ASSET MANAGEMENT PLAN

APRIL 2020 – MARCH 2030

Aurora ENERGY

12 June 2020

EXECUTIVE SUMMARY

This Asset Management Plan (AMP) outlines Aurora Energy's approach to managing its electricity distribution assets during the period 1 April 2020 to 31 March 2030. The AMP sets out the investments we need to make over the next ten years so that we can continue to provide a safe and reliable power supply to electricity consumers in Dunedin and Central Otago.

Our 2020 Asset Management Plan

We are publishing this AMP on 12 June as part of a Customised Price-quality Path (CPP) application that we are submitting to our sector regulator, the Commerce Commission (Commission).[1] This AMP forms part of our proposal and explains why the investments are necessary, and why certain investments should be prioritised over the three-year CPP Period (1 April 2021 to 31 March 2024).

Further information on our CPP application and additional supporting material can be found on our CPP website.

Our ten-year investment plan includes an initial period where we will focus on stabilising asset health and reducing safety risk. This catch-up period coincides with our proposed CPP Period.

It should be noted that our AMP remains a 'live' document that forms an integral part of our day-to-day business and asset management planning processes. We have sought to maintain consistency with the structure of our 2018 AMP to make the material accessible and comparable.

> **Impact of COVID-19**
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> The planning and engineering analysis underpinning the AMP was largely undertaken prior to the emergence of COVID-19 as a significant social and economic 'disruptor'. However, we have updated our investment plan to reflect our evolving views.
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> At this point, it is difficult to fully determine the impacts of COVID-19 on our work programmes in the short-term, or on our demand-driven investments over the medium term, but we have deferred growth investments in a number of areas to reflect the expected downturn in demand. Notwithstanding this uncertainty, we are currently operating on the basis that there may be a need for some refinement of our RY21 work plans as the impact of COVID-19 becomes clearer.
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> As a lifeline utility, we will continue to maintain essential operations if New Zealand has further COVID-19 related alerts. We will respond to emergency faults and carry out essential safety work.

Our 2020 AMP is an Important Part of our CPP Application

This AMP is a key supporting document for our CPP application as it explains how we invest to manage risk on our network and deliver services that meet the long-term interests of consumers. It provides information that stakeholders and the Commission can use to understand the basis for our proposal.

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1 We requested that the Commission grant an extension to the deadline for the publication of our 2020 AMP. This was granted to allow us to publish the AMP with our CPP proposal. The extension letter is published on our website.

The content of our AMP and the technical rationale that underpins it are consistent with the drivers of our CPP application. The CPP application and determination by the Commission do not impact on our RY21 renewal and maintenance plans. Our CPP application is based around our investment plans and proposed quality standards for the period 1 April 2021 to 31 March 2024.[2]

The Commission will review these investment plans and quality standards to determine whether they are prudent, efficient, and in the long-term interest of customers. This will build on the review undertaken by the Independent Verifier, which reviewed our draft CPP proposal. This detailed review assessed the underlying assumptions and needs case for our investment plan.

We expect the CPP will provide us with a price-quality path (comprising revenue allowance and reliability standards) appropriate to our circumstances. This is necessary if we are to continue to deliver a safe and reliable service to customers over the long-term and appropriately manage the risks inherent in managing an electricity network. We expect to transition to this new price-quality path in April 2021, being the start of the 2022 regulatory year.[3]

> **What is a Customised Price-quality Path (CPP)?**
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> A CPP is a regulatory mechanism that a regulated business can apply for if it believes its current price-quality path does not meet its needs, particularly its future investment needs.
>
> Following consultation with stakeholders a business submits a proposal to the Commission, which then completes a detailed assessment before determining what price-path and quality standards should apply.

We are proposing a three-year CPP to ensure our proposed investments and quality standards are as well specified as possible. Similar to other electricity distribution businesses, the accuracy and granularity of our forecasts becomes increasingly uncertain over time. Given the limited state of our asset information and associated systems our forecasts are materially more robust over the initial three years compared with years four and five.

Beyond this three-year period, we will need to continue progressing the investment catch-up we require, returning us to steady-state investment levels towards the end of the AMP planning period. Reflecting this timeline, we expect a further CPP will be required from RY25:

- CPP1: during the three years (RY22 to RY24) we will focus our investments on immediately rectifying assets that pose safety risks, addressing overdue renewals, improving maintenance, capability improvements, and ensuring we can connect customers.
- CPP2: for the subsequent five years (RY25 to RY29) we will propose a further set of investment plans and quality standards and engage with stakeholders on their preferences. These plans will build on our improved asset management capabilities and more comprehensive asset information.

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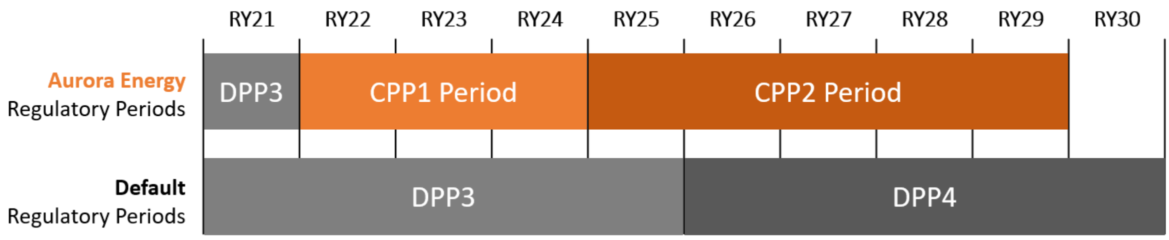
2 While we are proposing a three year CPP (RY22 – 24), we are required to submit five years of information as part of our application. For consistency we refer to the *CPP Period* as the three-year period (RY22-24).

3 Regulatory year 2022 (RY22) begins on 1 April 2021 and ends on 31 March 2022.

Our proposed regulatory periods will run in parallel with two default price-quality path (DPP) periods



During CPP1 our focus will be delivering priority investments and making improvements in our underlying data, risk management systems and fully embedding our expanded contracting and delivery frameworks. CPP1 delivery reporting will help inform stakeholders on our progress and ensure they are well placed to engage during our CPP2 consultation process. We believe this approach will ensure better outcomes for customers over the medium term and reduce the potential for less than optimal investments in the short term.

Commission's CPP consultation process

Over the coming months the Commission will engage with customers and other stakeholders on our proposal. During this time, we will continue to provide information to the Commission and answer queries to support its review. Their review is an opportunity for stakeholders to provide feedback on our plans to help ensure our plans meet their long-term needs. We are committed to continue working constructively with the Commission and other stakeholders to explain why this proposal delivers the best outcome for customers in light of the need case and circumstances we face.

Focus of our 2020 AMP Investment Plans

As signalled in previous AMPs, we need to increase the level of investment in our network. With low levels of historical investment, our assets have deteriorated. The detailed planning and analysis we have undertaken to support our AMP investment plans clearly shows a continuing need to lift maintenance and renewal expenditure in targeted asset fleets across our network.

Over the past three years we have already started to significantly lift investment in response to the risks posed by ageing assets. This increased investment exceeded the levels supported by our regulated revenue and therefore our prices to date have not reflected this spend. However, there was a compelling need to invest at that level to ensure our assets remained safe. This need remains due to the large portion of assets that continue to degrade and, if not addressed, pose intolerable risks.

While we have significantly increased our renewal and maintenance activity, more needs to be done if we are to ensure our assets do not pose safety risks to the public. The expenditure needed to achieve this is the key driver for our CPP proposal.

Our investment priorities have been shaped by our CPP Consultation

In developing our 2020 AMP investment plans, we have built on our 2019 forecasts with updated priorities that reflect feedback from stakeholders and the output from updated risk assessments. Our risk assessments have used improved asset information and our maturing analytical capabilities.

> **Our CPP Period investment plans reflect customer preferences**
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> As part of our CPP consultation process, we consulted extensively with customers and stakeholders and have listened carefully to their views. Our consultation material explained our recent performance, the issues we are seeing, and investment options to address these issues.
>
> While prudent engineering practice dictates where a large portion of investment is needed, our plans over the next three to five years were changed to reflect the expectations and value preferences of customers. While keeping our focus on safety related spend, and in seeking to minimise price impacts on customers, we have removed or deferred expenditure targeting reliability improvements and deferred investments in new technology.

During our CPP consultation, what we heard from customers was an understanding and desire for essential work to be done, but that the impact of proposed pricing increases was a major concern for affordability, particularly for vulnerable customers. Most respondents were satisfied with their current level of reliability and there was little appetite for improving reliability if this meant prices would need to go up. We have reflected these views in our forecasts for the CPP Period.

In summary we have used the following priorities to guide our investment decision-making:

- our primary, short-term focus is on investing to reduce the level of safety risk on the network
- reflecting customer feedback[4] we will not actively pursue reliability improvements
- we continue to address replacement 'backlogs' resulting from historical underinvestment
- target improvements to our asset management capability and align with good practice
- we will pursue improvements in our delivery capability and supporting processes
- we will improve our processes to deliver better and more streamlined customer services.

The CPP process provides a further mechanism for stakeholders to review and provide input on our proposed investment plans.

2020 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 begin to shift our focus to poor condition substation assets to reduce the safety risk posed by failure of these assets.

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4 We discuss this feedback in Chapter 2 and in our wider CPP application material.

- **Stabilise asset health**: we need to stabilise our asset fleets through proactive renewal focused on assets in poor condition, using criticality for prioritisation, where available. 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). An example is our aim to address the remaining pole backlog and reach steady-state where red-tagged poles are always addressed within three months of identification.
- **Improving capability**: we are committed to further improving our overall asset management capability to ensure we can cost-effectively meet the needs of customers. We will invest in the capability of our people and ensure that our systems, supporting data, and processes effectively enable our wider work programmes.
- **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**: reflecting consultation feedback, improving reliability through discretionary investments is not a short-term priority. As the AMP period progresses we expect to increase our focus on ensuring that customers receive their preferred levels of service. An important aspect of this will be successfully meeting our future regulatory quality standards.[5] It should be noted that investments we make to address safety risk on the network will reduce the likelihood of asset failures, which will (over the medium-term) lead to some degree of improvement in our reliability performance.
- **Supporting a return to growth**: international and national travel restrictions in response to COVID-19 have led to unprecedented reductions in demand on parts of our network. Areas of recent high growth such as Queenstown and Central Otago are now expected to have very low (if any) growth over the next couple of years. While acknowledging that there is significant uncertainty, we have reduced planned investments in new capacity and connections over the next three years. As the AMP planning period progresses we expect to see renewed development activity and a return to growth in tourism and other sectors. Being able to support this growth will become a focus for us as the region recovers. We will work closely with councils and agencies to ensure our planning assumptions are aligned, and that capacity is available when needed.

Of the above, managing safety risk and improving our capability will be our main focus in the coming two to three years. These are further explained below.

[5] As part of our CPP application we are proposing a new set of reliability limits that better suit our current circumstances and that reflect the preferences of customers.

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. We will prioritise safety related investments in the short term. This involves carefully managing our asset fleets with the aim of stabilising their condition and performance to effectively manage network and safety risk.

Over the past three years we have significantly increased our levels of investment in renewal and maintenance, but more needs to be done. In our overhead line fleets (with the exception of the poles fleet, due to the focus we have placed on our pole replacement programme) we have continued to see an unacceptable level of asset failures in recent years. There are also significant volumes of assets with poor health in other fleets, indicating that a large number of end-of-life assets remain in service.

Arresting these issues requires targeted investment to stabilise the underlying condition of our network and reduce the rate at which assets are failing in service. Alongside increased asset renewal we need to establish proactive and effective vegetation management and maintenance regimes.

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. This will need to be driven by analysis that utilises comprehensive, robust asset information. Alongside improved analytical capability this will require improved and expanded inspections and testing to better understand actual asset condition and related network risks.

We plan to implement improved inspection and condition assessment regimes, including the use of pole-top photography, LiDAR, conductor sampling, and aerial photography of our subtransmission lines. Data and information management practices will also need to be enhanced as we implement a new fit-for-purpose asset information system.

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 tolerable risk levels

The graphic below provides a summary of the impact of our planned investment over the AMP period. The graphic includes the following indicators:

- **inherent risk**: we have categorised our asset fleets based on the potential failure consequence of a typical asset in the fleet. These levels are explained in Chapter 5.
- **% of H1 assets**: the percentages refer to assets classified as H1, having reached end of useful life we aim to replace them (as deliverability constraints permit) within 12 months.
- **planned renewal Capex**: reflects currently planned renewal Capex on the fleet during CPP1 and the AMP planning period, respectively.

Summary of asset fleet investment outcomes

Asset Fleet	Inherent Risk	Current Health H1 %	Health post CPP H1 %		Health in 2030 H1 %	
Protection		47.0	19.8	$6.7m	2.0	$16.4m
Indoor switchgear		22.4	12.4	$26.5m*	1.8	$78.1m*
Subtransmission conductors		18.4	0.6	$15.5m	0.6	$24.6m
Crossarms		9.5	8.0	$22.9m	2.3	$62.9m
LV conductors		4.4	4.9	$10.6m	2.9	$31.9m
Poles		4.3	1.5	$35.2m	1.2	$81.8m
Distribution conductors		1.8	2.5	$16.2m	1.2	$49.9m
Power transformers		1.5	10.8	$26.5m*	1.5	$78.1m*
Outdoor switchgear		40.6	10.8	$26.5m*	0.8	$78.1m*
Ground mounted switchgear		6.3	3.9	$9.4m	1.4	$24.8m
Pole mounted transformers		5.1	6.4	$8.7m	1.9	$32.1m
LV enclosures		1.4	1.7	$5.8m	0.8	$13.8m
Subtransmission cables		6.3	7.8	$5.0m	11.4	$20.0m

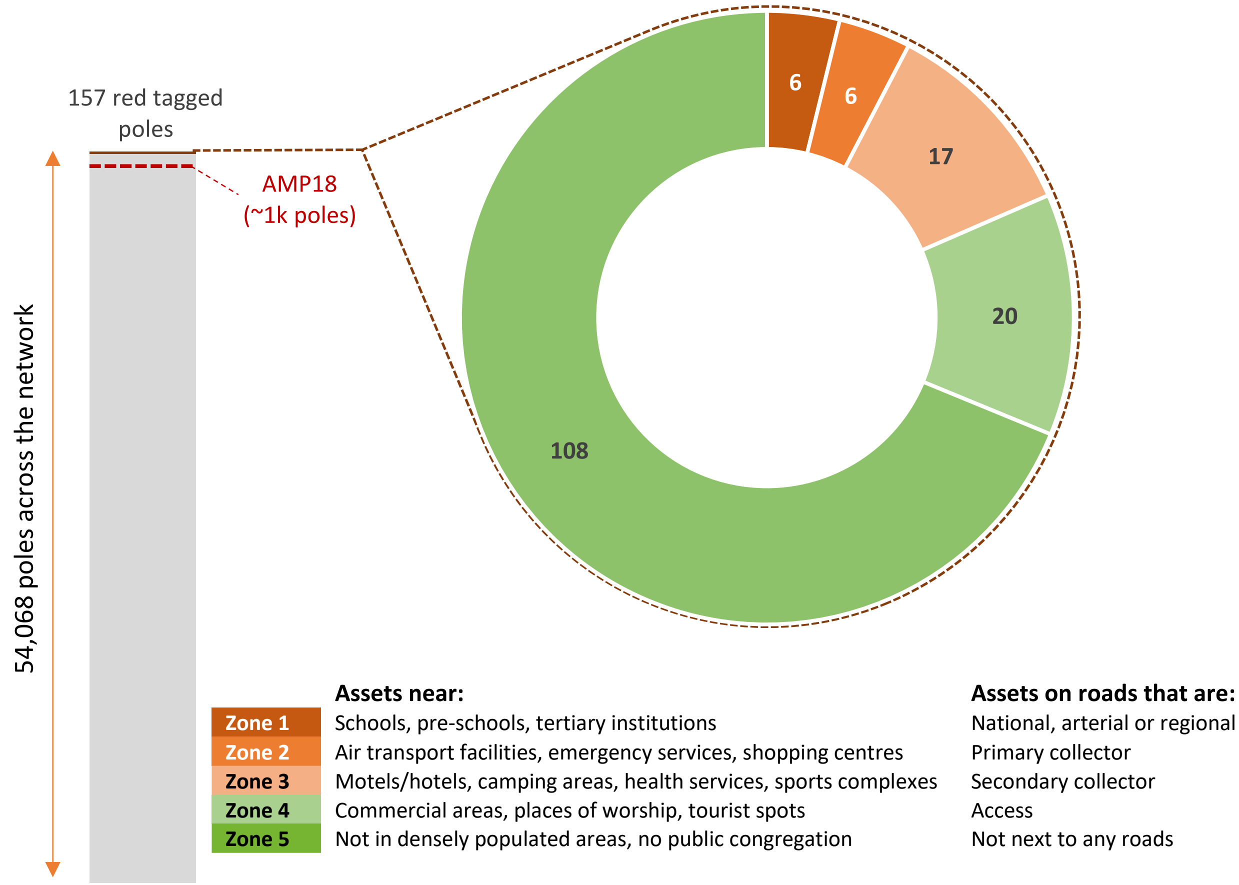
* This is *total* zone substation expenditure which covers power transformers, indoor switchgear and outdoor switchgear fleets.

Update on our poles programme

In our AMP 2018 we provided an update on our progress addressing red-tagged poles across our network. At the time (October 2018) we had approximately 1,000 red-tagged poles on the network. Since October 2018 we have remediated over 4,300 poles. The chart below shows our red-tagged poles as of 8 May 2020; a quantity of 157, the majority of which are in low public safety criticality zones (green segments). Of these, 141 are wood and 16 are concrete. These statistics show that we have made significant progress towards addressing our red-tagged pole problem.

Our pole renewal programme will continue at elevated, though reducing levels until the end of the CPP Period, before reaching steady-state renewal volumes. During this period, we will fully remove any remaining backlog by replacing red-tagged poles, prioritised by public safety criticality.

Red-tagged poles by criticality zone (as of 8 May 2020)



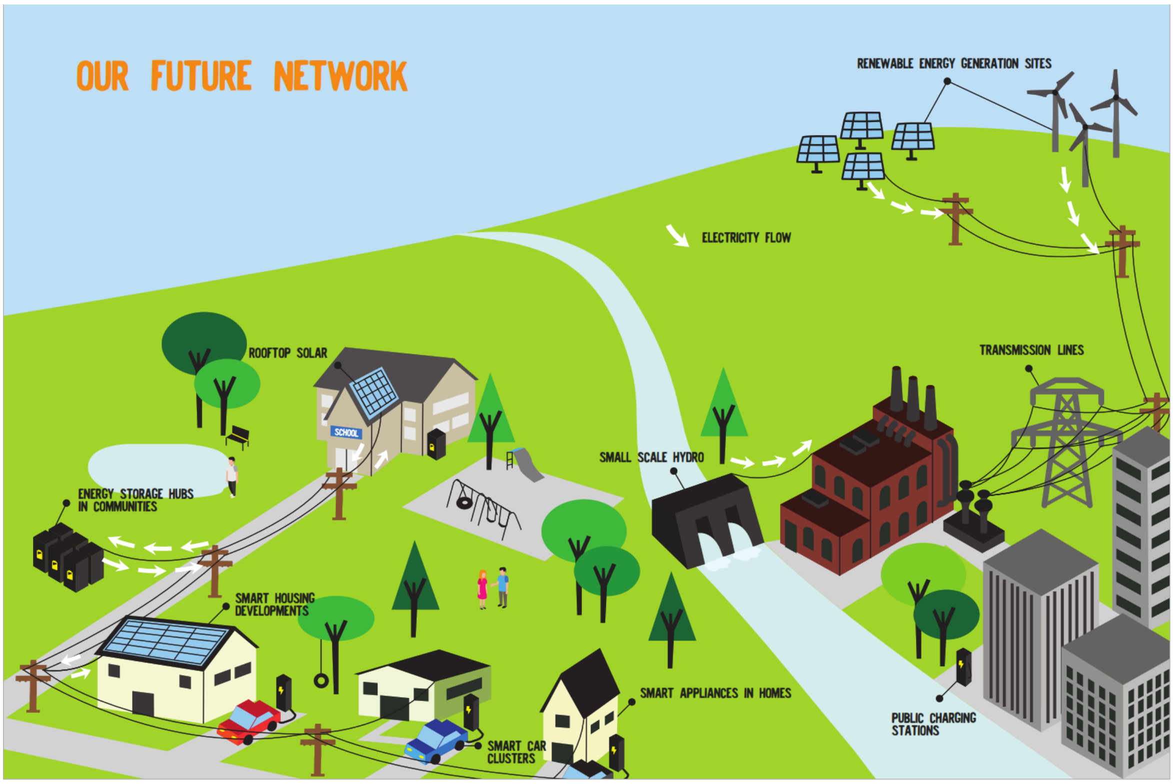
We expect our focus on future technology to increase over the AMP period

Over the coming years we plan to implement our network evolution plan (discussed in Chapter 6), to allow research and development, and testing of new and innovative network and non-network solutions. With increased efforts to promote decarbonisation, we expect to see more electric vehicles, photo voltaic installations and battery storage systems installed on our network. We believe it is prudent to prepare for increased uptake of these resources now, rather than react at a later stage.

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 to adopt new technologies.

A glimpse into this future is our planned 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 material cost savings and flexibility to cater for fast-changing demand. It will provide valuable learnings to our teams and to the wider industry, as we plan to share our experience.

A possible future network



Improving Capability

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 which underpins our CPP submission, illustrates some of the advances we have made. Our asset management analysis and supporting models have been tested by the Independent Verifier and deemed appropriate given the existing asset management system maturity, and data availability.

Looking forward, we are committed to further developing our overall asset management capability to meet internationally accepted best practice standards. The investments in capability and systems outlined in this AMP are important enablers of that goal. We have set ourselves an ambitious goal to be fully compliant with the internationally recognised asset management standard, ISO 55001, by 2023.

Asset management certification

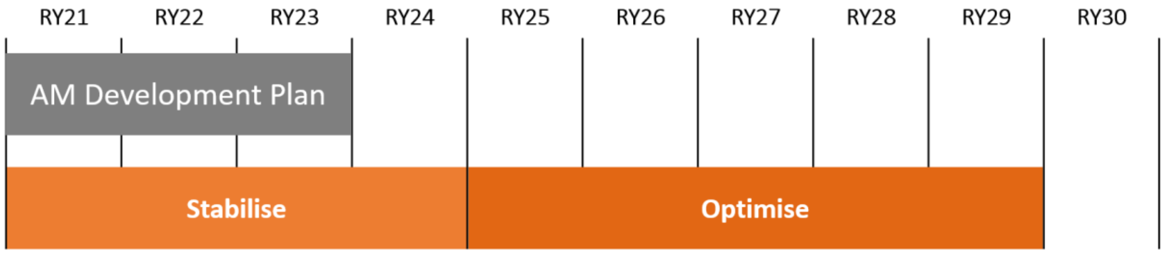
We will achieve leading practice asset management capability by 2023, evidenced by ISO 55001 certification. We have been making real progress over the past two years and will continue to prioritise this important initiative in the coming years.

Asset management development plan

As set out in our 2018 AMP, over the past few years we have put in place a series of business improvement initiatives. One of these is our Asset Management Development Plan (AMDP). This will lay the foundations for improving our asset management capability including our efforts to achieve ISO 55001 certification.

Our AMDP coincides with our CPP Period (see below) and its timing will allow us to leverage the improvement outcomes to optimise our CPP2 investment plans. The objective of these improvement initiatives is to ensure we can provide customers with a safe and reliable electricity distribution service, while minimising the whole-of-life cost of managing our assets.

Our asset management improvement timelines



To monitor our progress, we engaged asset management capability specialists to review our current capability. In addition, we have undertaken a thorough AMMAT[6] review, which was informed by this external review. This assessment (discussed in Chapter 7) resulted in a score of 2.13 (out of 4). This is a modest improvement over our 2018 score (1.94) and reflects our initial focus on building an asset management team and the foundations for future improvement.

The gaps identified during this review will be addressed as part of an updated AMDP, of which key focus areas will include:

- **engineering competency**: sufficient engineering competency – enough people with the right skills – will be a key determinant of our success in achieving our asset management objectives. Developing and broadening staff capability is a key focus. Effective leadership is crucial, and we continue to build appropriate structures, frameworks, and contractual relationships
- **works delivery capability**: our ability to successfully deliver our planned level of investment at efficient costs depends on having the right specialist skills, improved project management processes, and the necessary supporting information. This includes our use of improved procurement to reveal efficient market rates, adoption of standardised project management tools, and improving the utilisation of our service providers

[6] AMMAT: the Asset Management Maturity Assessment Tool is an Information Disclosure requirement.

- **investment decision-making**: we will require robust asset data, models, and processes to ensure we better understand the current and expected future performance and health of our assets over their full lifecycle. In particular, risk-based decision-making is being supported by improved asset health modelling and criticality approaches. Expanded programmes of physical inspection and testing during the CPP Period will ensure we are collecting the data we need. Improving our forecasting techniques will enable us to model (with increasing accuracy) the required levels of future investment.
- **analytical capability**: our asset management improvements need to be underpinned by strong analytical capability. If we are to successfully optimise future investments and limit price impacts there will be an increasing need for reliable information, expanded capability, and improved systems. Accurate and reliable asset data and modelling is an essential input.

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 CPP2 investment plans, others will take a number of years to fully implement.

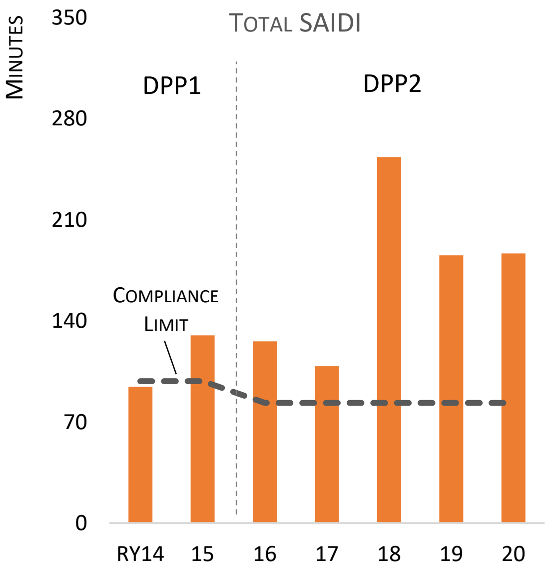
The linkages between our initiatives and quality improvements or efficiency gains is complex and often lagged. As a result, we expect that the impact of these initiatives on our performance will be gradual. However, we expect they will lead to greater scope for future efficiencies, which we have reflected in our forecasts by reducing expected expenditure in the later years of the AMP period.

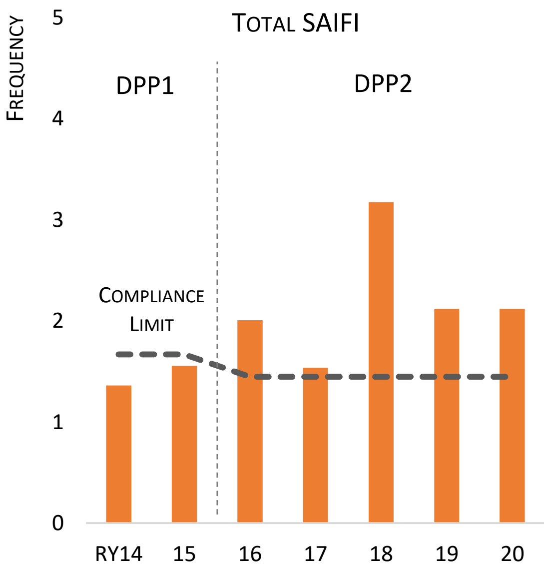
Need for Appropriate Quality Standards

Our reliability performance, as measured by SAIDI and SAIFI, has deteriorated in recent years.[7] As shown below, we have been unable to meet our SAIDI and SAIFI quality standards in recent years. In our view, this trend is to be expected given the underlying deterioration in asset health, which was not factored into our compliance limits.

It should be noted that our historical quality standards are based on a combination of planned and unplanned outages. Under the new DPP3, separate targets have been set for planned and unplanned outages. The reliability forecasts presented in this AMP and the quality standards we have proposed as part of the CPP proposal reflect the new DPP3 approach.

Historical reliability (SAIDI and SAIFI) performance[8]





While safety remains our primary focus, we recognise the importance of appropriate quality of supply to customers. Further investigation is required to understand all the drivers of reliability performance and to anticipate and control those drivers.

- **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. The dry summer of 2019/20 and extended periods of auto recloser disablement contributed to our RY20 unplanned SAIDI result.

7 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.

8 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.

- **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 exceptional storm events.

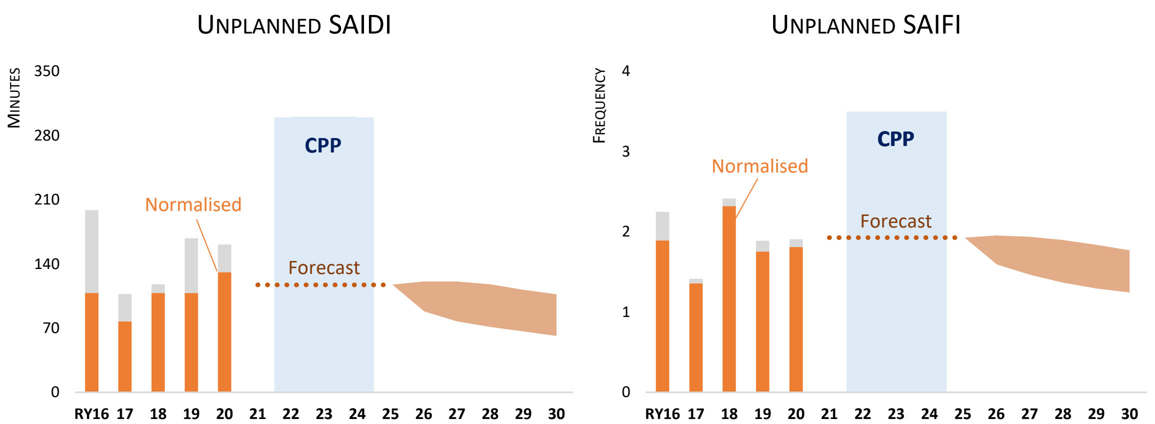
To better understand this deteriorating performance, we have begun to analyse these and other drivers and to develop process improvements to help address these over the AMP planning period.

We expect to stabilise unplanned outages in the short term

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 meant prices would need to go up. As discussed above, we have not included expenditure during the next four years to directly address reliability. However, we expect the investments we make to address safety risk will reduce the likelihood of asset failures, which will lead to some degree of improvement in our reliability performance.

Balancing this small improvement with the ongoing deterioration of our overall network we expect unplanned outages to stabilise as indicated by the forecast below. This forecast is based on our improved reliability modelling capability, which is based on projected changes in asset health, modelling of non-asset-related outages, and the impact of our vegetation management plans.[9]

Forecast unplanned SAIDI and SAIFI



The charts above include 'uncertainty bands' from RY25 onwards, which reflect the inherent uncertainty when forecasting long-term reliability.

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9 In addition, this modelling has informed the setting of our proposed CPP quality standards, which have higher targets than those set out under DPP3. This is discussed further in our CPP application document.

While we have some reservations about comparing historical performance with future forecasts due to the differences in regulatory reporting calculations, for context we have included our historical performance with our forecasts for unplanned SAIDI and SAIFI in the following charts.[10]

It is important to note that our renewal programmes are taking place during a time of deteriorating asset performance. Importantly, reversing this trend can be expected to take some years, as there is likely to be a lag between our increased investment and enhanced maintenance and seeing the results. In this context, stabilising current levels of performance is in itself a considerable challenge for us during the CPP Period.

We will consult with customers in RY23/24 on preferred levels of reliability beyond the CPP Period. We anticipate that continued investment in safety beyond the CPP Period will improve reliability performance. Additional reliability improvement could be achieved through targeted investment if customers prefer this outcome.

We can manage our work programmes under the DPP3 planned reliability allowances

Given that our level of investment will remain elevated we expect that current levels 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 is well-managed.

An appropriate planned outage allowance is important as it removes any unintended incentive to prevent delivery of our required work programme. A multi-year allowance provides scope to be more efficient when delivery planning, including scope to optimise field workforce utilisation by reducing constraints on annual work levels and allowing more flexible multi-year work scheduling.

With appropriate modifications (e.g. three versus five-year period) to the application of the DPP3 planned quality standards we believe we can manage our CPP work programme within our DPP3 planned quality standards. At times this will present a challenge, however we are confident we can achieve it given our planned delivery and outage planning improvements.

We note that the DPP3 planned outage framework encourages accurate and timely notification of outages. This is consistent with what customers have told us they want, and we are developing improved processes with our contractors to ensure that planned outages are communicated correctly and managed to plan.

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10 As part of each DPP, the rules for normalisation of major event-related outages have been refined

Our 2020 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.

> **Network Investment**
> We plan to sustain increased levels of network investment over the next decade, spending $778 million on renewing and maintaining the existing network. Of this, $274 million will be invested during the three-year CPP Period.

These levels of investments 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.

We modified our plans based on Independent Verifier feedback and to reflect the impact of COVID-19.

In addition to changes we made based on consultation feedback, we made further adjustments to our expenditure plans in response to the independent verification process:

- we applied a series of efficiency adjustments to our spend plans, based on a range of expected improvements. Over time these will lead to material reductions in costs (approximately $5m up to RY26). In the short-term, we expect the scope for material efficiency gains to be limited due to external factors and until our planning and delivery maturity further improves
- we deferred a number of non-critical renewal and growth projects to later in the AMP period
- we have reduced future business support costs to reflect likely productivity gains
- we have made a series of reductions in reactive and corrective maintenance expenditure to reflect potential improvements in overall asset condition and health.

While the long-term implications of COVID-19 are still emerging, we expect them to impact the local economy, especially the tourism and hospitality sectors. As an initial response, and to further reduce price impacts on customers, we have revised our growth-related investments, including:

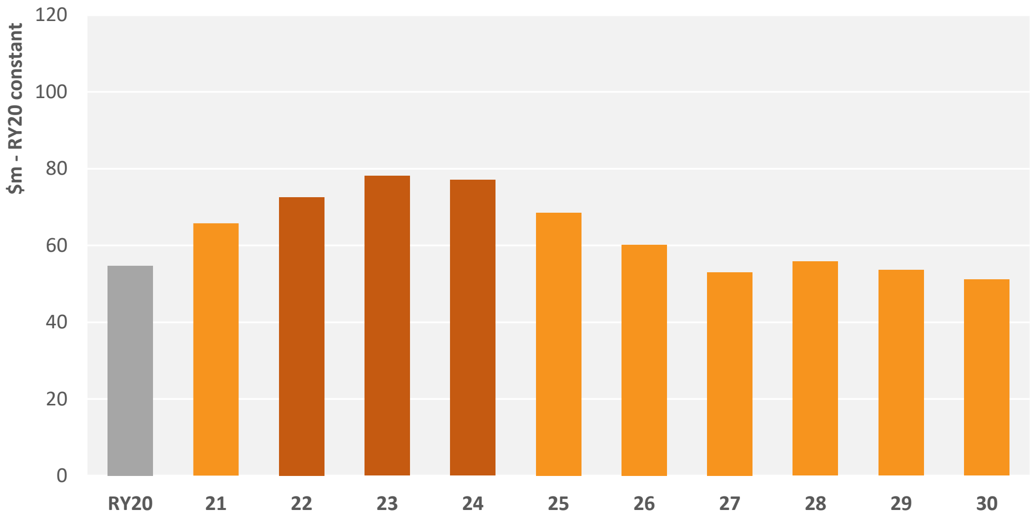
- deferred major growth projects in Central Otago and a resilience project in Dunedin
- reduced our consumer connections forecast to reflect a likely reduction in new applications
- deferred distribution reinforcement works due to expected lower growth.

Our short-to medium-term forecasts may be further refined, in terms of priority and timing, as we progress through the CPP review and consultation process. We will include updated investment outlooks in our 2021 AMP.

Capital expenditure

Our capital expenditure for the AMP planning period is set out below. As explained 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, in particular, ensure our network remains safe.

Total planned Capex during the AMP period ($m, constant 2020, net of customer contributions)



In general, the initial four years (RY21 to RY24) are more certain and are supported by more detailed plans. This increased level of certainty is a key driver for our decision to propose a three-year CPP Period (denoted by the darker orange bars). Our summary of asset health outcomes on page vii shows the significant portion of the above total that relates to asset renewal.

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.

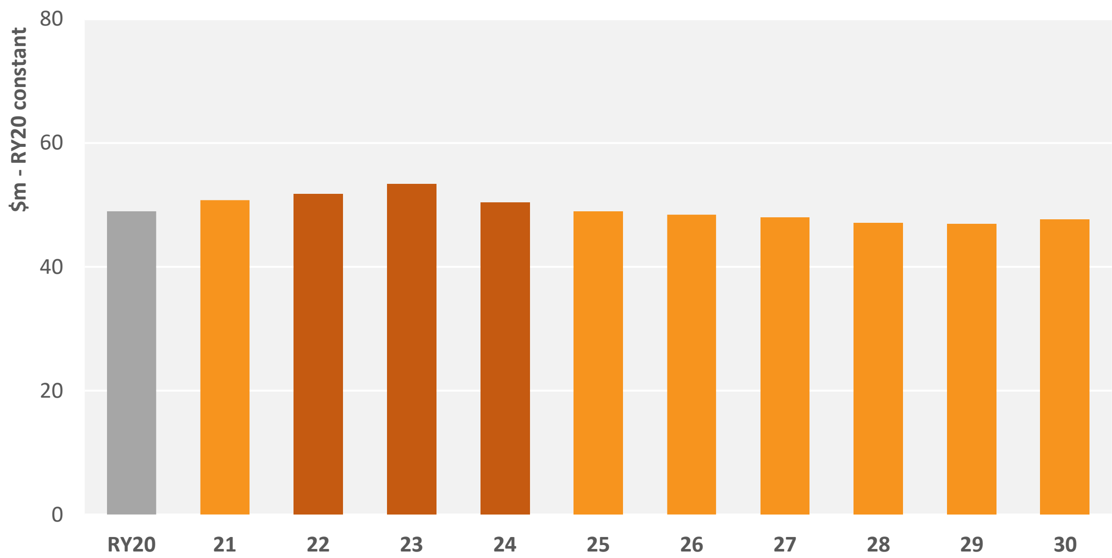
The assets that we plan to invest in:

- maintaining our elevated pole replacement programme for up to three more years, before returning to steady-state levels
- increasing the 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 (albeit at lower volumes in the short term)
- later in the period, we will resume our investments to provide the capacity required to facilitate demand growth
- implementing new ICT systems, and supporting processes, in the early part of the CPP Period, including an enterprise asset management system (EAMS).

Operating expenditure

Our planned Opex is expected to be relatively stable over the AMP planning period. In the short-term, we expect to incur slightly increased costs to ensure we maintain our network appropriately and to support our improvement initiatives.

Planned Opex during the AMP period ($m, constant 2020)



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:

- 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
- changing vegetation management from a largely reactive approach, to a good practice proactive approach to enhance safety and ensure full compliance with the Tree Regulations
- implementing a non-network solution to address capacity constraints in the Upper Clutha region.

We expect productivity and efficiency improvements to offset upward cost pressures in the latter part of the AMP period. Reflecting this we have applied efficiency adjustment factors to our Opex forecasts, leading to a reduction in our expenditure forecast in later years.

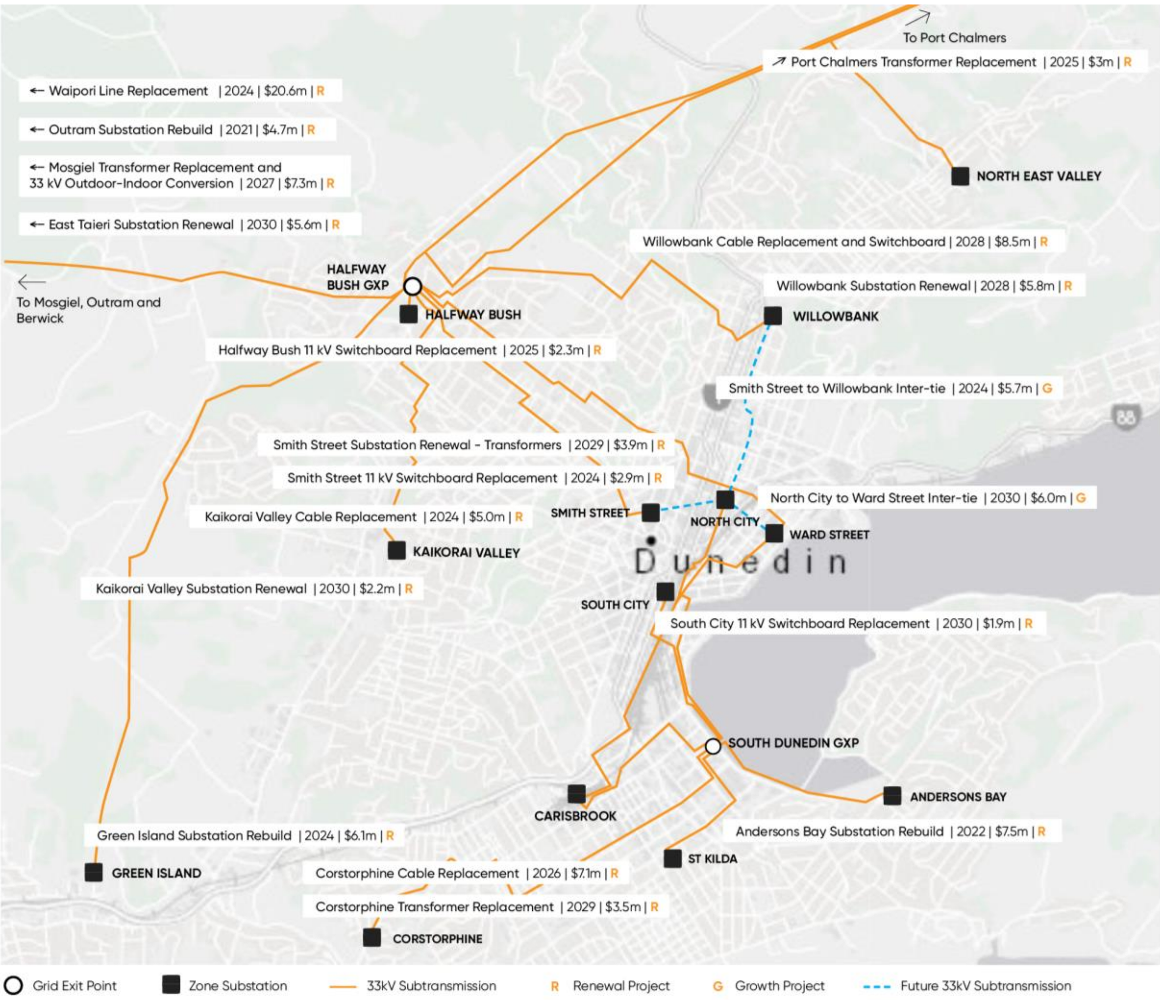
The efficiencies are indicative and are based on a composite of potential sources, including:

- **contractor productivity**: reflecting increased competitive tension and scale efficiencies that could be realised by the planned uplift in work
- **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. EAMS).

Summary of key investments

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

Large planned projects in Dunedin

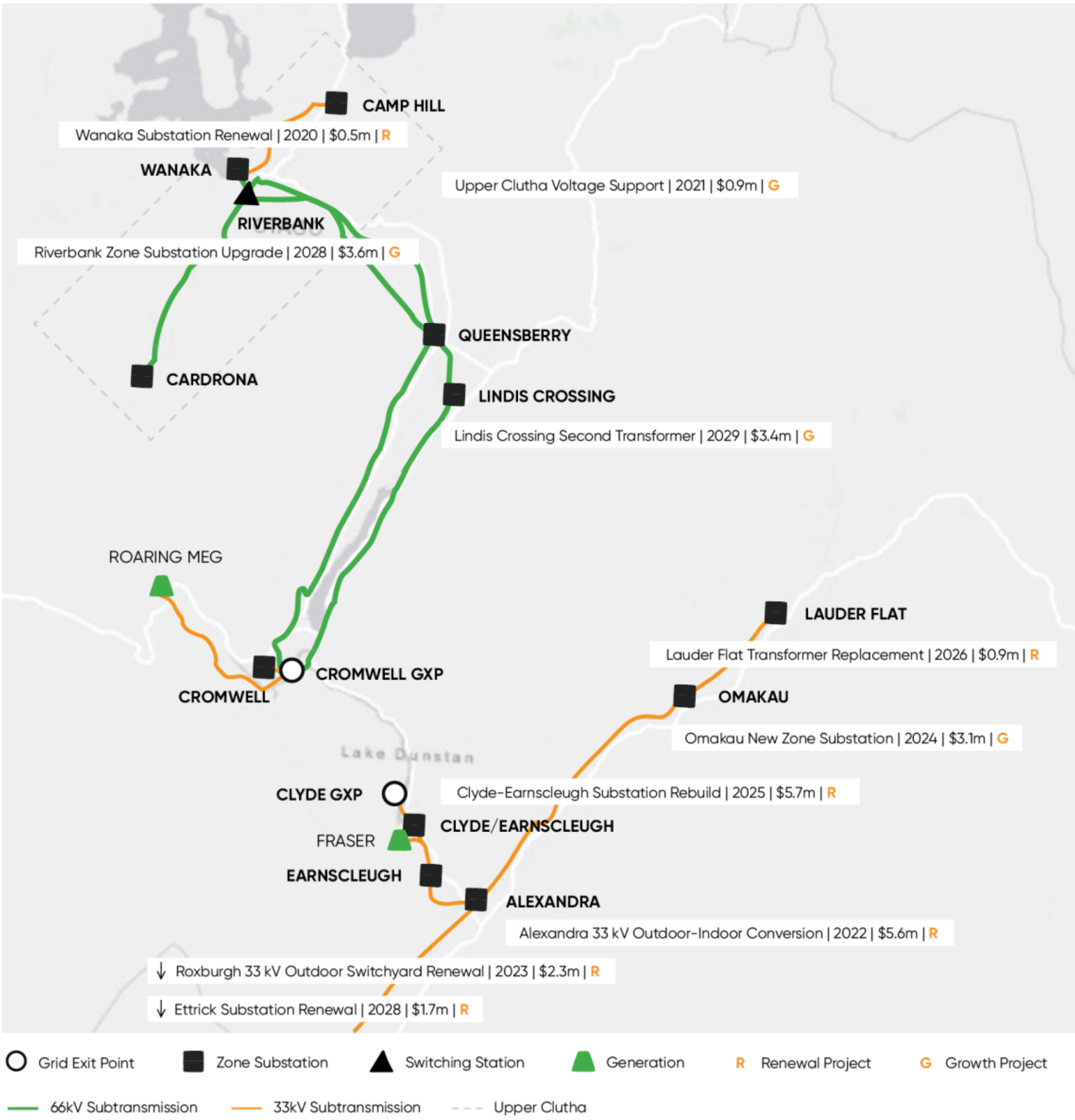


The year indicated for project completion ends at 31 March in each case.

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 mean we will replace assets including 33kV cables, power transformers and switchgear over the AMP period. Example projects include:

- rebuild of the Waipori subtransmission pole lines from Halfway Bush to Berwick
- cable 'intertie' projects that will ensure appropriate levels of security and resilience
- rebuilding Andersons Bay substation

Large planned projects in Central Otago



As discussed above, once the economic impact of the COVID-19 pandemic subsides we expect demand growth to return in Central Otago. Our assumption is that this will begin midway through the CPP Period and we will engage with local councils to ensure our investments can facilitate this recovery.

Large planned projects in Queenstown Lakes

We have deferred our most of our planned growth projects though we there remain a significant number during the AMP period. These include upgrades to the Arrowtown, Omakau, Lindis Crossing zone substations and Riverbank Road switching station.

A final word on Safety

Customer and stakeholder concern for network safety, and desire for it to improve, had been apparent for some time and is one of the factors in our decision to apply for a CPP. 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, and informs everything we do.

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.

1. INTRODUCTION

This chapter introduces Aurora Energy's 2020 Asset Management Plan (AMP).

1.1. PURPOSE OF THE AMP

The AMP outlines our long-term strategy for managing our network and the asset management approaches we use. Our 2020 AMP is a core document supporting our Customised Price-quality Path (CPP) proposal.

In the AMP we set out our planned investments for the coming 10 years, with a focus on the years that make up our proposed CPP. Our plans will allow us to continue to provide a safe, reliable and valued service, connect new customers, and begin to position our network for the future.

We intend to use this AMP as a basis to consult with our stakeholders, particularly on our planned investments. We hope that it will help stakeholders to understand our approach to managing our network assets.

1.1.1. AMP Objectives

This AMP meets the requirements of the Electricity Distribution Information Disclosure Determination 2012. 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 2020 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 the risks inherent in the network and the systematic processes in place to mitigate those risks
- explain the challenges we face as a business and how these will be addressed by our CPP application
- set out our corporate mission and vision and how these inform our asset management approach
- summarise our asset management document suite, 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.

1.1.2. Period Covered by the AMP

Our AMP covers a 10-year planning period, from 1 April 2020 to 31 March 2030. This includes our proposed three-year CPP during RY22 – 24 (CPP Period).

As might be expected, the earlier years of the AMP 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

The remainder of this document is structured as follows.

Table 1.1: Document Structure

CHAPTER		DESCRIPTION
1	**Introduction**	This chapter
2	**Background**	Sets out relevant context for our 2020 AMP
3	**Network Overview**	Describes our networks in Dunedin, Central Otago and Queenstown Lakes, and sets out 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 Asset Lifecycle Management**	Explains our overall approach to asset management
6	**Network Development**	How we address demand growth and connect new customers
7	**Operate and Maintain**	Explains how we operate and maintain our network
8	**Renew or Dispose**	Sets out our planned investments to renew our asset fleets
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**	An appendix that sets out the meaning of acronyms and technical terms.
B	**Disclosure Schedules**	Technical and financial disclosures and background on these disclosures.
C	**Reliability Management**	Provides detail on our plans to improve the reliability performance of the planning period.
D	**Work Programme Update**	Provides an update on our RY19 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 and is structured as follows:

- **overview of Aurora Energy**: provides background information on our business, its corporate structures, and new governance arrangements
- **our stakeholders**: explains who our main stakeholders are and discusses their needs. It includes a description of customer feedback we received during our CPP consultation
- **context for our 2020 AMP**: sets out the context impacting our 2020 AMP, including how we are regulated and the role of the AMP in supporting our CPP application.

> **Box 2.1: A note on COVID-19**
>
> The planning and engineering analysis underpinning the AMP was largely undertaken prior to the emergence of COVID-19 as a significant social and economic 'disruptor'. However, we have updated our investment plan to reflect our evolving views.
>
> At this point, it is difficult to fully determine the impacts of COVID-19 on our work programmes in the short-term, or our demand-driven investments over the medium term, but we have deferred growth investments in a number of areas to reflect the expected downturn in demand. Notwithstanding this uncertainty, we are currently operating on the basis that there may be a need for some refinement of our RY21 work plans as the impact of COVID-19 becomes clearer.
>
> As a lifeline utility, we will continue to maintain essential operations if New Zealand has further COVID-19 related alerts. We will respond to emergency faults and carry out essential safety work.

2.1. OVERVIEW OF AURORA ENERGY

Aurora Energy owns and operates electricity distribution network assets in Dunedin, Central Otago and Queenstown Lakes. 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 91,000 homes, farms and businesses throughout the regions we serve. Chapter 3 discusses our networks in more detail and describes the main customers in each region.

Aurora Energy was set up as a new organisation in July 2017. Up until then, Delta had undertaken asset management and service provider roles on behalf of Aurora Energy, the asset owner. Following some concern around the then governance and management arrangements, an independent review was commissioned. The outcome was that Dunedin City Holdings sought the formal separation of the two businesses and Aurora Energy formally separated from Delta. Today, we have approximately 150 staff based in Dunedin, Cromwell and Frankton supported by our team of field contractors.

The separation ensures that dedicated, focused governance and leadership is applied to the ownership and operation of our electricity assets, without the need for the wider focus required to also manage a contracting business (as was the case in the past). Structural separation has created clearer accountabilities for network ownership and service provision in the two entities, respectively.

It allows increased transparency and commercial tension in our procurement processes. These benefits have the potential, over time, to reduce the underlying cost of delivering our service to customers. Under the new operating model, Delta is an arms-length service provider subject to commercial terms.

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 over time.

2.1.1. Ownership and Governance

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

Ownership

Aurora Energy Limited is a subsidiary company of Dunedin City Holdings Limited which is owned by the Dunedin City Council.

Our directors are appointed by our shareholder 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 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 as hard as they can 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 mission, vision, and goals. To support this, it has established policies to safeguard and guide the use of resources and assets, including appropriate management of risk. This extends to ensuring clear, accountable performance management.

Our Board reviews and approves our AMP and ensures that the AMP meets regulatory requirements. This AMP was approved by our Board on 12 June 2020.

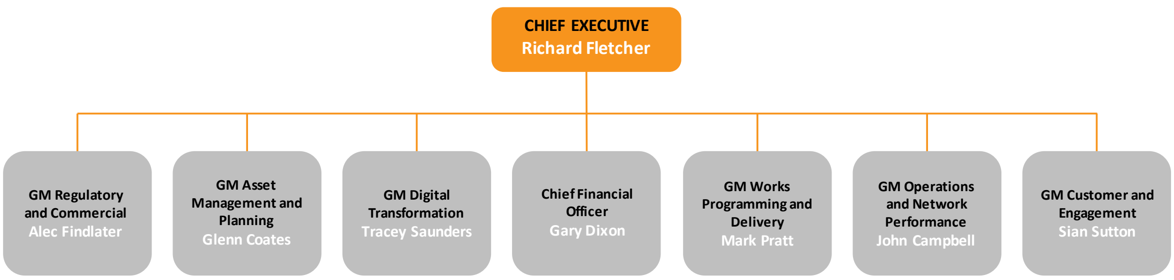
Overall governance and decision-making rests with the Board and CEO. Our Board provides strategic guidance, monitors effectiveness of management and is accountable to shareholders for the company's performance. From an asset management perspective, it does this by endorsing key documentation (including this AMP and annual business plans), that establishes our objectives and strategies for achieving those objectives, and 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 $0.5million.
- 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.

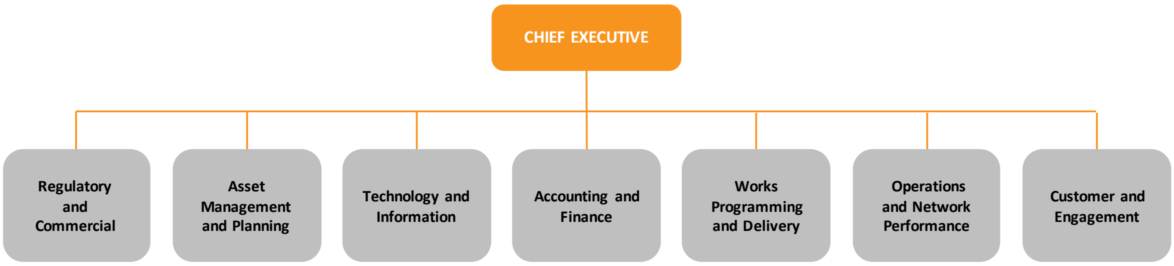
2.1.2. Governance Roles and Responsibilities

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 seven 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 our network meets customer requirements for reliable and safe energy delivery, is practical to operate, and is technically efficient. This includes maintaining current and accurate information about the performance of the network and its assets. An important aspect is monitoring technological and demand trends, assessing their potential impact and devising strategies to deal with 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 Replacement configuration Property and asset relocation planning Transpower planning interface Contingency planning

TEAM	KEY RESPONSIBILITIES INCLUDE
Asset Lifecycle	Prepare 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 Lead the development and review of design standards Design for customer works and major projects (where applicable) Protection modelling in network model Power quality monitoring and incident review Engineering graduate development programme New equipment assessment Safety-in-design Technical specifications Develop scopes for planning and replacement where appropriate
Strategy and Reliability	Asset management strategy Lead asset management development plan Lead network reliability / performance forecast Security of supply guide Asset lifecycle strategies HV/LV architectures Collaborate on communications architecture Demand-side management and emerging technology strategy Coordinate AMP preparation and AMMAT reviews

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

TEAM	KEY RESPONSIBILITIES INCLUDE
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	Health and Safety, and wellbeing governance frameworks Health and Safety management System Incident management processes Public Safety Management System Field auditing of contractor health and safety performance

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: Work Programming and Delivery functions

TEAM	KEY RESPONSIBILITIES INCLUDE
Works Delivery	Delivery of network capital programmes/projects Delivery of maintenance programme Deliver 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 Maintain contractor management plans Contractor performance Contract management (extensions, variations and renewals)
Network Procurement	Procurement of major plant and network equipment Critical spares process Preparation and evaluation of tender programme

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 9.3 and Appendix E.

Regulatory and Commercial

The Regulatory and Commercial group 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.

The group also monitors 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.

Accounting and Finance and Risk Assurance

The Accounting and Finance and Risk Assurance group is responsible for co-ordinating financial planning and business performance reporting, the maintenance of a company-wide risk management framework, business assurance programmes and cash flow 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 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.

Customer and Engagement

The Customer and Engagement group is responsible for managing stakeholder and customer interfaces within the organisation and reflecting these in stakeholder engagement plans. The group ensures that stakeholders, including the community and customers, have opportunities to provide feedback and input into future network investment plans. 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, 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

A key objective of our AMP is effective consultation with our stakeholders. As well as using it to inform our own decision making, it explains how we manage our assets. Our aim is that our AMP should provide enough detail to explain our plans and decisions in a way that enables others to understand our approach to asset management and the investment decisions we make. This includes explaining how we have prioritised certain work, and why. We also aim to make it a document that customers can easily follow.

We recognise that a key asset management function is to understand who our stakeholders are, what they value and why. We define stakeholders as groups or individuals with either a direct or indirect interest in our asset management approach and decisions.

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
- shareholder and the Board
- media.

Chapter 4 explains how we accommodate these stakeholder interests in our asset management framework and investment decisions. If a conflict between stakeholder interests is identified, then we will seek to resolve this to both address the issue and any stakeholder concerns. Ultimately, our Board decides the most appropriate way to resolve any significant conflict between stakeholder interests. We maintain alignment with the Utility Disputes Commissioner scheme requirements.

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 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 investment plans. We discuss the views of customers in further detail in Section 2.3.3.

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 safety, the impact of our assets on the environment, and network resilience. 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 various acts and regulations 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 2020 AMP is a key part of our application to the Commission for a customised price-quality path.

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 customers. 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 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, and wellbeing initiatives, performance reviews, and forward work planning so that staff can maintain an appropriate work/life balance.

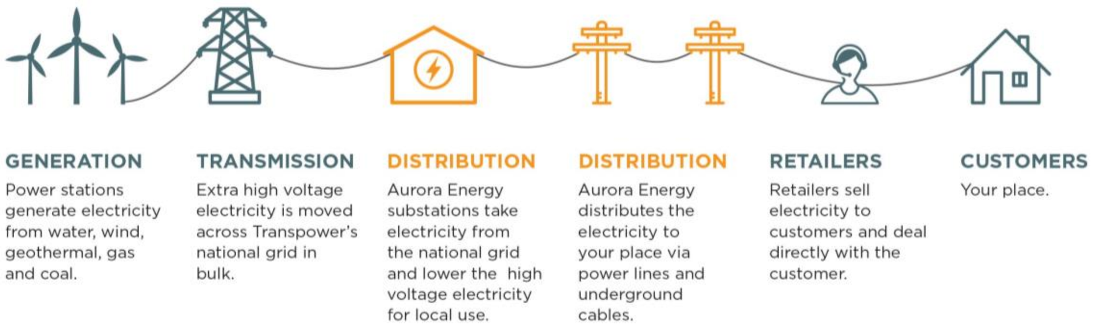
2.2.8. Other Stakeholders

We also interact with a range of other stakeholders. These include 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

We distribute electricity to 91,200 homes, schools, farms and businesses in Dunedin, Central Otago and Queenstown Lakes, supporting economic and social activity across these regions. It is important we fully understand what services customers require, and what value they place on these, now and into the future. As use and dependence on electricity has grown, so too have customers' expectations of the availability and quality of their supply. In addition to excellent customer service, customers increasingly expect good, 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

This segment includes residential customers and small to medium enterprises. The majority of our connections (approximately 99%) fall into this category. These customers typically buy bundled energy supply services directly from retailers and may not be fully aware of our role within the electricity industry. This is a situation we are actively trying to improve, for example, by publishing relevant information on our website and on social media.

Service expectations will vary, depending on where the customer lives (rural or urban) or their recent experiences of reliability. We find that most customers can accept occasional power cuts, and that our ability to keep them informed during these events is most important to them. Ensuring reliable, effective information flow to customers is a priority.

Growth in our mass market consumer base has been closely tied to population and is regionally diverse across our footprint. Our networks in Central Otago have seen significant historical growth, supported by inward migration to the region, tourism activity, and economic growth. However, since the emergence of COVID-19 we will need to revise our growth projections for this region (see Chapter 6). Historically, ICP numbers on our Dunedin network have been stable. We expect this to continue in the medium-term as the city should be less susceptible to lasting impacts of the response to COVID-19. The potential changes in customer numbers and demand means we need to continually refine our forecast load estimates.

Our customer connection teams and processes have been bolstered to ensure we meet the needs of residential and small commercial customers and continue to provide good customer service. Our approach to connecting new customers to our network is discussed in Chapter 6.

2.3.2. Major Customers

Our major customers are from the healthcare, dairy, food processing, transport, manufacturing, tourism and university sectors. Growth in this category is closely tied to general economic growth (indicated by GDP), for example the tourism sector continues to add large facilities (e.g. ski-fields).

Open dialogue with major customers is important to ensure we understand their businesses so 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 large 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.

A number of our large customers have taken part in our Customer Advisory Panel (see next section).

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 customer base, comprising residential, commercial and industrial customers 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 customers value and expect in their electricity supply and from Aurora Energy as their lines company.

It is worth noting that while these engagements are relatively recent they preceded the outbreak of COVID-19 in New Zealand and the associated economic and social impacts. We plan to canvas customers again once further certainty exists around the implications of COVID-19.

Based on these engagements, and previous research, we know that customers care about:

- a safe network: delivering electricity safely to customers is our core business and we know how important this is to customers and other stakeholders
- affordability: while the industry structure can mean customers 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, customers have a strong preference for smoothing any increase over sudden step changes
- reliability: based on feedback we received; a reliable electricity supply is very important to customers. Residential consumers care more about how long the power is out than how often it is out. They care more about power outages in winter and/or evenings. Outages during business operating hours are of most concern to business customers
- resilience: customers valued a network that can speedily recover from shocks such as natural disasters like storms and earthquakes
- good communications: customers value timely and accurate information about their supply, including information on planned outages. This has been driven, in part, by advances in mobile technology and social media that have created an expectation that information should be readily available through a number of channels. Customers 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 customers due to the potential financial losses associated with outages during their operating hours
- 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.

We also asked customers about future trends for their region and the impact of new technologies. They told us that:

- regional challenges: population growth, housing availability and affordability, climate change and infrastructure were all key challenges facing each of their regions – some more than others, but these were very consistent across all groups. In addition, we expect the regions we serve to face new challenges stemming from economic uncertainty related to COVID-19
- electric vehicles: for most, the cost to purchase and range anxiety were the main inhibitors to moving to an electric vehicle, a majority would consider making the switch if these deterrents were removed. The environmental benefits, running costs compared to combustion engine vehicles and charging convenience were all attractive
- roof-top solar: PV was of interest to some participants, but 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 an environmentally friendly alternative as reasons for why they would consider solar

- **future trends**: the rising impacts of population growth in their regions and an awareness of climate change were at the forefront of the discussion. Many could see the possibility of climate change affecting people's energy use, the rise of alternative energy resources impacting electricity infrastructure, and increased population and housing impacting electricity demand.

The above views informed our approach to developing our investment plans and related decision-making on our CPP proposal.

Customer Advisory Panel

In June 2019, we established a Customer Advisory Panel (Panel) to advise on and present the perspectives and preferences of consumers. The Panel has met five times to date, with an all-day workshop in November where we explained our draft CPP proposal.

The Panel's primary focus was to provide meaningful input into our CPP proposal, including our future investment plans and pricing options. The Panel has assisted us in understanding a wide range of consumer and community viewpoints on our proposal. Panel members represent a range of customers across our network and the diverse interests of the community: including residential, industrial, commercial and rural electricity consumers.

The composition of the Panel was designed to help overcome some of the challenges of consumer engagement on electricity network investment plans. These include the complexity of the topic being discussed, low levels of understanding of the role of electricity networks in bringing energy to consumers, and the wide-ranging impacts of EDB decisions on individual power bills and future network services.

The Panel prepared its own, independent, report on our draft CPP proposal. Key themes of the report were:

- **the need for essential work**: the Panel accepted the proposal's clear focus on minimising price increases while remediating the underinvestment of the past to make the network safe
- **affordability**: strong concerns about the impact that large and sudden increases in network prices will have on customers across the region – not just the most vulnerable in our community but businesses and those who manage on tight budgets
- **energy efficiency funding**: the Panel suggested accelerating the implementation of a fund to help households in energy hardship become more energy efficient as recommended by the government's Electricity Price Review[11]
- **avoiding a repeat of past underinvestment**: in accepting Aurora Energy's proposal, the Panel acknowledged the difficult trade-off that current management have made between safety and reliability. It stated that the network should never have been allowed to degrade to the state that it is now in. The Panel believed that regulations for electricity distribution businesses should be reviewed in the light of experience at Aurora Energy to ensure that this situation does not recur elsewhere

[11] For more details see MBIE website.

- **network transformation to a low carbon future**: Aurora Energy's proposal explicitly defers expenditure to integrate small-scale renewable generation and demand response, to minimise price shocks in the short term. While the Panel accepted this trade-off, it believed that giving customers more local options about how they meet their energy needs will see electricity distributors play an important enabling role as New Zealand decarbonises. The Panel expected this work to have a high priority in the subsequent CPP Period
- **stakeholder communication**: the industry is highly fragmented and does not engage with customers simply enough to maintain their confidence and trust. Aurora Energy will need to develop a communications plan for all stakeholders in which it integrates messages from other companies in the electricity industry if it is to achieve the level of community support on which a successful CPP will depend.

The above feedback has helped us in shaping the investment plans in our CPP proposal.

2.3.4. Our Performance

We have carried out regular telephone surveys of a sample of residential and small business customers since 2006 to 2018. In the lead up to our CPP application, we carried out comprehensive qualitative and quantitative research into what customers value and expect in their electricity supply and from us as their lines company. Findings include the following:

- residential customers have low levels of awareness of the name of their lines company (33% recall) and some (18%) wanted to receive further information from us
- half of residential customers have a favourable opinion of us
- asked about specific attributes, residential customers rated us highest for "promptly attends to power cuts" and "is safety conscious"
- most customers (86% of households and 79% of businesses) prefer to maintain their current level of unplanned power cuts rather than pay more for increased reliability.

These findings are broadly consistent with similar surveys undertaken in previous years.

Figure 2.4: Residential customer recall of Aurora Energy as their local electricity lines company

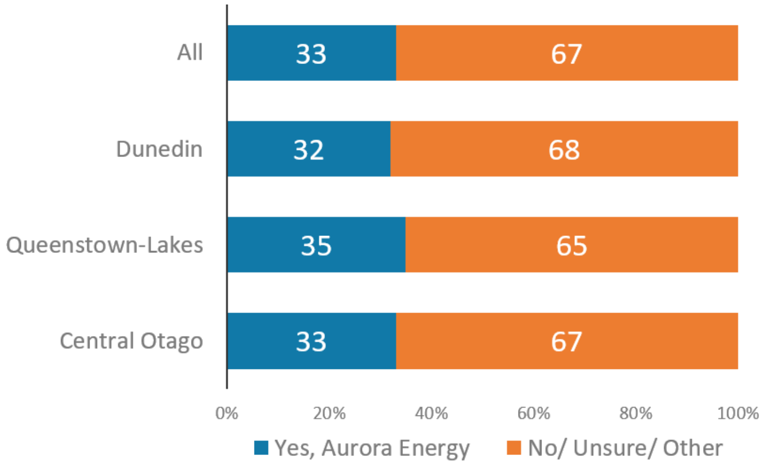


Figure 2.5: Customer favourability rating on Aurora Energy

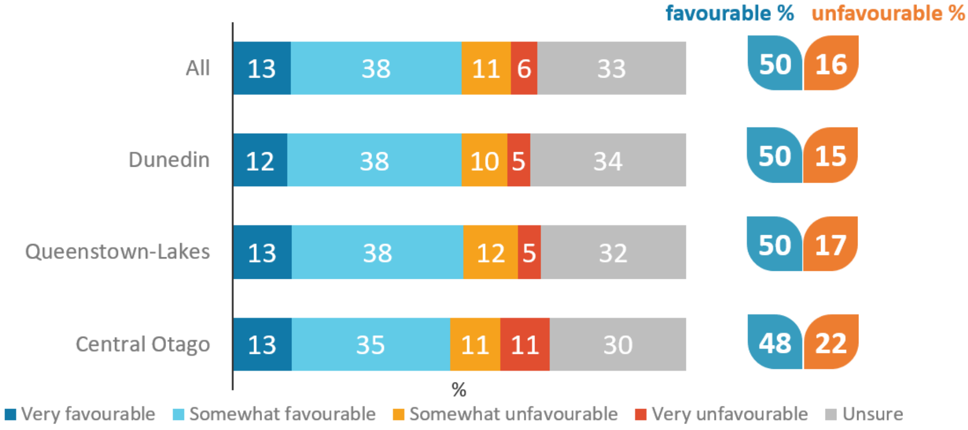
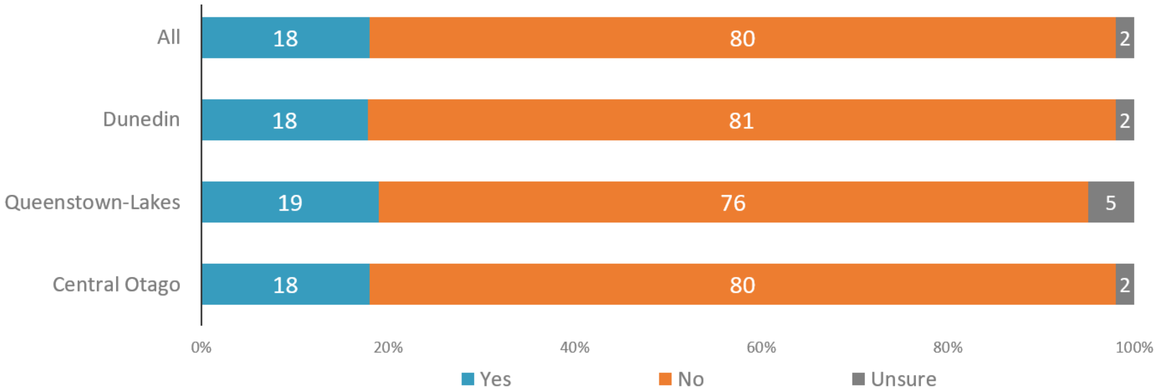


Figure 2.6: Wish to receive information from Aurora Energy



Customer Service Initiatives

We are meeting the current needs of customers on a number of metrics, but there remains room for improvement in others. In particular, we are seeking to further improve our engagement and communication with customers and to streamline the processes we use to connect customers to our networks (see Box 2.2).

We have published a Customer Charter[12] on our website, setting out our commitments to our customers, including safety, customer feedback, complaints resolution, responsiveness, and quality of service.

12 Customer Charter – Our commitment to you, Aurora Energy, January 2018.

Box 2.2: Customer service initiatives

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

- customer voice panels
- engagement on key focus areas, e.g. outputs of the independent risk review by WSP
- improvements to our customer-initiated works processes
- public safety campaign/communications
- attendance at Field Days events
- multi-channel approach to engaging with customers on public safety and outage notification
- improved outage notification.

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. We have established a customer voice panel comprising local electricity consumers. Its objectives are to improve our understanding of customer needs and expectations, in order to keep customers updated on what they are interested in, using the communication channels they prefer.

We have an ongoing campaign to increase public awareness of electricity network hazards and to engage the community in understanding electricity safety. We continue to focus on increasing public awareness of safety around our network through a series of radio advertisements, targeted at contractors and tradesmen. Through these interactions we have looked to deepen our understanding of public safety risk factors. The campaign includes public safety advertising focused on specific audiences, and communications on preparing for power outages.

We have made a number of improvements in our outage notification procedures. We notify customers of planned outages via electricity retailers (and advertising in the case of major outages) and provide media with safety advice prior to forecast severe weather events where there is a higher likelihood of network damage and power outages. We have also increased our outage communication across our digital channels with weekly updates on planned outages and timely updates during unplanned outages or major events.

Further improvements made include publishing planned outage information on our website and in the regional newspaper, developing a social media presence with outage information and safety tips, contacting medically dependent electricity consumers and businesses prior to planned outages, and establishing a dedicated customer support function. We have enhanced our communications, including providing real-time updates during major storm events.

We have improved our approach to facilitating customers connections. We use the term Customer Initiated Works (CIW) to describe works requested by individual customers and which require liaison with connecting parties, developers and their service providers. We are assessing ways to streamline our current processes to ensure customers receive a prompt and efficient service through using an optimal mix of internal resource and external specialists. Where appropriate the use of external resource for CIW design and construction management will enable a greater focus on improving design standards and asset management maturity to support the efficient delivery of our wider work programme.

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

We have increased our focus on digital engagement, with a multi-channel approach to outage notification, public safety campaigns and recruitment. Over the last 12 months we have seen a 70% increase on our Facebook page and a 420% growth across our LinkedIn page. We have continued to produce and distribute videos focusing on our story, recruitment and network projects.

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.

2.4. FURTHER CONTEXT FOR OUR 2020 AMP

Reflecting our ongoing asset management improvement programme, this 2020 AMP builds upon our last full AMP in 2018, which itself had been significantly revised and expanded from previous versions. In particular we offer an expanded amount of detail about our investment plans which are consistent with our application to the Commerce Commission for a CPP proposal.

As we enter the third year operating as a standalone company, we continue to deliver a growing investment programme to ensure our network is safe and reliable for the Dunedin, Central Otago and Queenstown Lakes 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 these changes and how they have they impacted our approach to asset management.

2.4.1. Impact of COVID-19

At this point, it is difficult to fully determine the impacts of COVID-19 on our work programmes in the short-term, or our demand-driven investments over the medium term, but we have deferred growth investments in a number of areas to reflect the expected downturn in demand. Notwithstanding this uncertainty, we are currently operating on the basis that there may be a need for some refinement of our RY21 work plans as the impact of COVID-19 becomes clearer.

2.4.2. 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 our process 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. 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 a robust review of current capability. This has been informed by input from an asset management capability specialist. 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 lift our maturity over the next few years.

Our ultimate aim is to ensure our asset management is consistent with leading New Zealand practice within five years. We plan to use asset management certification (specifically ISO 55001) to monitor and demonstrate our progress to stakeholders. Chapter 9 provides further detail on our asset management development plan.

2.4.3. Regulatory Context

Electricity distribution businesses such as Aurora Energy operate within a regulatory framework administered by the Commerce Commission. The framework specifies the level of revenue we can recover and sets out minimum quality standards in terms of supply interruptions.[13]

As signalled in our 2018 AMP and 2019 AMP Update, our investments had moved significantly beyond the allowances set under the default price-quality path (DPP) that the Commission established in November 2014. Since then, the Commission has made a determination on a new DPP (DPP3) which applies to us since 1 April 2020. This determination, in particular our new quality standards, continue to be inappropriate for our current and medium-term circumstances. The levels of allowed revenue cannot accommodate our current and planned renewal work programmes. There is a high likelihood we will breach our quality standards.

To ensure the sustainability of our business we need a bespoke allowance and quality standards, established under a CPP[14], if we are to fund the investment needed to maintain a safe and reliable network. A CPP provides a mechanism for our sector regulator, the Commerce Commission, and stakeholders to review and have a say on our proposed investment and the potential impact on consumer pricing before we finalise our investment plans.

This AMP forms part of our CPP application to the Commerce Commission. 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. The Commission will now complete a detailed assessment of it, including further consultation, before determining what price path and quality standards should apply.

13 Some consumer-owned EDBs are subject to a more limited regime based around Information Disclosure.

14 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.

We expect to transition to this regulatory mechanism from 1 April 2021.[15] We are proposing a three-year CPP from RY22-24 (CPP Period).[16]

As part of this process (as discussed above), we have undertaken a series of consultations with customers on our proposed investment plans and what these will mean for future network charges and reliability. This AMP, together with the submission published on our website, represents a further stage of stakeholder engagement and consultation on our future investment plans.

Our CPP timeline means we will retain current DPP expenditure allowances for the current regulatory year (RY21). However, as set out in later chapters, we will maintain our increased levels of investment despite the potential financial consequences for spending above our allowance.

2.4.4. Operational Context

This section provides an overview of the issues that impact our approach to asset management. The wider environment we operate in is an important factor in how we deliver our services. There are a range of factors that determine the operational environment. These include climate, access to third party land, and vegetation near our assets. The sections below discuss each environmental factor.

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. conductors), 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 drives investment in additional capacity.

Vegetation

Vegetation located close to our assets has the potential to interfere with their safe and reliable operation. We manage vegetation in accordance with the requirements of the Electricity (Hazards from Trees) Regulations 2003. We do this by patrolling, monitoring, and recording sites where vegetation could interfere with the safe and reliable supply to our customers. We trim, spray, or remove vegetation accordingly. Vegetation management is discussed further in Chapter 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

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15 RY22 begins on 1 April 2021 and ends on 31 March 2022.

16 Under the rules, we must submit five years of information in a CPP application and then request a shorter period. For consistency, within this document we refer to the *CPP Period* as the three-year period, RY22 to RY24 inclusive.

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 in order to formalise the respective party's 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.

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 transmission network. It sets out a summary of network demand and a profile of the major customers on each of our networks.

3.1. BACKGROUND

We own and operate two non-contiguous distribution networks in Dunedin and Central Otago. 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 network with major towns and cities

Like many other networks in New Zealand, much of our infrastructure was first built in the 1950s and 1960s. As a result, large portions of our network are now due to be renewed. Over the next ten years, we need to make significant investments to maintain and renew our distribution network.

Our two regional networks include five subtransmission networks (listed below), with each network being named after the GXP supplying it.

- Halfway Bush
- South Dunedin
- Frankton
- Cromwell
- Clyde

The two oldest networks – Halfway Bush and South Dunedin – are in Dunedin. The development of these networks started around 1910, although there were pockets of electricity supply before that. Central parts of Dunedin are mainly 6.6kV, with the outer suburbs such as Green Island and Mosgiel township being predominantly 11kV.

The three Central Otago networks – Frankton, Cromwell and Clyde – were mostly developed after 1960, although these also include pockets of older assets. Some of these networks were originally 6.6 kV, but apart from a small portion around Clyde, they have all been converted to 11 kV.

Equipment condition varies across the five networks. The Central Otago networks are generally in better condition than the Dunedin networks, mainly due to the younger age of the equipment.

Our Dunedin and Central Otago networks supply close to 55,650 and 35,550 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.

A small network was embedded within The Power Company network in Te Anau in 2005 and supplies over 130 customer connections.

Total energy throughput for the year ending 30 September 2019 was 1,406 GWh (including distributed generation). This is 4 GWh (0.3%) lower than the previous year, as the 2019 winter was very mild. Overall energy growth on our network has been mixed over the past five years, averaging 0.4% increase per annum.

3.2. NETWORK CONFIGURATION

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

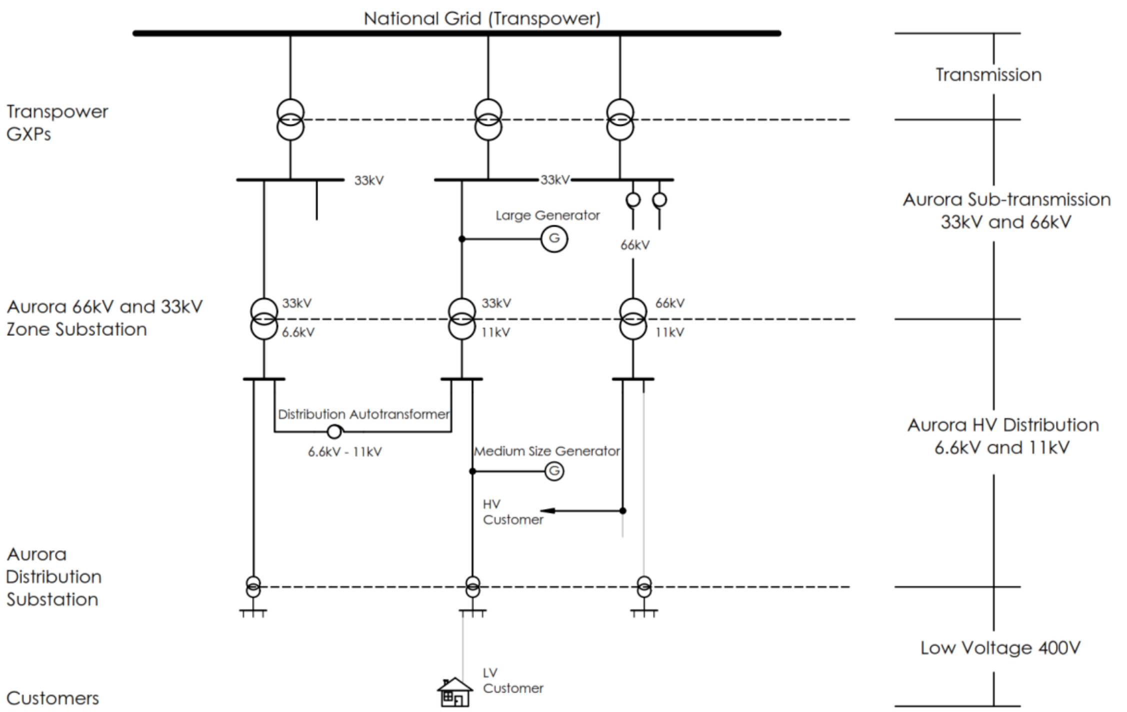
- **subtransmission**: operating at 66 kV (minority) and 33 kV
- **distribution**: generally operating at 11 kV in Central Otago and 6.6 kV in Dunedin
- **Low Voltage (LV)**: operating at 400 V three phase or 230 V single phase.

Electricity from higher voltage circuits (lines and cables) is transformed, at numerous substations, to supply lower voltage circuits. Generally, the voltage conversion is from 33 kV to 11 kV, then to the 400/230 V supplied to homes and businesses. We use subtransmission at 66 kV where there are long distances between GXPs and zone substations, as this reduces line losses incurred. In Wanaka and some parts of the surrounding area, the conversion is from 66 kV to 11 kV. The Dunedin distribution network is typically 6.6 kV, which reflects the age of the networks, with 6.6 kV the international standard distribution voltage prior to 1970, and 11 kV becoming standard from the 1960s. Each of our LV circuits serves between one and a few hundred customers.

The Dunedin distribution and LV networks are largely overhead, with 320 of 1,058 km of distribution and 392 of 1,656 km of LV network being underground. In Central Otago, 756 km of 2,325 km of distribution and 785 of 1,053 km of LV are underground.

Figure 3.2 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 3.2: Representative single line diagram



Zone substations convert high voltage electricity to lower voltages to supply customers over a wide area. Distribution transformers then lower the voltage further for local distribution at street level.

3.3. GRID EXIT POINTS

We deliver electricity from GXPs, through our networks, to close to 91,200 homes and businesses in Dunedin and Central Otago.

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 points are the interface between Transpower's transmission network and our distribution network.

Figure 3.3: Aurora Energy network areas and Transpower GXPs

Our subtransmission overhead lines and underground cables carry a large amount of electricity from Transpower's GXPs. A GXP failure could result in loss of supply to a large number of customers, so a highly reliable configuration is required. There is redundancy built into GXPs through duplication, so that the system can continue to function using an alternate path (N-1) in the event of a failure. See Chapter 6 for a description of our security of supply guidelines.

Figure 3.4: GXPs and transmission lines

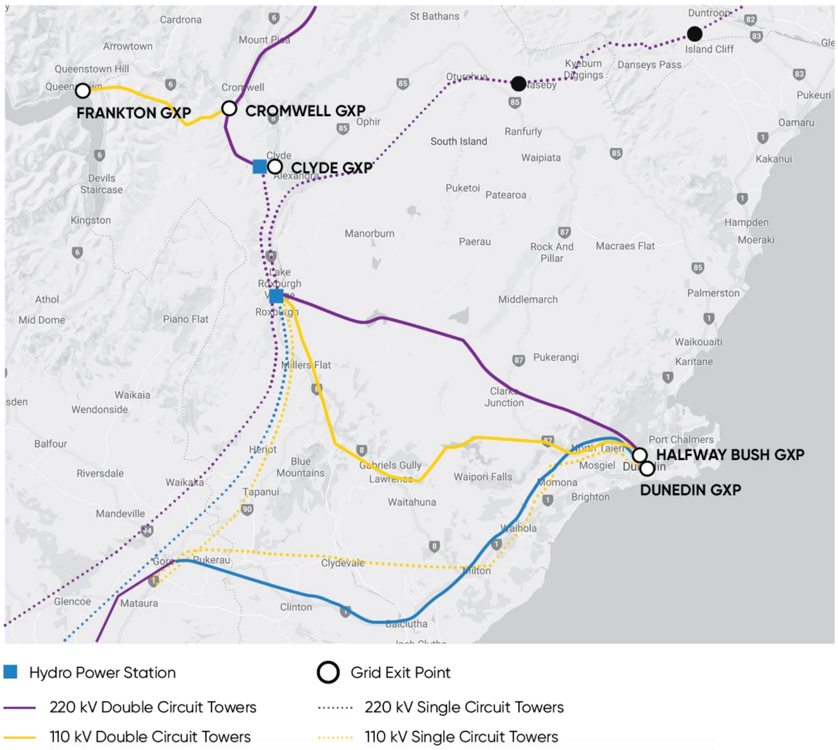


Table 3.1: GXP area statistics

TITLE	HALFWAY BUSH	SOUTH DUNEDIN	FRANKTON	CROMWELL	CLYDE
Number of customers	34,700	20,950	14,050	14,100	7,400
2019 load (MVA)	122	67	61	39	19.1
Zone substation transformers	22	12	13	10	8
Transformer capacity (MVA)	370	266	164	88.5	50

GXPs are owned by Transpower, although we have some equipment co-located at some of these sites (see table below). Each GXP supplies a specific zone or area (subtransmission network), with limited or no connectivity between the zones.

Table 3.2: Selected Aurora Energy assets at GXPs

TITLE	HALFWAY BUSH	SOUTH DUNEDIN	FRANKTON	CROMWELL	CLYDE
Ripple control plants	2	1	1		
Buildings	2	1			
Protection relays	Yes	Yes	No	Yes	Yes
SCADA and metering	Yes	Yes	Yes	Yes	Yes
Structures and air break switch	Yes	Yes	Yes	Yes	No
Other	33 kV cable gassing bank	33 kV cable oil reservoirs		2 x 30 MVA 33/66 kV autotransformers	

3.4. DISTRIBUTED GENERATION

Distributed generation schemes have the potential to make a significant contribution to future network development, in terms of security, efficiency and economy of network operation. However, distributed generation 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.

The level of small-scale distributed generation within our network is low at present but is expected to continue to grow during the AMP period. We expect that most new distributed generation connections will continue to be photovoltaic (PV) installations – these generate electricity during sunlight hours but will not materially impact peak demand during winter evenings.

Expected PV installations do not have a material influence on the network design and investment at this time but may drive the need for further network investment towards the end of the AMP period.

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

We have developed a standard distributed generation Use of System agreement as a basis for commercial negotiations. The standard agreement was developed with reference to relevant regulations and appropriate conditions in retail Use of System agreements. We consider that this approach maintains a degree of industry consistency and standardisation.

Commercial arrangements for distributed generation vary. For small distributed generation (generally below 10 kW), the default arrangements specified within Part 6 of the Electricity Industry Participation Code normally suffice. The commercial arrangements for larger generation warrant greater attention due to the greater use of, and impact on, system assets.

There is currently 138 MW of distributed generation connected to our network, across 1,200 connections. Hydro and wind generation remain the predominant forms of distributed generation, contributing 64% and 27% (respectively) of total distributed generation capacity. Small-scale photovoltaic generation comprises 97% of generation connections but makes up only 3.8% of capacity. Table 3.3 sets out all distributed generation connections that are 1 MW or greater.

Table 3.3: Distributed generation (1MW or greater)

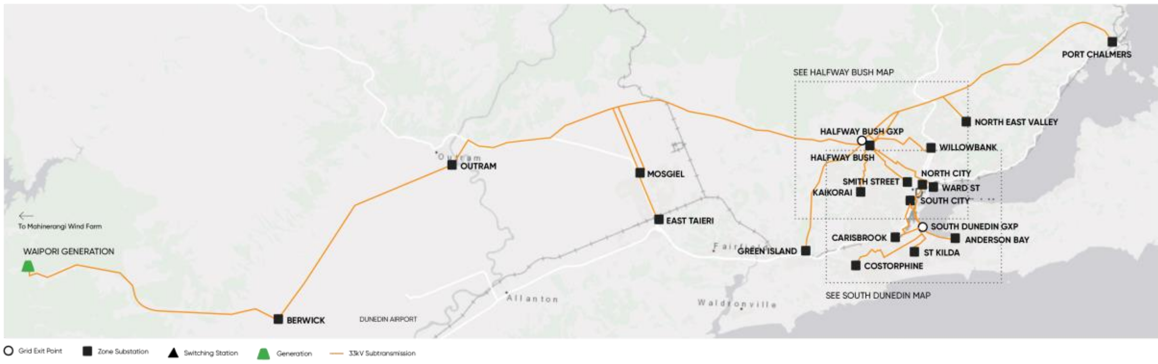
NAME	TYPE	CAPACITY (MW)
Waipori 33 kV, Waipori gen & Deepstream 1A, 2A	Hydro	53
Waipori 33 kV - Mahinerangi	Wind	36
Teviot stations	Hydro	13
Horseshoe Bend	Hydro	4
Horseshoe Bend Wind	Wind	2
Lower Fraser	Hydro	3
Upper Fraser	Hydro	8
Roaring Meg	Hydro	4
Wye Creek	Hydro	1
Ravensdown generation	Process steam	3
Talla Burn	Hydro	2
Container Port (Port Otago)	Liquid fuel	2
DCC wastewater treatment plant	Biomass	1

Distributed generation connections have been increasing at more than 15% per annum, the vast majority of these being small PV connections. Ongoing growth will be highly dependent on the cost of PV panels, and could also be impacted significantly by future changes in government policy in this area. Due to the size of PV connections, we do not expect continuing growth to have a material network impact, but we will continue to consider the cumulative impacts over time, particularly if evidence of generation clusters emerges.

3.5. DUNEDIN 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 added resilience for the city's supply.

Figure 3.5: Dunedin subtransmission networks



The urban subtransmission system in Dunedin is a radial system, where the 33 kV supply is distributed out from a single point. As a radial network, redundancy in supply to each zone substation is achieved by installing two underground cables in close proximity to one another. Redundancy minimises the impact of a failure of supply to a zone substation. The existing network configuration does not give us options to transfer significant load between GXPs.

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 5.

3.5.1. 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.

In the Dunedin area, we have experienced a small decline in demand in recent years. This is partly due to economic conditions, compounded by a series of mild winters, increased efficiency in utilisation (e.g. heat pumps and more efficient lighting) and a gradual uptake of edge technologies (such as photovoltaic generation). With the COVID-19 pandemic, we expect that the demand would slightly reduce in the next two years. As a result, investment in Dunedin will continue to be driven by the need to replace ageing assets and maintain existing levels of reliability.

Table 3.4: Dunedin load and customer statistics

	APPROX. CUSTOMER NUMBERS	RY19 (MVA)
Halfway Bush	34,700	122
South Dunedin	20,950	67
Total customers	**55,650**	
Coincident demand		**185**

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.

3.5.2. 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 at critical sites. These sites would become a priority for restoration of supply for any natural disaster, most likely in co-operation with Civil Defence.

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.

Construction of the new Dunedin Hospital in the near future may require the relocation of the North City substation and installation of a new supply to manage the expected increased load. Given the uncertainty around the project we have not made provision for the relocation in our forecasts.

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.

3.5.3. Halfway Bush Network

Our overhead subtransmission 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 subtransmission system from Halfway Bush supplies approximately 34,700 customers.

The Halfway Bush GXP feeds the following zone substations.

Table 3.5: Halfway Bush zone substations

ZONE SUBSTATION	FEEDER TYPE	TRANSFORMER[17] (MVA)	PEAK LOAD 2019 (MVA)
Berwick	Overhead line	3	2
East Taieri	Overhead line	12/24 and 12/24	16
Green Island	Cable	15 and 15	14
Halfway Bush	Cable	24 and 24	15
Kaikorai Valley	Cable	12/24 and 12/24	9
Mosgiel	Overhead line	10 and 10	7
North East Valley	Cable/Overhead line	9/18 and 12/24	8
Outram	Overhead line	3	3

[17] 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.

ZONE SUBSTATION	FEEDER TYPE	TRANSFORMER[17] (MVA)	PEAK LOAD 2019 (MVA)
Port Chalmers	Overhead line	7.5/10 and 7.5/10	7
Smith Street	Cable	9/18 and 9/18	14
Ward Street	Cable	12/24 and 12/24	10
Willowbank	Cable	15 and 15	13

Figure 3.6: Halfway Bush subtransmission networks

3.5.4. South Dunedin Network

The South Dunedin network is fed by a single GXP (South Dunedin). The subtransmission network is fully underground consisting of dual circuit cables feeding six zone substations. The subtransmission system supplies approximately 20,950 customers.

Figure 3.7: South Dunedin subtransmission network

The South Dunedin GXP feeds the following zone substations.

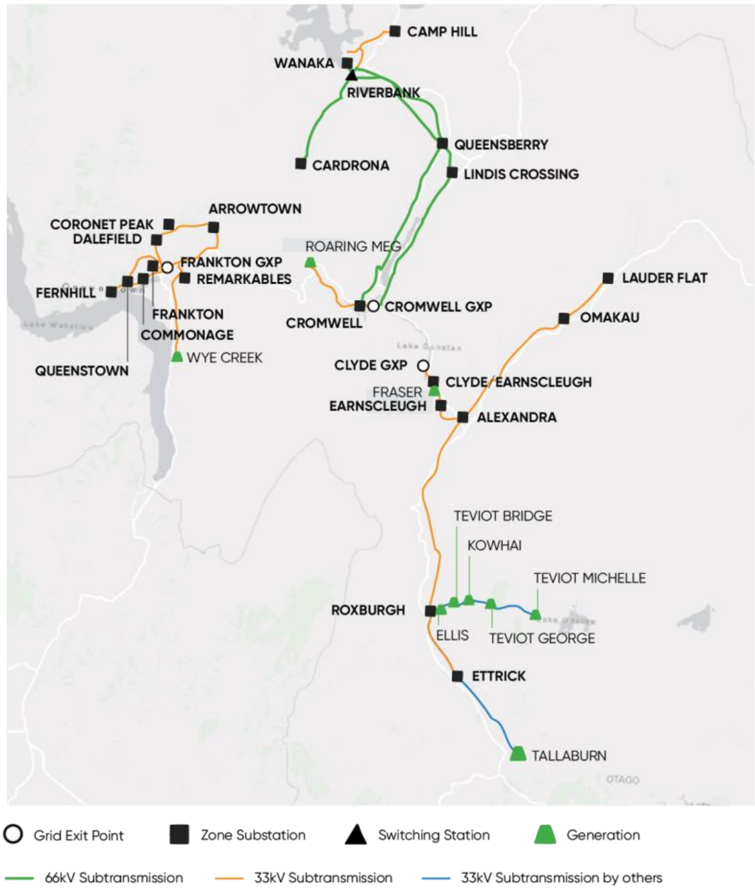
Table 3.6: South Dunedin zone substations

ZONE SUBSTATION	FEEDER TYPE	TRANSFORMER (MVA)	PEAK LOAD 2019 (MVA)
Andersons Bay	Cable	15 and 15	15
Carisbrook	Cable	18/24 and 18/24	12
Corstorphine	Cable	12/24 and 12/24	13
North City	Cable	14/28 and 14/28	18
South City	Cable	9/18 and 9/18	16
St Kilda	Cable	12/24 and 12/24	16

3.6. CENTRAL OTAGO OVERVIEW

The Central Otago network is supplied via the Frankton, Cromwell and Clyde GXPs. Each of the GXPs supply a geographically distinct network with no interconnection between the networks.

Figure 3.8: Central Otago subtransmission networks



Historically, Central Otago has been one of the fastest growing regions in New Zealand due to agriculture and residential developments. Central Otago 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.

3.6.1. Central Otago Load

We have seen steady load growth on the Central Otago network, driven by steady growth in residential subdivisions together with significant one-off projects such as ski field developments. We have also seen extremely high growth in irrigation load in some areas. However, with the COVID-19 pandemic, we anticipate a reduction in the rate of growth in the short term. Due to Central Otago's very dry climate, irrigation has always been important. A number of significant pumping stations have been in service for many years, some of which have legacy agreements for low-cost electricity supply.

Central Otago's ski fields are significant users and can control their own peak load, while some use diesel generation to supplement available supply. Capacity increases generally require a customer contribution and are managed under commercial agreements.

Table 3.7: Central Otago load and customer statistics

	APPROX. CUSTOMER NUMBERS	RY19 (MVA)
Frankton	14,050	61
Cromwell	14,100	39
Clyde	7,400	19
Total customers	35,550	
Coincident demand		115

3.6.2. Major Customers

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

Ski Fields

The Central Otago ski fields 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 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 networks have a significant amount of irrigation load (e.g. Dairy Creek Irrigation Scheme). 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. Irrigation load does not generally drive growth investments as it occurs outside of winter peak load periods. However, some zone substations have become summer peaking and required development specifically to supply irrigation load.

The Hawea 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 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.

Local Councils

The combined load of the Central Otago District Council and 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.

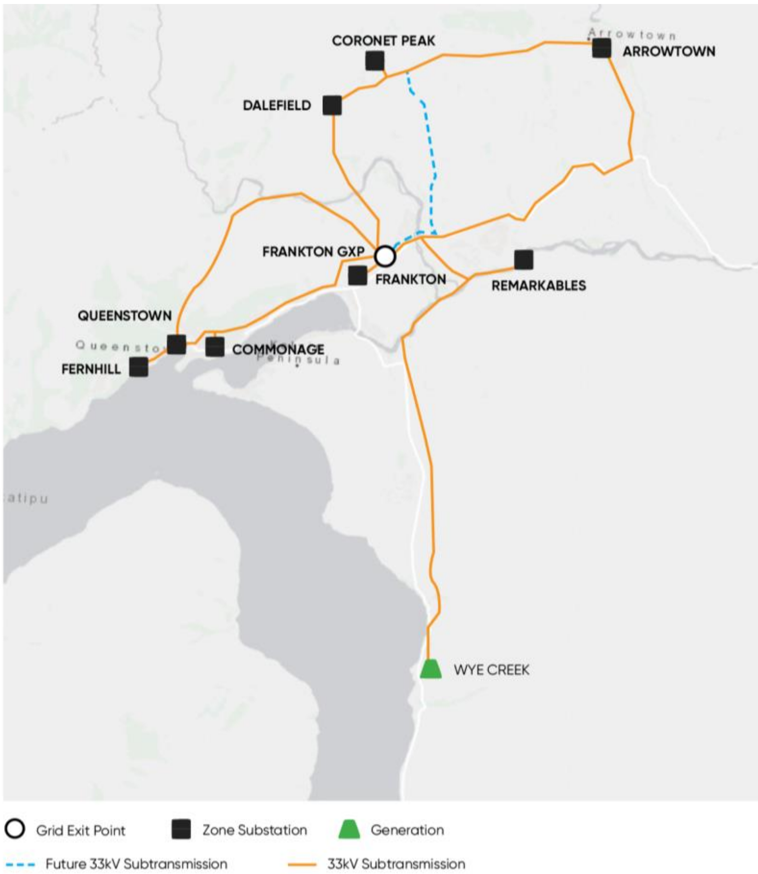
Queenstown Airport

In conjunction with tourism in Central Otago, 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 in the unlikely event the Frankton substation is out of service, including supply from the Commonage substation.

3.6.3. Frankton Network

The Wakatipu basin is supplied from the Frankton GXP. There are eight zone substations in the Queenstown, Frankton and Arrowtown areas that transform the voltage from the 33 kV subtransmission voltage to 11 kV distribution. From there, 11 kV circuits distribute power to smaller distribution transformers. Arrowtown zone substation has three power transformers.

Figure 3.9: Frankton subtransmission network



The Frankton, Queenstown, Arrowtown and Dalefield areas are supplied via 33 kV overhead lines from the Frankton GXP. A 33 kV ring network is used to feed Arrowtown, Coronet Peak and Dalefield and to provide backfeed capability should one section of the ring fail. It also connects the Wye Creek generation facility. The subtransmission system supplies approximately 14,050 customers.

The Frankton GXP supplies the following zone substations.

Table 3.8: Frankton zone substations

ZONE SUBSTATION	FEEDER TYPE	TRANSFORMER (MVA)	PEAK LOAD 2019 (MVA)
Arrowtown	Overhead line	5,5 and 7.5/10	9
Commonage	Overhead line	14/17 and 14/17	14
Coronet Peak	Overhead line	5/6	6
Dalefield	Overhead line	3	2
Fernhill	Cable	7.5/10 and 7.5/10	7
Frankton	Cable/Overhead line	12/24 and 7.5/15	16
Queenstown	Overhead line	10/20 and 10/20	15
Remarkables	Overhead line	3	2

The majority of zone substations have supply redundancy through N-1 33 kV lines or cables.

3.6.4. Cromwell Network

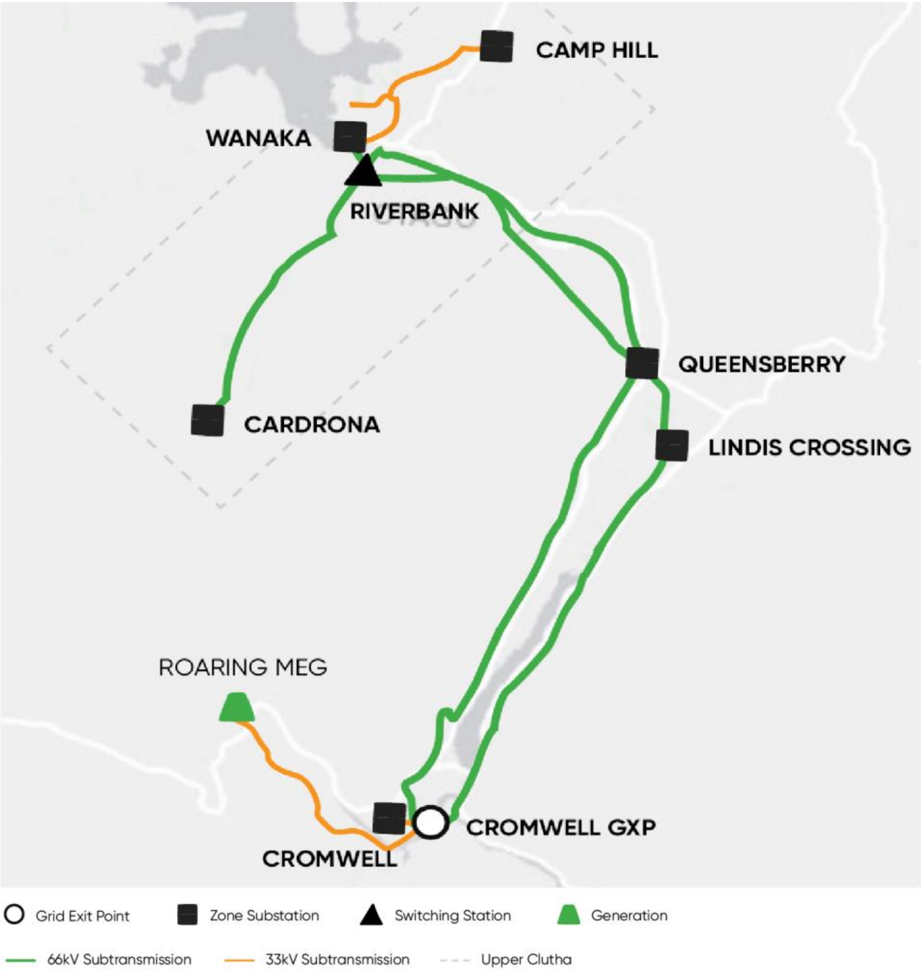
The Upper Clutha area is supplied from Transpower's Cromwell GXP. To supply the large electricity demand in the Wanaka, Cardrona and Hawea areas, two 66 kV overhead lines run from Cromwell to Wanaka, one on either side of Lake Dunstan. These 55km lines supply zone substations on the way to terminating at Riverbank switching station. The 66 kV lines from Riverbank to Wanaka and Cardrona complete the 66 kV circuits on our network.

There has been considerable demand growth in this area recently, necessitating the construction of Riverbank 66 kV switching station in 2018. There is provision to install two transformers on-site, allowing us to continue to reliably meet regional electricity growth. The commissioning of Riverbank switching station enabled the Cardrona line to be operated at 66 kV (as previously constructed) improving voltage management and the efficiency of electricity delivery to Cardrona.

At Wanaka zone substation the subtransmission voltage is transformed from 66 kV to 33 kV, with Camp Hill zone substation taking a 33 kV supply. All substations supplied from the Cromwell GXP supply the distribution network at 11 kV.

The subtransmission system supplies approximately 14,100 customers.

Figure 3.10: Cromwell subtransmission network



The Cromwell GXP supplies the following zone substations.

Table 3.9: Cromwell zone substations

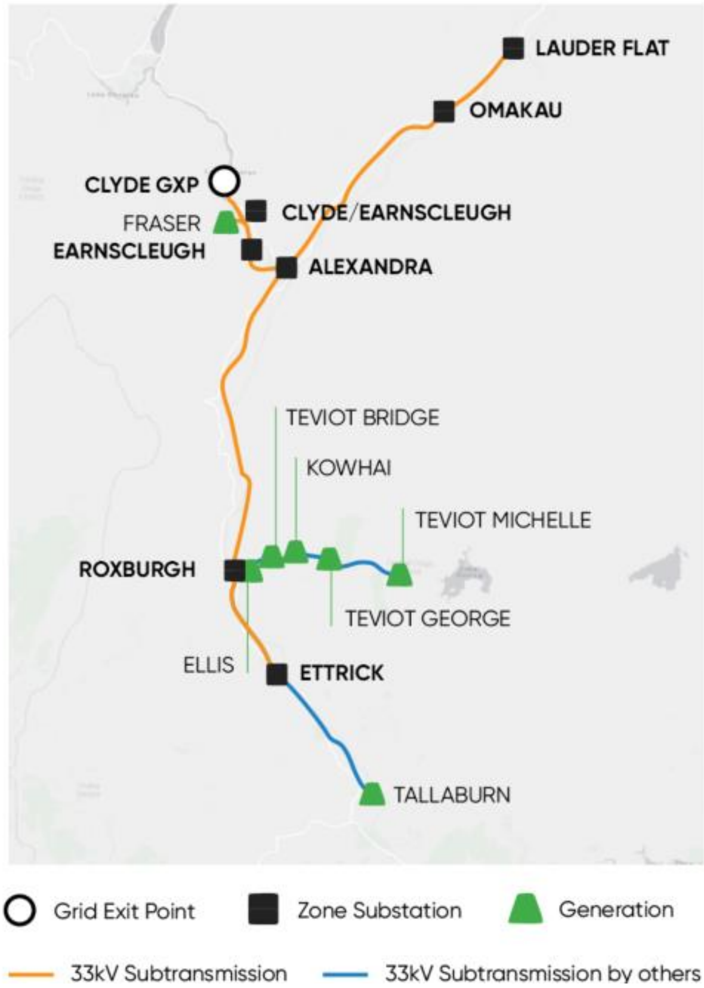
ZONE SUBSTATION	FEEDER TYPE	TRANSFORMER (MVA)	PEAK LOAD 2019 (MVA)
Camp Hill	Overhead line	7.5	6
Cardrona	Overhead Line	5/6	4
Cromwell	Cable/Overhead line	7.5 and 5/10	13
Lindis Crossing	Overhead line	7.5	7
Queensberry	Overhead line	3/4	3
Wanaka	Overhead line	12/24 and 12/24	21

3.6.5. Clyde Network

The Alexandra, Clyde, Manuherikia, Ida Valley and Teviot Valley areas are supplied via two 33 kV subtransmission circuits connected to the Clyde GXP. Most of the electricity demand in the Clyde GXP area is supplied from distributed generation sites at Teviot, Ettrick and Earnscleugh. Subtransmission plays an important role in delivering excess generation for injection into the national grid at the Clyde GXP. Two parallel 33 kV lines run between the Clyde GXP and Alexandra, and then onto Roxburgh. Ettrick is supplied by a single 33 kV line from Roxburgh, and Omakau, to the north-east of Alexandra, is supplied by a single 33 kV line from Alexandra.

The subtransmission system supplies approximately 7,400 customers.

Figure 3.11: Clyde subtransmission network



The Clyde GXP supplies the following zone substations.

Table 3.10: Clyde zone substations

ZONE SUBSTATION	FEEDER TYPE	TRANSFORMER (MVA)	PEAK LOAD 2019 (MVA)
Alexandra	Overhead line	7.5/15 and 7.5/15	12
Clyde / Earnscleugh	Overhead line	4	4
Ettrick	Overhead line	3	1
Lauder Flat	Overhead line	3	1
Omakau	Overhead line	3/3.6	3
Roxburgh	Overhead line	5	2

3.7. 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.

The graphic shown to the right illustrates the large number of diverse assets that make up our distribution networks. Each of the categories, in turn, comprises a number of asset types, for example, a crossarm assembly includes not only the crossarm itself, but the insulators and other hardware that sits on the crossarm, enabling it to connect to conductor.

The table below puts a different lens on our assets, comparing the relatively small number of high voltage assets and the very large number of distribution and low voltage assets that make up our network.

These views provide an indication of the breadth of knowledge and competency required to plan for, operate, and maintain distribution networks where failure of an asset as small as an insulator can have a significant impact in terms of both safety and reliability.

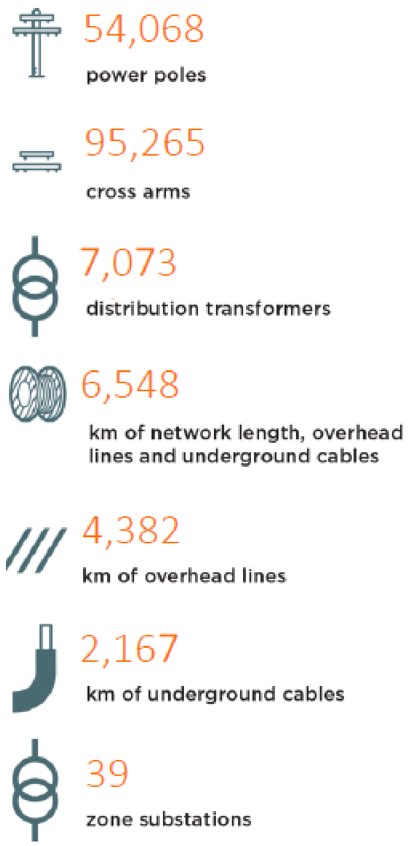


Table 3.11: Summary of network assets

	Grid Exit Points	Zone Substations		Distribution Transformers		Customer Connections	
Dunedin	Halfway Bush	33 kV	12	11 or 6.6 kV	2,654	400 or 230 V	34,700
	South Dunedin		6				20,950
Central Otago	Clyde		7		1,483		14,050
	Cromwell		6		1,672		14,100
Queenstown	Frankton		8		1,264		7,400
		Subtransmission		Distribution		Low Voltage	

4. STRATEGY AND GOVERNANCE

This chapter describes our asset management strategy and explains our overarching governance approaches, including the structures and responsibilities that support our investment decision-making. To ensure appropriate 'line-of-sight' our asset management framework translates our corporate vision and strategic priorities into asset management objectives that guide our investment and operational decisions. Effective risk management is a core function of good asset management and our approach is set out in this chapter.

4.1. ASSET MANAGEMENT FRAMEWORK

The diagram below provides an overview of our asset management framework.

Figure 4.1: Asset management framework

The graphic above illustrates how our asset management strategy informs all stages of the asset lifecycle, and how ongoing and systematic review drives continuous improvement. As evidenced by the refresh of our asset management objective areas (see Section 4.6) the ongoing review aspect has an important role in shaping our strategic approach.

Our framework incorporates a typical 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 we progress our asset management development plan (See Chapter 9) 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 use this concept when managing our asset fleets.

4.1.1. Asset Management System

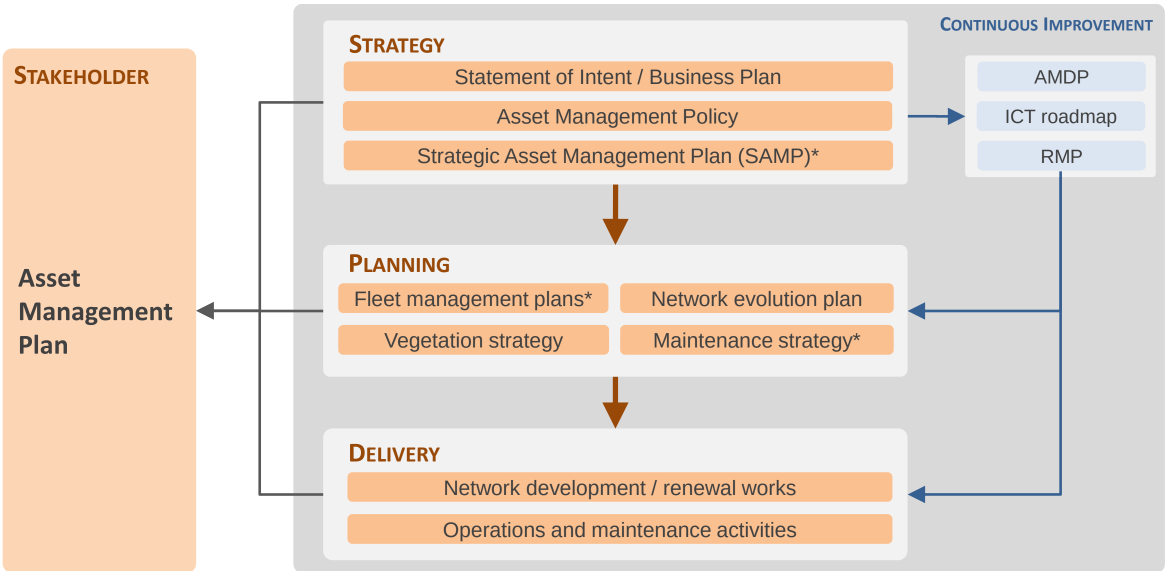
The core function of our business is to deliver electricity safely, reliably and affordably to customers, now and into the future. The overarching objective of our asset management system is to ensure we achieve this. The areas covered in our asset management system include all electricity distribution network assets and non-network assets that directly support the electricity distribution system, interactions with organisations that we outsource asset-related activities to including service providers and contractors, and our staff that directly and indirectly support our asset management activities.

Our asset management framework incapsulates the elements of our asset management system. This framework is undergoing significant change and development at present. The scope of our asset management framework will be reviewed as we scope and plan to achieve ISO 55001 certification.

4.2. STRATEGIC FRAMEWORK

As discussed above, our strategic framework seeks to reflect good industry practice [18] and encapsulates our approach to asset management. We organise our core set of asset management documents into a hierarchy that begins with the views of stakeholders, primarily through our business plan and asset management policy, to our day-to-day detailed activities.

Figure 4.2: Asset management document hierarchy



* under development

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.

18 This framework will evolve as we progress our asset management improvement initiatives towards ISO 55001 certification.

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 for the next three financial years
- **Business Plan**: (to be finalised) sets out our corporate vision, mission and values with further detail on the high-level corporate objectives outlined in our SOI. It directly reflects the interests of internal and external stakeholders who have an active interest in how our network and its assets are managed
- **Asset Management Policy**: aligns our asset management approach with our corporate objectives through a set of strategic priorities
- **Strategic Asset Management Plan (SAMP)**: (in development) will set out our asset management objectives, providing strategic direction for the development of our fleet strategies and objectives and our network development planning guidelines
- **planning documents**: including our fleet management and maintenance plans (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 the lifecycle management of our assets. Our network evolution plan and vegetation management strategy are recent additions to our document hierarchy and reflect key focus areas during the AMP period
- **delivery plans**: are 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 asset management objectives and investment plans over the AMP period, focusing on explaining these to stakeholders and complying with relevant disclosure requirements
- **continuous improvement**: as discussed below and in Chapter 9 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).

Each of the above elements has a defined ownership (e.g. the AMP is the responsibility of the GM Asset Management and Planning), and each has control and review processes to ensure consistency with our values, vision and mission. The documents are managed through our document management system (CDS) and by defining required reviewers and level of sign-off (e.g. our asset management policy is reviewed and approved by our CEO and Board).

Ensuring that the above documents and plans support and relate to one another is an important aspect of our asset management system. One of the objectives of our AMP is to ensure these are appropriately summarised for external stakeholders.

4.3. STAKEHOLDER INTERESTS

Our asset management approach recognises the diverse interests of our stakeholders.

Table 4.1: Stakeholder Interests and how these are identified

STAKEHOLDER	MAIN INTERESTS	HOW INTERESTS ARE IDENTIFIED
Electricity consumers	Reasonable prices Information on unplanned and planned outages Timely response to enquiries, faults, complaints Safe and reliable supply of electricity Resilience of the network	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	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
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

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 customers' 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.

Chapter 2 discusses our key stakeholders.

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 improvement.

Table 4.2: Our five strategic priorities

STAKEHOLDER	MAIN INTERESTS
Build a high-performance safety and wellbeing culture	Drive cultural transformation throughout our business to reposition our safety leadership and performance to a leading industry position
Deliver demonstrably optimised business performance	Optimise key elements of business performance through process and capability improvements to deliver demonstrably efficient outcomes and predictable cost and profitability
Deliver excellence in asset lifecycle management	Reposition our asset management approach to ensure that our network meets customer price and performance expectations while maintaining shareholder value and regulatory compliance
Deliver value to our customers – current and future	Achieve proactive and meaningful engagement with our customers and stakeholders to meet their long-term needs supported by transparent and streamlined processes
Create a high performing and respected team	Drive a positive and agile culture where individuals are engaged, and teams collaborate to deliver business outcomes

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 the communities of Dunedin, Central Otago, and Queenstown.

Our Vision is to be..

> *"A respected local partner recognised for providing essential electricity services to support the future growth and wellbeing 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 (below) 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 mind sets and standards of behaviour that guide how we work with each other and with our stakeholders. By living these values every day, we will create a work environment that brings out the best in everyone.

Figure 4.3: Our values

4.5. ASSET MANAGEMENT POLICY

Our asset management policy sets out high-level asset management principles that reflect our vision and values. 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 ensure safety of asset works
- use robust processes and improved asset data to make asset management and lifecycle decisions
- understand our customers' and stakeholders' balanced needs and values
- prepare for disruptive shifts in technology, customer expectations and the way our network is used
- seek best practice asset management including seeking ISO 55001 certification by the end of 2023
- comply with all statutory and regulatory requirements.

4.6. ASSET MANAGEMENT OBJECTIVES

Our asset management objectives set the direction for managing our network. They have been developed to achieve the following aims:

- 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 objective areas that link our corporate strategic priorities to our asset management and asset fleet objectives.

Table 4.3: Our five strategic priorities

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 – 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 to a changing landscape	– we respond to customer preferences and demand changes – 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, with (as relevant) information 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 both those working on our network as well as the wider public. As an employer, we aim to ensure an injury-free workplace. We have set out our commitments to health, safety and the environment in a policy published on our website.[19]

Our network assets and some asset management activities pose potential hazards to our workers and to the general public. Asset health is linked to likelihood of asset failure which can lead to negative consequences. Elevated safety risk is one potential consequence of poor asset health and is often accompanied by others such as reliability risk, environmental damage and non-compliance. Public safety risk is greatest for asset classes in close proximity to people, particularly overhead line assets. Safety risk to workers extends to assets in our substations and increases with deterioration of asset health.

Effective management of safety risks associated with our assets and activities is fundamental to our business and to fulfilling our statutory obligations. According to our recent customer survey our customers value the safety of our network most of all and believe this should not be compromised. This preference has been reflected in our CPP investment plans.

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

Our Performance

We have taken significant steps in improving our public safety management system. We conduct regular audits, which to date have shown an improving trend.

Table 4.4: Safety system audit results

CRITERIA	DEC. 2017	JUNE 2018	JULY 2019
Unattained (UA)	0	0	0
Partial attainment (PA)	6	7	2
Opportunities for improvement (OI)	13	5	4

The most recent report from July 2019 recognised a significant improvement (as indicated by lower PA and OI in Table 4.4) relating to processes for collecting, collating, and responding to calls to review and address potential network risks.

Our incident reporting system has been enhanced with deployment of the ICAM[20] investigation methodology. This has resulted in improved assessment of the potential and actual severity of

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

20 Incident Cause Analysis Method (ICAM) is a standardised approach to investigating incidents in the utilities sector.

incident outcomes. The incident classification system includes the recognition of key risks (critical risks). This allows us to focus our health and safety management on areas of greatest concern.

Our key performance targets for health and safety are set out below. Recognising the need for continuous improvement, the key strategies and initiatives described below will help drive a stronger safety culture. Over time, this will improve our TRIFR towards a best practice performance level of 3.5 by the end of the CPP Period in 2024. Zero public harm is our ultimate commitment and our target for public safety incidents and specifically harm to any member of public is zero.

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 RY25 targets to apply for the remainder of the AMP planning period.

Table 4.5: Health and safety performance targets (for calendar years)[21]

TARGET	2018	2019	2020	2021	2022	2023	2024	2025
TRIFR[22]	4.63	5.00	<4.50	< 4.25	< 4.00	< 3.75	<3.50	<3.25
Actual harm to public	0	1	0	0	0	0	0	0

One member of the public was harmed in 2019, after a phase to neutral transposition in Central Otago caused a utility shed to become livened. This resulted in a worker on the property receiving a non-fatal electric shock. In this instance the electric shock did not cause any injury requiring hospitalisation. However, the outcome had credible potential to be more severe. Our response, including post incident investigation helps us to understand the contributing factors and take action to prevent a repeat incident. The key learnings from this incident were shared across the organisation and with contractors.

The 2019 calendar year also saw a high number of contractor recordable incidents, most of which were aggravations of pre-existing or old injuries and the remainder were hand injuries. Work was done with the contractors to promote better innovation and use of tools to prevent these injuries and this continues to be a focus into 2020.

Our view is that our safety performances 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:

- analysing asset risks by safety consequence and defining adequate controls
- continue implementing our safety-in-design process
- prioritising our asset renewal programme on those asset fleets with greatest inherent risk
- implement a safety culture improvement program that will engage our management, staff and service providers

[21] Our targets for both 2018 and 2019 were: TRIFR (<4.75) and actual harm to public (0).

[22] Total Recordable Injury Frequency Rate (TRIFR) per 200,000 hours worked.

- invest in safety leadership training
- improve the reporting of hazards and near miss incidents
- enhance our approach to safety-in-design
- 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. Targeted safety messages are promoted through print and online advertising on the hazards of working near overhead lines, digging near underground cables, and being prepared in the event of power outages. We have been working on improvement of our safety message around trimming trees near electricity lines, supported by a safety guide for tree owners and advice on what species to plant (or avoid) near power lines and participating in a nationwide awareness campaign with other electricity distributors. New safety messages have been added on reducing summer fire risk and what to do if your car hits a power pole.

4.6.2. Reliability

Reliability of supply is measured in terms of duration and frequency of interruptions per customer. Major factors in determining levels of reliability performance include asset health, field response times, and network security in terms of flexibility to back up or restore lost supply. The service our customers receive from the network is largely determined by the assets we use to deliver their electricity. These reflect historical trade-offs between cost and service. Achieving target levels of service performance is often a long-term undertaking.

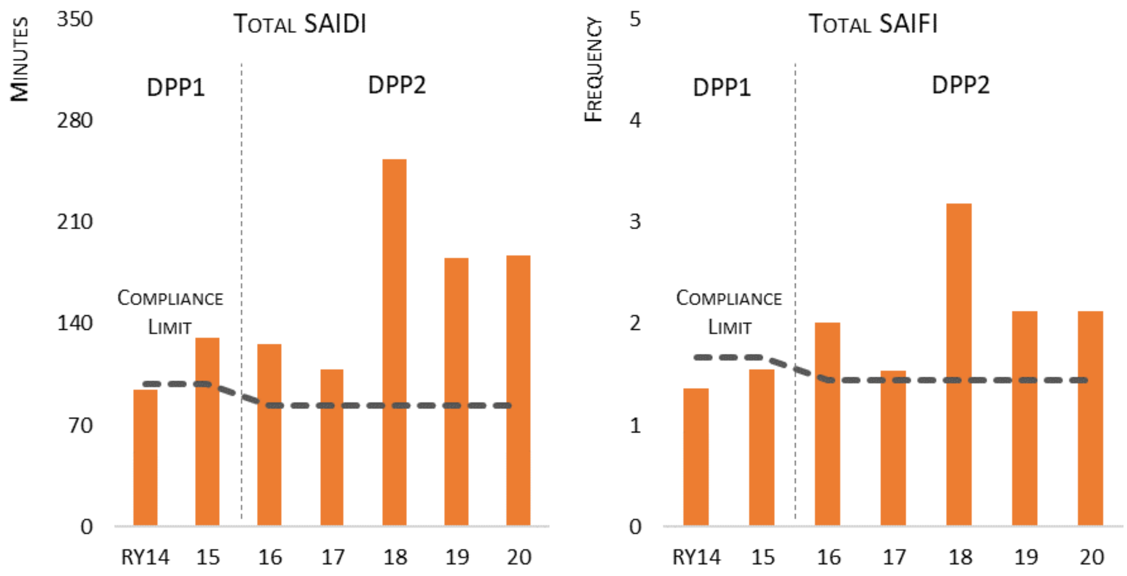
> **Box 4.2: Reliability Objective**
> Our objective is to deliver a cost effective and sustainable level of reliability performance that reflects customer preferences.

Historical Performance

In recent years, our network reliability has shown a deteriorating trend, as illustrated in the chart below. We have exceeded our SAIDI limits during the last six regulatory years, RY15 through RY20, while SAIFI limits have also been exceeded in recent years. Ageing assets have played a significant role in this deteriorating trend. Not only have we experienced an increase in the frequency of equipment defects contributing towards additional unplanned outages, but our increased work volumes have led to higher levels of planned outages.

Changes in operational practice have 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, enabling 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.

Figure 4.4: Historical reliability performance[23]



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.

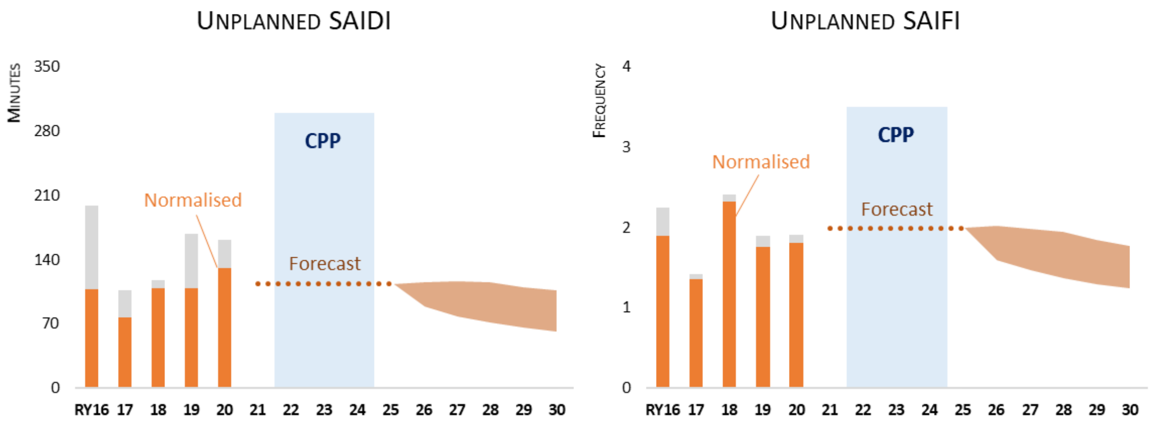
Our current investment plans focus on reducing safety risks through our renewals and maintenance programmes. This work will lead to some reliability benefits due to improving overall asset health. Subject to future consultation with customers, we may look to improve future network reliability by investing in network automation and similar capabilities.

It is important to note that our renewal programmes are taking place during a time of deteriorating asset performance. Reversing this trend can be expected to take some years, as there is likely to be a lag between implementing our investment plans and observing the results. In this context, stabilising current levels of performance is itself a considerable challenge for us during the CPP Period.

The following chart sets out our forecast unplanned reliability (SAIDI and SAIFI) for the AMP period, highlighting the reliability performance we expect during the CPP Period. These forecasts have been created using our new modelling capability developed as part of our asset management improvement initiatives (discussed in Chapter 9).

23 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 reduce the impact of Major Event Days.

Figure 4.5: Forecast unplanned SAIDI and SAIFI



The charts above include an 'uncertainty band' from RY25 onwards, which in part reflects the inherent uncertainty when forecasting long-term reliability but also reflects a range of reliability performance that could be delivered if customers indicated a preference to do so during future consultation. We anticipate that continued investment in safety beyond the CPP Period will improve reliability performance. We will consult with customers in RY23/24 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.

We can manage our work programmes under the DPP3 planned reliability allowances

Given that our level of investment will remain elevated we expect that current levels 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 so long as notification and communications are well-managed.

An appropriate planned outage allowance is important as it removes any unintended incentive to prevent delivery of our required work programme. A multi-year allowance provides scope to be more efficient when delivery planning, including scope to optimise field workforce utilisation by reducing constraints on annual work levels and allowing more flexible multi-year work scheduling.

With appropriate modifications (e.g. using a three versus five-year period) to the application of the DPP3 planned quality standards we believe we can manage our CPP work programme within our DPP3 planned quality standards. At times this will present a challenge, however we are confident we can achieve it given our planned delivery and outage planning improvements.

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 are developing improved processes with our contractors to ensure that planned outages are communicated correctly and managed to plan.

Reliability Targets

Reflecting the discussion above, the table below sets out our reliability forecast for the next six years.

Table 4.6: Forecast SAIDI and SAIFI (normalised, by regulatory year)[24]

MEASURE	2021	2022	2023	2024	2025	2026
SAIDI - Planned	195.96	195.96	195.96	195.96	195.96	195.96
SAIDI - Unplanned	113.4	113.4	113.4	113.4	113.4	113.4
SAIFI - Planned	1.11	1.11	1.11	1.11	1.11	1.11
SAIFI - Unplanned	1.99	1.99	1.99	1.99	1.99	1.99

As discussed above, we intend to consult with customers again in the lead up to our second CPP and will seek to understand their price-quality preferences at that point in time. This will inform our future reliability targets. In the interim, and acknowledging the uncertainty depicted in Figure 4.5, we will retain the same broad targets for the remainder of the AMP planning period.

Key strategies and initiatives

As part of our reliability management plan (RMP), we have defined 39 strategic initiatives (or reliability levers), which aim to ensure our approach to managing reliability is consistent with good practice. These levers extend across several areas of the business from works planning and scheduling to customer service. Appendix C sets out more detail on our RMP.

The levers can have short or medium to long terms effects on network reliability and address both planned and unplanned outages. As we progress our analysis, we can identify those which will deliver the greatest improvement in network reliability without a material impact to the cost our service.

4.6.3. Affordability

The affordability objective area is being introduced into our business as part of this AMP. As a result, we do not have relevant historical performance information. In future, we expect to report on our performance in this area as we monitor our progress.

Context

We recognise that affordability is a key concern of the customers we serve. Reflecting this, 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

[24] During DPP2 our target was to comply with our regulatory SAIDI/SAIFI limits, with our performance shown in Figure 4.4. We will retain this approach during DPP3 and the CPP Period. It should be noted that our *unplanned forecasts* (shown here) differ from our proposed CPP *reliability limits* included in Schedule 12d, in Appendix B. The latter has had standard deviations applied.

customers. However, our affordability objective ensures that we consider the impact of our asset management decisions on affordability for customers.

It is common to create 'cost effective' or 'optimum investment' objectives in asset management and as part of delivering an affordable service we will ensure that our decisions are cost effective but we developed 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. As discussed further in our CPP application, we have taken 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. This included reductions that reflect the uncertainty and economic impact of the COVID-19 pandemic in the regions we serve.

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 us ensure that we focus on affordability of our investment plans and that they strike the right balance between keeping bills affordable and 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.[25] 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 balance the desire to minimise price increases today against the need to deliver safe and reliable network services over the long-term. 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

[25] 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.

- 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 have set out a series of ambitious efficiency targets that will constrain future prices
- we will actively seek alternative solutions to improve cost outcomes.

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.

4.6.4. Responsiveness

The responsiveness objective area is being introduced into our business as part of this AMP. As a result, we do not have relevant historical performance information. In future, we expect to report on our performance in this area as we monitor our progress.

Context

Our asset management policy explains that we understand that there will be disruptive shifts in technology, customer expectations, and the way our network is used. It highlights that we will need to develop 'least regrets' plans that balance meeting short term needs with delivering the lowest whole of lifecycle cost to our customers in 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 new information and modelling on the consequences of natural disaster events. We need to enhance our plans to respond to new weather patterns and build additional resilience to natural disaster events.

To achieve these aims, 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 further enhance their performance and meet the expectations of our customers.

Increasing adoption of EVs, 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. In addition, climate change will present a significant challenge to infrastructure owners, bringing increased wind speeds, extreme storms, and temperature variation. Countering these challenges, we expect improved automation and artificial intelligence solutions will enable us to better respond to these uncertainties.

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 are beginning to develop 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
- 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 and probabilistic 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

The sustainability objective is being introduced into our business as part of this AMP. As a result, we do not have relevant historical performance information. 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. This includes what we do (delivering an electricity service) as well as how we do it (approach to managing our assets and supporting activities).

> **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 and that we can 'be in it for the long haul'. It means operating and investing in a way that is resilient and effective over the long term. Over the past three years, we have lifted network investment well above our regulatory allowances to manage our ageing asset fleets and in support of economic growth in our communities. This has become unsustainable from a financial perspective and our CPP proposal aims to address this over time by ensuring our revenues reflect required investments.

Key Strategies and Initiatives

To support an increased level of sustainability practice within our business, we have developed the following set of strategies and 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.

4.7. RISK MANAGEMENT

This section describes our approach to risk management. Risk management is a fundamental asset management discipline and all our asset management decisions are linked in various degrees to managing risk. Since publishing our 2018 AMP, we have lifted our focus on network risk and introduced a refined risk management framework.

We put in place a new Risk Control and Management Standard that defines requirements for effective risk management. It covers the development and implementation of risk management policy and standards, procedures and rules to manage the activities of our employees, and/or persons or entities contracted to us. It applies when undertaking planning, investigations, design, construction, commissioning, operations or maintenance work.

Our risk management activity includes controls to manage safety risks, avoid capacity constraints, manage failure likelihood through maintenance and renewals, and ensure 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

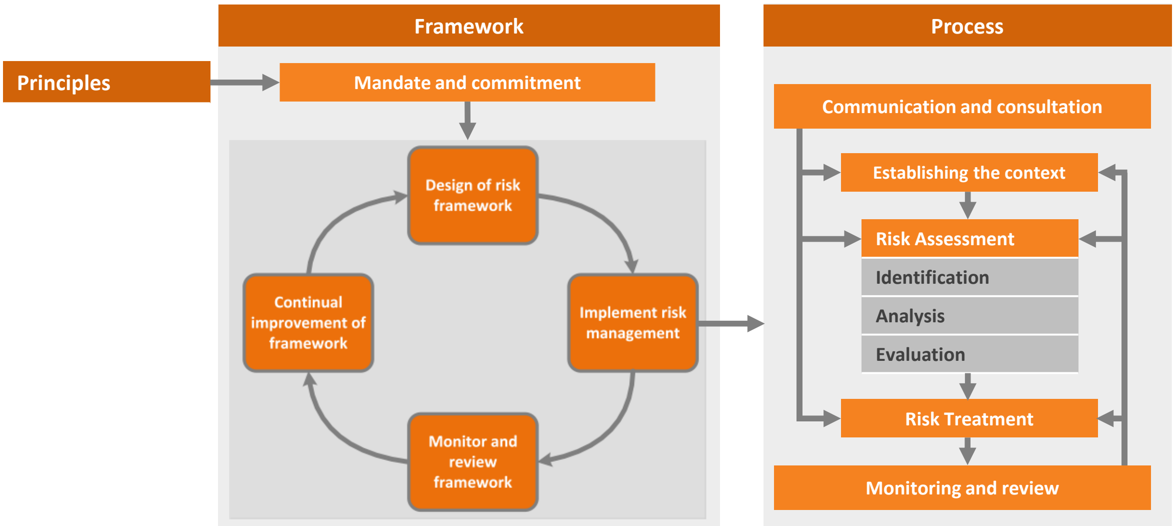
Effective risk management requires a framework that is built on sound governance processes and uses effective procedures and controls.

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 and 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.[26]

Figure 4.6: Risk management framework



Chapter 5 sets out in more detail how this framework is applied to our lifecycle management of network assets. In the following sections we discuss how we expect our network risk management approaches to evolve as we implement our asset management development plan.

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.

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

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.

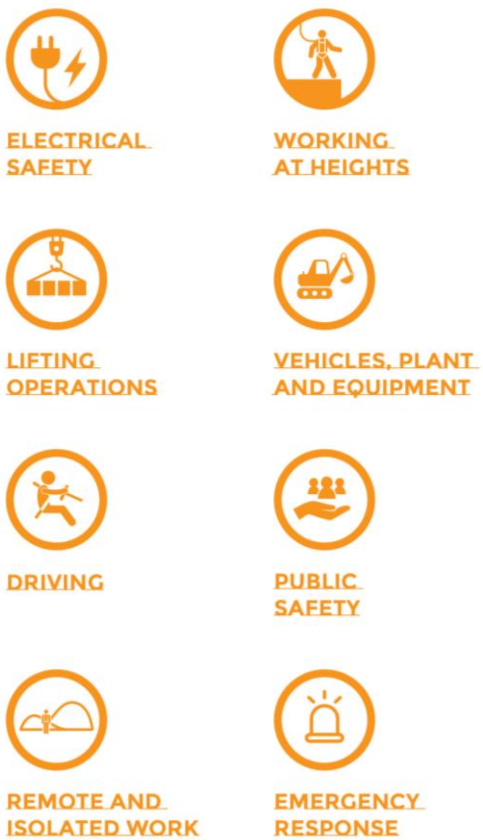
Workplace Safety Risk Management

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. We believe 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.

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 eight 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 use equipment that is fit for its intended purpose and wear protective equipment
- always keep a minimum safe distance from moving vehicles live equipment or working machinery
- always protect yourself from a fall when working at height

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.

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 network risk framework in more detail.

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 below.

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 how we test our investment decisions.

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:

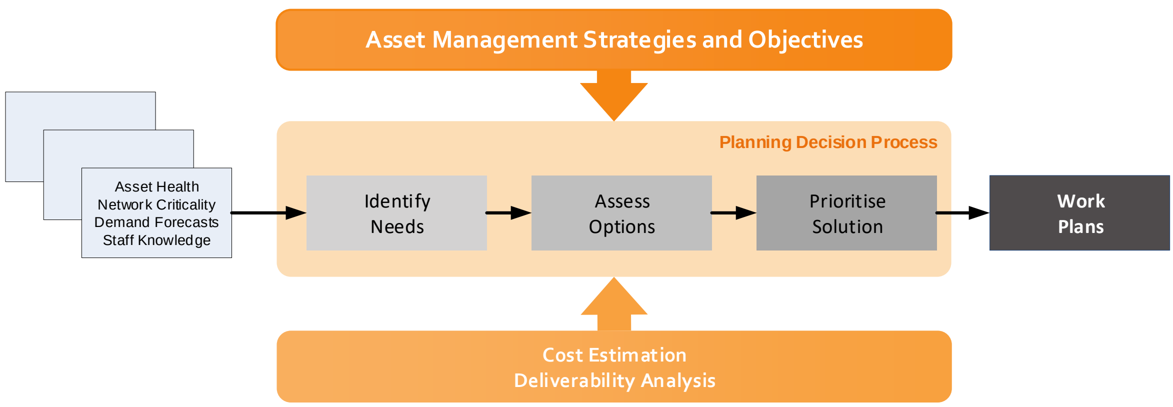
– formal deliverability testing to ensure our work programmes can be delivered cost effectively and to plan
– implementation of a centralised price-book to ensure transparent and repeatable project costing
– benchmarking of maintenance costs to inform our forecasting approach
– external review of capital 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 formal decision-making approach for network investments, as illustrated below. Our CPP application document sets out in detail how we developed, tested, and challenged our investments over the CPP Period. Chapters 5 and 6 provide more detail on how this generalised process is applied to our lifecycle and network development investments, respectively.

Figure 4.7: Generalised investment decision-making process



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

- **identify needs**: this involves the systematic review of network safety risks, capacity constraints, security, reliability, asset condition, type issues, maintainability, spares availability, and a range of network and site-specific feedback. For asset renewals it will include review of asset health forecasts. Identified needs are assessed based on a range of inputs including fleet strategies, risk assessments (including criticality attributes), and subject matter expert judgement.
- **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, 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. The prioritisation may occur within a particular asset portfolio (for example, zone substations) or across multiple portfolios.
- **work plans**: the prioritised solutions will be entered into a draft work plan, which sets out planned works. The deliverability of the overall set of solutions is evaluated in more detail, and cross-portfolio expenditure balancing is undertaken if required. Projects in the early years of the plan will be subject to review for full financial approval in accordance with our delegated authority policy.

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. 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, in April 2019 we 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 are developing an extensive set of specific technical standards for design, procurement, installation, and maintenance.

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. Key factors include seasonal timing to 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 the defined unit rates in 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 develop customised estimates using our defined price-book. To manage the risk of cost variances at the tender stage, budget approval for the current regulatory/financial year includes an estimation variance component for major projects. Where tender prices or project variations lead to costs that exceed approved budget, Board approval is sought for additional budget where it remains appropriate to continue with the project.

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.

Managing Contractor Resource Constraints

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 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

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, so too is balancing that with the need to address network risks and constraints that may compromise safety or impact customer supply through extended or more frequent outages.

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 subtransmission 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 lifelines utilities. We respond to many incidents routinely, as part of normal business. Our business continuity framework defines our strategy to the management of high-impact, low probability (HILP) events and other hazards that result in business interruption. 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 4.8: 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 R's 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 R's.

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 subtransmission 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 17,000 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 are also investigating a more interconnected Dunedin subtransmission 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 updated our business continuity and emergency response plans during 2019 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. These include earthquake, storm, wildfire, and pandemic response plans.

The programme also includes staff training in CIMS level 4, and simulation exercises to demonstrate capability and competence. A simulation schedule is in place with two simulations and a number of desktop exercises performed annually.

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.

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 subtransmission 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.

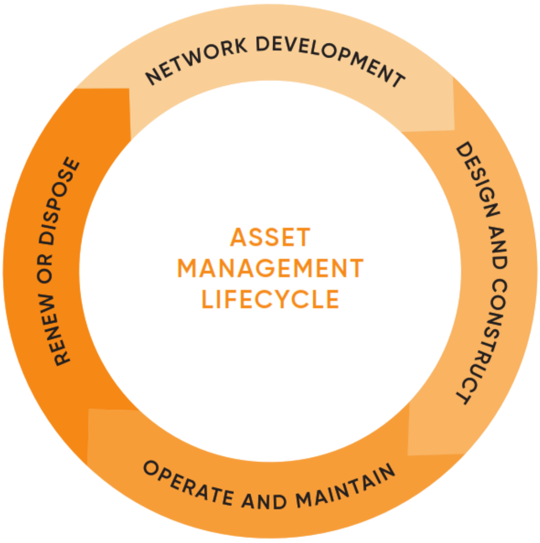
5. OVERVIEW OF ASSET LIFECYCLE MANAGEMENT

This chapter describes how we manage assets through their lifecycle. We have adopted a typical staged approach that governs the activities we adopt to manage assets over their lifetime. This chapter also sets out our approach to asset relocations including related expenditure forecasts.

5.1. INTRODUCTION

Effective asset management relies on a holistic approach that considers the full asset lifecycle. The lifecycle includes the creation of the asset, operation and maintenance over its lifetime, and decommissioning and disposal at end-of-life.

Figure 5.1: Asset management lifecycle



This chapter explains our approach to asset lifecycle management, which is based on four stages.

- **network development**: covers the creation of new or enhanced assets and spans the identification of the initial need, assessing options and preparing conceptual designs. This stage is described in more detail in Chapter 6.
- **design and construct**: includes detailed design, tendering, construction, project management, commissioning and handover of new assets to operational teams. This stage is discussed in this chapter, with further details in Chapters 6 and 8.
- **operate and maintain**: covers the operation and maintenance of our network assets. It aims to ensure their safe and reliable performance over their expected lives, see Chapter 7.
- **renew or dispose**: covers how we decide to renew and/or dispose of assets. Generally, a decision to renew or dispose of an asset is needed when it becomes unsafe, obsolete, or would cost more to maintain than to replace. This stage is discussed in Chapter 8.

5.1.1. Asset Fleets

To support our asset management approach, we define a set of asset fleets which forms the basis of our day-to-day asset intervention strategies. These fleets are in turn combined into a set of seven asset portfolios. The portfolios differ slightly from the asset categories specified by Information Disclosure. However, they better reflect the way we manage these assets and plan our investments.

As discussed in Chapter 4, we are developing a set of fleet plans to explain our lifecycle management approach in detail. Our seven portfolios and the fleets within them are set out in Table 5.1.

Table 5.1: Portfolio/fleet mapping

PORTFOLIO	ASSET FLEET
Support structures	Poles
	Crossarms
Overhead conductors	Subtransmission conductor
	Distribution conductor
	LV conductor
Underground cables	Subtransmission cables
	Distribution cables
	LV cables
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
	Metering

5.2. ASSET LIFECYCLE MANAGEMENT

There are several key lifecycle-based considerations when undertaking asset management activities. Below we list some of the aspects considered as part of our decision-making.

- decisions made at the concept and planning stages of an asset's life will have a major bearing on its practical and safe operation
- the value of an asset is maximised if it has a lifetime of safe, reliable operation. This requires sufficient maintenance, together with appropriate operation of the asset
- the cost of an asset involves more than the initial Capex. When comparing investment options, ongoing operational, maintenance and refurbishment costs over the expected life of the asset need to be considered.

This section sets out our approach to ensuring we effectively deliver capital works, undertake appropriate operations and maintenance activities, and renew or dispose our networks assets.

5.2.1. Design and Construct

Our future investments maintain a significant level of network investment over the AMP planning period. To support this increased level of investment, we have needed to expand and improve our delivery capability. We recognised a need to increase the capacity of both our field delivery capability (through our field service providers) and our internal delivery capability, as well as ensuring that sufficient plant and materials are available.

The design and construct stage includes implementation of projects approved in other stages. This stage sees the handover of capital projects from our planning to delivery teams. This covers detailed design, tendering, construction and project management, commissioning, and handover of new assets to the operational teams. The main activities in this stage include:

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

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

Detailed Design

Our design approach aims to standardise our network assets as much as reasonably practicable by following a suite of design standards and standard designs, which have been in the process of development since July 2017. This helps to simplify delivery and achieve long-term consistency across our network. Safety-in-design is a key driver for our designs.

Approach to detailed design

We build on pre-design work and design concepts to create a complete detailed design for large projects. This includes budget breakdowns, tender drawings, material lists and a general project overview. The detailed design identifies construction methods to help minimise risks to safety and reliability. The Design/Engineering team is involved for the duration of the project, for example, when design variations are needed during construction. Detailed design is not required in many cases, for example, standard installations and smaller defect jobs.

Design review

Design reviews take place at various stages of the project depending on scale, complexity and timing. Reviews cover completeness, adherence to standards, technical requirements and safety. Designs may be refined during the reviews to accommodate particular requirements in the construction phase. To ensure designs are deliverable, projects are collectively reviewed by the designer, project manager, project engineer, planning engineers and the construction manager.

Standard designs and equipment

Standard designs and equipment allow for efficiencies in design, construction, maintenance, operations, and spares management. Our suite of standard designs and equipment have been in the process of development since 2017. We are increasing the number of standard designs used in our day-to-day capital projects. Over time we expect to see resulting efficiencies and improvements in how we operate and maintain the resulting assets.

We have 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.

Design work is performed by our in-house design team, approved contractors, or design consultants dependent on the type and complexity of the work. We are continuing to build our standards library (Controlled Document System), which consists of a suite of design, construction and maintenance standards, procedures and forms. These are available online to our approved service providers.

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. The FSAs are the agreements we have with these three service providers for undertaking capital and maintenance work (including fault and emergency response). The FSA sets out the scope of services and the terms and conditions that apply.

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

Construction

This process includes commissioning planning, construction, testing, livening, and handing over the asset to our operations and maintenance teams. Where appropriate, we prepare a commissioning plan to ensure all these 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 the effective and safe operation of our assets over their intended lives.

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 also to verify that safe working practices are followed. The process is managed by the project managers using specialist, 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:

- confirm that the asset information systems have been updated
- capitalisation of assets within the financial systems
- archive relevant documentation
- analyse 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 system)
- undertake a review of lessons learned during the project, particularly on health and safety performance
- feed these lessons back into our planning and design processes

During the project, and formally at project close, we report back to our planning team so they can understand the performance of the particular solution and its cost. This is an essential step to ensure the ongoing improvement of our planning and design processes.

Delivery Model

Our field work is delivered entirely by external field service providers, including network field switching. In contrast to some EDBs we have no internal, directly employed field staff. The majority of 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 through our tendering processes.

Our strategy to outsource all of our field operations, as well as other services (e.g. some detailed design) is designed to maximise cost and delivery efficiency, allowing us 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.

5.2.2. Operate and Maintain

Effective asset management relies on appropriate links between operations and maintenance and the other lifecycle activities including capital works development, design and construct, and renewals. Following completion of commissioning, assets are put into service and the maintenance and operational stage commences and continues for the life of the asset. Many assets have a 40-60 year life meaning the operate and maintain stage has the longest time span of the asset lifecycle.

The operate and maintain stage includes network operations, maintenance, vegetation management and spares management. Vegetation management is discussed in Chapter 7.

Network Operations

With the exception of field switching, network operation is an insourced function. Its primary role is to ensure a constant 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. 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 each of the Dunedin and Cromwell networks are configured to allow either network to be controlled from either region, creating site and resource resilience.

Both our operators and planners must consider factors such as how asset loading and operation frequency affects asset life and performance, and how to safely remove assets from service for maintenance without compromising performance. Operations activities provide feedback to the lifecycle planning process on network and asset performance or risks, considering reliability, cost, safety and environmental aspects

Maintenance

Maintenance is the care of assets to ensure they provide the required capability in a safe and reliable manner throughout their lifetime. It 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.

As discussed above, when we outlined our approach to works delivery, network maintenance is an outsourced activity.

Note that 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/defer renewal.

Our maintenance activity is split into three types:

- **preventive maintenance**:[27] encompasses inspections, condition assessments and servicing. These are typically activities that are carried out on a regular basis (for example, every three months, annually, or every six years) in accordance with our maintenance standards. Recorded condition assessment data is used for analysis, forecasting and renewal planning. Defects and repair work (corrective maintenance) also arise from preventive maintenance.
- **corrective maintenance**: this is planned work arising from preventive maintenance work, ad-hoc identification of a defect or as a follow-up to a fault (i.e. 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. Work in this category is prioritised and scheduled (sometimes as rapid (90 days) response) on the basis of a number of factors. Failure to undertake this work increases reliability and safety risks.
- **reactive maintenance**:[28] this is work, including 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, this work is dispatched by the control room in response to network events. Failure to undertake this work in a timely manner will adversely affect the service provided to our customers and may increase public safety risk.

Details on the maintenance activities that apply to specific asset fleets are discussed in the respective fleet sections of Chapter 8. Chapter 7 sets out our forecast operations and maintenance expenditure for the planning period.

Vegetation Management

Vegetation management is another key activity that enables our assets to perform to expected service levels. We undertake vegetation management to keep trees clear of overhead lines. This is necessary to minimise vegetation related outages and meet our safety and statutory obligations. Left unchecked, vegetation can have a significant impact on network reliability and public safety. 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 follow-up tree trimming and removal.

Vegetation management is covered in more detail in Chapter 7.

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27 Our preventive maintenance category is a subset of Routine and Corrective Maintenance and Inspections (RCI) used in Information Disclosure. Our corrective category is also included within our RCI disclosures.

28 Our reactive maintenance category is equivalent to System Interruptions and Emergencies (SIE) used in Information Disclosure.

Spares Management

Spare parts for our assets, retained in appropriate locations, are required to maintain reliable supply. We retain both strategic and critical spares.[29] The number and type of spares retained for each asset varies depending on whether it is a subtransmission, distribution or zone substation asset, and whether it is a new or legacy asset. Spares management can be complex for legacy assets as there are often a large number of different makes and model in service, as in the case of switchgear. Standardising on equipment manufacturer, type, and rating allows asset availability to be maintained with fewer spares, reducing holding costs.

We plan to further develop our approach to spares management, including developing formal spares strategies and plans for each asset fleet. These will apply a standard approach to determine the number and locations of critical spares, considering the expected impact of various equipment failures, the number of each asset type in service and the risk each one represents. 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.

5.2.3. Renew[30] or Dispose

Asset renewal is the replacement of aging, damaged or under-performing assets with like-for-like or new modern equivalents,[31] or the refurbishment[32] of existing assets to extend their useful life or increase their service potential. Asset disposal follows the decision to remove it from our network, either because it is being replaced or has become redundant.

As assets deteriorate they eventually reach a state where ongoing maintenance to keep them safe and serviceable becomes ineffective or uneconomic. Refurbishment and replacement are key activities to manage asset condition, safety risk and network performance, resilience, obsolescence, and meet regulatory and legislative requirements. Our approach to renewal varies by asset fleet and in some cases there will be a range of risk reduction options to consider.

Our long-term renewal forecasting covers a 10-year planning horizon. It includes high value projects – typically zone substation renewals identified on an individual basis (termed ‘scheduled’ forecasting), and volume-based forecasts for high-volume low unit-cost asset types such as poles, crossarms and conductors (termed ‘volumetric’ forecasting). Longer term volumetric forecasts are converted to individual projects based on defined renewal triggers. ‘Targeted’ fleets are semi-identified, fitting somewhere between volumetric and scheduled in terms of approach. These approaches are covered in more detail below.

Asset health and criticality are fundamental inputs into our risk-based decision-making framework. Our frameworks and their application are covered in the following sections. Often our medium to

29 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.

30 We use the term renew to signify either asset replacement or refurbishment.

31 Expensed replacements (Opex) are included under our corrective maintenance portfolio.

32 Refurbishment is (generally) capital work that extends the expected life of an asset. Where expenditure is required to ensure that an asset is capable of meeting its design output, this is generally classified as maintenance (Opex).

long-term forecasting and short-term delivery approaches are different as it may be impractical to apply the same approach due to a range of factors.

Renewal drivers

Below we describe the main drivers for our medium to long term replacement and refurbishment expenditure forecasts.

Asset health

Asset health reflects the expected remaining life of an asset and serves as a proxy for likelihood of failure. It is the main driver behind our asset replacement and renewal forecasts, as assets assessed as in poor health are deemed to have an increased risk of failure, leading to additional reliability and safety risks.

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 remaining life is zero, it does not mean that failure is necessarily imminent, but does indicate that an intervention is likely to be required and should be investigated.

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

Based on asset health forecasts we can estimate the required future volume of asset interventions for our asset fleets. We can then consider trade-offs between different fleets based on constraints such as pricing, assisted by the use of asset criticality, in order to finalise the plan.

Asset condition

Where condition information is available at a consistent level of detail across a whole fleet, this is fed directly into asset health modelling. Where this information is not available for long-term planning, asset health provides the basis for forecasting, but condition provides the basis for shorter term renewal and refurbishment decision making.

We are in the process of inspecting all assets on the network, and with a backlog of assets not inspected and a lack of condition information, for most fleets we cannot forecast using period condition information fed back directly from the field. However, the renewal trigger on which specific assets get replaced is not age in the majority of cases.

Near real-time condition information also drives expenditure in other ways, such as reactive replacements, often subject to events such as 3rd party damage or network fault.

Safety

A key driver for many renewal investments is mitigating the risk that poor condition assets pose to the public and our service providers. We isolate or minimise hazards as much as reasonably practicable. Support structures, overhead conductors, and LV enclosures are inherently risky because their failure can place live electricity within unsafe distances from the public, and/or are often in populated areas.

Other examples include risk to service providers embedded in design during historical switchgear installations, often involving what is now obsolete equipment, such as oil filled switchgear.

Safety criticality is a key criticality dimension and we have developed a public safety criticality zoning to assist with prioritisation of renewal work.

Environment

Some of our assets can pose environmental risks, particularly those that contain oil or sulphur hexafluoride (SF_6). These risks can drive us to either mitigate the risks, such as through upgrades to oil bunding and containment systems, or to replace assets where the increased failure likelihood leads to unacceptable environmental risk.

We also have a duty to our communities to meet environmental statutory compliance. This may require other environmental investment such as transformer noise mitigations.

Reliability

We undertake renewals investment to manage reliability levels for our customers. This includes renewal of poor condition assets, and assets with known failure modes/type issues, such as where a particular asset type/model is found to fail prematurely. We are developing a near real-time reliability dashboard and reporting tool, enabling us to target asset renewal in areas of worst performance, following safety prioritised renewal plan.

Resilience

Our network needs to be cost-effectively resilient to extreme events, such as storms and earthquakes. Historical design standards are generally less stringent than standards of today. In some instances where the risk with legacy installations is deemed to be unacceptable, it may be necessary to renew assets to today's standards. This includes programmes such as upgrading the seismic ratings of our substation buildings and storm-hardening of the overhead network.

Obsolescence

Renewal may be warranted when existing assets are assessed to be obsolete. This can occur when:

- an existing asset is incompatible with our modern systems and standards, and lacks significant functionality when compared with modern equivalent assets
- spares may no longer be available to support the asset, or the asset may no longer be supported by the manufacturer, and no suitable alternative spare or contingency solution is available
- the knowledge within the workforce to maintain the asset is no longer available.

Obsolescence can be the primary driver of renewal of assets, particularly in the secondary systems portfolio. In this case, modern assets provide improved functionality and performance that allows us to better control and operate the network and to provide better value to our customers.

Renewal Triggers

Below we describe the main drivers for our decisions to replace or refurbish network assets.

Asset health or condition

Asset health and/or condition are the key renewal triggers. Most assets reach a health of H1/H2 or such a condition where replacement is prudent and run to failure is not applicable or sensible for a number of reasons. Considerations are given to criticality to assist with prioritising renewals when resources are limited.

For most assets, the decision on the actual assets to replace is driven materially by actual condition information gathered from the field – for example poles, crossarms, power transformers. However, on some assets, such as protection relays, and overhead conductor, determining the actual condition of the asset is either impossible or challenging. On overhead conductor, we are investigating further condition inspection techniques, and using conductor sampling to confirm expected lives. In some cases, historical conductor failures may trigger a renewal, both by indicating poor condition and having a driver to reduce reliability impact.

Risk

There may be times where asset health or condition is not such that investment would be warranted on that basis alone, but the asset has such a high criticality, either inherently or due to its function/location, that the risk is unacceptable.

Lifecycle cost

In some instances, it may cost more in a whole-of-life cost sense to retain an asset in service than to replace it. Higher Opex costs required to avoid or defer replacement can manifest in the form of increased maintenance frequency, expensive refurbishments or unacceptable fault rates, and when considering a future replacement, often it is more cost effective to replace earlier.

The cost to respond to the failure of large assets (e.g. zone substation transformers) reactively can also be substantially higher than replacing the assets in a planned and controlled manner. In these cases, the asset may be renewed to provide an overall expected lower lifecycle cost on a risk basis.

Reactive intervention

For certain fleets, such as smaller pole-mounted transformers and LV cables, run to failure is a viable strategy. These fleets generally have a low consequence and the customer is better served by getting the maximum useful life from the existing asset. For such assets, while we monitor multiple drivers for forecasting capital requirements, we may not act until a specific asset fails.

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

Asset criticality

The criticality assigned to an asset reflects the consequences of failure (also known as impact) of that asset in terms of safety, reliability, and other factors. For example, overhead assets in built up/highly populated areas are assigned a higher public safety criticality rating than those in lower density areas because of the relative risks. Similarly, assets located near facilities such as parks, schools, and major roads (i.e. 'points of interest') are considered more critical.

We have developed criticality frameworks for several fleets. Our public safety criticality rating (1-5) can be applied to all assets, and is used on renewals of poles, crossarms and conductor, given they are generally in spaces accessible to public. For poles and crossarms, criticality is used to prioritise poor condition assets for replacement. For conductor it is also used to prioritise the backlog of poor condition conductor replacements, and once this is cleared a true risk-based approach will be used – at this point in time the criticality may adjust the renewal trigger of asset health/condition to bring it forward. Inspections in the overhead network are also prioritised with a heavy weighting based on their public safety criticality rating; if poor condition assets in high criticality areas are found first, they can be remediated first.

For assets within zone substations, criticality focusses primarily on reliability and worker safety. For these larger assets, inputs are tailored to the particular fleet to ensure applicability. As an example, zone substation power transformers and indoor switchgear have customised criticality frameworks using a 1-5 scale with weighted aspects of:

- 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) and considering the percentage that can be backfed from other sources
- obsolescence: availability of spare parts and whether the asset continues to operate effectively with other systems.

Medium-term forecasting differs from short-term delivery

Sources of network and asset-failure risk, including those represented by the renewal triggers and drivers above, are managed through the following mechanisms:

- medium-term forecasting: developing a forecast for each fleet reflecting medium to long-term projections of renewal need (for example using statistical modelling techniques)
- short-term delivery: this includes delivering programmes of work directly informed by observed risks on the network (for example observed condition of overhead assets).

Depending on the fleet, we may have different approaches to forecasting and delivery. This is due to reasons such as the quantity and type of assets in the fleet and the value of each individual decision. A further consideration is whether option assessment is generally required. Currently, a key consideration is when sufficiently robust condition information is expected to be available, and how fast it needs to be acted upon. Descriptions of the main forecasting and delivery approaches are covered below.

Medium-term forecasting approaches

This forecasting approach informs the longer-term planning, and for some assets the yearly forecast quantity of volumetric assets.

- volumetric: is used for smaller, higher volume work that are routine and uniform. It does not identify specific assets to be replaced in advance but rather volumes of required remediations. When using the volumetric approach, because it does not identify specific assets to be replaced in advance on a year on year basis, the asset health model will not use condition information. Specific assets are determined when information is available.
- scheduled: is used for large projects that have well defined scopes and timings. These identify specific assets and solutions to meet specific sites requirements. Scheduled projects are generally prioritised by criticality or cost-benefit analysis. The scheduled approach, being asset specific, is generally supported by specific condition or other such trigger information in advance, and for zone substation power transformers and indoor switchgear, have an asset health model with condition inputs.
- targeted: is used for specific programmes of work, typically addressing type issues or defects. These are generally semi-identified, where specific assets may be identified in data sources however the forecast does not identify them on an annual basis. The targeted approach will have an asset health model that may or may not identify the specific assets to be done on a year on year basis, but specific assets are identifiable in advance based on some known trigger, such as a 'type' issue.

We explain our forecasting approaches in more detail when we discuss how we identify renewal needs in the following section.

Short-term delivery approaches

The delivery approaches set out below are examples of how the actual assets are identified for planned interventions. The use and suitability of these approaches will depend on the individual asset fleets.

- condition: assets are tested or visually inspected. Test results and/or visual observations are assessed, and interventions issued and prioritised by criticality if relevant
- reactive: assets are reactively replaced as part of fault response. This work is generally dispatched by the control room
- proactive: assets are scoped to be replaced using simple triggers, such as expected life. This is generally used for asset types that have demonstrated age-related failure modes however no reliable testing methodology has yet been developed. Depending on the fleet, proactive replacements are prioritised by criticality
- hybrid: combination of the reactive and proactive approaches
- scheduled: project manager and lead engineer further refine scope, undertake detailed design, tendering, and follow through construction.

Some work has a high degree of bundling into larger work packs, such as pole and crossarm replacements. Such bundling can provide scale and scope efficiencies.

Identification of Renewal Needs

As discussed above, we undertake renewal investments in response to a number of drivers, chief amongst these is the need to effectively manage safety risks. Needs may be identified from a number of sources including field inspections and assessments, network studies, safety reviews, and experiences of peer utilities.

Addressing network risk

Risk management is the primary driver for our network investments, particularly in asset renewal. We use an evolving risk framework to understand the cause, effect and likelihood of asset failures. Fundamentally, risk is the product of probability (asset health/condition generally used as a proxy) and consequence (criticality generally used as a proxy). This analysis is used to trigger and prioritise investments to manage the identified risks to an acceptable level. Using a risk-based framework is necessary to effectively identify assets that require proactive intervention, and also provides a way to manage backlogs of poor condition assets in the best way possible.

Our overall approach to risk assessment is broadly consistent with the approach that was undertaken by WSP in its independent risk review.[33] Our corporate risk framework informs the overall level of risk, which may include more than one category (e.g. reliability and safety). The level of risk is either above or below the line of acceptable risk tolerance as shown in the diagram below.

Figure 5.2: Network risk matrix

Likelihood \ Impact	Insignificant	Minor	Moderate	Major	Catastrophic
Almost certain	Low	Medium	High	Extreme	Extreme
Likely	Low	Low	Medium	High	Extreme
Possible	Insignificant	Low	Medium	High	High
Unlikely	Insignificant	Insignificant	Low	Medium	High
Rare	Insignificant	Insignificant	Low	Medium	Medium

Intolerable Risks

Projects that drive a risk level down across the risk appetite boundary (yellow 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 should be justified by cost-benefit analysis. This methodology is broadly consistent with a "As Low as Reasonably Practicable" (ALARP) approach to risk reduction.

In general, our long-term renewal forecasts are based on asset health with short term prioritisation of interventions being based on criticality. This prioritisation occurs both within and across fleets.

33 WSP, Independent Review of Electricity Networks, 21 November 2018, see our website.

Modelling of renewal needs

We use a number of modelling techniques to estimate future renewal volumes for our asset fleets. Our modelling approach will vary based on the type of fleet, particularly whether or not it should be forecast using a volumetric or scheduled approach. Types of volumetric forecasting models include:

- survivor analysis: a survivor curve model uses information on previous end-of-life asset replacements to build a probabilistic replacement rate curve, which produces a likelihood of failure for an asset of a given age. The replacement rate curve is then be applied to the current population of assets to predict the future number of replacements. Given this approach requires our own historical data, it can only be applied where the data is widely available. We have only used this approach for pole renewal forecasting. A survivor curve-based forecast results in a more accurate forecast of replacement than an age-based model as it recognises that some assets have longer than average lives while others have shorter than average, because of factors such as location or inherent durability. It considers the likelihood of replacement at all asset ages, which provides a smooth replacement rate that still reflects the age profile of the fleet[34].
- Repex:[35] a normal distribution is applied based on expected useful life across the fleet. Different factors such as material type may influence the expected useful lives of sub-populations. The use of a distribution means that statistically not all of the assets will require replacement at their stated end of expected life, as would be expected due to details that are impractical to gather and model. This is used where we don't have the data to create our own survivor function but believe this is a better reflection of what assets will require replacement than an age-based model, and in a similar way to a survivor curve, a smoother and more deliverable replacement profile is provided.
- age based: assets are considered for replacement when they reach a certain age; this age may be based on the type or other factors. There is no distribution or more complex statistical assumptions in the model. This can produce lumpy forecasts that are often not practical to directly implement. This approach can be used to effectively identify obsolescence or type issues.

It should be noted that for any forecasting approach that does not determine the actual assets that require replacement, these are determined in the short term based on the actual condition of the assets or other specific information if condition is not applicable (these are renewal triggers).

The degree of historical reactive replacements is also factored into asset health modelling where applicable, where this does not cause a double counting with the approach applied above.

[34] Comparatively a simple age-based model assumes all replacement happens at one predetermined age and can produce a lumpy forecast depending on the age profile of the fleet.

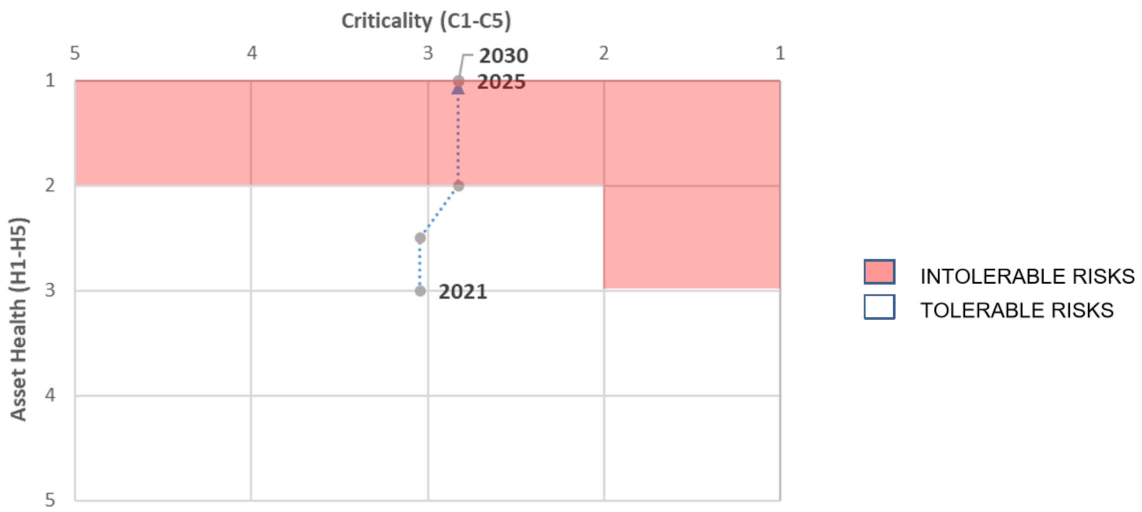
[35] Repex refers to replacement expenditure and is based on a modelling technique typically used by Australian utilities and endorsed by the Australian Energy Regulator (AER).

The forecasting approach and modelling used for scheduled fleets is:

- customised: for zone substation power transformers and indoor switchgear we have created customised asset health models based on inputs including condition information, specific attributes such as manufacturer make and model, 'type' issues, and operating duty and environment e.g. fault current, protection type, corrosion zone, number of operations.

In the zone substation portfolio, more critical assets are replaced before similar asset health/condition assets in less critical locations (i.e. the trigger for renewal is adjusted as opposed to just prioritisation). This is shown below where it can be seen that an H2 with a C1 rating requires the same treatment as an H1 with a C3 rating. This framework is consistent with our corporate risk matrix at a high level.

Figure 5.3: Example of zone substation risk analysis



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 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.

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

We do not currently have a fully quantified risk framework, so cannot directly compare all risks in a common 'currency'. Even if such a system was operational, the use of experience and good judgement is required to trade off against different types of risks in different areas and sense check any outputs.

We plan to move towards quantified approaches to the extent they remain proportionate to our business size and activity levels. 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 (somewhat negating the longer recall time aspects of cabled networks), 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 very 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. This is especially applicable to fleets where there appears to be a backlog, but the experienced failure rate is not extremely high. 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: we do not yet have complete condition information and have not yet defined complete criticality information in all dimensions on our network. We must rely on the structured information we have that has been vetted as trustworthy, make the best use of any information that is questionable or has gaps, and from a 'top down' view, rely on the combined experience of our skilled employee base and their professional judgement and both self and peer review. The WSP review has provided a useful point of reference from an external party.
- 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 a very short time period. 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 which form the basis of our day-to-day asset management intervention approaches and investment planning. These are set out in the table below, including the main renewal drivers, primary forecasting method, and primary delivery method.

Table 5.3: Summary of selected 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
Subtransmission conductors	High	Scheduled or volumetric	Scheduled / Proactive
Distribution conductors	High	Volumetric / Repex	Proactive
Low voltage conductors	High	Volumetric / Repex	Proactive
Subtransmission cables	Low/Medium	Scheduled	Scheduled
Distribution cables	Low	Volumetric / Repex	Hybrid, criticality-based bundling
Low voltage 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
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 problem in the future and steps are being taken to consider equipment that does not use this insulating gas. Our recently signed period supply agreement for indoor zone substation switchgear has chosen switchgear that does not contain SF_6 gas. Currently we are not required by law to report SF_6 volumes, and this will be a future improvement during the CPP Period.

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, we actively seek opportunities to re-use, sell or recycle redundant assets. Our preference is to recycle, sell or re-use 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 life cycle costing.

Site restoration and reinstatement

When substation 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.

5.3. 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.

5.3.1. 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.[36] 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

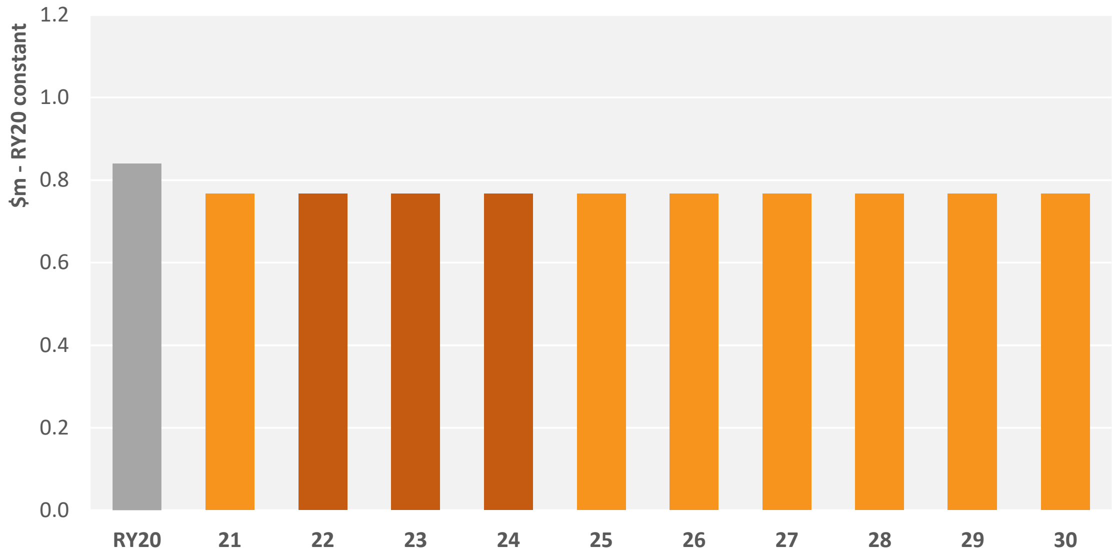
[36] Sections 32, 33 and 35 of the Electricity Act 1992 and Section 54 of the Government Roading Powers Act.

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.[37]

5.3.2. Forecast Relocations

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

Figure 5.4: Asset relocations Capex (net of capital contributions)



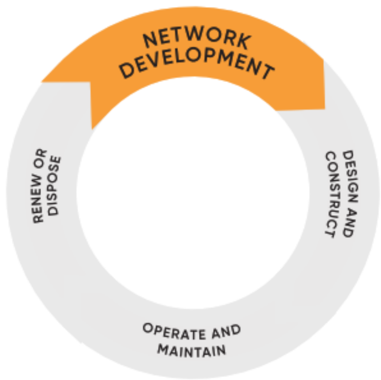
It is difficult to forecast as work is externally driven, often with short lead times. Therefore, we estimate relocation expenditure based on historic average expenditure, adjusted for known projects that are expected to occur within the next few years.

37 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. It provides a brief explanation of what we mean by network development, before focusing on the growth and security investments we plan to undertake during the AMP planning period.

The chapter also discusses investments focused on managing network reliability, and investments we make to facilitate customer connections.



6.1. INTRODUCTION

We use the term network development to describe capital investments that increase the capacity, 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
- **network evolution**: these are investments to transform our network to meet future needs with the advent of Distributed Energy Resources (DERs)
- **reliability-driven**: these investments aim to minimise the impact of a network fault, such as by automatically reducing the number of customers impacted by it[38]
- **consumer connections**: this expenditure facilitates connection of new customers to our network.

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. We expect investments in our Central Otago network over the planning period, driven primarily by increasing ICP numbers and demand.

In contrast to our Dunedin network, the Central Otago region has experienced sustained demand growth, mainly due to residential growth in areas such as Wanaka and Cromwell, as well as residential and commercial growth in Frankton and Queenstown. However, we anticipate that developments will be affected by the COVID-19 pandemic in the next two years.

[38] 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.

6.2. NETWORK DEVELOPMENT PLANNING

The objective of network development is to expand the network into new areas or increase the capacity or functionality of our 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, under forecast demand conditions. We plan for efficient and timely investment in additional capacity and security before reliability is adversely affected.

6.2.1. Growth and Security Investment

We classify our growth and security investments into the following types of project:

- **major projects**: generally involve zone substations, subtransmission or GXP related works
- **distribution and LV reinforcement**: works to ensure adequacy of our distribution feeder assets and LV network.

Our network evolution, reliability-driven, and consumer connection investments are discussed in Sections 6.6, 6.7 and 6.8, respectively.

Major Projects

Major projects typically involve zone substation, subtransmission 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 subtransmission 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 subtransmission 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 subtransmission and zone substation assets due to the number of customers and/or size of the load served by them.

In some situations, a temporary arrangement provided by a mobile substation can be a cost-effective alternative to building fixed redundancy into the network. The ability to deploy mobile substation transformers also provides significant regional resilience to our operations. Mobile substations are usually used at N-security substations to avoid planned outages when undertaking routine maintenance on tap changers and transformers.

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.[39]

We classify our distribution feeders 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 (refer to Table 6.3), and these are used in our planning process to assist in determining distribution network configuration needs.

The provision of alternative distribution feeder capacity (redundancy) for use in the event a primary asset is out of service varies across our network. For Dunedin and parts of urban Central Otago, the scale and high density of the network supports provision of interconnected distribution feeders at low cost. For the rural areas of Central Otago, distribution feeders are less often interconnected, as it is not cost effective or is practically difficult in many situations. This is reflected in our growth and security planning approach where we assess the performance and capacity of our 11 kV feeders against the criteria in our security of supply standard.

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. 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.[40] 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 (e.g. low voltages) 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

39 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.

40 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.

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, EVs, 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.

In the short term, with relatively low levels of customer behaviour change, we will manage the LV network capacity using improved high-level analysis and modelling tools that enable an annual review of the utilisation of all our LV feeders. We have limited capability in this area at present and we will be resourcing this as part of improving our asset management capability. This analysis will enable us to identify those feeders with high levels of utilisation (through either load or distributed generation) for more detailed analysis, and potentially install real-time monitoring equipment on them.

In the medium to long term, the customer uptake of emerging technologies may require the installation of widespread monitoring equipment. There is also an opportunity to better utilise customer metering data for planning analytics and/or real-time monitoring. An example of customer behaviour change that would benefit from real-time monitoring is residential battery use.

Distribution and LV reinforcement forecasting

Inclusive of the forecasting approach below, we reduced the forecast of distribution and LV reinforcement expenditure by 20% in RY23 and RY24 due to the expected impacts of COVID-19. We forecast Capex for these works in two categories:

- **distribution reinforcement:** covers distribution reinforcement projects that are individually identified through the planning process and planned 1-5 years out. For this year's AMP, we have only identified projects from RY21 to RY26. We forecast distribution reinforcement in two ways:
  - **scheduled projects**: scheduled projects are individually identified and planned through the needs identification and options analysis 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 LV reinforcement 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.

6.2.2. 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.

Figure 6.1: Growth and security planning process

The planning process is explained below.

Identify System Needs

We identify possible constraints using our demand forecast model in conjunction with our security of supply guidelines. We systematically analyse the network, using the network load flow model where necessary, and record where demand may breach the security of supply guidelines and the timing of this constraint. Possible solutions to these constraints are then identified and analysed in the next steps of the process.

Triggers for growth and security investments vary by voltage level, as follows:

- **GXPs/transmission spurs**: triggered by security criteria – effectively N-1 – being exceeded
- **subtransmission and zone substation**: triggered by security criteria which are effectively a qualified, or switched, N-1 being exceeded
- **distribution feeders**: triggered by guidelines or planning parameters related to voltage profile, thermal capacity of any given section of feeder, or security criteria being exceeded
- **LV feeders**: our process for determining investment needs has historically been based on new connection information.

Investment drivers are discussed in more detail in Section 6.3.

Our Security of Supply (SOS) guidelines are shown below in Table 6.3. The guidelines and our load forecast assist us in identifying constraints where there may be possible economic solutions.

Create Long List and Short List of Options (Options Analysis)

We carry out options analysis for all identified needs, with the level of complexity of the analysis in proportion to the level of risk associated with the identified constraint and the likely cost of a project to meet the need. This stage starts with identifying options and related work to ensure that all feasible alternatives are considered within the analysis process. Recognising other related work (e.g. renewals, ongoing growth projects) in the identify options stage may create cost-effective options where there was previously not a practical option available and also creates efficiency in delivery.

We have developed a systematic and objective process to assess options to achieve appropriate levels of capacity or reliability. Options include new assets, enhancements to existing assets, operational approaches, and non-network options. Options must be feasible and able to be safely and reliably implemented in sufficient time to meet the need.

Long list options

We identify a long list of possible options that can be implemented to address the forecast constraint. The list would typically include:

- 'do nothing' being the status quo option
- non-network solutions such as:
  - demand side management
  - energy storage
  - distributed generation
- network solutions such as:
  - installation of reactive support
  - upgrade of equipment or installation of new equipment
  - reconfiguration of the network architecture
  - mobile substations.

Short list options

An initial assessment is undertaken on each of the long-listed options to narrow the list down to a short list of credible options for more detailed analysis. The assessment considers the elements below.

Table 6.1: Assessment criteria

ASSESSMENT CRITERIA	DESCRIPTION
Safety	Is the option likely to be 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 with other planned work	Does the option fit with other planned work on the network?
Fit with applicable strategies	Does the option align with any applicable Aurora strategies?

To determine whether the options meet the business need we may need to carry out network load flow studies. The short listing 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 short list analysis.

The short list would typically contain 3-5 options (including the "do nothing" case if viable) that can be taken through to the detailed comparison stage.

The long list is reviewed based on seven key criteria in alignment with our asset management policy. The table below illustrates an assessment of long listed options against the criteria described above. For an option to be short listed, it has to meet the majority of the criteria.

Table 6.2: Example of long list to short list process

No.	Option Description	Safety?	Meet Business Need?	Likely to be cost-effective?	Practical to carry-out?	In line with good industry practice?	Fit with other planned work?	Fit with applicable strategies	Short listed?
1	Do Nothing	✓	✓	×	×	×	×	×	×
2	Option 2	✓	✓	✓	✓	✓	✓	✓	✓
3	Option 3	✓	✓	×	✓	✓	✓	✓	✓
4	Option 4	✓	✓	✓	×	✓	✓	✓	✓
5	Option 5	✓	×	×	×	×	✓	✓	×

Economic Analysis

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

- estimated capital expenditure
- probabilistic reliability costs
- any significant changes in operational expenditure.

We have developed a standard economic evaluation template in order to maintain a consistent approach to this analysis. The following paragraphs provide an overview of how the above aspects are assessed using the template.

Estimated capital expenditure

The cost estimate is built up for each option using Aurora's standard unit rates. 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. Information such as duration of the particular outage, the post contingent capacity, distribution backfeed and Value of Lost Load are also incorporated.

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.

Any significant change in Operational Expenditure

Any significant change in operational expenditure (Opex) is considered and the NPV is calculated in the economic evaluation.

Economic evaluation

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

Preferred Option

We take a number of factors into consideration in selecting a preferred option from the short-listed options. The results of economic analysis are a key component, but we also consider:

- the extent to which each option addresses the need
- the risk associated with each option
- any intangible benefits associated with an option
- an assessment of options against the corporate risk matrix
- how the options fit within the context of our wider asset management objectives (e.g. renewal plans).

Selecting a preferred option is not always straightforward and may require our planning team to apply engineering and economic knowledge. Network development projects need to fit within the context of our wider asset management activities (e.g. renewal plans), such that investments are optimised across all business objectives and constraints. As such, there may be some interaction between potential investments. For example, investments may be brought forward from their need date to enable the work to be integrated with related works. Deferral may also be possible, though this needs to be assessed in each case and may require careful management.

Scoping and Cost Estimate

Scoping

Once the preferred option is identified, it is scoped in more detail so that project costs can be estimated more accurately. 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.

Cost estimate

From the project scope, the cost estimate is prepared, and the costs allocated over the years the project is expected to take (while ensuring the project is completed by the required forecast need date).

Confirm the project

Using the updated cost estimate, the economic analysis undertaken in the options analysis stage is revisited to ensure the preferred option is still valid.

6.2.3. Key Planning Assumptions and Inputs

The key inputs informing our network development planning analyses are:

- historical demand data, by zone substation, subtransmission 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 networks
- manufacturer nameplate ratings, equipment thermal ratings and other factors impacting our equipment ratings
- voltage requirements and other regulated limits.

Key assumptions informing our planning are that:

- the uptake of new technology such as EVs, batteries and solar panels will accelerate, but will have only modest or clustered network impacts in the planning period
- existing levels of demand side management, including ripple control, are reflected in the historical data and will be reflective of future levels of demand management
- industry rules will remain broadly stable and not lead to step changes in security requirements or levels of distributed generation.

6.2.4. Network Modelling

We use Powerfactory to perform load flow and contingency analysis in our subtransmission network. We are in the process of developing a geographical network model (both subtransmission and distribution) in Powerfactory. For specific network studies on the distribution network, we currently create a Powerfactory model of that particular part of the network.

6.3. 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 established in order to prioritise the solutions. We give consideration of how the network will perform and operate under various scenarios of risk development 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
- **security of supply**: our ability to meet defined supply security guidelines
- **power quality**: ability to meet power quality regulatory and industry standards.

The following sections provide more detail on these key drivers.

6.3.1. System Demand

As described in Chapter 3, 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.

Capacity constraints caused by growth in peak demand are a key driver of investment needs.[41] We are seeing ongoing demand growth leading to capacity constraints in some areas of our Central Otago network. However, this growth may potentially be affected by the COVID-19 pandemic. Developments possibly will slowdown in the next two years which would impact the peak demand.

Demand Forecasting

To effectively plan for growth, we need to estimate the size and location of future loads. 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 subtransmission 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 example of this. Looking forward, uptake of new technologies (for example, photovoltaic generation, battery storage, EVs) will likely be the major cause of changing demand patterns.

We forecast demand on an annual basis, looking at ten years into the future at the GXP, subtransmission and zone substation levels. But we also consider future load on HV feeders, if needed, by adjusting for any known step changes, for example, 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. When assessing the need to upgrade GXP capacity we consider the reliability of embedded generation to offset demand.

Demand Forecast Model

The core of the forecasting engine is the statistical forecast of modelled load. Modelled load refers to all load for which historical relationships are considered appropriate indicators of future relationships – such as the relationship between households and peak load or between GDP and peak load. Modelled load is gross of all embedded generation to get as close to consumer demand as possible.

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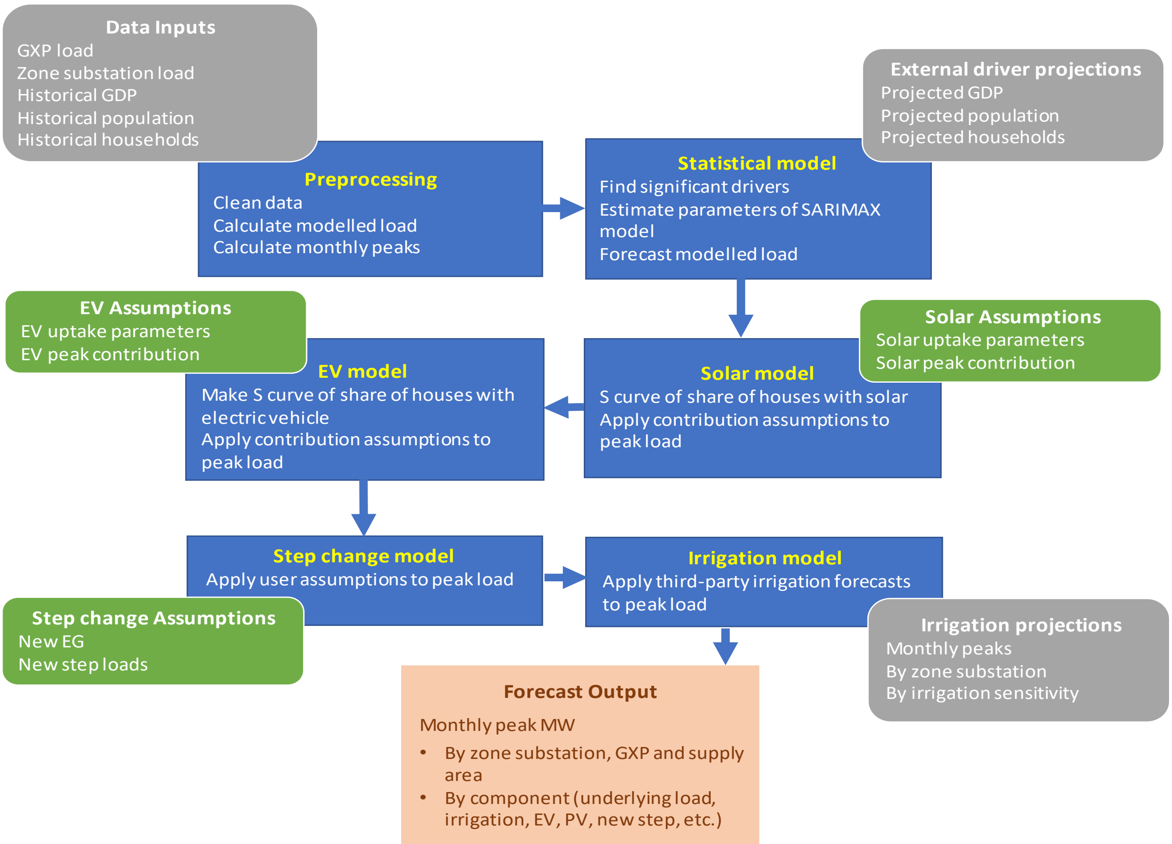
41 Note that capacity constraints do not reflect total instantaneous capacity, as they take security of supply requirements into consideration.

The demand forecast model (illustrated below) incorporates the following factors:

- historical load at zone substation and GXP levels
- population statistics (historical and forecast)
- gross domestic product (historical and forecast)
- photovoltaic and electric vehicle expected uptake (using bass diffusion uptake model)
- irrigation load
- large step changes in load or embedded generation connections.

Figure 6.2: Load forecast model process flow



The statistical model is a seasonal ARIMA model with exogenous regressors (SARIMAX). This is a standard classical time-series modelling technique that accounts for the relationship between data-points over time and between data-points and a set of external variables (e.g. household numbers or GDP). Good time-series modelling practice is followed by enforcing stationarity on datasets to reduce the chance of spurious results and only retaining drivers which are statistically significant to provide a parsimonious model with genuine explanatory features.

The SARIMAX fitting process outputs a fully specified model tailored to each zone substation, GXP, and supply area. This includes autoregressive and moving average parameters as well as weighting of any external drivers found to be significant.

Forecasts of modelled load are obtained by using the fitted models and feeding in projections of any required drivers. These forecasts form the basis for the zone substation, GXP and supply area forecasts.

The forecast produces a monthly peak MW by zone substation, GXP and supply area, also split by component (underlying load, irrigation, EV, PV, step load, etc).

Note that the degree of uncertainty in the load forecast increases over the forecast horizon. As such, we revisit our development plans and investments periodically to reflect the developing needs of our customers and stakeholders. At this point, the model does not include weather normalisation.

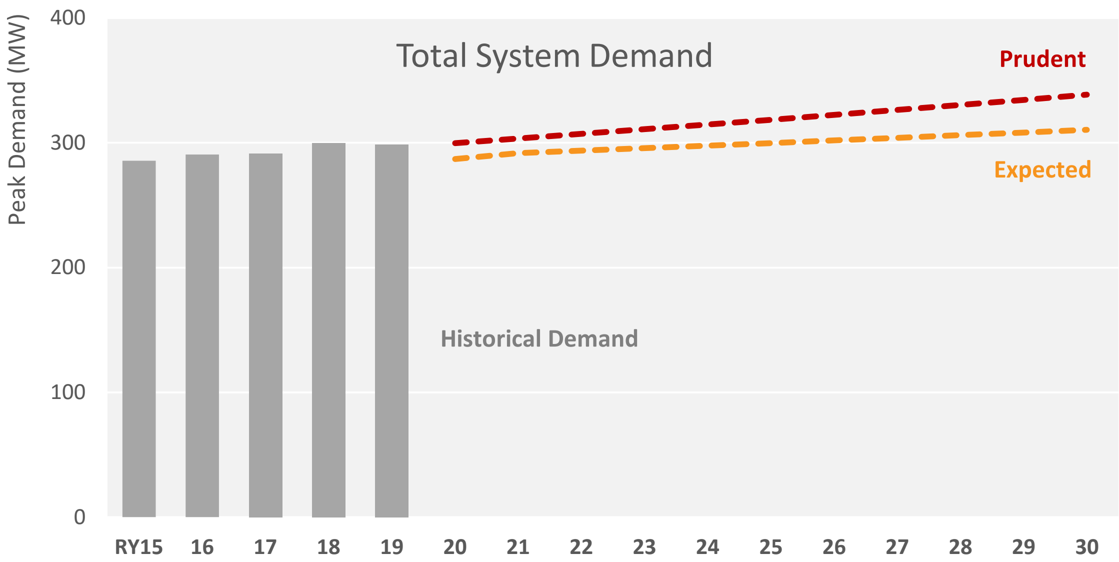
System Growth

The following figures show our historical and forecast of peak demand for the total system, GXPs, and substations. We expect that the demand forecast will be affected by the COVID-19 pandemic in the next two years. We will be monitoring the peak demands through the year (RY21) to determine the extent of the impact and revisit our demand forecast.

Total system

The chart below shows the historical and forecast peak demand for the total system. The peak demand is the coincident peak demand of the five GXPs supplying our network. In the meantime, we have deferred growth-related projects where the security of supply or growth risk is manageable – see Section 6.5.2.

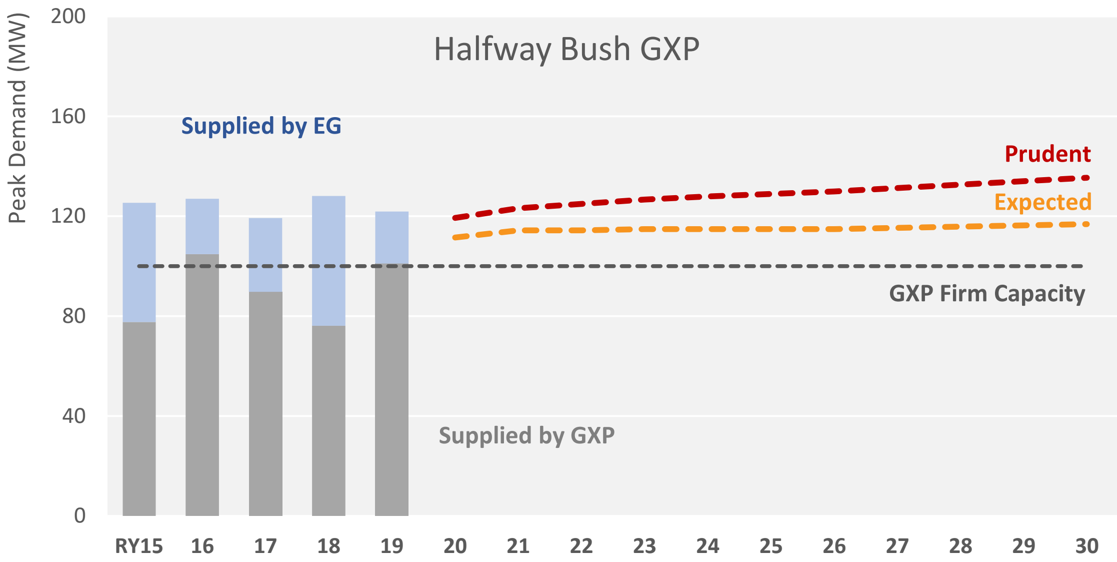
Figure 6.3: Total system peak demand forecast (MW)



Dunedin Network

The charts show historical and forecast peak demand for our two Dunedin GXPs.

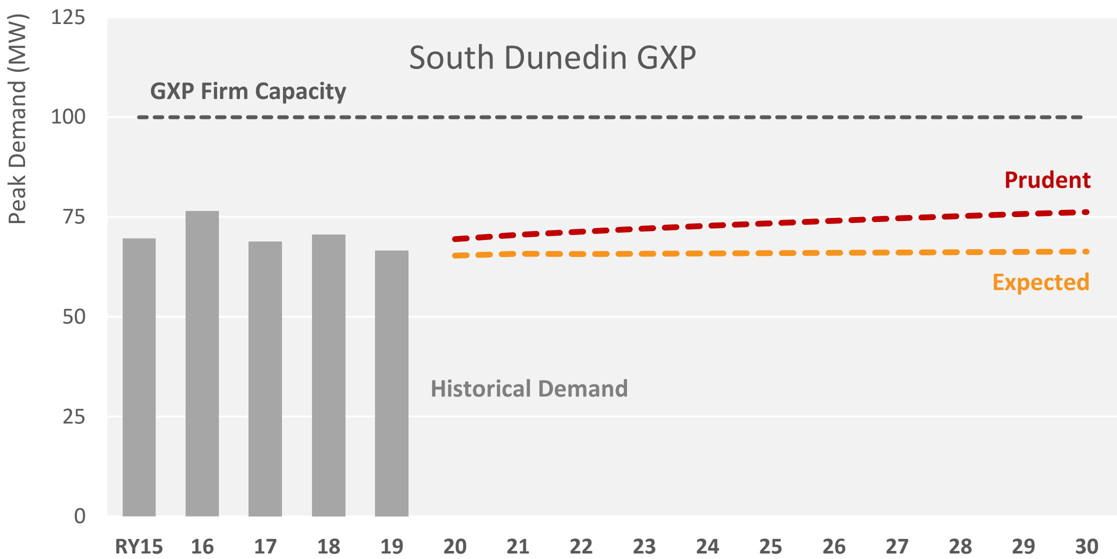
Figure 6.4: Halfway Bush GXP peak demand forecast (MW)



Note: The prudent and expected forecasts are gross peak demand (the sum of demand at the GXP plus embedded). Halfway Bush GXP is shared with Otago Net. The forecast above only shows Aurora Energy demand.

Peak load on the Halfway Bush GXP is offset by generation from Waipori which is embedded in our network. Neville Street zone substation was decommissioned in 2019 and the load was transferred to the new Carisbrook zone substation which is supplied from the South Dunedin GXP. Peak offtake at Halfway Bush has historically exceeded the N-1 post-contingency rating of the GXP.

Figure 6.5: South Dunedin GXP peak demand forecast (MW)



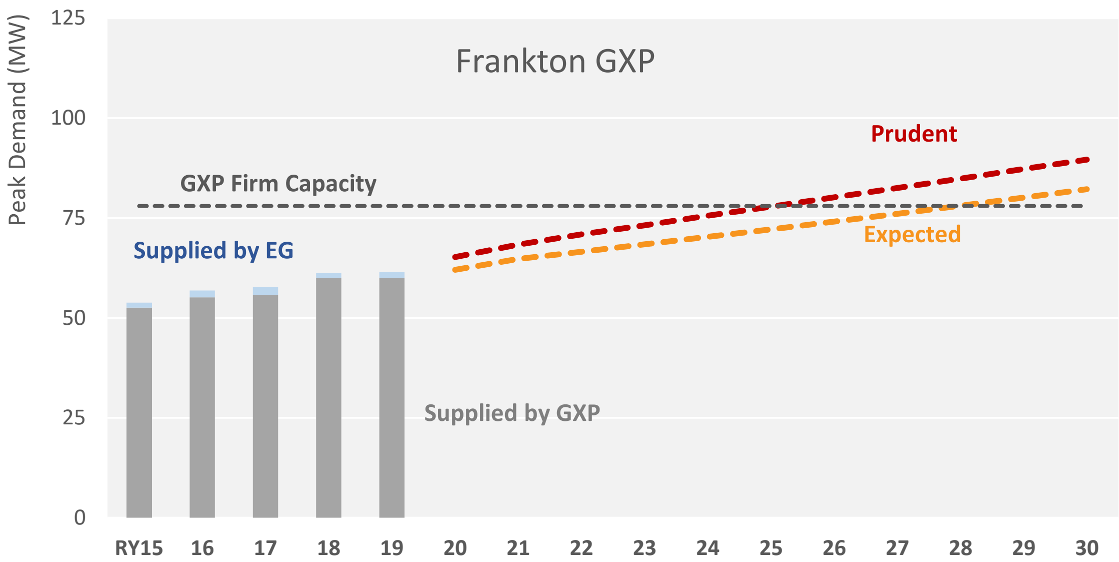
South Dunedin GXP has seen relatively stable peak demand over the last three years and the forecast extends this trend.

Central Otago network

The charts in this section show historical and forecast peak demand for the three Central Otago GXPs – Frankton, Cromwell, and Clyde.

Frankton GXP has shown steady growth over the past 5 years, in line with commercial and residential growth in the wider Queenstown area. Our prudent forecast anticipates that firm capacity will be exceeded by 2023, however this is likely to be affected by the COVID-19 pandemic. Collectively with Transpower and PowerNet, we are investigating options for the region to manage the possibility/risk of higher than expected growth and ensure adequate lead time for projects. This is further discussed in Section 6.5.3.

Figure 6.6: Frankton GXP peak demand forecast (MW)[42]

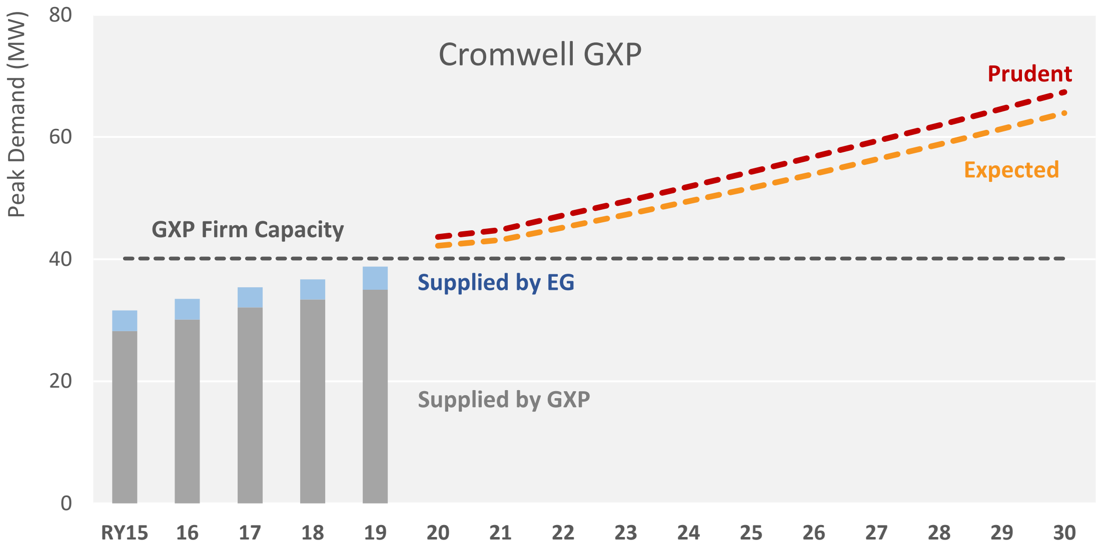


Note: The prudent and expected forecasts are gross peak demand (the sum of demand at the GXP plus embedded).

Cromwell GXP (see below) has seen strong growth in recent years as a consequence of development in both Cromwell and Wanaka. The GXP firm capacity is constrained to 41 MVA by protection limits and the 33 kV outdoor switchyard. We forecast that the GXP firm capacity rating will be exceeded by 2021 but this is likely to be affected by the COVID-19 pandemic. Transpower plans to replace the existing 33 kV switchyard with indoor switchgear which will resolve the 33 kV limits and increase firm capacity to 68 MVA. This is further discussed in section 6.5.3.

[42] Note: Frankton GXP is shared with PowerNet. The forecast above only shows Aurora Energy's demand.

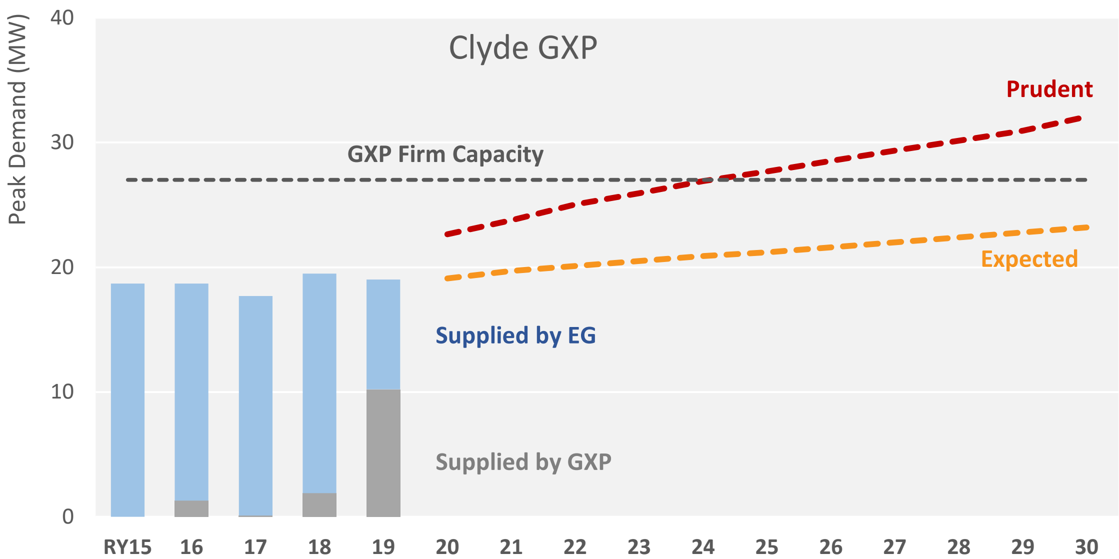
Figure 6.7: Cromwell GXP peak demand forecast (MW)



Note: The prudent and expected forecasts are gross peak demand (the sum of demand at the GXP plus embedded).

Due to high levels of embedded generation behind the Clyde GXP (see below), the transformers are lightly loaded most of the time. In the unlikely event that multiple sites of embedded generation are offline, the GXP peak demand could exceed 20 MW within the planning horizon. This is still below the N-1 post-contingency capacity limit. There is potential for further irrigation growth, but we do not expect either summer or winter peak demand to exceed the capacity of this GXP over the next ten years.

Figure 6.8: Clyde GXP peak demand forecast (MW)



Note: The prudent and expected forecasts are gross peak demand (the sum of demand at the GXP plus embedded).

Summary of GXP Demand Forecasts

Table 6.3: Halfway Bush GXP zone substation demand forecast

Zone Substation	Security Class	Firm Capacity MVA	Historical						Forecast									
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Berwick	Z3	3.6	1.4	1.6	1.2	1.5	1.8	**1.5**	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.2	2.2	2.3
East Taieri	Z1	24	15.9	17.0	15.8	15.6	16.1	**16.0**	16.6	16.7	16.8	16.9	17.0	17.1	17.2	17.3	17.4	17.4
Green Island	Z2	18	13.9	14.6	13.0	14.2	14.2	**13.0**	15.3	15.6	15.8	16.0	16.3	16.5	16.7	16.9	17.1	17.3
Halfway Bush	Z2	18	14.1	14.7	14.0	15.6	14.7	**12.9**	14.9	14.9	15.1	15.1	15.2	15.3	15.3	15.4	15.4	15.4
Kaikorai Valley	Z2	23	10.3	11.7	9.6	9.5	8.9	**9.1**	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Mosgiel	Z2	12	7.1	6.7	6.1	5.7	6.6	**6.5**	6.8	6.8	6.9	6.9	6.9	6.9	7.0	7.0	7.0	7.0
North East Valley	Z2	18	11.0	11.4	9.8	7.4	8.1	**10.1**	8.9	9.1	9.6	9.9	10.2	10.5	10.8	11.1	11.4	11.6
Outram	Z2	3.6	2.9	3.0	2.8	2.8	2.8	**2.8**	2.8	2.8	2.8	2.9	3.0	3.1	3.2	3.3	3.4	3.5
Port Chalmers	Z2	10	7.0	7.3	6.2	7.0	7.4	**6.5**	7.9	8.0	8.2	8.3	8.4	8.5	8.6	8.8	8.9	9.0
Smith Street	Z1	18	15.5	15.2	13.1	13.7	13.9	**13.6**	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Ward Street	Z2	23	12.8	12.8	10.5	11.0	9.5	**11.0**	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Willowbank	Z2	18	12.3	12.5	10.8	12.2	13.2	**12.2**	13.9	13.8	14.1	14.1	14.2	14.3	14.4	14.4	14.5	14.5

Table 6.4: South Dunedin GXP zone substation demand forecast

Zone Substation	Security Class	Firm Capacity MVA	Historical						Forecast									
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Andersons Bay	Z1	18	14.1	15.6	13.3	15.2	15.0	**14.3**	15.8	15.8	16.1	16.1	16.3	16.3	16.5	16.5	16.6	16.7
Carisbrook	Z2	18	13.1	12.4	10.5	11.4	11.8	**10.8**	13.0	13.5	13.8	14.2	14.5	14.9	15.1	15.4	15.7	16.0
Corstorphine	Z2	23	12.5	14.0	11.1	12.5	12.9	**12.0**	14.1	14.2	14.4	14.5	14.6	14.7	14.8	14.9	14.9	15.0
North City	Z1	28	19.1	18.8	17.2	19.1	18.5	**14.3**	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6
South City	Z1	18	14.9	16.1	13.7	14.8	16.2	**14.6**	16.8	17.1	17.3	17.5	17.7	17.9	18.2	18.4	18.7	18.9
St Kilda	Z1	23	15.5	15.9	13.5	15.4	15.8	**14.1**	16.2	16.7	16.9	17.3	17.5	17.8	18.0	18.3	18.6	18.8

Table 6.5: Frankton GXP zone substation demand forecast

Zone Substation	Security Class	Firm Capacity MVA	Historical 2015	2016	2017	2018	2019	2020	Forecast 2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Arrowtown	Z2	6	7.7	8.7	9.1	8.9	9.2	8.4	9.9	10.2	10.4	10.6	10.8	11.0	11.3	11.5	11.7	12.0
Commonage	Z2	17	10.1	10.8	12.0	12.9	13.6	**11.8**	14.5	15.0	15.5	15.8	16.0	16.4	16.8	17.1	17.5	17.8
Coronet Peak	NA	6	5.3	4.9	6.1	5.7	5.6	**5.5**	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Dalefield	Z3	3.6	1.4	1.6	1.5	1.7	1.8	**1.8**	2.0	2.1	2.2	2.3	2.3	2.5	2.6	2.7	2.8	2.9
Fernhill	Z2	10	6.2	6.3	6.4	7.1	7.0	**6.8**	7.1	7.5	7.7	7.9	8.0	8.2	8.4	8.6	8.8	9.0
Frankton	Z1	15	12.8	14.3	14.2	16.0	16.4	**17.0**	17.5	18.1	18.8	19.2	19.5	20.0	20.6	21.1	21.7	22.2
Queenstown	Z2	20	13.7	15.2	14.7	14.3	14.7	**16.0**	16.5	17.5	18.4	19.0	19.4	20.3	21.1	21.9	22.7	23.5
Remarkables	NA	3.6	2.4	2.3	2.8	2.8	2.3	**2.4**	2.9	3.1	3.2	3.3	3.4	3.5	3.7	3.8	3.9	4.1

The reconfiguration of Arrowtown zone substation in RY21 will increase capacity to 10 MVA.

The lower rated (15MVA) Frankton substation transformer will be replaced by a new 24MVA transformer in RY29.

Table 6.6: Cromwell GXP zone substation demand forecast

Zone Substation	Security Class	Firm Capacity MVA	Historical 2015	2016	2017	2018	2019	2020	Forecast 2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Camp Hill	Z2	7.5	3.8	5.2	5.6	5.8	6.0	**6.8**	6.9	7.4	7.6	7.8	8.1	8.3	8.5	8.8	9.0	9.2
Cardrona	Z3	6	3.1	2.8	4.1	4.4	4.0	**4.8**	4.5	4.7	4.8	4.8	5.0	5.1	5.2	5.2	5.3	5.4
Cromwell	Z2	9	10.5	10.6	11.6	11.9	13.0	13.2	13.6	13.8	14.2	14.5	14.9	15.3	15.8	16.2	16.6	17.0
Lindis Crossing	Z3	7.5	0.0	5.6	6.0	6.3	6.6	**6.8**	6.8	7.0	7.2	7.3	7.5	7.7	7.8	8.0	8.2	8.4
Queensberry	Z3	4	2.7	2.7	2.9	3.3	2.9	**3.1**	4.0	4.1	4.3	4.4	4.5	4.6	4.7	4.8	4.9	5.0
Wanaka	Z1	24	18.4	20.3	19.4	20.8	21.0	**22.0**	23.2	24.0	24.6	25.3	26.0	26.7	27.3	28.0	28.7	29.3

The two existing Cromwell zone substation transformers will be replaced in RY21 with two new 24MVA transformers.

The second transformer at Lindis Crossing scheduled for RY29 would support Lindis Crossing and Queensberry. The need for the additional capacity is dependent on the uptake of irrigation load. This will be monitored, and timing of the project will be reviewed.

The installation of a transformer at Riverbank switching station in RY28 will offload the Wanaka substation.

Table 6.7: Clyde GXP zone substation demand forecast

Zone Substation	Security Class	Firm Capacity MVA	Historical						Forecast									
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Alexandra	Z2	15	10.5	11.7	12.4	13.0	12.0	11.2	12.6	12.8	13.0	13.2	13.3	13.5	13.8	14.0	14.1	14.3
Clyde/Earnscleugh	Z3	4.8	4.2	4.0	3.7	4.0	4.0	3.5	5.0	5.1	5.3	5.4	5.5	5.7	5.8	5.9	6.0	6.1
Ettrick	Z3	3.6	1.7	1.8	1.6	1.8	1.4	2.0	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Lauder Flat	Z3	3	0.0	0.0	0.7	0.9	1.0	0.8	1.5	1.6	1.8	1.9	2.1	2.2	2.4	2.5	2.7	2.8
Omakau	Z3	3.6	3.6	3.3	3.4	3.6	3.2	3.1	4.0	4.2	4.3	4.5	4.6	4.8	4.9	5.0	5.2	5.3
Roxburgh	Z2	6	1.3	1.6	1.8	1.9	1.9	2.2	2.0	2.1	2.2	2.2	2.3	2.3	2.4	2.5	2.5	2.6
Earnscleugh		2																

Rebuild of Omakau zone substation on a new site with a transformer rated at 7.5 MVA (ex-Cromwell zone substation) is scheduled for RY24. Load transfers to Lauder Flat will occur in the short term.

Rebuild of Clyde/Earnscleugh substation on a new site with a transformer rated at 7.5 MVA (ex-Cromwell zone substation) is scheduled for RY26. Load transfers to Alexandra will occur in the short term.

Earnscleugh zone substation is the backup of Clyde/Earnscleugh zone substation and is planned to be decommissioned in RY26.

Asset Utilisation

Table 6.8: Load Factor and transformer utilisation

Load factor (%)	Historical					Forecast									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
System Load Factor (%)	54%	53%	53%	54%	58%	57%	57%	57%	57%	56%	56%	56%	56%	56%	56%
Dunedin Load Factor (%)	50%	52%	50%	53%	53%	57%	57%	57%	57%	56%	56%	56%	56%	56%	56%
Central Load Factor (%)	56%	54%	54%	56%	55%	57%	57%	57%	57%	56%	56%	56%	56%	56%	56%

Transformer Utilisation (%)	Historical					Forecast									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Transformer Utilisation (%)	31%	31%	31%	27%	29%	30%	30%	30%	30%	31%	31%	31%	32%	32%	32%
Dunedin Transformer Utilisation (%)	37%	35%	37%	28%	35%	30%	30%	30%	30%	31%	31%	31%	32%	32%	32%
Central Transformer Utilisation (%)	26%	26%	27%	26%	26%	30%	30%	30%	30%	31%	31%	31%	32%	32%	32%

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**: we assign a maximum continuous rating and also a four-hour rating which applies to post contingent load transfer in an N-1 context. Ratings may be amended from the standard to reflect local temperature extremes, or the shape of the load profile. Where a substation supplies irrigation loads a cyclic or seasonal rating may be applied
- **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 of the specific cable route conditions etc.

6.3.2. Security of Supply

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 (Chapter 4) and the reliability performance sought by our customers and stakeholders. Security criteria generally drive the larger investments related to the subtransmission 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, subtransmission and distribution networks) is set out below in Table 6.3.

Table 6.9: 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.					

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 load 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 actually achieved depends on a combination of security of supply and operational performance.

6.3.3. 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.

Where new customers are added, our planning team may recommend reinforcing back into the network. However, most of our work to address power quality issues is reactive, responding to customer complaints. Our plans to increase LV monitoring (discussed previously) will enable us to be more proactive in addressing power quality issues.

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 such as variable speed drives, Switch Mode Power Supplies, and electronic ballasts for fluorescent lamps and welders inject 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 6.10: Maximum voltage distortion limits in % of Nominal fundamental frequency voltage

INDIVIDUAL VOLTAGE DISTORTION (%)	TOTAL VOLTAGE DISTORTION THDV (%)
3.0	5.0

6.3.4. Additional Forecasting

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: ordinarily, we use a simple linear regression to forecast connection numbers; however due to the anticipated effect of COVID-19, we have reflected on historic connection activity following the global financial crisis and adjusted our forecast accordingly.
- distributed generation (DG): we have applied an annual growth rate of 3% for small-scale DG from a 2019 base and adjusted for any known large-scale DG.
- ICP demand and volumes: from the 2019 base, we have applied an annual growth rate of 1% to ‘demand on system for supply to consumers' connection points’ (consistent with our broader, disaggregated demand forecasts), 0.5% annual growth to ‘electricity entering system for supply to ICPs’, and 0.7MW per annum to high voltage DG output. We assume a constant loss factor of 6.2%

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 in.

The data produced is not used directly for investment forecasting as forecasts of final consumer connections does 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.

6.4. NON-NETWORK SOLUTIONS

When the network becomes constrained, investing in new infrastructure may not be the best option to relieve the constraint. Other alternatives include:

- demand side management, including energy and demand management systems, distributed energy resources, including distributed generation and energy storage solutions
- cost reflective pricing leading to change of use behaviour, and/or greater use of Demand side management (DSM) or DERs

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).

Box 6.1: Case study: non-network solution for a Upper Clutha voltage and capacity constraint

The Upper Clutha DER solution offers a medium-term solution to the capacity and voltage constraints on our Upper Clutha 66 kV network. It involves procuring the services of a DER solution provider to provide peak load demand reduction on an ongoing and as required basis (such as during exceptional peak demand or when one of the two Upper Clutha lines is out of service).

The solution involves the DER provider working with consumers in conjunction with a time-of-use pricing structure in the Upper Clutha area – this may require an adjustment to our existing pricing. We will pay the solution provider an agreed amount for each consumer in their scheme, with targets of number of consumers and non-network capacity support gained. The scheme will provide everyday demand management, in response to cost reflective pricing. It will also provide targeted demand response during network contingencies. Such demand response will attract a per event fee.

This project is planned as a trial in RY22 and RY23 before delivering a reliable alternative to network capacity in RY24 and beyond.

The non-network solution enables the flexible addition of demand management to the Upper Clutha area. The incremental nature of non-network alternatives is particularly attractive at a time of uncertain demand growth, following the likely economic disruption caused by the COVID-19 pandemic. To ensure that we are not locked into one solution provider, a standing offer for capacity support will remain open to any demand response aggregator who can provide us with suitable demand response capacity at an acceptable cost, while meeting our technical requirements.

6.4.1. 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.

6.4.2. Distributed Energy Resources

DERs 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.

The key difference between DSM and DERs is the greater flexibility of DERs, which typically have the ability to export energy or manage energy in both directions, whereas DSM cannot reverse the flow of energy.

The use of energy storage technologies such as batteries could enable us to defer or avoid expenditure on network development. The key network benefit would be peak reduction, though they could also be used to improve power quality by absorbing excess generation capacity from other DER sources to mitigate fluctuating voltages.

Battery storage is relatively expensive and its uptake in New Zealand is in its infancy. In some situations, mainly in remote rural areas, installing combined generation and battery storage units could provide an economic alternative to long service lines.

In the longer term, battery storage systems will have valuable applications for both lines companies and residential customers. They offer significant potential for increased reliability and resilience of supply, potential for deferring network reinforcements and lifting network utilisation, improving network stability, and maximising the value from DER sources. The cost of this technology is linked to the mass production of EVs and is projected to be an economic alternative to meeting growth or at the least offering a deferral of network upgrade solutions.

We anticipate growth in DERs over the AMP planning period and we are actively pursuing opportunities to make best use of these technologies to deliver viable non-network solutions. Active participation will help to decarbonise our economy and enhance the value chain for customers who pursue these technologies. We consider DERs will play a significant support role to the distribution network and the decarbonisation of the electricity and transport system in general over the next 20 years.

Our demand forecasts assume that DERs do not have a material impact on peak demand reduction during the planning period but as described above we do anticipate procuring DER based non-network alternatives to meet growth constraints on our network – particularly in the latter part of the AMP planning period.

6.4.3. 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.

A second benefit of smart metering data and analytics is improved customer service. The information could allow us to identify load trends and thus refine our network planning and design standards on the LV networks, address issues with power quality and proactively identify faults and potential safety concerns.

6.5. GROWTH AND SECURITY INVESTMENTS

The previous sections described the key drivers for growth and security investments and our approach to determining a preferred option in each case. This section discusses how we develop proposals for each of the preferred options. As the operating environment changes the investments forecast in the mid to latter part of the planning period may need to be refined.

6.5.1. Solution Prioritisation

The network development projects listed in this section are mainly driven by increased capacity and security requirements as a result of load growth. Where economic, we have selected solutions that meet our SOS guidelines.

This ensures that our network configuration and capacity is constructed in a consistent way and the impact on our reliability of supply service levels will be predictable.

Prioritisation of network solution 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.

6.5.2. Planned Growth and Security Projects

The following table shows selected growth and security projects we intend to undertake during the planning period. The timing of these projects has been modified based on our best assessment on the effect of COVID-19 pandemic. The complete list of the projects is shown in Appendix F.

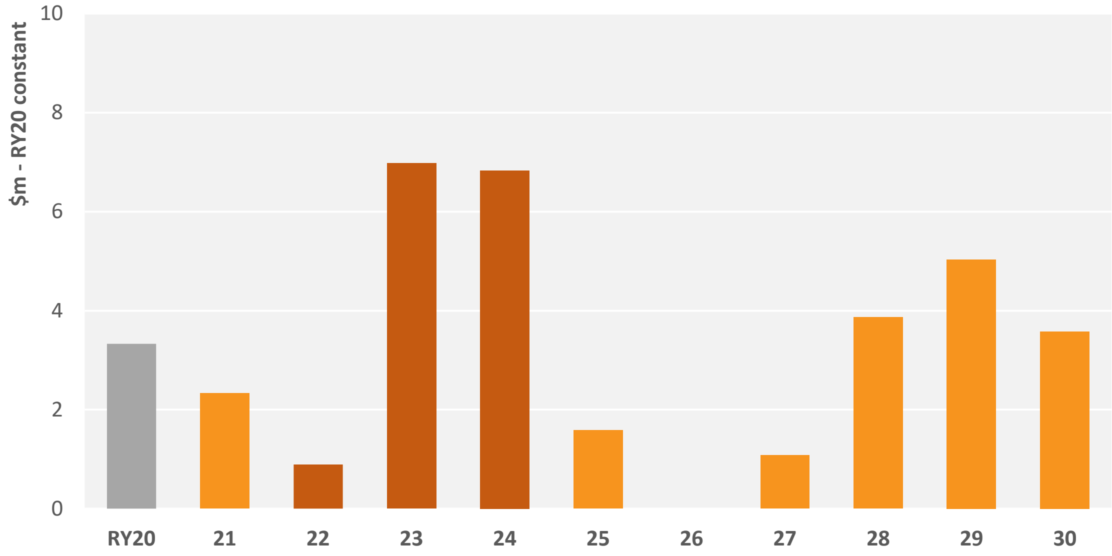
Table 6.11: Summary of key projects

PROJECT	FROM	TO	CAPEX
Arrowtown 33kV Ring Upgrade The Arrowtown ring is supplied from Transpower's Frankton grid exit point (GXP) and supplies four zone substations (Dalefield, Coronet Peak, Arrowtown and Remarkables). The demand on the Arrowtown ring has exceeded its firm capacity and security level in the last six years. This project includes installing a new 33kV underground cable circuit from Frankton GXP to increase the capacity of the ring.	2021	2024	$6 m
Arrowtown zone substation 33kV Indoor Switchboard The Arrowtown ring currently operated as an open ring with the open point located at the Arrowtown zone substation. The open point is a manually operated air break switch. The ring is categorised as Z1 security level according to the SOS guidelines, consumers should have no interruption for a single cable, line or transformer fault. This project will replace the existing outdoor switchgear with indoor switchgear. Included in the project is reconfiguration of the existing three transformers to increase the zone substation capacity.	2024	2025	$2.6 m
New Omakau substation The peak load supplied from the Omakau and Lauder Flat substations is forecast to exceed its firm capacity. The existing Omakau zone substation is located in a road reserve with no space for expansion. It is also very close to the river and has a flood risk. The substation has only one transformer with limited backfeed to/from adjacent substations. There is no space to park the mobile substation to offload the substation for maintenance and provide support for an unplanned outage. This project will construct a new zone substation in a different location. The new zone substation will include a transformer from Cromwell zone substation, a mobile substation parking bay and a 33kV outdoor bus with circuit breaker.	2021	2024	$3.1 m
Upper Clutha voltage support There is a voltage constraint in the Upper Clutha area (Wanaka, Hawea and Cardrona). This area is supplied from the Cromwell GXP by two 54 km 66 kV single circuit lines. These lines terminate at the Riverbank Road Substation in Wanaka. At peak load with all equipment in service the 66 kV voltage at Riverbank Road is less than 1.0 p.u. and with one of the 66 kV Upper Clutha circuits out it is less than 0.9 p.u. This project will install capacitors in the 11kV network on the Upper Clutha zone substations to mitigate the voltage constraint.	2021	2021	$0.9 m
Extend Ripponvale Road Spur to SH6 The 11kV spur of Cromwell zone substation feeder CM821 had a number of orchards built. During fruit season, this part of the network experiences voltage issues. This project involves a conductor upgrade and provides an intertie with an adjacent feeder circuit.	2021	2021	$0.3 m
New Clyde Township Supply The Clyde Township is supplied from a single feeder. A fault on the will cause a loss of power supply to Clyde township, with no switching restoration option. This project provides a second feeder to the township providing security of supply.	2021	2025	$0.4 m

Major Projects Capital Expenditure Forecast

Our forecast major projects expenditure during the AMP planning period is shown below.

Figure 6.9: Major projects Capex

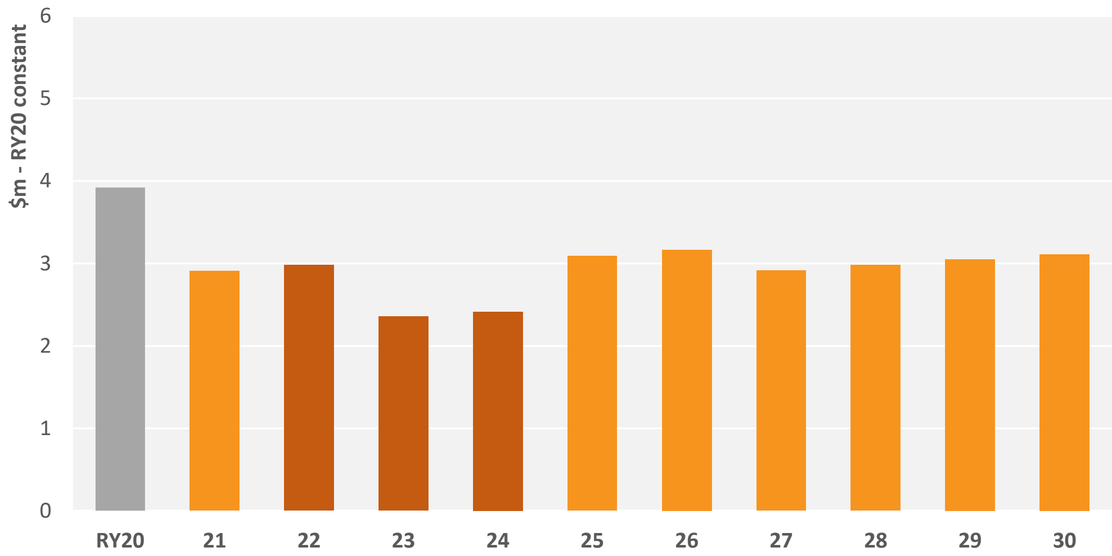


Major projects are 'lumpy' by nature due to the relatively small number of large projects required at specific times to address identified constraints. The timing of the projects has been adjusted in anticipation of the impact of COVID-19. The large step up into RY23 is due to the Arrowtown 33kV ring upgrade and the Smith St to Willowbank 33kV intertie project. The last three years is the combined cost of four projects - Riverbank substation, Lindis Crossing substation new transformer, Frankton substation transformer upgrade and the North City to Ward Street 33kV intertie.

Distribution and LV Reinforcement Projects Capital Expenditure Forecast

Forecast distribution and LV reinforcement Capex during the AMP period is shown below.

Figure 6.10: Distribution and LV reinforcement Capex



Distribution and LV reinforcement has a relatively consistent profile by nature due to the higher volume and lower cost of projects compared with major projects. The reduction of spend in RY23 and RY24 is due to the expected impact on demand from COVID-19.

6.5.3. Transpower GXP Capacity and Security Gaps

This section sets out information on identified capacity and security gaps in relation to GXPs and transmission lines that supply our network.

Table 6.12: GXP constraints

GXP/ASSET	CONSTRAINT	STATUS
Cromwell GXP	The firm capacity of 41 MVA (33 kV side) is forecast to be exceeded by 2021. The 33 kV outdoor switchyard and the protection components limit the capacity of the transformers.	Transpower has a planned 33 kV outdoor to indoor conversion project. This project would increase the firm capacity to 68 MVA.
Frankton GXP	The GXP is shared by Aurora Energy and PowerNet. Utilising Transpower's forecast, the firm capacity of 80 MVA will be exceeded in 2025.	Transpower has provided a high-level response to our capacity upgrade request: Install a 120MVA Transformer; then Replace the existing Cromwell GXP transformer's (T5A and T5B); then Install a second 120MVA Transformer.
Cromwell-Frankton 110 kV line	Utilising Transpower's forecast, the firm capacity of 77 MVA will be exceeded in 2023.	Aurora Energy and PowerNet have commissioned Transpower to provide a Solution Study Report and Grid Reliability Study for implementing variable line rating and tactical thermal uprating.

6.5.4. Aurora Energy-Driven GXP Projects

This section sets out information on identified capacity and security gaps in relation to GXPs and transmission lines that supply our network.

Table 6.13: Aurora Energy GXP projects

GXP	CONSTRAINT	STATUS
Frankton	The Arrowtown 33 kV ring upgrade project entails 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)	We have started discussion with Transpower and submitted a high-level request to Transpower for the new 33kV feeder CB.

6.6. NETWORK EVOLUTION PLAN

Our network evolution plan sets out we will prepare for the wider adoption of DERs. With increased efforts to promote decarbonisation, we expect to see more EVs, photo voltaic installations and battery storage systems installed on our network.

We believe it is prudent to prepare for increased uptake of these resources now, rather than react at a later stage. Two key themes of the network evolution plan are described below:

Theme 1: Support consumer uptake

Support consumer uptake of PV and EVs to decarbonise: prepare and manage LV networks for the future.

The uptake of PVs and EVs can lead to network congestion even at modest levels of penetration if this occurs in clusters on relatively weak areas of the network. However, understanding hosting capacity of the network will enable us to take steps to manage/mitigate congestion and defer or avoid network upgrades. This section sets out the steps to understand LV networks and put in place ways to avoid congestion. This prepares the management of LV networks for the future , and thereby supports consumers' uptake of PV and EVs.

- **understand the existing capability of LV networks and prioritise assessments:** to understand the network hosting capacity for PV and EVs, we need to enhance our network data and develop improved LV network modelling capability.
- **maximise capacity of networks to host DERs**: we would put in place new standards for the connection of PV and EV chargers to the LV networks. In turn the PVs and EVs themselves could be used to manage power flows, preventing network congestion and increase our capability to host greater levels of DER penetration.
- **identify and prioritise LV networks close to constraints**: the LV networks that are close to becoming congested require close monitoring of both PV and EV uptake.
- **share experience with industry**: the experience of implementing all of the above should be documented and shared with the rest of the distribution industry, ENA, and regulators, to support consistent implementation throughout New Zealand.

Theme 2: Increasing electrification

Increasing electrification is likely to require the provision of additional network capacity. Our aim is to deliver distribution and subtransmission network capacity as efficiently as possible. The implications of DERs for distribution and subtransmission networks include the potential for increased coincident power flow from reducing diversity between consumers, particularly in relation to PV. We need to understand the impact of changing load in a timely way to seek non-network support for the network. This would either delay or avoid upgrades to distribution and subtransmission networks, while maintaining reliability and quality of supply. This section sets out the steps we propose to take to better manage the subtransmission and distribution networks and to seek non-network support with the backdrop of increasing electrification:

- **improve technical modelling to explore load growth scenarios**: this will involve integration of GIS data, network data, and actual load from SCADA into industry standard power flow models. It will also involve the application of industry standard models to model the subtransmission network, or parts of it, without the need to create new models each time. In addition, load growth scenarios will need to be rapidly incorporated into the models.
- **Develop load growth scenarios**, involving forecasts of:
    - coincident peak load for areas (the load at each substation coincident with the area's peak load). An example is the coincident peak load for the Upper Clutha area, comprising the load at each substation, by season, that combine to give the peak load for the Upper Clutha area by season. This is required by year, for at least 10 future years, to enable analysis of subtransmission capacity adequacy into each region
    - peak load at each zone substation, by season, for at least 10 future years. This is required to enable analysis of substation adequacy using the tools
    - peak load by HV distribution feeder.

In each of the above cases, the ability to rapidly produce load duration curves from historical data for either the area, zone substation, or distribution feeder and scale them by the relevant peak demand to understand any capacity shortfalls by future year. In turn, this feeds directly into assessing upgrade requirements and seeking non-network support. Combined with this should be the ability to produce scaled load profiles at either the area, zone substation, or distribution feeder, to indicate when non-network support may be required, to further assess options.

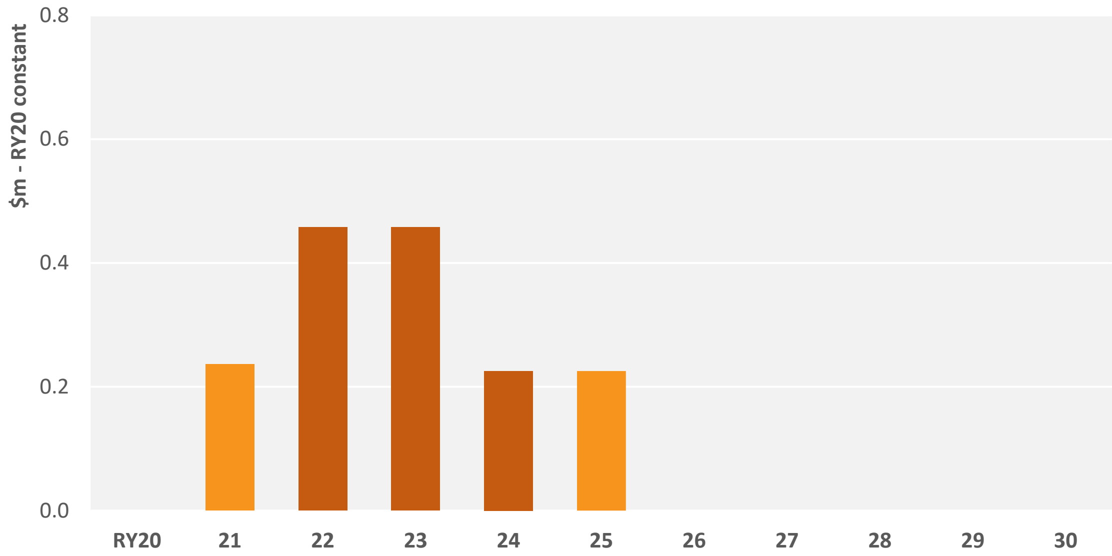
- **signal the need for non-network support by area**: ensure information is available in a timely and flexible manner, that indicates where capacity support is required.
- **develop information systems to gain non-network support**: such information system would advertise to appropriate ICPs, within the areas that support is required, to support the subtransmission system, zone substation or distribution feeder.
- **upgrade infrastructure where necessary and more economic**: non-network support may not provide sufficient quantity of capacity support, or the solution may not be economic compared to network solution.
- **share experience with industry**: the experience of implementing all of the above should be documented and shared with the rest of the distribution industry, ENA, and regulators, to support consistent implementation through New Zealand.

6.6.1. Network Evolution Capex

The network evolution forecast Capex includes an initial set of investments for the installation of LV monitoring systems to give greater visibility of our LV networks.

Historically we have not invested in these assets as there has been little need to have real-time power information for our LV networks. Consumer consumption behaviour has been reasonably predictable and could be catered for when customers connect to our network. With the introduction of new technologies in recent years this has created uncertainty in consumer behaviour and requires us to have greater visibility of our LV network to avoid constraints occurring. We plan to start deploying these systems from RY21 as shown below.

Figure 6.11: Network evolution Capex



In more recent years, since the introduction of new technology, our focus has been on network renewal and we have not invested in network evolution. We will begin to deploy LV monitoring on a trial basis to support connection of DERs from RY21. Our initial focus will be on general power quality monitoring at strategic locations across the network to get a baseline understanding of network power quality performance. In addition, we will undertake LV network monitoring in areas where analysis has identified potential constraints and/or DER congestion. In the medium term we anticipate that improved access to smart meter data will reduce the need to install LV network monitoring devices.

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

We use a simplified version of the network development planning process (described earlier in this chapter in relation to growth and security investments), for reliability-driven investments. This involves identifying needs, assessing options and selecting a preferred solution.

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
- **increased 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 also allow the prudent deferral of more expensive investments.

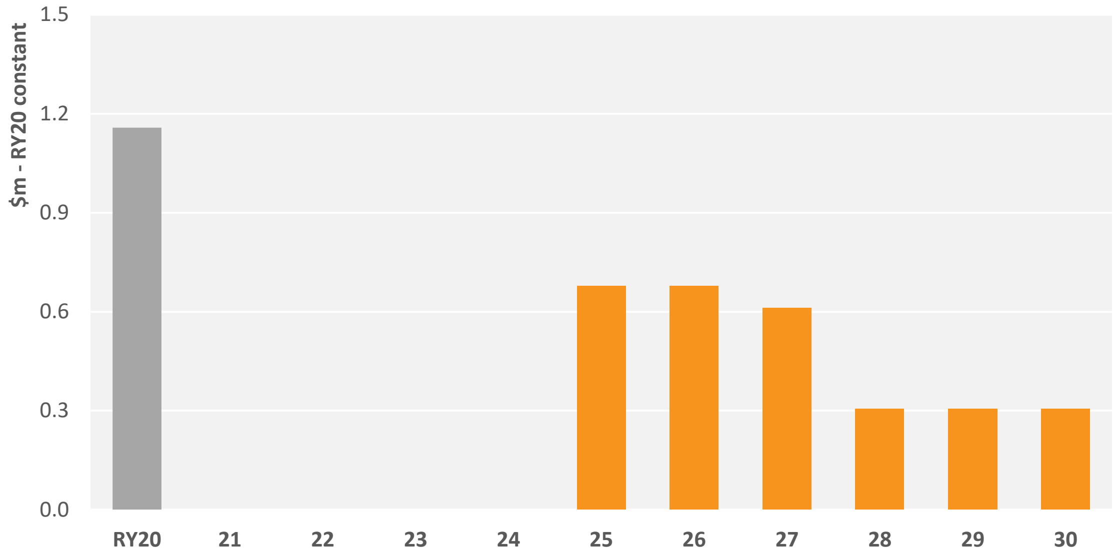
There is no spend forecast from RY22-24 for Reliability, Safety and Environment (RSE), as our plan is focused on mitigating safety risk and meeting required growth needs of the network rather than investing to directly improve reliability. Network safety risk is covered by our renewal workplan and there 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 a large number of these starting in RY25, reducing spend once the reliability benefits have been realised.

Reliability-Driven Capex

Our forecast reliability-driven Capex during the AMP planning period is shown below.

Figure 6.12: Reliability-driven Capex



We have not forecast any expenditure in RY21 and the CPP Period (RY22 to RY24) as our focus is on mitigating safety risk as a result of the consultation feedback. Subject to further consultation, our plan is to step up investment in RY25 to RY27 and carry out targeted reliability improvements on our network by installing auto reclosers, remote control and fault passage indicators. We plan to lower the spend in the last three years once the reliability benefits are realised.

6.8. CONSUMER CONNECTIONS

Consumer connection Capex is expenditure to facilitate the connection of new customers to our network. On average, we connect around 1,000 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 subtransmission 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. Historical 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:

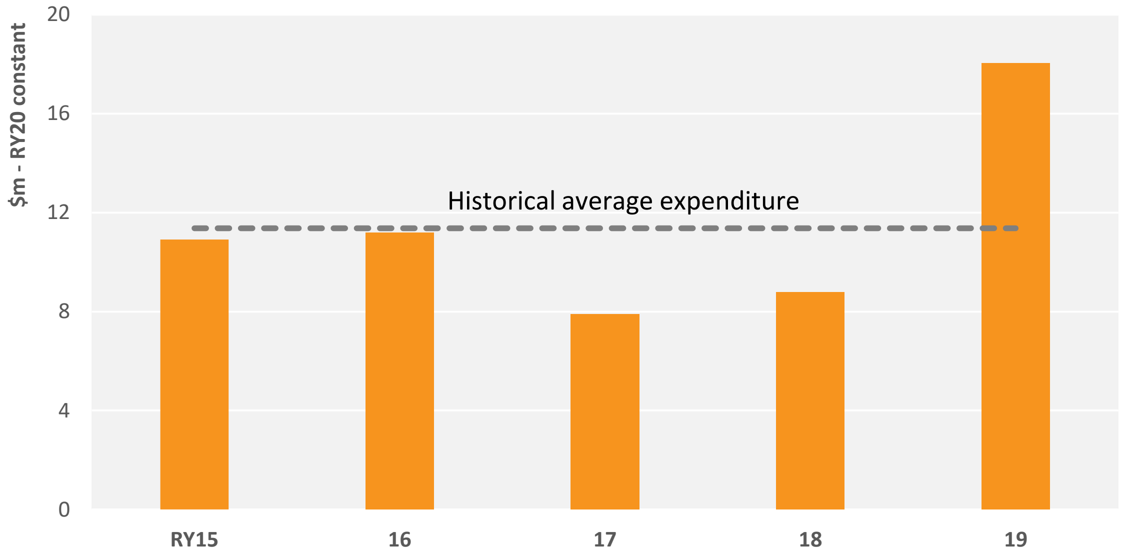
- **historical Capex trending**: identifying a level of expenditure that is appropriate to trend forward
- **trend changes**: reflects expected year on year changes that may affect the derived Capex trend, for example, changes in population growth rates
- **identified loads**: these are large known connections 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 five years expenditure (RY15-RY19); 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 RY15-19 with the dashed line showing average expenditure.

Figure 6.13: Average historical expenditure level (Gross)



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.

We have reviewed Statistics NZ forecast data for population and Gross Domestic Product (GDP) for our network areas, finding that population is forecast to increase at a reasonably steady rate and the GDP growth rate is relatively flat. We have concluded that as no significant changes in economic conditions or population growth are forecast for the period, no 'trend' adjustment is needed.

Identified Loads

The identified loads applied to our forecast are large known connections. The RY15-19 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.

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
- where population and GDP growth forecasts vary from historical growth levels this will have a direct impact on consumer connection Capex
- assumptions around large customer projects, including timing and cost, reflect our current best estimates and discussions with customers
- assumption that an increase in capital contributions to 60% by RY21 is possible as per the current proposed policy amendment
- a preliminary downward adjustment to our forecasts to reflect potential COVID-19 impacts
- no contingencies have been included.

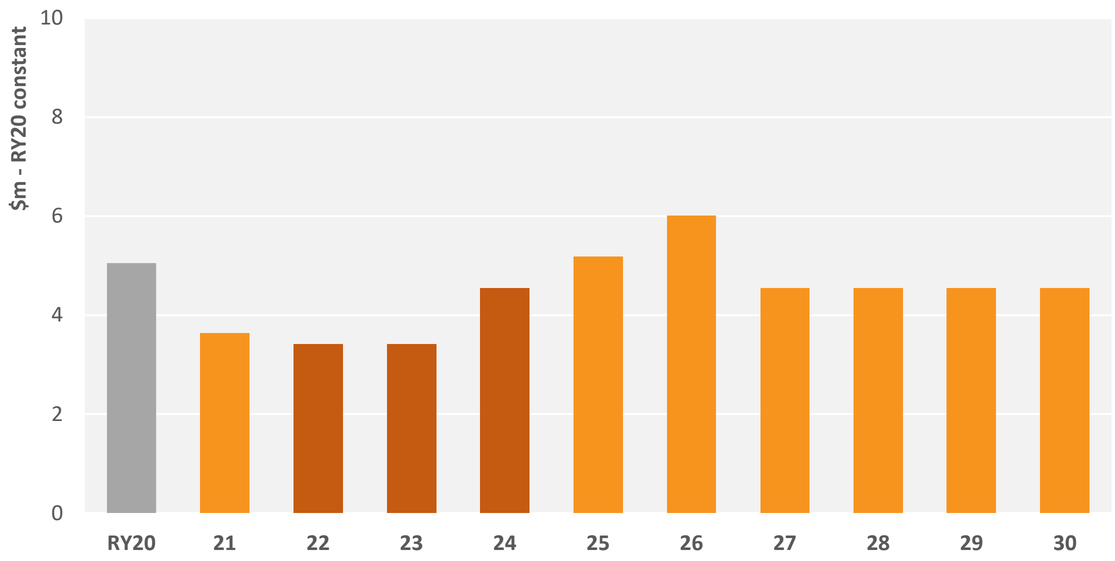
Capital Contributions

Long-term average capital contributions, as a percentage of connection and relocation expenditure, has fallen from around 60% in RY10 to approximately 45% in RY19. A new version of our policy is currently under review which proposes to return the average contributions to an average of 60% in RY21. This has been applied to the gross forecast to produce the net forecast figure.

Consumer Connection Capital Expenditure Forecast

The following chart sets out our Capex forecast, net of capital contributions.

Figure 6.14: Consumer connection forecast Capex (net of capital contributions)



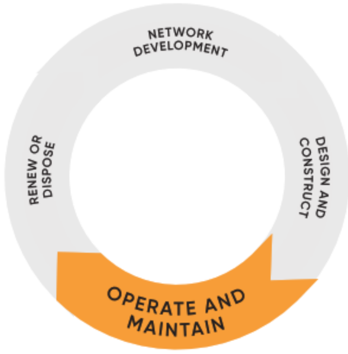
The trend down into RY22-23 and subsequent ramp back up to RY24 is due to the expected impact of COVID-19 on future demand. The uplift in RY25 and RY26 is due to forecast expenditure on an expanding ski field connection.

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 (e.g. 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).

Appropriate levels of network Opex ensures our assets are operated and maintained effectively, and that asset information needed to support effective expenditure in other areas (such as renewals) is obtained. We plan to increase network Opex-related activity 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 we move to a steady state of corrective maintenance, required to address defects that do not most cost effectively result in capital works
- pivoting our vegetation strategy from reactive to proactive and going beyond compliance requirements to improve long-term cost 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/defer renewal.

Key drivers of operations and maintenance are:

- **asset management system**: we need to gather information on assets to make cost effective, prudent decisions
- **legislative or regulatory requirements**: include minimum frequencies for inspecting overhead line assets, or safety requirements

- **maintenance standards:** that specify recommended inspection tasks, servicing intervals and reporting requirements
- **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 is important to ensure our asset management objectives are met. Portfolio objectives have been created for each of the maintenance portfolios and are covered in following sections.

Table 7.1: Asset management objectives relevance to operations and maintenance

OBJECTIVE AREA	
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. By gathering better asset information, well informed asset management decisions over a longer time period can be made to help reduce 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. An uplift in inspections through the first part of the planning period will provide us with improved condition information, which will allow us to make earlier, more informed asset management decisions. Furthermore, some asset characteristic/attribute information is absent and preventive maintenance provides a means to confirm or gather this data. Our maintenance plans currently have a somewhat shorter-term focus by necessity of our backlog of work due to historical underinvestment. Through the first half of the planning period 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 lifetime. It 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

Our maintenance standards define preventive maintenance activities and generally the frequency at which these are to be carried out. We use a preventive maintenance strategy where asset condition is generally assessed on a scheduled time interval basis. Some inspections timings are based on number of operations or faults, a requirement to gather data for decision making purposes, or on the criticality of the asset. Given the historical underinvestment resulting in a backlog of asset inspections, in some cases we are using criticality in conjunction with other known information on the asset to prioritise the backlog. Once the 'first pass' of all network asset inspections are completed, we will transition to steady state preventive maintenance programmes in those fleets.

We use information obtained from preventive maintenance activities, and occasionally reactive maintenance activities, to plan our corrective maintenance programme and inform renewal decisions. For defects, we are at the start of a journey 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 to more efficiently reduce risk and address poor performance. At present we only have a public safety criticality framework; however with the safety of the network as our primary objective this is an appropriate first step. Expanding our criticality framework will enable a more risk based approach to maintenance.

Our maintenance work programme is informed by:

- **preventive maintenance**: records of preventive maintenance on assets and comparison of these to our specified frequency of these activities, considering criticality in some fleets based on inherent risk, and where applicable we use an operations/duty basis
- **corrective maintenance**: preventive maintenance records, the database behind 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**: the NOC, which issues urgent reactive maintenance fault work on an individual job basis to our maintenance contractor
- **vegetation management**: our 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, and we update these base amounts 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 GM Asset Management and GM Works Programming and Delivery.

Maintenance Delivery

Below we explain our approach to managing the delivery of our maintenance activities.

Scheduling

Once the annual maintenance plan is developed, we schedule it based on contractor availability, keeping as smooth a resource profile as possible while attending to works which cannot be left until later in the year due to risk.

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 FSAs.

Our service providers are responsible for ensuring they have sufficient expertise and resources to undertake the assigned works in line with our requirements. They are also responsible for ensuring their staff are trained and qualified to undertake the assigned works. We monitor their compliance with these requirements. By maintaining our maintenance specifications and asset information records inhouse, we ensure that core asset knowledge is retained with in the business.

Quality management

While 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 will undertake early in the planning period.

Feedback and monitoring

Our FSA provides a mechanism for feedback both from and to our service provider. 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 access to the network for works required to develop and maintain the assets.

Our NOC and contact centre are in constant communication with contractors, generators, retailers and the public 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 manned 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 who respond to network events in the field and liaise with our control room to seek any work authorities or switching as required to restore supply and / or make the network safe.

Our network operators and planners consider factors such as how asset loading, and operation frequency affects asset life and performance, and how to safely remove assets from service for maintenance without compromising performance. When undertaking planning to deenergise the network to allow maintenance or renewal works key consideration is given to minimising impact to customers and communities and ensuring continued network performance.

Network operations is one of the focus areas of our business strategy and there are key focus areas 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.

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 subtransmission 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 as well as authorises work on the network and managing switching instructions that provide access to our contractors.

We are currently developing standards for ADMS symbols and alarm rationalisation to reduce the likelihood of human error in switching instruction development and increase the speed in which our controllers can identify and response to network events. These improvements will be seen by our customers as reduced outages and improved response time to an outage.

We are also preparing to move from our existing platform to a next generation system to ensure that our systems remain current and continue to be supported by providers. We are also preparing for the adoption of additional functionality within the 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 future power flow scenario analysis when we identify that a network abnormality will arise which will restrict or alter the normal flow of energy through our network. Enabling this functionality will provide assurance that we can continue to meet load demands now and into the future or provide early warning that contingency plans are required.

Outage Management System (OMS)

OMS derives network status data from the SCADA system. OMS is used to manage calls and outage restoration efforts, track interruptions to customers, and provide relevant information to customers through retailers, our website, or an interactive voice recording system. This system improves fault responsiveness and enables greater visibility of outage status to customers.

Operational Procedures

Operational switching is undertaken to disconnect sections of the network for safety isolation to enable maintenance or to restore 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. We are reviewing the operation procedures and remote-close practices associated with reclosers and sectionalises to prioritise public safety.

Network Access / Outage Planning

Our operations and network performance team includes the network access team who plan for the release of our subtransmission 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. Outage planning follows a process of release procedures. The procedures are documented and follow operational rules designed to promote system stability and security, and 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 are planning to implement business processes that put greater emphasis on reducing the impact on customers for planned work by ensuring that both we and our contractors have adequately explored alternatives to outages such as live line work, generation support, out or hours or weekend outages to minimise the impact of the outage.

Operational Performance Investigation

The Operational Performance team takes a tactical approach to improving operational performance that focuses on improving information capture and the investigation network events in order to identify root causes and causal factors and to implement improvement actions to drive continual improvement in asset lifecycle and strategy decision making. We will be implementing a network event and major event day investigation and review process. Information capture will be enhanced by improving 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 app has improved our ability to respond to public safety issues and compliance obligations. This fast track delivery process ensures that we respond to issues on our network promptly that can impact on public safety. We are looking at opportunities to improve its functionality and associated process so that we can deliver the best outcomes for our customers through this process.

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 are expanding 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 organisation coverage of CIMS training will enable the organisation to respond more effectively to a significant civil emergency.

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 electric car uptake. In the future distribution network, energy will no longer only flow from transmission networks down to customers. It 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 are planning to implement the mapping and management on the LV network into our ADMS and in time establishing power flow analysis and the ability to manage distributed generation on the LV network.

People Development

We are committed to the further development of our people to ensure that we continue to make the best use of our systems and technology so that we can adapt with 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 skill development is our ADMS and OMS and we will continue to support this by increasing training and internal capability. 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[43]
Network Operations Initiatives	The initiatives support our objective 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 availability to customers.	Short term
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 is a key tool to manage availability to customers.	Short term
ADMS improvement: symbology and alarms Implementing 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 personal	**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.	Short term
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 availability to customers by enabling the impact of faults to be found faster.	Short term
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.	Medium term
Outage scheduling calendar Developing an outage calendar that provides an improved ability to coordinate outages between contractors to minimise the impact on customers.	**Reliability** to defined levels – Having an outage scheduling calendar will help manage availability to customers. **Affordability** through cost management– more efficient use of outage windows should reduce costs.	Medium term
ADMS improvement Transitioning from Poweron fusion to Poweron advantage to maintain system currency and support	**Responsive** to a changing landscape – Ensuring our systems are up to date.	Medium term

43 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[43]
Switching Request Management Implement a switching request management system that will help the business optimise the outage planning calendar and minimise impact to customs for planned work.	Affordability through cost management– Increase efficiency in the outage planning process will reduce costs.	Long term
ADMS improvement Implementing distribution power flow and LV network mapping into the ADMS.	Responsive to a changing landscape – LV network modelling and monitoring will help ensure our network is enabled for future technologies.	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.	Short term
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.	Medium term
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

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.

We currently have a large backlog of preventive maintenance inspections due to historic underinvestment. Completing the 'first pass' of network inspections is paramount to identify defects and to gather or confirm asset information, and this is a key reason for an uplift in preventive maintenance in 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. Increasing preventive maintenance work may increase the number of defects identified (i.e. corrective work) in the short to medium term.

The expenditure in this portfolio reflects preventive maintenance works undertaken by our service providers.[44] 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
- **maintenance standards:** that specify recommended maintenance inspections 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.

44 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.

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[45]
Asset Specific Initiatives	The initiatives support our objective 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 and can appear fine from ground 2) It is harder to get good photos from the ground due to contrast between the pole and sky. Inspections are via camera on a hot. During these inspections we will also gather type information on insulators.	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
Acoustic pole testing triage trial We undertook an acoustic pole test device trial of in 2019 with mixed results - reasonable correlation with Deuar on hardwood poles, but not softwood poles. We have chosen to use an acoustic pole test device as a 'triage' method on hardwood poles in Central Otago that have not been Deuar tested yet, to help get to steady state as fast as reasonably practicable. We see the potential for such a device to be integrated into our test regime in future years	Safety first- Introducing additional triage' testing ensures we are doing all that is reasonably practicable to have all poles tested within a short time frame, helping to prevent further 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.	Short term
Increased maintenance on electromechanical relays While we have a prioritised plan for electromechanical 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.	Short term
Distribution surge arrestor inspections As NERs have been installed on the network, many surge arrestors on the network have become under rated and an increase in failures is being experienced. Many surge arrestors are unvented porcelain which are an explosion hazard in public areas. These inspections are to ensure that no flash overs have occurred, unventilated types are identified, and that the surge arrestor installed is of adequate rating.	Safety first- Unvented porcelain surge arrestors can explode when operating causing a safety hazard – this work will identify and replace those. Reliability to defined levels – Having equipment on the network that is not adequately rated can cause cascade.	Short term

45 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[45]
Low voltage enclosure inspections uplift The historical base level of LV enclosure inspections was inadequate. An inspection routine is required to ensure the condition of these enclosures and the public safety risks are managed. Unique asset identifying labels are being attached to the enclosures during inspections.	**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 and a new steady state reached.	Short term
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.	Short term
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.	**Reliability** to defined levels – Having operable air break switches will help us meet our reliability limits.	Short term
'UnableToTest' pole testing 'UnableToTest' poles 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.	Short term
Consumer-owned pole inspections Inspections are required by the electricity regulations to ensure consumer poles (and conductor) installed pre-1984, are in a "reasonable standard of maintenance or repair" prior to handing ownership back to consumers. Historically this has not been undertaken and we have to attend to any consumer pole failures; it is appropriate that we begin to manage and subsequently formally hand over these assets to consumers with their best interests in mind from a safety and affordability perspective. Many require difficult access/landowner liaison and subsequent vegetation clearance to access the pole for testing.	**Safety** first- Many consumer poles will not have been inspected in a long time, if ever, and hence may are likely to be in poor condition and presenting a failure risk. **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.	Medium term
LiDAR survey Currently we do not have consistent visibility on vegetation and lines clearances. Two yearly surveys will be undertaken 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.	**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

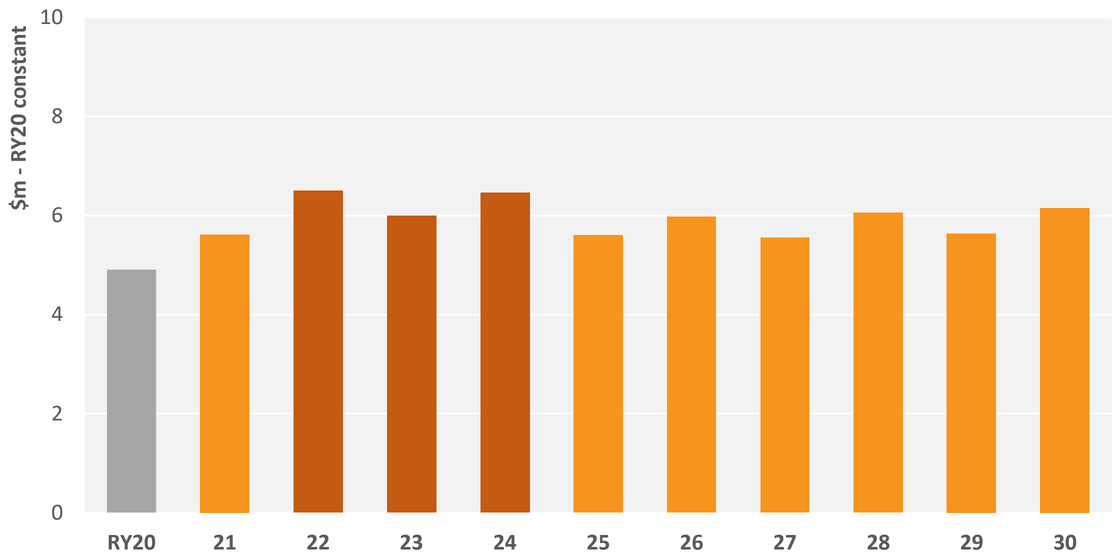
PREVENTIVE MAINTENANCE INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[45]
Survey of distribution conductor At present we do not undertake any detailed, routine conductor survey/inspections. We are noticing an increase in ACSR conductor drops. Investigations have revealed workmanship issues with fittings such as joints and terminations as the primary cause. We will start a routine survey of distribution conductor condition, with a focus on fittings and joint condition and type issues following a recent increase in failures. Inspections will be ground based for the majority, with inaccessible areas or areas not efficiently reached by vehicle or by foot being undertaken from helicopter as per sub-transmission inspections.	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 conductors. Proactive repairs can be managed via planned outages. Affordability by cost management – Proactively finding and subsequently remediating conductor issues is more cost effective than replacing upon failure. Sustainability by taking a long-term view- Confirming the extent of poor workmanship on the network will help us create a plan to ensure this does not continue to occur going forward.	Medium-term
Helicopter inspections of subtransmission lines Current inspection regime is visual assessments of the crossarms and pole top from the ground and no conductor condition survey is undertaken. It is harder to get good photos of pole tops and crossarms from the ground. Higher quality condition information and better photo quality is available when crossarms are viewed from above - crossarms can deteriorate from water damage on top and look fine from below. Pole heads can also rot in the core and appear sound around the diameter. We have experienced more insulator leakage and intermittent fault issues at subtransmission voltage than lower voltages. Corona camera will help identify these problems on the subtransmission network. Infrared camera will also help to pick up overheating issues with joints and fittings. We plan to start this survey on a five-year cycle.	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 subtransmission 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. Helicopter survey allows for large amounts of data to be gathered quickly, by resource that is mostly 'additional' to our main field service providers	Medium-term
Pole mounted distribution transformers inspections Historically we have not gathered detailed condition information on these assets.	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.	Medium term
SF_6 management improvements 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.	Sustainability by taking a long-term view – We want to lift our SF_6 management to best industry practice, given its long term impact on the environment.	Long term

PREVENTIVE MAINTENANCE INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[45]
Non-asset specific initiatives	The initiatives support our objective to:	
Complete 'first pass' of network asset inspections Historical under investment in preventive maintenance has led to a backlog of maintenance and/or inspections in many asset fleets. We will 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 of the preventive maintenance objectives.	Short term
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

The figure below shows forecast preventive maintenance Opex, which is approximately $6m on average per year.

Figure 7.1: Forecast preventive maintenance Opex



Reasons for this uplift are that prior to RY19 we did not complete all our preventive maintenance tasks and in RY20 we started to ramp up and these will now be included in future years. Our proposed maintenance initiatives result in an uplift from RY20, ramping up to reach a steady-state level. The 'saw-tooth' shape of the forecast expenditure is due to our planned two yearly Lidar programme.

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 informing our renewal work
- **reduced cost of works**: planned servicing is generally cost effective relative to unplanned remediation work. Lifecycle costs should be reduced by undertaking an optimal volume of preventive work
- **asset and condition information gathering**: a 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 more 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, well informed asset management decisions can be made to help reduce whole of life costs.

7.4. CORRECTIVE MAINTENANCE

7.4.1. Overview

The corrective maintenance portfolio incorporates planned work arising from 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 carrying it out reactively. 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**: further work undertaken following the initial (first) fault or emergency response 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 excavations by third parties near an underground cable or a crane operating near an overhead line
  - 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.[46] It includes defect rectification, repairs and replacement of minor components to

[46] 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

restore assets to operational condition. Failure to undertake this work increases reliability and safety risks and may shorten asset lives.

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.

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.

7.4.2. Objectives

Our corrective maintenance objectives and the asset management objectives they contribute to are set out in the following table.

Table 7.5: Corrective maintenance objectives

OBJECTIVE AREA	CORRECTIVE MAINTENANCE PORTFOLIO OBJECTIVES
Safety first	Prevent safety risks to our workforce and the public in a timeframe appropriate with the risk.
Reliability to defined levels	Ensure planned outages for corrective maintenance are undertaken considering our reliability performance target. 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, minimising whole of life costs. Undertake work 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 Aurora owned pole fleet health 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.

expenditure does not directly align with ID categories, but rather makes up part of the RCI category together with preventive maintenance.

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 7.6: Corrective maintenance initaitives

CORRECTIVE MAINTENANCE INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[47]
Asset Specific Initiatives	The initiatives support our objective 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 based on historical possum fault locations and fire risk. Cable guards will also be retrofitted to any pole requiring one during the possum guard programme as a safety initiative – timing is convenient with a similar skillet of resources required.	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
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 is Opex even if poles are replaced given 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 be in poor condition and present a failure risk. 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.	Medium term
Rectify backlog of cable corrective maintenance We have identified a backlog of corrective work on our subtransmission oil pressurised cables. Terminations require repair in some cases for leaks, and corrosion control/painting at aerial ends including cable stands. Replacement is magnitudes more expensive and cannot be justified in the near term based on other asset risks that cannot be remediated by lower cost repairs.	Affordability through cost management – These cables have generally been reliable and investing in maintenance now should ensure 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 but also cost perspective.	Medium term
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.	Affordability through cost management – Painting transformers before they pass the point of disrepair reduces overall cost of ownership.	Medium term

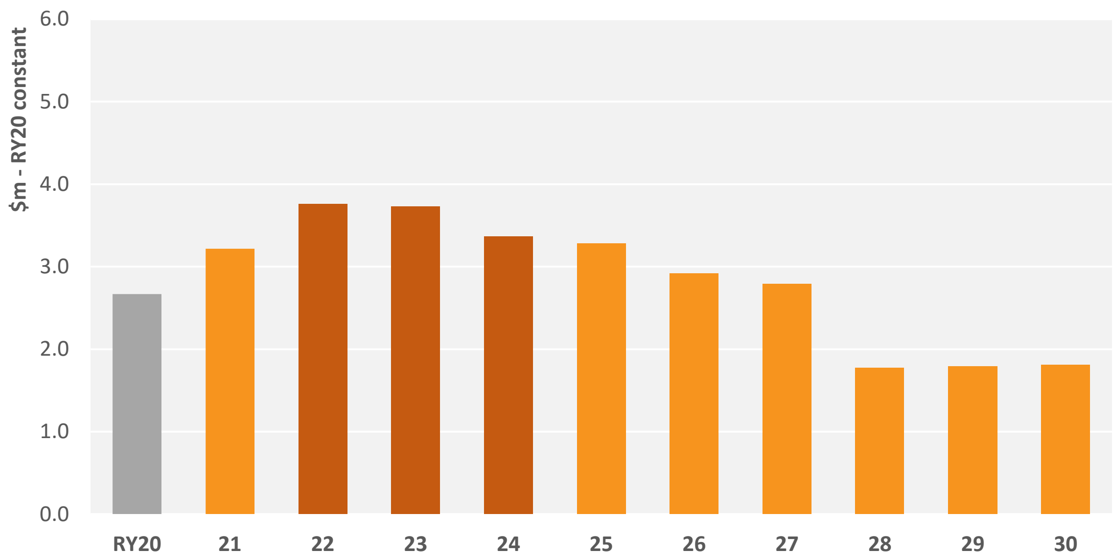
47 When used in this table: short term (underway), medium term (within 1-2 years), long term (within 1-4 years).

CORRECTIVE MAINTENANCE INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[47]
Legacy metal service pillar (LV enclosure) cover replacements A safety risk exists 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. This programme will replace metal covers with plastic covers to mitigate this risk, which is more cost effective than complete enclosure replacement.	**Safety** first- We must remediate a known failure mode in a legacy LV enclosure that does not meet 'safety by design' requirements.	Medium term
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.	Medium term
Distribution assets repainting Equipment repainting helps avoid repairs that can be more costly once past the optimum point of intervention, or worst-case replacement is required.	**Affordability** through cost management – Undertaking remediations on equipment before it passes the point of disrepair reduces overall cost of ownership.	Medium term
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 of our corrective maintenance portfolio objectives.	Medium term

7.4.4. Corrective Maintenance Forecast

The figure below shows forecast corrective maintenance expenditure. Our corrective maintenance expenditure requirement over the planning period is approximately $2.9m on average per year.

Figure 7.2: Forecast corrective maintenance Opex



Reasons for the uplift are that historically we did not complete sufficient corrective maintenance work. We have included non-asset specific step changes to reflect this. Our proposed additional maintenance initiatives result in an uplift of expenditure from RY20 until we complete a number of programmes, we expect to reach a steady-state after the CPP Period. The major step change in corrective work expenditure is the need to remediate poor condition pre-1984 consumer owned poles and conductor as covered in the initiatives section.[48]

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**: reducing unplanned outages will improve the network reliability experienced by our customers. 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 in order 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 and switching in response to an unplanned event or incident that impairs normal network operation. This work is undertaken by external service providers. It 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 impacted by an event, such as where vehicle damage to a pole has resulted in conductors on the ground. Field crews are directed by the control room to undertake switching or isolate damaged network sections by cutting away insecure conductors 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.

48 Consumer owned lines are poles and conductor in private land, generally supplying a single consumer.

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.

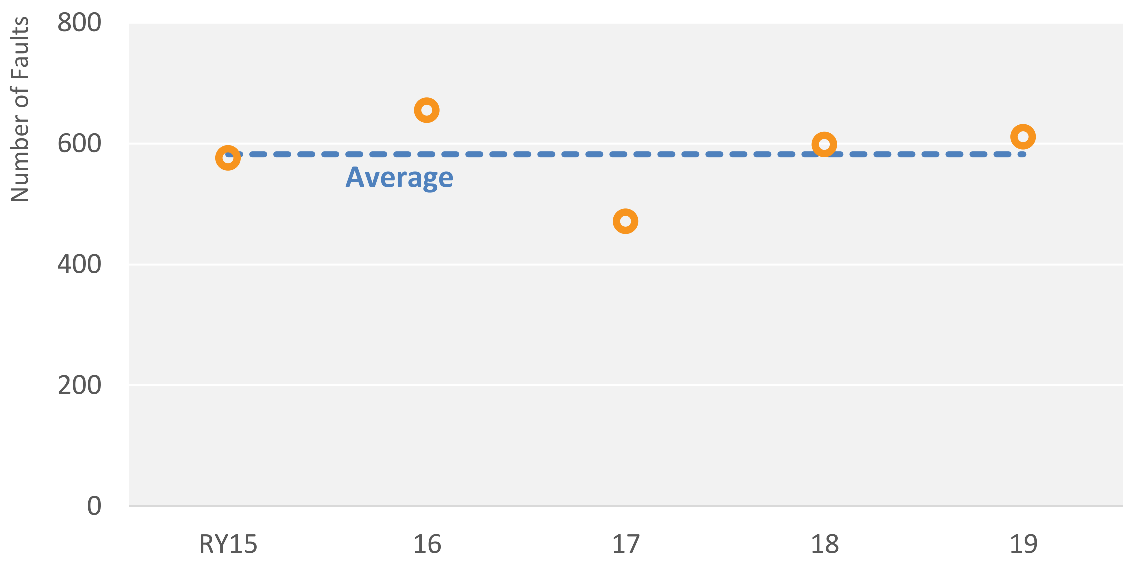
Reactive maintenance work can be challenging due to extreme weather or other severe conditions. Personnel must have a wide range of skills and competencies, and need to be maintained on standby at strategic locations across the network.

The expenditure in this portfolio reflects reactive maintenance works undertaken by our service providers.[49] 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 between RY15 -19. During the last five years we have dealt with an average of approximately 600 faults per year.

Figure 7.3: Historical fault numbers



The number of faults on our network has remained relatively flat. The movements around this trend are the result of a wide range of short (e.g. weather) and longer-term (e.g. asset condition) factors that interact in complex ways. RY17 saw relatively benign weather and therefore a lower number of weather-related faults.

49 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.

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 from different manufacturers have different 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
- **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 7.7: Reactive maintenance objectives

OBJECTIVE AREA	REACTIVE MAINTENANCE PORTFOLIO OBJECTIVES
Safety first	Control fault events and scenes in a timely manner to ensure that they do not cause harm to customers, contractors, members of the public, or cause damage to third party property.
Reliability to defined levels	Ensure fault response is timely to assist with meeting our current network reliability performance targets.
Affordability through cost management	Work with our service provider to identify and monitor efficiency measures and make continuous improvements to processes, procedures and practices to improve efficiency in fault response.
Responsive to a changing landscape	Use technology to assist in fault response and outage minimisation, such as SCADA improvements.
Sustainability by taking a long-term view	Ensure any work undertaken as a fault repair meets network standards and that asset and reactive maintenance data flows back to our systems so we can learn from it.

7.5.3. Reactive 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.

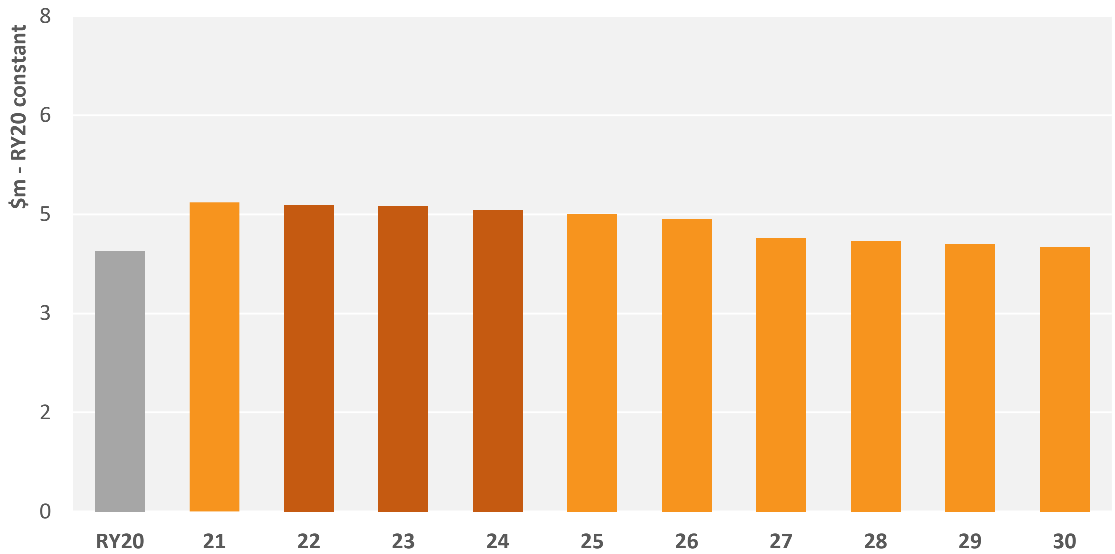
Table 7.8: Reactive maintenance initiatives

REACTIVE MAINTENANCE INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[50]
Asset Specific Initiatives	The initiatives support our objective to:	
Additional fault response Our faults contractor will establish a 24/7 dispatch service to operate and maintain our service and safety needs.	**Reliability** to defined levels - Ensure fault response times minimise impacts on customers and support achieving our reliability targets.	Medium term
Gathering better data from fault events and subsequent investigation process We will implement a mobile data capture solution to enable the collection of information from our contractors and integrate this information with our systems. We will improve our investigations of operational 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.	Medium 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 is approximately $4.4m on average per year.

Figure 7.4: Reactive maintenance Opex



We consider RY20 to be an outlier and expect our future expenditure to be more in line with our historical average. During RY20, we had a similar level of SAIFI to RY19 but higher than normal SAIDI minutes. We continue to investigate the cause of this disproportionate result but note that auto-

50 When used in this table: short term (underway), medium term (within 1-2 years), long term (within 1-4 years).

reclose was disarmed for an extended period in RY20 due to extra dry conditions in late summer. The disarming of auto-reclose (e.g. due to fire danger) tends to lead to a number of 'unknown faults' that are successfully reclosed after a patrol of the feeder, leading to a low cost to restore power when compared with a genuine fault. In general, RY20 had more benign weather than 'normal' and therefore we saw a lower level of reactive spend.

Our expenditure has a decreasing trend due to our expectation that the condition of the network will improve over time and therefore reduce the number of faults requiring reactive maintenance expenditure. We also have a downward trend due to expected efficiency improvements as our asset management approach matures.

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 of the costs attributed to our vegetation contractor to undertake this work.

Vegetation can have a notable impact on network safety and reliability. Trees close to live conductors pose a risk of electrocution to our people and fire in our local communities. Further, such events can result in significant damage to network equipment prompting network outages. On a national level, vegetation is one of the main contributors to unplanned SAIDI and SAIFI performance.

Effective vegetation management ensures that we adhere to relevant regulations, namely the Electricity (Hazards from Trees) Regulations 2003 which establish the rights and responsibilities for network owners regarding vegetation that encroaches overhead lines.

Our historical approach was largely reactive, responding to issues as they are identified by line inspections, notification, or after faults. We are moving to a more proactive, cyclical approach which will give us better visibility of the status of vegetation around lines, enabling us to take appropriate actions to minimise risk.

Key Drivers

The key expenditure drivers for the portfolio are:

- to provide a safe network for the public, our staff and contractors
- compliance with the Tree Regulations
- to reduce the risk of vegetation related events damaging network equipment
- to provide a reliable network for our customers, while meeting the 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. This includes that after an initial cut or trim, tree owners are responsible for maintaining their trees to keep them clear of our network. Our contractor liaison staff identify trees that need cutting and issue appropriate notification to tree owners. If tree owners fail to act, we are obliged to trim the trees to remove any danger. The regulations require that breaches of minimum clearance distances be corrected within a prescribed time. Where the tree owner chooses not to take action and we have provided notification to the requirements set out in the regulations and it is at least the second cut, we pass 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 are a large contributing factor to vegetation related faults. A more proactive approach to vegetation management will enable us to reduce the reliability impacts of vegetation encroaching on our assets.

7.6.2. Objectives

Our vegetation management objectives are set out in the following table.

Table 7.9: Vegetation management objectives

OBJECTIVE AREA	VEGETATION MANAGEMENT PORTFOLIO OBJECTIVES
Safety first	Minimise vegetation-related safety and environmental risks (e.g. fires). Improve education around risks associated with vegetation near conductors.
Reliability to defined levels	Reduce the risk of vegetation related events damaging network equipment to reduce 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. Incur less expenditure due to vegetation related faults.
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, addressing the current backlog of ‘first cut’ and avoid a backlog of routine second cut vegetation work. 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 7.10: Reactive maintenance initiatives

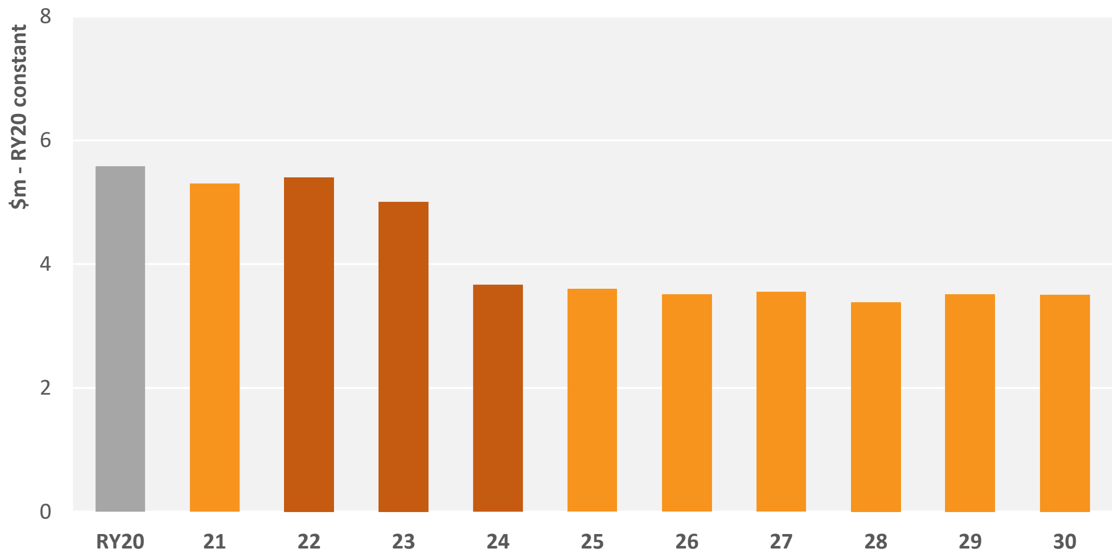
VEGETATION MANAGEMENT INITIATIVES	ASSET MANAGEMENT OBJECTIVE AREAS	TIMEFRAME[51]
Non-asset Specific Initiatives	The initiatives support our objective to:	
Move to proactive/cyclic tree trimming approach We have developed a cyclical trimming programme and implementation is underway. We will continue to review and adjust our 5-year routine cycle to optimise efficiency, such as assessing the level of risk presented by different areas.	**Safety** first - Ensuring that that vegetation around our network is well managed minimises safety and environmental risks. 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.	Medium term
Consideration of a risk-based work programme We will assess the need for a risk-based work programme to manage fall zone and hazardous trees (outside of the routine maintenance cycle).	**Safety** first- this will help ensure that that fall risk vegetation around higher risk areas is prioritised.	Long term
Improved asset management systems We will establish a vegetation management system to drive analytics, identify information gaps and create efficiency opportunities. Includes developing tools to enable historic agreements and easement data to be made available to field liaison personnel.	**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, reducing costs. **Responsive** to a changing landscape – system will be used to improve efficiency. **Sustainability** by taking a long-term view – Better works coordination will reduce landowner disruption.	Long term
Develop and deliver an improved communications programme To make tree owners aware of the safety issues and their responsibilities regarding trees.	**Safety** first – improves education around risks associated with vegetation near conductors. **Affordability** through cost management – reduces expenditure as landowners are more aware of their responsibilities.	Medium term
LiDAR survey Currently we do not have consistent visibility on vegetation and lines clearances. Two yearly lidar on the network will be undertaken 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

51 When used in this table: short term (underway), medium term (within 1-2 years), long term (within 1-4 years).

7.6.4. Vegetation Management Forecast

The chart below shows our forecast vegetation management Opex. Our vegetation management expenditure requirement over the planning period is approximately $4.2m on average per year.

Figure 7.5: Vegetation management Opex



We have a higher level of expenditure planned until RY23 to cover our 'first cut' cycle of vegetation management. We will reach a steady state 5-year management cycle in RY24

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 conductors
- **affordability**: improved efficiency by doing less reactive, and more planned cyclic work, leading to a faster completion of first cut and an associated fall in vegetation management costs in the future.

8. RENEW OR DISPOSE

This chapter describes how we manage assets at the end of 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.

This chapter describes our asset fleets in detail including a fleet overview, commentary on population and age and then condition performance and risk, prior to discussing strategies that inform our planned renewal expenditure over the AMP planning period.

Focusing on our asset fleets, it sets out specific details on other activities we undertake, for example details of maintenance approaches. It sets out our planned renewal Capex for the AMP planning period.

Points to note on the content in this chapter are set out below.

- all technical and quantity statistics are as of 31st March 2019 (unless specified otherwise)
- for explanations of modelling approaches including our definitions of 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. In each section we indicate how these relate to Information Disclosure categories.

Update on WSP risk review

For each of our portfolios we provide an update on our progress addressing the finding of the WSP report. These updates include a brief description of the issues raised by WSP, how we are responded to their findings, and expected timing for the issue to be addressed.

Please note we will be publishing an annual progress report in late July 2020. This will set out more detailed information on WSP-related work completed in RY20.

8.1. SUPPORT STRUCTURES

This section describes our support structures portfolio[52] 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.

During the planning period we expect to spend an average of $15m per annum on support structures renewals with expenditure declining from a peak of $19.7m in RY23 to $10m in RY30.

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. Combined with overhead conductors, they make up our overhead network that connects customers to the transmission system and enables electrical flow at various voltages. Support structures also support distribution transformers, air break switches, and third-party assets such as streetlights, communication assets and road signs.

Adequate performance of these assets is essential to maintain a safe and reliable network. 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: Update on WSP Review – support structures

Issues: risks identified by WSP included significant quantities of poles and crossarms past expected life, and incomplete or inadequate asset inspection data. WSP also stated there were Malaysian hardwood crossarms on the network which were thought to present an increased risk of failure.

Response: continuing elevated level of pole replacements, based on condition and prioritised by public safety criticality to manage failure risk. We will begin a standalone crossarms replacement programme. Following a review of data, subject matter expert knowledge, and forensic testing it is unlikely the network has material quantities of Malaysian hardwood crossarms. 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 RY24, while crossarm renewal will continue at elevated rates for the planning period. We have completed our planned wooden pole (and associated crossarm) inspection milestone in Dunedin, now focusing on concrete poles (and associated crossarm inspections). In our Central region we expect to reach the same milestone later in RY21.

52 All support structures capital expenditure is covered under the Asset Replacement and Renewal information disclosure category; line items 'Subtransmission' and 'Distribution and LV lines', and will be included in Schedule 11a(iv) in Appendix B.

8.1.1. Support Structures Portfolio Objectives

Portfolio objectives guide our day-to-day asset management activities and are listed below.

Table 8.1: Support structure portfolio objectives

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

We have approximately 54,000 poles across our network regions, primarily wood and concrete, with approximately 980 steel poles and a small number of lattice towers across the Otago Harbour. Our support structures carry conductor operating at all of our network voltages.

Historically, we fell behind the level of renewals required to manage the health of our pole fleet. In response to this, up to March 2020 we had remediated ~11,000 poles since RY17. We plan to maintain an elevated level of renewals until a steady state is achieved (forecast for RY24).

Concrete poles

We have two types of concrete poles 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. Pre-stressed poles are relatively robust against common concrete pole failure modes, e.g. cracking and spalling.

Mass reinforced concrete poles contain reinforcing steel bars covered by concrete. They were regularly used from the 1960s to 1980s, but infrequently since that time. 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, allowing water ingress which eventually leads to corrosion of the steel bars. Mass reinforced poles are still relatively robust even with exposed reinforcing, so even once reinforcing is exposed it will not drive replacement of the pole unless it is in a key area or involves 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. There is no single method to reliably assess all aspects of the condition of wood poles. The wide natural variances in timber strength result in performance variations.

We have a number of hardwood varieties in use on our networks, which have been installed throughout the last century. In some cases, the species is unknown, and performance varies by species, as well as by location. Failure or defect modes include loss of cross section due to below ground rot, splitting through the body, and split heads.

Softwood poles are generally pine that has been treated with copper chrome arsenic (CCA). These poles are lighter and lower cost than other types. However, many were historically installed in situations not suitable for their strength characteristics[53], and they are also prone to significant vertical cracking in our Central network region as a result of significant temperature and moisture changes. We have not widely installed them on our network in recent years.[54]

[53] Hence they tend to fail our test regime on inadequate design strength rather than significant condition based deterioration.

[54] Our current policy allows for softwood poles to be used only as service poles or where access limitations require a pole be physically carried to site (given their lighter weight). Lightweight steel poles are generally preferred

Over the last three years we have reinforced poles as a risk mitigation strategy, due to a historical underinvestment in poles leading to unacceptably high failure risk in this fleet.[55] We do not plan to reinforce poles in future. Reasons include that reinforcement guarantees a strength of the pole but not the foundation, and that we do not have suitable volumes (in hand) or forecast of reinforcement candidates to consider an ongoing programme of works. Reinforcement also does not mitigate all risks such as pole head defects or leaning poles due to poor foundation, and will not be economic in many cases where poles have other defects such as a crossarm requiring replacement.

We no longer use wooden poles in the construction of new network or for significant network rebuilds. We use them on the existing network for one-off replacements, only where specific strength properties are required and a steel pole isn't suitable due to location.

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 also have a number of steel lattice towers that we include in this category.

Figure 8.2: Example of a steel pole

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 where certain strength characteristics (more strength in multiple directions) are needed. However, the use of steel around other infrastructure must be taken into consideration due to Earth Potential Rise (EPR) and transferred voltage issues. It is also difficult to assess corrosion on the inside of steel poles and below ground. Our current approach is to use them only in limited circumstances.

55 Our reinforcement approach involved installation of a steel truss driven deep into the ground next to the pole and secured with metal banding, as opposed to reinforcing attached to the pole by drilling into the pole

Population and Age

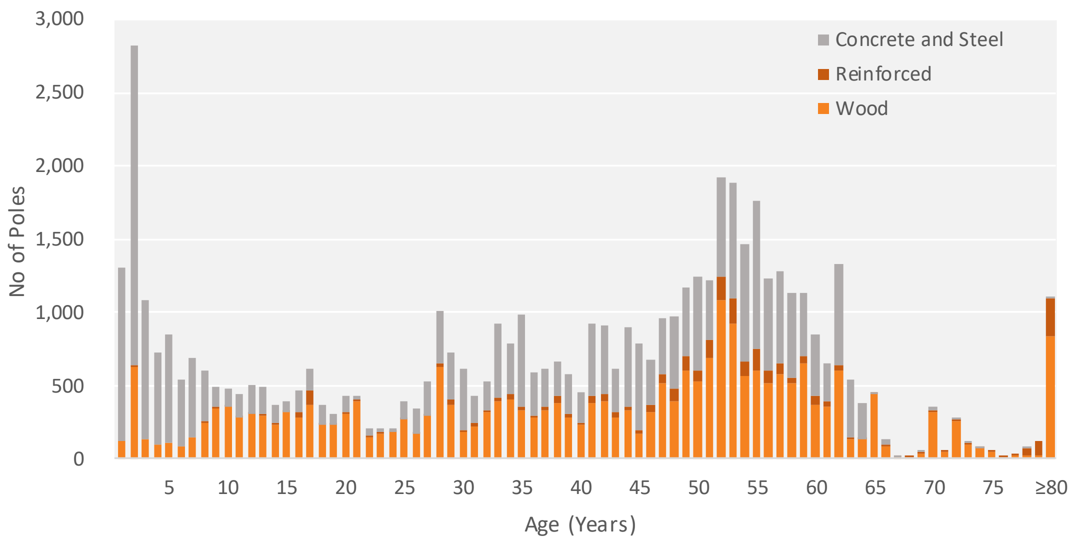
The table below summarises our population of poles by type. Wood poles currently make up just over half of the pole population. Given the wood pole age profile, we will be making a large investment in replacing them over the planning period.

Table 8.2: Pole population by material type

TYPE	POPULATION	PERCENTAGE
Wood	27,795	51%
Concrete	25,297	47%
Steel	976	2%
Total	54,068	100%

The chart below shows that a number of hardwood poles have exceeded, or soon will exceed, their expected life of about ~50 years[56]. Few concrete and steel poles have yet exceeded their 75 year expected lives. The average age of our concrete poles is ~34 years. The impact of our Fast Track Pole Programme (FTPP) is also evident. Under this programme we remediated approximately 8,700 poles in the RY17 to RY19 period.

Figure 8.3: Poles age profile



Many of the oldest wood poles on our networks are expected to be replaced as part of a project to reconductor the Waipori circuits in the early part of the planning period. 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 conductors on the ground (or with reduced

56 Estimated from our wood poles survivor curve, which is informed by historical data.

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 occurring when an asset with an existing defect is placed under stress. An example of this is when a failure occurs during heavy snow or high wind conditions – the adverse weather is not the root cause of the failure, but rather the defect is. 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 operate and maintain section below. We have yet to complete a full cycle of testing under the current testing regime, the fundamentals of which have been in place since 2017. Approximately 20% of our wood and 90% of our concrete poles remain to be tested in this regime. This must be completed as soon as practicable to ensure we have a full condition view of our pole fleet.

We have prioritised testing of wood poles over concrete because wood poles have a higher probability of failure, based on our historical data and industry experience.

Despite not recently inspected the majority our concrete and steel pole fleet, we expect them to be in good condition. We have not historically experienced unforced failures of these pole types.

With widespread concrete pole inspections ramping up over the next two years, we may identify a 'hump' of spalling mass reinforced concrete poles requiring remediation. In general, these are a lower priority for replacement than the backlog of poor condition wooden poles, due to the historical lack of unforced failures of concrete poles.

Based on condition data, as of 31 March 2019 we had a backlog[57] of ~2,100 poles awaiting replacement (nearly all wood). This included poles that failed our test and/or inspection requirements, warranting replacement within a period of up to 24 months, together with defected poles assessed as being in adequate structural condition, but which suffer from a significant split in the top of the pole.[58] Therefore, this backlog of poles includes red tagged poles, orange tagged poles, and other poles that have neither of those tags affixed. Despite having undertaken a large volume of replacements over the past few years, the number of poles in our backlog remains similar to, or slightly higher than in the past, although the number of high-risk red tagged poles is significantly less. There is still an unacceptable level of risk in our pole fleet which will only be fully addressed once the first round of testing is complete and all poor health poles have been remediated.

Meeting our portfolio objectives – safety first

Poles are replaced proactively based on condition information, aiming to mitigate safety risks above all other considerations.

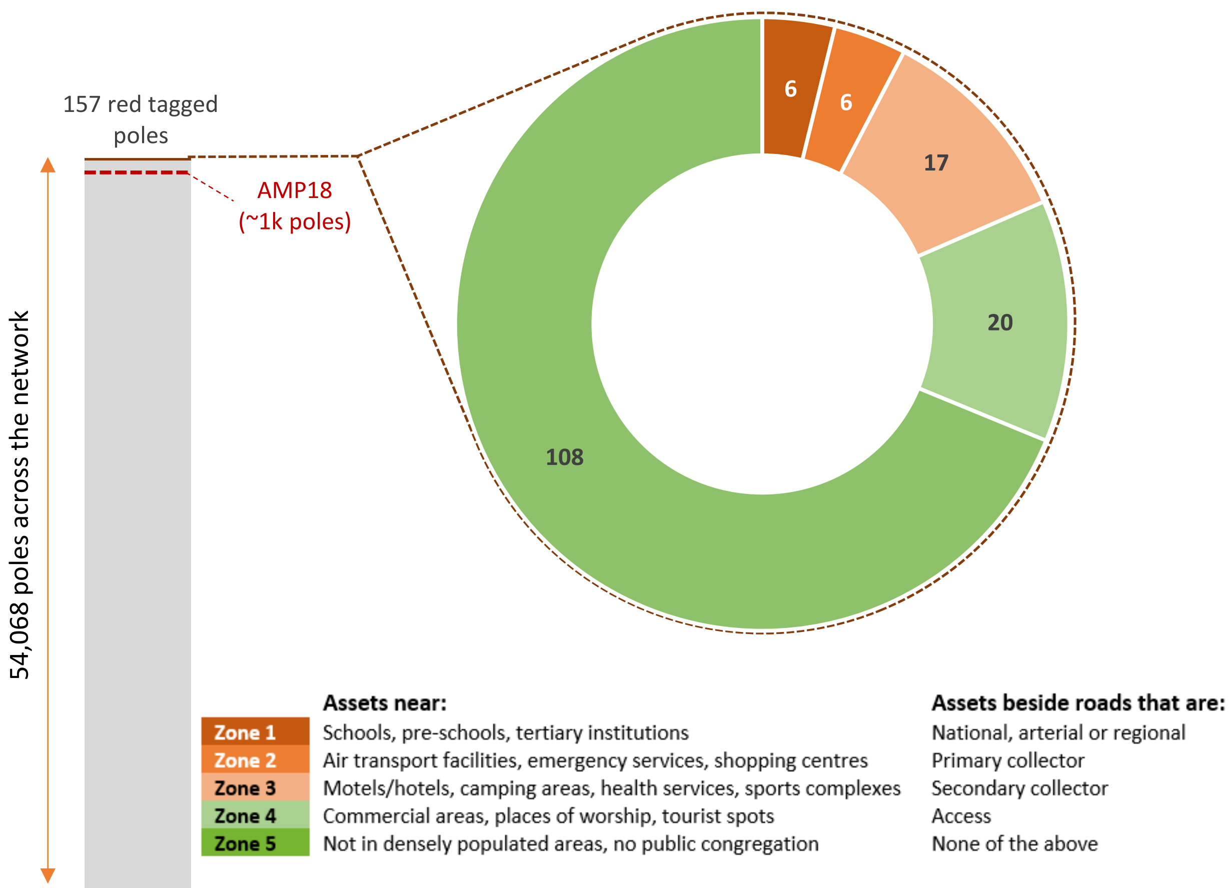
57 We have identified end of life poles faster than we have been able to remediate them, resulting in a backlog.

58 If the split extends near to or past where the crossarm is attached, and if the crossarm cannot be lowered to a level not affected by the split without breaching regulated clearances, the pole must be replaced. Otherwise a repair may be feasible.

In AMP 2018 we noted that addressing overdue red-tagged poles in high criticality areas was our urgent priority. At that time, we had ~1,000 red-tagged poles on the network. The figure below shows red-tagged poles as of *8 May 2020*; a quantity of 157, the majority of which are in lesser public safety criticality zones. Out of these 157 red tagged poles, 141 are wood and 16 are concrete. These statistics show that we have made significant progress towards addressing our red tag pole problem.

In clearing the 157 remaining red tagged poles, we are prioritising remediations by public safety criticality zone to ensure the poles that present the highest public safety risk are addressed first.

Figure 8.4: Red tagged poles by criticality zone (as of 8 May 2020)



Box 8.2: Pole remediation targets

We have set the following targets for statutory compliance with red and orange tag pole remediations:

- Red tag remediations as per statutory requirements (90 days to remediate) by June 2020
- Orange tag remediations as per statutory requirements (12 months to remediate) by March 2021

We have set a target to be compliant with our draft internal support structure remediation risk framework by July 2021. This ensures that we perform above statutory requirements where justified from a risk management perspective. Examples include replacing an orange tagged wooden pole outside a school in much less than 12 months.

Meeting our portfolio objectives – safety first

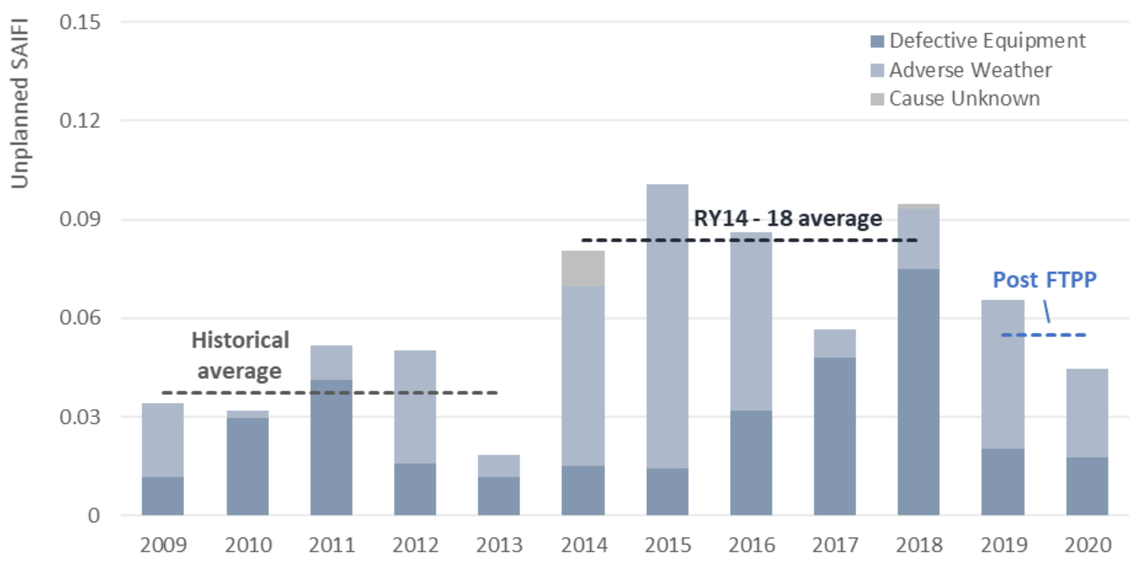
These targets are key to help us strive towards meeting our safety first portfolio objectives of: No fatalities from unforced support structure failure in either everyday operation or during climbing by our contractors; and a downward trend in unforced, condition-driven pole and crossarm failures.

Performance

Poles by their nature, create risks to public and personnel safety. We design poles with the strength to handle defined environmental conditions such as wind and snow loadings on conductors. While unlikely on poles designed to current standards and properly installed, failures may still occur

We do not have adequate historical data to accurately differentiate pole failure root causes. Using (un-normalised) SAIFI attributable to poles as a proxy for pole failures provides a useful measure of performance. The chart shows increasing pole related SAIFI, prior to the FTPP programme.

Figure 8.5: Poles failure unplanned SAIFI trend



Pole failures have increased since 2013, mainly attributed to 'adverse weather'[59]. The average number of failures over the RY14-18 period is higher than historical averages. However, we have seen a reduction in failures in the period post FTPP. This may indicate that failures are beginning to decline but given the age profile of our poles and known backlog of poor condition poles, it is important that we maintain the momentum to return our assets to a satisfactory state.

We do not have any 'unforced'[60] concrete pole failures on record and we are committed to capturing better failure data going forward.

59 'Adverse weather' as a failure mode is currently not well defined and in most cases the weather conditions would not exceed the design criteria.

60 Unforced means that the pole failed within its design criteria and without third party or vegetation involvement.

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 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

Current practice is that if new conductor is being applied to any legacy concrete pole, engineering assessment is undertaken to consider if the load change is acceptable on the pole. We know these poles can safely carry their working load (as they have been in service many decades without unforced failure) and so if no or negligible additional load is created by new conductors then we deem the continued failure risk of that pole acceptable. Our legacy concrete pole investigation will determine the appropriateness of recent practice and enable better informed future decisions.

Meeting our portfolio objectives – Responsive to a changing landscape

This improvement initiative will help us meet our responsiveness portfolio objective by assisting us to predict the effects of an increasing occurrence of adverse weather events.

Asset health

We estimate fleet asset health for wood poles primarily on the basis of age[61] and expected 'survivorship'. (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 proportion of poles have historically 'failed' by a certain age.[62] 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. 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.

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[63] but also reflects that they are an ageing population.

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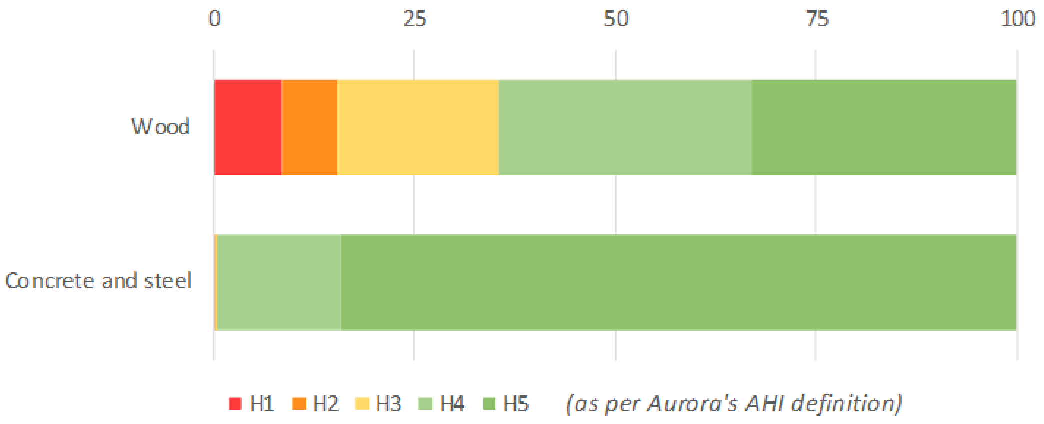
[61] As discussed, the majority of our wood poles have been inspected however their condition assessment results are not granular enough to be useful for long term forecast projections. As such, their expected survivorship in relation to age is used instead.

[62] '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.

[63] 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.

Figure 8.6: Pole asset health



Our asset health analysis indicates that we need to replace approximately 15% of our wood pole fleet over the next three years, and one-third over 10 years to appropriately manage the health of the fleet. Failure to replace these poles will likely expose our field staff and the public to an unacceptable level of safety risk. We expect to eliminate the backlog by RY24, even with additional poor condition poles entering the replacement pool during that time.

Risks

The table below summarises key risks we have identified in relation to our poles fleet.

Table 8.3: Pole risks

RISK/ISSUE	TYPE	RISK MITIGATION	MAIN RISK
Pole failure due to lack of embedment depth (whether when climbed or not).	All	Visual inspections, proactive replacement	Reliability
Vermin strike	All	Possum guard and stay wire retrofit	Reliability
Pole cannot be tested; condition cannot be determined during normal test routine.	All	Focused programme testing inaccessible poles, using traffic management, vegetation clearance, landowner liaison.	Safety
Unassisted wooden pole failure due to poor groundline condition (due to decay) or inadequate pole strength for design loadings.	Wood	Deuar and traditional inspections and proactive replacement of poor condition poles. Fit for purpose design standards.	Safety
Legacy concrete pole failure in high load scenarios (e.g. storm – potential lack of resilience) – not experienced prior.	Concrete	Traditional inspections and subsequent proactive replacement of poor condition poles. Concrete pole break testing to verify strengths and action accordingly.	Reliability
Assisted pole failure (pole fails outside design conditions e.g. extreme weather or third-party incident such as car vs pole, vegetation onto line causes pole failure).	All	Network planning considers electrical resilience of the network. Contingency planning in advance to shorten recall times. Vegetation management plan.	Safety
Vehicle collision risk or historical incidents are high due to pole location.	All	Poles more resilient to collisions, relocating pole, undergrounding spans	Safety
Guy wires fail (due to age-related deterioration etc.) reducing pole loading capability and increasing propensity to fail.	All	Visual inspections, replacement or repair of guy wires as necessary	Safety

Although we have carried out a substantial number of pole renewals in recent years, the backlog of pole replacements remains larger than our long-term sustainable level, as discussed above, and continued accelerated renewals are required to reduce this risk.

Design and Construct

When overhead line works are being undertaken, design is necessary to ensure the new asset complies with our design and construction standards (which in turn comply with external rules and standards such as AS/NZS 7000 – Overhead Line Design). In the case of replacing a single pole, this analysis will not attempt to bring all neighbouring poles up to modern standard, but the pole installed will have at least the capability (often better) of the pole it is replacing.

Design studies for reconductoring projects consider the impact of modern standards on all poles on the line section to be reconductored. This often identifies poles that are in 'good' condition but are understrength for the proposed loadings, especially in the case of angle and termination poles. This is due to changes in design loadings and assumptions relative to legacy standards and methods, plus a more rigorous design approach, made possible by the use of modern software-based design tools.

Pole design considers the location of the pole and the implications of the material type on safety and lifecycle costs. Our preferred pole type considering lifecycle management and upfront cost is a pre-stressed concrete type and therefore most new poles installed on our network are pre-stressed concrete. In some circumstances we use lighter-weight steel poles; for example where a pole needs to be installed using a helicopter in a remote location or an area with difficult access, or a custom high-strength pole is required (often for subtransmission, gorge or river crossings). The use of steel poles requires careful consideration of EPR, possibly causing step and touch potential issues. Wooden poles are installed in limited circumstances where these are the most effective solution due to the forces on the pole or where impact resistance is required. Wooden poles, like steel poles, are equally strong in every direction, but are better suited to corrosive environments or where impact strength is a consideration. Historical incidences of car vs pole and likely risk of future car vs pole are considered in pole placement and material choice through our safety in design process.

Box 8.4: Improvement Initiative – overhead network design software package

We plan to investigate the use of an overhead network design software package. Unlike our current design software which only considers isolated poles or sections of line, there are now software packages available that can load the entire distribution network using sources like our GIS system and LiDAR information. Real world conditions can be entered into this software (e.g. clearances, undulating terrain), allowing mass sensitivity analysis over the whole network to different conditions such as wind, ice and snow and consideration of performance against a range of different design standards.

The potential benefits include:

- better quality and more efficient design
- scenario and sensitivity analysis
- reduced design time and hence cost
- higher confidence in design accuracy and hence reduced rework for conditions found on site
- ability to target resilience improvements in the overhead network to get the most cost efficient resilience investment.

Meeting our portfolio objectives – Responsive to a changing landscape

Overhead network design software would support our responsiveness objective by assisting us to predict the effects of adverse weather events when planning new support structure design and installation.

All support structure network Capex delivery is outsourced to our field service providers, the majority of which is covered by an FSA. Pole replacement design is often outsourced to these service providers; however, 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 in house quality assurance staff who audit contractor's completed works.

We do not foresee any specific deliverability issues in relation to this portfolio as overall expenditure is roughly equal to or lower than recent years.

Operate and Maintain

Preventive maintenance

We undertake little to no invasive preventive maintenance work on poles. Poles are durable, static, and do not require routine mechanical or electrical maintenance work. We inspect and/or test poles on a periodic basis. It is essential to regularly inspect all poles because they may be damaged or compromised by a third-party action, age, poor ground conditions or land movement.

The detailed inspections regime for each type of pole is set out in our maintenance standards and manufacturer documentation supporting the test regime and mobile applications.

Table 8.4: Pole preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY STATE FREQUENCY
Pole test and visual condition inspection including crossarms: – for wooden poles, a Deuar test is default with a traditional test only undertaken if a Deaur test is infeasible (due to pole access issues) – for concrete or steel poles, a visual inspection is undertaken. Digging is required only if corrosion is sighted at the groundline.	Five yearly

The five yearly inspection frequency is based on the legislated time period under NZECP34:2001 for inspecting electricity conductor span clearances. We are currently in the first cycle under our testing regime introduced in 2017, with approximately 20% of our wood and 90% of our concrete poles remaining to be tested in this regime.

Meeting our portfolio objectives – sustainability by taking a long-term view

We currently have a backlog of poles to test, and once this first sweep of the network is completed we will transition into a more structured five-year feeder-based cycle. We also have some poles that have not been tested in such a time period that vegetation clearance is required to access the pole for testing. In future we will consider testing some sub-populations of poles more often – a risk-based approach, e.g. based on age, type, or location.

We have chosen for now to not actively test poles aged 5-10 years. This decision was made to ensure that we clear the backlog / first network sweep on higher risk poles as fast as possible. With our current environment of non-compliance with pole remediations which we are in the progress of addressing as soon as reasonably practicable, we may not strictly comply with the legislated time period for inspecting conductor span clearances related to these poles (5 yearly).

Box 8.5: Pole testing targets and risk based testing approach

We have set the following targets pole testing:

- all Aurora-owned wooden poles greater than 10 years old inspected prior to March 2021
- all Aurora-owned concrete poles greater than 10 years old inspected prior to June 2021

A risk-based approach has been used to identify (and test) highest risk poles first. This takes into consideration historical pole test results, pole material type, and public safety criticality zone. Remediation of higher risk poles is therefore also prioritised.

Meeting our portfolio objectives – affordability through cost control

Our risk-based approach to pole testing and remediation, with the remediation approach being the lowest overall cost option on a case by case basis, ensures we are meeting our affordability objectives by providing maximum value from investments.

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, including both visual assessment and physical testing for structural integrity.

The nature of wooden poles makes inspections difficult, as deterioration is typically internal and/or below ground. Testing techniques, such as drilling, can weaken poles and allow moisture ingress, which accelerates deterioration. Modern inspection techniques can identify most poles in poor condition, but no method is fool proof. We are in the process of expanding our inspection regime to include pole-top inspections of poles and crossarms using a camera on a hot stick. This will improve the quality of condition data on these aspects of poles and crossarms. We are also trailing acoustic pole testing and considering long term how this may potentially be integrated into our wooden pole test framework. We continue evaluate condition assessment techniques for wooden poles, verifying our existing test approaches, and undertaking forensic activities.

The climatic conditions in our two network regions are significantly different. We observe more issues with wood rot in Central and hence the first stage of our wood forensics investigation is occurring there. The reason for more rot issues in Central may include historical use of inferior (and possibly second hand) poles, low water table and large temperature fluctuations.

In the medium term we plan to undertake destruction testing of wooden poles to verify our confidence in our test regime. As per the wood forensics investigation, a range of condition grades will be tested to verify confidence in the test regime through all condition grades. This investigation will also consider the destructive testing of reinforced poles.

Box 8.6: Improvement Initiative – wood forensics and destructive testing

We forensically test poles removed from service to assess actual condition, species, and degree and type of rot to improve our understanding of degradation. Poles chosen for this analysis undergo a range of tests including Deuar and acoustic tests, and are a range of condition grades. This provides a fair sample across the population helping us to understand how each test regime responds and how accurate it is.

Meeting our portfolio objectives – sustainability by taking a long-term view

We will verify our pole testing methods via forensic inspections and destructive testing by end of RY22.

To improve our asset management approach, we have identified preventive maintenance initiatives to improve our performance in the 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. Given our historical underinvestment 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 yet fully embedded in our practices.

Table 8.5: Pole preventive maintenance initiatives

PREVENTIVE MAINTENANCE INITIATIVE	RELATED SUPPORT STRUCTURES OBJECTIVES	TIME FRAME
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. We are introducing inspections via camera on a hot stick to our pole testing regime. During these inspections we will also gather type information on insulators.	Safety first – aerial inspections may find 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 – the use of different technologies will provide increased data quality and allow for better asset management decisions.	Short term
Acoustic pole testing triage trial We have chosen to use an acoustic pole test device as a 'triage' method on ~2,900 hardwood poles in Central Otago that have not been Deuar tested yet, to help get to steady state as fast as reasonably practicable. We see the potential for such a device to be integrated into our test regime in future years – possibly as either an embedment depth check and/or use on younger poles that don't need loading checks as they have been adequately designed.	Safety first – introducing additional 'triage' testing ensures we are doing all that is reasonably practicable to have all poles tested within a short time frame. Responsive to a changing landscape – using different technologies serves as an opportunity to have a more specific and targeted test regime for different tests. Affordability through cost management – use of lower cost technologies where appropriate will reduce inspection costs.	Short term
'*UnableToTest'* pole testing *'UnableToTest'* poles are those flagged through our test regime that cannot be tested as originally planned. To complete the test requires additional 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.	Short term
Consumer pole inspections The electricity regulations require inspections of all consumer poles installed prior to 1984 to ensure consumer poles (and conductor) installed pre-1984, are in a "reasonable standard of maintenance or repair" prior to handing ownership back to consumers. Many require difficult access/landowner liaison and subsequent vegetation clearance to access the pole.	Safety first – many consumer poles will not have been inspected in a long time, if ever, and hence may be in poor condition, presenting a failure risk. Sustainability by taking a long-term view – it is in the long term interests of consumers for us to assess consumer poles.	Medium term

PREVENTIVE MAINTENANCE INITIATIVE	RELATED SUPPORT STRUCTURES OBJECTIVES	TIME FRAME
Helicopter inspections of subtransmission lines (including pole tops and crossarms) Current inspection regime is visual assessments of the crossarms and pole top from the ground and no conductor condition survey is undertaken. Higher quality condition information and better photo quality is available when crossarms are viewed from above – crossarms can deteriorate from water damage on top and look fine from below. Pole heads can also rot in the core and appear sound around the diameter. Infrared camera will also help to pick up overheating issues with joints and fittings.	**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 subtransmission network is paramount given 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.	Medium term

Corrective maintenance

Corrective maintenance on poles is fairly limited as the pole itself cannot generally be remediated via operating expenditure. The only part of the pole that can potentially be corrected as maintenance is the pole head. Pole-top corrective maintenance options include:

- cutting the split head off the pole (sometimes lowering the crossarm attachment point if modern clearances can be complied with)
- repairing the pole with an epoxy and wrap solution (where cost effective on large pole substations that otherwise have remaining useful life. This approach is currently under trial)
- shaving the pole head and fitting a pole cap.

All these actions help prevent the pole rotting or splitting down to where the crossarm is mounted – which would then require replacement of the pole.

When poles are accessed for other works, we retrofit pole caps to wooden poles if they are not present, to prevent or slow degradation of wooden pole heads. Possum guards are also retrofitted via a targeted programme as discussed below.

A large focus of corrective maintenance on poles, going forward, will be replacement and/or repair of consumer owned poles.

Table 8.6: Corrective maintenance initiatives – poles and crossarms

CORRECTIVE MAINTENANCE INITIATIVE	RELATED SUPPORT STRUCTURES 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. Cable guards will be retrofitted to any pole requiring and lacking one found during the possum guard programme as a safety initiative – timing is convenient with a similar skillset of resources required.	**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

CORRECTIVE MAINTENANCE INITIATIVE	RELATED SUPPORT STRUCTURES OBJECTIVES	TIME FRAME
Consumer pole and line remediations Following inspections of consumer poles (as discussed in preventive maintenance initiatives), remediations need to be undertaken as required on all 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.	Safety first – many consumer poles will not have been inspected in a long time, if ever, and hence many are likely to be in poor condition, presenting a failure risk. Sustainability by taking a long-term view – it is in the best long term interests of consumers if we remediate consumer poles that are not in a 'reasonable standard of maintenance or repair' prior to handing their ownership to consumers.	Medium term

Reactive maintenance

Reactive maintenance on poles includes dealing to faults when poles fail such as in storms or due to 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.

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.

Renew or Dispose

We renew poles primarily on the basis of asset condition and defects. We also replace a number of poles through our reconductoring programmes. Replacing overhead conductors, whether the driver is renewal or growth, requires design reviews to ensure design standards continue to be met. This often identifies poles that, although in reasonable condition, must be replaced for strength reasons.

Table 8.7: Summary of poles renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Proactive condition-based, prioritised by criticality Reconductoring projects (forecast under overhead conductor portfolio or growth portfolio) Reactive (e.g. third-party damage rendering the pole unserviceable, severe weather event)
Forecasting approach	Survivor curve (wood poles) Age-based model (concrete and steel poles) Planned reconductoring projects (forecast under overhead conductor portfolio)
Cost estimation	Volumetric; historical average unit rate covering pole mounted equipment replaced with the pole, when pole is in poor condition

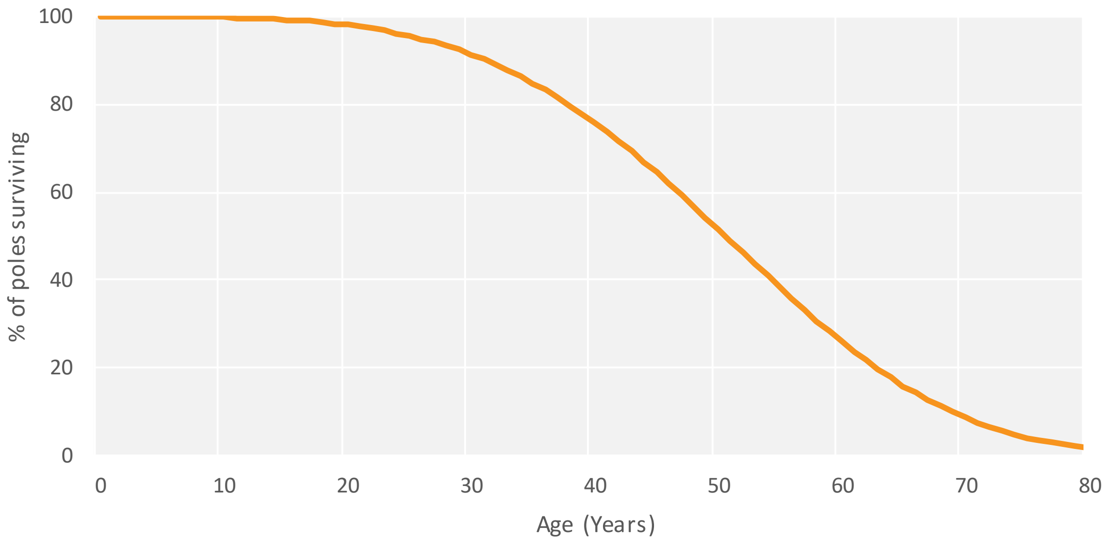
Renewals forecasting

We use survivorship analysis as a key component of pole replacement quantity forecasting. We have developed a survivor curve for our wooden poles, which we use to forecast renewal quantities via the asset health model.

A forecasting approach that incorporates defect history is more robust than a purely age-based approach because of the use of historical quantitative data. The following chart shows our wood pole survivor curve. The curve indicates the percentage of population remaining at a given age. The P50 survival age is ~50 years.

Our wooden poles tend to require replacement at a similar age to the industry expected life, although with a very wide distribution. The age at which they reach replacement criteria is influenced by factors such as wood type, location, design and manufacturing quality.

Figure 8.7: Wood poles survivor curve

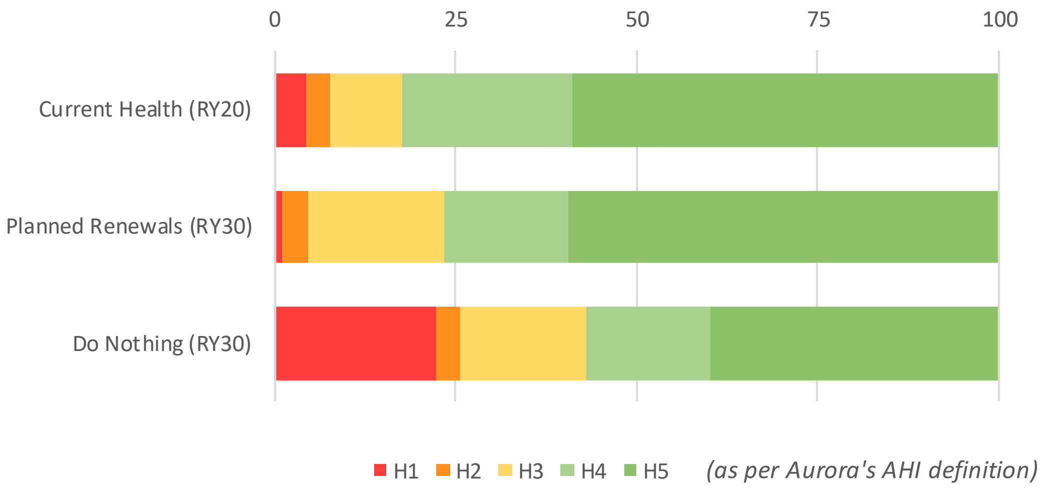


Condition-based pole replacements during the planning period will primarily focus on wooden poles. As discussed earlier, the health of our wooden pole fleet is poor.

For concrete and steel poles we use an age-based model to estimate asset health and renewal quantities. We do not expect to replace many concrete or steel poles during the planning period.

The figure below compares projected asset health in 2030 following our planned programme of renewals, with a counterfactual do nothing scenario. This comparison indicates the benefits provided by our proposed investment programme.

Figure 8.8: Projected pole asset health at 2030



Under the proposed work programme, the wood pole backlog will be removed by RY24. We will continue to replace poor condition poles after this, achieving our steady state level (corresponding to 400-500 poles replaced per annum) by RY30. The proposed work programme prevents ~20% of the pole fleet becoming H1 over the period to RY30, relative to the 'do nothing' approach.

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 pole testing and in turn pole remediations. Poles outside schools 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.

We have developed a draft risk based intervention framework for support structures. Once we have cleared 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. These will be more onerous than regulations in many cases based on location or other known risk factors with the pole.

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 poles when they are no longer needed because of asset relocation (e.g. undergrounding), asset replacement, or following failure. When a pole fails, we carry out diagnostic inspection and testing to assess the root cause of failure. As trends emerge from the failure analysis, we incorporate them into our pole fleet asset management approach.

CCA treated softwood poles need to be disposed of at an appropriately licensed facility. Hardwood poles may be repurposed for community projects, as in the case of the Cromwell-Clyde cycleway shown in the image below.

Figure 8.9: 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 or thermally uprate 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 of the poles replaced on reconductoring projects are covered under the overhead conductor portfolio forecasts.

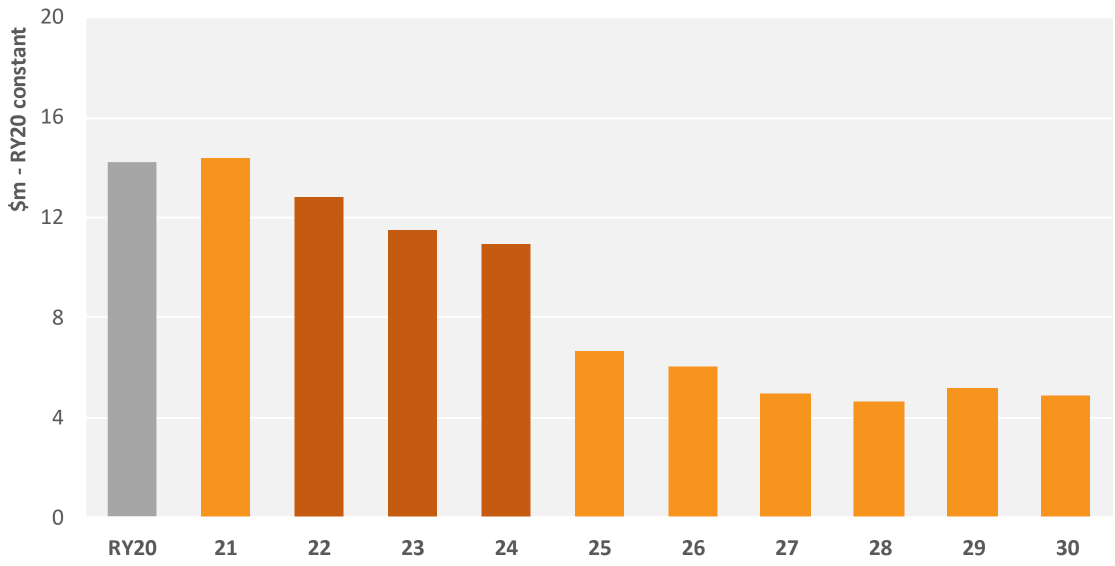
Meeting our portfolio objectives – reliability to defined levels

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 $82m during the planning period. This expenditure excludes poles replaced during reconductoring projects for both condition reasons and inadequate design strength. It covers the expected average pole mounted equipment replaced with a pole when a pole needs to be replaced due to pole driven reasons, based on average per pole historical expenditure.

Figure 8.10: Forecast poles Capex



We had high expenditure during the FTPP in RY18 when approximately 3,000 poles were replaced. While we do have a backlog of replacements, we have reduced the annual number of replacements to a level we are able to deliver on an ongoing basis when work on other assets is also required. Our forecast investment maintains 'elevated' (relative to future) levels of pole replacement up to RY24, before dropping to steady state levels as the aggregate health of the pole fleet improves.

Benefits

The major benefits expected from these investments are:

- improved safety: reduced risk of unassisted pole failure due to planned renewals, only 1% of poles are classified as H1 by RY26, shows an improvement in fleet health relative to the current state as the backlog is addressed. 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 RY24; this balances risk mitigation across all assets with sustainability of our business and the wider industry including our contractors.

8.1.3. Crossarms Fleet

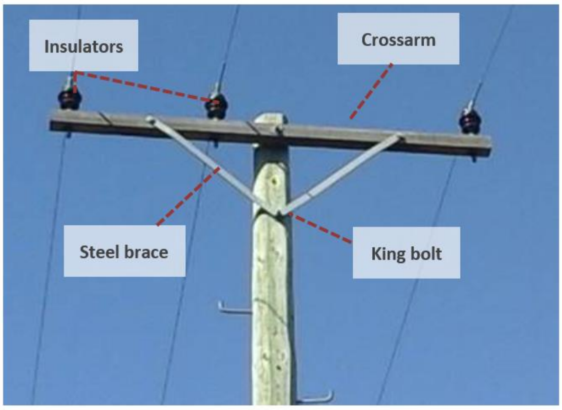
Where information is common to the poles section, it has generally not been repeated.

Crossarms Fleet Overview

Crossarms support overhead conductors. 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 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.

Historically, there has not been a proactive replacement programme for crossarms outside of our pole replacement programme. We are now managing our ~95,000 crossarms as a separate fleet and there is a clear need for a crossarm (only/retrofit) replacement programme.

Figure 8.11: Typical crossarm arrangement



There are significant safety and performance risks associated with crossarm failure. Crossarms are always replaced when a pole is replaced, but are also replaced separately on an existing pole based on identified defects, where the pole itself still has significant remaining life. We expect separate replacement of crossarm assemblies to be a relatively large programme of work over the planning period. This need for this programme of work is supported by risk reviews and recent failure events.

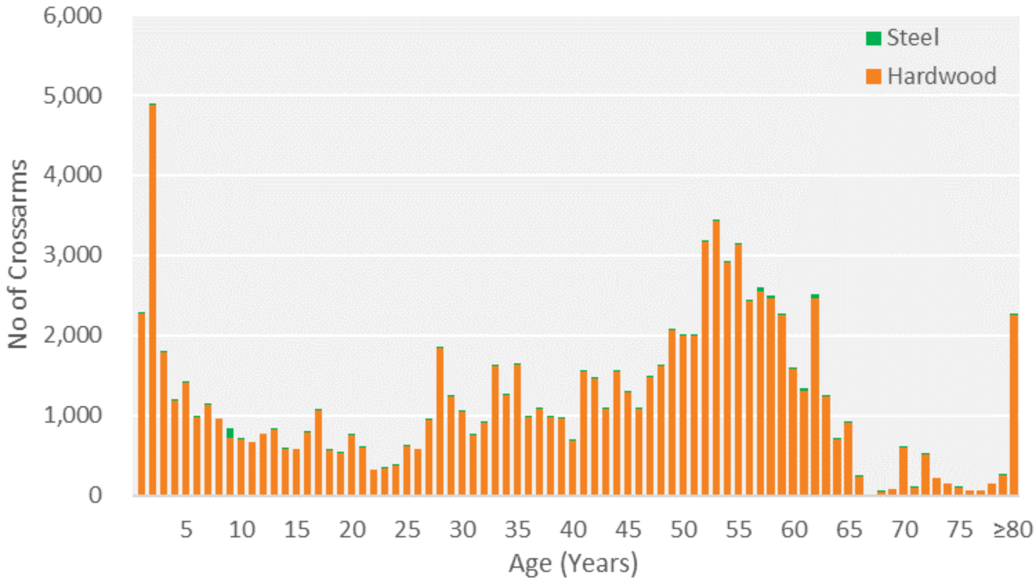
Population and Age

We have approximately 95,000 crossarms, an average of 1.7 crossarms per pole. The majority of these are wooden, with only 680 steel crossarms.

Our data sets do not have age entries for crossarms. In all cases where a pole is replaced, new crossarms are installed, and given there has been no historical crossarm (retrofit) replacement programme, we have assumed all crossarm are the same age as the poles on which they reside. We believe this is a sound assumption, and 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, although 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 only 3% of our steel crossarm fleet has exceeded 75 years.

Figure 8.12: Crossarms age profile



A significant volume of new crossarms were installed two years ago. These were replaced as part of our FTPP, as each new pole installed includes new crossarms for practicality and cost reasons.

Condition, Performance and Risk

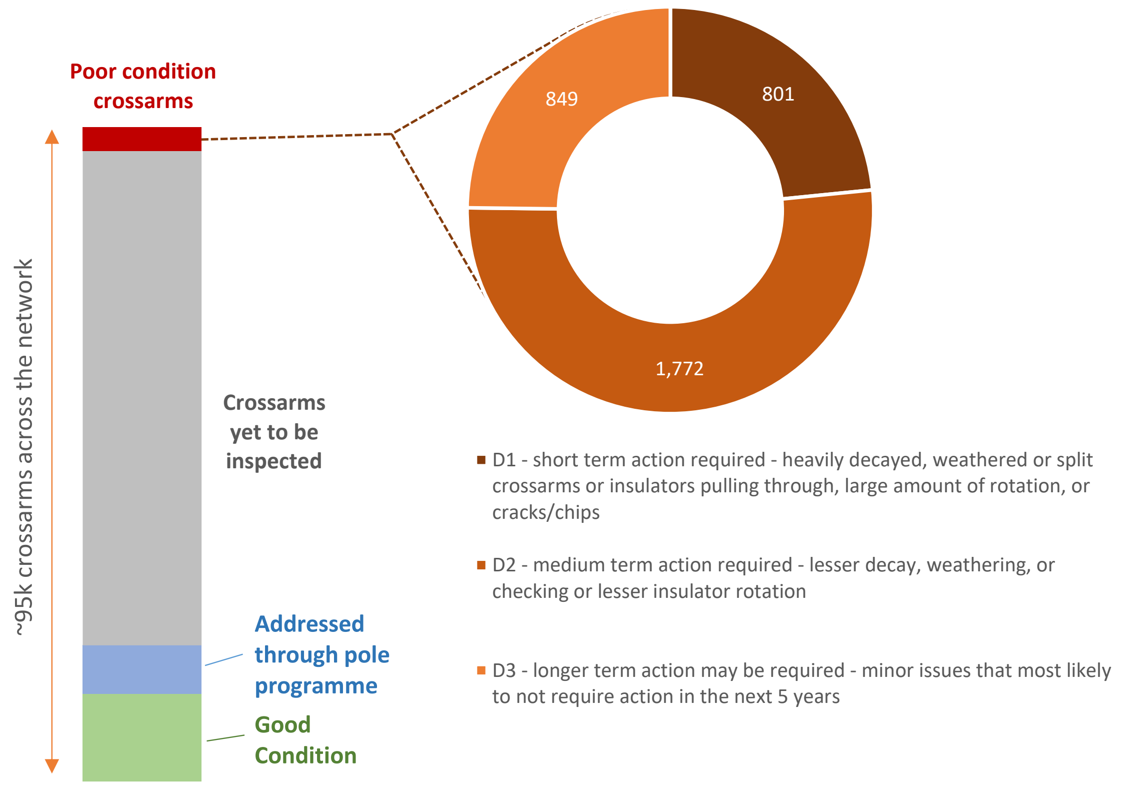
Condition

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. We have yet to complete a full cycle of testing under the current testing regime. Approximately 20% of our wood and 90% of our concrete poles (and hence crossarms) remain to be inspected. This will be completed as soon as practicable to ensure we have a full condition view of our crossarm fleet.

The majority of the 'crossarms yet to be inspected' are those located on concrete poles, because we have focused on wood pole testing to date. This represents our most significant risk with regard to crossarms, as many have exceeded their expected life. The other components of the bar graph relate to crossarms on wood poles, which have been inspected. Of the 'poor condition crossarms' component, our renewal programme is targeting the D1-classified crossarms first, using a location based risk prioritisation as for poles. The D2 crossarms form the basis of the crossarm replacement programme in the near term, with D3s being replaced when other work is occurring in the same outage zone.

The diagram below shows a graph of crossarm condition for crossarms on tested wooden poles, where pole replacement is not warranted.

Figure 8.13: Crossarm condition



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 N-1 subtransmission lines).

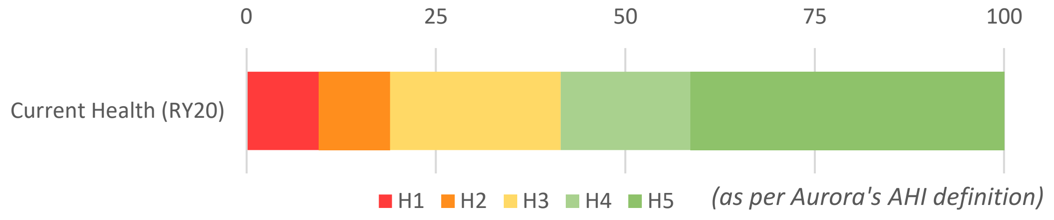
Ideally, we would measure performance based on the number and type of crossarm failures. However, until recently we have not recorded this information at a level of detail useful for analysis. We are collecting this data going forward. We do know that our conductor drops, or events where conductors have 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 reflects the expected remaining life of an asset and provides a proxy for likelihood of failure that we use for renewals forecasting. Our AHI for crossarms are based on expected remaining life (where 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 yet to be tested crossarms – primarily on concrete poles. 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 ~10% of our crossarms are at end-of-life (H1), with ~40% requiring replacement over the next 10 years. This is primarily due to a large number of crossarms exceeding their expected life.

Figure 8.14: Crossarm fleet asset health



Risks

The table below sets out the key risks and mitigations we have identified in relation to our crossarms.

Table 8.8: Crossarms risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
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 conductors 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 (LV)) 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 Often the causal condition issue cannot be seen by the naked eye or average camera from the ground.	Ground based and aerial based inspection programmes, leading to replacement of visually defective crossarms (new arms (except LV) have post insulators). Ad-hoc use of acoustic discharge test equipment to find intermittent faults.	Reliability
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 may consider the use of fibreglass crossarms in the future, however New Zealand's unique UV exposure is expected to challenge longevity. We are monitoring developments in polymer insulators and considering their wider usage.

Aeolian vibration dampers are being installed on 66 kV circuits with a history of aeolian vibration related failure. Vibration monitoring is not cost effective and dampers have a low unit price.

The considerations around contracting and design arrangements are the same for crossarms as for poles, however crossarm replacement tends to require significantly less, if any, actual design work.

Our crossarm forecast is ramping up significantly, however as we forecast a ramp up in crossarm volumes, we also forecast a ramp down in pole volumes, and the resource requirements are similar. Therefore we don't foresee any major deliverability issues with this fleet.

Operate and Maintain

Preventive maintenance

Crossarms are inspected at the same time as the poles which they are attached to. Our preventive pole and crossarm inspections were set out in Table 8.4 in the poles section.

Likewise, many of the preventive maintenance improvement initiatives covered in Table 8.5 will also improve our ability to detect and remediate poor condition crossarms, notably the pole-top inspections (aerial photography) and helicopter inspections of subtransmission lines.

In light of the need identified to undertake a crossarm (only/retrofit) replacement programme, the improvement initiative on pole-top/crossarm and helicopter inspections will collect specific data on type for individual insulators (e.g. strain vs support, glass vs porcelain, pin vs post). This information will be loaded into our data storage systems and assist in decision making and prioritisation of the crossarm replacement programme.

Meeting our portfolio objectives – responsive to a changing landscape

In light of issues with our crossarm fleet, it is prudent to use different and newer technologies to get better condition information. Use of high definition cameras on 'hot sticks' and from helicopters will help ensure we get the best data to make well informed decisions.

We also have used acoustic testing on an ad-hoc basis to track down leaking pin insulators on subtransmission 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

Corrective maintenance on crossarms is very limited. Any proactive work on crossarms replaces the entire crossarm assembly regardless of the defect, making it Capex. This approach is more efficient from a whole of life cost perspective (considering other insulators of the same age on the crossarm with the same failure mode), with the exception being where there is an obvious workmanship defect such as bolts not tightened adequately or subsequently loosened on a young installation which would justify a repair only.

Reactive maintenance

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.

Renew or Dispose

Historically, we have taken a mainly 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 8.9: Summary of crossarms renewal approach

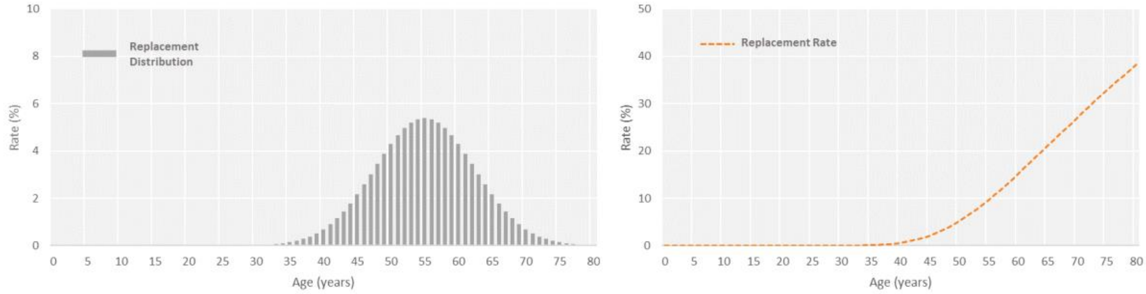
ASPECT	APPROACHES USED
Renewal trigger	Proactive condition-based, prioritised by criticality
Forecasting approach	Repex model
Cost estimation	Volumetric; historical average unit rate

We will prioritise renewal work programmes of poor condition crossarms based primarily on public safety criticality. Poor condition crossarms will be identified from 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 is based on the average age 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.

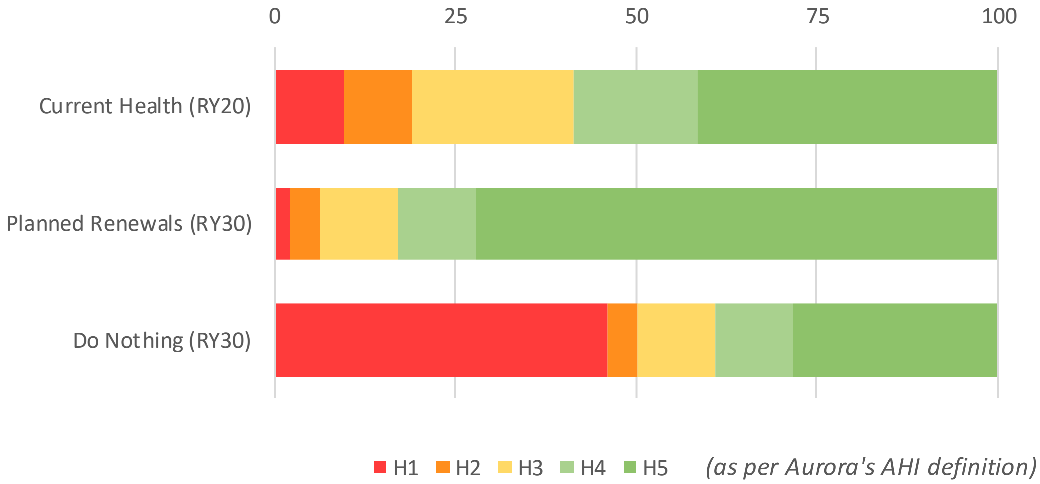
Figure 8.15: Wooden crossarms replacement distribution and rate



With improvements in data gathering and management, we will look to 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 8.16: Projected wooden crossarm asset health



Our planned investment will lead to a significant improvement in overall health relative to the 'do nothing' counterfactual. A sizable number of crossarms will still require replacement after 2030, as indicated by the H1-H3 portion in *Planned Renewals (RY30)*.

Options analysis

Options analysis for crossarm replacements is generally limited to considering the most economical way 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 replacing the entire pole is more cost effective. Cases include where there are high overhead costs such as traffic management, or a large number of individual crossarms. 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 in turn pole remediations (hence crossarm inspection and remediations). Crossarms outside schools will be prioritised against poles in 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. 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 and hence the same requirements as poles apply.

Coordination with other works

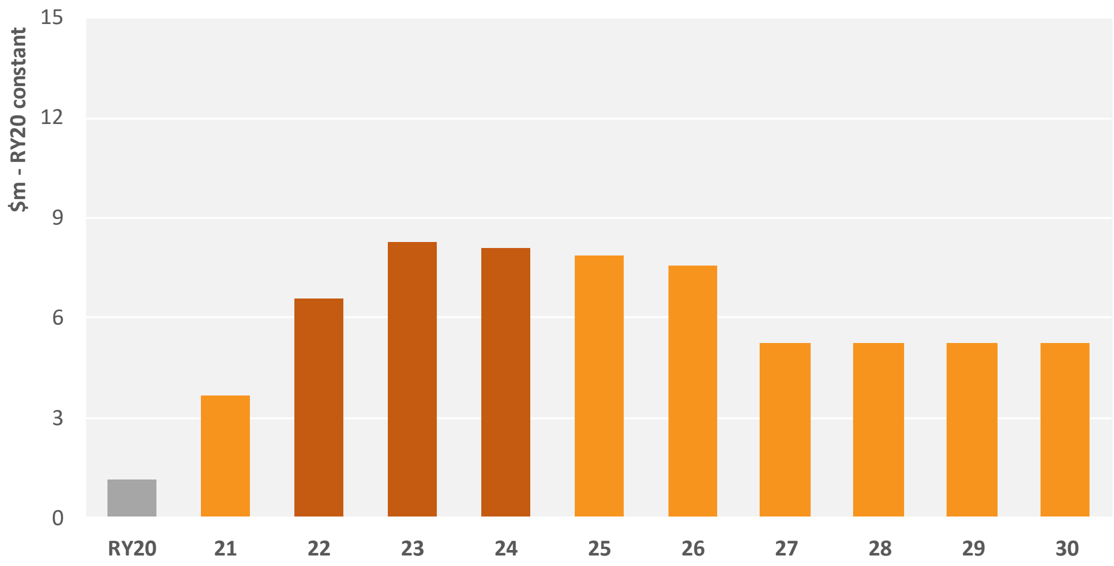
Like poles, crossarms are often replaced as part of overhead line reconstruction projects, such as conductor renewal or conductor upgrades as part of network development works, or consolidated into pole replacement work packs to make maximum use of outage windows.

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; crossarms replaced as part of reconductoring projects are accounted for in our conductor fleet forecasts.

Crossarm Fleet Capex Forecast

We have forecast renewal Capex for standalone crossarm replacements of approximately $62.9m during the planning period. This expenditure forecast excludes expenditure on crossarms replaced with pole replacements or with conductor replacements, and excludes other assets replaced as part of the crossarm assembly replacement (e.g. fuses).

Figure 8.17: 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 in RY21 and step up again in the RY22-26 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 reduces post RY26 but still at an elevated level, aiming to achieve steady state levels beyond RY30.

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 associated with ageing equipment, potential pole fires and conductor drops, helping us meet our safety objectives.
- 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 conductors portfolio[64] and summarises our management plan. The portfolio includes three asset fleets:

- subtransmission 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 subtransmission project) and identified under-clearance violation remediations.

During the planning period we expect to spend an average of $11m per annum on overhead conductor renewals with expenditure declining from a peak of $17.5m in RY23 to $10.6m in RY26.

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 (67% 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 the above range of voltages. 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. 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. These factors, together, can lead to different lifecycle strategies.

Box 8.7: Update on WSP Review – conductors

Issues: WSP identified material quantities of conductor past expected life, a lack of condition inspection data, high failure rates posing public safety and reliability risks, and under clearance violations.

Response: increased volumes of conductor replacements, focusing on 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 forensic testing of overhead conductor to support our renewal modelling.

Timing: elevated distribution and LV conductor renewal will 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 mean that managing our conductors effectively is critical to public safety.

[64] All overhead conductors Capex is covered under the Asset Replacement and Renewal Information Disclosure category, line items 'Subtransmission' and 'Distribution and LV lines', are included in Schedule 11a(iv) in Appendix B.

8.2.1. Overhead Conductor Portfolio Objectives

Portfolio objectives guide our day-to-day asset management activities and are listed below.

Table 8.10: 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. Subtransmission Conductor

Subtransmission Conductor Fleet Overview

Subtransmission conductor connects our supply points at Transpower GXPs to our zone substations, and generator connections and also interconnections between our zone substations, at voltages of 66 kV and 33 kV. Our subtransmission conductor fleet consists of 524 circuit kilometres of conductor, of which the majority is the Aluminium Clad Steel Reinforced (ACSR) type. Approximately 75% is located in our Central Otago network region. The nature of subtransmission is that the lines often cross private land on direct routes rather than following roadside corridors commonly used for distribution lines. This can mean that reconductoring involves extensive landowner consultation and consenting. Subtransmission lines can have 'underbuilt' distribution line and LV lines on the same poles.

Subtransmission lines are critical assets given the amount of power they carry compared to distribution lines. The impact of subtransmission 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 for pole strength. Higher voltage equipment generally also has a higher cost. Together, these factors mean that subtransmission line builds tend to have a higher cost than distribution line builds. All of these factors support managing subtransmission conductor as a separate fleet to the other voltage brackets.

We have only forecast one subtransmission line reconductoring project 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.

Subtransmission 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. However, subtransmission assets are often afforded with faster acting protection than the other conductor fleets, which provides a degree of risk mitigation over the other conductor fleets.

Population and Age

The following table summarises our population of subtransmission conductor by type. ACSR conductor currently makes up about 74% of circuit kilometres, with most of the rest being copper.

Table 8.11: Subtransmission conductor population by type

TYPE	POPULATION (CIRCUIT KM)	PERCENTAGE
ACSR	390	~74%
Copper	128	~25%
Aluminium alloy (ABC/AAC/AAAC)[65]	5	~1%
Total	524	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. However, in the 1960s the price of copper increased significantly, and ACSR stranded conductor[66] became the conductor of choice. 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. Corrosion can be reduced by galvanising or grease coating the core but this increases the conductor's weight. ACSR remains the conductor of choice for new installations and conductor replacement in Central Otago.

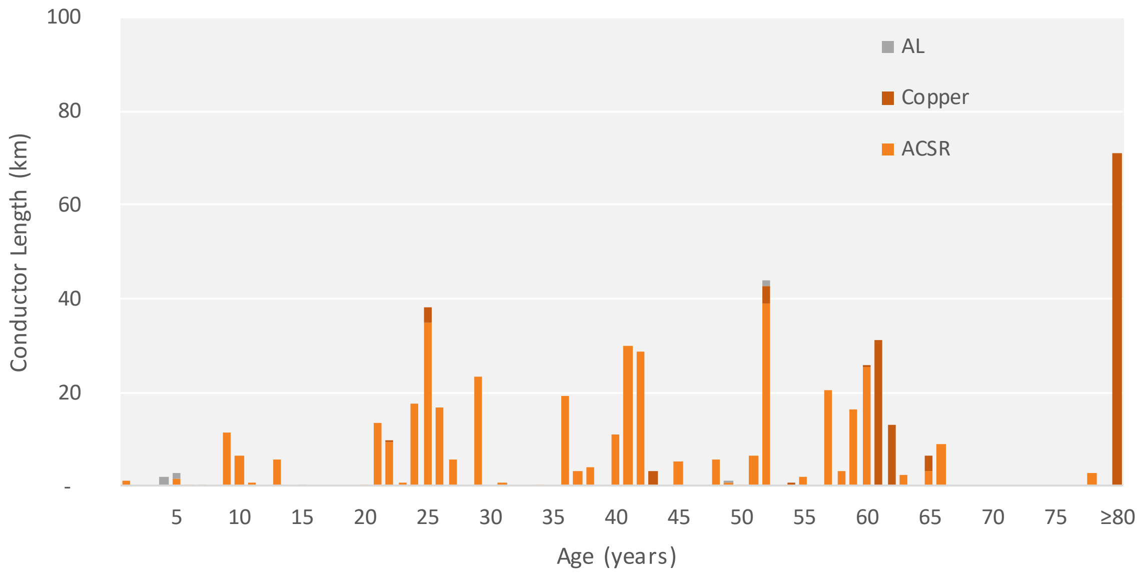
AAC, which was introduced next, is lighter (and cheaper) than ACSR, but without the same strength. The final transition has been a move from AAC to AAAC, an aluminium alloy conductor with very similar characteristics as AAC but with a higher strength for the same size and weight. The majority of our AAAC conductor has been installed over the last five years. In general we use it in areas without snow loading or long spans; it is our preferred conductor in Dunedin.

We have a very small amount of the Aerial Bundled Cable (ABC) at subtransmission 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 subtransmission and distribution applications.

65 AAC: All Aluminium Conductor and AAAC: All Aluminium Alloy Conductor.

66 ACSR comprises an inner core of solid or stranded steel, and one or more outer layers of aluminium strands.

Figure 8.18: Subtransmission conductor age profile



The average age of our subtransmission conductors is 50 years. A significant volume of conductor, primarily copper, has already or soon will exceed its expected life. The oldest copper conductor is on the Waipori A/B/C line circuits.

Table 8.12 sets out our conductor expected lives.[67] 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 8.12: 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.[68]

67 Note that this table applies across all voltages. There is no No.8 Wire conductor on the subtransmission network.

68 Conductor sampling and testing is covered in the Distribution Conductor fleet section.

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, particularly if the conductor has landed on something other than the ground, such as a fence. Manual intervention by circuit breaker operation on receipt of information of the line being on the ground may be needed to de-energise the conductor.

Conductor failure can also cause loss of supply. At subtransmission level this is often not the case as the circuit will often comprise more than one line (i.e. N-1 security). However the loss of a single subtransmission line 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 subtransmission circuit and the loss of this line would result in loss of supply to all customers supplied from that zone substation (N security).[69] Several substations connect to multiple subtransmission circuits, but not in a standard configuration (do not have a closed bus) so the loss of a subtransmission circuit will also cause a loss of supply to the zone substation until manual switching has occurred and the alternative subtransmission 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. Detailed visual observation, whether from the ground or air, is time consuming and can result in huge amounts of data which may not contain useful or usable information. Also, a lack of visual defects does not necessarily mean the conductor is in good condition.

We have not historically had a periodic 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 plan to move to a more systematic inspection programme to increase our knowledge of conductor and conductor fitting condition.

While our subtransmission conductor fleet is ageing, line failures are rare, largely due to its heavier, more robust construction. In addition, many subtransmission 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.[70] In addition, we have had a small number of incidents due to aeolian vibration on one of our 66 kV lines, that has caused multiple occurrences of floating conductors due to the vibration loosening studs on insulators and causing

69 Some customers may be able to be switched over to another feeder, reducing loss of supply. However this is a manual process which can take some time to undertake.

70 Tie wires bind the conductor to the insulator. We are replacing tie wires with distribution ties on new installs.

them to detach from the crossarm.[71] To minimise this phenomena we will continue to install vibration dampers on these lines when replacing defective crossarms or significantly degraded poles. The new crossarms have lightweight polymer insulators rather than the existing ~20kg porcelain insulators with screw in studs (which loosen under vibration) which should also help to reduce this failure mode.

Figure 8.19: Floating conductor following insulator failure (left), and lightweight polymer insulators (right)[72]

Aerial Bundled Conductor (ABC) at subtransmission voltage (33 kV) is aluminium core and 49 years old. It has marginal test results and incurred a recent failure, and hence will need to be replaced in the medium term. The solution will require investigation and options analysis due to the trees in close 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 subtransmission conductor fleet having a high percentage of ACSR conductor 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 subtransmission 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 subtransmission 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

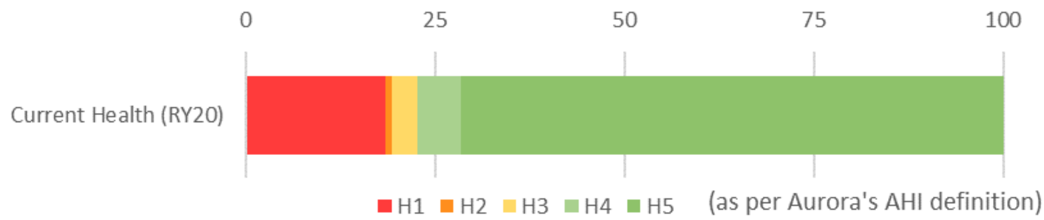
Our AHI for subtransmission conductor is based on expected remaining life considering conductor type, size, and location. Life expectancy is represented by a normal distribution for each expected

71 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.

72 Polymer insulators shown in a no crossarm arrangement but similar insulators are also used in crossarm configuration.

life grouping, as this approach is more robust than simply assuming that equipment fails at a particular set age.

Figure 8.20: Subtransmission conductor current asset health



Based on asset health, we expect to need to replace 23% of subtransmission lines over the next 10 years. The Waipori A/B/C lines make up the majority of the H1-classed subtransmission conductor sections. These are forecast to be replaced by RY24.

Risks

The table below sets out key failure modes by type of conductor on our subtransmission network.

Table 8.13: Subtransmission conductor failure modes

TYPE	FAILURE MODE(S)
ACSR	The steel core that gives ACSR its strength makes it more vulnerable to corrosion in coastal areas. (This can be reduced by galvanising or grease coating the core but this increases the conductor's weight.) Single piece joints or fittings which clamp only the outer aluminium of the conductor are not rated for full tension and are prone to failure, particularly with workmanship issues
Copper	Susceptible to annealing and fretting or 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 which connects it to the insulators. Affected by fatigue caused by the flexing of conductors 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 conductors 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 conductors or foreign object strikes (vegetation, birds, etc) can cause mechanical damage leaving 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 conductors which do fail to ground.

Table 8.14: Conductor failure risks

Risk/Issue	Risk Mitigation	Risk
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 replacement 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	Safety, reliability
Conductor floating, due to failure of hardware such as fittings and joints	New conductor inspection regime includes fittings and joints 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, 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 Fitting of falcon guards onto steel crossarms	Reliability, environ-mental
Third party conductor damage	Permit processes, safety programmes, inspection regime and subsequent remediations of under clearances and damaged conductor	Safety, reliability
Risk to home owners 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 subtransmission 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 along a road side). 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. ACSR requires particular care when preparing and jointing, as well as utilising the more complicated two piece full tension sleeves.

In general we try to avoid increasing the number of different conductors on the network and are standardising 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, 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; however 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 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 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 8.8: Improvement Initiative – Planned LiDAR survey and overhead network design software

We plan to start LiDAR survey in RY22, with one network region (Central Otago or Dunedin) every two years going forward. LiDAR will systematically show us all of the areas where conductor does not meet statutory requirements, and provide detailed information that 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 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.

Operate and Maintain

Preventive Maintenance

We undertake little invasive preventive maintenance work on conductors. NZECP34:2001 requires us to check the clearance heights of all overhead electricity lines at least every five years, which we do as part of 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 and a lack of structure to the data has meant it has not always been usable in an efficient way. Conductor observations are made as part of pole inspections, but data has the characteristics stated prior.

This current preventive work on subtransmission conductor is summarised below.

Table 8.15: Subtransmission conductor preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY STATE FREQUENCY
Conductor clearance and basic condition observations assessment (in conjunction with pole condition assessments).	Five yearly

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 the areas of 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 underinvestment 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 8.16: Subtransmission overhead conductor preventive maintenance initiatives

PREVENTIVE MAINTENANCE INITIATIVE	RELATED CONDUCTOR OBJECTIVES	TIME FRAME
Helicopter inspections of subtransmission lines Current inspection regime for subtransmission conductor is ad-hoc (generally in response to faults). We are noticing an increase in ACSR conductor drops. Investigations have revealed workmanship issues with fittings such as joints and terminations as the primary cause. Conductor failures also occur due to visible condition issues e.g. broken strands, signs of clashing, overheating and general ageing. Infrared camera will also help to pick up overheating issues with joints and fittings.	**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 subtransmission network is paramount given its criticality and 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

PREVENTIVE MAINTENANCE INITIATIVE	RELATED CONDUCTOR OBJECTIVES	TIME FRAME
LiDAR survey Two yearly lidar (alternating network regions – each network region every four years) will be undertaken to provide quality data, primarily for vegetation management but with future uses in network design and asset management.	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

Corrective maintenance

Corrective maintenance on 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.

Spares

Conductor drums are kept at depots for our most common conductor types. However, it is not always possible to quickly obtain the exact conductor in all circumstances given we have over 50 different types of conductor on our networks. In the event of a particular size not being available, we will put up a similar conductor for continued reliable service. Due to the age and uniqueness of some of our conductors, we may not always be able to source spares of the exact same type and hence a suitable substitute is required, and in some cases this may necessitate a longer term solution after the initial fault response.

Conductor hardware such as fittings and joints are standard components and stock is kept by our faults contractor at strategic locations, as well as in fault responders vehicles in limited quantities to enable fast return to service.

We are standardising on conductor types for each network region (Central Otago and Dunedin). This is appropriate given they have different characteristics such as wind exposure and corrosion propensity. As conductor is replaced this will assist in reducing the range of conductors on the network, which in turn will mean less hardware is required in stock for fault response.

Standardising on conductor types will allow us to better control the conductor joints and fittings and enable our line crew to repair failures more quickly with fewer returns to depots. Limiting the number of spares we hold in stock is a related benefit of having a standard set of conductors.

We are in the process of standardising joint types to ensure no mid-span joints that cannot withstand full tension are installed, and to be able to more easily control workmanship issues. We will also keep abreast of new products in the industry which 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.

Renew or Dispose

We renew subtransmission conductor primarily on the basis of age (vs expected life), as a proxy for condition. 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 8.17: Summary of subtransmission conductor renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Age (vs expected life)
Forecasting approach	Repex Tailored for Waipori A/B/C lines
Cost estimation	Volumetric; estimate of unit rate based on historical conductor projects Tailored for large projects such as Waipori A/B/C lines

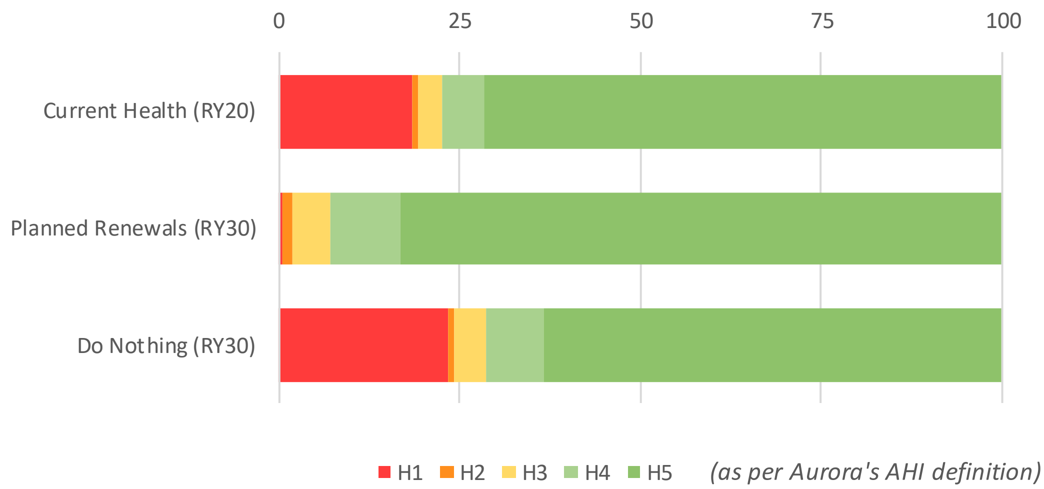
Renewals forecasting

We use a Repex approach for forecasting subtransmission conductor renewal volumes for all but 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 subtransmission conductors that will likely require replacement by a particular age.

In the case of large projects such as replacement of the Waipori A, B and C lines, we take a tailored approach to determining renewal requirements.

The figure below compares projected asset health in RY20 following our planned programme of renewals, with a counterfactual do nothing scenario. This comparison indicates the benefits provided by our proposed investment programme.

Figure 8.21: Projected subtransmission conductor asset health



Waipori A/B/C lines make up the majority of the H1 subtransmission conductor sections in the top bar. These are forecast to be replaced by RY24, in addition to which we plan to undertake an average of 2.5 km per annum of volumetric replacements (i.e. excluding Waipori).

Options analysis

Before making a subtransmission 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 subtransmission conductor given the implications of it on network design, and also its high cost.

When considering renewal of a subtransmission conductor, we assess the overall condition of the subtransmission 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:

1. proactive repair of the conductor (Opex) where renewal is not yet warranted by condition e.g. proactively replacing joints and other fittings
2. 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 amount of poles requiring replacement due to loading increases causing them to be under-designed)
3. 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 for loading increase reasons
4. 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
5. 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
6. rebuilding at a different voltage – in the majority of cases this would require an overwhelmingly growth driven driver and be classed as a growth project. However, at a low marginal cost, lines can be constructed 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 requires new transformers and switchgear
7. network alternative solution – 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. Remote area power supplies may also be used to increase reliability in specific areas. This option is generally not suitable for subtransmission 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 conductors 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 subtransmission 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; however this is not always possible. 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

Subtransmission 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

As replacement is generally based on condition (aside from conductor replaced for growth), the conductor is generally sufficiently degraded that reuse is not an option. When replacing conductor we scrap the degraded material. Historically there has been second hand conductor used on our network and at present we have no reason or opportunity to continue this practice.

Coordination with other works

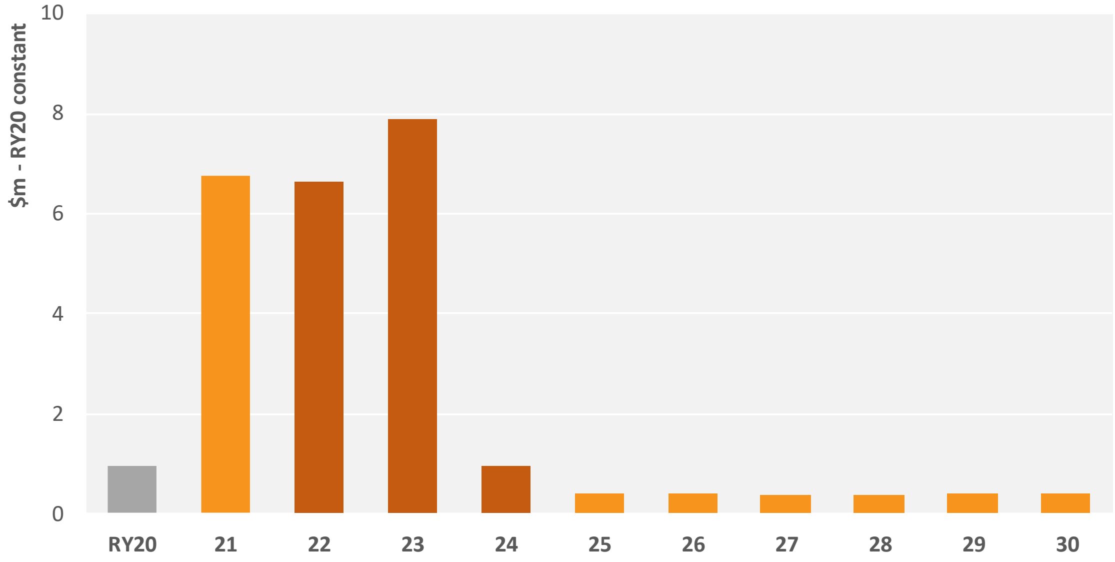
Subtransmission conductor works may be driven by load growth. If a conductor requires replacement in the medium term (or has already been identified for replacement), forecast growth will be considered, and the preferred solution may be to replace the conductor with a larger size. This decision is supported 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 conductors, 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.

Subtransmission Conductor Expenditure Forecast

We have forecast subtransmission conductor renewal Capex of approximately $24.6m during the planning period.

Figure 8.22: Forecast subtransmission conductor Capex



Historically our expenditure on replacing subtransmission conductors 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 replacement of the Halfway Bush to Berwick lines (over the period to RY21 to RY24). The remainder of the planned expenditure to RY30 is an estimate of reactive replacement requiring capex investment; there are no lines that are forecast to be past expected life in the period.

Benefits

The key benefits of our planned subtransmission conductor renewal are improvements in fleet asset health, and a reduction in public safety risk as we remove poor condition conductor from our network. 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, and 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 the subtransmission conductor section, it has generally not been repeated here.

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.[73] We own approximately 2,300 circuit kilometres of overhead distribution conductor, comprising of steel (mainly No.8 wire[74]), ACSR, copper and aluminium types. Distribution conductor makes up more than half of our total overhead circuit length. 67% of our distribution conductor is located in our Central network and the remaining 33% in Dunedin. Distribution conductor is supported by our overhead structures (poles and crossarms). The same support structures may also support subtransmission, distribution and LV conductors, with distribution over LV a common pole/conductor configuration (conductors 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 subtransmission lines. The large quantity of conductor sections and their generally significantly lesser implication on network design and performance compared to subtransmission conductor 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 8.18: Distribution conductor population by type

TYPE	POPULATION (CIRCUIT KM)	PERCENTAGE
Aluminium	34	1%
ACSR	1,512	66%
Copper	525	23%
Steel (primarily No.8 Wire)	236	10%
Total	**2,307**	**100%**

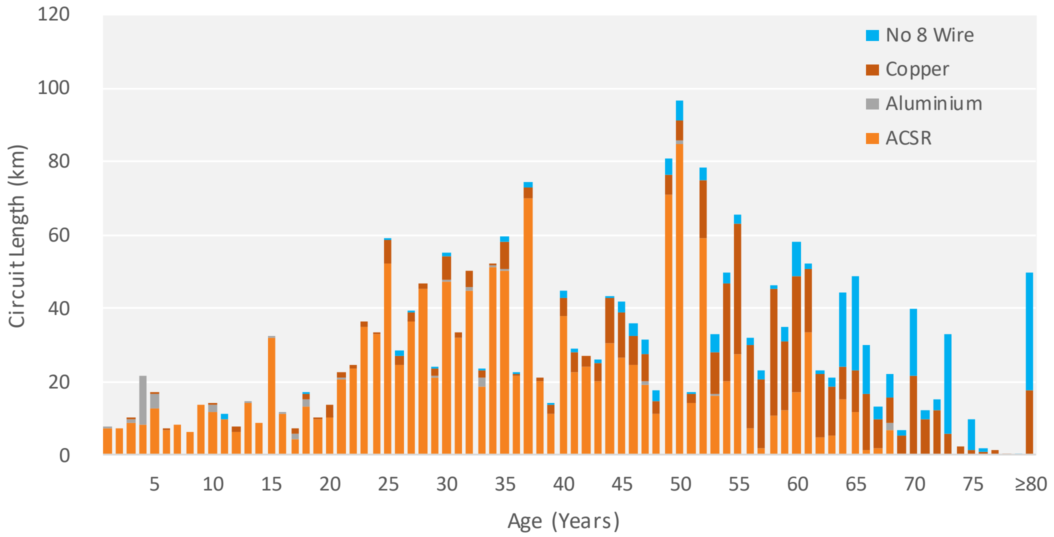
The figure below depicts the age profile of our distribution conductor. No.8 Wire and copper were the main types used until about the mid-1960s, when AAC and ACSR type conductors became the preferred types. Significant network expansion took place from around the 1960s, much of which is now approaching or has reached end-of-life. Our copper and steel conductors have the highest

[73] Some customers are directly connected to our network at 6.6 kV and 11 kV.

[74] Number 8 steel wire is a 0.16 inch diameter gauge of wire on the British Standard Wire Gauge.

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, as while not being fully insulated, does provide a degree of resistance to vegetation related faults.

Figure 8.23: Distribution conductor age profile



The expected lives of distribution conductor are based on Table 8.12 in the subtransmission 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 the expected lives provide a good starting point and are within the bounds of good practice when compared to lives used by other New Zealand electrical asset owners, we expect to refine these as our knowledge, gained from sampling and condition assessment, increases. 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.

Box 8.9: 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 conductors 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 continuing and sampling will become more extensive by considering the expected lives of all conductor types, sizes, and location combinations that have large amounts nearing their expected life.

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.

Meeting our portfolio objectives – sustainability by taking a long term view

We will undertake systematic testing and using 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.

Condition, Performance and Risks

The condition, performance and risk considerations of our distribution conductor are similar to those for our subtransmission conductor. However, distribution conductor failure 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 conductors that these conductors 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 condition 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) is eroded and the steel corrodes. This has been expedited by the use of copper coated wire as binders where the insulators support the conductors. 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.

Figure 8.24: Mid-span joints on distribution conductor

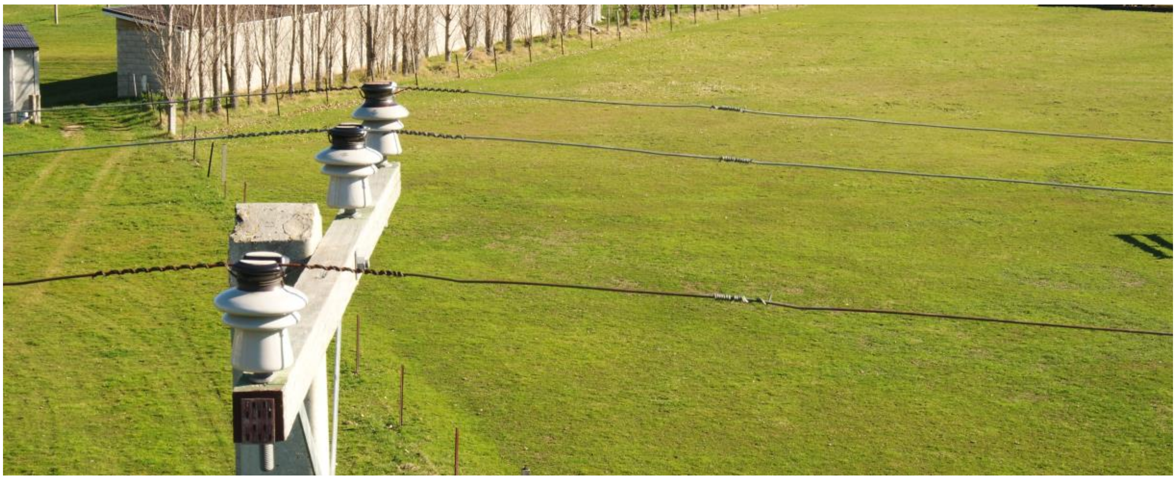


Figure 8.25: Rusted No. 8 wire at an insulator tie point due to bimetallic corrosion with copper tie

We have identified some type defects in our conductor fleet, warranting replacement before expected life is reached. For example, we have ~3km of 'Simalec' conductor which is a doped AAAC type conductor which was 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 subtransmission 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 (or reconductoring as applicable if the quantity of joints in one section is very high or other issues are found) will be undertaken.

Performance

Our overhead network is designed to cope with defined environmental conditions such as certain wind and snow loadings.[75] However, failures leading to conductor drops do occur, caused by vegetation, pole or crossarm failures due to poor condition, wind / snow loading, failure of conductor joints or fittings, or damage by possums or bird contact. This results in a safety risk to the public and our service providers.

We are working to improve our recording of outage cause data and undertake follow up investigations on all conductor incidents. 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 drops (using SAIFI as a proxy) we have recorded on our network over the past 10 years, illustrating an increase in failures since 2015.

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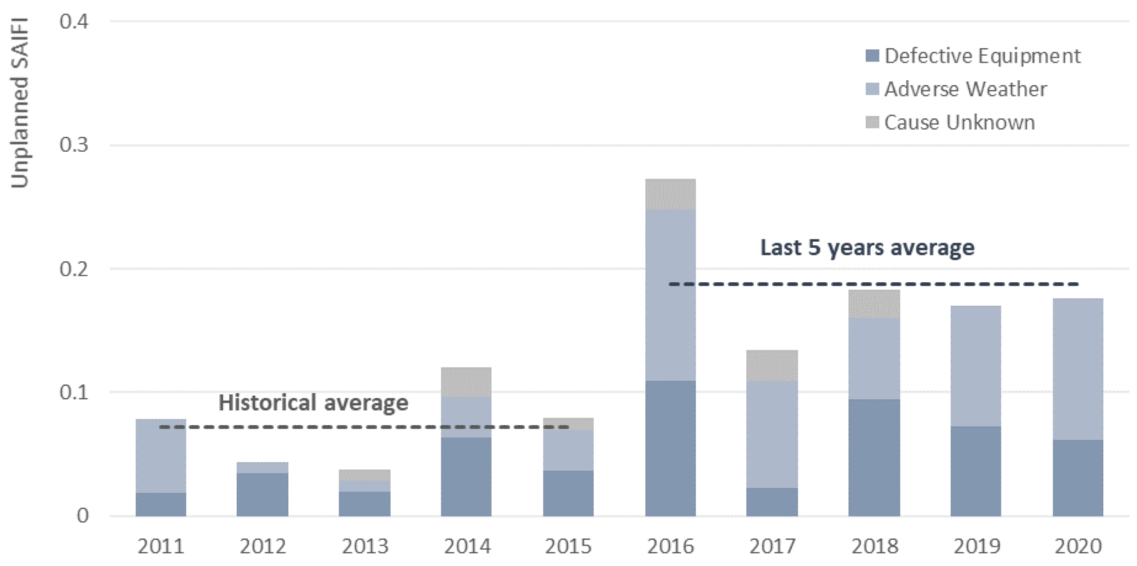
75 Note that the design standards that applied to many of our existing assets have changed over time.

Figure 8.26: Distribution conductor performance – conductor drops



As we design our overhead lines to handle these loads/situations, the apparent increase in the 5-year averages is concerning, likely reflecting the ageing fleet and emerging workmanship issues. 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 high failure rates are occurring on No. 8, 16 mm^2 copper, and with ACSR fittings and joints.

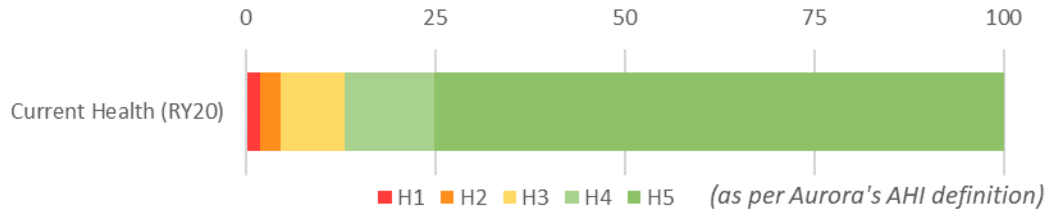
We do have instances of high vehicles contacting our distribution conductor, and in most cases the line clearances are compliant. We have a register of under-clearances and often these are located in aged parts of the network. In the time passed since original construction, design standards have changed and 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 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. The current health of our distribution conductor fleet is shown below.

Figure 8.27: Distribution conductors current asset health



Approximately 13% of our distribution is nearing replacement criteria (H1-H3, replace within ten years). Most of the replacement will be the aged copper and No.8 wire conductor types.

Risks

Table 8.13 (above) set 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 8.19: Distribution conductor failure modes

TYPE	FAILURE MODE(S)
No. 8 steel	No. 8 steel wire 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 rust has set in. As noted prior, this is greatly accelerated by the historic use of copper binders creating a galvanic cell.

Table 8.14 in the subtransmission 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, all of the considerations covered for subtransmission conductor also apply to distribution conductor. Distribution conductor is generally in public areas (unlike subtransmission) 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 joint 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 so 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.

Operate and Maintain

Preventive maintenance

Condition assessment for conductor is relatively challenging and our current inspection regimes are the same in distribution conductor; they are limited to those statutory requirements covered during a pole test or are otherwise ad-hoc.

We are implementing a new inspection programme across distribution and LV conductor. Initially inspections will be targeted to locations that have historically experienced conductor failure, followed by using these inspections to fill data gaps, particularly with LV conductor, before becoming a fully integrated test regime.

Table 8.20: Distribution conductor preventive maintenance initiatives

PREVENTIVE MAINTENANCE INITIATIVE	RELATED CONDUCTOR OBJECTIVES	TIME FRAME
Survey of distribution conductor We will start a routine survey of distribution conductor condition, with a focus on fittings and joint condition and type issues following a recent increase in failures. Inspections will be ground based for the majority, with inaccessible areas or areas not efficiently reached by vehicle or by foot being undertaken from helicopter as per subtransmission inspections.	Safety first – Identifying condition, workmanship, and type issues before they fail could prevent 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.	Medium term

Corrective Maintenance, Spares, and Reactive Maintenance

With the one exception below, all considerations are the same as subtransmission conductor.

One notable difference with reactive maintenance on distribution conductor is that when a distribution conductor fault occurs and is downstream of tee off fuses, there will most likely be 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.

Renew or Dispose

We renew distribution conductor primarily on the basis of age (vs expected life), as a proxy for condition, prioritised by criticality and deliverability at present due to a backlog of conductor past its expected life. Some conductor sections to date have been replaced based on failures occurring, and these have supported our expected lives. 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 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. 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 on a reconductoring project.

We have been focusing on replacing smaller conductors past expected life, including No. 8 steel and 16 mm^2 copper, for which there have been confirmed conductor drop incidents. We address low clearance spans as identified. The table below summarises our renewal approach.

Table 8.21: Summary of distribution conductor renewal approach

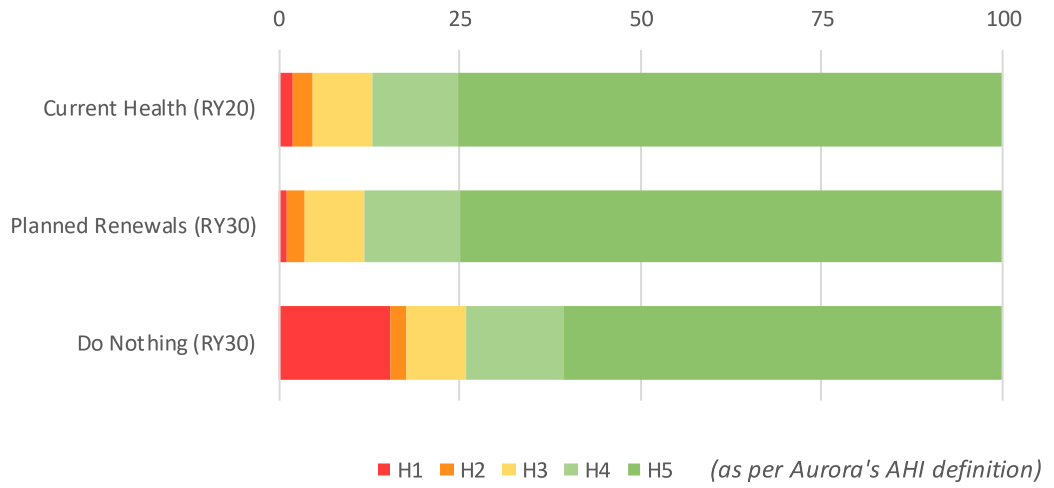
ASPECT	APPROACHES USED
Renewal trigger	Age (vs expected life), with criticality/deliverability/risk prioritisation Under-clearances, with criticality prioritisation
Forecasting approach	Repex Known under-clearance violations
Cost estimation	Volumetric; historical average unit rates for conductor, and separately per low span (under-clearance)

Renewals forecasting

We plan to gradually increase our distribution conductor expenditure from RY21 to address the backlog of distribution conductor requiring replacement. We expect to reach steady-state renewal levels by RY28. Achieving steady state faster would be desirable, but taking into account resourcing and impact on other works, we do not believe this is deliverable.

The chart below compares projected asset health in 2030 following our planned programme of renewals, with a counterfactual do nothing scenario.

Figure 8.28: Projected distribution conductor asset health



Our proposed level of investment will improve overall fleet health, helping manage the risks associated with conductor failure. If we do not invest, 15% of our fleet, as depicted by the H1s in the 'Do Nothing' scenario, will be at risk of failure by RY30, creating intolerable public safety risk. This comparison indicates the benefits provided by our proposed investment programme.

Options analysis

Generally little options analysis is required for distribution conductor. Exceptions are 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 comprise many different conductors serving different loads (with slightly different needs), for example sections close to towns versus spur sections on the end of radial feeds may be different conductors. Easement considerations tend to be significantly less than subtransmission conductors, as the majority of distribution conductor is in public property (road reserve).

As such, options analysis is not normally warranted other than verifying non-network solutions are not more cost effective where customer numbers are small, and considering if during the renewal any change in ampacity is justified or any network reconfiguration is justified. Large network reconfigurations that cause the scope to change significantly are classed as growth projects. As per subtransmission, 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, conductors supplying higher priority customers such as hospitals and emergency operation centres will be prioritised over those that supply residential premises. In addition, conductors 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 are looking to improve on this model over time, breaking the distribution network into smaller areas to better reflect the real life process of an unplanned outage and better reflect the potential outcome of a conductor down incident.

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

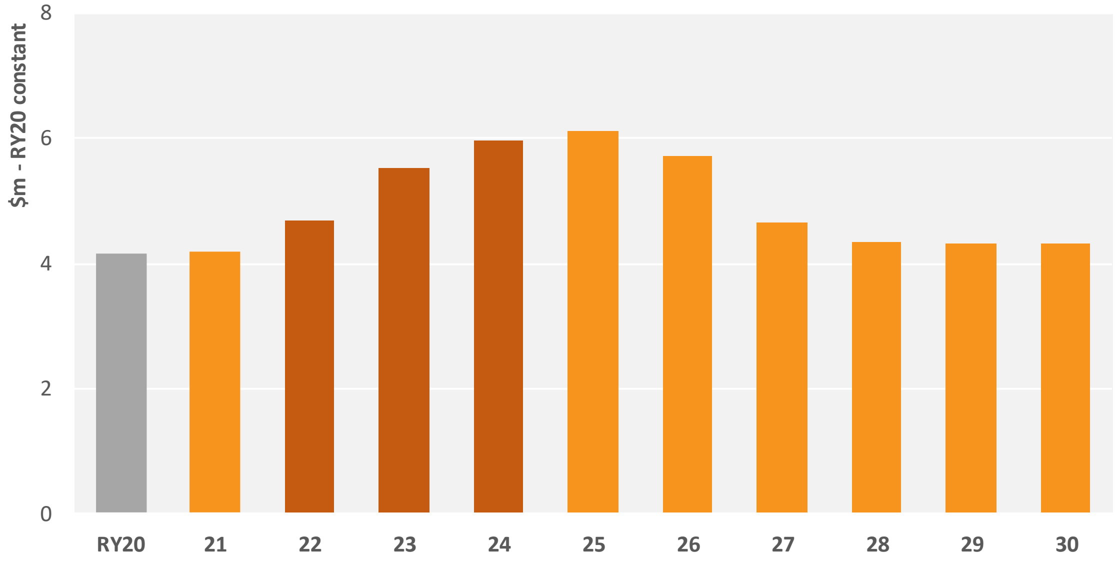
In making distribution conductor replacement decisions we consider whether the investment should be combined with other projects, such as conductor upgrades or new feeders required to supply load growth as a result of residential infill housing or new subdivisions. We also consider other needs such as managing low voltages in areas with customer loads supplied by long 'stringy' lines.

When we need to replace or thermally uprate conductors, 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 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 Expenditure Forecast

We have forecast renewal Capex of approximately $50m during the planning period.

Figure 8.29: Forecast distribution conductor Capex



The programme of work to replace end-of-life distribution conductors 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 conductors 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 300 km (13%) of our distribution conductor over the period to RY30, of which most will be copper and No.8 wire. Poles and their crossarms that need to be replaced to enable conductor replacement (such as if they are under strength, in poor condition, or unsuitable to meet clearance requirements) are included in this portfolio forecast.

Benefits

The major benefits expected from our planned distribution conductor renewals are reductions in public safety risk (reduced risk of conductor drop or third party conductor impact (for low spans)) and improved asset reliability (fewer 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 subtransmission 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, 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 1,600 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, since LV cannot be used for long distances due to voltage drop, tend to be shorter than distribution conductor sections. LV can be underneath higher voltages on the same poles (known as 'underbuild'), or on separate pole lines. Many LV lines serve few customers, and consumer lines that serve a single customer are not Aurora owned and hence are not covered explicitly in any statistics throughout this document. At present like most other EDBs, we have less visibility of our LV network, both in terms of asset data and utilisation than our higher voltage networks, and this and the physical characteristics of LV lead us to manage this as a separate fleet to the other conductor fleets.

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 1,551 circuit kilometres, with the balance being ACSR and No.8 wire.

Meeting our portfolio objectives – sustainability by taking a long term view

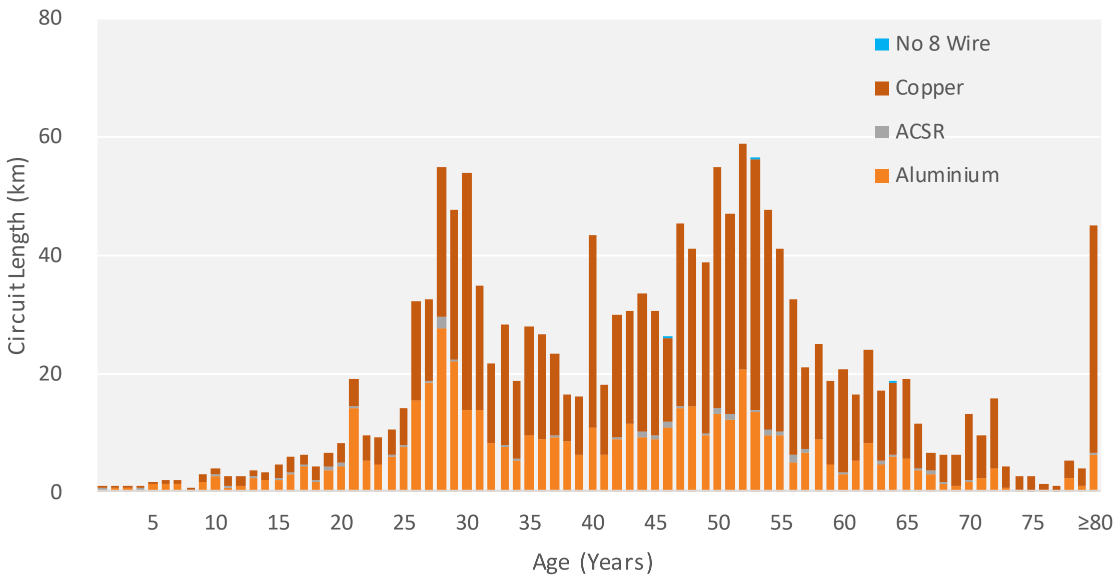
For 40% of our LV conductor fleet, we have no master data specifying conductor type. We have prorated the unknown types of LV conductor across the proportions of other types, based on their age. We will use our new conductor inspection regime to identify unknown types over the first half of the planning period to have a better understanding of our LV conductor fleet.

Table 8.22: LV conductor population by type[76]

TYPE	POPULATION (CIRCUIT KM)	PERCENTAGE
Aluminium[77]	512	1%
Copper	1,018	33%
ACSR	21	66%
No.8 Wire	0.2	0%
Total	**1,551**	**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 (48 years) and a sizable proportion of this will require renewal in the medium term. As per 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 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 41 years.

Figure 8.30: LV conductor age profile



[76] This includes prorated types as discussed above.

[77] Includes ABC conductor.

The expected lives of LV conductor vary with type, size, and location. The expected lives of LV conductor reflect Table 8.12. 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 are similar to those 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 subtransmission conductor condition, condition assessment for overhead conductor is relatively challenging. We have not historically collected condition data for our LV conductor fleet, other than with associated pole inspections. We are implementing an inspection programme across primarily distribution conductor in the first instance and eventually LV conductor to improve our knowledge of conductor condition and other issues such as poor workmanship and to fill data gaps.

An additional factor for LV conductor due to the higher percentage of such conductor is the degradation of the outer insulation layer (PVC on our newer conductors, hessian was also used in the past) on covered conductor due to the high level of UV radiation in New Zealand. The issue is particularly relevant in Otago as it experiences higher UV levels than Dunedin. However the covered LV conductor in Otago tends to be younger 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 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 conductors.

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.

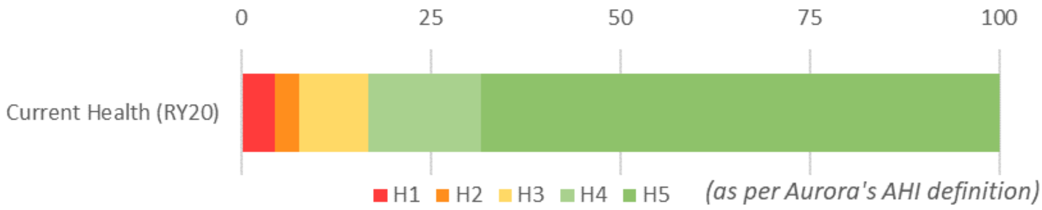
As per distribution conductor, we also have a register of under-clearances on main roads to address.

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 8.31: Low voltage conductors current asset health



Our LV conductor asset health suggests that we need to replace approximately 7% of our LV conductor fleet over the next 3 years (H1 and H2), and 17% over the planning period (H1 to H3) (to RY30). This predominantly consists of copper conductor that has exceeded its expected life.

Risks

Earlier in Table 8.13 and Table 8.19, we set out the key failure modes of the types of conductor on our network, which also apply to LV conductor. Table 8.14 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 risk is elaborated on in Table 8.23 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 conductors is partially mitigated by the use of 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, and good PVC insulation may assist with lines remaining live on the ground due to further increasing fault impedance, but reduces the area of the conductor on the ground which has propensity to electrocute (only the broken end has no insulation on it).

Table 8.23: LV conductor-specific failure risks

RISK/ISSUE	RISK MITIGATION	RISK
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 of the considerations covered in section 8.2.6 for subtransmission conductor also apply to LV conductor. LV conductor is generally in public areas (unlike subtransmission) 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 conductors in use. Our preferred LV conductor is now PVC covered AAC with a similar rating uncovered neutral conductor. ABC is also used as required to mitigate clearance issues or other special circumstances.

We have not yet started our LV conductor renewal programme. As the projects will be smaller due to smaller sections, this work should be able to be fitted in between larger jobs such as distribution conductor projects. With the ramping down of pole replacement work that uses similar resources, we don't foresee a deliverability issue in the LV conductor replacement programme, noting that we have set a realistic timeframe to remove the LV conductor backlog taking account of deliverability and risk.

Operate and Maintain

Preventive maintenance

As described in section 8.2.5 for subtransmission conductor, condition assessment for conductor is relatively challenging and our current inspection regimes are the same in distribution conductor; they are limited to those statutory requirements covered during a pole test or are otherwise ad-hoc.

We are implementing a new inspection initiative across distribution conductor as described in Table 8.16. Initially inspections will be targeted to locations that have historically experienced conductor failure (which is overwhelmingly within the distribution conductor fleet), followed by using these inspections to fill data gaps, particularly with LV conductor, before becoming a fully integrated test regime.

Corrective Maintenance, Spares, and Reactive Maintenance

All considerations are the same as the other conductor fleets.

One notable difference with reactive maintenance on LV conductor is that when LV faults occur, regardless of where the fault occurs on the LV conductor, assuming the LV fuse operates properly and no operation of a high voltage circuit breaker or recloser occurs there is no visibility of this fault in our control room. 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 predict LV fault locations and the LV fault outage impact based on information received from customers.

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 (vs expected life), as a proxy for condition, 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 conductors 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.

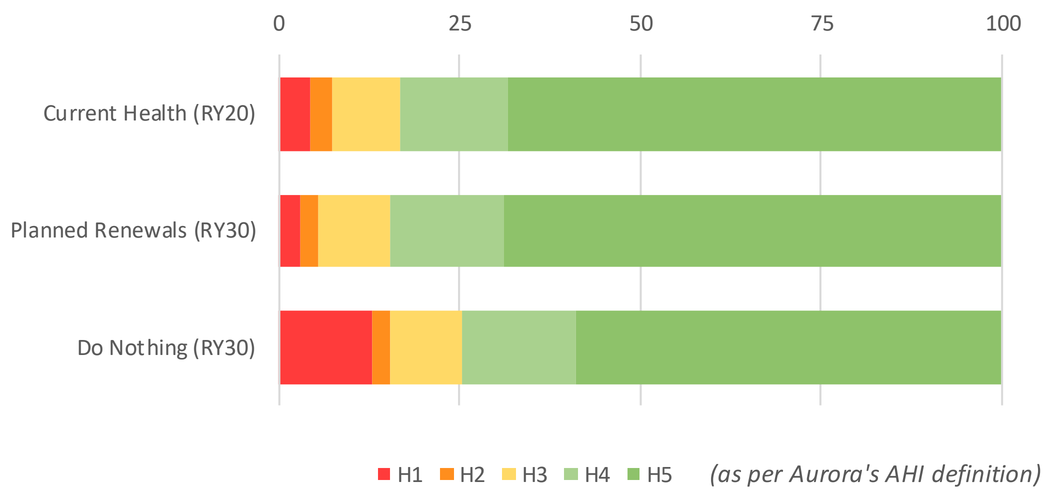
Table 8.24: Summary of LV conductor renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Age (vs expected life) *Future: 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 RY30. 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 RY30 following our planned renewals, with a counterfactual do nothing scenario. This comparison indicates the benefits provided by our proposed investment programme.

Figure 8.32: Projected LV conductor asset health



Our proposed level of investment will improve overall fleet health, helping manage the risks associated with conductor failure. In the hypothetical 'do nothing' scenario, 13% of our fleet, as depicted by the H1s will be at risk of failure as at RY30, and creating intolerable public safety risk.

Options analysis

With LV conductor more so than the other conductor fleets, we must consider the potential impacts, and enablement of embedded generation. As solar, battery, and electric vehicle penetration increases, there will be more impact on our LV network than other parts of the network. In areas where MDIs signal high loading, undertaking power quality monitoring prior to scoping LV conductor renewal will be prudent, to ensure the right option is chosen, including consideration to the replacement conductor ampacity.

Use of criticality in works planning and delivery

We are yet to develop a criticality based prioritisation framework for LV conductor, and will develop one as we have for distribution conductor in due course. In our GIS system consumer connections are often approximated by 'virtual connections', meaning getting accurate data on exactly which span customers are physically connected to and other LV information in general can be challenging. 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

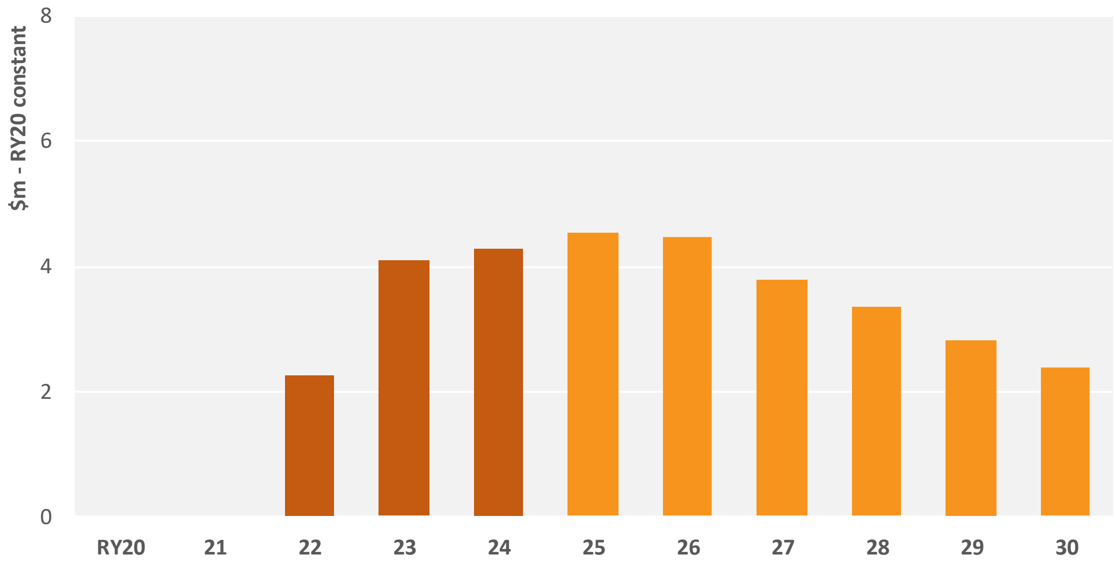
Planned network development projects focus on subtransmission and distribution constraints. LV enhancement works are undertaken as an outcome of Customer-Initiated Works (CIW) programmes, as customers request connection and require reinforcement of existing assets, or in response to voltage complaints and power quality monitoring proving that we have not met 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 Expenditure Forecast

We have forecast LV conductor renewal Capex of approximately $32m during the planning period.

Figure 8.33: Forecast LV conductor Capex



We have historically only replaced LV conductor on a reactive basis. The programme of work to replace end-of-life LV conductors will start in RY22. We will replace approximately 260 km (17% of our LV conductor fleet) over the planning period and continue to rectify low under clearances. This new programme of work will initially involve replacing an average of 31 km of conductor per annum (to RY26). Beyond this, we will continue to replace an average of 27 km per annum of conductor over the RY27-30 period, in order to return the associated risks of the fleet to an acceptable state. 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.

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[78] which includes three asset fleets:[79]

- subtransmission 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 subtransmission 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 subtransmission 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 $4.2m per annum on cable asset renewals, approximately half of this on subtransmission renewals.

Our cables work programmes focus on maintaining reliability and addressing safety concerns. The reliability impacts of cable faults, particularly subtransmission faults, can be greater than for overhead conductor due to the longer repair times requiring specialist resources.

Underground cables, like overhead conductors, convey electricity between the transmission system and zone substations and between different zone substations (subtransmission 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 various voltages. Underground cable makes up approximately 33% 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 the operating voltage of the cable. 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. These factors, together, can lead to different lifecycle strategies.

Box 8.10: Update on WSP Review – underground cables

Issues: WSP identified signs of condition deterioration in some oil/gas-filled subtransmission cables and also cast iron cable terminations, noting their potential explosive failure mode and public locations.

Response: replacement of all cast iron cable terminations with prioritisation based on public safety criticality. We will continue our programme of subtransmission cable replacements based on condition, obsolescence and resilience drivers.

Timing: we plan to replace all cast iron cable terminations by RY25. Subtransmission cable replacements will continue over the AMP planning period.

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78 All underground cables capex expenditure is covered under Asset Replacement and Renewal ID category, line items 'Subtransmission' and 'Distribution and LV cables, and will be included in Sch 11a(iv) in Appendix B.

79 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.

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 the underground cables portfolio are listed below.

Table 8.25: 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 and not rise.
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. Subtransmission Cables

Subtransmission Cables Fleet Overview

Subtransmission 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 subtransmission cable fleet consists of ~100 circuit kilometres of cable, approximately 80% of which is located in our Dunedin network region and includes any subtransmission cable ancillary equipment such as surge arrestors, and gas and oil pressurisation equipment. The nature of our subtransmission 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.

Subtransmission cables are critical on the network given the amount of power they commonly convey (compared to distribution cables). To mitigate failure risk, almost all of our subtransmission 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.

Subtransmission cables are inherently under greater stress than distribution and LV cables, by the nature of the voltage that they operate at. This makes them less resilient when defective.

Network considerations, in addition to being more complex and higher value equipment, mean that subtransmission cable projects tend to have a much greater cost than distribution cable projects. All of these factors support managing subtransmission cables as a separate fleet.

Our fluid-filled subtransmission cables are becoming obsolete due to unavailability of parts and specialist workers. Given that approximately half of our subtransmission cable is expected to require replacement within the planning period, we plan to take this opportunity to reconfigure the Dunedin subtransmission cable network in a manner which improves resilience to major events such as earthquakes. Some investments involved in the reconfiguration will be classified as subtransmission 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 subtransmission cable network consists of nitrogen gas-filled and oil-filled paper insulated cables (both of which can be classed as fluid-filled cables)[80], 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 more than 40% of total cable circuit length.

Table 8.26: Subtransmission cable population by type

TYPE	POPULATION (CIRCUIT KM)	PERCENTAGE
Gas-filled	22	22
Oil-filled	24	24
PILC	11	11
XLPE	42	43
Total	**99**	**100%**

Most of our Dunedin subtransmission 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 54 and 44 years respectively, with the gas cables just over 60 years old about to be decommissioned. While they have an expected life of 60 years, both of these cable types are now obsolete.

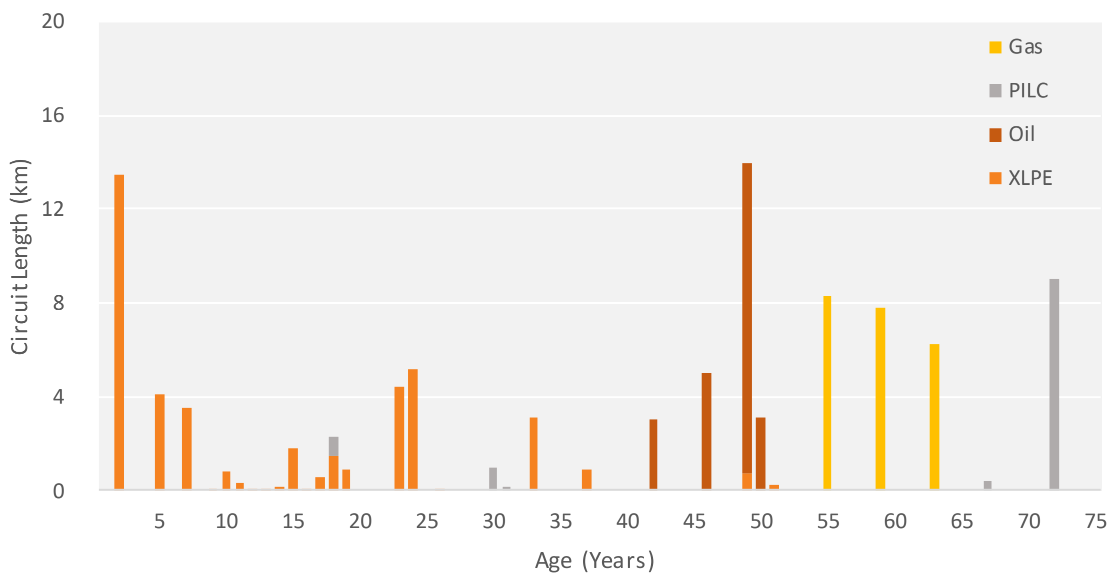
Our gas cable circuits use a mix of aluminium and copper conductor, while our oil-filled cables use only aluminium conductor. They both have a lead sheath and use paper insulation over the cable conductor. However unlike PILC (solid) cables, pressurised gas or oil is used to increase the voltage withstand 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

[80] 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.

cable operation is reliant on the pressurised fluid system containment, and require more maintenance and monitoring.

PILC (solid) 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 subtransmission cable is PILC type. PILC cables can use aluminium or copper conductor. It has an expected life of 80 years.

Figure 8.34: Subtransmission cable age profile



First generation XLPE cable, manufactured in the 1960s and 1970s, is known to fail prematurely due to water-treeing causing 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, quantities are minute and we are not seeing these failure modes. We are certain that we have no first generation XLPE at subtransmission 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 and aluminium is generally more cost effective and hence more widely used today.

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 as the skills required to repair these cables are becoming increasingly difficult to obtain.

Condition, Performance and Risks

Failure of a subtransmission 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 subtransmission cable assets is important for meeting our performance and environmental objectives. The main determinant of subtransmission cable life is how well the integrity of the cable sheath can be maintained. For fluid filled and solid PILC types, this is about how well the brass tapes/wipes are protected from corrosion, in turn protecting 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 the ground in which they were installed.

Our oil / gas-filled pressurised cables, which are the focus of our renewal programme, are obsolete technology. In particular, 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, and 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, 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 are of concern. This is more from the perspective of sheath continuity – to ensure moisture cannot progress into the cable – than the leaking of oil itself. We have scheduled replacement of our oil-filled cables for later in the planning period primarily indicated by 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 subtransmission 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 subtransmission 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.

The planned replacements are supported by performance data on our subtransmission cables. The figures below show the frequency and duration of equipment outages of subtransmission cable equipment since 2012.

Figure 8.35: Subtransmission cable performance – frequency of faults

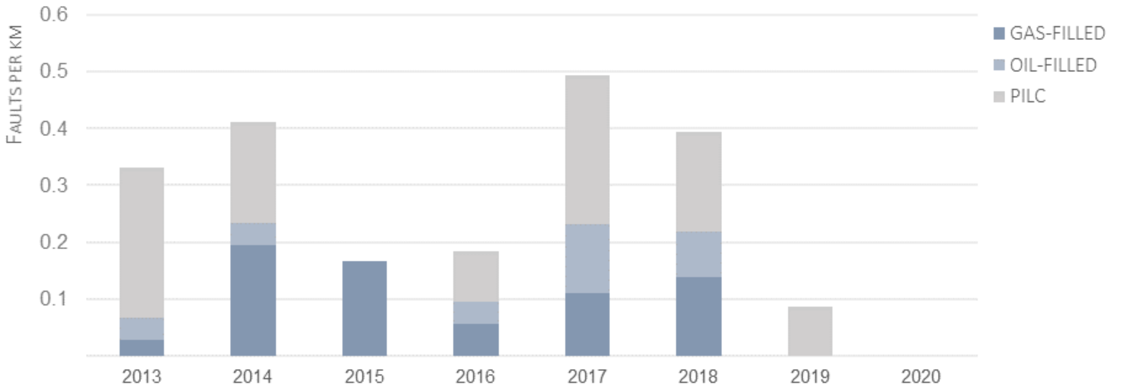
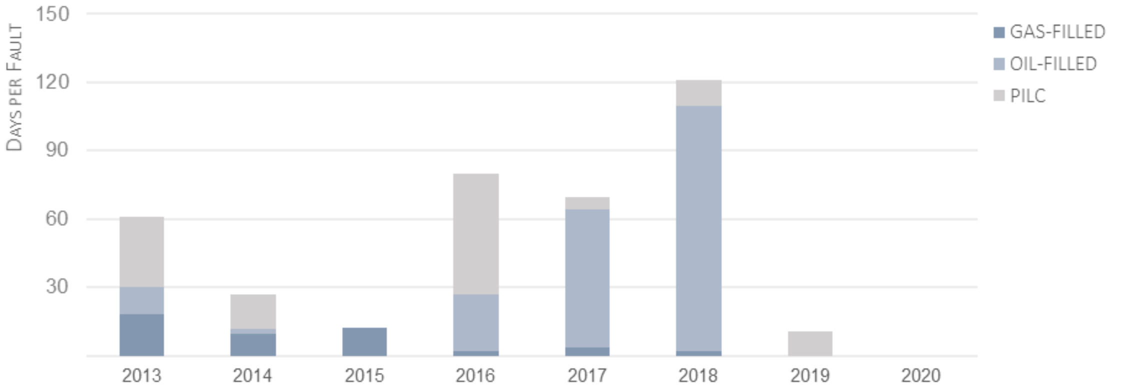


Figure 8.36: Subtransmission cable performance – duration of faults

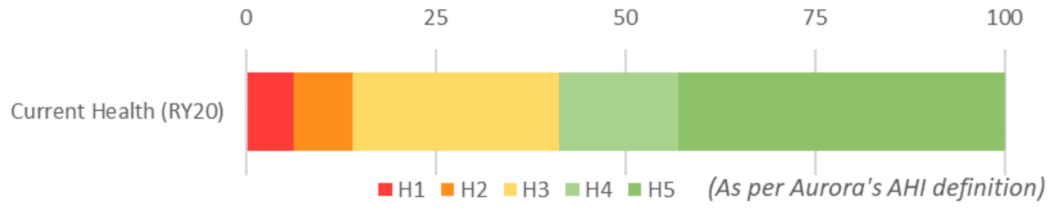


Most issues relate to our aged solid PILC and gas-filled pressurised cable which are scheduled for near term replacement. Outage duration is important when considering cable assets, as it can take an extended time to repair these assets and return them to service, particularly in the case of oil and gas-filled cable. While both duration and frequency of faults appears to have improved in recent years, it is too early to infer an improving trend.

Asset health

We estimate fleet asset health for subtransmission cables primarily on the basis of age (vs expected life) and condition. Subtransmission cable asset health is shown below.

Figure 8.37: Subtransmission cable asset health



Our asset health analysis indicates that approximately 15% of our subtransmission cable length has already or will reach end-of-life within the next three years, and close to half within ten years. Our proposed investment programme will maintain asset health at around the present level.

Risks

The table below sets out the key risks and mitigations we have identified in relation to our subtransmission cable fleet.

The instantaneous effects of a subtransmission cable failure are typically mitigated by the redundancy provided in the network design. However, repairs to subtransmission cable failures can be lengthy operations, creating significant reliability risk for the duration of the repair.

Table 8.27: Subtransmission cable risks

Risk/Issue	Type	Risk Mitigation	Main Risk
Cable strike	All	B4UDIG service Cable depth requirements, mechanical protection requirements Historical practice of both subtransmission circuits in the same trench now avoided Strategic spare cable joints N-1 redundancy in subtransmission 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 (environmental issue))	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	All	Some intertie capacity at distribution voltage level and a limited capacity 33kV link between Ward St and Carisbrook zone substations Dunedin subtransmission architecture changes will lead to diverse cable routes via a ring architecture, and hence a reduction of common mode failures	Reliability

RISK/ISSUE	TYPE	RISK MITIGATION	MAIN RISK
Fault due to PILC cable drying out	PILC (solid)	Cable differential protection is fast and limits cable damage N-1 redundancy in subtransmission installations Condition input of known historical failure modes factored into subtransmission cable replacement programme	Reliability
Oil/grease leakage at joints/pot-heads due to cable laid with high head	PILC (solid), gas-filled, oil-filled	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 subtransmission installations	Reliability
Ground level change due to landscaping / erosion	All	Regular survey of subtransmission cable routes	Reliability
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 arrestors protecting subtransmission cables; potential failure of the surge arrestor under fault conditions	All	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 subtransmission 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 subtransmission 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 subtransmission 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 subtransmission cable projects, they are expected to be competitively tendered.

We do not foresee significant deliverability issues in relation to subtransmission 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'.

Operate and Maintain

Preventive maintenance

We undertake little to no invasive preventive maintenance work on cables. Preventive maintenance involves regular inspections and testing to verify condition. Gas and oil-filled cables require additional inspection and testing due to their ancillary pressurisation and fluid storage systems. Our preventive maintenance regime for our subtransmission cable assets is summarised below. The detailed regime for each type of asset is set out in our maintenance standards.

Table 8.28: Subtransmission cable preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	STEADY STATE FREQUENCY
Ground based visual inspections of terminations (to identify deterioration such as fluid leaks, or damage that could lead to future failure such as rusting flanges)	Annual
Oil and gas-filled pressure tests (for early detection of leaks)	Two weekly
Alarm tests to confirm condition of alarms	Six monthly
Outer sheath electrical integrity testing	Annual
On line partial discharge testing	Annual

We continuously monitor fluid-filled subtransmission cable pressures via SCADA alarms. We will consider the use of very low frequency testing as a maintenance task as opposed to just a commissioning task, to improve our knowledge on our subtransmission cable condition.

Corrective maintenance

Subtransmission cable defect works include replacement joints or terminations, such as when identified as having partial discharge, sheath or termination repairs to minimise deterioration or in the event of an oil leak, or corrosion treatment and painting on terminations and ancillary cable equipment. Components on the cable ancillary equipment such as gauges and alarm contacts may also need repair or replacement. We will implement a corrective maintenance initiative as described below.

Table 8.29: Subtransmission cables corrective maintenance initiatives

CORRECTIVE MAINTENANCE INITIATIVE	RELATED CABLES OBJECTIVES	TIME FRAME
Rectify backlog of cable corrective maintenance We have identified a backlog of corrective work on our subtransmission oil pressurised cables. Terminations require repair in some cases for leaks, and corrosion control/painting at aerial ends including cable stands.	**Affordability** through cost management –These cables have generally been reliable and investing in maintenance now should ensure 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 but also cost perspective.	Medium term

Reactive maintenance

Reactive maintenance on subtransmission cables includes work required to return the circuit to service following a fault, whether the fault was unforced (the cable failed because of an issue with the cable), 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 resource which often has to be flown in to assist with fault finding or repairs.

We undertake post-fault root cause analysis for subtransmission cable failures, which enables us to identify if end-of-life failures are occurring.

Spares

We retain spares to manage the risk associated with our subtransmission cable fleet. We have experienced some problems procuring replacement spares for some of the older cable accessories and terminations on the PILC (solid) subtransmission cables, as well as the gas and oil-filled cables. Spares for gas cables are hard to source and the condition of those remaining in our stores is questionable. Oil cable spares are available for purchase though they are not widely available. These issues will be ultimately resolved by replacing aged subtransmission cable in coming years.

XLPE cables are current technology and are fully supported. 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.

Renew or Dispose

We replace sections or entire subtransmission 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 subtransmission cable renewal.

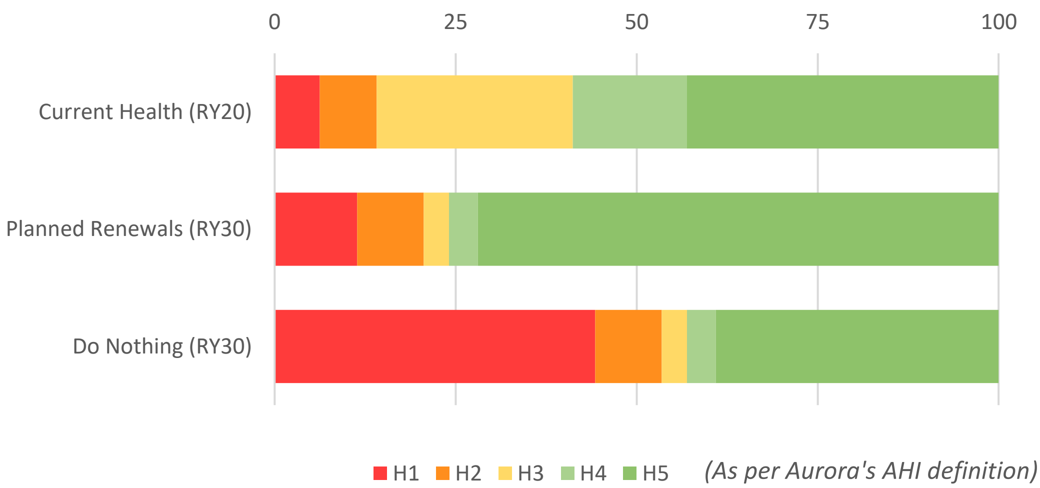
Table 8.30: Summary of subtransmission cable renewal approach

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 forecast renewals using a combination of age (against expected life), known condition, and obsolescence issues. Our work programme involves replacing 33 km of subtransmission cable in the Dunedin area during the planning period, comprising four renewal and two growth/resilience projects. The planned new 33 kV cable architecture will make some of the existing cables redundant. The chart below indicates the asset health improvements provided by our proposed investment programme.

Figure 8.38: Projected subtransmission cable asset health



Options analysis

When considering renewal of a subtransmission 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 subtransmission cable remediation include:

1. 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.
2. Replacing a section of subtransmission cable which has been found to be problematic, e.g. hill sections with joint failures.
3. Like-for-like replacement of the subtransmission cable along the existing route (electrically, and potentially physically) with a cable of economically justified ampacity.
4. Replacing the subtransmission cable, creating a different electrical network architecture
5. Replacing the subtransmission cable with a different voltage cable – in the majority of cases this would require a substantial growth driver and would be classed as a growth project. However, 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.

The options considered in each instance will take into account security considerations, 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 subtransmission 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 subtransmission 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 is a good example of this.

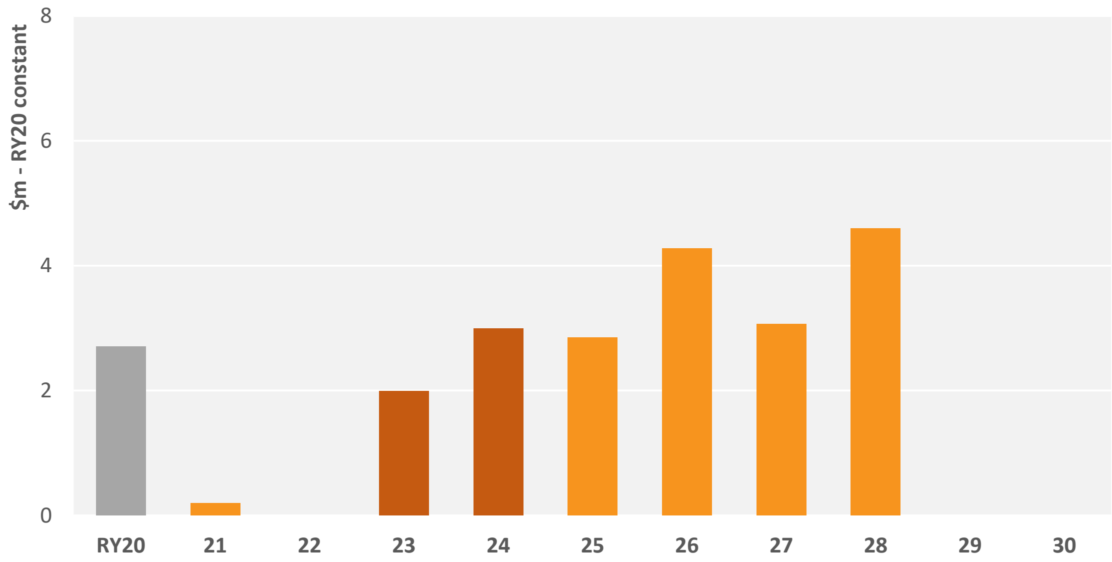
As trenching makes up a large proportion of cable replacement cost, we may align renewal works to take place in combination with CIW, growth projects and/or other underground infrastructure projects, to maximise value to our customers and communities.

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.

Subtransmission Cable Expenditure Forecast

We have forecast renewal Capex of approximately $20m during the planning period. Our focus is on replacing aged, obsolete gas-filled cable with failed sheaths, aged PILC subtransmission cable with dry-out issues, and obsolete oil cable. This will mitigate performance and safety risks.

Figure 8.39: Forecast subtransmission cables Capex



Benefits

The key benefit of our planned subtransmission cable renewal is to maintain reliability performance at the current level. The reconfiguration of the Dunedin subtransmission 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.

8.3.3. Distribution Cables

Where information is common with the subtransmission 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.[81] We own approximately 1,000 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 85 years ago. In contrast to subtransmission cable, distribution cable has often been built in relatively short sections. Overall our distribution cable assets are young relative to their expected

81 Some customers are directly connected to our network at 6.6 kV and 11 kV.

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

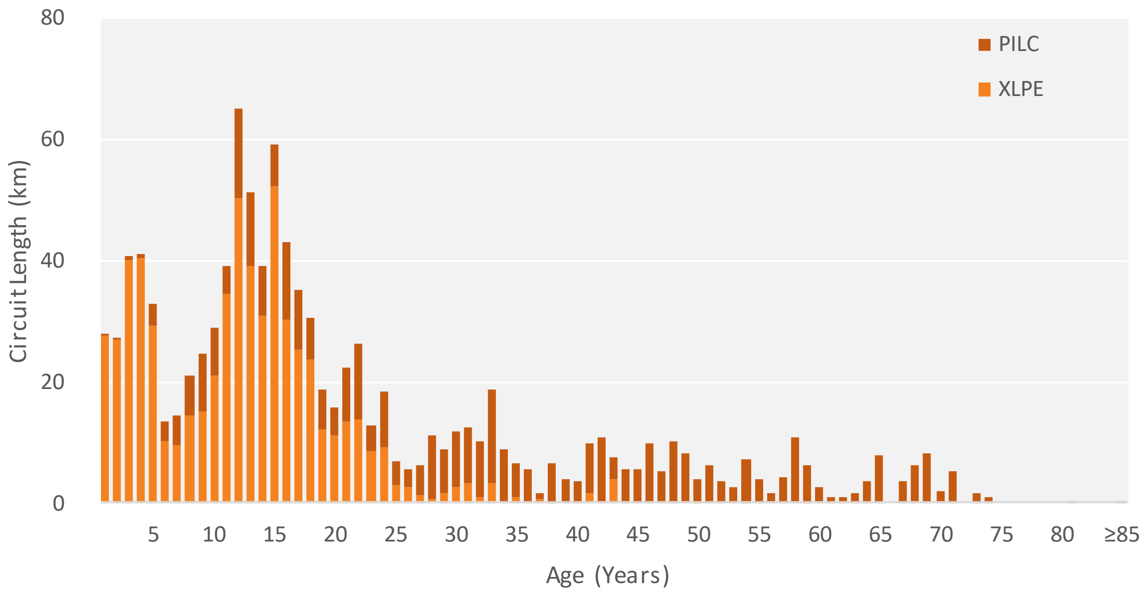
The table below summarises our population of distribution cable by type. The majority of our PILC distribution cable is in our Dunedin network region. PILC cable stopped being the standard cable used in our Dunedin network region in the 2000s, while XLPE was adopted earlier in our Central network region by the previous network owners. The majority of our XLPE distribution cable is in our Central Otago network region.

Table 8.31: Distribution cable population by type

TYPE	POPULATION (CIRCUIT KM)	PERCENTAGE
PILC	429	40%
XLPE	650	60%
Total	**1,079**	**100%**

The chart below shows our distribution cable age profile. Our distribution cable fleet is considerably younger than our subtransmission 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 10-15 years.

Figure 8.40: 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. However, the quality of our historical data is not such that detailed analysis can be easily undertaken and hence we are making improvements in fault information capture.

In general PILC cable does not cope well with being moved. Movement can occur when replacing poles with cables terminated, 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 remaining 400 cast iron cable terminations (a mixture of distribution and LV) during the planning period through a prioritised work plan.

Figure 8.41: 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.

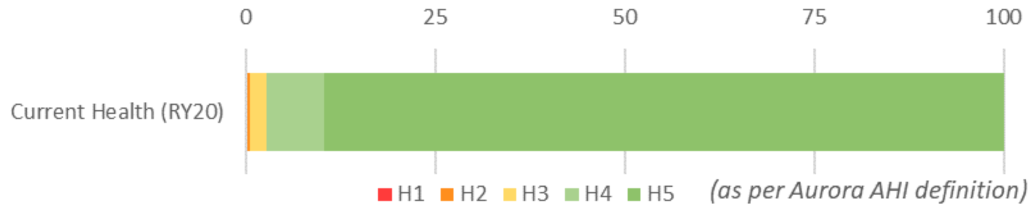
Meeting our portfolio objectives – safety first

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 8.42: Distribution cable asset health



The analysis indicates that approximately 3% of our distribution cable will reach end-of-life within the next ten years. Our fleet is relatively young 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 8.32: Distribution cable risks

RISK/ISSUE	TYPE	RISK MITIGATION	MAIN RISK
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 subtransmission 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 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, or replacing 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.[82]

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[83], 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

82 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 cables portfolio. If a ground mounted solution is required the total Capex falls into the distribution transformers portfolio.

83 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

fulfils 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.

Operate and Maintain

Preventive maintenance

Once outside the zone substation, sections of distribution cable commonly join 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 some of their maintenance and inspection activities.

As per subtransmission cables, we undertake little to no invasive preventive maintenance work on distribution cables. Our preventive maintenance regime for distribution cable is summarised below.

Table 8.33: Distribution cable preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	STEADY STATE FREQUENCY
Inspect cable risers for any obvious defects	Five yearly (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 yearly (oil-filled RMUs) Ten yearly (solid dielectric and SF_6 RMUs) (programme being established)
Insulation resistance and polarisation index of distribution cables - during RMU maintenance	Six yearly (oil-filled RMUs) Ten yearly (solid dielectric and SF_6 RMUs) (programme being established)
Clean dry type cable terminations on zone substation circuit breakers- during zone substation maintenance (where cable boxes are not fluid/compound filled)	Four yearly

Corrective maintenance

Corrective maintenance of cable assets is planned work to remediate defects identified either during preventive maintenance, or identified during fault response but not required for safe re-livening.

Distribution cable defect works include replacement joints or terminations[84], such as when they fail insulation resistance tests.

Reactive maintenance

Reactive maintenance on distribution cables includes work required to return the circuit to service following a fault, whether the fault was unforced (the cable failed because of an issue with the cable), 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.

[84] This statement applies to modern single phase termination types. Replacement of cast iron cable terminations is Capex.

Spares

We retain spares to manage the risk associated with our distribution cable 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.

Renew or Dispose

The table below summarises our approach to distribution cable renewal. Expenditure on distribution cables 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.

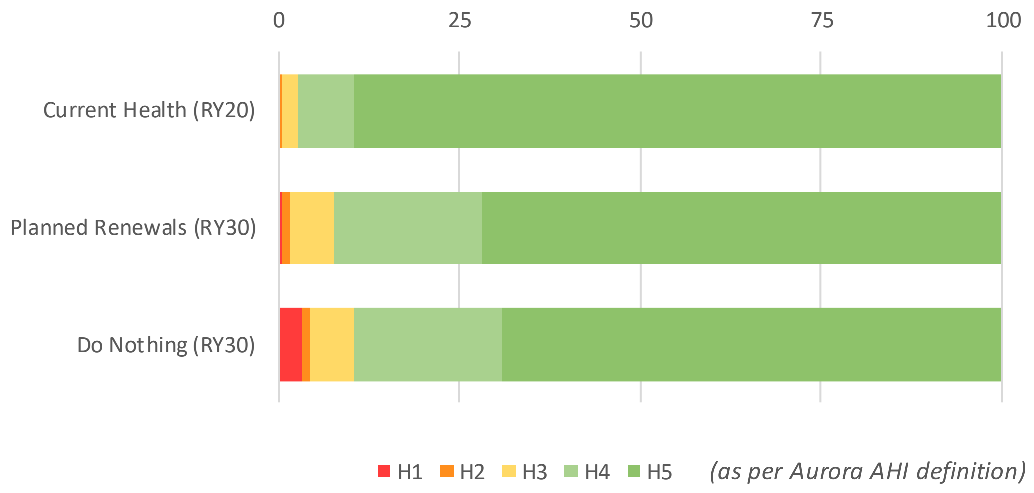
Table 8.34: Summary of distribution cable renewal approach

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 2030 following planned renewals, with a counterfactual do nothing scenario. It demonstrates the benefits of our proposed investment programme.

Figure 8.43: Projected distribution cable asset health



Currently only about 0.2% of our distribution cable is classified as H1. Under our planned programme of investments, this will increase slightly, to 0.4% by the end of the period. Failure to undertake the forecast level of renewals will increase H1 to about 3%. 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, and take 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 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.

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.

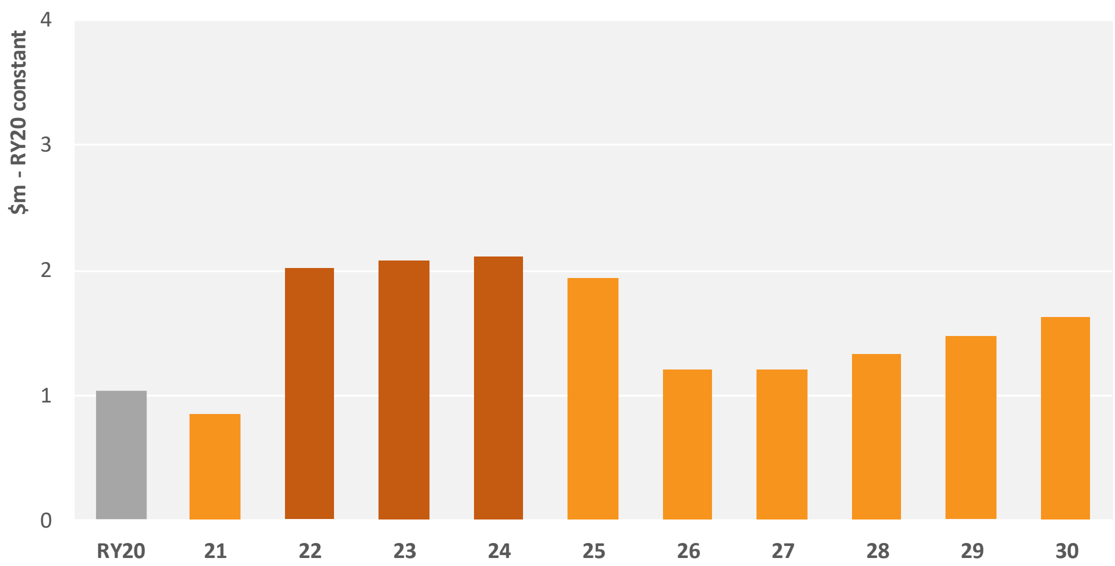
Meeting our portfolio objectives – sustainability by taking a long term view

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 Expenditure Forecast

Our forecast distribution cable renewal Capex is approximately $16m 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 8.44: Forecast distribution cables Capex



Historical expenditure has been relatively low due to the relatively young average age of these assets. Forecast expenditure during the period reflects our aim to replace all remaining cast iron pothead cable terminations by RY25. 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 subtransmission 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. However we also 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 80% of the population with small populations of PILC and PVC cable.

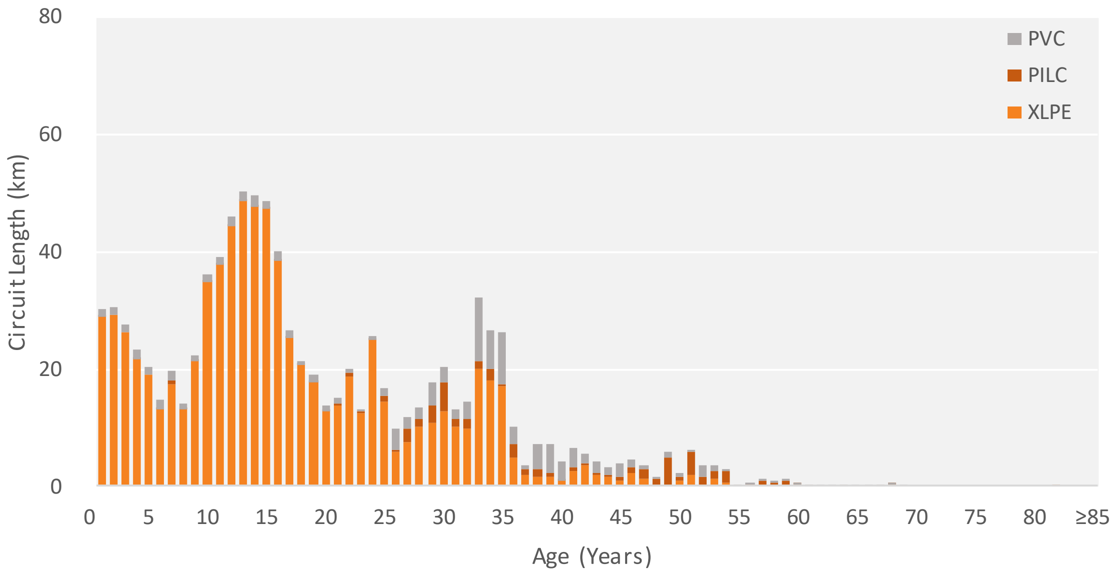
Table 8.35: LV cable population by type

TYPE	POPULATION (CIRCUIT KM)	PERCENTAGE
PILC	49	5%
XLPE	825	83%
PVC	114	12%
Total	**988**	**100%**

The chart below depicts our LV cable age profile. The same expected lives apply as per our other cable fleets. PVC cable is not present in the other fleets, and has an expected life of 60 years.

Our LV cable fleet is relatively young, much of it reflecting network growth over the past 10-15 years. Many councils now require underground cables in preference to overhead lines; leading to an increased use of cable, particularly in the case of new subdivisions/connections in Central Otago.

Figure 8.45: LV cable age profile



As discussed in the subtransmission 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. However, 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.

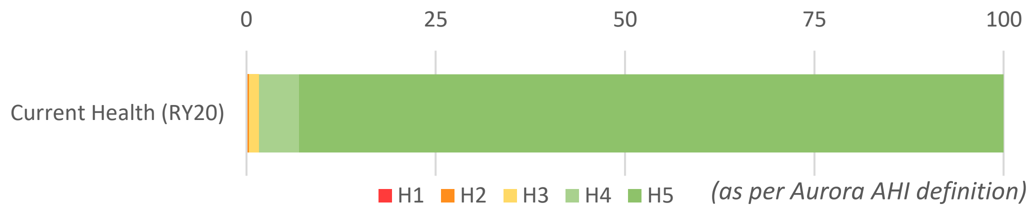
The majority of LV cable failures are attributable to damage from third party construction and ground movement. As the older PILC cables are fragile, movement is detrimental. We have also seen some issues with crystallisation of the lead sheath in Central Otago, which can lead to cracking of the lead sheath if the cable has force exerted on it (such as during works or a fault), which will quickly reduce the cables life expectancy. These cases are rare, and 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 8.46: LV cable asset health



Our asset health analysis indicates that approximately 2% of our LV cable will reach end-of-life within the next ten years. This reflects the relative youth of the fleet.

Risks

The following table sets out the key risks we have identified in relation to our LV cable fleet.

Table 8.36: LV cable risks

RISK/ISSUE	TYPE	RISK MITIGATION	MAIN RISK
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 so equipment is generally designed for cables to be broken out inside the equipment. Single core cable may be required for sufficient rating in some applications.

Operate and Maintain

Preventive maintenance

We do not undertake any material LV cable preventive maintenance. However, during other equipment inspections we do inspect LV cable terminations, and when LV terminations are out of service for other equipment maintenance and are accessible, we clean them as necessary.

Our preventive maintenance regime for our LV cable assets is summarised below. The detailed regime for each type of asset is set out in our maintenance standards.

Table 8.37: LV cable preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	STEADY STATE FREQUENCY
Inspect visible LV cable and terminations	Five yearly (during pole inspections) During LV enclosure inspections During ground mounted transformer inspections
In addition to visual inspection, clean LV cable terminations	During RMU maintenance, where the associated ground mounted transformer is on the same site and is de-energised

Corrective Maintenance, Spares, and Reactive Maintenance

These considerations are the same as for the other cable fleets, noting the specific issue with LV cable breakout repairs which are remediated under corrective maintenance.

One notable difference with reactive maintenance on LV cable is that with LV faults 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.

Renew or Dispose

The following table summarises of 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.

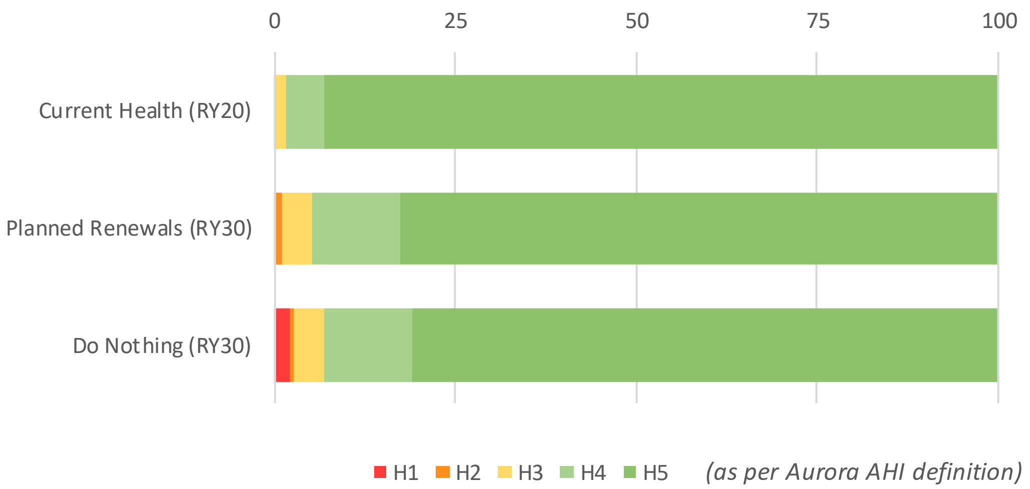
Table 8.38: Summary of LV cable renewal approach

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 following chart compares projected asset health in 2030 following planned renewals, with a do nothing scenario. It demonstrates the benefits of our proposed investment programme, i.e. we maintain our health levels. Note that the proportion of H2 classed cables increases under our planned renewal approach, reflecting that the assets are getting older, and potentially signalling future increased renewal levels, in the 10 years out horizon.

Figure 8.47: Projected LV cable asset health



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

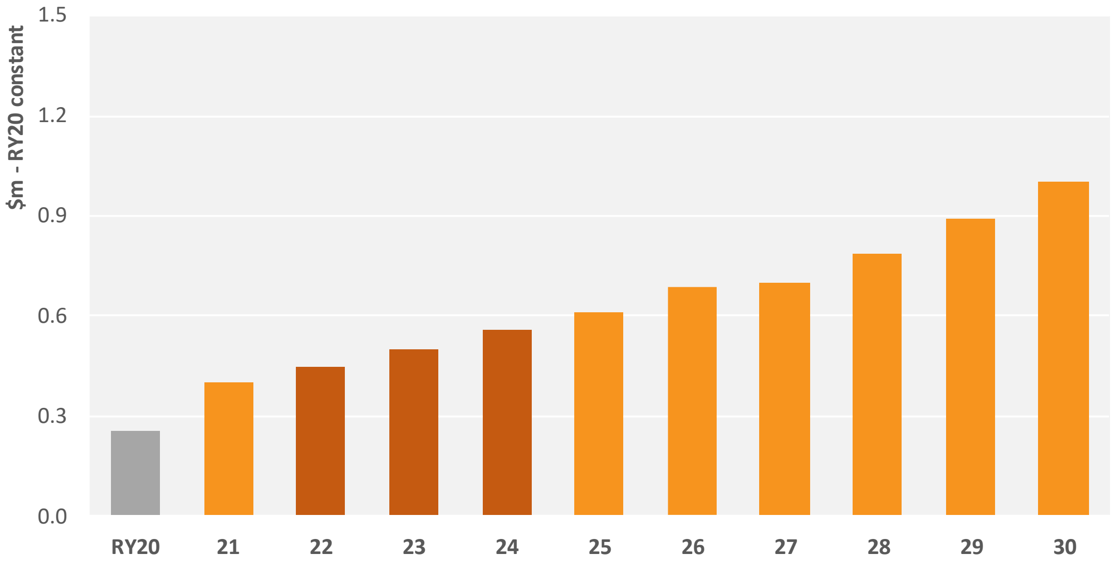
With the exception of opportunistic replacements (such as part of replacing a poor condition pole), we are prioritising replacement of cast iron cable terminations based on public safety criticality zone. Higher criticality areas are highly populated areas such as schools and beside significant roads.

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 Expenditure Forecast

Our forecast of LV cables renewal Capex is approximately $6.6m during the planning period. It excludes LV cable and termination replacements undertaken as part of other work such as distribution transformer, pole, and LV enclosure replacement.

Figure 8.48: 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 slowly ramp up expenditure throughout the CPP Period and beyond to manage health of the LV cable network and respond to third party damage. We will remediate all cast iron cable terminations by RY25.

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.

8.4. ZONE SUBSTATIONS

This section describes our zone substations portfolio[85] 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 $7.8m, 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. At that time we 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 11 kV switchboards have a higher than acceptable arc flash risk. We have prioritised replacement of oil filled, non-arc fault contained switchgear.

Zone substations take supply from GXPs through subtransmission feeders (both overhead and cable). The photo below shows one of our modern zone substations. They provide connection points between subtransmission 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.

[85] All zone substations Capex is covered under the Asset Replacement and Renewal information disclosure category, line item 'Zone Substations' and is included in Schedule 11a(iv) in Appendix B.

Figure 8.49: Camp Hill zone substation

Box 8.11: Update on WSP Review – zone substations

Issues: risks that WSP identified included 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 8.39: Zone substations portfolio objectives

OBJECTIVE AREA	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. The buildings and grounds 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

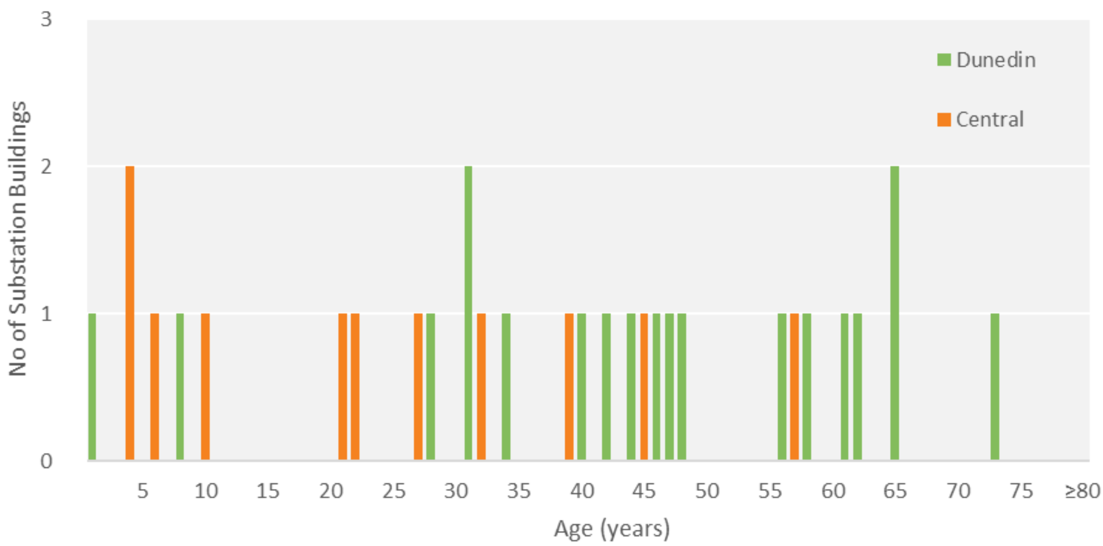
The table below summarises our population of zone substation buildings by network location. Some of our smaller zone substation sites do not have buildings but have fencing and earthing.

Table 8.40: Zone substation buildings by region

REGION	POPULATION
Central	11
Dunedin	19
Total	30

The figure below depicts the age profile of our zone substation buildings by region.

Figure 8.50: Zone Substation buildings age profile



Overall, the average age of our zone substation buildings is 39 years. The buildings in our Dunedin region have a higher average age (46 years) than those in our Central region (26 years). Our oldest substation building is located at our Ward Street substation in Dunedin (and is a heritage building).

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, and use this as a proxy for the building containing the switchgear.

Risks

Many of our buildings do not have air conditioning and we have started 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, 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 developed detailed designs for seismic strength upgrades of the buildings which 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 8.41: Zone substation building and ground risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
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	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 switchroom 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.

As part of design for our projects underway at present, we will consider the creation of 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 have created a steady work plan that is deliverable with our FSA partners and supplementary contractors as required.

Operate and Maintain

Preventive Maintenance

Our preventive building and grounds works are summarised below. Detailed condition inspections to support corrective maintenance activity works are undertaken by suitably qualified personnel.

Table 8.42: Buildings and grounds preventive maintenance and inspection tasks

Maintenance and Inspection Task	Steady State Frequency
Substation grounds maintenance; lawn mowing, weed management, security inspections	Two weekly
Substation monthly inspection, checklist followed to record issues sighted, includes alarm checks etc.	Monthly
Ripple injection CO_2 system and fire mitigation system checks/tests	Annually, pressure test every five years
Fire system checks/tests	Annually
Earth grid testing	Five yearly

Corrective Maintenance

Corrective maintenance involves remediating defects such as, graffiti, damaged fences, and broken gutters, and proactive corrective work such as painting. As part of our efforts 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 in the area of affordability.

Table 8.43: Buildings and grounds corrective maintenance initiatives

Corrective Maintenance Initiative	Related Zone Substations 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. Issues found are remediated during seismic upgrades or future upgrade or renewal work at the site.	**Affordability** through cost management – Undertaking remediations on buildings reduces overall cost-of-ownership.	Medium term

Reactive Maintenance

Reactive maintenance on buildings is limited. Typical examples include addressing security/fire alarms that have been activated, or first response to any issues, for example, weather related issues, broken windows, a burst water pipe, or response to reported intruder sighting.

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 8.44: Summary of buildings and grounds renewal 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 power 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 65 power transformers.[86] 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.

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. This limits interchangeability and operational flexibility.

Table 8.45: Power transformers population by size

REGION	HIGHEST OPERATING VOLTAGE	SIZE (MVA)	POPULATION
Power Transformers	33 kV	<10	28
		10-20	32
	66 kV	<10	1
		10-30	4
Total			65

86 This excludes our mobile substation transformer which is covered under zone substation ancillary equipment.

The figure below shows the age profile of our power transformers.

Figure 8.51: Power transformers age profile

Their average age is 37 years, against a life expectancy of 60 years. Eight of our power transformers have exceeded 60 years of age.

Condition, Performance and Risks

Condition

Our now ongoing routine testing and inspection of power transformers helps us understand how they are ageing and indicates 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.

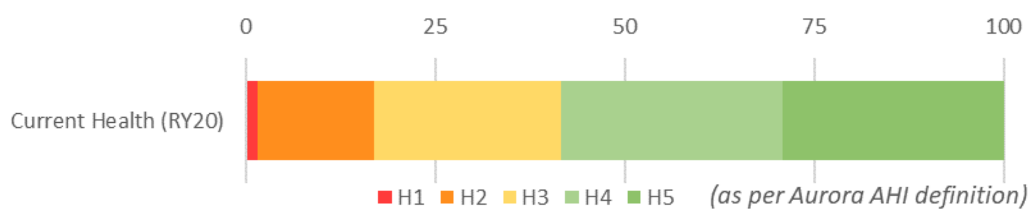
Asset health

We assess the health of our power transformers using a similar approach to that recommended by the "EEA's Asset Health Indicator Guide"[87]. Our power transformer AHI 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 8.52: Power transformer asset health



This shows that 2% have a health of H1, suggesting replacement in the near term is likely required. A further 15% have a health score of H2 and are likely to require replacement early in the planning period.

87 "Asset Health Indicator Guide (AHI Guide)", Electricity Engineers' Association, 2016, see https://www.eea.co.nz/

Criticality

For power transformers, the key criticality dimension is reliability and this is related to the load served and the level of backup supply. In order to prioritise their replacement we have, along with AHI, 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
- 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).

This means that, for 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.

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 8.46: Power transformer risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
Oil spill	New transformers have bunding and oil containment 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	Environmental, reliability
Fire as a result of transformer failure	Replacement transformers meet standard fire clearance requirements or 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 arrestors on new transformers as standard practice Retrofit surge arrestors onto existing transformers where feasible	Reliability
Excessive transformer noise	Investigate complaints and remediate to council limits if required Acoustic studies and transformer specification	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 program, 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 arrestors, 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.

Operate and Maintain

Preventive Maintenance

Preventive work is summarised below with detailed regimes set out in our maintenance standards.

Table 8.47: Power transformer preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	STEADY STATE FREQUENCY
Oil level recordings	Monthly
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	Monthly
Dissolved gas analysis to identify the presence of internal faults	Annually
Oil quality and furan analysis to evaluate the rate of transformer ageing	Four yearly
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 yearly
Tap changer maintenance; occurs after the earlier of a time period or set number of operations to ensure continuing operation and reliability of tap changer.	Manufacturer recommended, variable according to tap changer type

Corrective Maintenance

Power transformer defects such as rust repairs, oil leak repairs or replacement of a seized fan are dealt with under corrective maintenance. Some minor works may be undertaken while undertaking four yearly out of service maintenance.

To improve fleet performance we have identified a corrective maintenance initiative. This initiative supports our affordability objective.

Table 8.48: Power transformers corrective maintenance initiatives

CORRECTIVE MAINTENANCE INITIATIVE	RELATED ZONE SUBSTATIONS 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.	Affordability through cost management – through cost management – Painting transformers before they pass the point of disrepair can reduce overall cost-of-ownership.	Medium term

Reactive Maintenance

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 and if N security 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.

Spares

We have a 66-33/11-6.6 kV mobile substation (5 MVA at 11 kV and 3 MVA at 6.6 kV), and a number of our N security zone substations are enabled for its connection. We also have a spare 33/11 kV, 5 MVA transformer which can provide longer term coverage should a transformer fail or the mobile substation is in use.

For our larger zone substation transformers, we currently do not have a spare transformer. We expect to have two larger, mid-life, zone substation transformers released in RY21. We will consider their re-deployment permanently at other end-of-life N security sites, or retention as spares. We plan to create contingency plans for each transformer, and through this analysis will consider future procurement of a larger strategic spare transformer among other risk mitigation options.

Box 8.12: 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.

When transformers are decommissioned, if spare parts are shared with other units on the network they are retained as spares. Examples are bushings and tap changers. Our standardisation of transformers and major components will make spares holdings simpler going forward.

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.

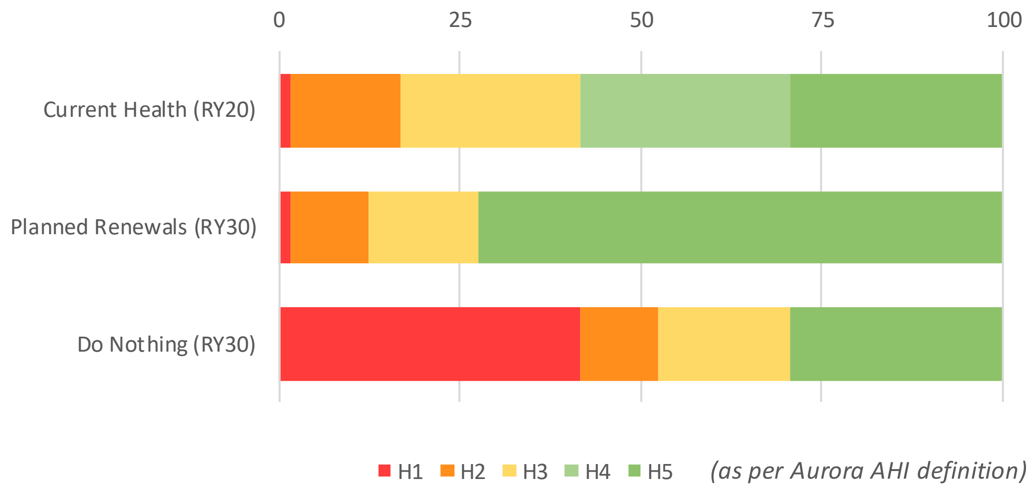
Table 8.49: Summary of power transformer renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Risk based using asset health and criticality
Forecasting approach	Risk based 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. 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 8.53: Projected power transformer asset health



Our power transformer fleet is ageing and likelihood of asset failure is increasing. This is reflected in our current asset health where approximately 40% (H1-H3) require replacement in the planning period. Under our planned renewals programme overall transformer health will improve over the period to RY30. However, aggregate health would decline to a significantly lower level in the absence of any transformer replacements ('do nothing' scenario).

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 the options of replacement, refurbishment (off site), decommissioning or component replacement (on site) are generally considered. 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, Bucholz 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.

We have identified one (Earnscleugh) small N security zone substation that can be decommissioned through reconfiguring the network to bypass this substation.

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 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 8.54: Modern 11 kV 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 and 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

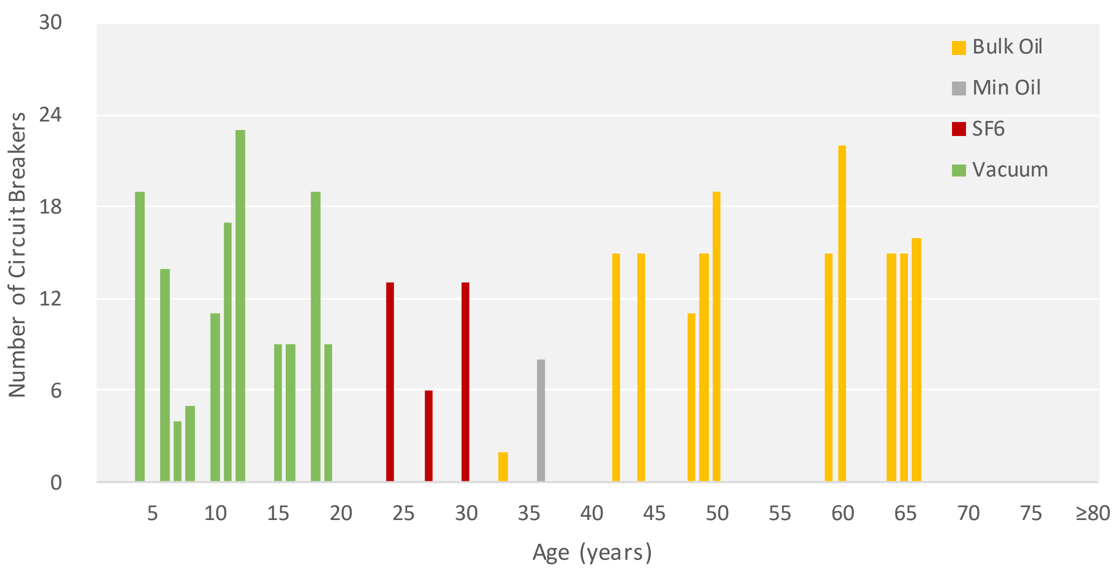
Our zone substation portfolio contains a total of 339 indoor circuit breakers (making up 30 switchboards). The table below summarises the population by type and rated voltage.[88]

Table 8.50: Indoor switchgear population by rated voltage

	INTERRUPTING MEDIUM	6.6 KV	11 KV	33 KV	TOTAL
Indoor switchgear	Oil	61	107	0	168
	SF_6	0	26	6	32
	Vacuum	0	136	3	139
Total		**61**	**269**	**9**	**339**

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.

Figure 8.55: Indoor switchgear age profile



The average age of our indoor circuit breakers is 33 years, with those in our Dunedin network region having a higher average age than those in our Central Otago network region. Our life expectancy for

[88] Some of our 11 kV switchboards in Dunedin operate at 6.6 kV.

vacuum and SF_6 circuit breakers is 45 years. For bulk oil and minimum oil circuit breakers life expectancies are 50 and 35 years, respectively. These circuit breaker life expectancies are based on standard industry practice. A significant number of our oil circuit breakers have exceeded their expected life, with the average age of oil circuit breakers currently at 53 years, and the oldest being 66 years. 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.

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 11kV 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[89]. 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.

During the WSP review, field visits identified that a number of 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.

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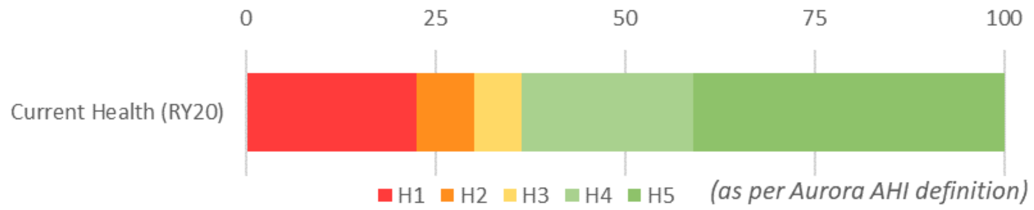
89 We have had catastrophic failures of indoor switchgear installed in outdoor enclosures, which are covered in our outdoor switchgear fleet.

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 8.56: Indoor switchgear asset health



A significant proportion (22%) have a health score of H1 and need replacement in the short term. Also, ~8% have a health score of H2, 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). In order 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
- 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.

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 gasses. 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 switchroom 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 8.51: Indoor switchgear risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
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 explosion	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 arrestors 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.

Operate and Maintain

Preventive Maintenance

Preventive work is summarised below, with detailed regimes set out in our maintenance standards.

Table 8.52: Indoor switchgear preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	STEADY STATE FREQUENCY
Visual inspection of circuit breakers including cyclometer readings	Monthly
Thermography, partial discharge and acoustic tests	Annually
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 yearly
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 yearly

We have identified a preventive maintenance initiative to improve performance of the indoor switchgear fleet as set out below. This initiative supports our safety and reliability objectives.

Table 8.53: Preventive maintenance initiatives – indoor switchgear

PREVENTIVE MAINTENANCE INITIATIVE	RELATED ZONE SUBSTATIONS 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, ranging from an outage until switching occurs through to worst case – collateral damage to the rest of the switchboard causing an extended outage.	Short term

Corrective Maintenance

Indoor switchgear defects identified during inspections and maintenance are dealt with under corrective maintenance. An example includes the replacement of insulating washers on current transformers after they fail 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.

Reactive Maintenance

Reactive maintenance occurs in response to switchgear alarms received to the control room, maloperation or failure. In all cases on-site inspection is required, and potentially further action subject to the findings.

Spares

We have limited spares for our oldest indoor switchboards. We 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 spares review once a full stocktake of spares is complete. Some additional spares may be purchased and contingency plans created as a result of this review. When switchgear is decommissioned, if spare parts are applicable to other assets remaining in service, some will be retained.

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.

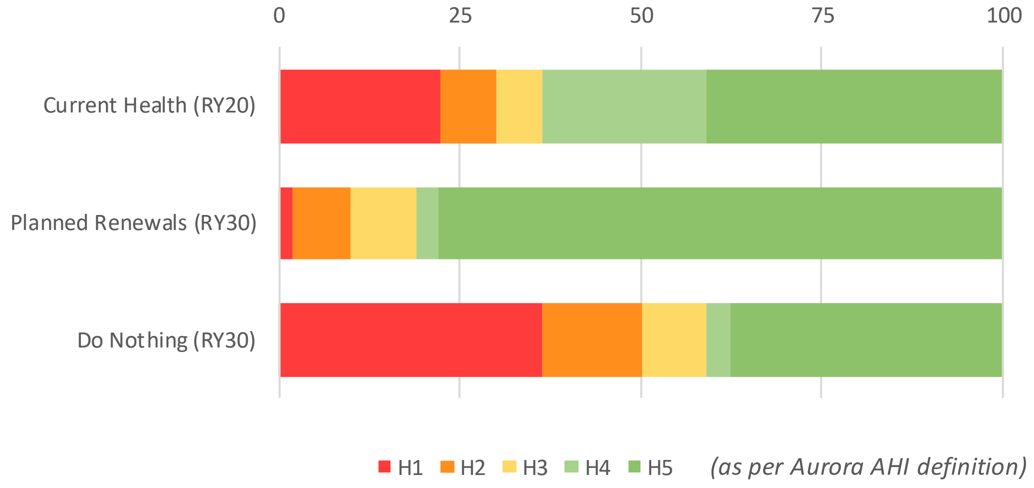
Table 8.54: Summary of indoor switchgear renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Proactive, asset health
Forecasting approach	Risk based 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.

Figure 8.57: Projected indoor switchgear asset health



Our indoor switchgear fleet is ageing and its likelihood of failure increasing. This is reflected in our current asset health with approximately 35% of our fleet requiring replacement over the planning period. Our planned renewals programme will improve overall fleet health, with H1s reducing to approximately 2%. However, aggregate health would decline resulting in a significantly higher level of H1s in the absence of any indoor switchgear renewals ('do nothing' scenario).

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 as a greenhouse gas, and also being contaminated with toxic arc by products, 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

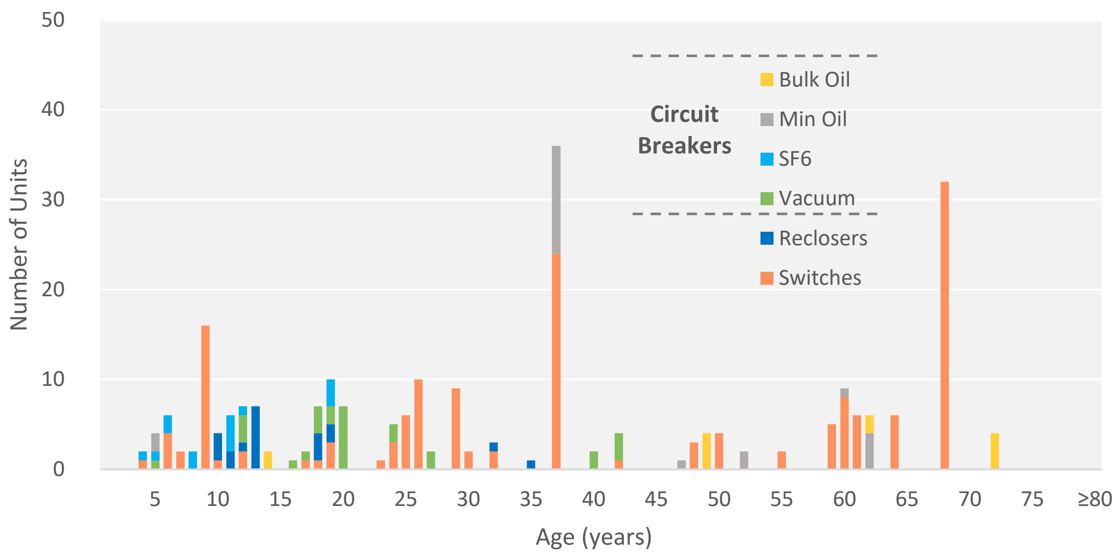
Our zone substation portfolio contains a total of 250 outdoor switchgear units, comprising of circuit breakers, reclosers (within zone substations, reclosers provide zone substation circuit breaker functionality), and switches. The table below summarises their population by type.

Table 8.55: Outdoor switchgear population by rated voltage

	INTERRUPTING MEDIUM	TOTAL
Outdoor circuit breakers	Oil	34
	SF_6	14
	Vacuum	27
Reclosers		20
Air break switches		155
Total		**250**

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. Their average age is 31 years.

Figure 8.58: Outdoor switchgear age profile



Our vacuum and SF_6 circuit breakers are relatively young, with average ages of 22 and 11 years, respectively. The life expectancy of vacuum and SF_6 circuit breakers is 40 years. In contrast, our bulk oil and minimum oil insulated circuit breakers have respective average ages of 53 and 42 years, against respective life expectancies of 45 and 35 years. A number of our OCBs have already exceeded their life expectancy and we cannot source spares for our minimum OCBs which has reduced their serviceable life.

A significant number of the switches in our zone substations have exceeded their life expectancy 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

We have not been able to internally access our minimum OCBs for some time due to unavailability of spares from the manufacturer, and therefore have not been able to undertake a full condition assessment. We have not been able to assess contact condition but are able to flush the oil during maintenance. The WSP review identified a need to replace these circuit breakers.

While not strictly a condition issue, we are replacing a type of oil-immersed interrupter vacuum circuit breaker due to a potential failure mode of moisture ingress through the seals on the bushings. The bushings were locally modified to accommodate current transformers with the result that these circuit breakers have a reduced life span based on this failure mode and historical failures. The bushing modification requires the seals to be in an unrealistically good condition to be effective.

We have a population of indoor type minimum oil-filled 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 are fixed rather than withdrawable. In the 1980's 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 8.59: Indoor minimum oil-filled circuit breakers (left) installed in 'outdoor cubicles' (right)

Performance

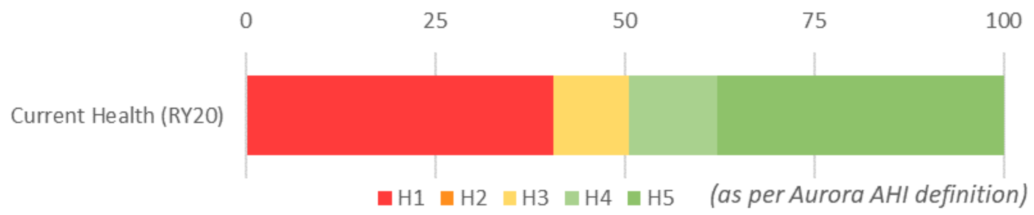
Our ageing population of oil-filled outdoor switchgear poses safety and performance risks. However, unlike our indoor switchgear fleet, our outdoor switchgear has an elevated track record of poor performance . We have recent experience of outdoor switchgear failures:

- 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 switches (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, recloser or switch, from its life expectancy. The chart below summarises current AHI for the fleet.

Figure 8.60: Outdoor switchgear asset health



A significant number (41%) have a health of H1 and need replacement in the near term. The poor health predominantly reflects old ABS and oil-filled circuit breakers. Approximately 50% of the fleet is due for renewal in the planning period.

Criticality

Our assessment of renewal need does not specifically use criticality. In the future we intend to include criticality in 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 8.56: Outdoor switchgear risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
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 arrestors 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.

Operate and Maintain

Preventive Maintenance

Our preventive outdoor switchgear works are summarised below. The detailed regime for each activity is set out in our maintenance standards.

Table 8.57: Outdoor switchgear preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	STEADY STATE FREQUENCY
Visual inspection of circuit breakers including cyclometer readings	Monthly
Thermography, partial discharge and acoustic tests	Annually
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 yearly
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 yearly
Air break switch maintenance; identify visually apparent defects, diagnostic testing, operational checks, check cement (two piece) cleaning, minor repairs	Four yearly

We have identified the following initiative to improve the performance of the outdoor switchgear fleet. This initiative supports our safety and reliability objectives.

Table 8.58: Preventive maintenance initiatives – outdoor switchgear

PREVENTIVE MAINTENANCE INITIATIVE	RELATED ZONE SUBSTATIONS OBJECTIVES	TIME FRAME
Post fault zone substation oil circuit breaker servicing Historically OCBs 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.	Short term

Corrective Maintenance

Outdoor switchgear defects are dealt with under corrective maintenance. An example includes treating corrosion on an outdoor circuit breaker stand.

Reactive Maintenance

Reactive maintenance occurs in response to switchgear alarms received to the control room, maloperation or failure. In all cases this requires on-site inspection and potentially further action.

Spares

We have spare 11 kV and 33 kV outdoor circuit breakers. We have no spare 66 kV circuit breaker but are investigating procurement options. We will conduct a spares review once a full stocktake of spares is complete. Subsequently, additional spares may be purchased and contingency plans created, such as for current and voltage transformers. When switchgear is decommissioned it will be retained if spare parts are usable.

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 8.59: Summary of outdoor switchgear renewal approach

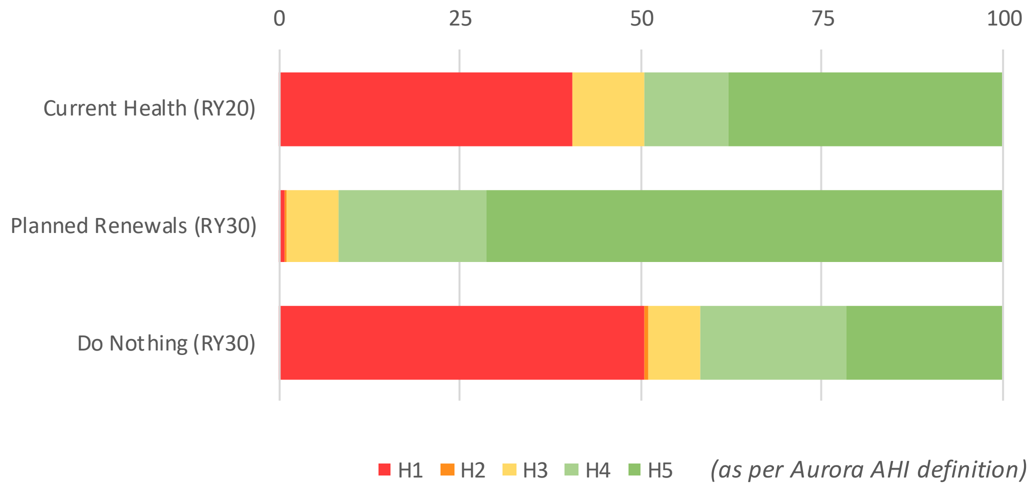
ASPECT	APPROACHES USED
Renewal trigger	Proactive, age vs expected life
Forecasting approach	Remaining life Consolidation of zone substation projects
Cost estimation	Tailored estimates

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 40% of the fleet has already exceeded its life expectancy (H1). Our planned replacement programme will reduce the number of H1s down to 1% by 2030.

Figure 8.61: Projected outdoor switchgear asset health



Options analysis

Where a significant amount of outdoor switchgear is planned for renewal, conversion to indoor modern equivalent is considered and the costs and benefits compared. 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 includes 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 ten 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. On the modern (2011), solid state, 317 Hz system, in Dunedin we operate two or three[90] ripple injection load control systems in parallel injecting at GXPs, controlled via the Dunedin SCADA master station. Two injection units exist at one GXP and one injection unit with two converters at the other.

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

[90] If the bus at Transpower's Halfway Bush substation is operationally spilt we need to operate three ripple plants.

solid state ripple injection plants in our Central region. 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 container buildings housing ripple plants have no temperature or humidity control and this is also being investigated.

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 rustkill/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 8.60: Ancillary zone substation equipment failure risks

Risk/Issue	Risk Mitigation	Main Risk
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 LVAC panels as part of zone substation projects	Safety

Design and Construct

The main design consideration in this fleet is physical layouts of outdoor substations. 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.

Operate and Maintain

Preventive maintenance

The table below sets out preventive maintenance tasks for ancillary equipment.

Table 8.61: 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)	Monthly
317 Hz / 1050 Hz ripple plant visual inspection (at monthly zone substation inspection)	Monthly
Local service system visual inspection (at monthly zone substation inspection)	Monthly
1050 Hz ripple plant maintenance	Four yearly
317 Hz ripple plant inspection and maintenance	Yearly
Mobile substation full maintenance	Four yearly
Mobile substation checks and roadworthiness	Six monthly

Corrective maintenance, spares, and reactive maintenance

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, mitigating the risk of a fault impacting on performance. However, we do need to procure some spares for key 317 Hz ripple plant components.

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 8.62: 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 317Kz ripple injection equipment during the planning period. We are progressively removing 1050Hz 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 the majority of 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

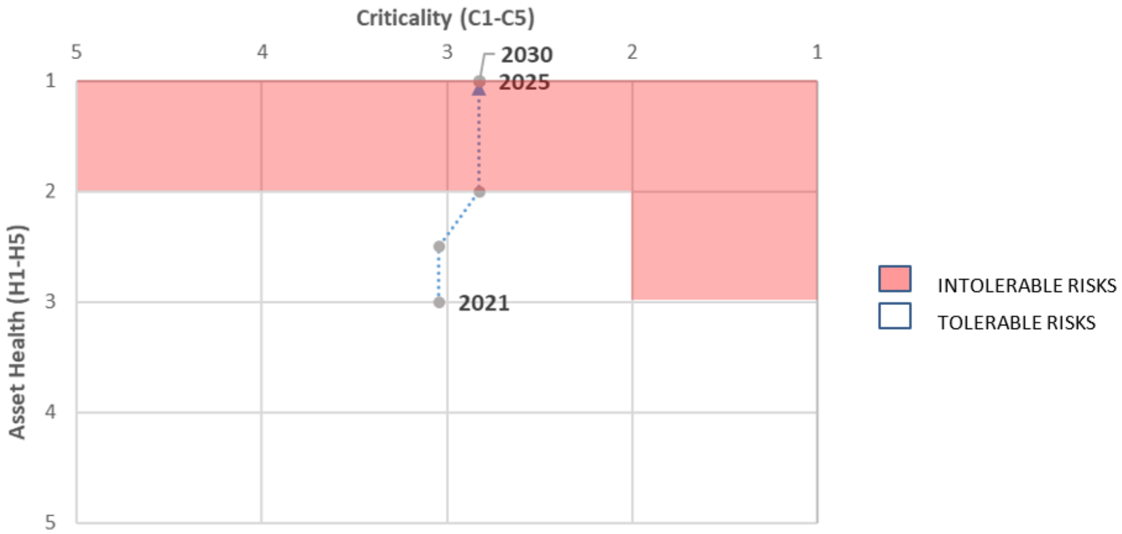
We forecast renewal needs for power transformers, indoor switchgear and outdoor switchgear using models informed by AHI and, where possible, criticality. The models help us to identify and prioritise the replacement of zone substation equipment. We coordinate zone substation and secondary systems renewal works to align these projects and reduce overall costs and equipment downtime.

The figure below shows an example risk matrix over the period RY21 to RY30 as the asset's health degrades from H3 to H1. We consider risk levels in the pink shaded area to be intolerable and, for the example shown, the risk becomes intolerable in RY23 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 8.62: Example risk matrix used to assess renewal need



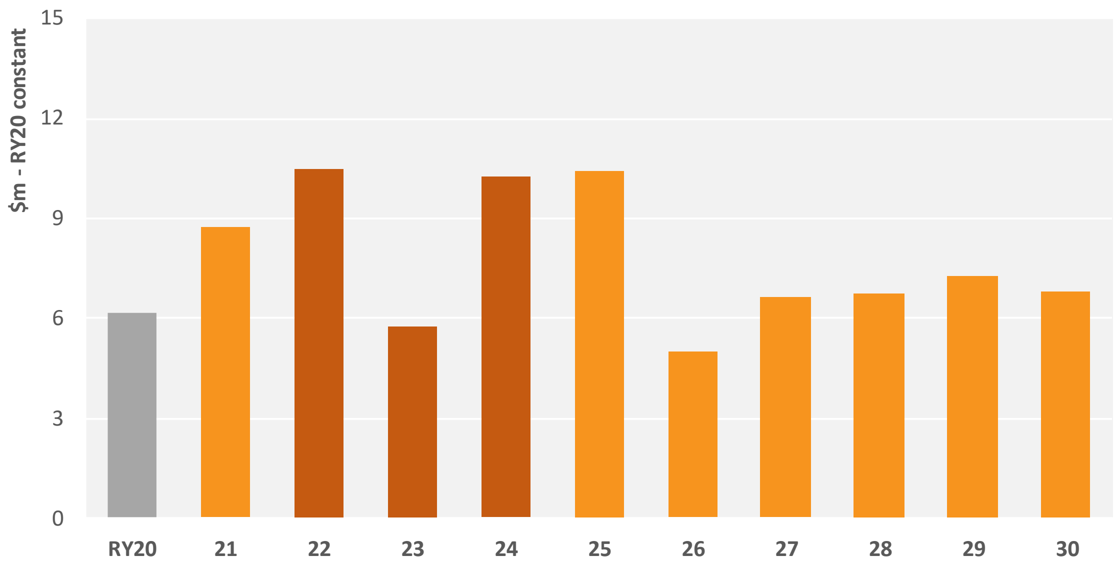
We review all zone substation projects and optimise the project timings. This review involves the use of a coordination tool to ensure that equipment is replaced in a coordinated manner. For example, if switchgear and transformer replacements are required at the same zone substation within a five-year 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 Substations Expenditure Forecast

The figure below shows forecast Capex for zone substation renewals over the AMP planning period.

Figure 8.63: Historical and forecast zone substation Capex



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.

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[91] 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 $5.5m per annum on distribution switchgear renewals with expenditure declining from a peak of $7m in RY23 to $4m in RY28.

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[92], and switching facilities. This portfolio comprises a large number of diverse asset types. It 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 8.13: Update on WSP Review – distribution switchgear

Issues: WSP identified material quantities of ground mounted switchgear past expected lives, with 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, the programme will continue at a lower steady-state level once the highest risk assets have been replaced.

91 In general. distribution switchgear Capex is covered under Asset Replacement and Renewal ID category, line items 'Distribution switchgear'; exceptions are 'Distribution and LV cables' includes our LV enclosures fleet, and 'Distribution substations and transformers' includes our ancillary distribution substation equipment fleet, as set out in Schedule 11a in Appendix B.

92 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.

8.5.1. Distribution Switchgear Objectives

Portfolio objectives (set out below) guide our day-to-day asset management activities.

Table 8.63: 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.

8.5.2. Ground Mounted Switchgear

Ground Mounted Switchgear Fleet Overview

This fleet includes RMUs, other high voltage ground mounted switches, HV[93] ground mounted fuses, indoor HV switchboards located at customer premises, and ground mounted LV switchboards. Ground mounted switchgear is generally associated with our underground cable network, however some 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), does not meet modern operational safety requirements, and most types 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 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.

[93] HV is 11 kV or 6.6 kV in this instance.

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

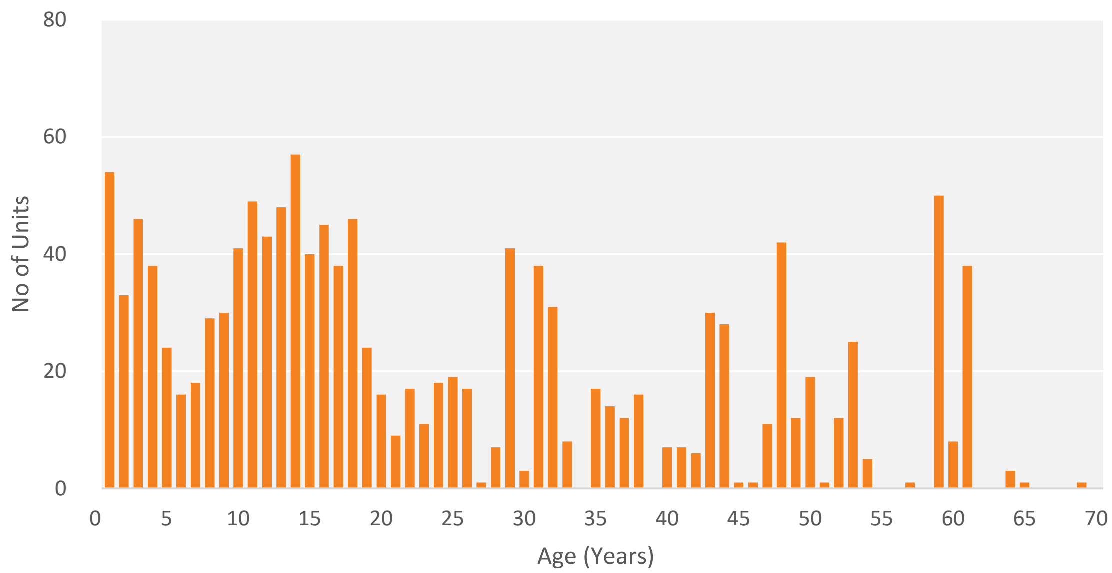
The fleet includes 1,323 units of various models and insulating media as shown below.

Table 8.64: Ground mounted switchgear population by insulation medium

INSULATION MEDIUM	POPULATION	PERCENTAGE
Oil	1,122	85%
SF_6	189	14%
Solid dielectric	12	1%
Total	**1,323**	**100%**

The majority of the fleet is oil-filled switchgear. A large proportion of our older generation of oil-filled switchgear has exceeded their expected lives and many have condition and safety issues. Modern switchgear uses SF_6 or solid dielectric rather than oil for insulation.

Figure 8.64: Ground mounted switchgear age profile



Our ground mounted switchgear assets are relatively young (average age 24 years) although many units have already exceeded their life expectancy (40 to 50 years depending on the switchgear type). Of our four HV switchboards, two are very old (65 and 52 years old).

Condition, Performance and Risks

In-service failure of 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 switchgear failure will generally result in loss of supply to consumers. We always aim to proactively replace ground mounted switchgear units before they fail, to minimise failure risks.

Condition and performance

Older oil-filled 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 RMUs to reduce safety risk until they can be replaced.

In RY14, we began to remove aged oil-filled RMUs, 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 ground mounted switchgear. Recognising the need to better understand their condition, we undertook annual inspections of our RMUs 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 switchgear. Replacement of these units continues to be a priority. The majority of our remaining RMUs are the ABB-SD and Long and Crawford types, although we have a large population of Statter switches in the Dunedin area.

Table 8.65: Known type issues with ground mounted switchgear

TYPE	RISKS/ISSUES
Andelect and 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 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 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 plastic or fibreglass covers, which also provide protection from general weather and some protection should an internal failure occur. The most common RMUs 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 RMU 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 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 do detailed pole fuse inspections – unless supported by failure evidence.

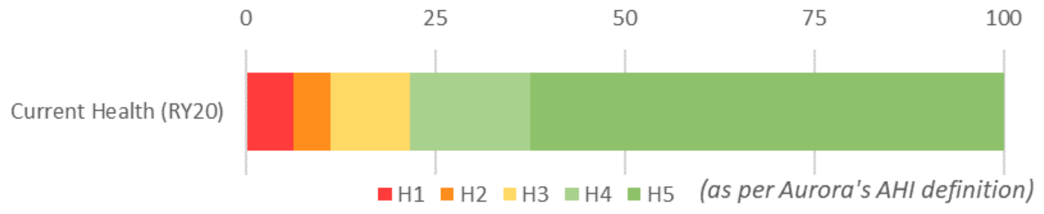
Our historical records on RMUs and other high voltage ground mounted switches show no failures recorded since 2013. RMUs themselves have proven to be highly reliable devices.

The main performance issues in the ground mounted switchgear fleet relate to inoperable equipment. RMUs past their allowable tilt limit and 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 ground mounted switchgear is based on expected remaining life. This AHI covers RMUs, other high voltage ground mounted switches 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 RMUs and other high voltage ground mounted switches is shown below.

Figure 8.65: Ground mounted switchgear asset health (percentage per AHI category)



Based on asset health, 6% of our ground mounted switchgear have already reached end-of-life (H1). The predominant driver for this is ageing oil-filled switchgear, the majority of which are in Dunedin.

Risks

The table below summarises the key risks in our ground mounted switchgear fleet.

Table 8.66: Ground mounted switchgear risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
Andelect, 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 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 RMUs 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 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 switchgear to applications without a viable alternative thereby minimising our environmental impact. We continue to assess new market offers on switchgear that do not contain SF_6.

We have many instances of single HV oil fuse switches installed in our network, 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 RMU is installed given the cost differential is marginal at time of replacement.

'Group fusing' installations, where many 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 RMUs to provide standard protective and switching functionality.

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 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.

Operate and Maintain

Preventive Maintenance

Unlike many of our other assets, oil-filled ground mounted switchgear requires regular invasive maintenance in addition to inspection activities and we have now embedded a maintenance regime for them. Our preventive works are summarised below.

Table 8.67: 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 yearly (oil-filled RMUs/switches)
Partial discharge wand checks prior to removal from service, out of service inspection, check SF_6 gauges, check cable boxes and clean terminations	Ten yearly (solid dielectric and 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 (none older than four years yet)
DC testing of RMUs with protection/battery	Annually
LV boards inspections	With associated ground mounted transformer inspection
Indoor high voltage switchboard maintenance	Four yearly

Corrective maintenance

In response to finding significant oil leaks and poor earth contact resistances on Andelect units we swap the unit for a ABB Series 2 SDAF3 under corrective maintenance. This has been used in response to finding significant oil leaks and poor earth contact resistances on Andelect units.

We are also 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

DNO equipment such as tilted RMUs reduce the operability of our network. Tilted RMUs can generally be remediated via a corrective maintenance procedure rather than replacement, cost-effectively restoring the reliability performance of our network.

Reactive maintenance

The most common reactive activity 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.

Spares

The majority of 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 standard inventory (orphan spares). We hold new spares for our SF_6 RMUs.

Renew or Dispose

We replace units on the basis of asset condition and defects, usually identified during inspections. Repair or replace decisions depend on the specific make and model of enclosure and the defect(s) found. We are progressively replacing our fleet of old and obsolete oil-filled RMUs. We are focusing on Andelect and Reyrolle units, followed by Statter models. Subsequently we expect to focus on more recent oil-filled types (ABB-SD and L&C models) when found to be in poor condition.

Table 8.68: 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

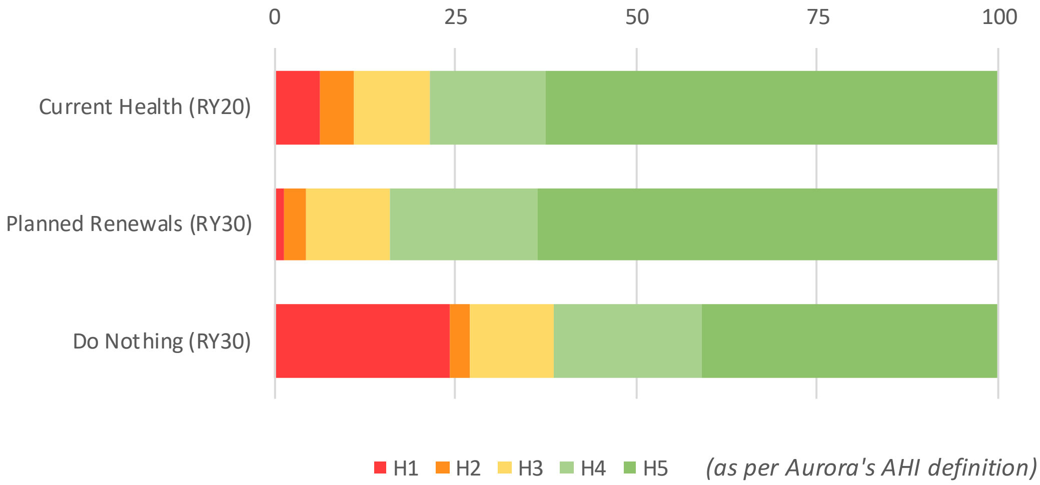
We are working to create a risk prioritisation framework for RMU replacements that will consider an asset health score and criticality factors based on safety and load characteristics. This will drive repeatability and consistency in decision making and ensure the highest risk RMUs are addressed.

Renewals forecasting

AHI for ground mounted switchgear is based on expected remaining life, with expected life ranging from 30 to 50 years depending on type. Our ground mounted switchgear assets are relatively young (average age 24 years), though many oil-filled units have already exceeded their life expectancy.

In order to address a backlog of required switchgear replacements we propose to increase our expenditure during the RY21-RY25 period. The backlog will be addressed by RY25 whereupon expenditure and replacement rates will drop to a steady-state level. The chart below compares projected AHI in RY30 following our planned renewals, with a counterfactual do nothing scenario.

Figure 8.66: Projected ground mounted switchgear asset health



This comparison indicates the benefits provided by our proposed investment programme. If we undertake no replacements we would expect H1s to be approximately 24% by RY30, compared to 1% under our proposed replacement programme.

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.

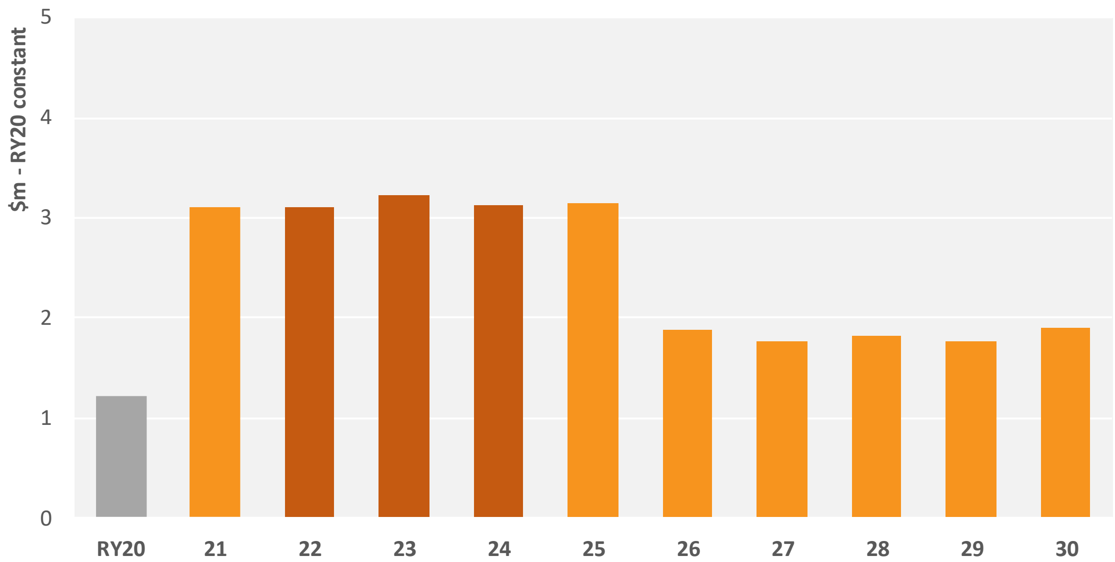
Coordination with other works

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 Expenditure Forecast

Our forecast renewal Capex is approximately $25m during the planning period, as shown below.

Figure 8.67: Forecast ground mounted switchgear Capex



Historically our expenditure on replacing 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. Our programme, to address overdue ground mounted switchgear, involves an increase in investment levels during the RY21 to RY25 period. In RY26 our backlog will be addressed after which expenditure will drop to steady state levels as the aggregate health of our ground mounted switchgear improves.

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

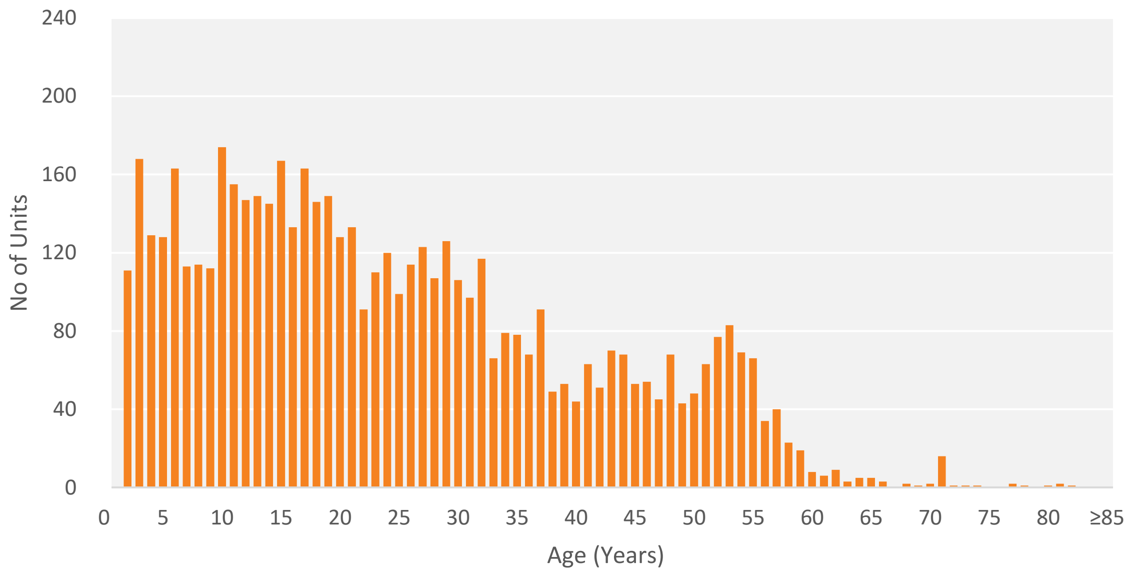
Pole mounted fuses are simple devices that provide protection and isolation functionality. HV fuses primarily isolate and protect distribution transformers and HV cables (terminating on poles). In rural areas HV units also provide fault isolation for network tee-offs that supply low customer density spur lines or cables. The fleet includes expulsion drop out (EDO) and 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 (maximum demand indicators) MDIs inside.

Population and Age

Our fleet consists of 5,672 fuse units that are all very similar in design and function, but comprise a wide range of makes and models.

Figure 8.68: Pole mounted fuses age profile



Our pole mounted fuses are relatively young (average age 25 years) although some units have exceeded their life expectancy of 55 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 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 8.69: EETEE HV 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.

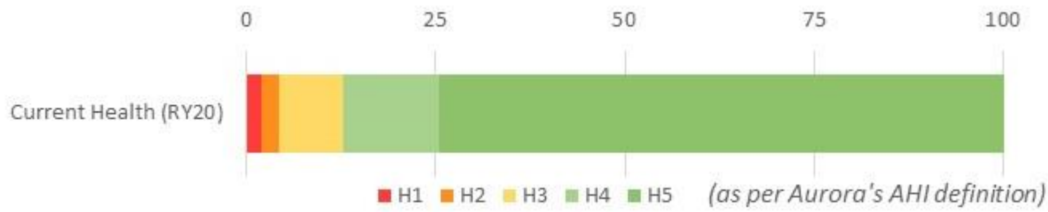
Performance

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 8.70: Pole mounted fuse asset health



Based on asset health, 2% of our pole mounted fuses have already reached end-of-life (classified as H1) and we expect that up to 12% (H1 to H3) of them will require replacement in the planning period.

Risks

The table below summarises the key risks in our pole mounted fuse fleet.

Table 8.69: Pole mounted fuse risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
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.

Operate and Maintain

Preventive maintenance

Our preventive works are summarised below.

Table 8.70: Pole mounted fuses preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY STATE FREQUENCY
Visual inspection of fuses for corrosion, defects and gathering of type information	Five yearly (during pole inspections)
Thermography of HV and LV transformer fuses	During distribution transformer inspections

Corrective maintenance

We generally do not undertake any corrective maintenance on fuses.

Reactive maintenance

Reactive maintenance covers replacement of fuses when they blow to clear faults. If the fuse is one our EETEE types, the entire fuse assembly has to be replaced as no cartridges are available.

Spares

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.

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.

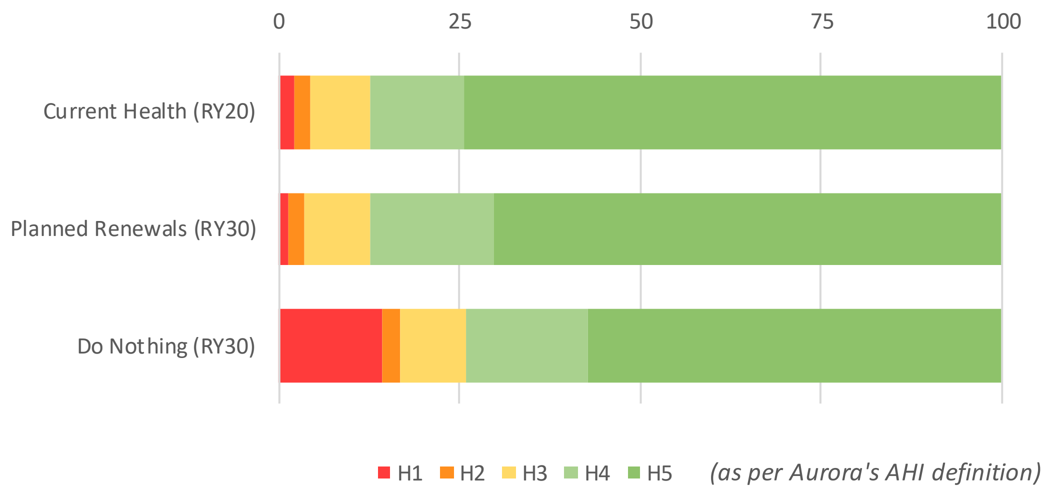
Table 8.71: Summary of pole mounted fuse renewal approach

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 RY30 following our programme of renewals, with a counterfactual do nothing scenario.

Figure 8.71: Pole mounted fuse asset health



This comparison indicates the benefits provided by our proposed investment programme. If we undertook no replacements we would expect the proportion of H1 pole mounted fuses to be approximately 14% by RY30, compared to 1% under our proposed replacement programme.

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.

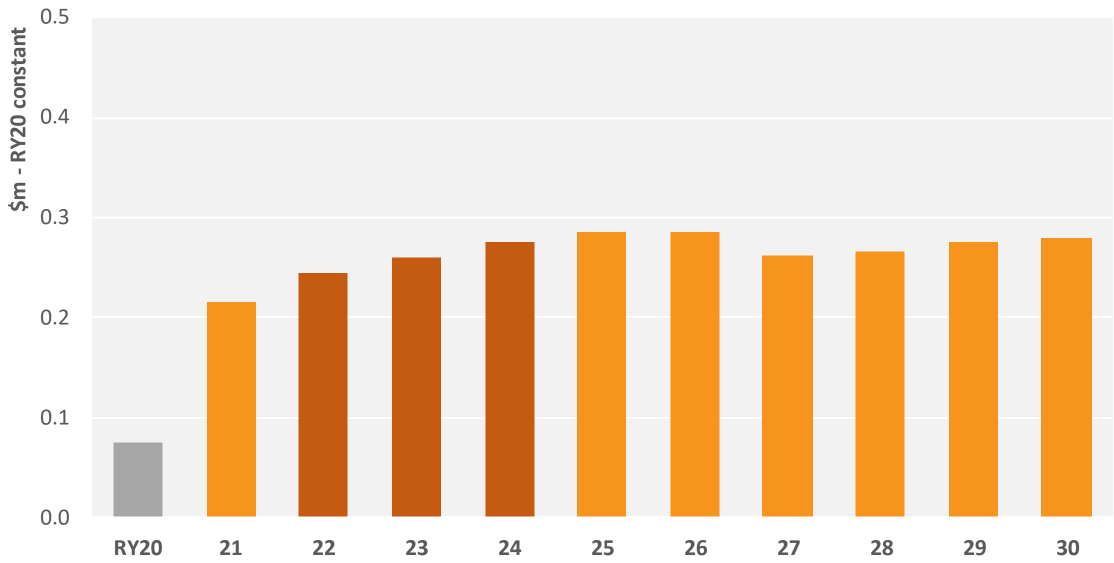
Meeting our portfolio objectives –reliability to defined levels and affordability by cost management

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 the reliability of our network.

Pole Mounted Fuse Expenditure Forecast

We have forecast pole mounted fuse renewal Capex of approximately $3m during the planning period, as shown below. This excludes pole mounted fuses replaced during pole replacements.

Figure 8.72: 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. During the planning period we will replace poor condition and inoperable pole mounted fuses.

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

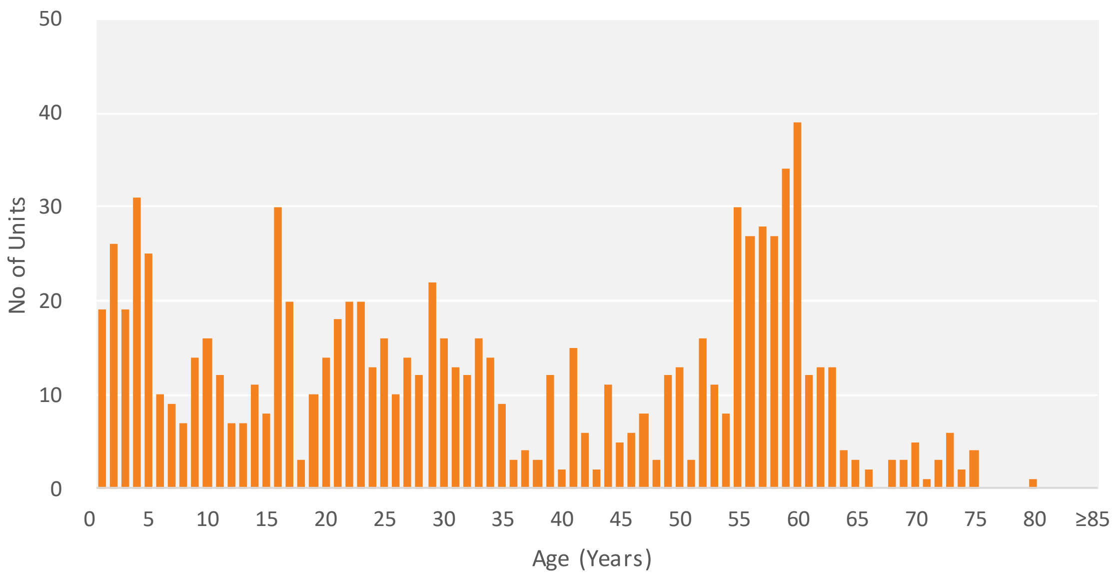
This portfolio incorporates switches and links that are mounted on poles outside of zone substations. Pole mounted switches come in a wide variety of configurations and insulating mediums (SF_6 and air). For switches, we most commonly utilise ABSs which use air as the dielectric and can be operated using 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 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 926 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 8.73: Pole mounted switches age profile



These assets have an average age of 34 years and 33% have exceeded their life expectancy of 50 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 DNO tagged.

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.

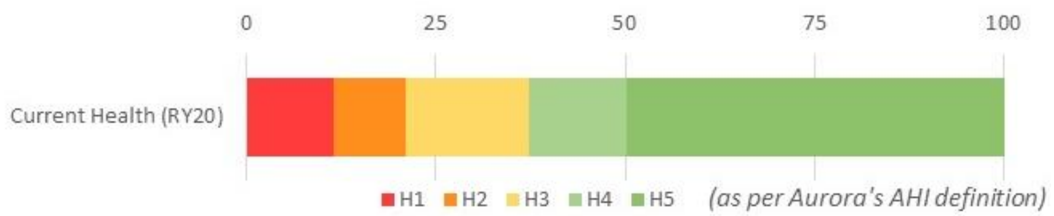
Performance

Our historical outage records indicate that, since 2002, we have experienced eleven outages due to faulty pole mounted switches. This does not include all incidents of switch failures as our service providers will not operate pole mounted switches that are found to be in poor condition and therefore the full impact of faulty/inoperable switches is not currently captured as a cause in our reliability reporting. We have had a number of performance issues with older pole-mounted switches. 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, preventing the switch from operating.

Asset health

AHI for pole mounted switches is based on expected remaining life, as shown below.

Figure 8.74: Pole mounted switch asset health



Based on AHI, 12% of the fleet have already reached end-of-life (classified as H1). The majority of the end-of-life switches are in Dunedin. These aged assets present a safety risk while attempting to operate and/or a reliability performance risk associated with inoperability.

Risks

The table below summarises the key risks identified in our pole mounted switch fleet.

Table 8.72: Pole mounted switch risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
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

RISK/ISSUE	RISK MITIGATION	MAIN RISK
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. However, a 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, and therefore they 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 than absolutely necessary but will continue to monitor new equipment options.

Operate and Maintain

Preventive Maintenance

We are beginning to undertake inspections and use this information 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 8.73: Preventive maintenance initiatives – pole mounted switches

PREVENTIVE MAINTENANCE INITIATIVE	RELATED 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 – operable ABS ensures safe operation for our contractors Reliability to defined levels – having operable ABS will help us meet our reliability objectives.	Short term

Corrective maintenance

At present we only undertake simple repairs in-situ on pole mounted switches.

Reactive maintenance

If an ABS or HV link fails, the likely course of action to swiftly restore consumer supply is to either open the switch and reconfigure the network, or remove the switch or install jumpers to short it out, before fixing or replacing the switch under non-fault conditions.

Spares

We hold new spare ABSs in stock.

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.

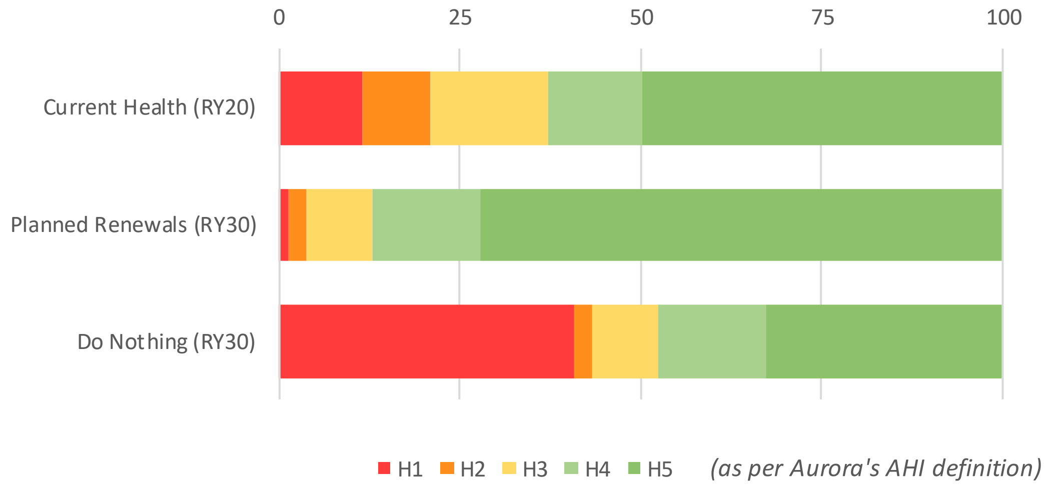
Table 8.74: Summary of pole mounted switch renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Proactive condition-based Associated renewal work (e.g. pole renewal) Type based
Forecasting approach	Repex
Cost estimation	Volumetric

Renewals forecasting

The figure below compares projected AHI in RY30 following planned renewals, with a counterfactual do nothing scenario. This comparison indicates the benefits provided by our proposed investments.

Figure 8.75: Projected pole mounted switch asset health



If we undertook no replacements we expect the proportion of end-of-life pole mounted switches to be approximately 41% by RY30, compared to 1% under our proposed replacement programme.

Options analysis

At present we do not have a 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.

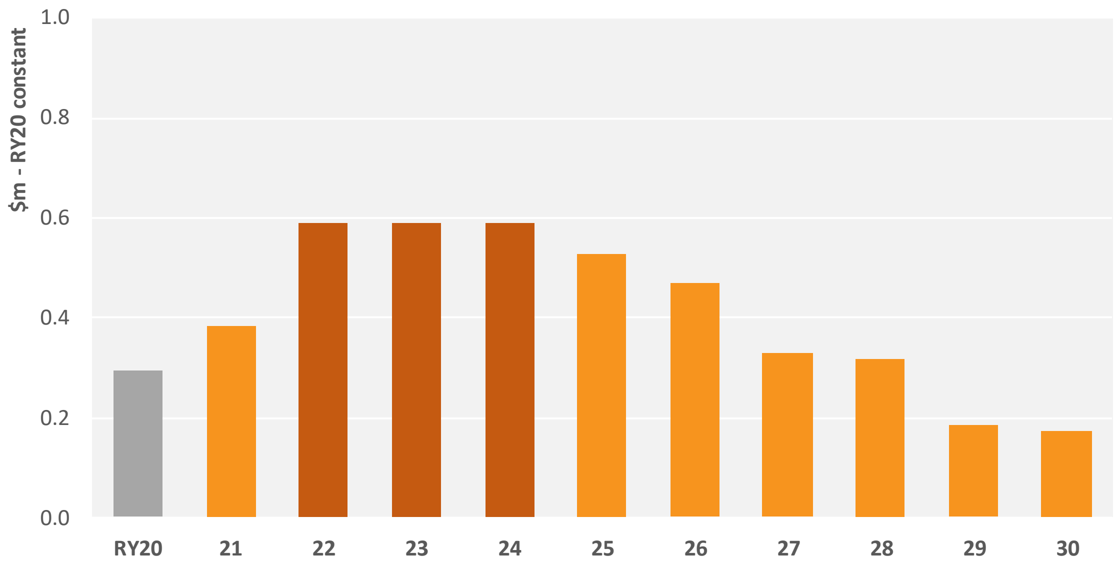
Coordination with other works

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 Expenditure Forecast

We have forecast pole mounted switch renewal Capex of approximately $4m during the planning period. This Capex excludes pole mounted switches replaced during pole replacements.

Figure 8.76: Pole mounted switch expenditure



To address a backlog of required switch replacements we will increase expenditure over the RY21-RY25 period. Expenditure and replacement rates will drop to a steady state level by RY29 once the backlog has been addressed.

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

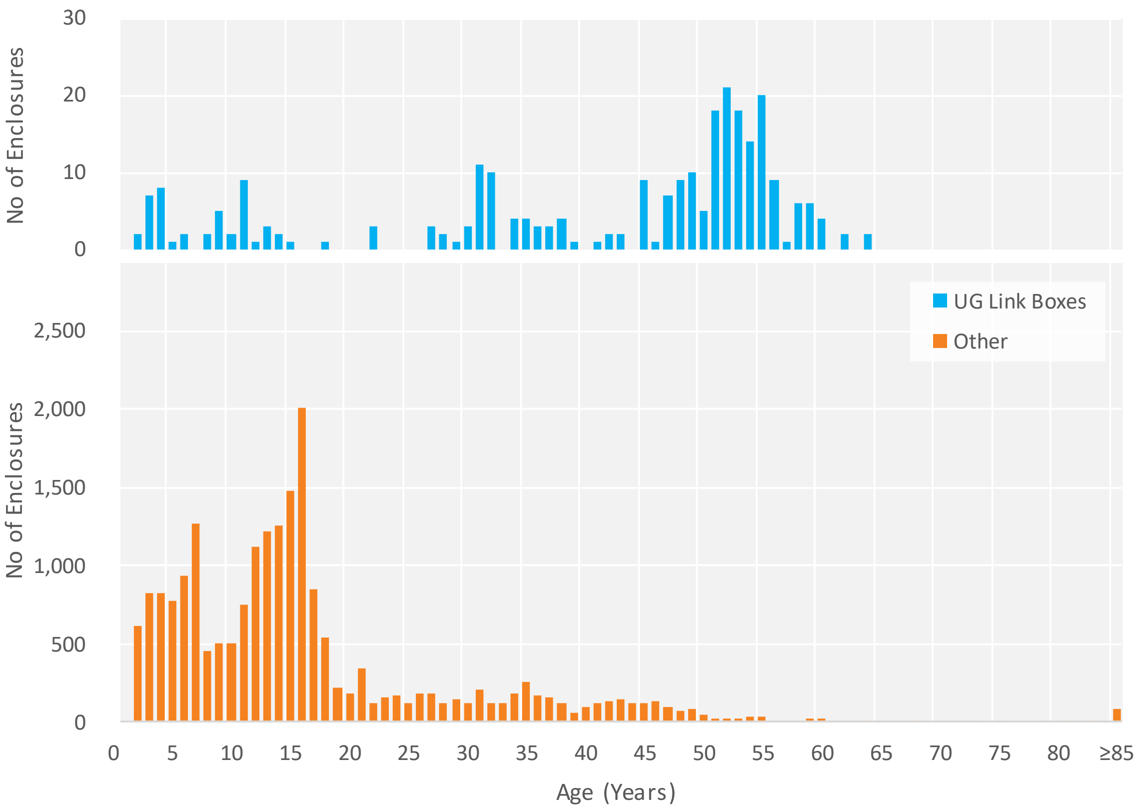
LV Enclosures Fleet Overview

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 link pillars, which are above ground. We refer to these enclosures as 'underground link boxes'. The remainder are service pillars/boxes used to terminate consumer connections.

Population and Age

We have approximately 21,000 LV enclosures. Of these, only 265 are the underground link box type. The figure below depicts age profiles of our two categories of LV enclosure.

Figure 8.77: LV enclosures age profile



The underground link boxes are an older population, with an average age of 41 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. In particular the Henley underground link boxes, most of which are more than 45 years of age, 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 8.78: Decommissioned Henley underground link box

We do not have a complete record of the exact type and make of 'other LV enclosures', but we have a reasonable record of their age and location. We have not historically inspected them so we do not have comprehensive data on their condition. Since RY19 we have been undertaking inspections to gather information on these including type, make, and condition, and it will be a number of years before the entire fleet has been inspected.

Frequent failure modes of our other LV enclosures include vehicle collisions and vandalism, which generally cannot be predicted on an individual asset basis. These failures can present some public safety risk due to their accessibility and involve the risk of electrocution. This is particularly the case with legacy design LV enclosures that have metallic covers as these can inadvertently become live when wiring insulation or fuses within the enclosure fail to perform their normal function.

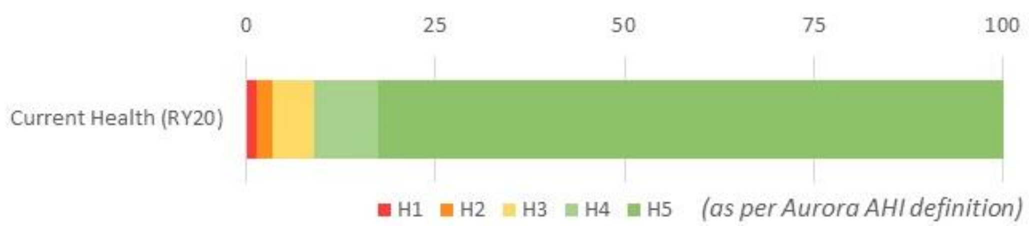
Through inspection results to date, we are finding large numbers of pillars in unsuitable locations. Many have had retaining walls or fences built around or over them, and some have been buried in gardens. These pillars require relocation to be accessible.

We have not historically collected LV outage data, so we do not have reliability performance information for LV enclosures.

Asset health

The figure below shows asset health of our LV enclosures.

Figure 8.79: LV enclosures asset health



Based on asset health, 3% of our LV enclosures have reached end-of-life (classified as H1). The majority of the 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; however 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 8.75: LV enclosure risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
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	Reliability, safety
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.

Operate and Maintain

Preventive maintenance

Historically, our 'other 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 8.76: LV enclosures preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY STATE FREQUENCY
LV enclosure inspection and minor repairs as/if required	Five yearly

Corrective maintenance

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 8.77: Corrective maintenance initiatives – LV enclosures

CORRECTIVE MAINTENANCE INITIATIVE	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. We will replace metal covers with plastic covers, which is more cost effective than complete enclosure replacement.	Safety first- We must remediate a known failure mode in a legacy LV enclosure that does not meet 'safety by design' requirements.	Medium term

Reactive maintenance

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.

Renew or Dispose

We are replacing our LV enclosures on the basis of as-found condition, usually identified 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.

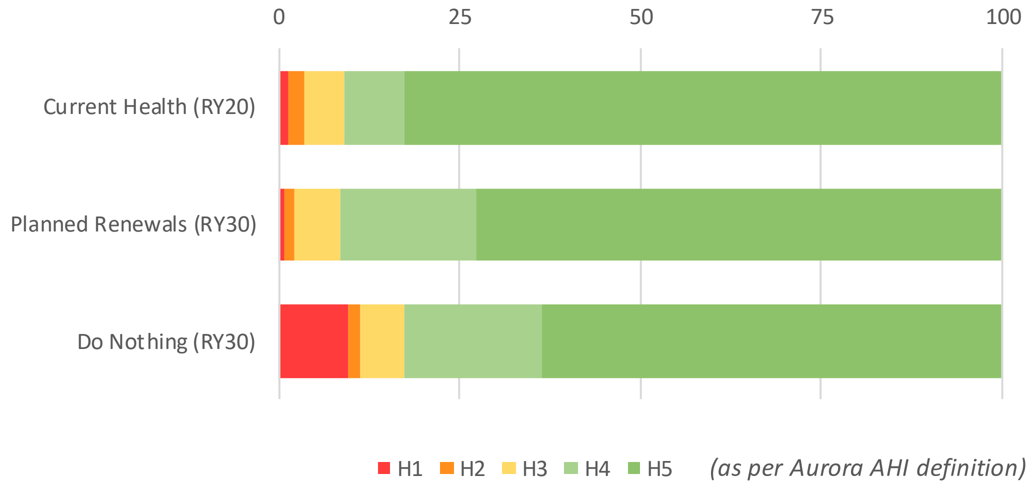
Table 8.78: Summary of pole LV enclosure renewal approach

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 RY30 following our planned programme of renewals, with a counterfactual do nothing scenario.

Figure 8.80: Projected LV enclosure asset health



This indicates the benefits provided by our investment programme. If no replacements are undertaken we would expect the proportion of end-of-life LV enclosures to be approximately 15% by RY30, compared to 1% under our proposed replacement programme.

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 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.

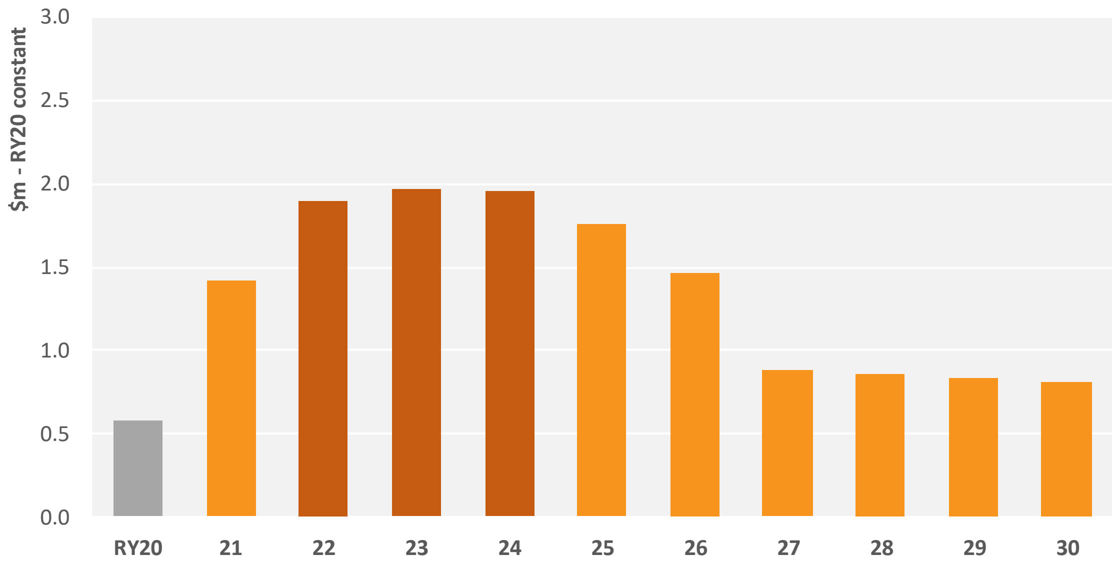
Meeting our portfolio objectives – safety first

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 Expenditure Forecast

We have forecast LV enclosures renewal Capex of approximately $14m 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 8.81: 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 in RY21 and further increase it for the period RY22-RY26 to address the backlog of LV enclosure renewals, within deliverability constraints. Our plan will replace the majority of overdue underground link boxes and 'other LV enclosures' by RY26, after which expenditure will return to steady state levels.

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

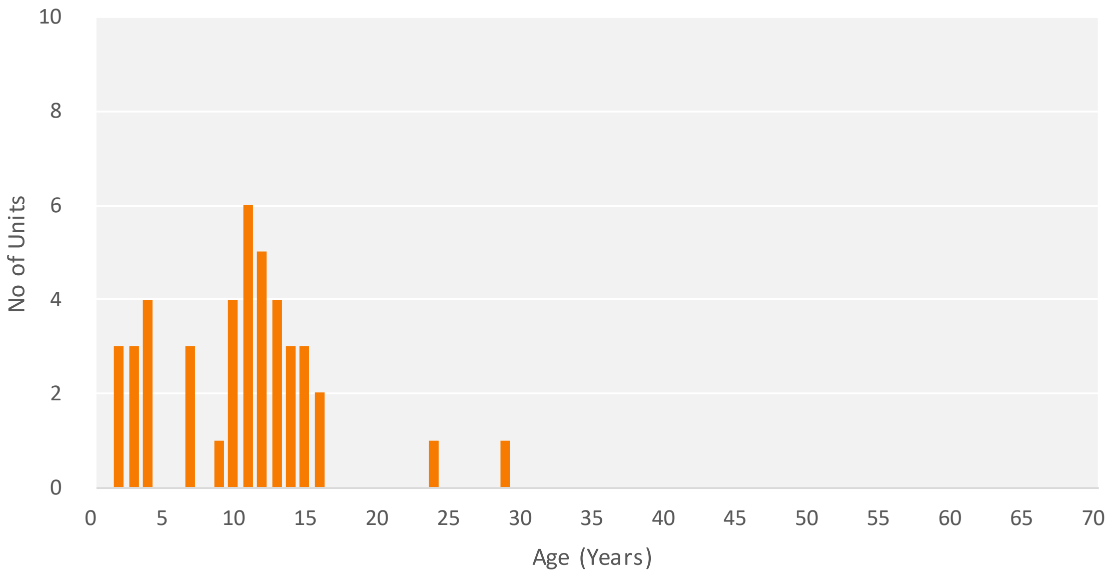
Reclosers and Sectionalisers Fleet Overview

Reclosers and sectionalisers are devices that improve the reliability of our network by reducing 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 43 HV reclosers, the chart below shows their age profile.

Figure 8.82: Reclosers and sectionalisers age profile



The majority 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. We are assessing the best method of mitigating this risk. We have had isolated problems with some controllers from our recloser fleet.

Asset health

We have not yet developed AHI for our recloser and sectionaliser fleet, given the small population. Developing AHI will be a future improvement.

Risks

The table below sets out sets out the key risks identified in our recloser and sectionaliser fleet.

Table 8.79: Recloser risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
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 ABS bypassing facilities, 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.

Operate and Maintain

Preventive maintenance

Reclosers require material preventive maintenance activities, as summarised below. Much of this maintenance has not been performed historically.

Table 8.80: Recloser preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY STATE FREQUENCY
Visual inspection, thermographic testing	Annually
Maintenance service – test protection, rectifier, SCADA points, bypass checks, check settings, adjust settings if required, replace battery	Four yearly

Corrective maintenance

Recloser corrective maintenance consists of activities such as adjusting settings outside of preventive maintenance activities due to network changes, and fixing communication problems.

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.

Spares

We maintain a spares pool of reclosers should a reactive replacement be required.

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 8.81: Summary of recloser renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Proactive condition-based
Forecasting approach	Individual sites
Cost estimation	Volumetric

Reclosers and Sectionalisers Expenditure Forecast

Given the small quantities of renewals, we have not created a long-term Capex forecast at this time.

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 as a separate grouping in this fleet, 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 do not have a record of the number and age of our distribution surge arrestors. We are undertaking inspections to gather information. We have both porcelain and polymer types.

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 8.83: 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 arrestors installed in locations where the supplying GXP has NERs. As we now install NERs at HV when doing major zone substation works, we may see increasing surge arrestor failures if we do not replace inadequately rated surge arrestors. We have a population of unvented porcelain surge arrestors. These have a propensity to explode upon operation (arresting surges), spraying porcelain shards tens of meters, creating a safety hazard.

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 8.82: Ancillary distribution substation equipment risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
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
Unvented porcelain surge arrestor failure	Inspection and replacement programme	Safety, reliability
Underrated surge arrestor failure	Inspection and replacement programme 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 ten 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 arrestors that will be used on all replacements which are rated for an ineffectively earthed system.

Operate and Maintain

Preventive maintenance

Our preventive works are summarised below.

Table 8.83: 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 monthly
Distribution earth testing on all assets with earths	Six yearly

We are undertaking a new maintenance activity as set out below.

Table 8.84: Preventive maintenance initiatives – ancillary distribution substation equipment

Preventive Maintenance Initiative	Related Objectives	Time Frame
Distribution surge arrester inspections As NERs have been installed, many surge arrestors have become underrated and an increase in failures is being experienced. These inspections are to ensure that no flash overs have occurred, unventilated types are identified, and that the surge arrestor installed is of adequate rating.	Safety first – Unvented porcelain surge arrestors 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

Underground substation corrective maintenance consists of work on all the individual assets, plus the repair of any of the structural, access, alarm or other components of the underground substations. Surge arrestors are 'maintenance-free' items, but their earthing connections may need remediation if found to be installed with copper bar that prevents the base from blowing off. Distribution earths will need corrective maintenance remediation if they are found to pose too high a resistance or if any other earth connections are found to be inadequate.

Reactive maintenance

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 high 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

The electrical equipment in our underground substations is common to above ground substations, so spares are available. We hold stock of spare surge arrestors.

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 8.85: Summary of ancillary distribution substation equipment renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Type based (underground substations, unvented and underrated surge arrestors) Proactive condition-based
Forecasting approach	Individual sites (underground substations) Engineering estimate (surge arrestors)
Cost estimation	Engineering consultant estimates (underground substations) Volumetric (surge arrestors)

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 arrestors 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 arrestor replacements may be coordinated with other works.

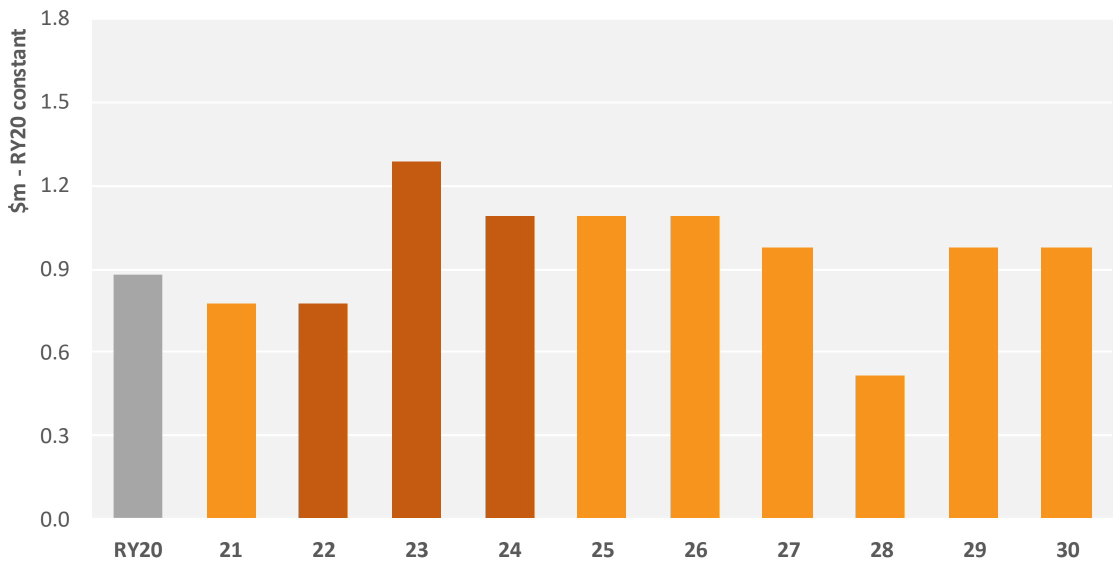
Meeting our portfolio objectives – sustainability by taking a long term view

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 Expenditure Forecast

We have forecast ancillary distribution substation equipment renewal Capex of approximately $10m during the planning period.

Figure 8.84: Ancillary distribution substation equipment expenditure



Our plan is to replace the 17 underground substations over 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 safety and reliability risks of surge arrestor 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[94] 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 $3.6m 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, with associated environmental and fire risks. We have a large number of legacy assets across our two networks.

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 both planned and fault work.

Box 8.14: Update on WSP Review – distribution transformers

Issues: key risks WSP identified 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.

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94 Distribution transformer Capex is covered under Asset Replacement and Renewal ID category, line item 'Distribution substations and transformers', except for mobile and standby generators which are under 'Other network assets', both are included in Schedule 11a(iv) in Appendix B.

8.6.1. Distribution Transformers Portfolio Objectives

Portfolio objectives (set out below) guide our day-to-day asset management activities.

Table 8.86: 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, 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.

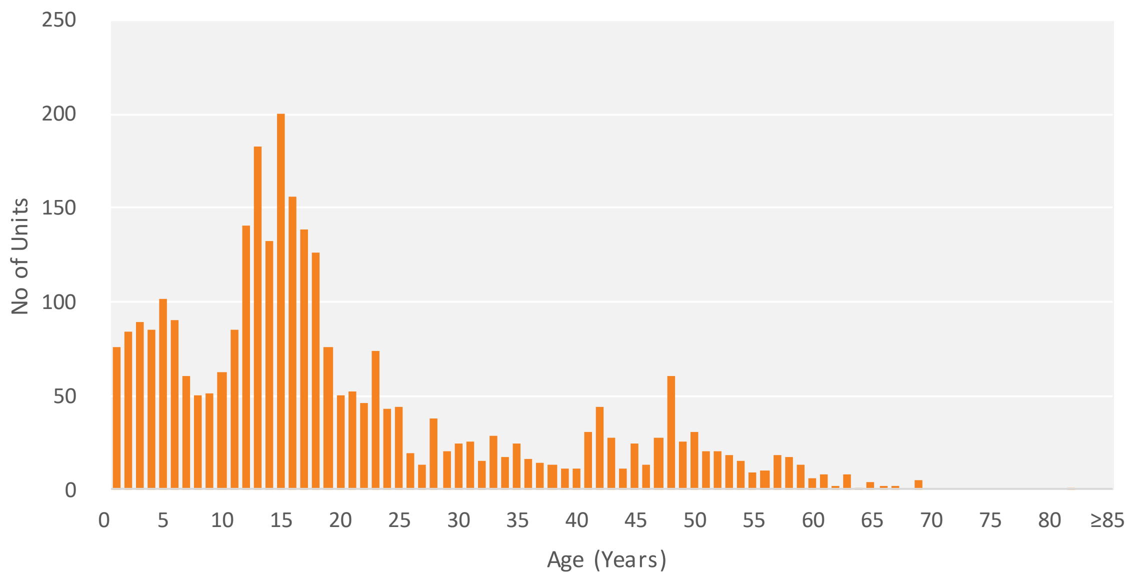
Ground mounted distribution transformers are inherently more seismically robust than pole mounted transformers but still require seismic restraint. They are also vulnerable to vehicular impact and flooding.

Ground mounted transformers can be installed in various locations: on public property, inside an Aurora-owned distribution substation building, or in customer premises.

Population and Age

We have approximately 3,000 ground mounted distribution transformers.

Figure 8.85: 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.

The table below 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.

Table 8.87: Ground mount distribution transformers ratings

RATING (KVA)	POPULATION	PERCENTAGE
0 to 100	1,394	45%
100 to 200	161	5%
200 to 300	476	16%
>300	1,032	34%
Total	**3,063**	**100%**

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 8.15: 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.

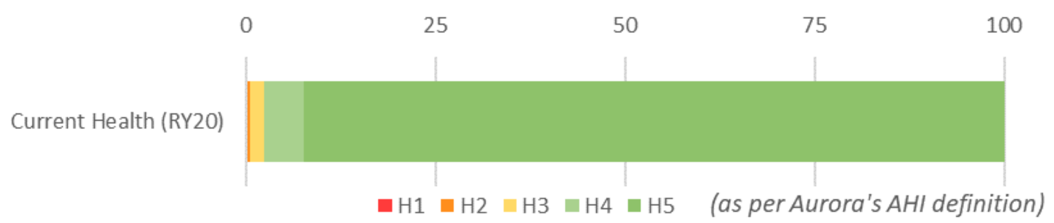
Meeting our portfolio objectives –responsive to a changing landscape

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 8.86: Ground mounted distribution transformer asset health



The overall health of this fleet 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 0.2% (H1) of ground mounted transformers in the next 12 months and ~2% within the planning period.

Risks

The table below sets out the key risks identified in the fleet.

Table 8.88: Ground mounted distribution transformers risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
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
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
Pole 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 standards	When the transformer is due for renewal it is replaced outside the building and the building demolished or sold.	Safety, reliability

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 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 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 uneconomic.

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 in house which fulfils a range of roles. Deliverable quantities remain small and so we do not foresee any deliverability issues in this portfolio.

Operate and Maintain

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 as part of developing the maintenance strategy for this fleet. We will consider if introduction of tests such as DGA/oil testing on large ground mounted transformers is worthwhile.

Table 8.89: 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	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

Corrective maintenance

Corrective maintenance includes clearing rubbish and debris from the site, replacing locks and fixing security issues as required, graffiti remediation and any transformer repairs taken on site.

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 of these activities are included in corrective maintenance.

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(s). Any internal transformer faults or significant vehicular impact will require a new transformer.

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.

Renew or Dispose

The table below summarise our renewal approach for ground mounted transformers.

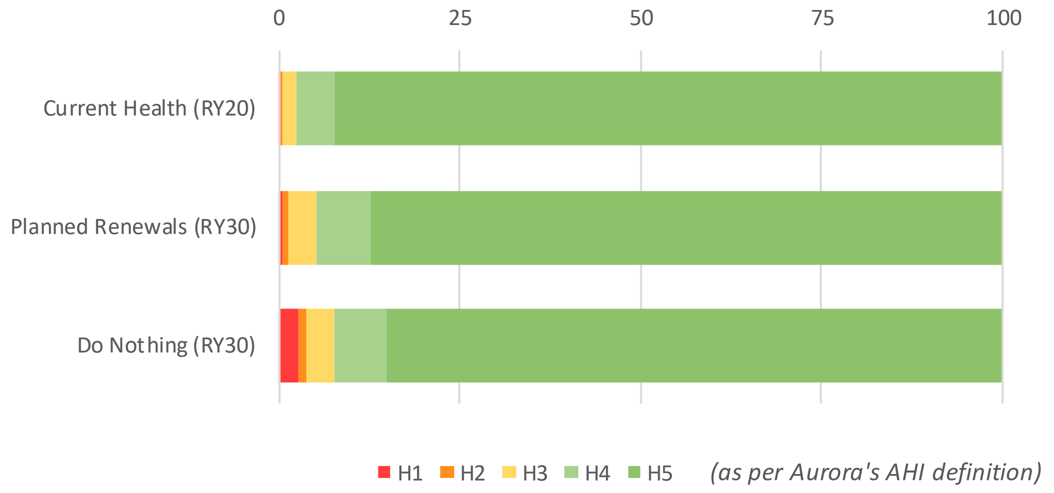
Table 8.90: Summary of ground mounted distribution transformer renewal approach

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 2030 following our programme of renewals, with a counterfactual do nothing scenario. This indicates the benefits of our programme.

Figure 8.87: Projected ground mounted transformer asset health



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 for a like-for-like spare replacement is often cost effective. Alternately, a new transformer may be installed. In making this decision consideration has to 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.

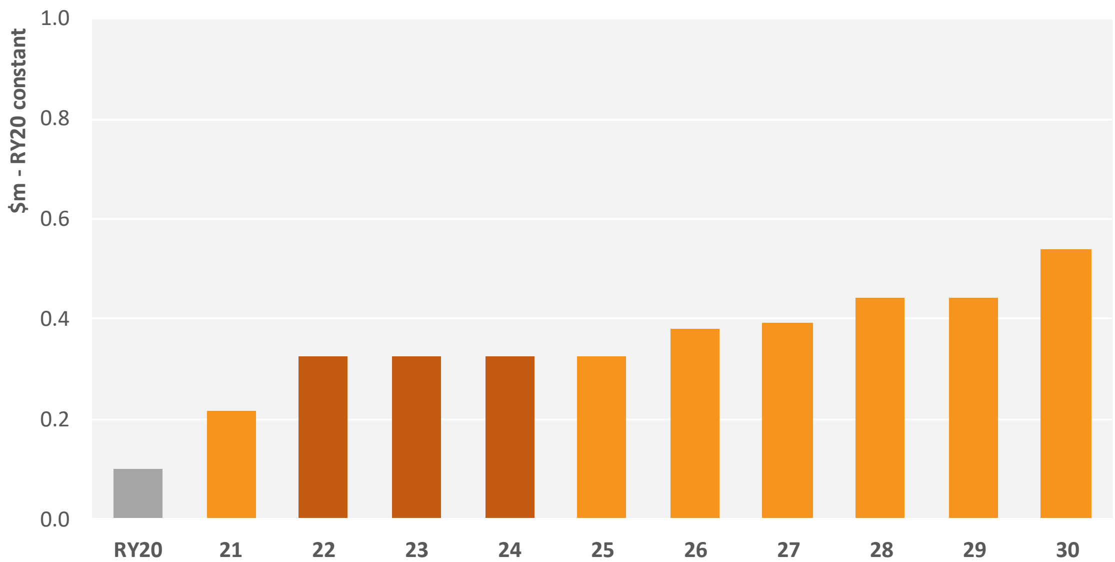
Coordination with other works

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 Expenditure Forecast

Our forecast ground mounted distribution transformer renewal Capex is shown below.

Figure 8.88: 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, but renewal quantities will remain small for the duration of the planning period.

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

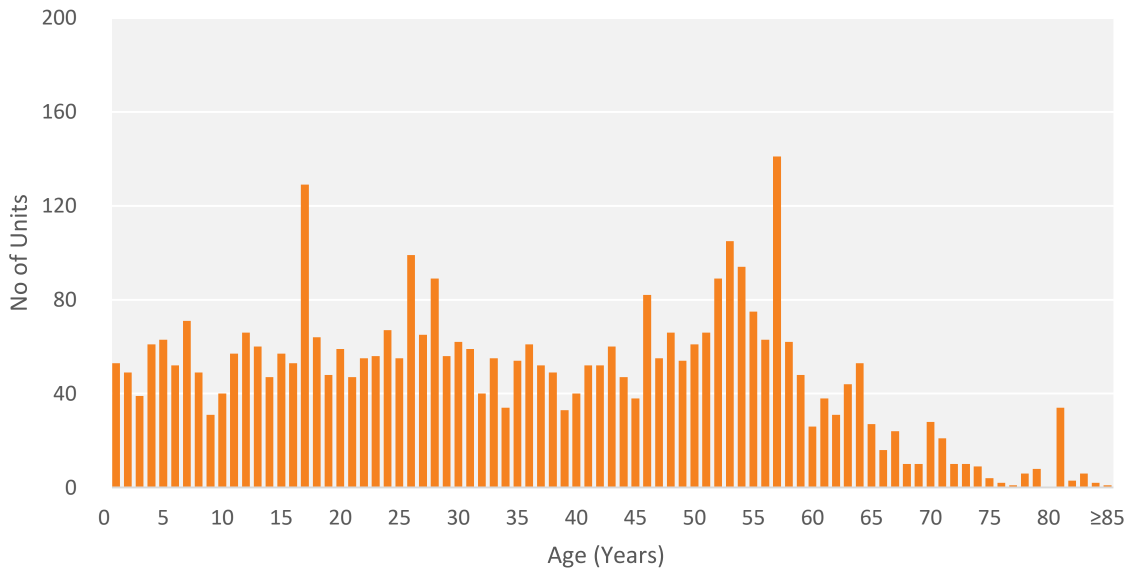
We have more than 4,000 pole mounted distribution transformers, 90% of which are below 120 kVA.

Table 8.91: Pole mounted distribution transformer ratings

RATING (KVA)	POPULATION	PERCENTAGE
≤15	1,590	39%
15 to 30	1,153	29%
30 to 120	876	22%
120 to 200	29	1%
>200	362	9%
Total	4,010	100%

The chart below shows the age profile of our pole mounted distribution transformers.

Figure 8.89: Pole mounted distribution transformers age profile



Given their 60 year expected life, ten percent of them 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 RY21 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.

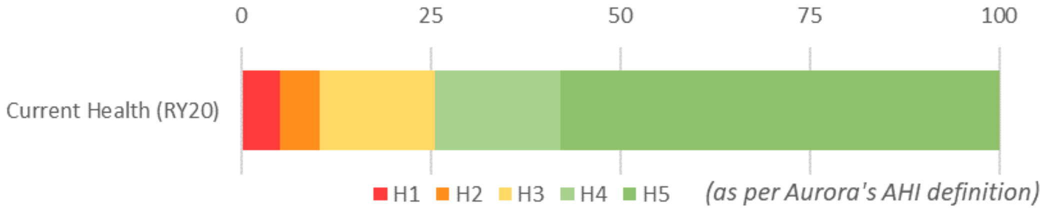
Meeting our portfolio objectives –safety first and sustainability by taking a long term view

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 8.90: Pole mounted distribution transformer asset health



The analysis indicates that we need to replace 5% (H1) of our pole mounted transformers within the next year, and ~25% over the AMP planning period.

Risks

Table 8.88 (above) set out the key failure modes of ground mounted transformers. Transformer specific risks (i.e. regardless of mounting arrangement) also apply to pole mounted transformers. The table below sets out additional risks identified in relation to our pole mounted transformer fleet.

Table 8.92: Pole mounted distribution transformers risks

Risk/Issue	Risk Mitigation	Main Risk
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. However, 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 ABSs 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 which is more costly. 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 8.91: Legacy pole-and-a-half substation with an ABS and two cast iron cable terminations

Any pole mounted transformers installed at a height such that clearance standards (at the time of install) have not been complied with, will be replaced with a new pole substation as applicable.

Operate and Maintain

Preventive maintenance

Preventive maintenance primarily involves inspections to verify visible and audible condition issues. Our current preventive works are summarised below showing that we currently only do cyclic inspections as part of pole inspections.

Table 8.93: 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	Five yearly

We have identified a preventive maintenance initiative to improve the performance of the fleet. This will primarily support our affordability objectives.

Table 8.94: Pole mounted distribution transformers preventive maintenance initiatives

Preventive Maintenance Initiative	Related Objectives	Time Frame
Pole mounted distribution transformers inspections We plan to commence collection of condition and other relevant data by undertaking specific inspections.	**Affordability** through cost management - better asset management decisions using more complete condition data.	Medium term

Corrective maintenance

Corrective maintenance on pole mounted distribution transformers is limited. Significant repair work such as repairing oil leaks is impractical on site. We may swap out the unit for a similar spare transformer, which may already have been refurbished.

Reactive maintenance

Any pole mounted transformer faults will generally necessitate a transformer swap, whether from older like-for-like spares or an as-new spare.

Spares

We hold spares of new pole mounted transformers based on our standard sizes, and 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.

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 a large number of 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.

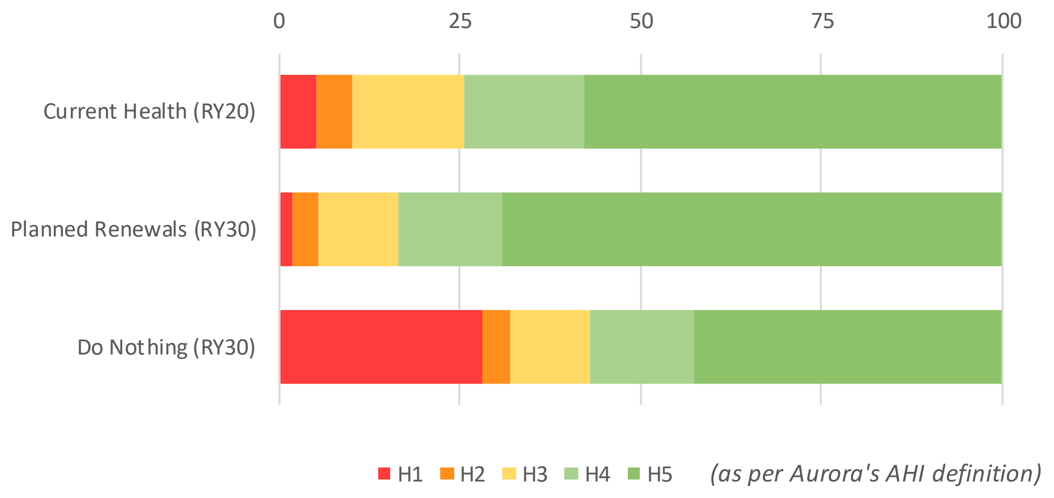
Table 8.95: Summary of pole mounted distribution transformer renewal approach

Aspect	Approaches Used
Renewal trigger	Reactive (upon failure) Condition-based proactive
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 5% of the fleet is classified as H1 (replace within one year); we plan to improve the overall health of the fleet during the AMP period, reducing H1's to 2% of the fleet under the planned renewals scenario. The proportion of H1s would increase to 28% under a 'do nothing' scenario due to the age profile of the fleet.

Figure 8.92: 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 two pole transformer substations. 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.

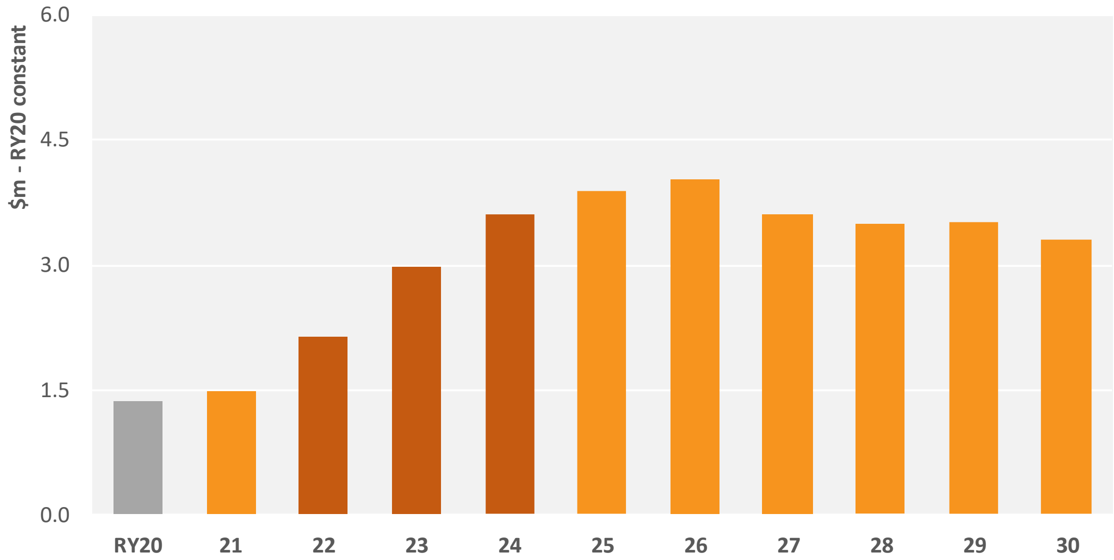
Coordination with other works

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 Expenditure Forecast

We have forecast renewal Capex of approximately $32m during the planning period,. This excludes units replaced onto new poles during pole replacements, where the driver is pole replacement.

Figure 8.93: 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. As pole renewal expenditure declines over the medium term we need to scale up our standalone renewal programme to manage fleet health.

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

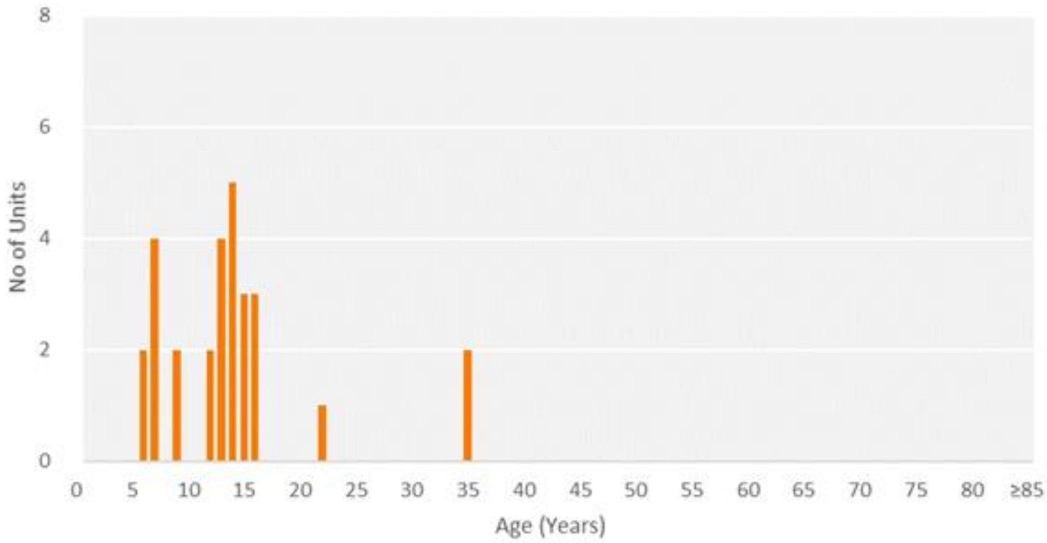
Voltage regulators automatically maintain a set voltage level on our 11 kV or 6.6 kV network. The length of some of our HV distribution lines necessitates the installation of voltage regulators partway along the feeders to compensate for undersized and/or long rural lines feeding isolated loads which 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 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.

Population and Age

We have 28 voltage regulators, either three phase units or single phase 'cans' making a three phase voltage regulation site.

Figure 8.94: Voltage regulators age profile



The majority of our voltage regulators are under 20 years of age, as a fleet they have an expected life of 45 years, however we may need to revise using corrosion zones as we expect those in higher corrosion areas will deteriorate more quickly.

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

We have not yet developed AHI for our voltage regulator fleet, given the small population. They are under site specific management at present and developing AHI will be a future improvement.

Risks

The table below sets out sets out the key risks identified in relation to our voltage regulators fleet.

Table 8.96: Voltage regulator failure risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
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

We are working on developing standard designs for our most common two 'can' and three 'can' pole mounted voltage regulator sites which will include an ABS bypass. Our fleet ranges from a single 1 MVA pole mount voltage regulator site to a 3 MVA ground mount voltage regulator site and therefore the creation of a single standard design is not feasible.

A simple design is usually all that is required when undertaking individual unit like-for-like swaps..

Operate and Maintain

Preventive maintenance

Compared to other distribution transformers, voltage regulators require significantly more preventive maintenance. This is because they have moving mechanical parts in the OLTC, and also control and communication systems.

Table 8.97: Voltage regulator preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY STATE FREQUENCY
Visual inspection, thermographic testing, tap changer operation, communications checks	Annually
Maintenance service - to ensure continuing operation and reliability.	4-10 yearly depending on loading, or 100,000-120,000 operations

Corrective maintenance

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.

Reactive maintenance

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 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 it will be disposed of, 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.

Renew or Dispose

Voltage regulators have an expected life of 45 years, however we may need to incorporate the use of corrosion zones as 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 8.98: 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 the 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 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 pole and other 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 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 1x 300 kVA and 2x 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 8.99: Mobile distribution substation and generator fleets failure risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
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.

Operate and Maintain

Preventive maintenance

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 8.100: 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 monthly
Mobile substation return from service inspection	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	Monthly
Standby generator oil and coolant testing	Six monthly
Standby generator full service (engine heaters keep engine at temperature 24/7)	Four to six yearly

Corrective maintenance

Rust repairs have been periodically required on the mobile distribution substations. There are no other significant items to note based on the substation components of the mobile substations.

Spares

Our mobile distribution substations use equipment common to our other network equipment, so spares are available. The cables are a special flexible type and one set was recently replaced upon failing test. 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.

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 8.101: Summary of voltage regulator renewal approach

Aspect	Approaches Used
Renewal trigger	Condition (proactive)
Forecasting approach	Individual sites
Cost estimation	Volumetric

Mobile Distribution Substation and Generator Expenditure Forecast

At this point, no renewal Capex is planned for our mobile assets during the period to RY30.

8.7. SECONDARY SYSTEMS

This section describes our secondary systems portfolio[95], which includes four asset fleets:

- protection systems
- DC systems
- Remote Terminal Units (RTUs)
- metering.

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 $25.7m on replacing secondary system assets.

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 8.16: Update on WSP Review – secondary systems

Issues: key risks identified include significant quantities of electromechanical 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 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 have reduced the maintenance cycle of electromechanical relays and improved battery systems testing. We will replace all electromechanical relays that are past end-of-life by the end of RY24.

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 equipment and transformer temperature alarms and transmit it to our control rooms for action.

95 All secondary systems Capex is covered under Asset Replacement and Renewal ID category, line item 'Zone substations' and will be included in Schedule 11a(iv) in Appendix B.

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 8.102: 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. Our fleet largely 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 four 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 obtain and repairs are not generally economic.
- **microprocessor**: electronic devices, these older technology relays have a wider range of functionality than electromechanical relays but less than numerical types.
- **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 schemes[96] 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 scheme may consist of multiple relays (e.g. a feeder relay may consist of earth fault and overcurrent relays). Numerical schemes make around 40% of our population of protection schemes.

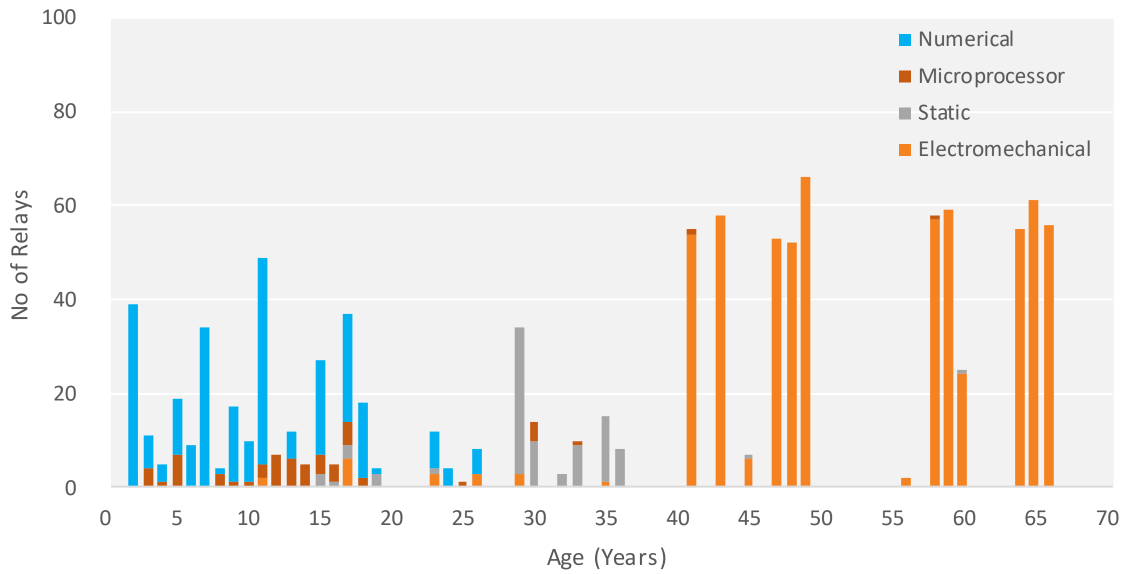
Table 8.103: Protection asset population by type and function

	Protection Function (No. of schemes / No of relays)					
Relay Type	Bus Zone	Subtransmission	Transformer	Feeder	Recloser	Total
Electromechanical	12 / 50	14 / 20	29 / 162	132 / 389	-	**187 / 621**
Static	2 / 5	5 / 14	13 / 44	18 / 20	5 / 5	**43 / 90**
Microprocessor	-	-	3 / 6	12 / 12	43 / 43	**58 / 61**
Numerical	8 / 11	49 / 59	26 / 62	125 / 126	-	**208 / 258**
Total	22 / 66	68 / 93	71 / 276	287 / 547	49	496 / 1030

96 Each protection scheme consists of one or more relays. We count the number of schemes because a modern equivalent scheme may comprise fewer relays than the scheme it is replacing.

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 8.95: 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 electronic types, a 20 year life is expected. Approximately 60% of our relays (about 40% of schemes) 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. Most microprocessor and 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. Many 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. WSP identified our electromechanical relays as the highest risk assets on our network. Other relay types do not face the same calibration issues as electromechanical 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 conductors on the ground not being detected and remaining energised. WSP estimated that, over the period RY15-RY18, there were fifteen incidents where a conductor fell to the ground and remained live, and should have been detected by a protection relay. Also, over the last 16 years we have recorded 40 incidents (that have contributed to consumer outages) involving incorrect protection relay settings.

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. This limits their performance in comparison to numerical relays that 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 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 8.104: Protection system risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
Failure to detect conductor to ground	Increased preventive maintenance on electromechanical 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	Safety, Reliability
Incorrect protection settings applied resulting in maloperation	Controlled settings database and procedures for revising settings	Safety, Reliability
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 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 it can be easily maintained. Lifecycle cost is an important consideration.

We have recently finished our subtransmission and zone substation protection philosophy/standard document. This 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.

Operate and Maintain

Preventive maintenance

We regularly inspect and test our protection assets to ensure they will operate reliably in response to a fault. Electromechanical relays require more 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 8.105: Protection systems 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 yearly.
Inter-trip testing	Six monthly (electronic and electromechanical)

We have identified a preventive maintenance initiative to improve the performance of the fleet.

Table 8.106: Protection preventive maintenance initiatives

PREVENTIVE MAINTENANCE INITIATIVE	RELATED PROTECTION OBJECTIVES	TIME FRAME
Increased electromechanical 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.	Short term

Meeting our portfolio objectives – safety first and affordability through cost management

Our plan for electromechanical relay renewal will run to the end of RY24. 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.

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.

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.

Spares

We retain spare relays in three locations around our networks; usually two to three of each relay type and model. When new types or models are introduced, spares are also purchased. We hold some spares for our electromechanical relays and new spares are difficult to source. Renewals will create more spares holdings. 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.

Renew or Dispose

There are a number of drivers for renewal of protection schemes; the main ones 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 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 subtransmission 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 modern numerical 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 8.107: 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 forecasted 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 microprocessor and 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. However, 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, but 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 and will include consideration of public safety risk, given protection protects assets in public areas such as overhead feeders.

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 Bucholz devices contain mercury and will use appropriate disposal methods when these are replaced.

Coordination with other works

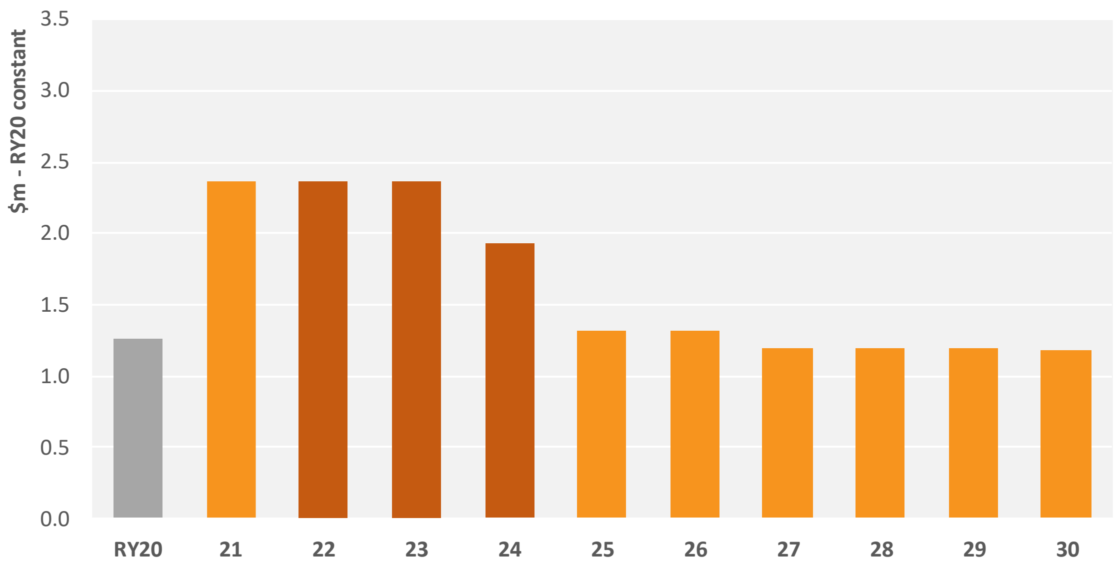
Where possible we coordinate replacement of protection relays with other project works, such as zone substation upgrades – whether renewals or growth driven – or Transpower projects at GXPs.

Protection Expenditure Forecast

We take a volumetric approach to protection renewal forecasts. Unit rates vary with the function of the relay, with bus zone or subtransmission protection relays having higher unit costs.

We have forecast protection renewal Capex of approximately $16m during the planning period. This expenditure excludes protection replaced under zone substation projects.

Figure 8.96: 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 until RY24. The higher renewal levels reflect our target to replace all electromechanical relays by RY24 and that these are higher cost schemes. Our annual renewal volumes will remain relatively steady throughout the AMP period but Capex will reduce in RY25 as we move to lower cost schemes. We plan to have replaced all end-of-life protection relays by RY30.

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, and 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 and monitors. Chargers are also known as rectifiers, as they convert AC into DC to charge the battery.

Our batteries are predominantly lead acid, and provide DC supply at voltages from 12 V to 110 V, the latter mainly serving protection equipment. The 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

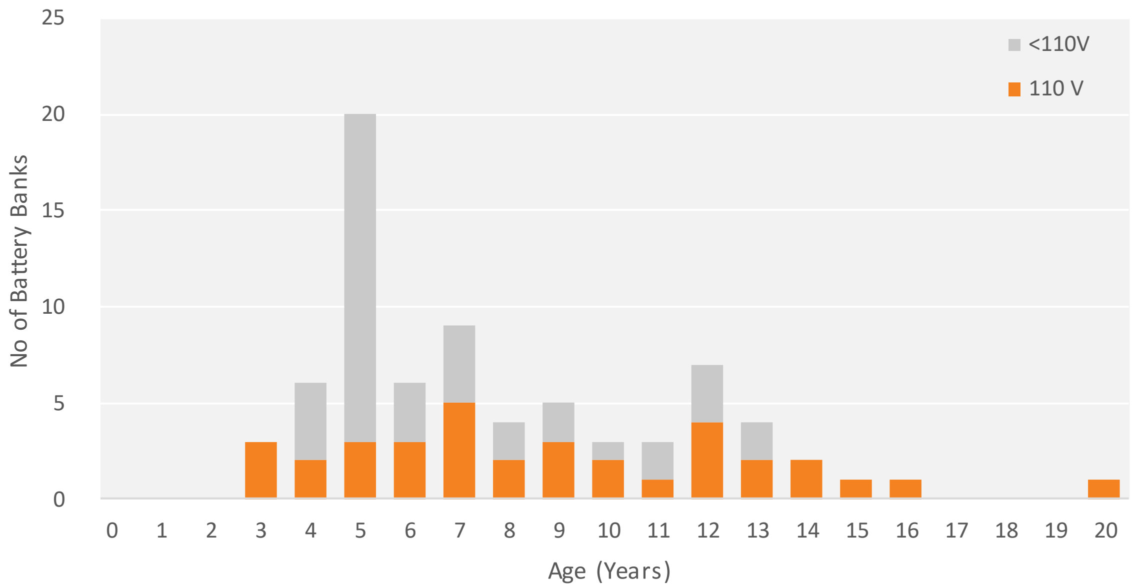
The following table summarises our population of DC systems.

Table 8.108: DC system asset population by voltage

VOLTAGE	NO OF BATTERY BANKS
110V	35
48V	11
12 / 24V	29

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.

Figure 8.97: 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.

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.

In RY20 we had one battery bank that failed discharge testing at a Dunedin zone substation. The bank was over 10 years old and hence was past expected life.

Risks

The following table sets out the key risks identified in relation to our DC systems.

Table 8.109: Protection system risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
DC system fails in service leading to protection maloperation, no visibility or 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 carry over times, which vary by battery location based on likely response time. Batteries are installed on seismically rated stands and the connections between cells are to be fully insulated. Covers are installed to prevent tools being placed on the battery banks.

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 DC-DC converters.

Operate and Maintain

Preventive maintenance

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 8.110: DC systems preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	STEADY STATE FREQUENCY
Battery bank and charger tests	Annually
Battery bank and charger visual inspections	Monthly (with monthly zone substation inspection)

Corrective maintenance

Battery cell failures are usually identified during routine inspections or occur during diagnostic testing. Failed cells are replaced immediately upon discovery.

Reactive maintenance

Reactive maintenance on DC systems involves responding to alarms as required, for example, temperature alarms, or responding to a DC system failure.

Spares

We do not maintain spare batteries as they lose charge over time, and our stores do not have the required temperature controls to maintain them in good condition. However, 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.

Renew or Dispose

Key drivers of expenditure for renewal of DC systems:

- **condition**: if battery banks fail discharge testing 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 six to eight years (depending on system redundancy and the environment they are installed in) 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 battery bank replacement.

Table 8.111: Summary of DC systems renewal approach

ASPECT	APPROACHES USED
Renewal trigger	Age Reactive condition-based Type (non-standard chargers only)
Forecasting approach	Age based
Cost estimation	Volumetric based on historical average unit rates

Disposal

Lead acid batteries are recycled and chargers are disposed of as per other electronic equipment

Options analysis

In our protection philosophy/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

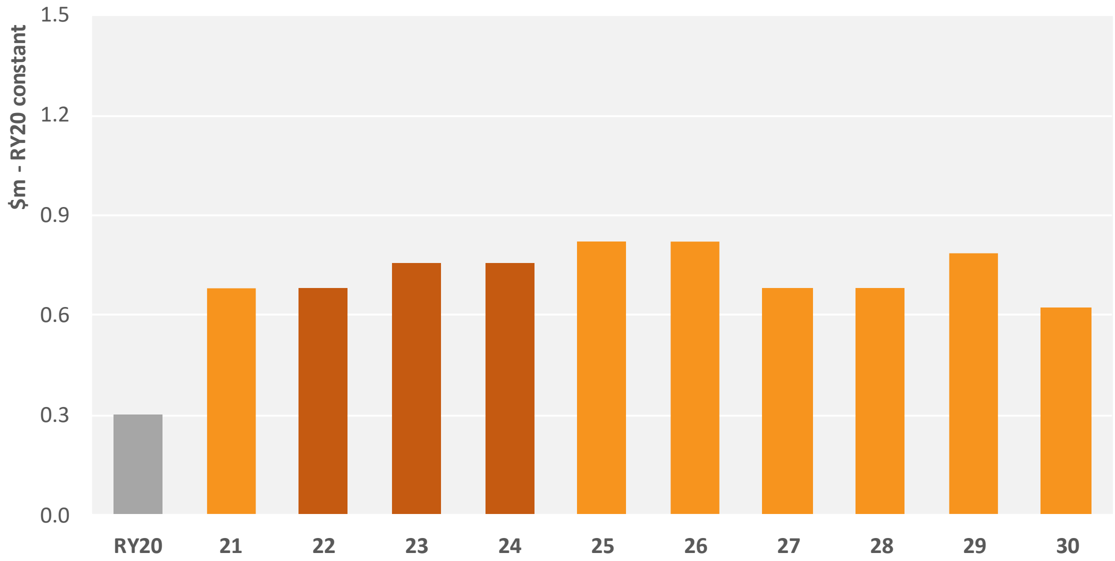
We undertake battery replacements in conjunction with zone substation upgrades where possible due to the synergies of combining the works. However, given their importance, if DC systems have exceeded their expected life they must be replaced as soon as possible rather than waiting for future project consolidation.

DC Systems 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 $7m during the planning period. This expenditure excludes DC systems replaced under zone substation projects.

Figure 8.98: 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 ramp up renewals to reach a new normal steady state.

Benefits

DC systems ensure a constant power supply to other vital secondary systems equipment. 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

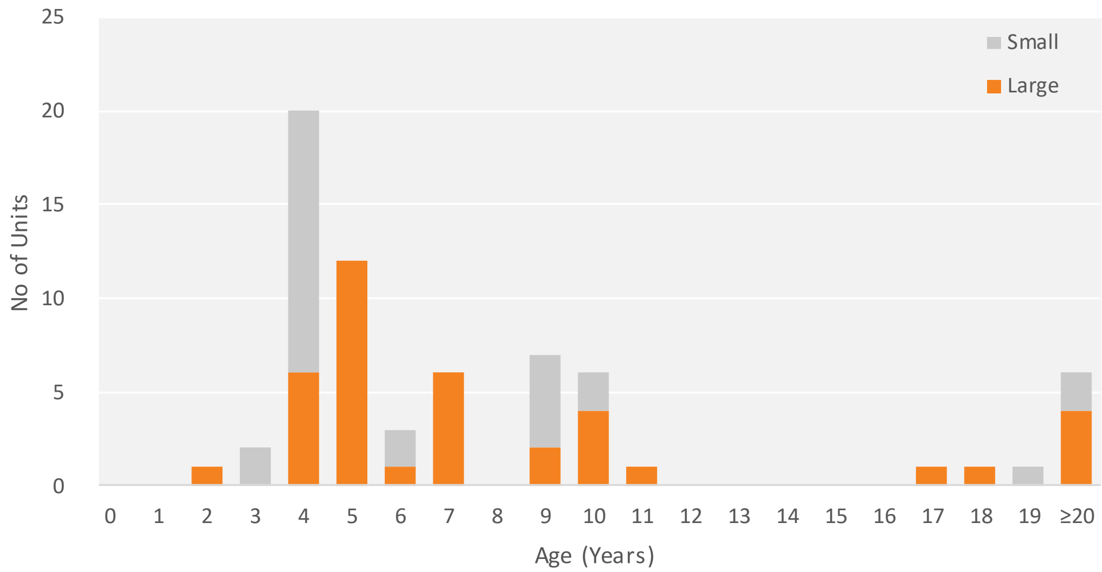
RTUs are an integral component of our SCADA and telemetry system. RTUs communicate with intelligent electronic devices (IEDs) in a zone substation. IEDs include protection relays, transducers, and human machine interface displays to provide information to our network operation personnel and control centre. We use various communication mediums with our RTUs that include 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 are 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 67 RTUs across our network.

Figure 8.99: 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 four to five 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 8.112: RTU system risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
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.

Operate and Maintain

Preventive maintenance

Maintenance of our RTUs is primarily preventive. Testing of all RTU points is undertaken as part of our zone substation maintenance procedures.

Table 8.113: 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 four yearly
Visual inspection	Monthly substation inspection

Corrective maintenance

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.

Reactive maintenance

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

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 if they do not comply with the DNP3 protocol over TCP/IP standard.

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 8.114: 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. Firmware upgrades have already been undertaken where applicable to extend the life of RTUs.

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 we dispose of RTUs in the same manner as we dispose of other electromechanical or electronic devices.

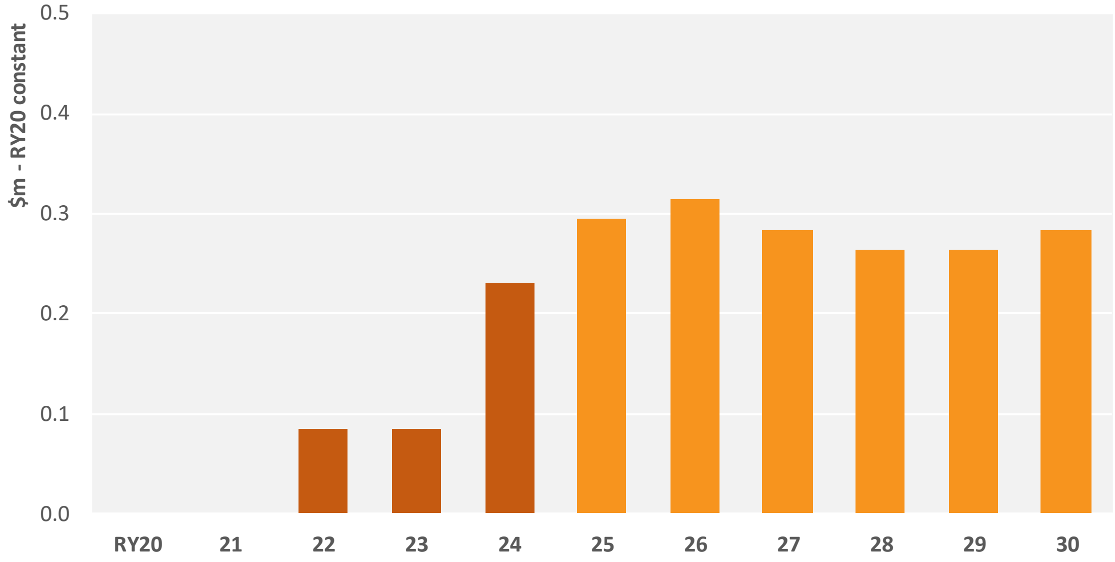
Coordination with other works

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.

RTUs Expenditure Forecast

We take a volumetric approach to RTU renewal forecasting. We have forecast Capex of approximately $2m during the period. This excludes RTUs replaced under zone substation projects.

Figure 8.100: 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 a control system upgrade. Our forecast comprises steady state renewals, where units reach end-of-life. 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 two 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 power transformer incomers at newly built zone substations. 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. These parameters are not available from our normal specification protection relays.

Population and Age

We have nine check meters across our networks. The oldest one is over 25 years old and other Central Otago units are ageing, while the six Dunedin units will all soon be less than five years old. Our three power quality meters are all less than five years old. The life expectancy of electromechanical and modern meters is 25 and 15 years respectively.

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 8.115: Metering risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
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

Operate and Maintain

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.

Renew or Dispose

Renewal of meters is usually undertaken with other works such as GXP and protection upgrades.

Table 8.116: 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 Expenditure Forecast

No metering renewal 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 do so more effectively 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 the ability to manage our new 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 uptake of EVs and residential PV installations). Gaps in our asset management capability are reflected in our most recent self-assessment of asset management maturity, 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 planned DER solution in Upper Clutha (see Chapter 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 and communicate this to staff. 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 which underpins our CPP submission, illustrates some of the advances we have made. Our asset management analysis and supporting models have been tested by the Independent Verifier and deemed appropriate given the existing asset management system maturity, and data availability.

Looking forward, we are committed to further developing our overall asset management capability to meet internationally accepted best practice standards. The investments in capability and systems outlined in this AMP are important enablers of that goal. We have set ourselves an ambitious goal to be fully compliant with the internationally recognised asset management standard, ISO 55001, by 2023.

> **Box 9.1: Asset management Certification**
>
> We will achieve leading practice asset management capability by 2023, evidenced by ISO 55001 certification. We have been making real progress and will continue to prioritise this important initiative in the coming years.

9.1.2. AMMAT Assessment

We undertake periodic reviews of our asset management maturity using the AMMAT assessment tool.[97] This consists of a self-assessment of our maturity compared to good asset management practices.

When preparing our previous assessment in 2018 we arranged for a group of our own management and staff to reassess our asset management maturity using the EEA guide. Our internal assessment produced an overall average AMMAT result of 1.94.

For 2020 we have used a review carried out by AMCL in 2019 against ISO 55001 to inform our assessment. This resulted in an overall average AMMAT rating of 2.13.

Figure 9.1: Comparison of our AMMAT scores by assessment area

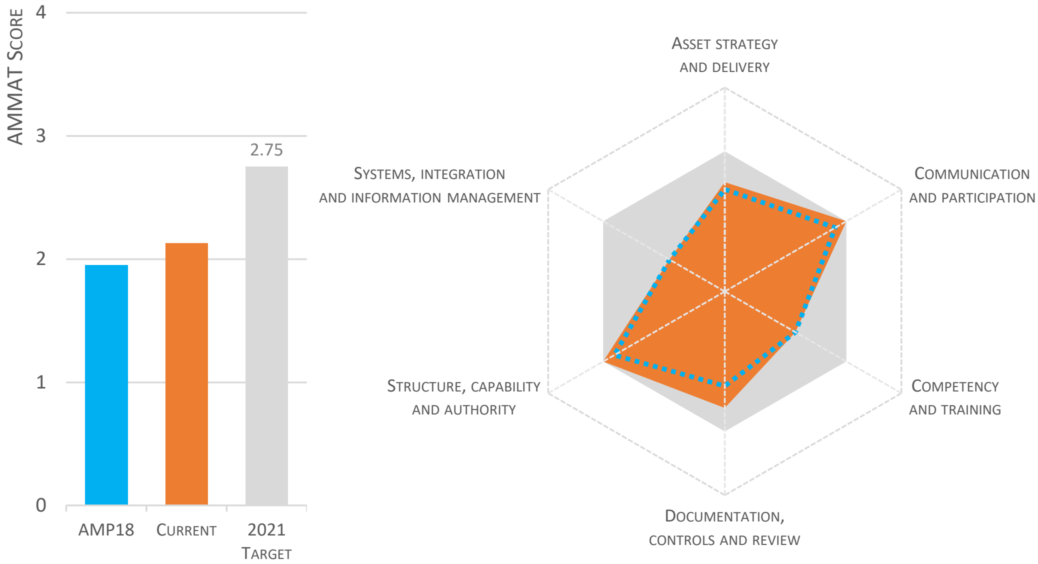
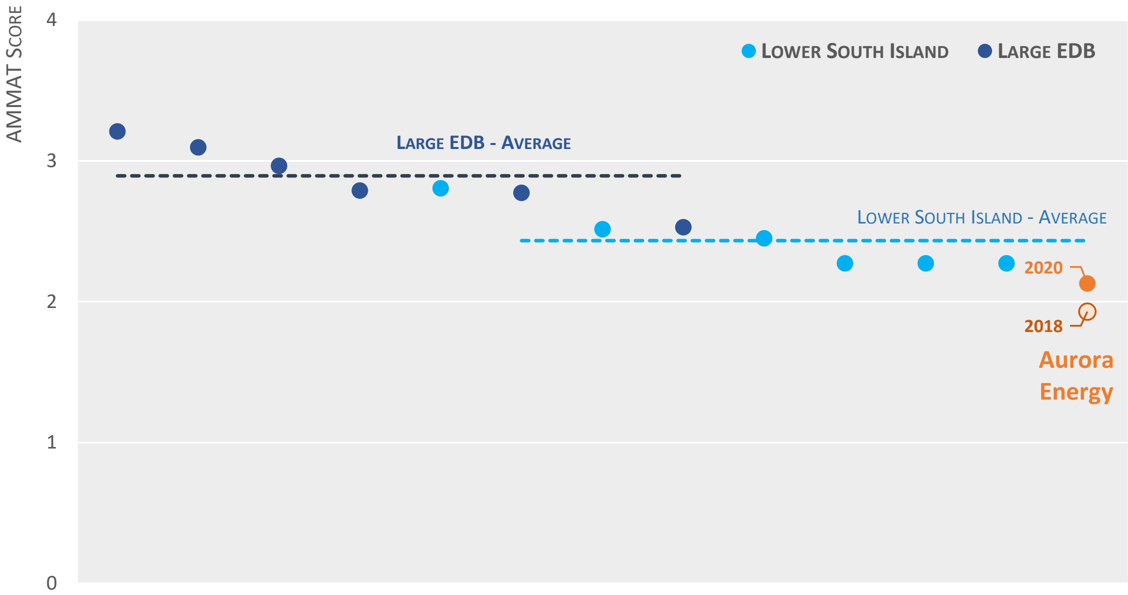


Figure 9.1 compares our current assessment with the 2018 results. AMMAT questions have been grouped and presented in six key assessment areas. The results are the average rating of several assessment questions.

We believe the 2.13 score reflects a fair assessment of our capability against the capability levels needed to manage our network effectively over the planning period. It indicates that we have a good understanding of asset management principles but are still embedding these in practice. Our AMMAT rating places us below the self-assessments published by other electricity distribution businesses (see Figure 9.2).

97 As an electricity distributor we are required to undertake and publicly disclose the AMMAT self-assessment results (Schedule 13 of the Electricity Distribution Information Disclosure requirements).

Figure 9.2: Comparison with a selection of EDBs



The analysis by AMCL highlighted areas where significant improvement in our asset management system is required. We have used this review of our asset management maturity as an important input to the development of our asset management development plan. The overall aim of this improvement effort is to achieve an average AMMAT rating of at least 2.75 by 2021 and to build on this to achieve ISO 55001 certification by 2023.

Figure 9.3: Comparison by category

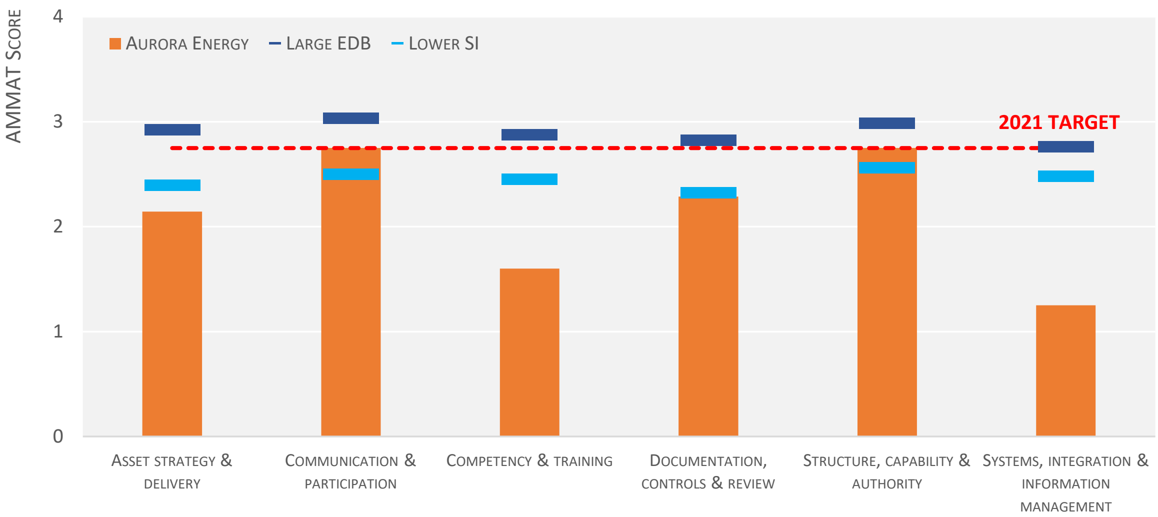


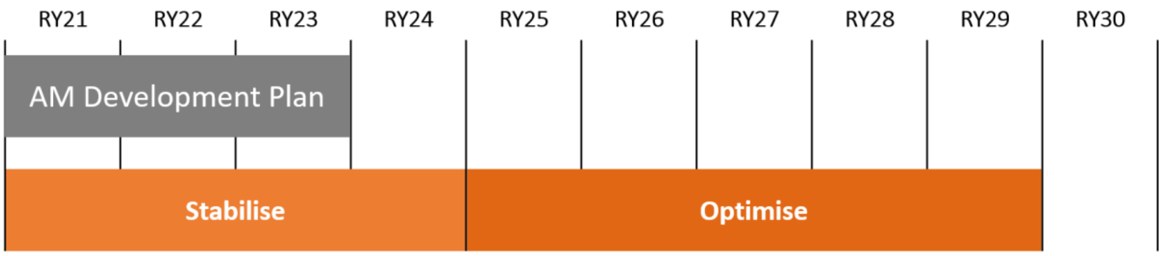
Table 9.1 (see next section) presents a summary of our asset management development plan. We have grouped these improvement initiatives to allow us to focus clearly on the main areas of need and to minimise overlap. As a result, these topic areas differ from the summary categories shown in the AMMAT illustration above.

9.1.3. Asset Management Development Plan

Our AMMAT score is a frank assessment of our current capabilities, strengths as well as shortcomings. Our review indicated a good understanding of the core principles of asset management, but the result falls well short of the standard expected from a mature asset manager. We do not consider this sufficient and accordingly have put in place a plan to improve our asset management capability. Our Asset Management Development Plan (AMDP) will lay the foundations for improving our asset management capability including our efforts to achieve ISO 55001 certification.

Our AMDP coincides with our CPP Period (see below) where our primary aim is to stabilise the network and address safety risks. The timing of the AMDP will allow us to leverage the improvement outcomes to optimise our CPP2[98] investment plans. The objective of these improvement initiatives is to ensure we can provide customers with a safe and reliable electricity distribution service, while minimising the whole-of-life cost of managing our assets.

Figure 9.4: Our asset management improvement timelines



To monitor our progress, we engaged asset management capability specialists to review our current capability. Understanding the maturity of our asset management practices is necessary for determining the scope of asset management improvements in our AMDP. We plan to address the identified shortcomings, to the extent possible, during the CPP Period.

Asset Management Improvement Areas

Continuous improvement 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 where we need to improve if we are to achieve our goal of good industry practice.

Our asset management improvements need to be underpinned by strong analytical capability. If we are to successfully optimise future investments and manage network risk there will be an increasing need for reliable information and expanded capability, and improved systems and data. Accurate and reliable asset data and modelling is an essential input.

[98] The subsequent five years (RY25 to RY29) following our initial CPP will see us propose a further set of investment plans and quality standards and engage with stakeholders on their preferences. These plans will build on our improved asset management capabilities.

The shortcomings that we want to address as part of an asset management improvement journey are consolidated in our 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
- works delivery: we are planning significant levels of ongoing expenditure on the network over the AMP period. Improving our delivery capability will help ensure our expenditure is prudent and efficient, and that we contain costs and limit price increases to customers
- reliability management: we have put in place a dedicated work programme to improve our overall reliability performance and to address historical breaches of the quality standards (further detail is set out in Appendix C)
- competency: we will develop our asset management capability through effective recruitment and development of our staff, ensuring appropriate competency levels and breadth of skills
- risk and review: 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: improvements to the tools and analysis approaches used to support our asset intervention decisions
- asset knowledge: define and document key requirements for asset and network data to support decision-making, including master data, condition data, work and defect history, and performance records.

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 CPP2 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 and other stakeholders. 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 Development Plan

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 9.1 presents the main improvement initiatives, by topic area and progress to date.

Table 9.1: Asset Management Development Plan

AREA	INITIATIVE	SUMMARY	PROGRESS
Competency	ISO 55001 Certification	We will identify and address the necessary steps to achieve ISO 55001 certification by 2023.	Gap analysis to ISO 55001 has been carried out by AMCL.
Competency	Competency framework	Develop a competency framework and provide targeted training to meet business needs, broaden technical skill sets and grow our leaders.	Introduced Performance and Development Plans (PDP) and a broader performance framework. Developed a remuneration and rewards strategy and introduced SP10 Job Evaluation.
Competency	Build and retain capability	Review and amend our people frameworks, systems, and processes to ensure they are relevant and can attract, engage and retain quality people and motivate high performance.	Refined our recruitment process and implemented a modern and progressive leave management standard. Developed a holistic learning and development standard and learning 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
Organisation and people	Appropriate structures	Review organisational structures, processes, roles and responsibilities and contractual relationships. Effective leadership will be a key aspect.	Structure reviewed and changes implemented.
Risk management	Business continuity planning	Undertake a strategic review of contingency preparedness and emergency response capability.	Review complete and tested under several scenarios.

AREA	INITIATIVE	SUMMARY	PROGRESS
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, 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
AM decision-making	Cost estimation	Improve in-house cost estimation capability, which incorporates feedback from systematic reviews of outturn costs of delivered works.	We have established a centralised price-book that will begin to incorporate feedback.
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

AREA	INITIATIVE	SUMMARY	PROGRESS
Asset knowledge	Asset information roles	Develop an implementation plan to drive improvements in asset information collection and data quality. This will include clarifying the roles of data owners and stewards.	Ongoing
Asset knowledge	Asset data structures	Define and document key requirements for asset and network data to support decision making, including master data, condition data, work and defect history, and performance records.	Ongoing

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**: is 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**: 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

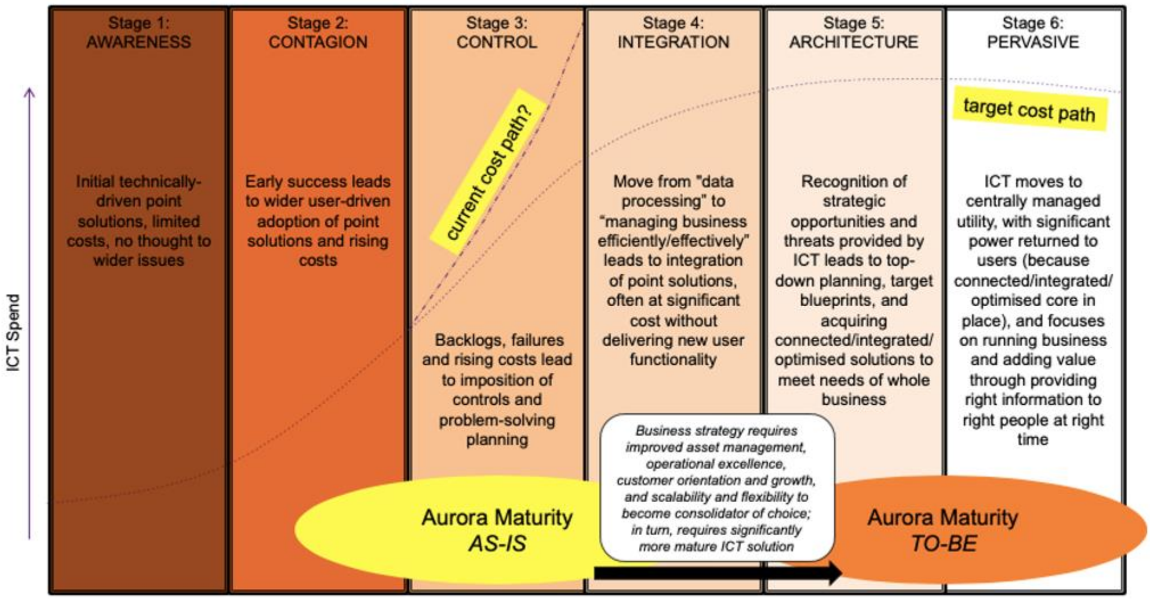
ICT-related Opex is included in business support for Information Disclosure purposes (note our ICT Capex is included in the non-network Capex forecast).

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 9.5: Current ICT maturity assessment[99]



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:

[99] Adapted from Nolan, Norton & 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 will 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 9.2: Business service categories

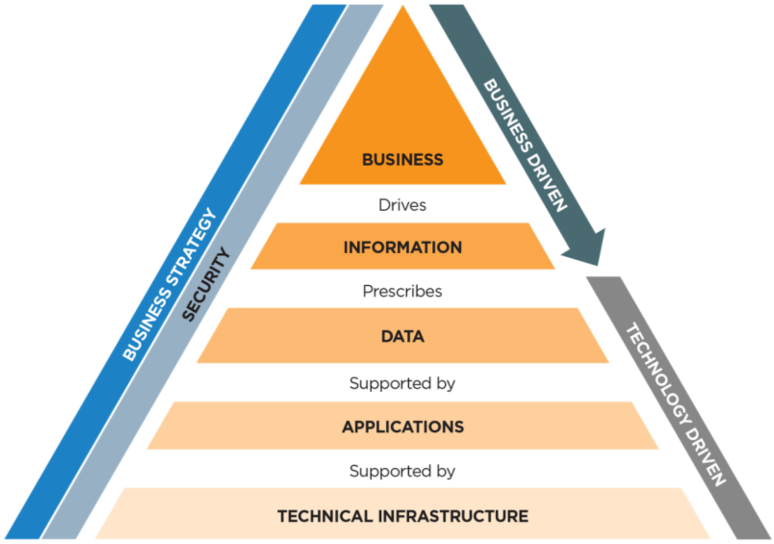
BUSINESS SERVICE	DESCRIPTION
Asset Management	Support the creation, management and operation of assets and asset management. Support the forecasting and planning of distribution asset maintenance and our data collection systems.
Operational Technology	Includes SCADA and associated systems to support 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.

Figure 9.6: Enterprise architecture framework[100]



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.

[100] This is a variant of a typical enterprise architecture framework.

Box 9.2: Technology and Information Principles

The following principles govern our technology environment

- we are an electricity distribution business. We use technology.
- 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 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.

These principles increasingly drive our selection, implementation and operation of technologies.

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 period up to 2022
- Horizon 2: covering the years 2022 to 2024
- Horizon 3: covering a period from 2025 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 9.3: Horizon 1 RY20 to RY22

BUSINESS SERVICE	INVESTMENT FOCUS
Asset Management	Implementing new capability to support rapidly developing asset information strategies and the increasing amount of data being obtained from both real-time systems and growing field capture of asset information.
Operational Technology	Upgrading the capability of the recently implemented Advanced Distribution Management and Outage Management Systems to allow more field-based visibility to improve worker safety and improve customer service for outages.
Customer and Commercial	Maintaining billing systems, planning increased customer care and service capability.
Corporate	Continued support of existing systems while improving operational efficiency.
Enterprise Technology and Infrastructure	Expanding the use of cloud services. Fully separating Aurora Energy infrastructure and services from Delta. Optimising our communications network taking advantage of merging radio and mobile.

Table 9.4: Horizon 2 RY22 to RY24

BUSINESS SERVICE	INVESTMENT FOCUS
Asset Management	Extending and embedding 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 new capability.
Operational Technology	Extending distribution management capability further into the LV network. Increasing capability for management of distributed energy and sensor technology.
Customer and Commercial	Improving customer case management and customer services.
Corporate	Re-platforming core financial systems. Re-platforming employee management and payroll systems with hosted or cloud services.
Enterprise Technology and Infrastructure	Standardising our communications network to prepare for the forecast growth in data from distributed systems and assets and the increasing use of sensors.

Table 9.5: Horizon 3 investment focus

BUSINESS SERVICE	INVESTMENT FOCUS
Asset Management	Adding/improving capability to support external data sets. Increasing work automation. Potentially undertaking a lifecycle replacement of one or more parts of systems used – GIS, Asset Management, analytics toolsets.
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 Machine learning and use of Artificial intelligence to drive enhanced asset performance.

9.3.4. 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.

9.3.5. 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 would expect to exploit these options if they prove efficient – effectively replacing Capex with Opex but at similar or lower Totex over a five to ten-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 RY20 and RY24 – covering Horizons 1 and 2 – we will scope, select and implement new work, job and contract 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.

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 two to three years we will begin to extend this capability to the LV network and increase mobile capability. A lifecycle replacement of our core supervisory control SCADA tool is planned later in the period. Although cloud-provisioned SCADA is not yet commercially available, it is possible that this may be an efficient implementation option for us.

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 include 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. 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.

9.3.6. 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 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.

Table 9.6: Facilities assets

TITLE			
Dunedin	Halsey St	Leased	Main office, control room and storage
Central Otago	Ellis St (Alexandra)	Owned	Storage, part leased to third party
	Barry Avenue (Cromwell)	Owned	Storage
	Hawea	Owned	Residential rental (potential storage/sale)
	McNulty Rd (Cromwell)	Leased	Main office and control room
	Terrace Junction (Frankton)	Leased	Office
	Success St (Alexandra)	Leased	Storage

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, PC and communication equipment. 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 and screens
- 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, handsets and related peripherals required to service their ICT needs.

9.4.2. Motor Vehicles

We have a fully maintained fleet of 37 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 set out in a company policy[101] which sets out how we procure and permit the utilisation rules for company motor vehicles.

We periodically undertake lease versus ownership analysis for our vehicles 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.

[101] 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 forecasts 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. This includes reflecting the outcomes of the Commission's consultation process and subsequent decision on our CPP application.

Box 10.1: Note on our expenditure charts

The charts in this chapter show actual expenditure (grey column) for RY20 (1 April 2019 to 31 March 2020) and our forecasts (orange columns) for the remainder of the planning period. The darker bars indicate our proposed CPP Period.

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 RY20 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.

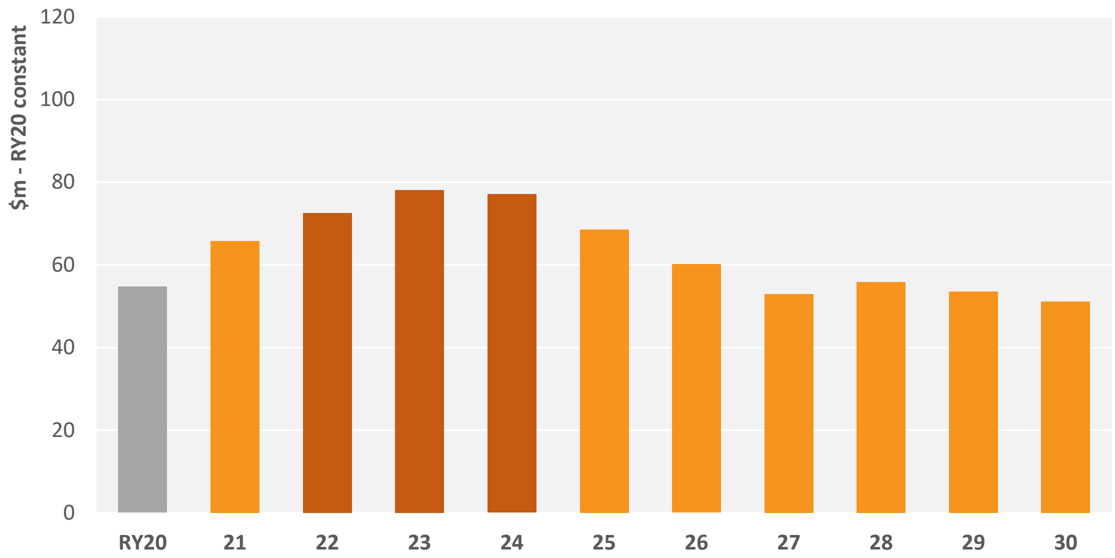
10.1.1. Total Capex

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. However, over time this will reduce as we migrate to service-based IT solutions.

Figure 10.1: Forecast total Capex (net of contributions)



Our overall Capex is broadly consistent with our 2019 AMP and continues to represent a significant increase on historical levels. 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:

- increasing conductor and crossarm renewals over the period, as we progressively address the deteriorating health of these fleets
- maintaining our accelerated pole replacement programme for up to three more years, before returning to steady-state levels
- replacement of poor condition assets in other fleets that present safety risks, particularly ring main units and indoor switchgear
- supporting new connections to our network
- later in the AMP period, post the impacts of COVID-19, we expect to resume investments to serve growing communities in Arrowtown, Wanaka, Queenstown, and Cromwell
- implementing new ICT systems, and supporting processes, in the early part of the CPP Period, including an EAMS
- 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 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.

10.1.2. Total Opex

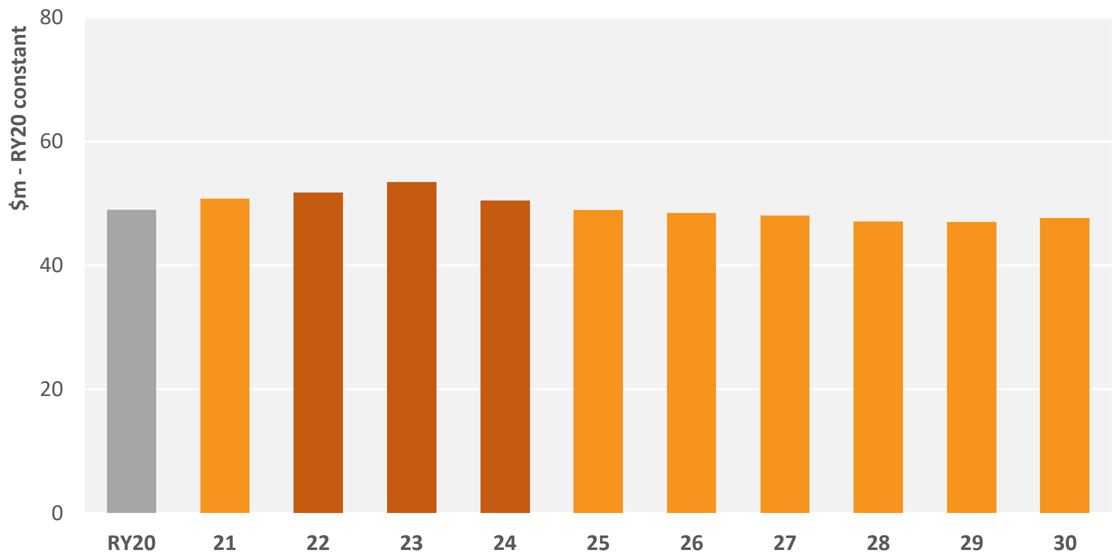
Our total Opex forecast is relatively stable over the planning period. We expect expenditure to reduce following the CPP Period as we refine our asset management approaches and modelling and begin to see improved levels of efficiency across our network activities.

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 decline over the AMP planning period. In the coming two to three 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.

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
- **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 most of our expenditure portfolio. We have introduced these efficiencies compared to our initial forecasts so that future price increases are more affordable. We have responded to concerns regarding affordability and specific feedback from the Independent Verifier.

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.[102] 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 applied different cost escalators to our constant (RY20) price expenditure forecasts. Our 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 conductors that are impacted by the inputs. These were applied to our constant (RY20) forecasts to produce the nominal dollar forecasts for the Information Disclosure schedules in Appendix B.

10.2. CAPEX FORECASTS

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.[103] 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.

102 All groups Consumer Price Index.

103 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.

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.

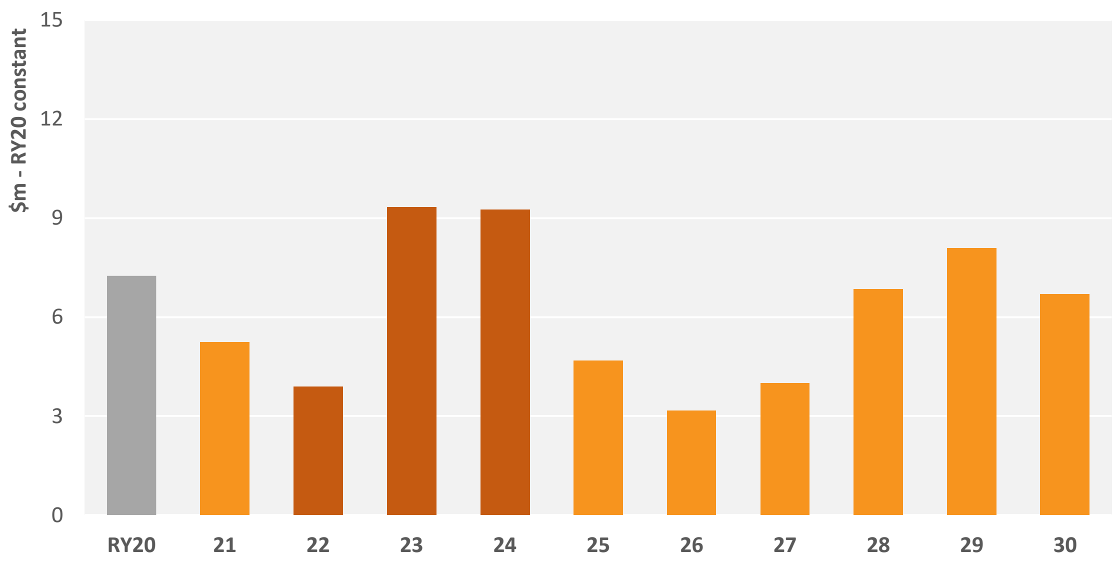
Network development includes three main types of investment:

- growth and security Capex: is used for investments that increase the capacity of our networks in response to increasing demand or to meet our SOS guidelines
- reliability-driven: these investments aim to minimise the impact of an event, such as 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.

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 transformer upgrades, subtransmission capacity upgrades, and new substation builds.

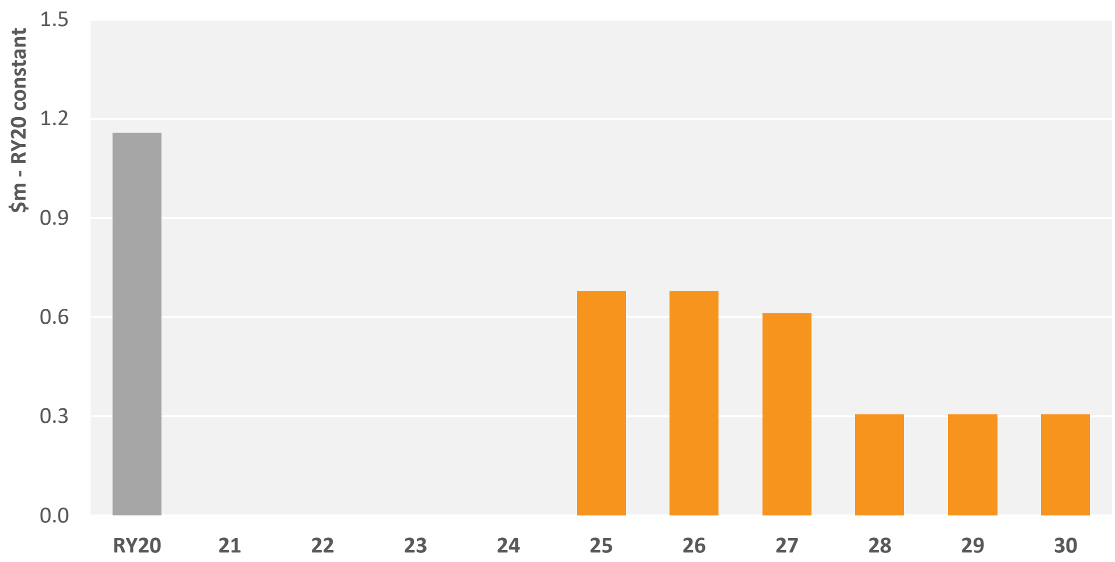
In addition to our major projects, distribution and LV reinforcement spend amounts to approximately $3m per annum with a relatively consistent profile over the period. We have reduced this spend in RY23 and RY24 due to the expected impact on demand from COVID-19.

The overall profile is relatively lumpy, with expenditure spikes reflecting overlapping spend on two or more large projects. The timing of our major projects has been adjusted in anticipation of the impact of COVID-19. The large step up into RY23 is due to the Arrowtown 33kV ring upgrade and Smith St to Willowbank 33kV intertie projects. The last three years increase is due to the combined cost of four projects - Riverbank substation, Lindis Crossing substation new transformer, Frankton substation transformer upgrade and the North Street to Ward Street 33kV intertie.

Reliability[104]

Reliability-driven investments aim to maintain or improve reliability of service at appropriate levels, reflecting the preferences of customers.

Figure 10.4: Reliability Capex



Capex in this category relates to installing new reclosers on problematic and unreliable feeders, procuring mobile generators and installing fault passage indicators. All of these initiatives are targeting improved quality of supply. We plan to undertake the following initiatives starting later in the AMP planning period:

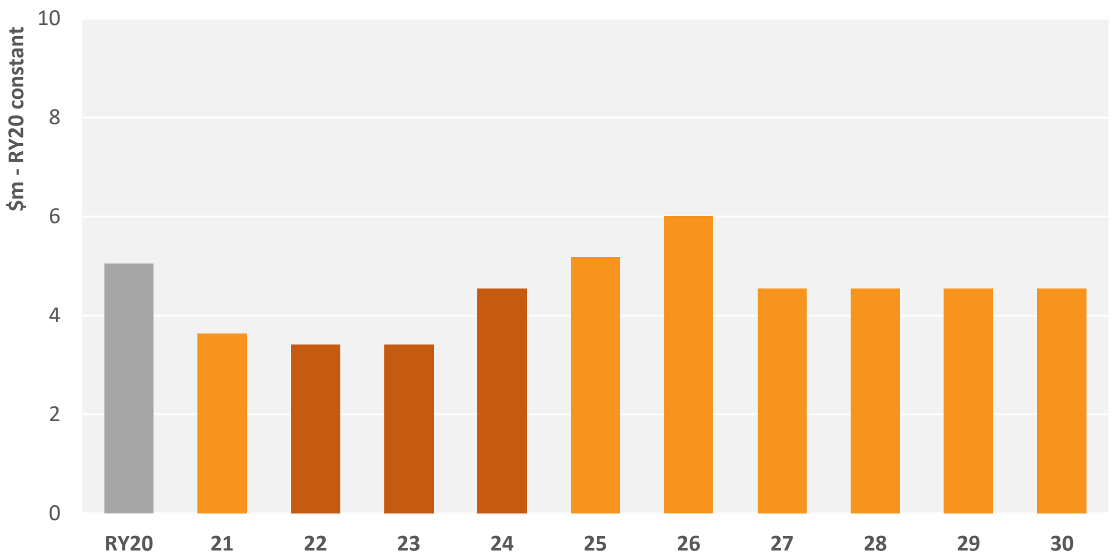
- installing strategically placed auto-reclosers on the network to reduce the number of consumers affected by planned/unplanned interruptions
- Installing remote controlled switches on feeders to reduce the average time that consumers are affected by unplanned interruptions
- installing fault passage indicators to reduce the time taken to find faults, reducing the average time consumers are affected by unplanned interruptions.

104 We include these investments within the Reliability, Safety and Environment (RSE) category under Information Disclosure.

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.

Figure 10.5: Consumer connections Capex (net of capital contributions)



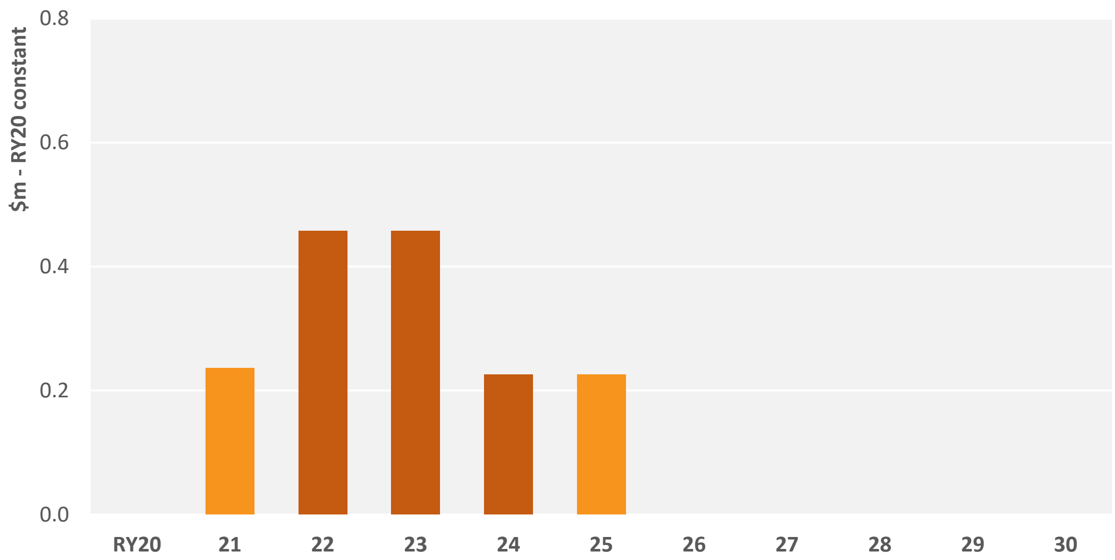
Historically, we have seen significant year-on-year variation in both customer connection Capex and capital contributions. Typically, we would forecast future investment levels based on the average of recent years. This forecast would then be adjusted where we knew of significant new connections that are larger than typical, and that are unlikely to be accommodated within the average. At this stage we expect there to be significant large developments taking place in RY25 and RY26, this is discussed further in Chapter 6.

We have retained this broad approach for the AMP planning period with the exception of the next two to three years. Reflecting the likely reduction in economic activity due to the COVID-19 pandemic, we have adjusted our forecasts down for the three-year period RY21 to RY23.

Network Evolution

Our network evolution investments aim to help prepare us for the wider, future adoption of DERs. Over the AMP period, we expect to see more EVs, photo voltaic 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 begin to deploy LV monitoring to support connection of DERs from RY21.

10.2.2. Lifecycle Management Capex

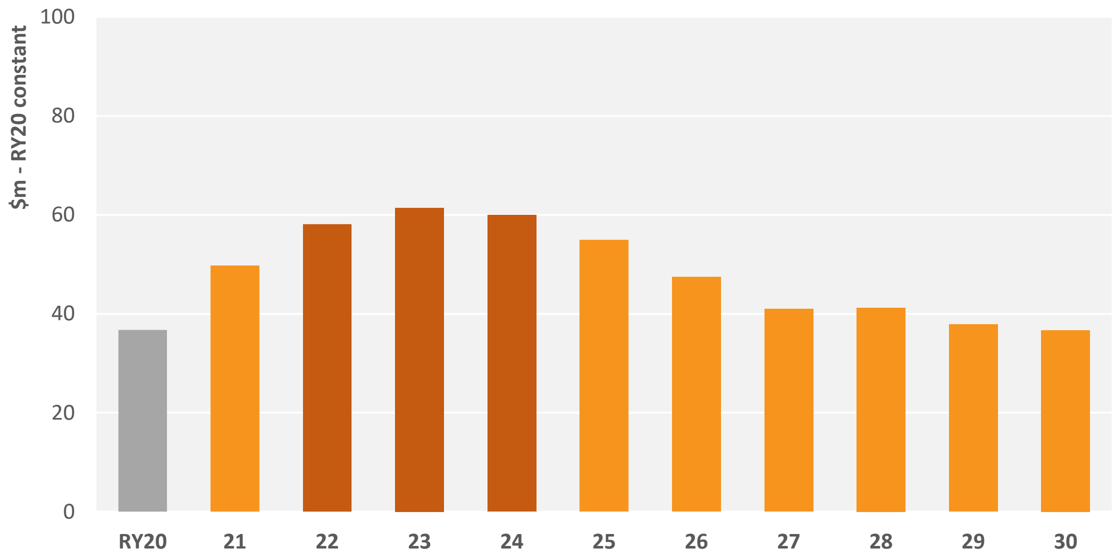
The lifecycle management Capex category includes seven expenditure portfolios that are used for budgeting purposes. These seven portfolios, in turn, include 27 asset fleets. Our day-to-day asset management is at the fleet level. Fleets are also the basis for medium-term forecasts. We also include asset 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 overall driver is that renewing network assets is essential to maintaining the overall health and condition of an electricity network. Not doing so would allow deteriorating condition to increase safety and reliability risks due to the higher likelihood of asset failure.

We have been addressing backlogs in required renewals since publishing 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

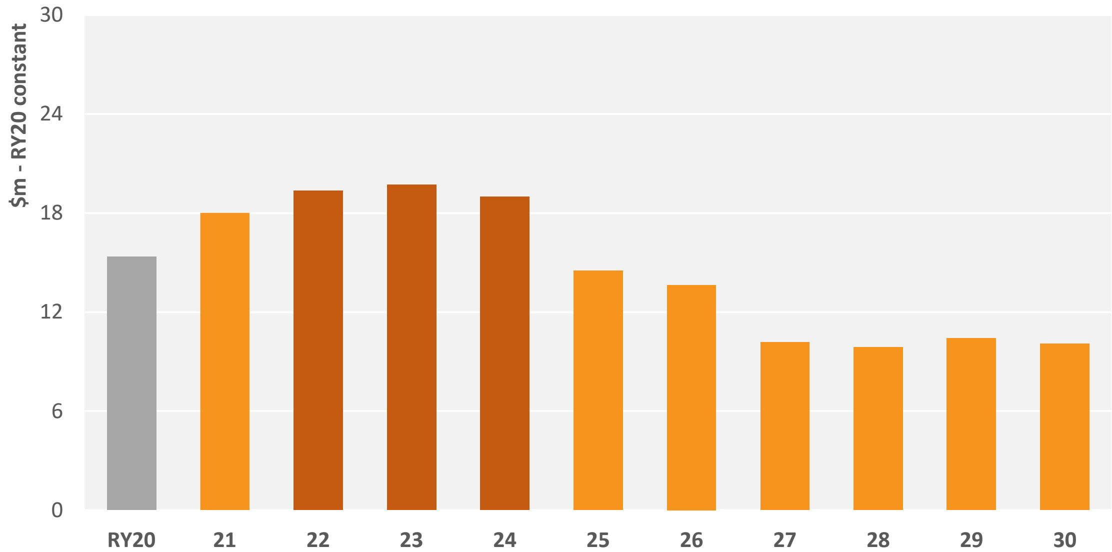


The following sections set out our planned renewals Capex for each of the seven portfolios. Appendix B sets out this expenditure using Information Disclosure categories.

Support Structures

Chapter 8 explained that our support structures portfolio includes our pole and crossarm fleets.

Figure 10.8: Support structures renewal Capex



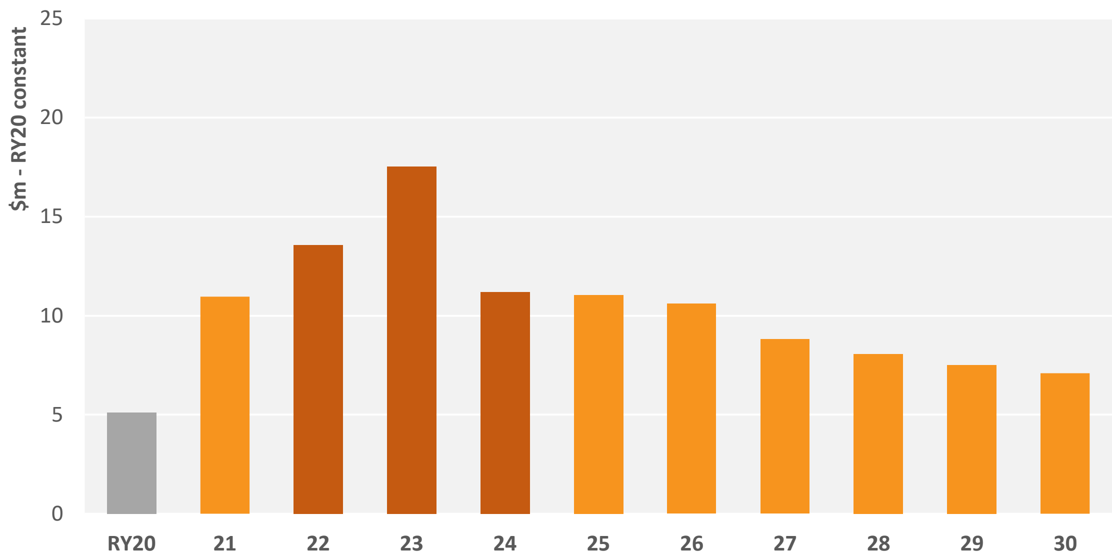
Our planned renewals Capex for support structures over the next two years focuses on our ongoing work to replace our worst condition poles and the expansion of a separate programme to replace poor condition crossarms. Our pole renewal programme reflects our expectations of the condition of pole assets as continue to mechanically test these assets. During the CPP Period we will gradually reduce the level of pole investment until RY23 when we should approach a steady-state level of annual renewal.

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 Conductors

The chart below shows our forecast investment over the planning period in our three conductor fleets: subtransmission; distribution; and LV.

Figure 10.9: Overhead conductor renewal Capex



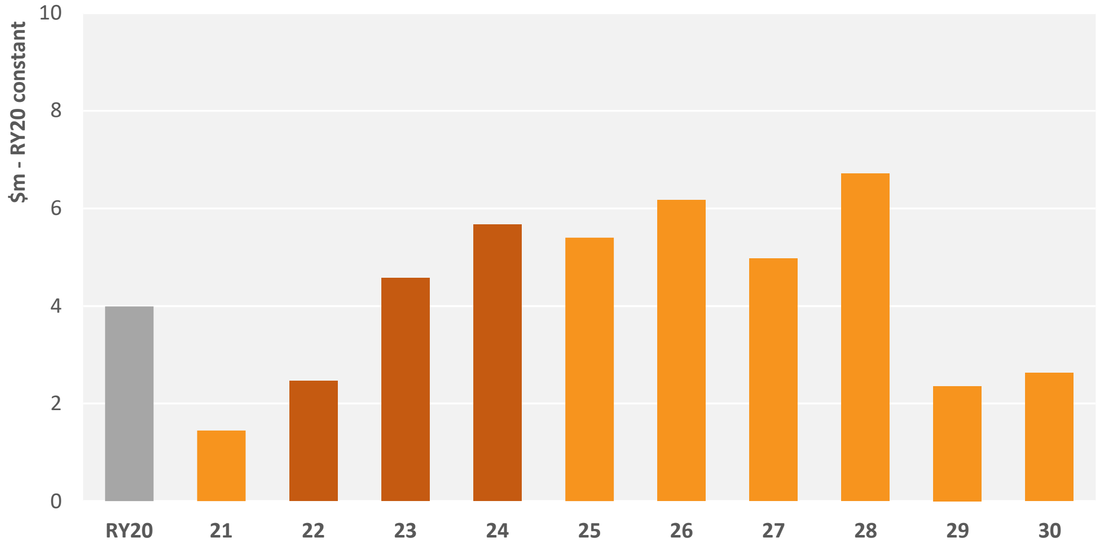
As discussed in Chapter 8, we have a relatively large volume of aged conductor. To address this, we began a renewal programme in RY20 to progressively replace distribution and LV conductor deemed to pose the greatest safety risk. Based on age and location of our various types of conductor, we have estimated likely replacement volumes over the planning period.

Early in the period we have scheduled a large reconductoring project on our subtransmission 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 RY23. The remainder of the period will see us undertake relatively low volumes of additional subtransmission renewal.

Cables

The chart below shows our forecast investment in our underground cable fleets.

Figure 10.10: Cables renewal Capex

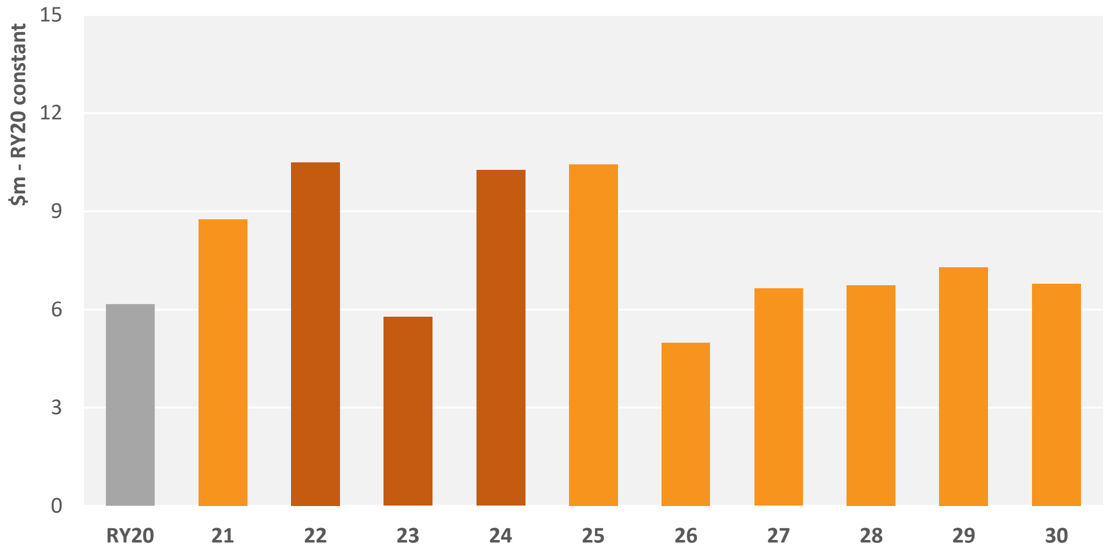


The condition of our subtransmission cable, and the risk associated with a significant failure mean that many need to be replaced during the planning period. We plan to replace a large number of cast iron potheads and some poor condition PILC distribution and LV cable.

Zone Substations

The chart below shows our planned renewal investment in our zone substation assets.

Figure 10.11: Zone substations renewal Capex

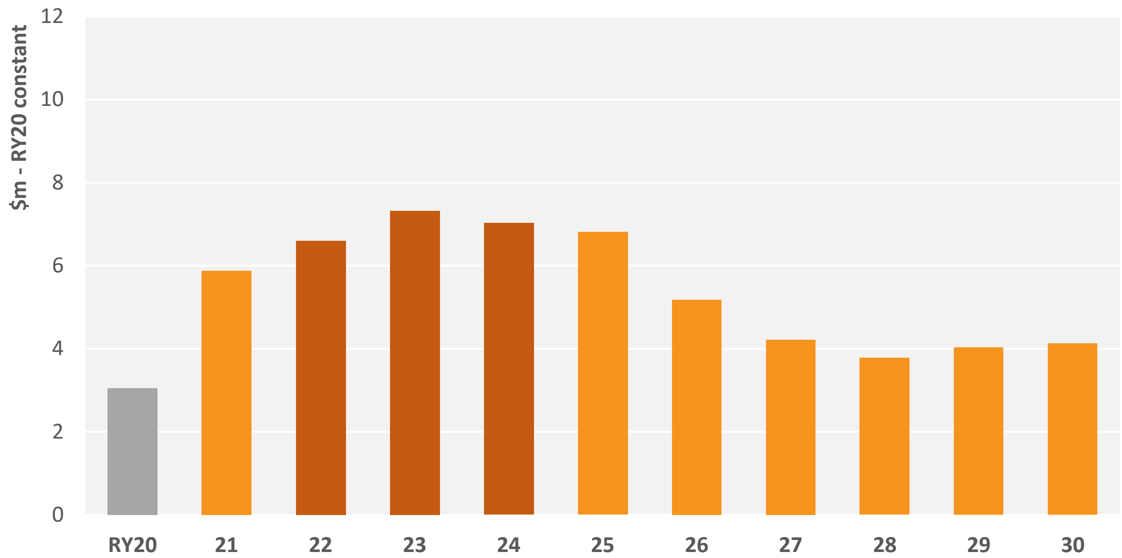


Chapter 8 explains the need to replace zone substation assets due to drivers such as asset health, criticality, and safety/environmental risk. Most zone substation works are large projects, which leads to a relatively 'lumpy' investment profile over the planning period.

Distribution Switchgear

The chart below shows our forecast investment on our distribution switchgear fleets.

Figure 10.12: Distribution switchgear renewal Capex

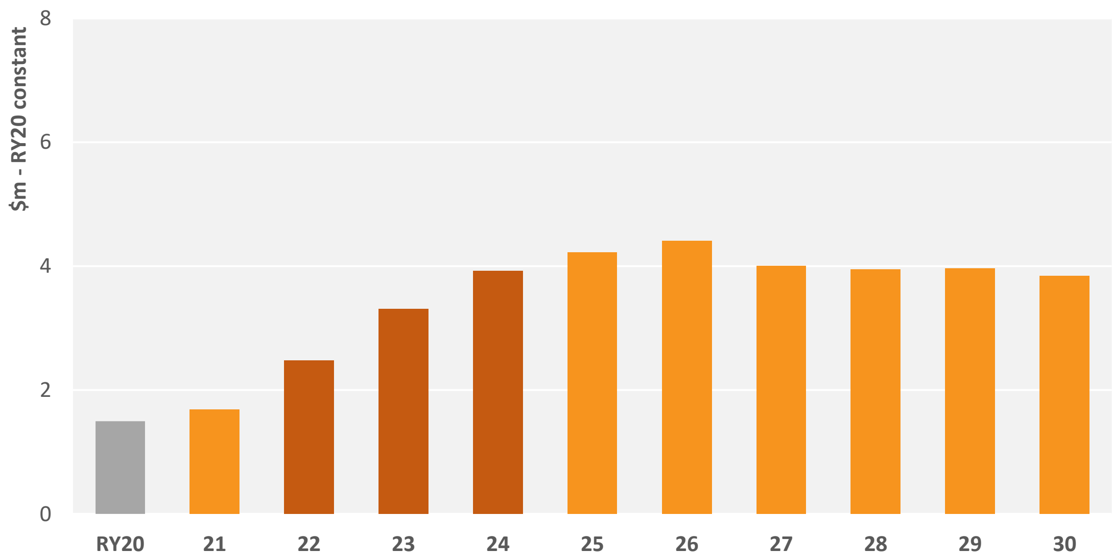


Capex on distribution switchgear such as fuses and pole-mounted switches is often undertaken reactively, so our renewal forecasts are partially based on historical failures. However, we also plan to increase proactive replacement of ground-mounted switchgear with known type issues, and LV enclosures 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

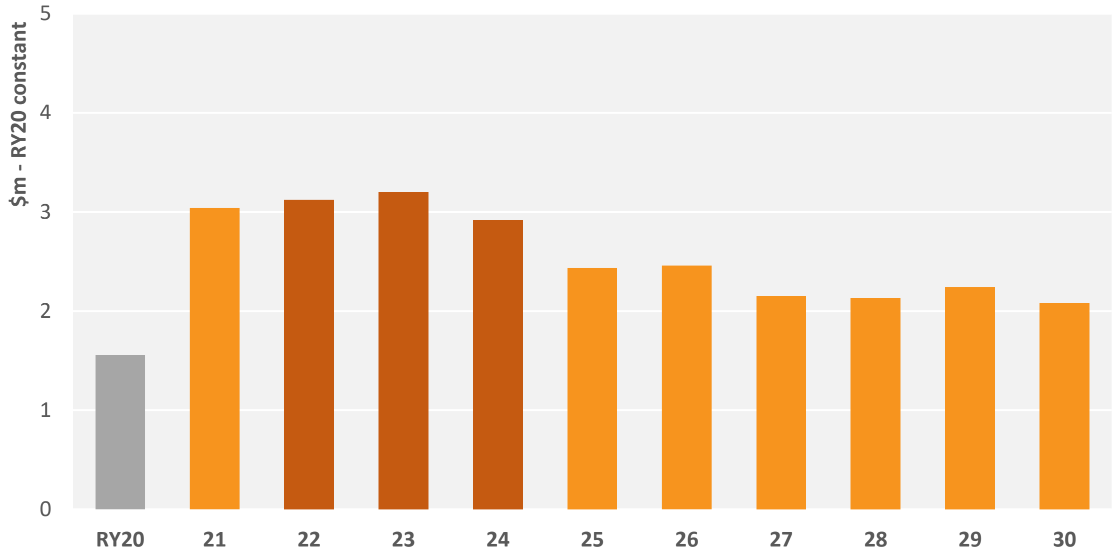


Our distribution transformer renewals forecast ramps up until the end of the CPP Period, after which we will have reached steady state. A key driver is the conversion of large pole-mounted transformers to ground-mounted units to reduce safety risk.

Secondary Systems

The chart below shows our forecast investment on secondary system assets.

Figure 10.14: Secondary systems renewal Capex

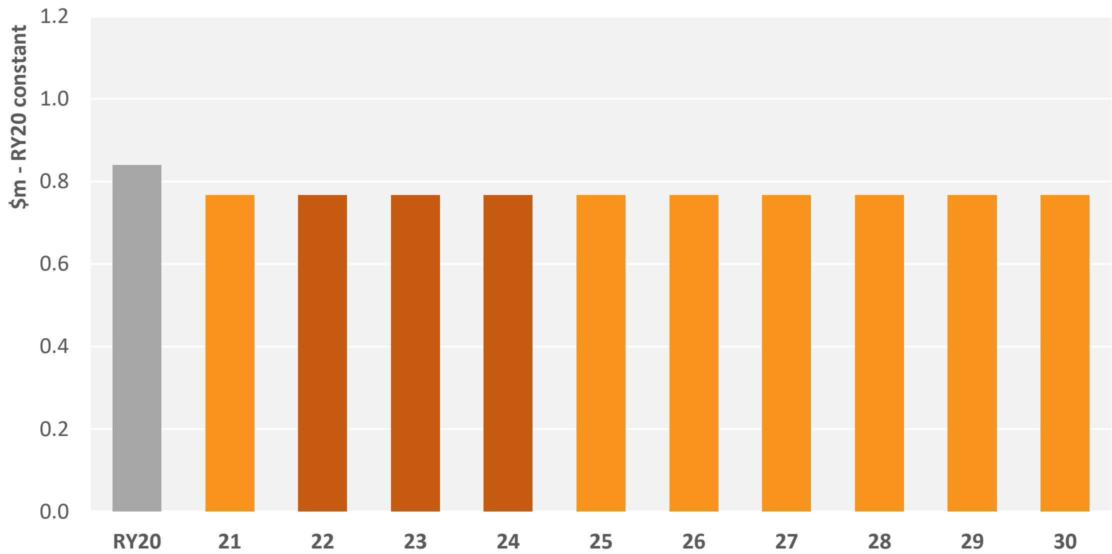


We are planning to replace a large number of old electromechanical relays (by RY24) and DC systems during the AMP period. We align these replacements with zone substation projects where practical.

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 few years. This Capex is associated with moving our assets to enable other parties to undertake projects. 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.

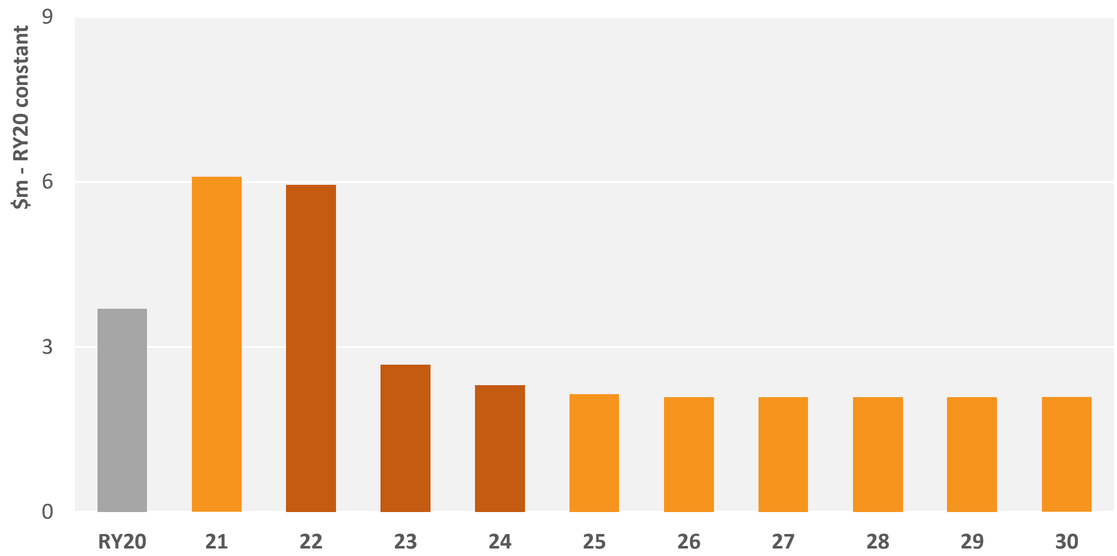
10.2.3. Non-network Capex

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[105]



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.

105 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.

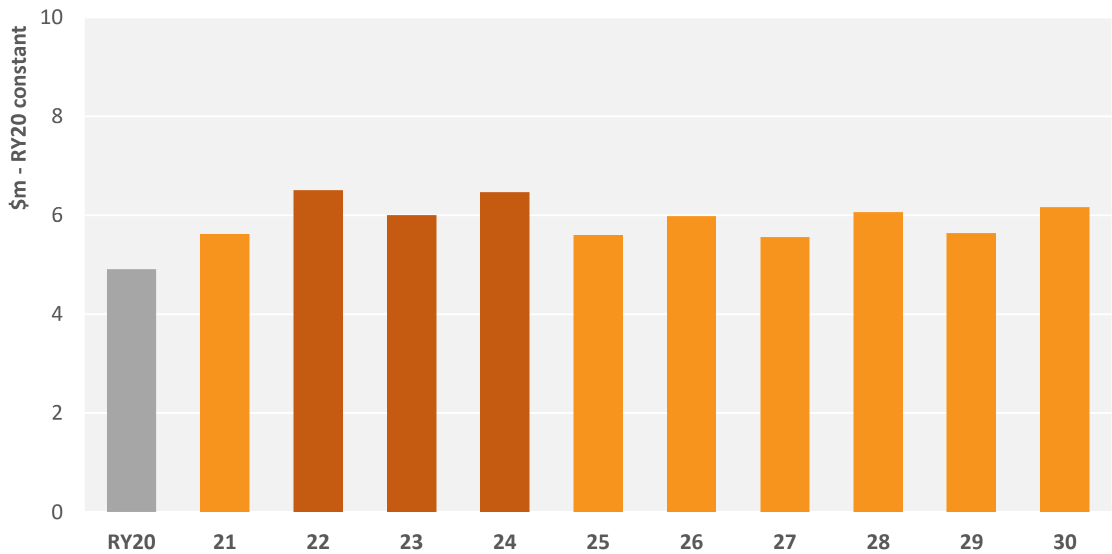
- preventive maintenance: this encompasses inspections, condition assessments and servicing. These are typically activities that are carried out on a regular basis (for example, every three months, annually, every six years) in accordance with our maintenance standards.
- corrective maintenance: this 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



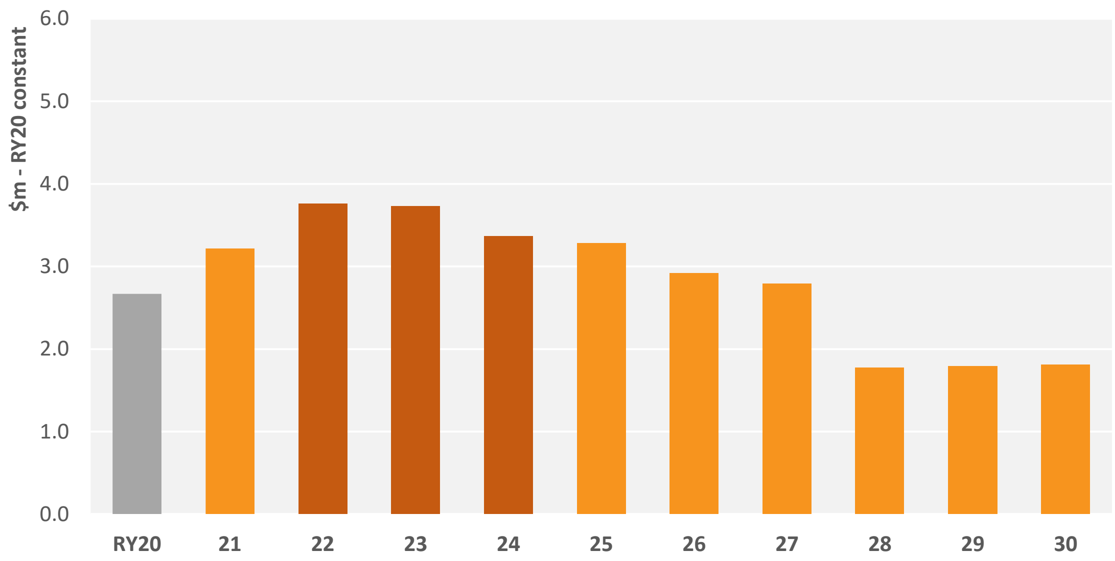
Increased expenditure in coming years is due to additional and expanded activities, some of which are listed below. Some of these (e.g. consumer pole inspections) will be temporary, leading to a slight reduction in expenditure towards the end of the period. Key drivers include:

- **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.
- **introduction of LiDAR surveys**: we will start two yearly LiDAR surveys to identify clearance violations, vegetation encroachment, and natural terrain details.
- **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. It helps ensure assets are safe and provide reliable service.

Figure 10.18: Corrective maintenance Opex



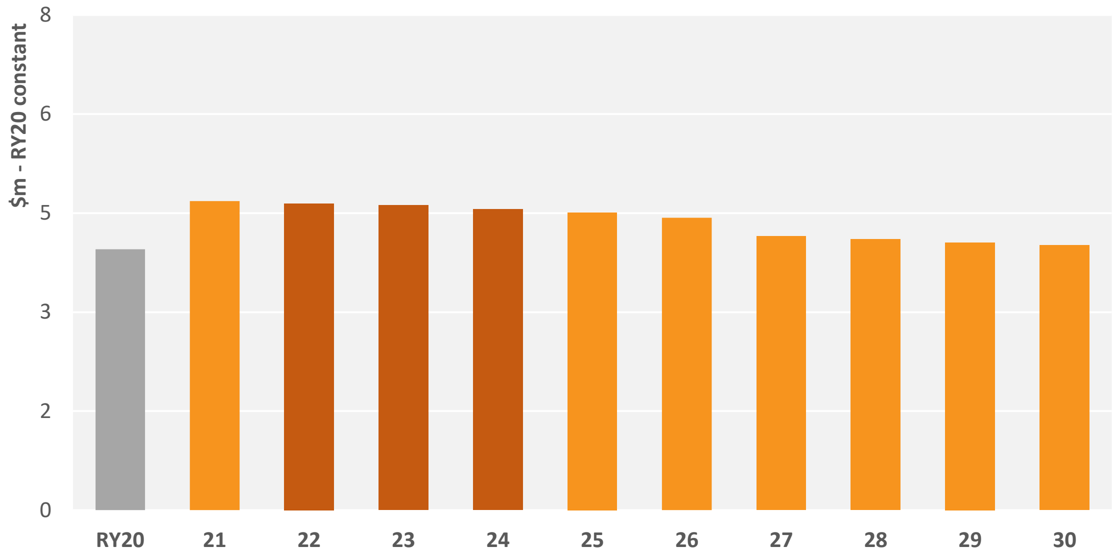
Increased expenditure in coming years is due to the additional activities listed below. Some of these will be temporary, leading to an eventual reduction in expenditure towards steady-state levels.

- **defect numbers**: are 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.

Figure 10.19: Reactive maintenance Opex



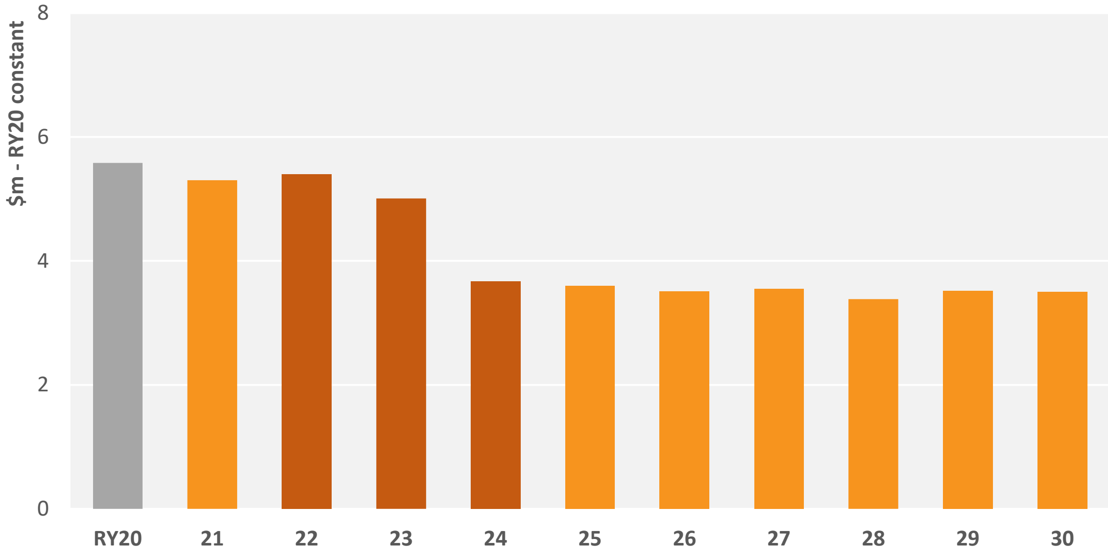
By its nature, reactive maintenance requirements cannot be accurately predicted for any particular year. Annual reactive work is driven by the frequency and severity of network faults. Other than from poor asset condition, network faults are mainly influenced by external, often random, events.

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.

10.3.4. Vegetation Management

The following chart below shows our forecast vegetation management Opex during the AMP planning period.

Figure 10.20: Vegetation management Opex

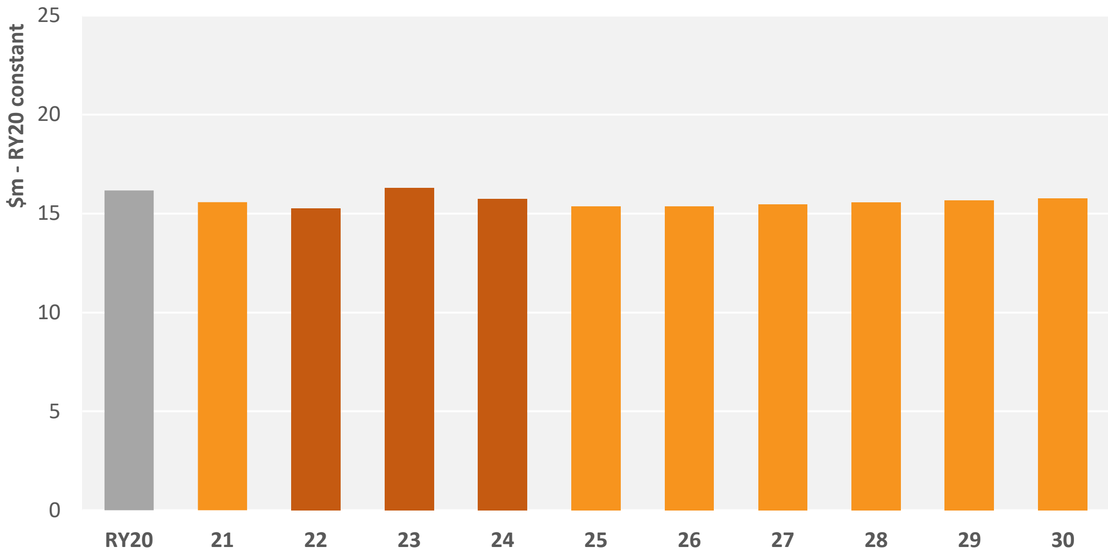


We are moving to a more proactive approach to managing vegetation, which over time has significant savings compared with our historical, mainly reactive, approach. The overall number of trees to be inspected and trimmed will reduce as more of the network is under a fully cyclical approach. We expect to reach a materially lower steady-state expenditure level towards the end of the CPP Period, while delivering an improved level of compliance with the Tree Regulations.

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[106]



106 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.

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.

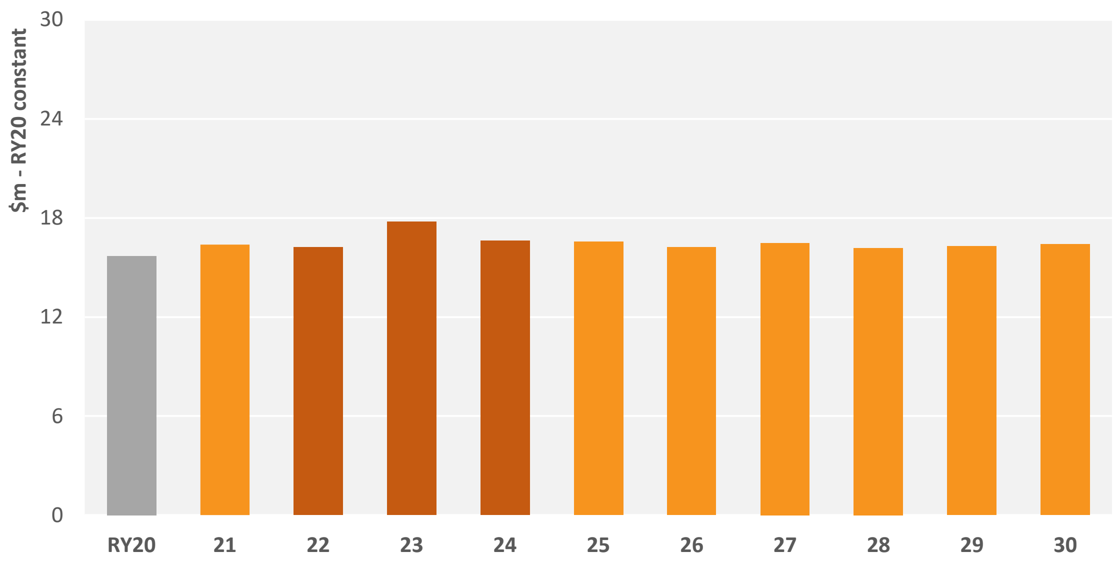
Our forecast expenditure is largely constant over the planning period. While we have an ongoing focus on improving our efficiency and are confident that improvements can be made, we also recognise that there will be additional demands and requirements that may offset these savings. We expect that business support Opex will be broadly constant from the end of RY21 despite upward cost pressures.

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[107]



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.

107 Note, the amounts presented here (and SONS 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.

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
- **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 achieving ISO 55001 certification in 2023) 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).

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 a large 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 program 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 overinvestment.

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

APPENDIX A. GLOSSARY

ACRONYM	MEANING
ABS	Air break switch
ACSR	Aluminium conductor steel reinforced (cable)
AHI	Asset Health Indices
ADMD	After diversity maximum demand
AMMAT	Asset management maturity assessment tool
AMP	Asset Management Plan
CB	Circuit breaker
CAIDI	Consumer average interruption duration index
CAPEX	Capital expenditure
CODC	Central Otago District Council
CPP	Customised price-quality path
DC	Direct current
DCC	Dunedin City Council
DGA	Dissolved gas analysis
DSM	Demand side management
EV	Electric vehicle
GIS	Geospatial Information System
GWh	Gigawatt hour
GXP	Grid exit point
HILP	High impact low probability (events)
HV	High voltage
HWB	Halfway Bush
ICP	Installation control point
IEDs	Intelligent electronic devices
km	Kilometre
kV	Kilovolt
kVA	Kilovolt ampere
kVAr	Kilovolt ampere reactive
kW	Kilowatt
LV	Low voltage
MPL	Maximum Practical Life
MVA	Mega volt-ampere
MVAr	Mega volt-ampere reactive
MW	Megawatt (one million watts)

ACRONYM	MEANING
NZTA	New Zealand Transport Agency
NBS	New Building Standard
ORC	Otago Regional Council
PILC	Paper insulated lead cable
PV	Photo voltaic
QLDC	Queenstown Lakes District Council
RC	Replacement cost
RMU	Ring Main Unit (distribution switchgear)
RSE	Reliability, Safety and Environment (Capex)
RTU	Remote Terminal Unit
SAIDI	System average interruption duration index (minutes)
SAIFI	System average interruption frequency index
SCADA	Supervisory Control and Data Acquisition System
SF6	Sulphur hexafluoride
SWER	Single wire earth return
V	Volt
VoLL	Value of Lost Load
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 11a: report on forecast Capital Expenditure

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2020 - 31 March 2030

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8												
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	14,351	9,241	8,788	8,929	12,110	13,988	16,494	12,741	13,016	13,297	13,585
11	System growth	7,250	5,355	4,038	9,961	10,058	5,180	3,580	4,588	7,943	9,575	8,217
12	Asset replacement and renewal	36,713	50,850	60,385	65,215	64,854	60,245	53,312	46,909	48,260	45,133	44,870
13	Asset relocations	1,242	1,962	2,002	2,046	2,095	2,138	2,182	2,237	2,294	2,352	2,412
14	Reliability, safety and environment:											
15	Quality of supply	1,157	242	478	488	245	1,006	772	713	366	376	385
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
18	**Total reliability, safety and environment**	1,157	242	478	488	245	1,006	772	713	366	376	385
19	**Expenditure on network assets**	60,714	67,650	75,691	86,639	89,362	82,557	76,340	67,188	71,879	70,732	69,469
20	Expenditure on non-network assets	8,615	6,379	6,690	3,122	3,006	2,502	2,355	2,412	2,733	2,637	2,590
21	**Expenditure on assets**	69,329	74,029	82,381	89,761	92,368	85,060	78,695	69,600	74,612	73,370	72,059
22												
23	*plus* Cost of financing	776	903	631	939	740	659	545	628	566	617	465
24	*less* Value of capital contributions	9,702	6,722	6,474	6,585	8,523	9,676	11,205	8,987	9,186	9,389	9,598
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27	**Capital expenditure forecast**	60,403	68,210	76,538	84,114	84,585	76,043	68,035	61,241	65,993	64,597	62,925
28												
29	Assets commissioned	60,693	71,774	82,718	73,727	91,256	79,840	72,481	61,091	66,233	63,800	66,645
30		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31												
32		**$000 (in constant prices)**										
33	Consumer connection	14,351	9,092	8,524	8,524	11,365	12,935	15,028	11,365	11,365	11,365	11,365
34	System growth	7,250	5,238	3,879	9,332	9,247	4,680	3,165	3,997	6,848	8,078	6,694
35	Asset replacement and renewal	36,713	49,776	58,078	61,426	59,982	54,849	47,436	40,937	41,246	37,823	36,671
36	Asset relocations	1,242	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917
37	Reliability, safety and environment:											
38	Quality of supply	1,157	236	458	458	226	904	678	610	305	305	305
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
41	**Total reliability, safety and environment**	1,157	236	458	458	226	904	678	610	305	305	305
42	**Expenditure on network assets**	60,714	66,260	72,856	81,657	82,737	75,286	68,225	58,827	61,683	59,489	56,953
43	Expenditure on non-network assets	8,615	6,237	6,408	2,932	2,771	2,264	2,089	2,089	2,312	2,179	2,089
44	**Expenditure on assets**	69,329	72,497	79,264	84,590	85,507	77,550	70,314	60,917	63,995	61,668	59,042
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses											
48	Overhead to underground conversion											
49	Research and development											
50												

Difference between nominal and constant price forecasts

$000	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
Consumer connection	-	149	264	405	745	1,053	1,465	1,376	1,650	1,931	2,219
System growth	-	117	159	629	811	500	415	591	1,095	1,498	1,523
Asset replacement and renewal	-	1,074	2,307	3,789	4,872	5,396	5,877	5,971	7,014	7,309	8,198
Asset relocations	-	45	84	129	178	221	265	320	377	435	495
Reliability, safety and environment:											
Quality of supply	-	5	20	30	19	102	94	102	61	70	80
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
Total reliability, safety and environment	-	5	20	30	19	102	94	102	61	70	80
Expenditure on network assets	-	1,390	2,835	4,982	6,626	7,271	8,115	8,361	10,196	11,243	12,516
Expenditure on non-network assets	-	142	281	189	235	238	266	323	421	459	500
Expenditure on assets	-	1,532	3,116	5,171	6,861	7,509	8,381	8,684	10,617	11,702	13,016

11a(ii): Consumer Connection

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
*Consumer types defined by EDB**	**$000 (in constant prices)**					
10 Consumer connection	14,351	9,092	8,524	8,524	11,365	12,935
**include additional rows if needed*						
Consumer connection expenditure	14,351	9,092	8,524	8,524	11,365	12,935
less Capital contributions funding consumer connection	9,300	5,455	5,114	5,114	6,819	7,761
Consumer connection less capital contributions	5,052	3,637	3,410	3,410	4,546	5,174

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	-	963	-	6,028	2,997	-
Zone substations	3,367	1,395	891	972	3,737	1,559
Distribution and LV lines	1,608	1,191	1,223	966	990	1,268
Distribution and LV cables	1,176	872	895	707	724	928
Distribution substations and transformers	510	378	388	306	314	402
Distribution switchgear	569	421	433	342	350	448
Other network assets	21	18	50	12	135	76
System growth expenditure	7,250	5,238	3,879	9,332	9,247	4,680
less Capital contributions funding system growth	-	-	-	-	-	-
System growth less capital contributions	7,250	5,238	3,879	9,332	9,247	4,680

11a(iv): Asset Replacement and Renewal

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
		$000 (in constant prices)					
	Subtransmission	3,642	7,323	7,045	10,171	4,114	3,494
	Zone substations	7,727	11,172	12,809	8,676	12,061	11,636
	Distribution and LV lines	19,510	22,196	26,303	29,367	29,231	25,145
	Distribution and LV cables	827	1,907	2,477	2,520	2,754	2,642
	Distribution substations and transformers	3,409	3,119	5,065	6,403	7,159	7,329
	Distribution switchgear	1,599	3,867	4,088	4,118	4,156	4,122
	Other network assets	-	191	290	172	506	481
	Asset replacement and renewal expenditure	36,713	49,776	58,078	61,426	59,982	54,849
less	Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
	Asset replacement and renewal less capital contributions	36,713	49,776	58,078	61,426	59,982	54,849

11a(v): Asset Relocations

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	*Project or programme**	**$000 (in constant prices)**					
	11 Asset relocations	1,242	1,917	1,917	1,917	1,917	1,917
	**include additional rows if needed*						
	All other project or programmes - asset relocations	-	-	-	-	-	-
	Asset relocations expenditure	1,242	1,917	1,917	1,917	1,917	1,917
less	Capital contributions funding asset relocations	402	1,150	1,150	1,150	1,150	1,150
	Asset relocations less capital contributions	840	767	767	767	767	767

11a(vi): Quality of Supply

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	*Project or programme**	**$000 (in constant prices)**					
	13 RSE	1,157	-	-	-	-	678
	12 Future Networks	-	236	458	458	226	226
	**include additional rows if needed*						
	All other projects or programmes - quality of supply	-	-	-	-	-	-
	Quality of supply expenditure	1,157	236	458	458	226	904
less	Capital contributions funding quality of supply	-	-	-	-	-	-
	Quality of supply less capital contributions	1,157	236	458	458	226	904

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5

11a(vii): Legislative and Regulatory

*Project or programme**	**$000 (in constant prices)**					
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	-	-	-	-	-	-

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5

11a(viii): Other Reliability, Safety and Environment

*Project or programme**	**$000 (in constant prices)**					
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment expenditure	-	-	-	-	-	-
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

11a(ix): Non-Network Assets

Routine expenditure						
*Project or programme**	**$000 (in constant prices)**					
Non-Network Assets	8,615	6,237	6,408	2,932	2,771	2,264
**include additional rows if needed*						
All other projects or programmes - routine expenditure	-	-	-	-	-	-
Routine expenditure	8,615	6,237	6,408	2,932	2,771	2,264
Atypical expenditure						
*Project or programme**						
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	-	-	-	-	-	-
Expenditure on non-network assets	8,615	6,237	6,408	2,932	2,771	2,264

Schedule 11b: report on forecast Operational Expenditure

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2020 - 31 March 2030

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
7												
8												
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	3,951	4,805	4,870	4,962	5,016	5,068	5,080	4,858	4,897	4,939	4,984
11	Vegetation management	5,580	5,440	5,663	5,377	4,040	4,048	4,025	4,153	4,040	4,278	4,349
12	Routine and corrective maintenance and inspection	7,576	9,073	10,772	10,463	10,831	10,008	10,222	9,779	9,370	9,066	9,911
13	Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
14	**Network Opex**	17,106	19,319	21,306	20,802	19,887	19,124	19,327	18,790	18,306	18,283	19,245
15	System operations and network support	15,037	16,129	16,291	18,356	17,834	18,245	18,248	18,904	18,951	19,459	19,986
16	Business support	15,299	15,195	15,222	16,714	16,552	16,709	17,071	17,537	18,016	18,508	19,013
17	**Non-network opex**	30,337	31,324	31,512	35,070	34,386	34,954	35,318	36,442	36,967	37,967	38,998
18	**Operational expenditure**	47,443	50,643	52,818	55,873	54,273	54,078	54,645	55,232	55,273	56,250	58,243
19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	3,951	4,683	4,645	4,621	4,557	4,507	4,426	4,150	4,101	4,055	4,012
23	Vegetation management	5,580	5,301	5,401	5,008	3,670	3,600	3,507	3,548	3,383	3,513	3,501
24	Routine and corrective maintenance and inspection	7,576	8,835	10,260	9,728	9,827	8,886	8,890	8,338	7,832	7,430	7,963
25	Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
26	**Network Opex**	17,106	18,819	20,306	19,357	18,053	16,992	16,823	16,035	15,316	14,997	15,476
27	System operations and network support	15,037	15,744	15,589	17,158	16,245	16,277	15,966	16,216	15,937	16,043	16,154
28	Business support	15,299	14,807	14,517	15,566	15,035	14,854	14,868	14,974	15,081	15,189	15,297
29	**Non-network opex**	30,337	30,551	30,106	32,723	31,280	31,132	30,833	31,190	31,018	31,232	31,451
30	**Operational expenditure**	47,443	49,370	50,412	52,080	49,333	48,124	47,656	47,225	46,334	46,229	46,927
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance											
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40												
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	123	225	341	459	561	654	708	796	884	972
43	Vegetation management	-	139	262	370	370	448	518	605	657	765	848
44	Routine and corrective maintenance and inspection	-	238	512	735	1,004	1,122	1,332	1,442	1,538	1,637	1,948
45	Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
46	**Network Opex**	-	500	999	1,445	1,833	2,131	2,504	2,755	2,990	3,286	3,769
47	System operations and network support	-	386	702	1,198	1,589	1,968	2,282	2,689	3,014	3,416	3,832
48	Business support	-	388	705	1,149	1,517	1,855	2,203	2,563	2,935	3,319	3,716
49	**Non-network opex**	-	774	1,407	2,347	3,106	3,823	4,485	5,252	5,949	6,735	7,548
50	**Operational expenditure**	-	1,274	2,406	3,793	4,939	5,954	6,989	8,007	8,939	10,021	11,316

Schedule 12a: report on asset condition

	Company Name	Aurora Energy Limited
	AMP Planning Period	1 April 2020 – 31 March 2030

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref												
7					Asset condition at start of planning period (percentage of units by grade)							
8												
9	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
10	All	Overhead Line	Concrete poles / steel structure	No.	0.08%	0.01%	0.30%	15.49%	84.12%		3	0.27%
11	All	Overhead Line	Wood poles	No.	8.53%	6.87%	19.97%	31.52%	33.12%		3	17.85%
12	All	Overhead Line	Other pole types	No.							N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	18.55%	0.85%	3.38%	5.90%	71.32%		2	20.11%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	1.82%	98.18%		3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	53.74%	46.26%	-		3	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	27.92%	34.95%	37.13%	-	-		3	27.92%
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	50.00%	32.97%	17.02%		3	50.00%
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.	3.33%	-	16.67%	40.00%	40.00%		2	30.74%
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.	46.00%	-	-	8.00%	46.00%		2	42.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.							N/A	
30	HV	Zone substation switchgear	33kV RMU	No.							N/A	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.							N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	100.00%		3	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	22.42%	7.67%	6.19%	22.71%	41.00%		3	22.42%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	31.58%	-	-	5.26%	63.16%		2	28.95%
35												

36					Asset condition at start of planning period (percentage of units by grade)							
37												
38	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	1.54%	15.38%	24.62%	29.23%	29.23%		4	18.46%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.82%	2.74%	8.47%	11.80%	75.17%		2	8.79%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km	46.53%	-	-	18.07%	35.41%		2	46.53%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.15%	0.23%	1.34%	7.38%	90.89%		2	0.66%
44	HV	Distribution Cable	Distribution UG PILC	km	0.43%	0.57%	3.27%	8.09%	87.64%		2	1.63%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	100.00%	-	-	-		2	100.00%
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	-	2.33%	97.67%		2	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	55.56%	-	-	-	44.44%		2	55.56%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	3.38%	3.33%	9.52%	12.81%	70.96%		2	6.64%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	0.75%	0.25%	-	-	99.00%		2	1.00%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	8.14%	6.38%	14.02%	21.24%	50.21%		2	17.04%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	5.10%	5.20%	15.28%	16.60%	57.83%		2	9.25%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.20%	0.33%	1.83%	5.26%	92.39%		3	0.91%
53	HV	Distribution Transformer	Voltage regulators	No.	19.05%	-	4.76%	4.76%	71.43%		2	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	50.00%	50.00%	-		1	-
55	LV	LV Line	LV OH Conductor	km	4.36%	3.17%	9.23%	14.87%	68.37%		2	7.85%
56	LV	LV Cable	LV UG Cable	km	0.17%	0.22%	1.35%	5.25%	93.01%		2	0.60%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	2.75%	2.03%	6.19%	11.17%	77.87%		2	5.06%
58	LV	Connections	OH/UG consumer service connections	No.	2.88%	2.60%	7.37%	11.70%	75.45%		2	6.70%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	49.40%	4.23%	23.39%	22.98%	-		2	46.77%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	20.90%	5.97%	22.39%	50.75%	-		2	29.85%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	100.00%		2	-
62	All	Load Control	Centralised plant	Lot	71.43%	-	-	-	28.57%		2	71.43%
63	All	Load Control	Relays	No.	15.57%	6.63%	38.27%	39.53%	-		2	-
64	All	Civils	Cable Tunnels	km							N/A	

Schedule 12b: report on forecast capacity

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Alexandra	11	15	N-1	-	75%	15	76%	No constraint within +5 years	
10	Anderson's Bay	14	18	N-1	5	79%	18	79%	No constraint within +5 years	
11	Arrowtown	9	12	N-1	2	71%	12	81%	Subtransmission circuit	Subtransmission constraints mean that some reconfiguration work is required at Arrowtown to fully utilise the capacity of the transformers
12	Commonage	12	17	N-1	6	69%	17	81%	No constraint within +5 years	
13	Corstorphine	12	23	N-1	6	52%	23	52%	No constraint within +5 years	
14	Cromwell	13	9	N-1	-	147%	24	65%	No constraint within +5 years	A project to upgrade the Cromwell transformers is in progress and expected to be completed soon.
15	East Taieri	16	24	N-1	4	67%	24	71%	No constraint within +5 years	
16	Frankton	17	15	N-1	6	113%	15	135%	Transformer	We will monitor growth at Frankton and plan to upgrade the smaller 15MVA transformer at this site in RY29.
17	Fernhill	7	10	N-1	4	68%	10	76%	No constraint within +5 years	
18	Green Island	13	18	N-1	6	72%	18	72%	No constraint within +5 years	
19	Halfway Bush	13	18	N-1	6	72%	24	57%	Other	The capacity at Halfway Bush is currently constrained to 18MVA by the 6.6kV switchboard which has a planned replacement in RY22
20	Kaikorai Val.	9	23	N-1	4	40%	23	40%	Other	
21	Mosgiel	7	12	N-1	3	54%	12	54%	No constraint within +5 years	
22	Carisbrook	11	23	N-1	6	47%	23	47%	No constraint within +5 years	
23	North City	14	28	N-1	6	51%	28	51%	No constraint within +5 years	The North City forecast excludes the new hospital connection. Similarly the cost to relocate North City zone substation (if required) has not been included our financial forecasts
24	North East Val.	10	18	N-1	4	56%	18	56%	Other	
25	Port Chalmers	7	10	N-1	3	65%	10	65%	No constraint within +5 years	
26	Queenstown	16	20	N-1	6	80%	20	87%	No constraint within +5 years	
27	Smith St	14	18	N-1	6	76%	18	76%	No constraint within +5 years	
28	South City	15	18	N-1	6	81%	18	81%	No constraint within +5 years	
29	St Kilda	14	23	N-1	6	61%	23	61%	No constraint within +5 years	
30	Wanaka	21	24	N-1	1	87%	24	103%	Transformer	It is proposed to relieve the Wanaka constraint by the installation of transformer capacity at Riverbank in RY28
31	Ward St	11	23	N-1	6	48%	23	48%	No constraint within +5 years	
32	Willowbank	12	18	N-1	4	68%	18	68%	No constraint within +5 years	
33	Berwick	2	4	N	4	42%	4	45%	No constraint within +5 years	
	Cardrona	5	6	N	1		5	104%	Transformer	Load growth subject to Cardrona expansion going ahead. This AMP makes no provision for a Cardrona upgrade at this stage
34	Clyde/Earnscleugh	4	5	N	-	81%	5	91%	No constraint within +5 years	
35	Coronet Peak	6	6	N	2	92%	6	92%	No constraint within +5 years	
36	Dalefield	2	4	N	1	50%	4	58%	No constraint within +5 years	
37	Earnscleugh	-	2	N	-	-	2	-	No constraint within +5 years	Earnscleugh is used as a back up to Clyde Earnscleugh
38	Ettrick	2	4	N	2	56%	4	58%	No constraint within +5 years	
39	Lindis Crossing	7	8	N	4	91%	8	116%	Transformer	The exact level of further irrigation load growth at Lindis Crossing is uncertain, we will monitor and respond accordingly.
40	Camphill	5	8	N	2	71%	7	92%	Transformer	Further irrigation load growth at Camphill is uncertain - at this stage, no upgrade project has been included in the AMP period
41	Omakau	3	4	N	2	86%	3	107%	Transformer	Subject to further irrigation growth, it is proposed to upgrade and shift Omakau substation in RY24
	Lauder Flat	1	3	N	1	27%	4	53%	No constraint within +5 years	
42	Outram	3	6	N	2	47%	8	37%	No constraint within +5 years	
43	Queensberry	3	4	N	2	78%	4	86%	No constraint within +5 years	
44	Remarkables	2	4	N	-	67%	4	103%	Transformer	Load growth may occur with expansion of the Ski Field.
45	Roxburgh	2	6	N	1	33%	6	35%	No constraint within +5 years	

46 [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 2020 - 31 March 2030**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref			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 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
11	*Consumer types defined by EDB**							
12	Residential		965	754	629	461	629	587
13	Load Group 0		(1)	3	2	2	2	2
14	Load Group 0A		(27)	7	6	4	6	6
15	Load Group 1A		17	9	7	5	7	7
15a	Load Group 1		44	57	48	35	48	44
15b	Load Group 2		150	65	54	40	54	50
15c	Load Group 3		(1)	2	2	1	2	2
15d	Load Group 3A		7	2	1	1	1	1
15e	Load Group 4		2	1	1	1	1	1
15f	Load Group 5		1	-	-	-	-	-
16	Street Lighting & DUML		-	-	-	-	-	-
17	**Connections total**		1,157	900	750	550	750	700
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		1,244	1,420	1,597	1,774	1,951	2,128
21	Capacity of distributed generation installed in year (MVA)		1	1	1	1	1	1
22	**12c(ii) System Demand**							
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)**	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
25	GXP demand		227	229	231	233	236	238
26	*plus* Distributed generation output at HV and above		56	57	57	58	59	59
27	**Maximum coincident system demand**		283	286	289	292	294	297
28	*less* Net transfers to (from) other EDBs at HV and above		(0)	(0)	(0)	(0)	(0)	(0)
29	**Demand on system for supply to consumers' connection points**		283	286	289	292	294	297
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		1,293	1,300	1,306	1,313	1,319	1,326
32	*less* Electricity exports to GXPs		64	64	64	64	65	65
33	*plus* Electricity supplied from distributed generation		202	202	203	204	205	206
34	*less* Net electricity supplied to (from) other EDBs		0	(0)	(0)	(0)	(0)	(0)
35	**Electricity entering system for supply to ICPs**		1,431	1,438	1,445	1,452	1,460	1,467
36	*less* Total energy delivered to ICPs		1,342	1,349	1,356	1,362	1,369	1,376
37	**Losses**		88	89	90	90	90	91
38								
39	**Load factor**		58%	57%	57%	57%	57%	56%
40	**Loss ratio**		6.2%	6.2%	6.2%	6.2%	6.2%	6.2%

Schedule 12d: Report on forecast interruptions and duration

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2020 – 31 March 2030
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
9		for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
10	**SAIDI**							
11	Class B (planned interruptions on the network)		55.71	195.96	195.96	195.96	195.96	195.96
12	Class C (unplanned interruptions on the network)		131.37	146.29	146.29	146.29	146.29	146.29
13	**SAIFI**							
14	Class B (planned interruptions on the network)		0.307	1.108	1.108	1.108	1.108	1.108
15	Class C (unplanned interruptions on the network)		1.813	2.507	2.507	2.507	2.507	2.507

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2020 – 31 March 2030
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
9		for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
10	**SAIDI**							
11	Class B (planned interruptions on the network)		33.43	117.58	117.58	117.58	117.58	117.58
12	Class C (unplanned interruptions on the network)		52.55	58.52	58.52	58.52	58.52	58.52
13	**SAIFI**							
14	Class B (planned interruptions on the network)		0.18	0.66	0.66	0.66	0.66	0.66
15	Class C (unplanned interruptions on the network)		0.73	1.00	1.00	1.00	1.00	1.00

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**
Network / Sub-network Name	**Central Otago 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 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
10	**SAIDI**							
11	Class B (planned interruptions on the network)		22.28	78.38	78.38	78.38	78.38	78.38
12	Class C (unplanned interruptions on the network)		78.82	87.78	87.78	87.78	87.78	87.78
13	**SAIFI**							
14	Class B (planned interruptions on the network)		0.12	0.44	0.44	0.44	0.44	0.44
15	Class C (unplanned interruptions on the network)		1.09	1.50	1.50	1.50	1.50	1.50

Schedule 13: Report on asset management maturity

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**
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	Asst Management Policy is authorised by Chair and CEO and published within Controlled Document System		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	We have determined some new asset management objective areas that support our corporate strategic priorities. These still require targets Strategies for each fleet are summarised in the AMP. As explained in Chapter 4 underpinning documents are currently being developed along with a strategic asset management plan (SAMP).		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	We document decision-making criteria, performance, strategic approaches and forecasting processes for lifecycle management (see Chapter 5 and 8). This will be expanded via suite of fleet management strategies.		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	Our forecast models include work volumes and costs across the relevant time periods for all asset types and all stages of the life-cycle. We have begun to develop structure and hierarchy of the our strategies and have begun documenting the lifecycle plans in draft fleet plans.		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 2020 – 31 March 2030
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 team meetings, one on 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.

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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. We have quantified future delivery resource needs as part of our challenge processes		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	ELT emphasises the need to meet asset management requirements, including the commitment to seek ISO 55000 certification. There are regular team briefings to staff that refer to Asset Management Objectives and progress against them.		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?	2	We have a team dedicated to contract and job management reporting to the GM Works Programming and Delivery. They help ensure the compliant delivery of our strategies and plans through their own efforts and utilise external Auditors for benchmarking purposes. Improvements are also underway in performance monitoring and reporting for outsourced activities.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	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	We have established an organisation chart with identification for the resources required for activities associated with our Asset Management System. Responsibilities for asset management strategy and objectives are defined.		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?	1	Position descriptions for asset management roles include requirements based on our understanding of good industry practice. Competency registers are maintained for those people who require safety-related operational competencies for field work only. Training records are maintain for each instance but this does not form part of an overall dataset. We have not yet begun a systematic process to determine competency requirements and plan to deliver and monitor them.		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?	1	We intend to formalise controls for outsourced competency management through a defined framework. Our current approach is being systematically embedded as we integrate our new field service providers. Competency assessments are a core aspect of our recruitment processes and asses levels of asset management competency.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2	A significant amount of communication is undertaken digitally and in person during team meetings, one on one discussions and governance groups.		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?	1	There is a good understanding of what our asset management information systems should contain. We have begun a process of implementing an Enterprise Asset Management System which includes documenting the information requirements need to support Asset Management		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?	1	See question 62. Until we implement the new EAMS system, we have put in place a set of controls to ensure material used in decision-making is fit-for-purpose and up-to-date.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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AMP Planning Period	1 April 2020 – 31 March 2030
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?	1	We have carried out a major review of its asset management information systems. Improvements are needed in: accessibility of information for diverse users – particularly for management via outsourcing; systems to support improvement in data quality; and efficient and effective linkages with other systems.		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	We have defined a asset risk management framework as set out in Chapter 4 of our 2020 AMP. This will be refined as part of our AMDP. Improvements are needed in quantification of risk approaches to support lifecycle decision and the design and implementation of criticality frameworks.		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	We mandate skill requirements for critical operational safety related tasks, in response to our understanding of the risks. We have a People Strategy, identification of future resource, competence and training requirements is ongoing.		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	We use 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

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2	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. We use an extensive set of technical standards in our controlled documents system.		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 formal monitoring of these difficult to achieve. 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 improved and expanded to support future lifecycle management. Condition assessment methodologies are improving and our asset health models are used to inform renewal planning.		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.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2020 – 31 March 2030
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 a external reviews of our asset management systems and practices have been recently carried out. WSP-Opus and Sapere reviewing the overall Asset Management capability of the busines and AMCL assessing against ISO55001. External audits of our Public Safety Management System occur on a periodic basis. Internal audit processes will be developed as part of AMDP.		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	Performance and condition measures have been incorporated into some fleet strategies. We have established a framework to begin monitoring network performance and carrying out root cause analysis of outages. Asset failures are investigated by ICAM trained staff and the results reported to the wider business.		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	Where feasible investment decision making accounts for cost / risk / performance over the lifecycle of the assets, but they are only mature in some asset classes. Regular workshops 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 peer utilities. Staff membership of industry and professional bodies. Attendance at industry conferences and trade shows. A key planning team function is monitoring new development in the industry.		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 (e.g., 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

6. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.
7. 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)

8. 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 2020 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)

9. 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.

APPENDIX C. RELIABILITY MANAGEMENT

Context

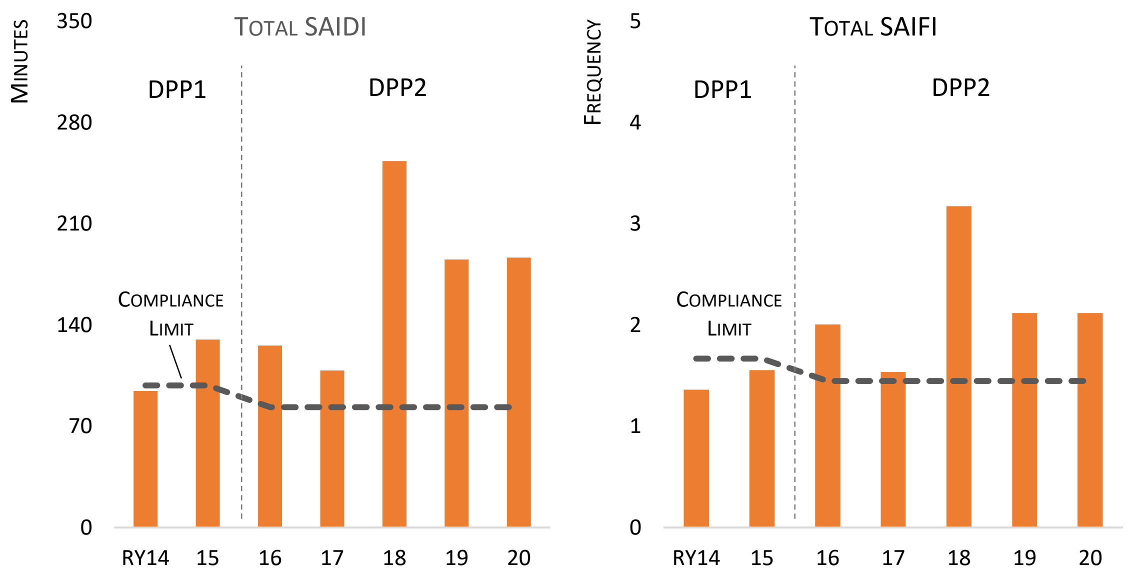
We recognise the need to maintain the reliability of our network to ensure customers receive an appropriate level of service and that we meet our regulatory quality standards. We also understand that while customers are concerned about reliability levels they are reasonably happy with current performance and do not want improved reliability if would require price increases.

Our CPP submission primarily targets network safety risks. However, we will achieve marginal improvement of network performance as we improve the underlying health of our network assets.

We exceeded our quality standards during recent regulatory years as a result of long-term underinvestment materialising in an increase in unplanned interruptions driven by end-of-life assets and planned interruptions driven by accelerated asset renewal programs attempting to make up for lost time.

The historical values shown in Figure C.1 reflect 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.

Figure C.1: Historical reliability (SAIDI and SAIFI) performance



We are currently undertaking a large scale, multi-year programme of asset renewals. In many cases, this require interruptions of supply so that the work 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.

Changes in operational practice have 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.

Reliability Management

Our reliability management aims to achieve continuous improvement in our approach to managing network reliability, both for planned and unplanned interruptions. It aims to bring our reliability management approach into line with good industry practice.

In 2019 we identified a total of 39 controllable (planned and unplanned) reliability performance levers across the following categories:

- reliability performance analytics
- engineering and asset management
- work planning and scheduling
- operations and day-to-day network management
- contractor performance
- customer service, engagement and communication.

We then grouped the levers into improvement areas are listed below:

- work planning and scheduling
- data/Information and Intelligence
- operations and contract management
- business support systems
- customer service and outage communication
- policies impacting reliability.

These categories are expanded upon in our reliability management plan where improvement initiatives are set out. The improvements incorporate recommendations from external reviews and the feedback associated with historical breaches of regulated quality standards.

Objectives

Our key objectives for improving our approach to reliability management are to:

- define and manage drivers that impact network reliability
- achieve an optimum balance between reliability performance and cost
- 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 Initiatives

The following table summarises our strategic initiatives targeting improvement of network reliability.

Table C.1: Reliability management plan initiatives

AREA	ASPECT	DESCRIPTION
Work planning and scheduling	Investment impact on reliability	– Needs case reflect risk and reliability drivers – investment / reliability trade-offs
	Design standards / policies	– Reliability by design / engineering standards
	SAIDI / SAIFI modelling	– Model planned work vs SAIDI & SAIFI outcomes – Model unplanned SAIDI & SAIFI vs investment
	Future network design and topology	– Network and non-network new technologies – SCADA / monitoring / LV sensors
Data / information and intelligence	Base reliability data	– Outage data by feeder / ICP / cause – LV outage data – QA process - data capture and improvement plan
	Analytics / understanding of root cause	– Enhanced root cause / correlation / trends – Major event – weather analysis
Operations and contract management	Operations	– Targeted vegetation management – Recloser and sectionalisers – Major event response and action plans – Quick operational win e.g. wildlife prevention – Track time to detect unplanned outages – Real-time response – fault/ interruption analysis
	Work planning and delivery	– Optimised work planning – reduce planned outages – Service provider metrics and incentives – Analysis of cancellation causes – Outage overrun statistics – Contractor training re. Aurora requirements
Business support systems	ICT	– Outage Management System (OMS) – EAMS roadmap
Customer service and communication	Customer service and communication	– Outage communications and information (pre & post) – Customer charter – New service standards – Complaints management and analysis – Retailer engagement
	Value of interruptions	– Willingness to pay - VoLL. (cost of reliability) – Understand reliability-driven pricing impacts – Customer price / quality trade-off preference

AREA	ASPECT	DESCRIPTION
Policies impacting reliability	Policies impacting reliability	– Live-line vs deenergised work policy – Recloser policy – Backup generator policy – Undergrounding

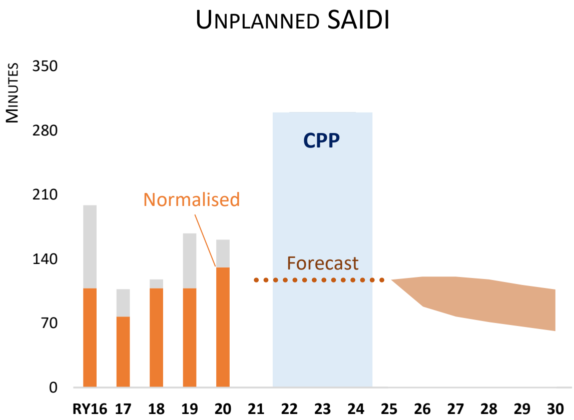
We plan to further refine these initiatives and incorporate them into our day-to-day work plans. We have started several working groups where the initiatives will be managed.

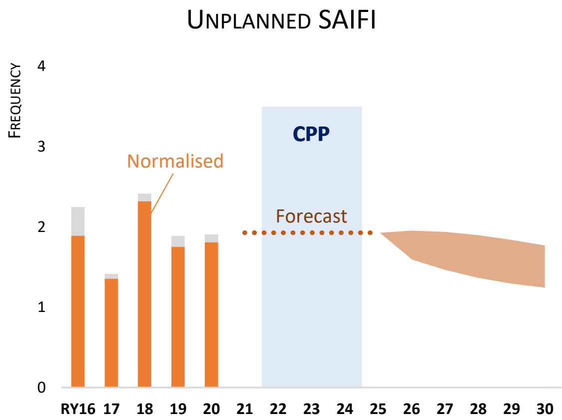
Reliability Forecasts

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 understand the impact of various initiatives that we are considering. To date we have developed simple models for forecasting planned and unplanned SAIDI and SAIFI for the 2021 – 2030 period.

Below we set out our forecast unplanned reliability (SAIDI and SAIFI) for the AMP period, highlighting the reliability performance we expect during the CPP Period.

Figure C.2: Forecast unplanned SAIDI and SAIFI





We expect unplanned outages to stabilise as indicated by above. This forecast is based on our improved reliability modelling capability, which is based on projected changes in asset health, modelling of non-asset-related outages, and the impact of our vegetation management plans. This modelling has informed the setting of our proposed CPP quality standards, which have higher targets than those set out under DPP3. This is discussed further in our CPP application document.

The charts above include 'uncertainty bands' from RY25 onwards, which reflect the inherent uncertainty when forecasting long-term reliability. We will consult with customers in RY23/24 on preferred levels of reliability beyond the CPP Period. We anticipate that continued investment in safety beyond the CPP Period will improve reliability performance. Additional reliability improvement could be achieved through targeted investment if customers prefer this outcome.

With appropriate modifications (e.g. three versus five-year period) to the application of the DPP3 planned quality standards we believe we can manage our CPP work programme within our DPP3 planned quality standards. At times this will present a challenge, however we are confident we can achieve it given our planned delivery and outage planning improvements.

Reliability forecasts

Reflecting the discussion above the following table sets out our reliability forecast for the next six years.

Table C.3: Forecast SAIDI and SAIFI (normalised, by regulatory year)

RELIABILITY MEASURE	2021	2022	2023	2024	2025	2026
SAIDI - Planned	195.96	195.96	195.96	195.96	195.96	195.96
SAIDI - Unplanned	113.4	113.4	113.4	113.4	113.4	113.4
SAIFI - Planned	1.11	1.11	1.11	1.11	1.11	1.11
SAIFI - Unplanned	1.99	1.99	1.99	1.99	1.99	1.99

APPENDIX D. WORK PROGRAMME UPDATE

This appendix provides information on our progress against physical and financial plans set out in our 2019 AMP. In summary, we have exceeded our capital works forecast by 6% and our maintenance programme by 2%.

Development Projects

During RY19 we undertook a series of network development projects. The table below provides a summary of key projects, their progress, and discussion of material variances against plan.

Table D.1: Update on development projects

PROJECT	DESCRIPTION	RY19 PROGRESS	VARIANCE
Riverbank switching station	New switching station	Construction complete	No significant variance
McDonnell Road 11kV feeder reinforcement	Installation of new 11kV feeder cables to reinforce the Arrowtown supply	Construction complete	No significant variance
Install two new 24 MVA transformers at Cromwell Substation	Upgrade supply to Upper Clutha from Cromwell GXP	Project started	No significant variance
5 MVA spare transformer	Purchase of a s 5MVA spare transformer	Project started	Project delayed due to design issues

Most of the projects actual costs to date are in line with the total project budget. The difference in spend is due to design issues with the spare transformer creating delays in the project.

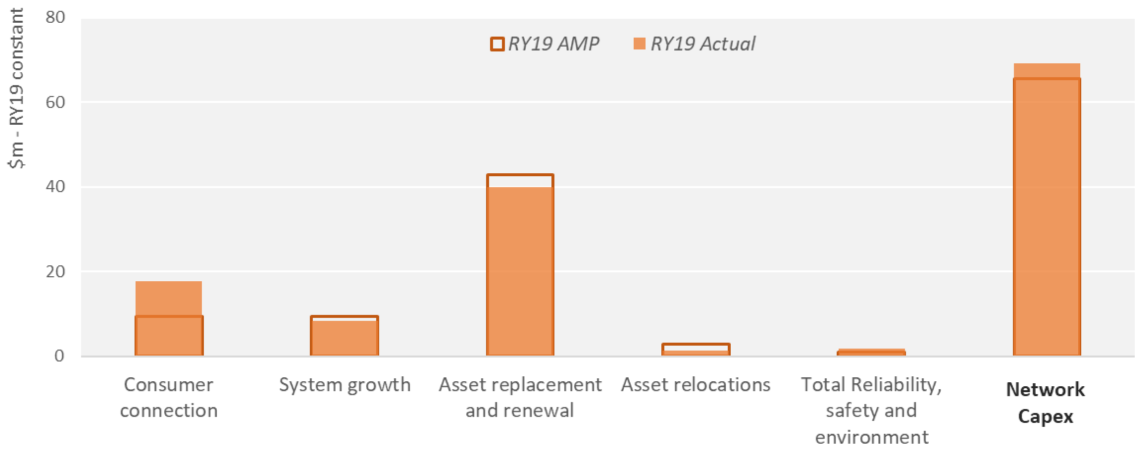
Maintenance Programme Delivery

The RY19 routine maintenance programme was largely completed, however some of our new activities did not progress as expected.

Financial Progress Against Plan

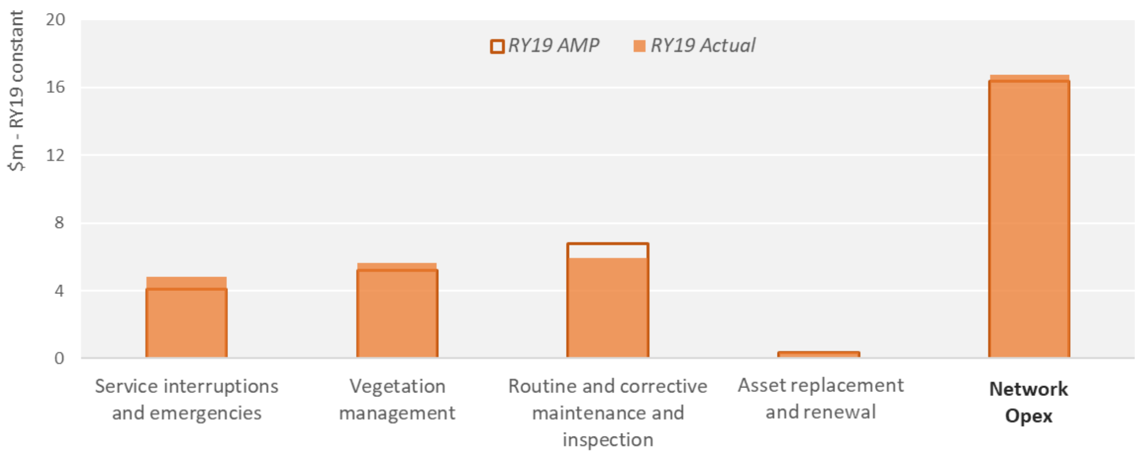
Total direct expenditure on our distribution network was largely in line with the 2019 AMP forecast. There are some variances between categories which are shown in the figures below.

Figure D.1: Capex variance RY19



The Queenstown lakes and Central Otago region saw an unprecedented, higher than normal, volume of new connections in RY19. This led to a significant uplift in consumer connection Capex as this is directly influenced by the level of economic activity in the region. 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 7% below forecast. This variance is largely attributable to projects deferred due to design, consenting and network access issues. Asset relocations expenditure was less than forecast by 50%. This reduction was due to NZTA driven Queenstown projects being deferred.

Figure D.2: Opex variance RY19



Service interruptions and emergencies expenditure was higher than forecasted by 17% as we managed a high level of unplanned 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 2018. These reflect changes in forecast expenditure (by Information Disclosure sub-categories) during the overlapping period i.e. RY20 to RY28 inclusive. All amounts are in constant RY20 dollars.

Table D.2: Expenditure profile comparion (RY20 constant, 000's)

	AMP18	AMP20	% CHANGE	COMMENTS
Capex				
Consumer connection	71,601	102,552	43%	Higher than expected consumer connection requests, inclusion of expected large connections. Updated forecast approach.
System growth	59,600	53,637	-10%	Further analysis carried out on growth projects led to deferrals and cheaper solutions. Deferrals due to COVID-19
Asset replacement and renewal	400,572	450,444	12%	Updated renewals modelling, identifying additional safety-driven needs in crossarms, conductors, and zone substations fleets
Asset relocations	13,803	16,579	20%	Update in forecast approach using recent years expenditure
Reliability, safety and environment	1,436	5,034	250%	Inclusion of network evolution plan Inclusion of recloser / remote control devices in later years
Expenditure on non-network assets	38,436	29,132	-24%	Shift towards SaaS based capability has reduced ICT Capex
Opex				
Service interruptions and emergencies	33,696	39,639	18%	Refined base-step-trend model, updated with more recent information
Vegetation management	43,054	38,998	-9%	New cyclical strategy expected to reduce future clearance requirements
Routine, corrective maintenance and inspection	66,738	80,171	20%	Several new maintenance initiatives are planned to improve and expand inspection regimes and to address defect backlogs.
Asset replacement and renewal	844		-100%	Category no longer used
System operations and network support	128,754	143,483	11%	Refined base-step-trend model Inclusion of network evolution plan and non-network DER solution
Business support	104,833	145,425	39%	Refined base-step-trend model has been updated with more recent information Increased ICT Opex (shift from Capex)

APPENDIX E. ICT ASSET INFORMATION

This appendix provides further information on the ICT systems that support our electricity 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.

GIS

At present, we use GIS to capture, store, manage and visualise our network assets. GIS currently holds the master records for commissioned assets in the network, but it also distributes and informs other systems about these operating assets. In 2020 we commenced a project to procure an EAMS, which will replace the storage, reporting and management of assets currently facilitated by GIS.

GIS will continue 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 two to three 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 tightly to the new 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 voice and 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.

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 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 fully meet our needs. We require improved 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:

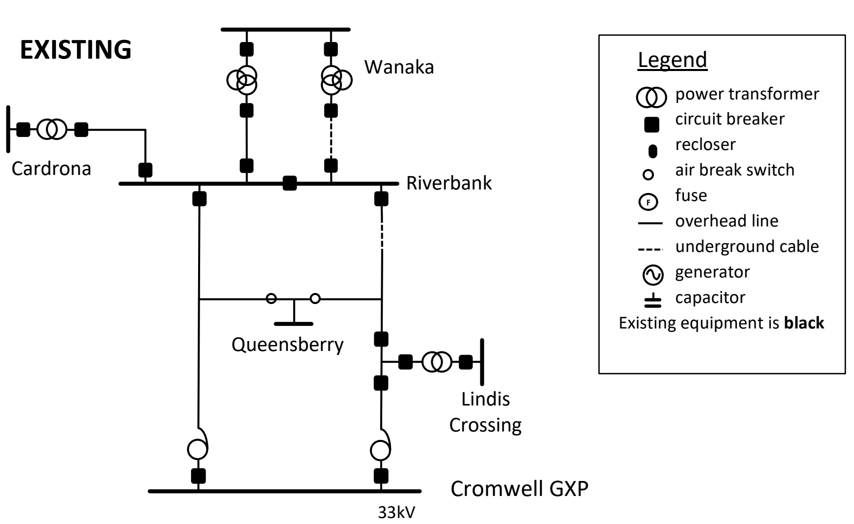
- visualise asset condition, work order and defect history
- visualise selected asset performance data from real-time systems
- undertake predictive analysis and develop forecasts of risk and intervention needs
- define and manage plans and programmes of interventions
- apply reference cost tables to 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.

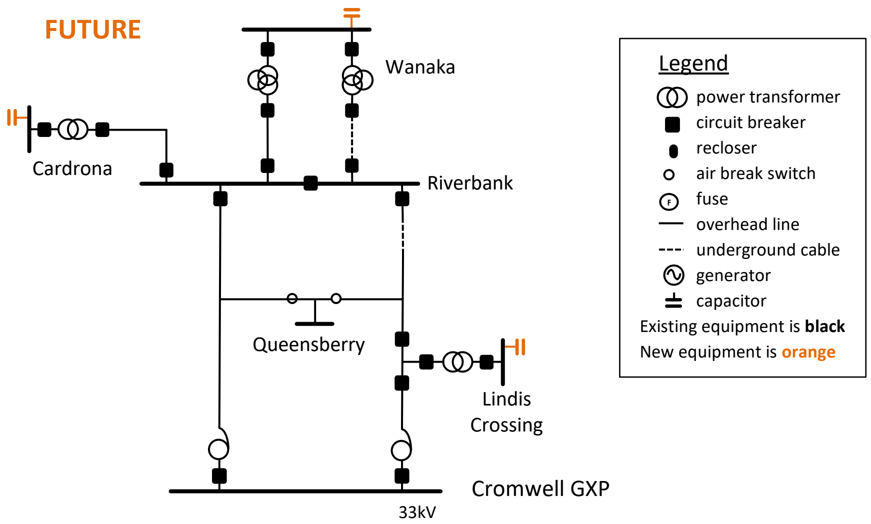
This chapter outlines the enabling ICT initiatives that will support these capabilities. Our current priorities are improving the way we manage and use information across the company and establishing an EAMS system capability. Work is underway on this and will largely be complete before the CPP Period. Given the pressures on our internal resources and the urgency with which me must improve our capabilities we are not currently contemplating a major ERP-based transformation but a fit-for-purpose transition based on core enterprise systems, improved digital integration and consistent information sourcing and management.

APPENDIX F. GROWTH PROJECT DETAILS

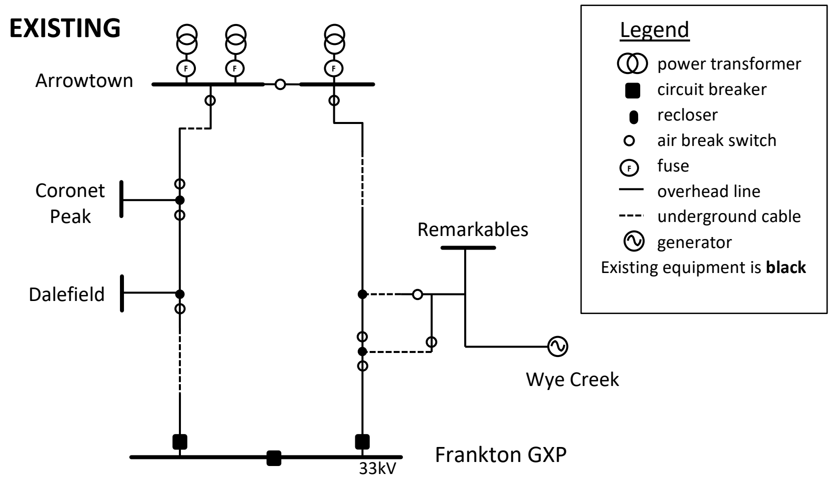
The following tables set out our main planned major network development projects for the AMP planning period.

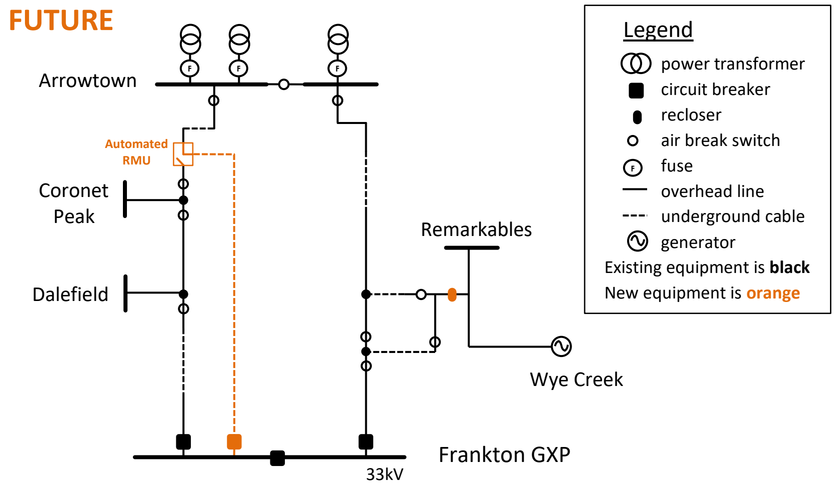
PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Upper Clutha Voltage Support	During peak load, the voltage drops below 66 kV particularly when one of the two circuits is out of service.	– Do Nothing – Install 10MVAr of voltage support at Riverbank substation – Install a total of 10 MVAr of voltage support on the 11 kV bus of Wanaka, Cardrona and Lindis Crossing substation.	**Install a total of 10 MVAr of voltage support on the 11 kV bus of Wanaka, 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	0.9



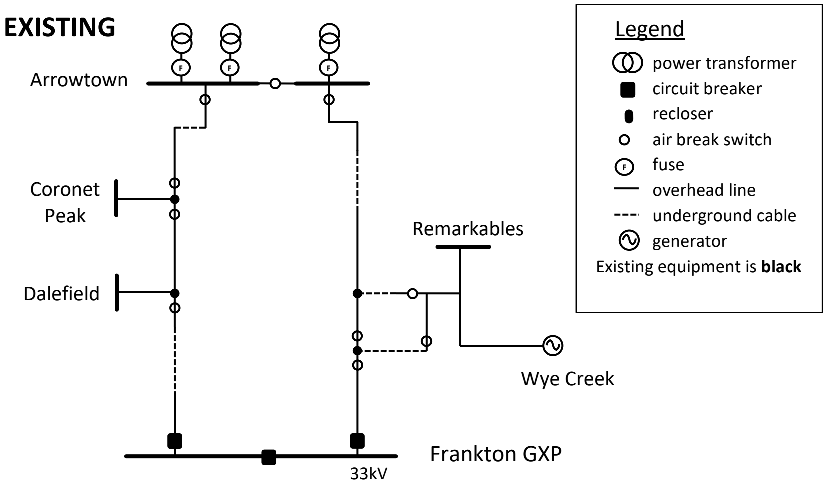


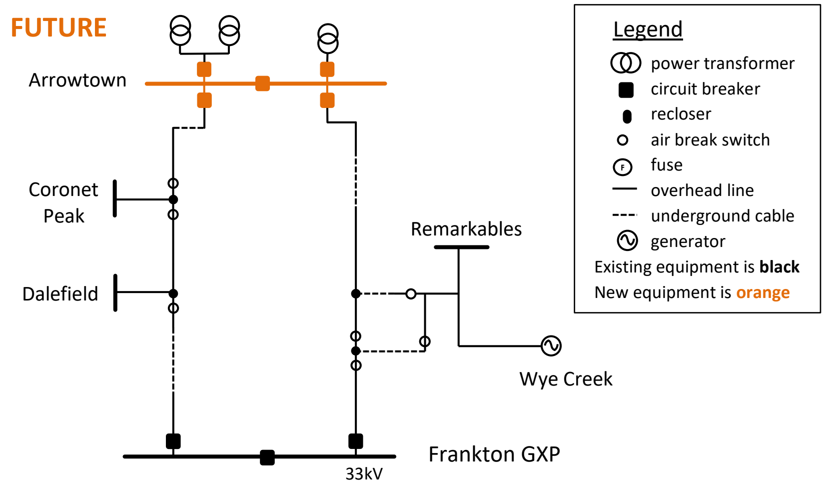
PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Arrowtown 33kV Ring Upgrade	The demand of the Arrowtown ring has exceeded its firm capacity and security level in the last six years.	– Do Nothing – New Frankton–Coronet Peak 33kV circuit – Arrowtown 33kV ring upgrade	**New Frankton–Coronet Peak 33kV circuit.** 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 34MVA on the Arrowtown 33kV Ring. – Reduces the risk of a HILP event that would see significant outages in the Dalefield, Coronet Peak and Arrowtown areas.	2021-24	6.1





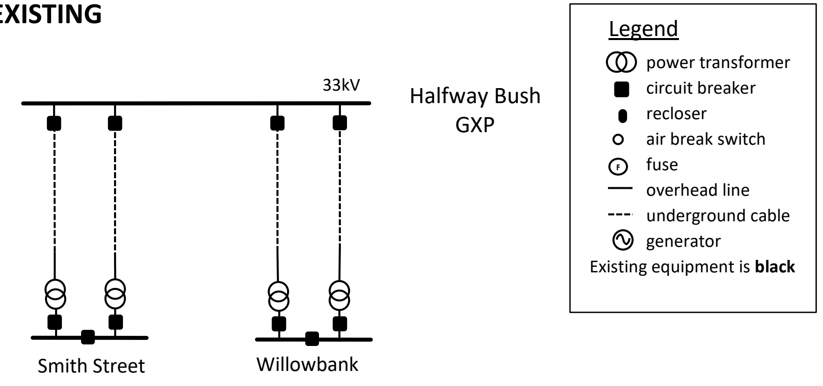
PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Arrowtown 33 kV indoor switchboard	The security level of the Arrowtown ring requires no break in electricity supply. This is not currently achieved as the ring is operated as an open ring. The open point is at the Arrowtown zone substation using a normally open, manually operated, 33kV 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 the Dalefield/Coronet Peak/Arrowtown region – Together with the Arrowtown 33kV Ring upgrade, provides firm capacity of 34MVA to meet future growth on the Arrowtown 33kV Ring – 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 subtransmission 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 33kV gas-filled subtransmission 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 subtransmission 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	5.7

EXISTING



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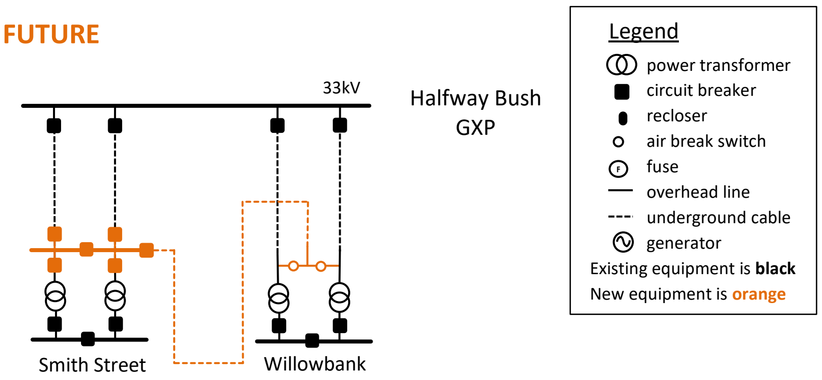
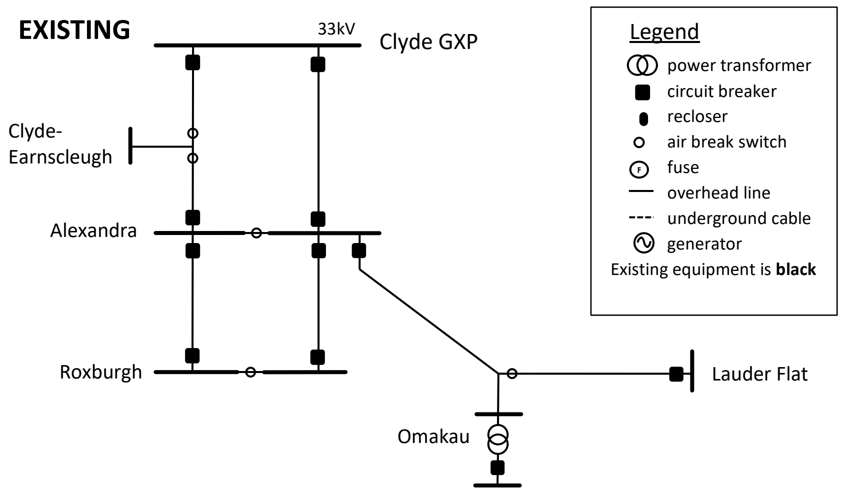
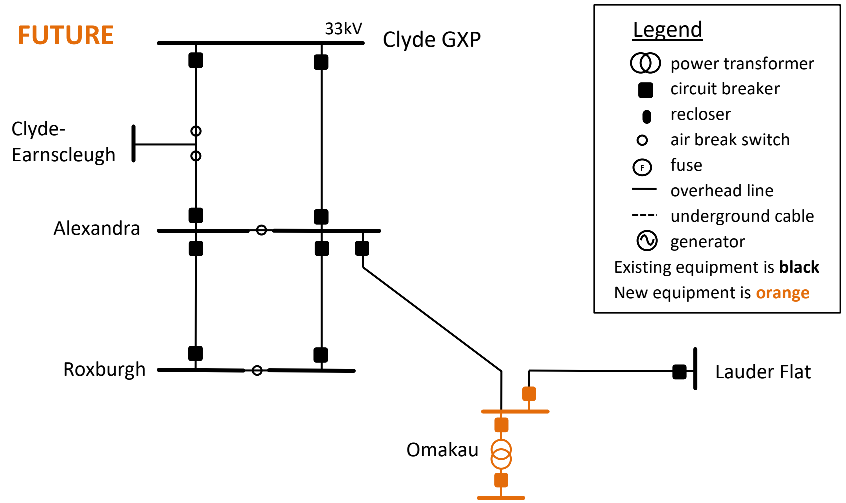
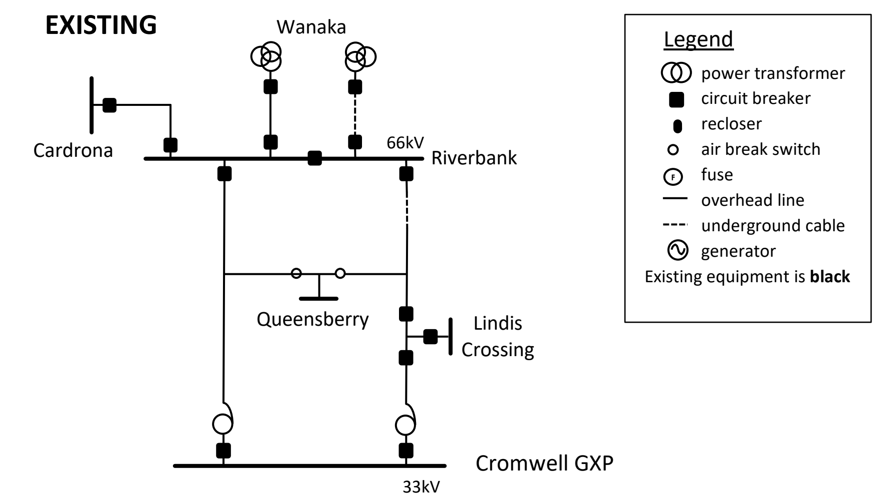


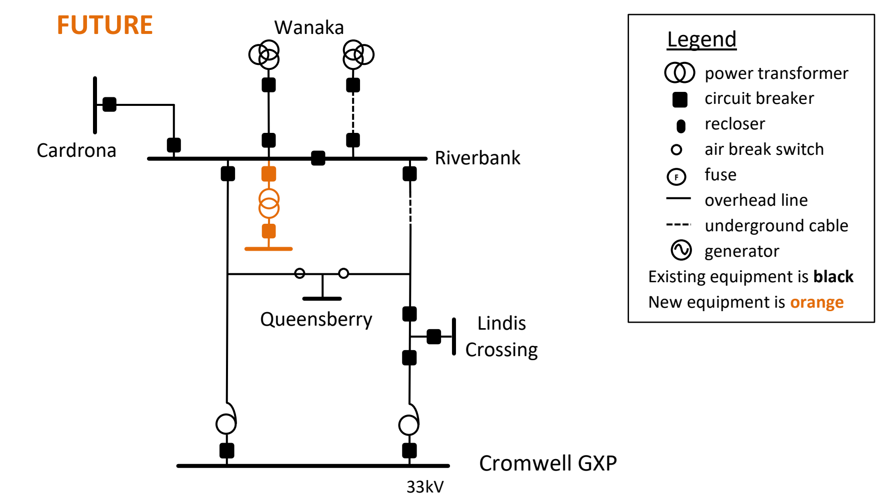
PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Omakau New Zone Substation	The load of the single power transformer has reached its capacity. The substation has limited backfeed from adjacent substations and does not have a mobile parking area. These limit 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



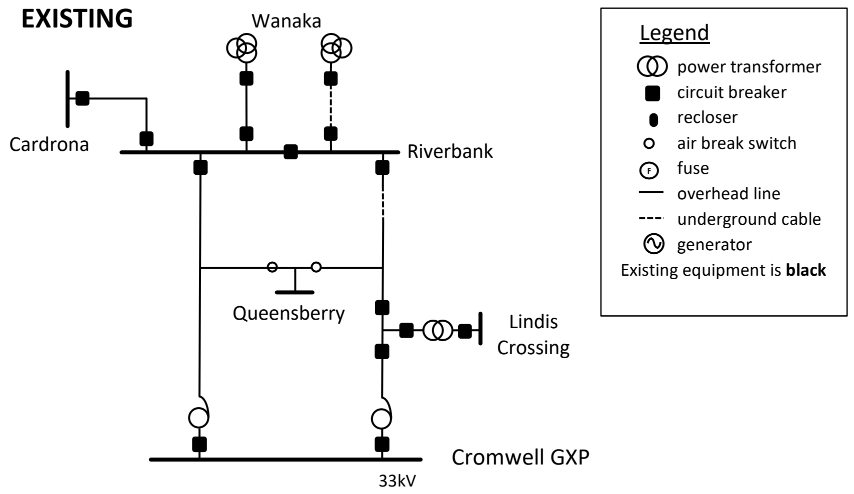


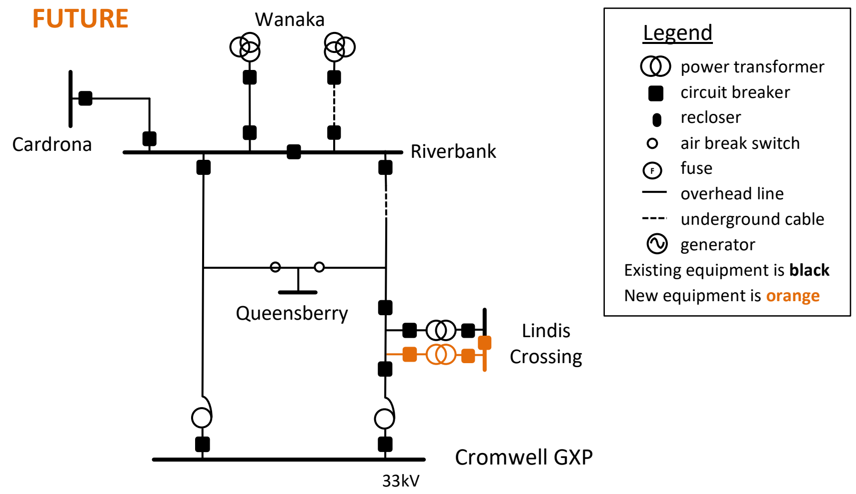
PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Riverbank zone substation upgrade	Firm capacity is forecast to be exceeded during RY24.	– Do Nothing – New transformer and switchgear at Riverbank – New zone substation at another location. – Purchase spare transformer.	New transformer and switchgear at Riverbank This solution provides the following benefits: – Improves security of supply for Wanaka and Hawea region – Provides a firm capacity of 48 MVA from the combined Wanaka and Riverbank zone substations. – Provides additional 11 kV feeders into Wanaka 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 Wanaka and Camp Hill substation, that would see significant outages in the Wanaka and Hawea area.	2027-28	3.6





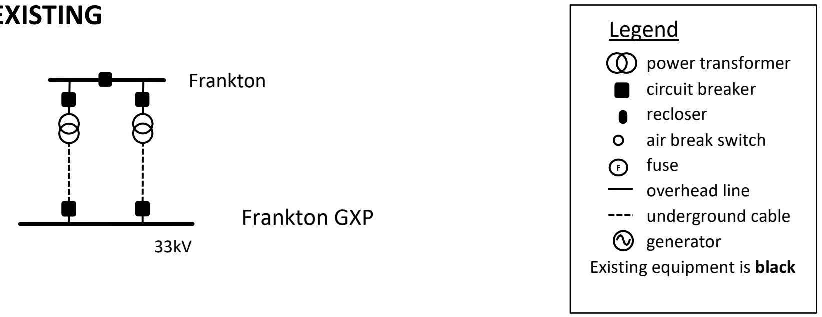
PROJECT	INVESTMENT NEED	SHORT LIST OPTIONS	IDENTIFIED SOLUTION AND BENEFITS	PERIOD	CAPEX ($M)
Second transformer at Lindis Crossing	The firm capacity is forecasted to be exceeded during RY28.	– Do Nothing – Install a new 7.5MVA transformer and extend 11 kV switchgear at Lindis Crossing zone substation. – As above, with 5MVA transformer. – Rebuild Queensberry zone substation with a new 7.5 MVA transformer at a new site.	Install new 7.5 MVA transformer 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. – 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.	2028-29	3.4





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.	2029	0.6

EXISTING



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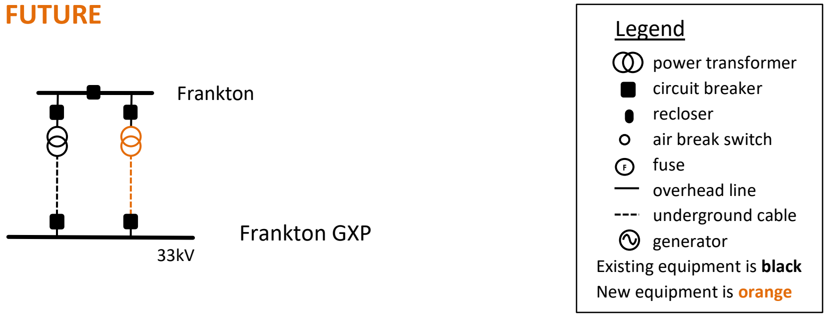

APPENDIX G. DISCLOSURE REQUIREMENTS

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) (consolidated as of 3 April 2018).

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	
	Subject to clause 2.6.3, before the start of each disclosure year commencing with the disclosure year 2014, every EDB must- (1) 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 Attachment A to this determination; (d) contains the information set out in the schedules described in clause 2.6.6; (e) contains the Report on Asset Management Maturity as described in Schedule 13; (2) Complete the Report on Asset Management Maturity in accordance with the requirements specified in Schedule 13; and (3) Publicly disclose the AMP.	(1) (a) This is addressed in the Executive Summary. (b) Refer to 2.6.2 below. (c) Compliance with Attachment A is demonstrated in this compliance matrix. (d) This information is included in Appendix B. (1)(e), (2) Our AMMAT report is included in Appendix B. (3) We have published the AMP on our website.
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;	(1)(a) Chapter 2 sets out a background on our business, Chapter 3 provides an overview of our network and Chapters 4 and 5 discuss the management of our assets. (1)(b) Historical reliability is detailed in the Executive Summary (refer to pages XI to XIV) and Section 4.6.2, Section 2.3.4 discusses our performance in relation to customers and Section 4.6 discusses our asset management objectives and strategy.

REGULATORY REQUIREMENTS		AMP REFERENCE
	(3) Should provide a sound basis for the ongoing assessment of asset-related risks, particularly high impact asset-related risks.	(1)(c) We refer to expected efficiencies in a number of sections, including in the Executive Summary (refer to page XV) and Section 10.1.3. (2) We have 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. Asset performance and risks are discussed for specific assets throughout Chapter 5.
2.6.6	Every EDB must— (1) 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) 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.	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.

REGULATORY REQUIREMENTS		AMP REFERENCE
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.
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 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 Chapter 9. 1.3 Chapter 4 details corporate strategy and governance and how that aligns with our corporate vision and strategy. 1.4 Chapter 4 details our business strategies and objectives, their relationship to our asset management practices and our service performance (including objectives and targets). 1.5 Section 2.1.1 discusses our ownership and governance structures and 2.1.2 sets out our governance roles and responsibilities. 1.6 Chapter 3 provides an overview of our network assets, while Chapter 8 provides further detail on each of our fleets. 1.8 Chapter 5 explains our approach to managing our asset fleets, and Chapter 8 sets out our fleet plans, taking a total lifecycle approach. 1.9 Section 6.4 sets out our approach to non-network solutions.
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; 2.2 Are clearly documented and made available to all stakeholders;	2.1 The elements of asset management identified in clause 1 are referenced above, while further elements are discussed throughout the AMP itself. 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

REGULATORY REQUIREMENTS		AMP REFERENCE
	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.	to Appendix B. Asset management capability is discussed in Section 9.1. 2.4 Chapter 4 discusses our service performance and supporting initiatives. Reliability initiatives are also 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. 2.7 Governance roles and responsibilities are discussed in Section 2.1.2 and capability is further discussed in Chapter 9. 2.8 Section 2.2.6 discusses our service providers and expectations and Section 9.1.1 discusses organisational capabilities. 2.9 Appendix E provides information on our supporting ICT systems. 2.10 We have 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 asset management improvements areas.
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 a brief overview of the contents and highlights 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 a background to our asset management and planning processes, while Chapter 4 discusses in detail our management strategy and governance approaches.

REGULATORY REQUIREMENTS	AMP REFERENCE
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 contained in Section 1.1 and Section 1.1.1 details our AMP objectives. 3.3.2 Section 4.4.1 discusses our vision, mission and values. 3.3.3 Section 4.2 discusses our strategic framework. 3.3.4 Chapter 4 discusses our strategy and governance. 3.3.5 Chapter 4 details our strategy and governance.
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;	Section 2.1.1 states the date on which the AMP was approved by Aurora Energy's board of directors.
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 Identification of stakeholder interests is discussed in Section 4.3. 3.6.2 Stakeholder interests are detailed in Section 4.3. 3.6.3 Section 4.3 discusses how stakeholder interests are accommodated. 3.6.4 Section 2.2 details how conflicts are managed.
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	3.7.1 Section 2.1.1 details our ownership and governance structure. 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.

REGULATORY REQUIREMENTS	AMP REFERENCE
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;	
3.8 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 Section 2.4.1). 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 6.2.3, 6.8.2, 10.1.4, 10.4.2, 10.4.5). 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, future reliability is discussed in the Executive Summary and Section 4.6.2 and uncertainty bands are provided for in relation to SAIDI and SAIFI. 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;	We comment on the possible expenditure variance due to the impact of the COVID-19 pandemic on demand forecasts and growth and security expenditure (refer to Sections 6.2.1, 6.5.2). We also note that future disclosed forecasts may vary due to the Commission's CPP determination and improvements to our asset management systems and modelling (refer to page XV of the Executive Summary and Sections 2.4.2 and 10.1).

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 life cycle management of each of our fleets. Sections 4.2, and 4.4 to 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 Section 4.2. 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-* *(i) the processes used to identify asset management data requirements that cover the whole of life cycle of the assets;* *(ii) 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;* *(iii) the systems and controls to ensure the quality and accuracy of asset management information; and* *(iv) the extent to which these systems, processes and controls are integrated.*	(i) Renewal drivers such as asset health and asset condition are discussed in Section 5.2.3. Our approach to network operations and maintenance is discussed in Section 7.2. Section 9.3.5 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. (ii) Renewal drivers such as asset health and asset condition are discussed in Section 5.2.3. Section 7.2 sets out the key drivers of operations and maintenance, including our asset management system and asset condition. Section 9.3.5 provides an overview of our ICT requirements and discusses our ICT governance, strategy and planning and ICT assets. Chapter 8 details the process of inspections and reporting on asset condition and performance for each fleet. (iii) Asset management systems are discussed in Section 9.3.5 and further in Appendix E. Improvements to our asset management capability are set out in Section 2.4.2. (iv) Systems and controls are discussed in Appendix E.
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 9.3.5 and limitations and initiatives to improve data are discussed in Appendix E. Improvements to our asset management capability are set out in Section 2.4.2.

REGULATORY REQUIREMENTS	AMP REFERENCE
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;	3.13.1 Section 5.2 details our operations and maintenance approach in terms of fleet management. Maintenance approaches for each fleet are discussed in more detail in Chapter 8. 3.13.2 Our approach to developing our network is discussed in Chapter 6. 3.13.3 Performance is discussed in Chapter 4.
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 9.3.5 and 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.
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 4.6.5 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 box 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 3.7, with more detailed fleet information contained in Chapters 5 and 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 3.5 and 3.6. 4.1.2 Major customers are discussed in Sections 3.5.2 and 3.6.2. 4.1.3 Load characteristics are discussed in Sections 3.5.1 and 3.6.1 4.1.4 Detailed in Chapters 3 and 6.
	4.2 a description of the network configuration, including- 4.2.1 identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point; 4.2.2 a description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings; 4.2.3 a description of the distribution system, including the extent to which it is underground; 4.2.4 a brief description of the network's distribution substation arrangements; 4.2.5 a description of the low voltage network including the extent to which it is underground; and	4.2.1 This information is set out in Sections 3.3 and 3.4 4.2.2 Chapter 3 describes our subtransmission network. The capacity and security ratings of individual zone substations is set out in Section 6.3.1. 4.2.3 Chapter 3 describes our distribution network. 4.2.4 An overview is provided in Section 8.6. 4.2.5 Chapter 3 describes our low voltage network, in particular sections 3.2 and 3.7. 4.2.6 An overview of secondary systems is provided in Section 8.7. Chapter 3 includes network maps and a single line diagram.

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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 subtransmission 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.*	
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 An overview of network assets is provided in Section 3.7, with Chapter 8 providing a more detailed description for each fleet. 4.4.3 These are described individually for each fleet in Chapter 8. 4.4.4 These are described individually for each fleet in 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 Chapter 8 discusses our fleets individually, with a fleet reference provided in Section 5.1.1. 4.5.2 This is discussed in Section 3.3. 4.5.3 Mobile substations are discussed in Section 8.4. 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 2.3.4 discusses feedback from customers on our performance. 7.2 Section 8.1.2 sets out performance indicators for pole failures and Section 6.3.1 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 performance targets and strategies.
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 Chapter 4.

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 6.2.2 and key planning assumptions and inputs in Section 6.2.3.
	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 6.2.2 and our security guidelines are set out in Section 6.3.2
	11.3 A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs;	These aspects are discussed in Section 5.2.1 and 5.2.2.
	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;	Sections 5.2.1 and 5.2.2 set 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 demand management and related solutions is set out in Section 6.4.
	11.6 A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network; The criteria described should relate to the EDB's philosophy in managing planning risks.	Section 6.3.1 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 6.2.2 includes discussions on 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,	11.8 System demand is discussed, and demand forecasts are provided, in Section 6.3.1. 11.8.1 The method used for load forecasting is set out in Section 6.3.1. 11.8.2 Load forecasting is set out in Section 6.3.1. 11.8.3 Network constraints are discussed in Section 6.3.1.

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making clear the extent to which these uncertain increases in demand are reflected in the forecasts; 11.8.3 identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and 11.8.4 discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives;	11.8.4 Distributed generation is discussed in Section 3.4 and demand management in Section 6.4.1
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 6.5.2 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 6.5.1. Further detail on these projects (including alternative options considered and the reasons for choosing the selected option) is set out in Appendix F.

REGULATORY REQUIREMENTS		AMP REFERENCE
	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.
	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 6.4.
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 in Chapters 5 and 8.
	12.1 The key drivers for maintenance planning and assumptions;	These are discussed in Section 5.1.
	12.2 Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include- 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 Chapter 8 provides this information for each fleet individually. 12.2.3 A capex summary is provided for in Section 10.2.2.
	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 Refurbishment and renewal is discussed in Section 5.2.3 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 Chapter 6.4.

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	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 12.3.5 an overview of other work being considered for the remainder of the AMP planning period; and	12.3.3 to 12.3.5 This is discussed in Chapter 8 for each fleet individually.
	12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	Chapter 8 provides this information for each fleet individually.
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; 14.3 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.*	14.1 Risk management and resilience are discussed 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
	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.
	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 XI to XIV) 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.
	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.

REGULATORY REQUIREMENTS		AMP REFERENCE
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 plans.	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 asset management governance. 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.

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 Margaret Patricia Devlin, 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
12 June 2020	12 June 2020
Date	Date

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