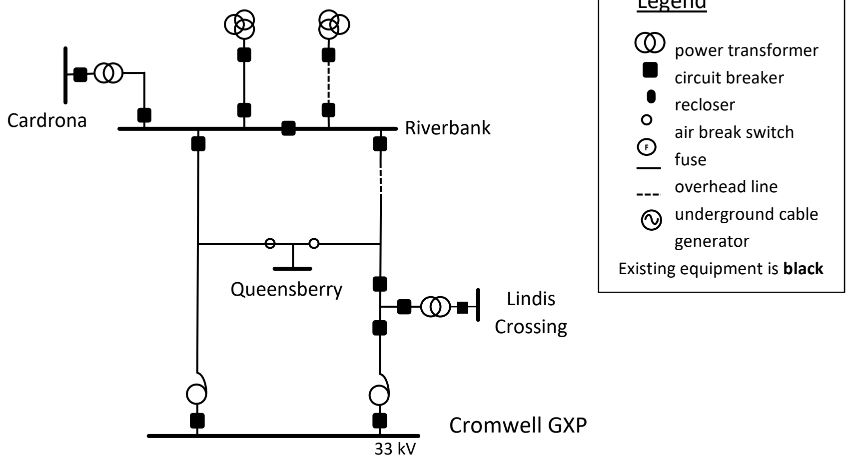
PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Riverbank zone substation upgrade	Firm capacity is forecast to be exceeded during RY24.	– Do Nothing – New transformer and switchgear at Riverbank – New zone substation at another location – Purchase spare transformer.	**New transformer and switchgear at Riverbank** This solution provides the following benefits: – Improves security of supply for Wānaka and Hāwea region – Provides a firm capacity of 48 MVA from the combined Wānaka and Riverbank zone substations – Provides additional 11 kV feeders into Wānaka area, thereby reducing load on existing feeders and enabling better backfeed for planned and unplanned outages – Significantly reduces the risk of a HILP event, involving the total loss of the Wānaka and Camp Hill substation, that would see significant outages in the Wānaka and Hāwea area.	2023-25	5





PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Second transformer at Lindis Crossing	The firm capacity is forecast to be exceeded during RY24.	– Do Nothing – Install a new 7.5 MVA transformer and extend 11 kV switchgear at Lindis Crossing zone substation – As above, with 6 MVA transformer (ex-Cardrona) – Rebuild Queensberry zone substation with a new 7.5 MVA transformer at a new site.	**Install 6 MVA transformer (ex-Cardrona) and extend 11 kV switchgear at Lindis Crossing zone substation** This solution provides the following benefits: – Provides capacity to cater for load growth, particularly irrigation and fruit packhouses – Provides ability to backfeed Queensberry zone substation which has only one transformer – Provides additional 11 kV feeders into Bendigo area, thereby reducing load on existing feeders and enabling better backfeed for planned and unplanned outages.	2027-28	1.4

EXISTING



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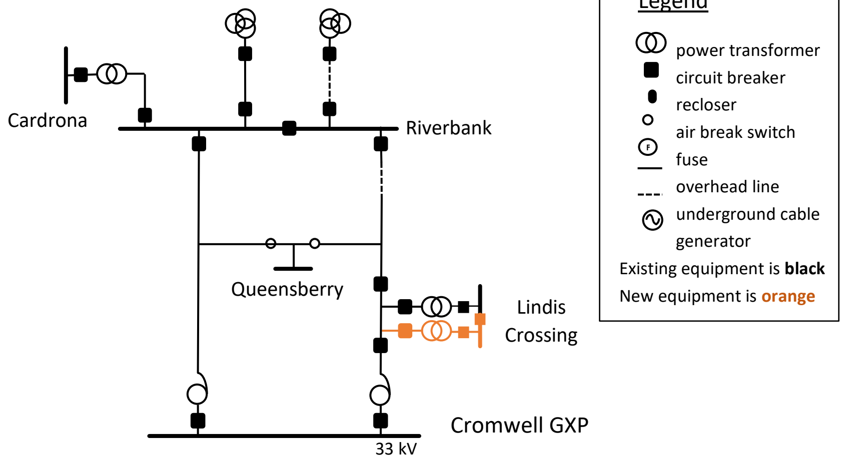
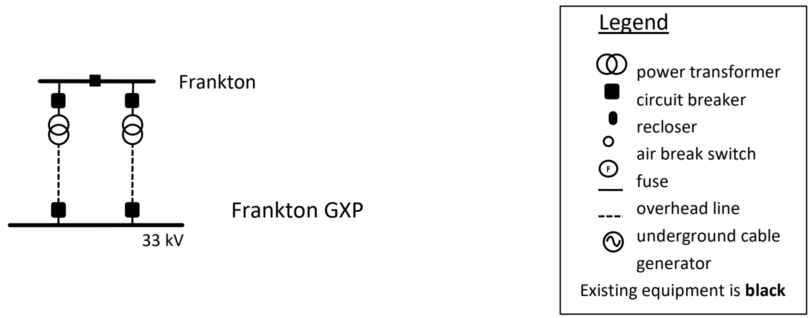


PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Frankton Zone Substation Upgrade	Load growth breaches security of supply guideline and exceeds the capacity of the smaller rated transformer.	– Do Nothing – Replace 7.5/15 MVA transformer with the 24 MVA (same rating as the bigger rated transformer) – Upgrade 11 kV network and offload Frankton zone substation.	**Replace 7.5/15 MVA transformer with the 24 MVA (same rating as the existing higher rated transformer)** This solution provides the following benefits: – Increases the firm capacity from 15 MVA to 24MVA.	2024-25	0.9

EXISTING



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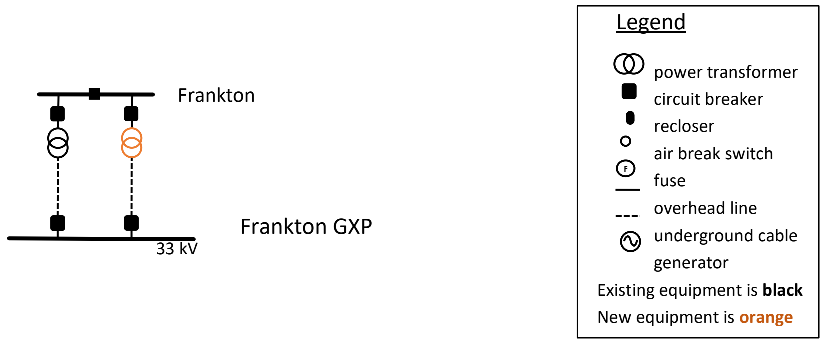
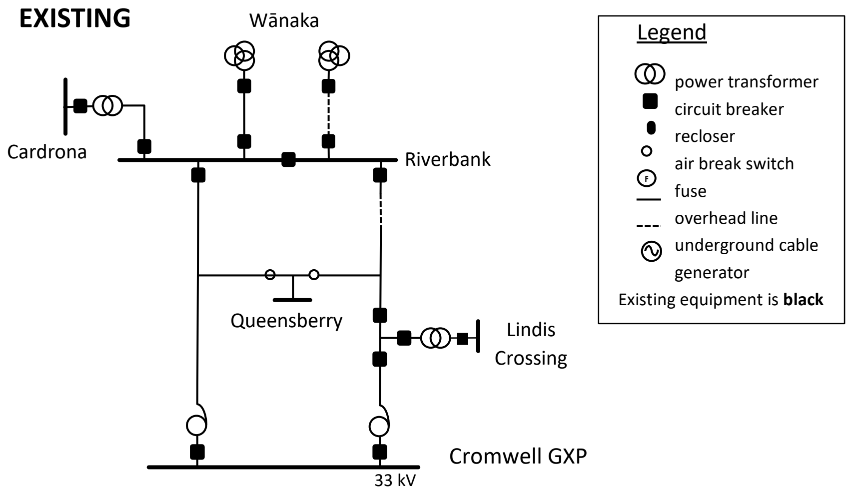
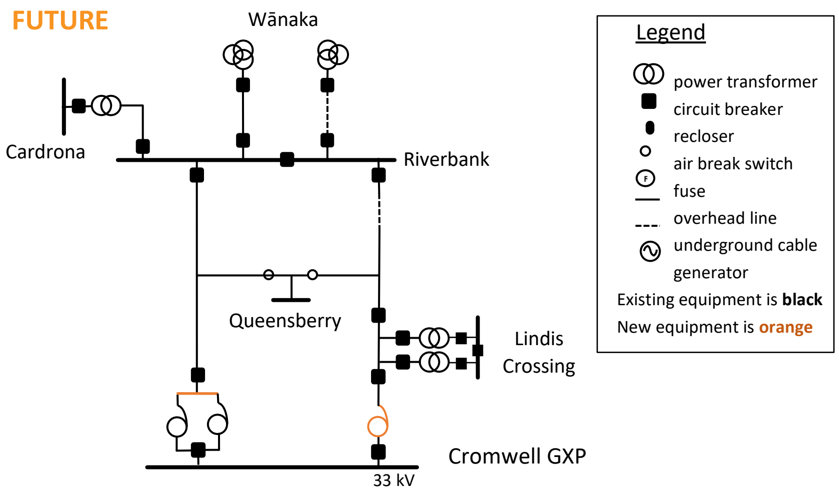
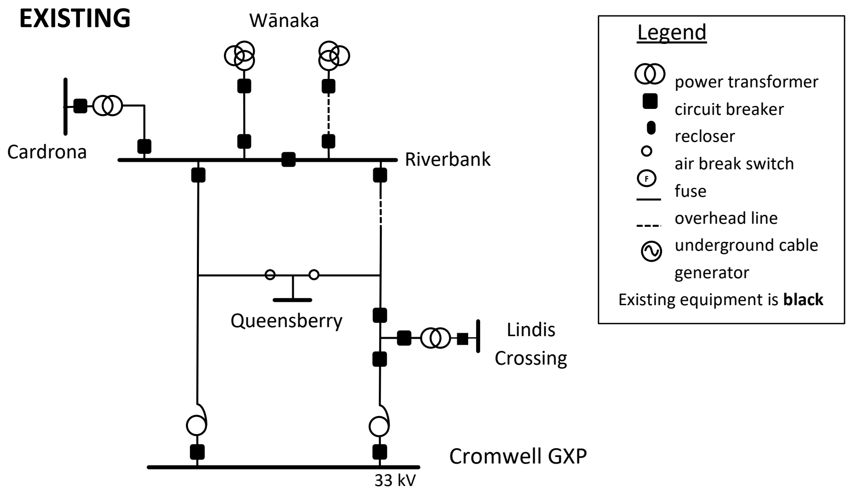


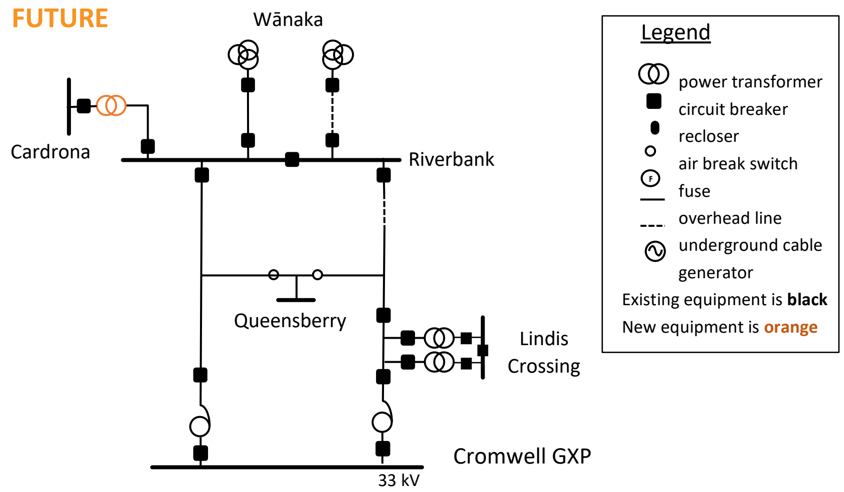
PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Upper Clutha Autotransformer replacement	To cater for load growth in the Upper Clutha	– Do Nothing – Install two new higher rated autotransformers – Parallel existing autotransformers and install one new higher rated autotransformer.	**Parallel existing autotransformers and install one new higher rated autotransformer** This solution provides the following benefits: – Increases capacity to cater for load growth.	2023-24	5



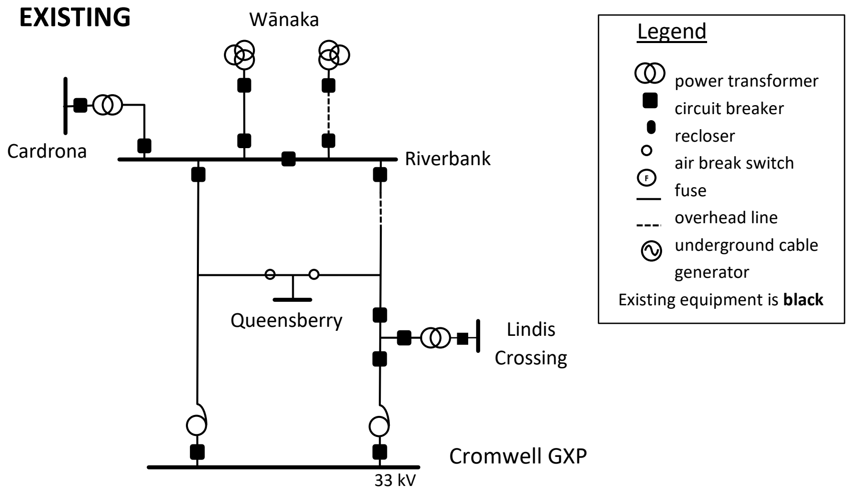


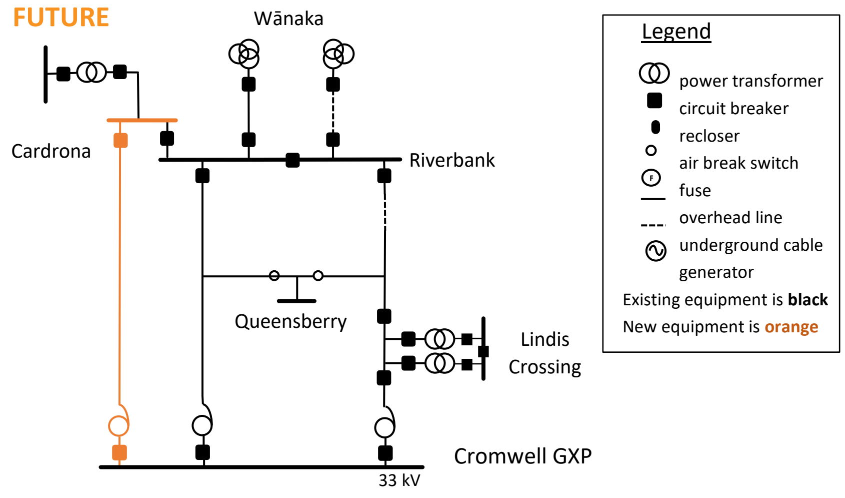
PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Cardrona substation transformer replacement	To meet the growth plans of Cardrona ski fields and other developments such as the Mount Cardrona Station.	– Do Nothing – Install a new 7.5MVA transformer in parallel with the existing transformer. – Install a new 24MVA transformer to replace existing transformer.	**Install a new 24MVA transformer to replace existing transformer** This solution provides the following benefits: – Increases capacity to cater for load growth in Cardrona.	2022-24	3.7





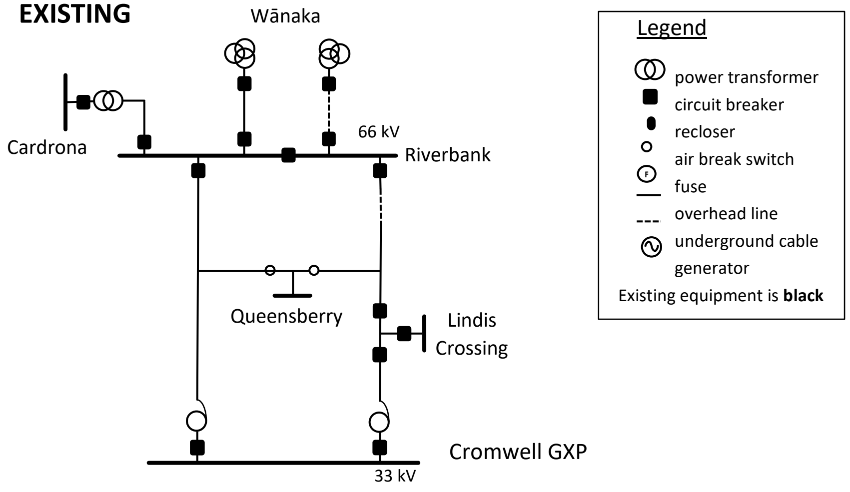
PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Upper Clutha new 66 kV line	Existing lines are anticipated to reach thermal and voltage constraints	– Do Nothing – Install a new 66 kV line from Cromwell to the Upper Clutha sub-network.	**Install a new 66 kV line** This solution provides the following benefits: – Significantly increase transmission capacity to the Upper Clutha region – This solution is indicative only and further investigation work is required to establish the final configuration.	2032-34	18.3





PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Riverbank zone substation second transformer	Need to increase level of security in the Wānaka area	– Do Nothing – Second transformer and switchgear at Riverbank	**Second transformer and switchgear at Riverbank** This solution provides the following benefits: – Improves security of supply for Wānaka and Hāwea region – Enables better backfeed for planned and unplanned outages.	2032-33	1.4

EXISTING



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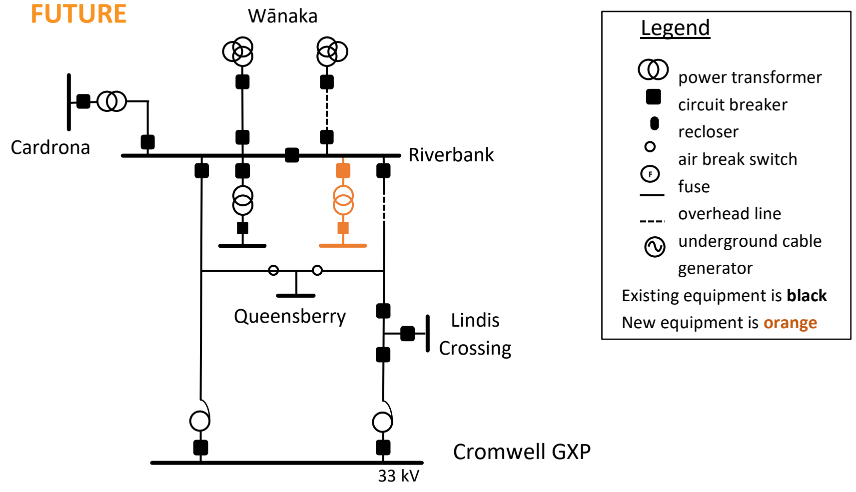
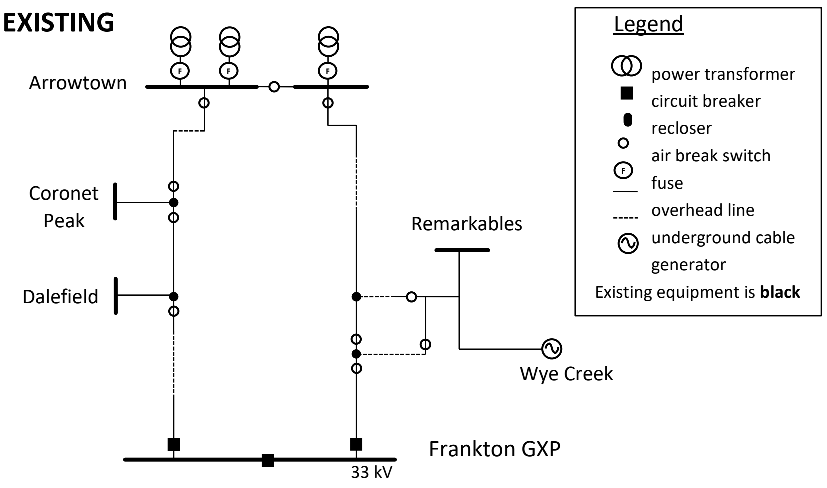
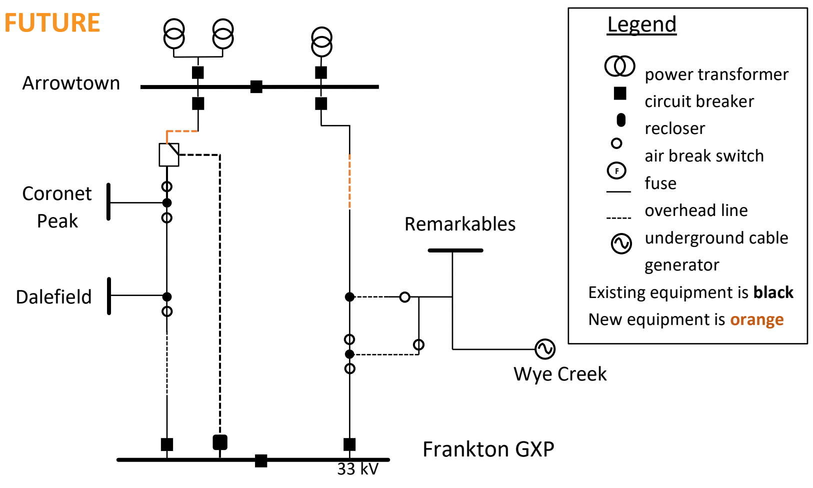


PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Wakatipu sub-transmission conductor upgrades	The existing connections are anticipated to reach thermal constraint	– Do Nothing – Replace existing conductor	**Replace existing conductor** This solution provides the following benefits: – Significantly improves the network voltages on the Arrowtown 33 kV ring – Enhances capacity in these parts of the ring	2032-34	1.3





Appendix G. DISCLOSURE REQUIREMENTS

This compliance matrix provides a look-up reference for each of the Commission's Information Disclosure requirements. The reference numbers are consistent with the clause numbers in the Electricity Distribution Information Disclosure Determination 2012.

Table G.1: Disclosure requirements checklist

REGULATORY REQUIREMENTS		AMP REFERENCE
2.6	ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	
	Disclosure relating to asset management plans and forecast information	
2.6.1	Except as provided in clause 2.6.1A, and subject to clause 2.6.3, before the start of each disclosure year commencing with the disclosure year 2014, (1) Each EDB must complete an AMP that— (a) relates to the electricity distribution services supplied by the EDB; (b) meets the purposes of AMP disclosure set out in clause 2.6.2; (c) has been prepared in accordance with: (i) in Aurora's case, clauses 1 to 18 of Attachment A; and (ii) in the case of other EDBs, clauses 1 to 17 of Attachment A; (d) contains the information set out in the schedules described in clause 2.6.6; and (e) contains the Report on Asset Management Maturity as described in Schedule 13; (2) Each EDB must complete the Report on Asset Management Maturity in accordance with the requirements specified in Schedule 13; and (3) Each EDB must publicly disclose the AMP. (4) Each EDB may choose to publicly disclose the information in clauses 17.1 – 17.6 of Attachment A in any of the following forms: (a) wholly in the EDB's AMP, in line with clause 2.6.1 above; or (b) wholly in a document(s) separate to the AMP, provided that- (i) the document is made publicly available on the EDB's website; and (ii) the contents page of the EDB's most recent AMP includes a hyperlink reference to the website where the document(s) can be located;	(1) (a)I This is stated in the Executive Summary. (b) Refer to 2.6.2 below. (c)(i) This compliance matrix demonstrates our compliance with Attachment A of the Information Disclosure. (d) See Appendix B. (e) Our AMMAT report is included in Appendix B. The results are discussed in Section 9.1.2. (2) Our AMMAT report is included in Appendix B. The results are discussed in Section 9.1.2. (3) We have published the AMP document on our website. (4) The information in clauses 17.1-17.6 is wholly disclosed within this AMP. Reference to this information is included in this Appendix G.

REGULATORY REQUIREMENTS		AMP REFERENCE
2.6.1A	Despite clause 2.6.1, (1) Clause 3.11.1(e) and (f) and clauses 12.5-12.7 of Attachment A do not apply in respect of the AMP required to be disclosed before the start of disclosure year 2024; (2) In respect of the AMP required to be disclosed before the start of disclosure year 2024, if an EDB chooses to publicly disclose the information in clauses 17.1-17.6 of Attachment A in a document separate to the AMP in line with clause 2.6.1A(2)(b), the EDB— (a) must publicly disclose that information by 30 June 2023; and (b) is not required to include in its AMP for disclosure year 2024 (publicly disclosed by 31 March 2023) a hyperlink reference to the website where the document(s) can be located. (3) In fulfilling the requirements of clause 2.6.1A(2) above, EDBs are exempt from the director certification requirements set out in clause 2.9 below in respect of the information disclosed in line with the requirements under clauses 17.1-17.6 of Attachment A, contained in either: (a) the EDB’s AMP required to be disclosed before the start of disclosure year 2024; or (b) in a document(s) separate to the AMP, which must be made publicly available on the EDB’s website by 30 June 2023.	See above.
2.6.2	The purposes of AMP disclosure referred to in subclause 2.6.1(1)(b) are that the AMP— (1) Must provide sufficient information for interested persons to assess whether- (a) assets are being managed for the long term; (b) the required level of performance is being delivered; and (c) costs are efficient and performance efficiencies are being achieved; (2) Must be capable of being understood by interested persons with a reasonable understanding of the management of infrastructure assets; (3) Should provide a sound basis for the ongoing assessment of asset-related risks, particularly high impact asset-related risks.	(1)(a) Chapters 3-5 provide an overview of our network and assets. (b) Historical reliability is detailed in Section 4.6.2 in relation to our overall asset management objectives. Section 2.3.4 discusses how stakeholders help to share our objectives. (c) We refer to expected efficiencies in a number of sections. See Section 5.4.4 for our approach to optimising asset replacements, and also Chapters 7 and 8 where we outline initiatives to improve cost and performance efficiencies per fleet. See also Section 10.1.3. (2) We attempt to clarify all technical terms within the body of the document. We have also included a glossary in Appendix A which will aid in understanding. (3) Risk management and resilience is discussed in Sections 4.7 and 4.9 respectively. Asset specific risks are identified and discussed throughout Chapter 8.
2.6.6	Each EDB —	(1) This information is included in Appendix B.

REGULATORY REQUIREMENTS		AMP REFERENCE
	(1) must, except as provided in subclause 2.6.6 (2), before the start of each disclosure year, complete and publicly disclose each of the following reports by inserting all information relating to the electricity distribution services supplied by the EDB for the disclosure years provided for in the following reports— (a) the Report on Forecast Capital Expenditure in Schedule 11a; (b) the Report on Forecast Operational Expenditure in Schedule 11b; (c) the Report on Asset Condition in Schedule 12a; (d) the Report on Forecast Capacity in Schedule 12b; (e) the Report on Forecast Network Demand in Schedule 12c; (f) the Report on Forecast Interruptions and Duration in Schedule 12d; (2) for the purposes of the Report on Forecast Capital Expenditure set out in Schedule 11a required under clause 2.6.6(1)(a), and the Report on Forecast Operational Expenditure set out in Schedule 11b required under clause 2.6.6(1)(b),- (a) is not required to publicly disclose information on cybersecurity expenditure, but must provide that information to the Commission; and (b) in respect of disclosures before the start of disclosure year 2024, is not required to- (i) complete and publicly disclose the information on cybersecurity expenditure in these reports; or (ii) provide the information required on cybersecurity expenditure to the Commission; and (3) must, If the EDB has sub-networks, complete and publicly disclose the Report on Forecast Interruptions and Duration set out in Schedule 12d by inserting all information relating to the electricity distribution services supplied by the EDB in relation to each sub-network for the disclosure years provided for in the report.’	(2) The requirements at 2.6.6(1)(a) do not need to be complied with until the start of disclosure year 2024. (3) This information is included in Appendix B.
2.7	EXPLANATORY NOTES TO DISCLOSED INFORMATION	
2.7.2	Before the start of each disclosure year, every EDB must complete and publicly disclose the Mandatory Explanatory Notes on Forecast Information in Schedule 14a by inserting all relevant information relating to information disclosed in accordance with clause 2.6.6.	This information is included in Appendix B.
2.9	CERTIFICATES	
2.9.1	Where an EDB is required to publicly disclose any information under clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2, the EDB must at that time publicly disclose a certificate in the form set out in Schedule 17 in respect of that information, duly signed by 2 directors of the EDB.	A copy of the certificate is included in Appendix H.

REGULATORY REQUIREMENTS		AMP REFERENCE
AMP design		
1.	The core elements of asset management— 1.1 A focus on measuring network performance, and managing the assets to achieve service targets; 1.2 Monitoring and continuously improving asset management practices; 1.3 Close alignment with corporate vision and strategy; 1.4 That asset management is driven by clearly defined strategies, business objectives and service level targets; 1.5 That responsibilities and accountabilities for asset management are clearly assigned; 1.6 An emphasis on knowledge of what assets are owned and why, the location of the assets and the condition of the assets; 1.7 An emphasis on optimising asset utilisation and performance; 1.8 That a total life cycle approach should be taken to asset management; 1.9 That the use of 'non-network' solutions and demand management techniques as alternatives to asset acquisition is considered.	1.1 Section 4.6.2 discusses our historical service performance. 1.2 Recognition of the need to improve our asset management and management capabilities, including a discussion regarding our AMMAT assessment and asset management improvement areas, are discussed in Section 9.1. 1.3 Sections 4.3-4.6 details the alignment between stakeholder needs, corporate vision and strategy, and our asset management objectives. 1.4 Sections 4.4-4.6 detail our business strategies and objectives, their relationship to our asset management practices and our service performance (including objectives and targets). Sections 5.3 and 6.4 outline the asset management drivers for meeting these performance targets. 1.5 Section 2.1.2 sets out our governance roles and responsibilities. See Section 4.8 for a description of governance roles within asset management teams. 1.6 Chapter 3 provides an overview of our network assets, including locations, while Chapter 8 provides further detail on each of our fleets. 1.7 Chapters 5, 7 and 8 detail our approach to identifying renewal or maintenance needs in order to ensure a full, safe, and reliable lifecycle. Section 6.3 looks at identifying areas for investment to improve the performance and reliability of the network. 1.8 Chapter 5 outlines a multi-stage approach for managing assets throughout their lifecycle. Chapters 6-8 then set out our investment approaches for each stage. 1.9 Our approach to non-network solutions is outlined in Section 6.3.8.
2.	The disclosure requirements are designed to produce AMPs that— 2.1 Are based on, but are not limited to, the core elements of asset management identified in clause 1;	2.1 The elements of asset management identified in clause 1 are referenced above, while further elements are discussed throughout the AMP itself.

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2.2 Are clearly documented and made available to all stakeholders; 2.3 Contain sufficient information to allow interested persons to make an informed judgement about the extent to which the EDB's asset management processes meet best practice criteria and outcomes are consistent with outcomes produced in competitive markets; 2.4 Specifically support the achievement of disclosed service level targets; 2.5 Emphasise knowledge of the performance and risks of assets and identify opportunities to improve performance and provide a sound basis for ongoing risk assessment; 2.6 Consider the mechanics of delivery including resourcing; 2.7 Consider the organisational structure and capability necessary to deliver the AMP; 2.8 Consider the organisational and contractor competencies and any training requirements; 2.9 Consider the systems, integration and information management necessary to deliver the plans; 2.10 To the extent practical, use unambiguous and consistent definitions of asset management processes and terminology consistent with the terms used in this attachment to enhance comparability of asset management practices over time and between EDBs; and 2.11 Promote continual improvements to asset management practices.	2.2 Our AMP is made available on our website to all stakeholders. 2.3 Our evaluation of our asset management processes is contained in Schedule 13 (Report on Asset Management Maturity) – refer to Appendix B. Asset management capability is discussed in Section 9.1. 2.4 Our reliability targets are set out in Section 4.6.2, while improvement initiatives are discussed in Appendix C. 2.5 Chapter 8 discusses the condition, performance and risk for each individual fleet. Sections 4.7 and 4.9 discuss risk management and resilience in general, while Section 9.1.3 sets out our asset management development plan. 2.6 Service delivery is discussed in Section 4.8.2 and works delivery in 4.8.3. Solution development for major projects is also discussed in Section 6.3.2. Section 5.4.2 discusses our approach to design and construction. 2.7 Governance roles and responsibilities are discussed in Section 2.1.2 and capability is further discussed in Chapter 9. 2.8 Sections 2.2.6 and 7.2.1 discuss the performance quality of our service providers, and Section 9.1 discusses our organisational capabilities. 2.9 Section 9.3 and Appendix E provides information on our ICT team and supporting systems. 2.10 We attempt to clarify all technical terms in the body of the document. We have also included a glossary of terms in Appendix A. 2.11 Section 4.6 discusses asset management objectives and strategy and Section 9.1 discusses our asset management capability, including our current asset management capability and areas for improvement.

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Contents of the AMP		
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;	3.1 The Executive Summary provides an overview of our investment plans and highlights other information that we consider significant.
	3.2 Details of the background and objectives of the EDB's asset management and planning processes;	3.2 Chapter 2 provides background to our asset management and planning processes, while Chapter 4 discusses in detail our management strategy and governance approaches.
	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; 3.3.2 states the corporate mission or vision as it relates to asset management; 3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB; 3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management; and 3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans;	3.3.1 Our purpose statement is provided in Section 1.1 and further outlined in Section 4.4. 3.3.2 Section 4.4.1 discusses our vision, mission and values. 3.3.3 Section 4.2 discusses the role of documentation within our strategic framework. 3.3.4 Section 4.2 outlines the role of each planning document and their overall relationship. 3.3.5 Chapter 4 relates our asset management objectives with our business objectives and the needs of stakeholders.
	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;	Section 1.1.2 details the period covered by the AMP.
	3.5 The date that it was approved by the directors;	See Section 2.1.1.
	3.6 A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates- 3.6.1 how the interests of stakeholders are identified 3.6.2 what these interests are; 3.6.3 how these interests are accommodated in asset management practices; and 3.6.4 how conflicting interests are managed;	3.6 Sections 2.2 and 4.3 discuss our stakeholders. 3.6.1 Section 2.3 explains our engagement with stakeholders to identify key interests. 3.6.2 Stakeholder interests are set out in Section 2.3.3. 3.6.3 Section 4.3 shows how our asset management objectives align with stakeholder interests. 3.6.4 Section 2.2 details how conflicts are managed.

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3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including- 3.7.1 governance—a description of the extent of director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to directors; 3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured; and 3.7.3 field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used;	3.7.1 Section 2.1.1 details our ownership and governance structure regarding key asset management decisions. 3.7.2 Section 2.1.1 discusses our executive team. 3.7.3 Section 4.8.2 discusses our service delivery, while Section 4.8.3 discusses our works delivery. Section 5.4.2 outlines the process for project delivery with our service providers.
3.8 All significant assumptions- 3.8.1 quantified where possible; 3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including- 3.8.3 a description of changes proposed where the information is not based on the EDB's existing business; 3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and 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;	3.8.1 We comment on the possible impacts of certain assumptions (E.g. impact of the COVID-19 pandemic on demand forecasts and growth forecasts, refer to the Executive Summary and Chapter 2, Box 2.1). These assumptions are qualified where possible. 3.8.2 Significant assumptions are discussed throughout the AMP, including in Chapters 6 and 10. Where possible they are clearly identified by the headings to the relevant section (refer, for example, to Sections 6.3.3, 10.1, 10.4). 3.8.3 Not applicable. 3.8.4 Sources of uncertainty (and the potential effect of the uncertainty on information) are discussed throughout the AMP. For example, several factors that influence network demand may change over time, which is why we develop multiple scenarios to assists with planning. Section 6.3.6. 3.8.5 Section 10.1.4 discusses inputs and assumptions underpinning our forecasts.
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;	Our cost estimation assumptions for our investment plans are outlined in Section 10.4. Our investment plans are based on forecast asset risk and network growth; we outline our forecasting approaches, and their limitations, in Sections 5.4.4 and 6.3.6 respectively.

REGULATORY REQUIREMENTS		AMP REFERENCE
	3.10 An overview of asset management strategy and delivery; *To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management strategy and delivery, the AMP should identify-* *(i) how the asset management strategy is consistent with the EDB's other strategy and policies;* *(ii) how the asset strategy takes into account the life cycle of the assets;* *(iii) the link between the asset management strategy and the AMP; and* *(iv) processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented.*	Section 4.6 discusses our asset management strategy and objectives, and Chapter 8 our lifecycle management of each of our fleets. Section 4.2 and Sections 4.4-4.6 discuss our strategic framework, our corporate strategy and asset management policy. Section 4.1 provides an overview of our asset management system. The link between asset management strategy and the AMP is discussed in Sections 4.2 to 4.6. Section 4.2 discusses our strategic framework and Section 4.8 details the processes that we have in place in terms of asset management governance.
	3.11 An overview of systems and information management data; To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe- (a) the processes used to identify asset management data requirements that cover the whole-of-life cycle of the assets; (b) the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets; (c) the systems and controls to ensure the quality and accuracy of asset management information; and (d) the extent to which these systems, processes and controls are integrated; (e) how asset management data informs the models that an EDB develops and uses to assess asset health: and (f) how the outputs of these models are used in developing capital expenditure projections.	(a) Renewal drivers such as asset health and asset condition are discussed in Section 5.4.4. Our approach to network operations and maintenance is discussed in Section 7.2. Section 9.3.1 provides an overview of our ICT requirements, with further information contained in Appendix E. Our asset management approach for each fleet is discussed in Chapter 8. (b) Asset management systems are discussed in Section 9.3.3 and further in Appendix E. (c) Asset management systems are discussed in Section 9.3.3 and further in Appendix E. Improvements to our asset management capability are set out in Section 2.4.8. (d) Systems and controls are discussed in Appendix E. (e) Not required to be disclosed before the start of disclosure year 2024 pursuant to clause 2.6.1a(1) of the Determination. (f) Not required to be disclosed before the start of disclosure year 2024 pursuant to clause 2.6.1a(1) of the Determination.
	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;	ICT investment in relation to asset management data is discussed in Section 9.3 and limitations and initiatives to improve data are discussed in Section 9.1.4 and Appendix E. Improvements to our asset management capability are set out in Section 2.4.8.

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3.13 A description of the processes used within the EDB for- 3.13.1 managing routine asset inspections and network maintenance; 3.13.2 planning and implementing network development projects; and 3.13.3 measuring network performance;	3.13.1Section 5.4.3 provides an overview of our maintenance approach. Chapter 7 details our inspection and maintenance approaches for each asset fleet. 3.13.2Our approach to developing our network is discussed in Chapter 6. 3.13.3Performance is discussed in Section 4.6 and Appendix C.
3.14 An overview of asset management documentation, controls and review processes. *To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should-* *(i) identify the documentation that describes the key components of the asset management system and the links between the key components;* *(ii) describe the processes developed around documentation, control and review of key components of the asset management system;* *(iii) where the EDB outsources components of the asset management system, the processes and controls that the EDB uses to ensure efficient and cost effective delivery of its asset management strategy;* *(iv) where the EDB outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house; and* *(v) audit or review procedures undertaken in respect of the asset management system.*	Chapter 4 discusses our strategy and governance. In particular: • Section 4.1.1 discusses our Asset Management System. In addition, asset management systems are discussed in Section 9.3and further in Appendix E; • Section 4.2 discusses our strategic framework; • Section 4.5 discusses our Asset Management Policy; • Section 4.6 discusses our Asset management objectives; • Section 4.8 discusses our asset management governance; • Sections 4.8.2 and 4.8.3 discuss components of our asset management system that are outsourced. • Section 7.2.1 explains how we ensure that we retain core asset knowledge in-house. • Section 4.1.1 discusses our review procedures in relation to our asset management system.
3.15 An overview of communication and participation processes; *To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should-* *(i) communicate asset management strategies, objectives, policies and plans to stakeholders involved in the delivery of the asset management requirements, including contractors and consultants; and* *(ii) demonstrate staff engagement in the efficient and cost effective delivery of the asset management requirements.*	Chapter 2 details our relationship with our stakeholders and customers and Section 4.3 also discusses community and stakeholder interaction. Sections 2.2, 2.3 and 4.3 discuss our interactions with stakeholders. Section 2.1.2 details our governance roles and responsibilities and Sections 2.2.6 and 2.2.7 discusses our service providers and staff.

REGULATORY REQUIREMENTS		AMP REFERENCE
	3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and	This is stated in Section 10.1.
	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.	The structure of the AMP is detailed in Section 1.2.
Assets covered		
4.	The AMP must provide details of the assets covered, including-	An overview of assets is included in Section 3.9, with more detailed fleet information contained in Chapter 8.
	4.1 a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including- 4.1.1 the region(s) covered; 4.1.2 identification of large consumers that have a significant impact on network operations or asset management priorities; 4.1.3 description of the load characteristics for different parts of the network; 4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	4.1 Service areas are discussed in Chapter 3. 4.1.1 The regions covered by our network are discussed in Chapter 3, in particular Section 3.6 to 3.8. 4.1.2 Major customers are discussed in Sections 3.6.2, 3.7.2 and 3.8.2. 4.1.3 Load characteristics are discussed in Sections 3.6.1, 3.7.1 and 3.8.1. 4.1.4 We provide peak load information per zone substation in Chapter 3. See Sections 3.6-3.8. This section also includes total energy delivered.
	4.2 a description of the network configuration, including- 4.2.1 identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point; 4.2.2 a description of the sub-transmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the sub-transmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x sub-transmission security or by providing alternative security class ratings; 4.2.3 a description of the distribution system, including the extent to which it is underground; 4.2.4 a brief description of the network's distribution substation arrangements; 4.2.5 a description of the low voltage network including the extent to which it is underground; and	4.2.1 This information is set out in Sections 3.3 and 3.4. Peak demand for each supply point is provided in Section 6.4. 4.2.2 Chapter 3 describes our sub-transmission network for across our three sub-networks. The capacity and security ratings of individual zone substations is set out in Section 6.4.1. 4.2.3 See Chapter 3 for a description of our distribution network. Section 3.9 includes information on overhead vs. underground assets. 4.2.4 An overview is provided in Section 8.6. 4.2.5 See Chapter 3 for a description of our LV network. Section 3.9 includes information on overhead vs. underground assets. 4.2.6 An overview of secondary systems is provided in Section 8.7. For maintenance of these assets, see Section 7.7.7.

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	4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems. *To help clarify the network descriptions, network maps and a single line diagram of the sub-transmission network should be made available to interested persons. These may be provided in the AMP or, alternatively, made available upon request with a statement to this effect made in the AMP.*	Chapter 3 includes network maps and a single line diagram.
	4.3 If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.	Refer to 4.2 above.
	Network assets by category	
	4.4 The AMP must describe the network assets by providing the following information for each asset category- 4.4.1 voltage levels; 4.4.2 description and quantity of assets; 4.4.3 age profiles; and 4.4.4 a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	4.4 Network assets are detailed in Chapters 3, 5 and 8. 4.4.1 These are provided, where relevant, in Chapter 8. 4.4.2 In Chapter 8, we describe our network assets and include their quantities. 4.4.3 These are described individually for each fleet in Chapter 8. 4.4.4 For each asset fleet, we outline overall health distribution and identify key failure risks that we monitor. See Chapter 8.
	4.5 The asset categories discussed in clause 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; and 4.5.4 other generation plant owned by the EDB.	4.5.1 We manage our fleets using our own categories. In Table 8.1 we map our asset categories to those included in the Schedules. 4.5.2 Assets installed at bulk supply points are listed in Chapter 3, Table 3.2. Their voltage level, age profile, and condition ratings are covered in their respective fleet plans in Chapter 8. 4.5.3 Mobile substations are discussed in Section 8.6.5. 4.5.4 Not applicable.

REGULATORY REQUIREMENTS		AMP REFERENCE
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.	Section 4.6 sets out our performance indicators and targets.
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.	These are set out in Section 4.6.2.
7.	Performance indicators for which targets have been defined in clause 5 should also include- 7.1 Consumer oriented indicators that preferably differentiate between different consumer types; and 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.	7.1 Performance indicators for safety and reliability are discussed in Sections 4.6.1 and 4.6.2. In addition, Section 2.3 discusses feedback from customers which helps us to set our targets. 7.2 Section 8.1.2 sets out performance indicators for pole failures and section 6.4 sets out performance indicators for load factor and transformer utilisation. Our investment plans do not use asset performance targets at this stage. We expect to include such targets in future AMPs. Section 9.1.3 sets out information about our Asset Management Development Plan.
8.	The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders’ requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	Section 4.6 discusses our key asset management objectives and their related performance indicators.
9.	Targets should be compared to historic values where available to provide context and scale to the reader.	Sections 4.6.1 and 4.6.2 set out historic values for safety and reliability performance targets.
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. *Performance against target must be monitored for disclosure in the Evaluation of Performance section of each subsequent AMP.*	Forecast expenditure is detailed in Chapter 10 and service level forecasts in Section 4.6.2.

REGULATORY REQUIREMENTS		AMP REFERENCE
Network Development Planning		
11.	AMPs must provide a detailed description of network development plans, including—	Network development is discussed in Chapter 6.
	11.1 A description of the planning criteria and assumptions for network development;	Our planning process is discussed in Section 6.3; key planning assumptions and inputs are found in Section 6.3.3.
	11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	Our planning criteria is discussed in Section 6.3 and our security guidelines are set out in Section 6.3.5.
	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;	These aspects are discussed in Section 5.4.2. See also Section 6.3 for our approach to cost efficiency for major projects.
	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; and 11.4.2 the approach used to identify standard designs;	Section 5.4.2 sets out the approach used to identify standard designs. Chapter 8 sets out information about the categories of assets and designs that are standardised.
	11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network;	Our approach to flexibility management and related solutions is set out in Section 6.6.
	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; *The criteria described should relate to the EDB's philosophy in managing planning risks.*	Section 6.4 discusses the investment drivers, including system demand (capacity). Asset and network planning in terms of asset risk management are discussed in Section 4.7.
	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;	Section 6.3 includes discussions on identifying network needs and solution prioritisation.
	11.8 Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand; 11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates; 11.8.2 provide separate forecasts to at least the zone substation level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	11.8 System demand is discussed, and demand forecasts are provided, in Section 6.4. 11.8.1 The method used for load forecasting is set out in Section 6.3.6. 11.8.2 Load forecasting is set out in Section 6.4. 11.8.3 Network constraints are discussed for each sub-network in Section 6.4. 11.8.4 Distributed generation is discussed in Section 3.4 and demand management in Section 6.4.

REGULATORY REQUIREMENTS		AMP REFERENCE
	11.8.3 identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and 11.8.4 discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives;	
	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; and 11.9.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;	Major projects are discussed in Section 6.5 and Appendix F
	11.10 A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include- 11.10.1 a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months; 11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and 11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period; *For projects included in the AMP where decisions have been made, the reasons for choosing the selected option should be stated which should include how target levels of service will be impacted. For other projects planned to start in the next five years, alternative options should be discussed, including the potential for non-network approaches to be more cost effective than network augmentations.*	Network development investments are discussed in Section 6.5, in particular Section 6.5.3. Further detail on these projects (including alternative options considered and the reasons for choosing the selected option) is set out in Appendix F.
	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; and	Distributed generation is discussed in Section 3.4.

REGULATORY REQUIREMENTS		AMP REFERENCE
	11.12 A description of the EDB's policies on non-network solutions, including- 11.12.1 economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation; and 11.12.2 the potential for non-network solutions to address network problems or constraints.	Non-network solutions are discussed in Section 6.3.8.
Lifecycle Asset Management Planning (Maintenance and Renewal)		
12.	The AMP must provide a detailed description of the lifecycle asset management processes, including—	Our lifecycle management approach is discussed across Chapters 5, 7 and 8.
	12.1 The key drivers for maintenance planning and assumptions;	See Section 7.2 for an outline of our maintenance activity drivers, including our approach to planning.
	12.2 Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include- 12.2.1 the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done; 12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and 12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period;	12.2.1 and 12.2.2 Section 7.7 documents our maintenance activity for each fleet individually. 12.2.3 Opex budgets for asset maintenance are provided in Sections 7.3-7.5.
	12.3 Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include- 12.3.1 the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets; 12.3.2 a description of innovations that have deferred asset replacements; 12.3.3 a description of the projects currently underway or planned for the next 12 months; 12.3.4 a summary of the projects planned for the following four years (where known); and	12.3 Refurbishment and renewal is discussed in Section 5.4.4 and further in Chapter 8 for each fleet individually. 12.3.1 Chapter 8 provides this information for each fleet individually. 12.3.2 Non-network solutions are addressed in Section 6.6.1. 12.3.3 to 12.3.5 This is discussed in Chapter 8 for each fleet individually.

REGULATORY REQUIREMENTS		AMP REFERENCE
	12.3.5 an overview of other work being considered for the remainder of the AMP planning period; and	
	12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	All asset types from clause 4.5 are included, however, we do use our own asset categories. See Table 8.1.
	12.5 Identification of the approach used for developing capital expenditure projects for lifecycle asset management. This must include an explanation of: 12.5.1 the approach that the EDB uses to inform its capital expenditure projections for lifecycle asset management; and 12.5.2 the rationale for using the approach for each asset category.	Not required to be disclosed before the start of disclosure year 2024 pursuant to clause 2.6.1A(1) of the Determination.
	12.6 Identification of vegetation management related maintenance. This must include an explanation of the approach and assumptions that the EDB uses to inform its vegetation management related maintenance.	Not required to be disclosed before the start of disclosure year 2024 pursuant to clause 2.6.1A(1) of the Determination.
	12.7 The EDB's consideration of non-network solutions to inform its capital and operational expenditure projections for lifecycle asset management. This must include an explanation of the approach and assumptions the EDB used to inform these expenditure projections.	Not required to be disclosed before the start of disclosure year 2024 pursuant to clause 2.6.1A(1) of the Determination.
Non-Network Development, Maintenance and Renewal		
13.	AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including— 13.1 a description of non-network assets; 13.2 development, maintenance and renewal policies that cover them; 13.3 a description of material capital expenditure projects (where known) planned for the next five years; and 13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	13.1 Chapter 9 and Appendix E detail our non-network assets. 13.2 Section 9.3.3 details our ICT strategy and planning. Section 9.4.2 details our company policy in relation to motor vehicles. 13.3 This is discussed in Sections 9.3.3 and 10.2.3, and Appendix E. 13.4 Material ICT maintenance and renewal projects are discussed in Section 9.3.3. There are no other material maintenance and renewal projects in relation to other non-network assets.
Risk Management		
14.	AMPs must provide details of risk policies, assessment, and mitigation, including— 14.1 Methods, details and conclusions of risk analysis; 14.2 Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events;	14.1 Our risk framework is mentioned in Sections 4.7 and 4.9. 14.2 and 14.3 High impact low probability events are discussed in Section 4.9. 14.4 Emergency procedures and plans are discussed in Section 4.9.3.

REGULATORY REQUIREMENTS		AMP REFERENCE
	14.3 A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and 14.4 Details of emergency response and contingency plans. *Asset risk management forms a component of an EDB's overall risk management plan or policy, focusing on the risks to assets and maintaining service levels. AMPs should demonstrate how the EDB identifies and assesses asset related risks and describe the main risks within the network. The focus should be on credible low-probability, high-impact risks. Risk evaluation may highlight the need for specific development projects or maintenance programmes. Where this is the case, the resulting projects or actions should be discussed, linking back to the development plan or maintenance programme.*	
Evaluation of performance		
15.	AMPs must provide details of performance measurement, evaluation, and improvement, including—	
	15.1 A review of progress against plan, both physical and financial; *referring to the most recent disclosures made under Section 2.6 of this determination, discussing any significant differences and highlighting reasons for substantial variances;* *commenting on the progress of development projects against that planned in the previous AMP and provide reasons for substantial variances along with any significant construction or other problems experienced; and* *commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted.*	This is addressed in Appendix D where we compare our forecast and actual performance for the previous regulatory year.
	15.2 An evaluation and comparison of actual service level performance against targeted performance; *in particular, comparing the actual and target service level performance for all the targets discussed under the Service Levels section of the AMP in the previous AMP and explain any significant variances.*	The Executive Summary (refer to pages XIV to XVII) and Section 4.6.2 discuss our reliability performance, our primary service performance measure.
	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.	Section 9.1.2 sets out 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 objectives of Aurora's asset management and planning processes.

REGULATORY REQUIREMENTS		AMP REFERENCE
	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.	Sections 4.6 and Appendix C address gaps identified in clause 15.2 and Section 9.1.2 addresses gaps identified in clause 15.3.
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; and 16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP.	16.1 Chapter 4 discusses our objectives, strategy and governance practices. 16.2 An overview of our ownership and governance structure is included in Section 2.1 along with governance roles and responsibilities. Chapter 4 details further our approach to strategy and governance, including in particular the processes and procedures in place relating to authorisation and delivery of our investment plans. Deliverability in light of our field service contractors is discussed in Section 2.1.2 and 2.2.6. Chapter 9 discusses the functions and assets that support our asset management activities.
Requirements to provide qualitative information in narrative form		
17.	AMPs must include qualitative information in narrative form, as prescribed in clauses 17.1-17.7 below:	
	Notice of planned and unplanned interruptions 17.1 a description of how the EDB provides notice to and communicates with consumers regarding planned interruptions and unplanned interruptions, including any changes to the EDB's processes and communications in respect of planned interruptions and unplanned interruptions;	Pursuant to clause 2.1.2 of the Determination, Aurora Energy is not required to comply with clauses 17.1-17.3 of Attachment A.

REGULATORY REQUIREMENTS		AMP REFERENCE
	Voltage quality 17.2 a description of the EDB's practices for monitoring voltage, including: 17.2.1 the EDB's practices for monitoring voltage quality on its low voltage network; 17.2.2 work the EDB is doing on its low voltage network to address any known non-compliance with the applicable voltage requirements of the Electricity (Safety) Regulations 2010; 17.2.3 how the EDB responds to and reports on voltage quality issues when the EDB identifies them, or when they are raised by a stakeholder; 17.2.4 how the EDB communicates with affected consumers regarding the voltage quality work it is carrying out on its low voltage network; and 17.2.5 any plans for improvements to any of the practices outlined at clauses 17.2.1-17.2.4 above;	Pursuant to clause 2.1.2 of the Determination, Aurora Energy is not required to comply with clauses 17.1-17.3 of Attachment A.
	Customer service practices 17.3 a description of the EDB's customer services practices, including: 17.3.1 the EDB's customer engagement protocols and customer service measures – including customer satisfaction with the EDB's supply of electricity distribution services; 17.3.2 the EDB's approach to planning and managing customer complaint resolution;	Pursuant to clause 2.1.2 of the Determination, Aurora Energy is not required to comply with clauses 17.1-17.3 of Attachment A.
	Practices for connecting new consumers and altering existing connections 17.4 a description of the EDB's practices for connecting consumers, including: 17.4.1 the EDB's approach to planning and management of - (a) connecting new consumers (offtake and injection connections), and overcoming commonly encountered issues; and (b) alterations to existing connections (offtake and injection connections); 17.4.2 how the EDB is seeking to minimise the cost to consumers of new or altered connections; 17.4.3 the EDB's approach to planning and managing communication with consumers about new or altered connections; and 17.4.4 commonly encountered delays and potential timeframes for different connections.	17.4.1(a) Section 2.3.4, 6.8 and 10.2.1 outline our approach to new connections and our planned expenditure for this area. 17.4.1 (b) Section 5.3 and Section 10.2.2 outline our approach to asset relocations and our planned expenditure 17.4.2 Section 6.8 covers our approach to consumer connections. Section 5.3 outlines the costing of altered connections and our aim to upgrade assets when in poor condition. 17.4.3 Section 4.8.2 describes our approach to communication about Customer Initiated Works (CIW) 17.4.4 Section 4.8.2 addresses commonly encountered delays.
	New connections likely to have a significant impact on network operations or asset management priorities	

REGULATORY REQUIREMENTS		AMP REFERENCE
	17.5 A description of the following: 17.5.1 how the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network, including: (a) how the EDB measures the scale and impact of new demand, generation, or storage capacity; (b) how the EDB takes the timing and uncertainty of new demand, generation, or storage capacity into account; (c) how the EDB takes other factors into account, eg, the network location of new demand, generation, or storage capacity; and 17.5.2 how the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity;	17.5.1 Chapter 6 discusses in detail our approach towards demand forecasting as well as other topics within network growth such as solar PV uptake, electric vehicles, and distributed generation. 17.5.2 Section 6.3 discusses the approach used for planning our future network development. A key aspect of our demand forecasts and network planning involves utilising several scenarios to capture a range of possible outcomes.
	Innovation practices 17.6 a description of the following: 17.6.1 any innovation practices the EDB has planned or undertaken since the last AMP or AMP update was publicly disclosed, including case studies and trials; 17.6.2 the EDB's desired outcomes of any innovation practices, and how they may improve outcomes for consumers; 17.6.3 how the EDB measures success and makes decisions regarding any innovation practices, including how the EDB decides whether to commence, commercially adopt, or discontinue these practices; 17.6.4 how the EDB's decision-making and innovation practices depend on the work of other companies, including other EDBs and providers of non-network solutions; and 17.6.5 the types of information the EDB uses to inform or enable any innovation practices, and the EDB's approach to seeking that information.	17.6.1 We discuss several innovations in relation to operations and maintenance of our network in Chapter 7, including a trial of an early fault detection system (see 7.7.2). Additionally, Section 6.6.1 discusses our involvement in a trial to use flexibility management to mitigate demand constraints and defer network investment. 17.6.2 Section 5.3 discusses our bespoke risk framework, in which we outline the benefits this will bring to our customers through improved planning efficiency, reduced costs, and improved asset performance. 17.6.3 Section 7.2.3 explains how innovation practices are identified and approved, and how we measure their success. 17.6.4 Section 6.3.8 and 6.6.4 highlight our continued use and investigation into non-network solutions. Section 5 details our approach to lifecycle management, in which we build upon best industry practice. 17.6.5 Section 2.3 details our use of customer communication to inform customer focused innovation. We also refer to our connection with the wider industry context on a variety of topics in Section 2.4.
	17.7 For the purposes of disclosing the information required under clauses 17.6.1-17.6.5 above, an EDB is not required to include commercially sensitive or confidential information.	

	REGULATORY REQUIREMENTS	AMP REFERENCE
Additional AMP disclosure requirements for Aurora		
18.	Aurora must summarise in its AMP Aurora's development plan under clause 2.5.4(1) to develop and improve its: 18.1 Asset data collection and asset data quality practices as specified in clause 2.5.4(1)(d); 18.2 Asset management practices and processes as specified in clause 2.5.4(1)(e)(i) to (iii); 18.3 Practices for identifying and reducing safety risks as specified in clause 2.5.4(1)(e)(iv); 18.4 Practices for estimating the costs of capital expenditure and operational expenditure projects and programmes as specified in clause 2.5.4(1)(f); and 18.5 Quality assurance processes as specified in clause 2.5.4(1)(g)	Section 9.1.4 summarises our development plan in relation to the requirements outlined in 17.1 through 17.5.

Appendix H. DIRECTOR'S CERTIFICATE

Certification for Year beginning Disclosures

Pursuant to Clause 2.9.1 of Section 2.9

We Stephen Richard Thompson and Janice Evelyn Fredric, being directors of Aurora Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Aurora Energy Limited prepared for the purposes of clauses 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c, and 12d are based on objective and reasonable assumptions which both align with Aurora Energy Limited's corporate vision and strategy and are documented in retained records.

Director	Director
29 March 2023	29 March 2023
Date	Date