

For the disclosure year ending 31 March 2025

ANNUAL DELIVERY REPORT

**Aurora**
ENERGY

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1. INTRODUCTION

1.1. CONTEXT

Aurora Energy owns and operates the electricity network in Dunedin, Central Otago and Queenstown Lakes. It owns the poles, lines and equipment that distribute electricity from Transpower's national grid to more than 96,700 homes, farms and businesses. It is responsible for maintaining and renewing infrastructure, and the safety and reliability of electricity supply is a critical driver across all elements of our business.

In 2021, the Commerce Commission (Commission) approved a customised price-quality path (CPP) for Aurora Energy that enabled investment of \$563 million over five years (1 April 2021 to 31 March 2026 (CPP Period)) to address safety and reliability risk across the network.

Aurora Energy is subject to information disclosure regulation made under Part 4 of the Commerce Act 1986. The Commission regulates information that must be disclosed to stakeholders. Clause 2.5.5 of the Electricity Distribution Information Disclosure Determination 2012 (Determination) requires Aurora Energy to disclose an annual delivery report in relation to the delivery of its CPP. This annual delivery report (Annual Delivery Report) has been prepared pursuant to that clause for the period 1 April 2024 to 31 March 2025 (RY25).

On 31 March 2022, Aurora Energy disclosed the following three plans, which are referenced throughout this Annual Delivery Report:

- Safety Delivery Plan
- Project and Programme Delivery Plan (PPDP)
- Development Plan.

A copy of each plan is available at www.auroraenergy.co.nz.

References throughout this Annual Delivery Report to 'us', 'we' and 'our' are to Aurora Energy.

1.2. CONTENT OF ANNUAL DELIVERY REPORT

The content of this Annual Delivery Report is specified in the Determination. A matrix showing the relationship between the requirements set out in the Determination and the contents of this Annual Delivery Report can be found in Appendix A.

1.3. CERTIFICATION

This Annual Delivery Report was certified in accordance with clause 2.9.5 of the Determination on 27 August 2025. A copy of the Director's Certificate can be found in Appendix B.

1.4. ASSURANCE REPORT

Audit NZ has prepared an assurance report that meets the requirements of clause 2.8 of the Determination. A copy of that report can be found in Appendix C.

2. CHAIR AND CHIEF EXECUTIVE'S REPORT

We are pleased to present our Annual Delivery Report for the fourth year of our CPP, which outlines the progress during RY25 on our plans to deliver upgrades to the electricity network in Dunedin, Central Otago and Queenstown Lakes. Providing a safe and reliable electricity supply is a critical driver across all elements of our business.

The main priority for us throughout the CPP period is to deliver projects and programmes that will improve the safety of our network. Those projects and programmes will also improve the reliability of our network in the future. Four years into our five-year CPP period, we are making good progress on the delivery of our CPP programme, noting that we continue to see strong growth in Central Otago which has again given rise to competing demands for resources and capital budgets, and the need to accelerate a number of growth-related investments.

In March 2022, we published the following three documents related to the CPP Period:

- Development Plan outlining business process-related improvement initiatives we planned to implement;
- Safety Delivery Plan outlining network asset-related safety improvements we planned to achieve; and
- Project and Programme Delivery Plan detailing projects and programmes that we planned to deliver.

Since publishing these Plans we have continued to incrementally improve and mature our business practices whilst also responding to changing circumstances. As further information has come to hand, the outputs from our planning models and investment priorities have changed, therefore care is required in some cases when comparing progress against original forecasts. Variances against the original Plans are presented throughout this Annual Delivery Report. A more up-to-date view of current work programmes and expenditure forecasts can be found in our 2025 Asset Management Plan.

Throughout the CPP Period we have had to adapt procurement processes in response to changes in global supply chains (including material availability and shipping delays) and escalating costs in order to reduce our exposure to supply delays and cost escalation. This adaptation is helping us to mitigate upstream supply-side constraints, however the competing growth versus renewal demand impact continues to make it more difficult to deliver the asset replacement quantities we had originally planned. We continue to prioritise the replacement of those assets within our safety sensitive fleets that have the lowest asset health ratings.

Despite these challenges, we have seen a positive improvement in our reliability performance during RY25. While planned interruptions remain high as we continue to deliver an elevated work programme, our unplanned reliability performance has improved significantly compared to previous

years. Our improving asset management capabilities are also enabling us to identify root causes more effectively and learn from and respond to that information.

The reduced renewal quantity impact of supply chain and inflationary pressures continues to be partially offset in some network asset fleets by new favourable asset inspection information as we continue to mature our network risk assessment practices. When favourable asset inspection information is received, there is a reduction in the quantum of the asset renewal backlog and forecast asset quantities requiring renewal. Through a combination of asset inspection improvements and renewals undertaken in RY22 to RY25, we have been able to successfully reduce our reported network risk for the following safety-sensitive fleets to either lower than which we had forecast, or as planned, in our Safety Delivery Plan at this point of the CPP Period:

- Poles
- Crossarms
- Subtransmission and low voltage conductor
- Cables (including cable terminations involving cast-iron potheads)
- Pole mounted switches
- Reclosers and sectionalisers
- Ground mounted distribution transformers
- Pole mounted distribution transformers.

Conversely, some network fleets are showing higher than forecast levels of safety risk, such as our protection, outdoor switchgear, subtransmission conductor and low voltage enclosure fleets. We are currently re-prioritising our work plans with service providers and these fleets will remain in focus throughout the last year of the CPP Period and beyond.

Overall, the delivery of our safety risk reduction plan remains on track with some fleets ahead of forecast and others requiring reprioritised focus to address newly identified defects from our cyclical inspection programme. The nature of fleet management is such that new inspection information will continue to lead to further reprioritisations of the plan on a regular basis. Our current network safety risk profile is discussed further in section 3.

We continue to remove cast iron cable terminations (potheads) from the network, with priority given to cast iron potheads in highly populated areas. Only 2 zone 1 (highest public safety zone classification) potheads remained on the network at the end of RY25. The overall programme to remove cast iron potheads is approximately 89% complete with 54 remaining on the network. We are on track to complete this programme of work within the CPP period.

In the Queenstown area, we completed the upgrade of the Frankton zone substation. This will provide increased capacity to the Frankton area as it continues to grow.

In response to continued growth and the need for additional capacity in the Upper Clutha region, we completed replacement of the Upper Clutha auto transformer ahead of schedule.

At the time we developed the PPDP published in March 2022, we had planned to replace switchgear at the Arrowtown zone substation. As a result of growth in the Arrowtown and Dalefield areas we

have since identified the need for a new zone substation in Dalefield. This decision impacts on the timing and need to replace the switchgear at the Arrowtown zone substation and as a result this project will no longer be delivered within the CPP Period.

Replacement of the transformer at the Riverbank zone substation has also been deferred to RY27 due to us reorganising the way we respond to capacity constraints in the Upper Clutha region. The need to deliver this project still remains, however the timeframe for delivery has changed since preparation of the PPDP.

Our CPP investment plan and associated work programmes entailed significant step changes in the planning and delivery of asset upgrades and renewal work, and we remain committed to delivering that work in a prioritised manner as efficiently and effectively as possible. The initiatives we are implementing to further improve asset management and works delivery practices are outlined in section 4.2 of this report. The bundling of work packages is reducing the number of planned outages on our network and we have continued to focus on upskilling our project managers in the Prince2 project management methodology.

Looking ahead to the final year of our CPP, we remain fully committed to delivering the network safety focussed outcomes in our Plans and also expect growth to remain strong in the Central Otago, Wanaka and Queenstown regions.

We are continuing to see a growing focus on decarbonisation through electrification and consistent with the high values of work delivered throughout the CPP period to date, our RY26 work programmes will again accelerate some urgent growth projects.

We are fortunate to have a dedicated team at Aurora Energy and it is thanks to their hard work and customer-first approach that we have made such good progress on our five-year investment plans. They always remember there is a person or business at the end of the line.

Our contracting partners are pivotal in supporting us to deliver our commitments and we thank them for working at all times of the night and day and in all weather conditions to keep the lights on.



Steve Thompson

Chair



Richard Fletcher

Chief Executive

3. WHAT WE HAVE DELIVERED

Our PPDP detailed the capital expenditure and operational expenditure projects and programmes that we planned to deliver throughout the remainder of the CPP Period. That plan was intended to form the basis of our work plan for RY22 through to RY26, along with any adjustments reflected in our subsequent asset management plans (AMPs).

As mentioned in section 2, our ability to deliver at the elevated levels planned throughout the CPP Period has been challenged by global supply chain pressures, particularly those experienced in the earlier years of our CPP Period, inflation and escalating costs, and the corresponding need to manage financial resources as efficiently as possible. In addition to these external factors, strong growth in Central Otago continues to require re-allocation of contractor resources and capital budgets to meet the higher than forecast levels of customer driven growth projects in RY25. We continue to focus on delivering those parts of our plan that will improve the safety of our network, while at the same time meeting the increased demand from communities reliant on our network for their future electricity supply.

During RY25, we continued to receive new favourable asset inspection information in some fleets and maintained our focus on maturing asset management practices with respect to evidence-based investment decision making. This has enabled us to reassess which assets need to be renewed or replaced, and to flex our asset replacement and renewal programmes accordingly.

During the year, our dedicated project team, "Rūma Mihīni", handed over the new asset management software solution, Maximo, to our business operations, marking a significant milestone in this multi-year project. We will now work on some supporting process improvement opportunities so we fully realise the benefits that it can bring. The Rūma Mihīni project is discussed further in section 5.5.

In this section, we outline the key capital expenditure and operational expenditure projects and programmes in the PPDP that we:

- have not yet completed, but which are on schedule in accordance with the PPDP
- delivered on time in RY25
- projects delivered related to other regulatory years in the CPP Period
- have not completed on time, but had planned to complete in RY25
- have not commenced, but had planned to commence, in RY25.

Projects and programmes not yet completed, but on schedule to complete

There were no capital expenditure projects forecast for RY25 that fell within this category.

Our capital expenditure and operational expenditure programmes are integral to the operation of our business throughout the five-year CPP Period and beyond. We have continued to focus on the delivery of these programmes in RY25. Cost escalation, global supply pressures (including material availability and shipping delays) from earlier in the CPP Period, and the re-allocation of resources to

ensure we are able to service growth, has impacted our ability to deliver zone substation renewals and ground mounted switchgear renewals to the extent we had planned in RY25.

Further detail about our expenditure and the assets we are delivering in our asset replacement and renewal programme compared to that which we forecast in our PPDP can be found in chapter 9.

Projects and programmes delivered on time in RY25

- **Frankton zone substation upgrade:** The Frankton zone substation upgrade was completed in December 2024. This project involved upgrading the existing 15MVA transformer to 25MVA. This will benefit the community by providing increased transformer capacity to the Frankton area as it continues to grow. It also gives Aurora Energy more flexibility when carrying out maintenance within the zone substation as one transformer can carry the load while the other one is out of service.

Projects delivered related to other regulatory years in the CPP Period

- The **Upper Clutha auto transformer replacement** that was planned for delivery in RY26 was delivered ahead of schedule in RY25, providing more capacity to the Upper Clutha area. This gives Aurora Energy more flexibility when carrying out planned maintenance and asset replacement work on the two Upper Clutha circuits, reducing the risk of unplanned outages to a very large customer base.
- The **Upper Clutha special protection scheme** which was planned for RY25 was delivered ahead of time in RY24 (please see Aurora Energy's RY24 Annual Delivery Report).
- The **Omakau new zone substation** which was planned for RY24 delivery has been delivered in RY25. The transformer and switchgear were livened in March 2025 and are now supplying the network. The larger 7.5MVA transformer replaces the old 3MVA transformer providing increased capacity to the region. The requirement for more capacity has been mainly driven by irrigation load.
- The **Smith Street to Willowbank Inter-tie** which was planned for RY24 delivery had been delivered at the time of writing (RY26). We have been creating a ring network to improve the security of electricity supply for the approximately 5,900 customers supplied by the Smith Street and Willowbank substations. Work was coordinated with the Dunedin City Council's centre city upgrade, the timing of which impacted on our ability to deliver within the timeframe initially planned in the PPDP. At the time of writing, the final stage of this project had been completed, which tied in with the commissioning of the new switchgear at the Smith Street zone substation.

Projects and programmes we have not completed on time, but had planned to complete in RY25

- **Riverbank new transformer** – Completion of the replacement of the transformer at the Riverbank zone substation has been deferred to RY27 due to reorganising how we respond to capacity constraints in the Upper Clutha region. The need to deliver this project still remains, however the timing since preparing the PPDP has changed.

Projects and programmes we have not commenced, but had planned to commence, in RY25

At the time of preparing the PPDP, we had identified a need to commence the upgrade the **Arrowtown Zone Substation 33kV indoor switchgear**, which we had planned to commence in RY25.

Since then, we have identified the need for a new zone substation in the Dalefield area, which means that this work no longer needs to be undertaken. Please see our 2025 Asset Management Plan for further discussion.

4. SAFETY

4.1. PROGRESS AGAINST OUR SAFETY DELIVERY PLAN

In March 2022 we published a Safety Delivery Plan, which detailed how the delivery of our CPP period capital and operational expenditure projects and programmes is expected to reduce our network safety risks.

We recognise two parts of network safety risk:

- Safety of public
- Safety of personnel.

Our Safety Delivery Plan outlines the key network safety risks and the actions we plan to take to reduce those risks during the CPP Period, with reference to the principle of reducing risk to ‘as low as reasonably practicable’.

4.1.1. Improving risk practices

As we progress through the CPP Period, we are continually improving our asset management practices, which is subsequently enhancing our understanding of asset condition and our ability to quantify risk. These commitments were documented in our Development Plan. We report on progress in relation to Asset Management practices and processes, against our Development Plan including safety risk in section 5.6.

As we incrementally and continually mature our view of asset health and risk quantification, the resulting outputs will change. Therefore, care is required in interpreting the movement in asset fleet health and risk scores through the CPP Period.

At the time of preparing the Safety Delivery Plan, we used a predominantly age-based approach in discerning a baseline view of asset health. As we embed improvements, such as shifting to a condition-based approach, we have and will continue to see a refined view of asset health and consequently risk.

We have now progressed asset health index (AHI) modelling maturity from age based to single or multi-weighted modelling for several key fleets, including poles, air break switches, distribution ground mount switchgear and power transformers.

We continue to focus on gathering updated and enhanced condition information related to our assets by developing detailed inspection and/or maintenance standards and implementing these regimes with our service providers. This means that we are improving the visibility of assets reaching the end of their useful life, enabling more targeted investment and risk reduction. New condition information related to an asset can add or remove years to / from the previously age-based asset fleet profile life, enabling us to flex our plan and focus investment on the assets that are at greatest risk of failure.

Since RY24 we have reviewed our approach to understanding the condition of all overhead assets, distribution transformers, low voltage enclosures and ground mounted distribution switchgear. In October 2023, we rolled out a new overhead inspection programme which broadened the focus beyond just poles to all overhead assets, such as crossarms, conductors and insulators. The enhanced inspection programmes for distribution transformers, low voltage enclosures and ground mounted distribution switchgear commenced in RY25 and will be fully implemented for RY26 inspections.

In recognition of some of the limitations of visual inspections, we implemented advanced inspection techniques on a risk-based approach and continue to embed them within our inspection regime. The new techniques include thermal, acoustic, and aerial inspections. We are maintaining a balance between the cost and return on investment (defect discovery rate) from each technique, to ensure they are only deployed where cost effective and necessary. Thermal cameras enhance the outcomes from overhead inspections because they enable us to identify defects not detectable by visual inspection.

We have documented fleet strategies and plans for our safety critical fleets, which include plausible failure modes. These documents enable a structured and evidence-based approach to investment decisions. The identified maintenance and renewal activities are informed by our understanding of failure modes and our improving view of condition-based health. Incremental improvements continue to be made to how we model asset health, by fleet and are captured in the fleet strategies.

In RY25 we undertook an internal maturity assessment of our fleet strategies and also engaged an independent asset management consultant to review our fleet strategies and associated asset health models. These reviews have led to fleet specific improvement plans and a roadmap to enhance asset health modelling.

We have built on our root cause analysis (RCA) initiative to improve our understanding of asset failures and launched a dedicated project to ensure the efficient and effective capture, analysis and use of relevant data. The project has documented the RCA process and updated standards and expectations in relation to understanding asset failures on the network. We are responding to the learnings/outcomes of our RCA and adjusting asset management practices accordingly.

By understanding why an asset failed, we can take actions to prevent future occurrences of the same nature, e.g. by updating inspection programmes, design and/or material standards. This approach supports a targeted approach to investment, ensuring we understand and respond to the root cause of events on the network. It also provides us with a feedback loop to our fleet strategies and modelling and drives an informed and holistic approach to determining solutions.

Inspection informed asset scoring allows us to make adjustments to expected asset lives, and to be more targeted in our asset renewals.

In addition, our asset health profile is also improved by the renewal of associated assets (for example a primary reconductoring job may replace several support structures as well, which are considered associated assets). This changes the overall fleet health, which improves the risk profile.

4.1.2. Change in network safety risk

Asset health

We calculate the total network risk as the sum of individual asset risks for fleets with public safety risk potential. Figure 1 below compares the percentage of the assets in each safety-sensitive fleet that have an H1 health rating as at 31 March 2025 with the forecast percentage in the Safety Delivery Plan. As described above, the result is a function of both the delivery of our capital and operational expenditure projects and programmes, and our maturing asset management practices. Through improved inspection standards and RCA processes, our understanding of asset condition has evolved since the initial baseline set in the PPDP.

Figure 1: Percentage of H1 assets within safety-sensitive fleets

| SAFETY SENSITIVE FLEET | START OF RY22 | END OF RY25 FORECAST | END OF RY25 ACTUAL |
|--|---------------|----------------------|--------------------|
| | H1% | H1% | H1% |
| Protection | 48.0% | 12.4% | 43.7% |
| Indoor Switchgear | 37.8% | 29.6% | 13.9% |
| Subtransmission Conductor (km) | 13.6% | 10.7% | 12.8% |
| Crossarms | 17.8% | 15.5% | 0.7% |
| LV Conductor (km) | 17.4% | 15.8% | 8.8% |
| Poles | 12.2% | 9.8% | 1.0% |
| Distribution Conductor (km) | 6.3% | 5.4% | 4.4% |
| Power Transformers | 10.6% | 10.6% | 3.1% |
| Outdoor Switchgear | 21.4% | 4.8% | 10.1% |
| Ground Mounted Switchgear | 8.7% | 4.8% | 4.3% |
| Pole Mounted Distribution Transformers | 13.3% | 14.2% | 3.7% |
| Low Voltage Enclosures | 11.0% | 10.1% | 10.8% |
| Subtransmission Cables (km/units*) | 9.0% | 13.8% | 0.0% |
| Reclosers and Sectionalisers | 10.5% | 14.7% | 1.9% |
| Ground Mounted Distribution Transformers | 4.6% | 6.1% | 0.1% |
| Pole Mounted Switches | 40.9% | 37.5% | 19.5% |
| Distribution Cables (km/units*) | 2.4% | 0.7% | 0.0% |
| LV Cables (km/units*) | 2.2% | 3.6% | 2.9% |

We have made significant progress across the network in improving the health of safety-sensitive fleets, with the health of some fleets progressing ahead of our plan/forecast. We are ahead of forecast or tracking to forecast in 14 of our 18 safety sensitive fleets.

Throughout the CPP period we have prioritised improving the health of the fleets which are physically present in our communities, for example, on property boundaries, in road verges or in the overhead spaces above streets. We have also prioritised high safety criticality areas, for example near schools and busy public areas. The actual % of H1 assets within the fleets predominantly located in these areas (poles, crossarms, low voltage conductor, ground mounted switchgear and ground mounted distribution transformers) are all lower at the end of RY25 than the RY25 forecasts established in RY22. We are proud of the significant progress we have achieved on these priority fleets.

For some of the remaining fleets, however, we will need to reprioritise our plan during the last year of the CPP Period (and beyond) to ensure that we meet our objective to reduce safety network risks as soon as practical.

Two of the fleets most behind their RY25 forecasts in the Safety Delivery Plan (Protection and Outdoor Switchgear) are generally sheltered from the public within zone substation boundaries or have lower safety risks due to backup systems. These factors support a lower priority rating being attributed to our Protection and Outdoor switchgear fleets, than the fleets located more predominantly in public areas.

- **Protection:** At the beginning of the CPP period we estimated that 48% of all protection relays were in the H1 category, and in Our Safety Delivery Plan we forecast to reduce this figure to 12.4% by the end of RY25. Current data records show that despite a number of protection replacements at critical sites, 43.7% of our relays remained in the H1 category as at 31 March 2025. As reported previously, there are two dominant factors influencing this result:
 - Modern protection scheme solutions often require a reduced number of relays. For example, a modern 11kV numerical protection relay will typically displace two older electromechanical relays on average. This reduction in relay count impacts the percentage scoring outlined above as a significant number of electromechanical relays continue to be removed.
 - The completeness and accuracy of our protection relay data and systems have improved and additional relays have been identified since the original Safety Delivery Plan forecasts were produced.

We remain committed to our protection renewal program, and in AMP25 we documented our intention to undertake an accelerated plan to reduce the percentage of H1 assets to 3% by the end of RY28.

Protection replacements were recently completed at our Omakau and Queenstown zone substations, and Protection replacement is also underway at our Alexandra, Green Island, Riverbank, Smith Street, North-East Valley and Fernhill zone substations.

We are focusing on relay types with an increased risk of failure and those that have exceeded expected useful life, noting that the failure of a protection system does not generally cause a direct safety risk of itself, rather it is the failure of a protection system in combination with the failure of a primary asset that can lead to a safety or reliability performance risk.

- **Outdoor Switchgear:** At the beginning of the CPP period, we estimated that 21% of all outdoor switchgear was in the H1 category, and in Our Safety Delivery Plan we forecast to reduce this figure to 5% by the end of RY25. Current data records show that 10.1% of the fleet remained in the H1 category as at 31 March 2025 (versus only 2.3% the end of RY24). The increase in this year's RY25 actual H1% has resulted from improvements to the asset health data model for this fleet. Our latest revised plan is targeting a reduction in H1 outdoor switchgear to 5% by 2030.
- **Subtransmission Conductor:** Whilst actual RY25 H1% (12.8%) is slightly above the RY25 forecast (10.7%) in Our Safety Delivery Plan, our subtransmission conductor health management is broadly on track. We are undertaking routine inspections and completing high priority renewals and maintenance as a risk control.
- **LV Enclosures:** We have completed a full round of inspections on this fleet and have responded to the defects identified. The remedial works undertaken provide assurance that safety issues

have been addressed, however we are yet to fully capture the condition data which will enable us to remodel the health index for this fleet. The reported 10.8% of H1LV enclosures as at 31 March 2025 has been sourced from an age-based model. We believe this percentage will reduce to below the RY25 forecast (10.1%) once the health index remodelling is complete.

As low as reasonably practicable

While our asset renewals programme continues to prioritise fleets with the highest inherent and/or residual risk on the network, we also continue to replace a modest level of assets in most lower safety risk fleets where asset health indicates an end-of-life asset, thereby addressing other risk types such as reliability. These practices align to an 'As Low As Reasonably Practicable' (ALARP) approach to safety. A detailed explanation of our intervention strategies for end-of-life assets, is set out in our 2025 Asset Management Plan.

We consider a number of risk management strategies to achieve ALARP safety risk. ALARP or similar phrases are widely used in safety regulation. When following the ALARP principle to safety management, an organisation will implement or execute all reasonable actions to reduce safety risk. When ALARP has been achieved, the cost or effort of all remaining possible actions to reduce safety risk will be disproportionate to the safety benefit gained.

When making a choice between the implementation of different risk controls it is important to understand their effectiveness. As outlined in our Safety Delivery Plan, we consider a hierarchy of controls:

- **Eliminate:** removal of asset; this strategy is mostly impracticable for existing network assets providing a required function/purpose
- **Substitute:** asset relocation to a safer location or replacement with a safer option; this is the most effective strategy available for Aurora Energy
- **Engineering:** asset maintenance, improvement of design standards, addressing specific failure causes; we will use this strategy as a complimentary measure to the more effective Substitute
- **Administrative:** procedures for delivery of planned works; public awareness campaigns; emergency response procedures; this is a complimentary strategy.

Risk tolerance

Figure 2 below sets out the number of assets in risk quantified fleets that are above the risk tolerance line of our corporate risk matrix as at 31 March 2025, while Figure 3 depicts this as a percentage. As we transition from age-based health assessment to condition based, we are better informed with respect to asset health and risk which has enabled us to reevaluate our risk profiles.

Not all safety sensitive fleets depicted in Figure 1 above are able to be 'risk quantified'. Fleets which are unable to be 'risk quantified' have been excluded from Figure 2 and Figure 3 below.

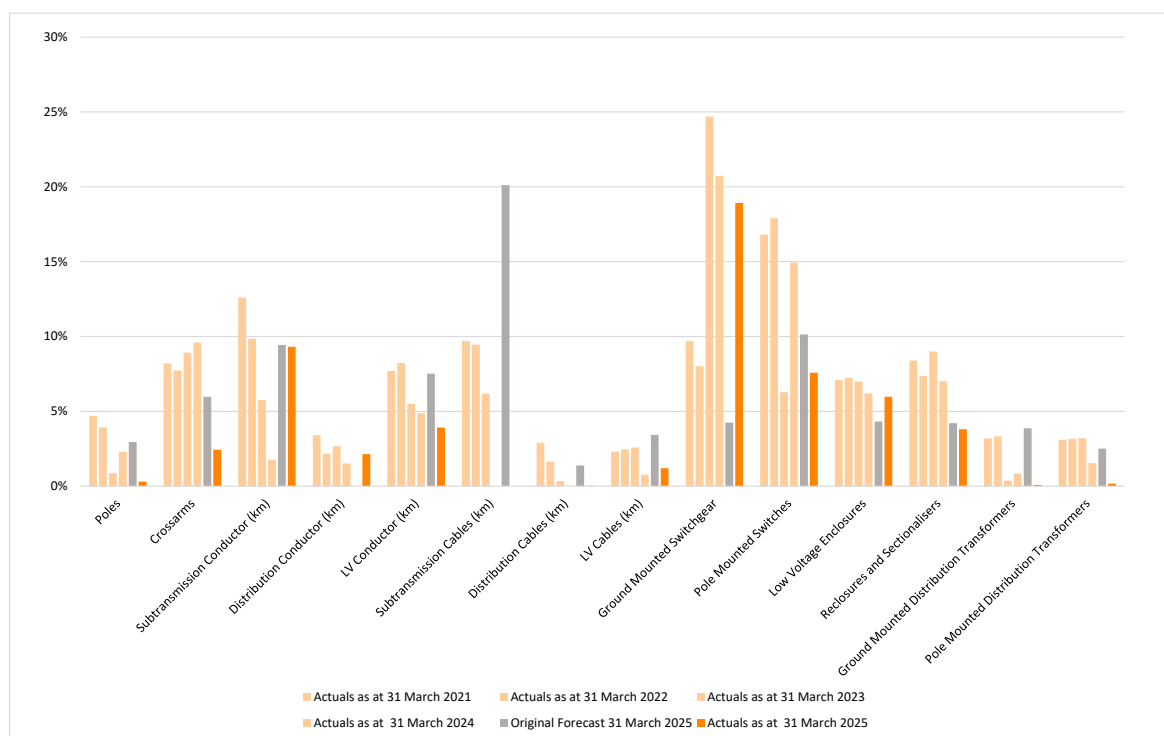
Asset risk is the product of the likelihood of a failure occurring and the consequence of the failure mode. Our approach to risk quantification considers asset health as a proxy to likelihood of failure, alongside of asset criticality as a proxy to the consequence of failure. Within this framework we

calculate asset safety impacts depending on the location of assets within safety zones implemented in our geospatial information system.

Consistent with our current Risk Control and Management Standard, the corporate risk matrix assesses asset risks with a potential safety impact of more than 'moderate' and a likelihood rating of 'possible' or higher, as above our risk tolerance level.

Figure 2: Number of assets within a safety-sensitive fleet above risk tolerance level

| SAFETY SENSITIVE FLEETS | NUMBER OF UNITS ABOVE TOLERANCE | | | | | |
|--|---------------------------------|----------|----------|----------|----------|----------|
| | ACTUALS | ACTUALS | ACTUALS | ACTUALS | FORECAST | ACTUALS |
| | AS AT 31 | AS AT 31 | AS AT 31 | AS AT 31 | AS AT 31 | AS AT 31 |
| | MARCH | MARCH | MARCH | MARCH | MARCH | MARCH |
| | 2021 | 2022 | 2023 | 2024 | 2025 | 2025 |
| Poles | 2487 | 2089 | 461 | 1226 | 1570 | 168 |
| Crossarms | 7664 | 7209 | 8488 | 9189 | 5581 | 2323 |
| Subtransmission Conductor (km) | 66 | 51.5 | 29 | 9 | 49 | 48 |
| Distribution Conductor (km) | 76 | 49.2 | 60 | 35 | 0 | 49 |
| LV Conductor (km) | 72 | 76.8 | 51 | 50 | 70 | 40 |
| Subtransmission Cables (km) | 8 | 8.2 | 5 | 0 | 18 | 0 |
| Distribution Cables (km) | 32 | 18.5 | 4 | 0 | 16 | 0 |
| LV Cables (km) | 23 | 25.4 | 27 | 9 | 35 | 14 |
| Ground Mounted Switchgear | 199 | 164 | 340 | 296 | 87 | 278 |
| Pole Mounted Switches | 197 | 210 | 63 | 191 | 119 | 97 |
| Low Voltage Enclosures | 1102 | 1113 | 1111 | 1051 | 664 | 1140 |
| Reclosures and Sectionalisers | 8 | 7 | 9 | 8 | 4 | 4 |
| Ground Mounted Distribution Transformers | 101 | 106 | 12 | 28 | 123 | 3 |
| Pole Mounted Distribution Transformers | 120 | 123 | 126 | 63 | 98 | 7 |

Figure 3: Percentage of safety-sensitive fleet above risk tolerance level


As discussed above, we have made significant progress in reducing the safety risks associated with assets that are in the vicinity of the public. The improved position is attributed to a combination of work completed in the field to replace end of life assets, and the benefits we are seeing from the ongoing improvements in our asset management practices. Notable progress has been made on the overhead network and ground mounted fleets. We no longer have a backlog of red tagged poles and are currently focused on remediation of remaining orange tag poles. Our new overhead inspection data, along with failure analysis and destructive testing, confirms a more favourable health profile for crossarms.

We have been unable to reduce the safety risk for three of our safety-sensitive fleets to the extent that we had planned to as at 31 March 2025:

- **Distribution conductor:** Our new overhead inspection programme has enabled us to validate data and improve confidence in our risk-based approach to renewals within this fleet. We continue to progress our replacement programme, which is risk prioritised and informed by known conductor type issues and validated by our RCA learnings. We will be in a position to revise the timeframes within which we plan to reduce this risk once we have completed the inspection of the network. We concurrently plan to enhance the modelling by incorporating condition data.
- **Ground mounted switchgear:** We continue to make progress on our oil filled ring main unit major maintenance programme resulting in greater confidence that the life of these assets could be extended in some cases. The number of H3 assets makes up a significant portion of the units above risk tolerance. Typically, at H3, switchgear has an assessed remaining life such that renewal is signalled but not expected until the latter part of our 10-year plan, i.e. it is not urgent.

In RY25 we introduced a new inspection programme to compliment the current maintenance activities. The health models will be updated to reflect the data obtained.

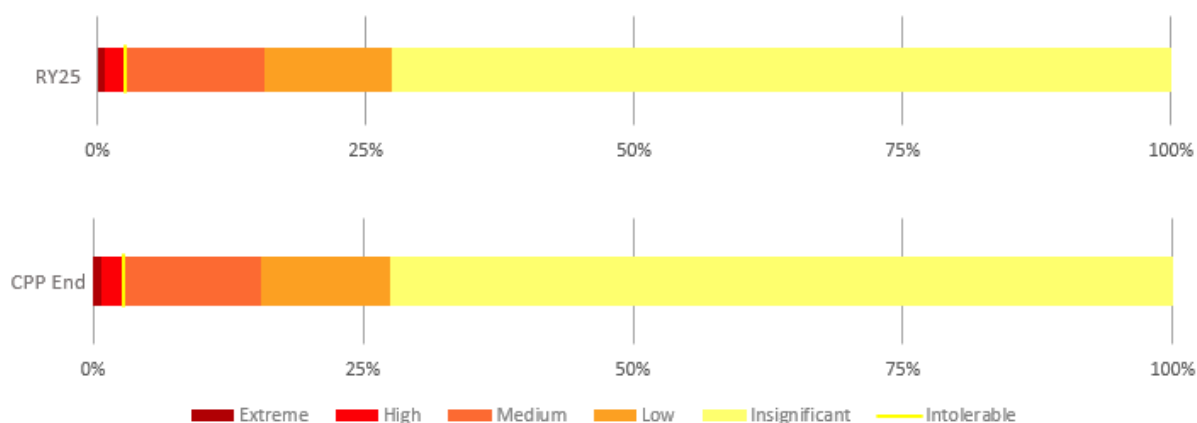
- **LV enclosures:** Having completed an invasive inspection programme, we have improved data on this fleet and we have responded to the inspection information, undertaking replacements as required. We are currently progressing a targeted renewal programme to replace the asset types with known issues, to further improve the risk position for this fleet. We expect to achieve the expected risk forecasts for these fleets by the end of the CPP Period. We also expect to see improvements once the model progresses in maturity, shifting from age based to capturing condition data.

Across our overall programme, several factors influenced our ability to achieve our forecast risk reduction, including:

- The re-allocation of contractor resources and capital budgets to meet higher than forecast levels of customer driven growth projects in RY25.
- Cost escalation has exceeded the forecast used when setting our CPP allowances. This has meant that the capital expenditure allowances are not sufficient to complete all works as forecast in the PPDP. We will continue to prioritise our renewals to best manage the impact of cost escalation on our planned risk reduction targets.
- Global supply chain issues that were experienced in earlier years of the CPP Period have had flow on impacts to the delivery of some projects and programmes. We note supply chain issues have not reduced the value of capital works delivered. Transfers and substitutions between projects and programmes have ensured that the overall plan is being progressed to the extent possible within the regulatory allowances. We have adjusted our procurement lead times for specific assets where supply is constrained as we progress into RY26.

Our revised view of the total network critical safety risk change as at 31 March 2025 is illustrated in figure 4 below.

Figure 4: Total network asset risk profile change



4.2. SAFETY-RELATED INCIDENTS

Aurora Energy's fundamental value is "Safety First – Safety First means people come first", which is described as "It's our No. 1 because we care about the safety and wellbeing of our team and community". This value underpins our approach to identifying, reviewing and, as necessary, taking corrective action regarding safety-related incidents on our network.

In section 9.4, we report on the number of safety-related incidents that present a risk to the public, our contractors or staff in each of our pricing regions.

We have continued to emphasise with our contractors the value in reporting all network related minor incidents, near misses and hazards. We are encouraged by the improved safety culture that is being established and pleased that we are seeing the reporting of minor incidents and near misses being positively reinforced.

This improving reporting culture makes it difficult to compare the number of incidents reported in the current year with previous years in which the culture was not as robust. Lessons learnt and corrective actions from reported events and investigation findings are shared and discussed through safety alerts, follow ups during site interactions, conversations with workers in the field, monthly contract meetings, open conversations with contractors, and via health and safety forum attendance and participation. Safety forums held in RY25 with our contractors have resulted in Aurora-led working groups involving contractor participation targeting specific improvement areas. These are all initiatives that we have established over the years and that are improving our safety culture.

In our previous ADR, we identified that we have been reporting the summation of incidents, near misses and uncontrolled hazards in our previous figures. We have continued this approach this year to ensure trends remain comparable, but it is relevant to note that the near miss and hazard reports are in effect leading indicators and opportunities for improvement before an incident occurs.

While we have seen an increase in both leading and lagging indicators between RY24 and RY25, our number of recordable injury incidents has not increased (17 in RY24, 15 in RY25). This provides context to the number of safety-related events that we are reporting in section 9.4 and demonstrates the value of our ongoing approach to ensuring all opportunities for risk reduction are reported.

In RY25, we implemented a new integrated risk management system that enables us to better map incidents to critical risks and their controls. This is helping us to target improvement activities into the right areas.

Third-party contact with our assets was again the largest contributing type of safety-related incidents on our network in RY25. Other key contributors to safety-related incidents during the year were asset failure, contractor work activities and use of vehicles.

Third-party contact with our assets incidents include vehicles striking low voltage service enclosures, vehicles hitting poles, underground cable strikes and contact with overhead lines. Third-party contacts accounted for 30% of all reportable events in RY25. We have continued our proactive public safety advertising campaign across various media channels. This has included specific messages targeted at our most frequent third-party contact event type, being vehicle contact with pillars. We

have also initiated a trial of high visibility markers on our pillars. We continued our support of the beforeUdig service, co-sponsoring their “Don’t play with your safety” advertising campaign.

The number of incidents involving asset failure has decreased since last year. This was due to a large decrease in asset failures in Dunedin, countered by a small increase in both our Central Otago & Wānaka and Queenstown networks. The overall decrease in asset failure incidents is primarily attributed to the targeted use of acoustic inspections to complement our routine asset inspection practices. We also continue to undertake asset failure investigations by reviewing RCA data and applying learnings to the wider network fleet through enhanced inspections and/or design changes. Vegetation contact with our assets continues to represent a low proportion of asset related incidents.

We are committed to contractor and staff safety in the field to ensure everyone goes home safely at the end of the day. The highest proportion of reportable events related to contractor work activities during RY25 were minor slips, trips, strains or sprains which reflects the ongoing focus of our field service providers on reporting of all minor incidents, near misses and hazards.

We continue to focus on driving and vehicle related incidents due to the high potential impact of related events. The most common events encountered arise from traffic management at worksites, and incidents encountered while driving to and from worksites. We continue to engage with local councils on effective traffic management practices, as well as our contractors and staff around safe driving practices.

We are also maintaining a close focus on operational safety and network reliability related incidents from a high potential impact point of view, even though they contribute a relatively small proportion (3%) of our total event numbers. Our operational teams continue to undertake both proactive and reactive improvement work to further reduce the frequency of these incidents.

5. DEVELOPING OUR PRACTICES

In March 2022 we published a Development Plan, which detailed how we planned to improve our business practices in certain areas throughout the CPP Period. We set out in the Development Plan the planned initiatives for the remaining years of the CPP that will result in Aurora Energy achieving its defined objectives for specific areas by the end of the CPP period.

In this Annual Delivery Report, we provide a summary of the progress that we are making in each of these areas and have assessed ourselves on a scale of 1 to 5 as to how well we are tracking based on the delivery of the planned initiatives in the Development Plan. We report on these in each of our Annual Delivery Reports.

What do our ratings mean?

- **1 – Not started:** no planned activities/initiatives have started
- **2 – Not achieved:** no planned activities/initiatives have been achieved
- **3 – Partially achieved:** less than 50% of planned activities/initiatives have been achieved
- **4 – Largely achieved:** 50% or more of planned activities/initiatives have been achieved, but not 100%
- **5 – Achieved/Exceeded plan:** 100% of planned activities/initiatives have been achieved or are progressing ahead of schedule

Our self-assessment rating is measuring delivery of our planned initiatives in each regulatory year. The rating does not assess our position in relation to our final goal at the end of the CPP period, but rather where we are, year-on-year, in delivering what we say we will deliver and therefore whether we are on track for our final goal.

5.1. ENSURING THE PUBLIC UNDERSTANDS ELECTRICITY PRICING

The way electricity pricing is set is changing, and we want to help customers understand these changes and what it means for them.

How prices are set for each pricing region (Dunedin, Central Otago and Wānaka, and Queenstown) is outlined in our pricing methodology which is published on our website. We evolve and update our pricing methodology each year in alignment with our pricing strategy, to make things easier for customers to understand.

We rate ourselves 5/5 for ensuring that the additional information that we disclose in our pricing methodology enables interested persons to understand how we set prices for each of our pricing regions.

We have rated ourselves this score because we have continued to publish the additional information in our pricing-related disclosures and have subsequently refreshed the information in our latest pricing methodology which we disclosed in March 2025. The additional information enables interested persons to understand how we set prices for each of our pricing regions, including a

worked example of how an average domestic customer’s price would be calculated in each pricing region. In addition, we have published our cost of supply model with supporting explanatory material on our website which shows how costs are allocated to each pricing region.

We continue to make progress against the pricing strategy and roadmap that we published in April 2021. The pricing strategy includes initiatives to make electricity pricing simpler and improve the cost-reflectiveness of prices. We expect our pricing strategy will be fully implemented by 2027.

During RY25, we have:

- **Refined our long-run marginal cost (LRMC) differentials:** Our published LRMC approach transparently demonstrates our rationale and calculations that support our time-of-use tariffs (ToU) in each pricing area. In RY25, for residential customers we implemented a mild price differential between peak and off-peak consumption. Over the next years, we will gradually move towards more cost-reflective tariffs, so that by 2027 our prices better align with the estimated LRMC for each area.
- **Improved information on our website:** We continue to update and improve the pricing information available on our website. In RY25, this included new frequently asked questions to help customers better understand how electricity pricing works and what it means for them.
- **Continued to engage with key stakeholders:** Between January and March 2025, Aurora Energy took part in several community events across the region, including the Brighton Gala Day in Dunedin, the Lake Hayes A&P Show, the Central Otago A&P Show in Omakau, and the Wanaka A&P Show. These events provided valuable opportunities to speak directly with customers about electricity pricing and hear their feedback.

5.2. LOW VOLTAGE NETWORK PRACTICES

Voltage limits are regulated to ensure satisfactory power quality levels can be achieved for customers. We are working on ways to continue to improve how we monitor power quality to identify emerging trends, including the identification of locations requiring power quality improvement, and do what we can to remediate them.

We rate ourselves 5/5 for developing our low voltage network practices during RY25.

| KEY ACTIVITIES / MILESTONES | RY22 | RY23 | RY24 | RY25 | RY26 |
|-----------------------------------|------|------|------|------|------|
| Reacting to monitoring | █ | | | | |
| Monitoring to anticipating | | | | | |
| DTM Programme and Field Work | | | | | █ |
| Hosting capacity study | | █ | | | |
| Network scenarios | | █ | | | |
| Hotspot modelling | | | █ | | |
| Anticipating to predicting | | | | | |
| Refine scenarios | | | █ | | |
| Predictive modelling | | | █ | █ | |

| KEY ACTIVITIES / MILESTONES | RY22 | RY23 | RY24 | RY25 | RY26 |
|-----------------------------|------|------|------|------|------|
| Standards and strategies | | | | | |
| Preventive solutions | | | | | |

We have rated ourselves this score because we:

- **Predictive modelling:** We have now completed further low voltage network analysis using the ANSA modelling tool and incorporated a static sample of smart meter consumption data into our modelling. This included running a future constraint risk model and associated LV capex model for investment planning based on the impact of PV/EV uptake forecasts. The results will enable us to assess emerging constraints and invest in network upgrades ahead of power/voltage quality issues arising for consumers.

Standards and strategies: We have reviewed and modified our voltage management standard and begun standardising transformer tap settings to improve low voltage network performance. We have also updated our residential after diversity maximum demand (ADMD) specification standard and lifted the criteria to enable greater DER penetration and reduce the likelihood of power quality constraints in new LV networks.

5.3. ENGAGEMENT ON CUSTOMER CHARTER AND CONSUMER COMPENSATION ARRANGEMENTS

Consumers are at the heart of our business, and we are committed to building a more customer-focused organisation that provides genuine benefits for consumers.

Our Customer Charter outlines what we are committed to, and what we expect in return from consumers so we can meet their expectations to deliver a safe, reliable and efficient electricity supply.

Our Customer Charter incorporates our customer service incentive payment scheme, which outlines how consumers are compensated if we fail to meet certain customer service incentives.

At the time the Development Plan was set, our Customer Charter had not been reviewed for some time and public knowledge about the Charter was low. We committed to changing that.

We launched a new Customer Charter in August 2024, following extensive review and a public consultation on the proposed changes. This was a year behind schedule because while we undertook external consultation with consumers on our new Customer Charter, we delayed publishing the new Charter while we considered the feedback received and engaged further with the Commerce Commission and electricity retailers.

We regularly promote the new Customer Charter both with the public and also with new staff to help us continue to build a customer centric culture at Aurora Energy.

We rate ourselves 5/5 for developing our engagement with customers on our customer charter and consumer compensation arrangement in RY25

| KEY ACTIVITIES / MILESTONES | RY22 | RY23 | RY24 | RY25 | RY26 |
|---|------|------|------|------|------|
| Initial review, consultation and launch of a revised customer charter and compensation arrangement | | ■ | | | |
| Increase knowledge of, and commitment to, our customer charter and compensation arrangement | | | ■ | | |
| Promote and celebrate Aurora Energy’s commitment to customer experience | | | | ■ | |
| Conduct a further review of the customer charter and compensation arrangement to ensure it remains fit for purpose and is well understood | | | | | ■ |

We have rated ourselves this score because, following the launch of our new customer charter and compensation arrangement in August 2024:

- **Increased knowledge of, and commitment to, our customer charter and compensation arrangement:** we have increased knowledge of, and commitment to our Customer Charter by making information available at public events such as A&P Shows, regular features in our community update ‘Your Network, Your News’ and on our social media channels. All new staff to Aurora Energy are given an induction session that includes information on the Customer Charter. We want to make them aware of how integral it is to how we operate, by putting consumers at the centre of our decision making.
- **Promoted and celebrated Aurora Energy’s commitment to customer experience:** we have produced a promotional video on the new Customer Charter that is available on our website and have shared this on our social media channels.

5.4. CUSTOMER OUTAGE PLANNING, MANAGEMENT AND COMMUNICATION

We are aware that no time is perfect for the power to go off, so we are committed to improving the way we plan, manage and communicate outages to minimise the impact on customers as much as we reasonably can.

To deliver on our network renewal programme, we know that the current elevated level of planned power outages will need to continue so we can carry out work to upgrade and maintain the electricity network safely.

We rate ourselves 2/5 for developing our planning, management, and communication of planned interruptions to customers during RY25

| KEY ACTIVITIES / MILESTONES | RY22 | RY23 | RY24 | RY25 | RY26 |
|--|------|------|------|------|------|
| Bundled works | | | | | |
| Increased use of bundled works | | | ■ | | |
| Develop reliability zones | ■ | | | | |
| Use reliability zones in outage planning | | ■ | | | |
| Stage gate process | | | | | |
| Develop stage gate process | ■ | | | | |

| | |
|---|---|
| Improve the ways in which we clean up our data | ■ |
| Implement data management controls | ■ |
| Implementing data audits | ■ |
| Introduction of new analytical tools for internal use | ■ |

We have rated ourselves this score because we:

- **Automated systems for collecting data from contractors:** We have implemented a central integration hub that will allow us to collate information received from our field service providers in a consistent manner. This has been implemented for static data and will be extended to dynamic data.
- **Implemented an asset management software solution:** The Rūma Mihīni project was launched to deliver an innovative asset and works management system with the goal of minimising touchpoints across the business. Having this system in place allows us to establish a reliable source of information and system which enables efficient, data-driven decisions about our network.

Planned processes have been delivered, and the system and three associated integrations with our FSPs are up and running.

Key accomplishments include:

- Development and deployment of the asset and work order management application – MaxiCloud
- Seamless integration with existing ERP and financial systems for procurement activities
- Completion of data migration from GIS
- Completion of integration of asset and location data with GIS
- Integration with FSPs to deliver work from Maximo
- Training conducted for all end-users and administrators.

The dedicated project team has now handed the system over to the business and we are considering how we can continue to leverage Maximo to build on Aurora Energy's digital asset management capabilities to further enhance our processes, improve data accuracy, reporting and increase operational efficiency within Aurora, our FSP's and approved contractors.

We have not yet retired all legacy asset and works management spreadsheets, and other technological debt (claim sites). We will do so once we have ensured that all asset data is managed via Maximo.

- **Developed and implemented a data integration hub:** Asset attribute data is captured in Maximo, geospatial data is captured GIS. The integration hub ensures data is automatically exchanged between the two systems and directly with the mobility solutions of our three field service providers. We have met with all three field service providers and have agreed project plans to integrate the next tranche of field service provider activities directly to our asset management system, including customer-initiated work, defects and inspection and maintenance work.
- **Implement data management controls:** A policy, standard and procedure have been written and are supported by a tool. As part of the migration to Maximo, the rationale of data capture has

been reassessed. The integration software allows for embedding data integrity rules. Completeness is ensured by the status within Maximo. Data integrity is maintained by preventative and reactive controls that can report on missing or incorrect data.

- **Introduction of new analytical tools for internal use:** We have made some of our asset management information available within PowerBI and have established foundational analytics across a number of areas to support asset management across the business. This is now a business-as-usual process and we will continue to leverage PowerBI to analyse various datasets as and when the need arises.

5.6. ASSET MANAGEMENT PRACTICES AND PROCESSES, INCLUDING SAFETY RISK

Continuous improvement in asset management is critical for us to meet our safe network objectives, operate successfully in a changing environment, meet customers’ evolving expectations, and address changes in network demand and technology. Our vision is to enable the energy future of our communities.

It is increasingly important that we continue to build on our existing asset management capability so we can enable the right investment on the right assets at the right time.

We rate ourselves 3/5 for developing our asset management practices and processes

We rate ourselves 5/5 for completing all the initiatives committed to in our development plan related to developing practices for identifying and reducing safety risk.

| KEY ACTIVITIES / MILESTONES | Ry22 | Ry23 | Ry24 | Ry25 | Ry26 |
|---|------|------|------|------|------|
| Strategy and Planning | | | | | |
| Strategic Asset Management Plan (SAMP) | | ■ | | | |
| Fleet Strategies and Plans | | ■ | ■ | | |
| Asset Information | | ■ | ■ | | |
| Asset Failure Modes | | ■ | | | |
| Define and Evaluate Risk | | | | | |
| Asset Health | | ■ | ■ | | |
| Asset Criticality | | ■ | ■ | | |
| Risk Evaluation | | ■ | ■ | ■ | |
| Asset Management Decision Making | | | | | |
| Align decision-making with risk | | ■ | ■ | ■ | |
| Define and monitor risk control effectiveness | | ■ | ■ | ■ | ■ |
| Define and document investment approval process | | ■ | ■ | ■ | |
| Live asset risk evaluation (aspirational) | | | | | ■ |
| Risk Management and Review | | | | | |
| Review our critical business risks | | ■ | | | |

| | |
|-----------------------------------|--|
| Risk treatment plan and ownership | |
| Governance Reporting | |

We have rated ourselves these scores because:

- **Strategic asset management plan:** We have started the development of our Strategic Asset Management Plan (SAMP) to more comprehensively capture the asset management strategy and objectives outlined in our AMP. We have prioritised the Fleet Strategies and development of other key asset management strategies such as our Reliability Strategy and our Vegetation Strategy. We have also developed an Asset Management Strategy Template which was used to develop a Reliability Strategy and Vegetation Strategy, documenting strategic intent with respect to Asset Management which will inform the SAMP. Our next step is to confirm identified focus areas for both the Reliability and Vegetation Strategies and subsequently develop an implementation plan. We also intend to use the Asset Management Strategy template to develop the Resiliency Strategy.
- **Fleet strategies and plans:** Fleet strategies and plans have been developed for all key fleets. These were used to inform our AMP24 and AMP25 forecasts. We have enhanced some AHI models. We undertook a Maturity Assessment of our fleet strategies since our last update and completed an independent review of the fleet strategies completed to date. The output of that review is informing a fleet-by-fleet improvement plan, or road map to what we deem to be the appropriate strategy documentation and modelling complexity, for Aurora, by fleet. With the independent review completed and roadmap set out, we are better positioned to ensure we have effectively prioritised improvement plans across all fleets.
- **Asset Information** Part of progressing the fleet strategies includes assessing the information required to determine asset condition/health, and putting in place the standards to enable us to better measure condition after considering the documented failure modes by fleet. This year we completed new inspection standards for Distribution Transformers, Ground Mounted Distribution Switchgear and LV Enclosures.
- **Asset Criticality:** We continue to utilise public safety criticality zones to inform public safety risks, enabling us to prioritise assets by health and by the safety criticality zone they are associated with. Documentation of a Reliability Criticality Framework is a focus area of our recently completed Reliability Strategy.
- **Risk evaluation:** We currently use the AHI modelling as a proxy for likelihood of failure in creating indicative asset risk assessment and forecast. Improving our health modelling will enable us to mature our approach to risk quantification and evaluation. This will come about as the likely correlation between AHI Grades and likelihood of failure is strengthened to quantitative relationship.

As we broaden the focus on our reliability strategy and reliability criticality framework, we will incorporate safety and reliability criticality into risk evaluation.

We have set out fleet specific targeted improvements with respect to the advancements we want to realise in our modelling – key to informing advancements in how we evaluate risk. Rather than investing now, in sophisticated technology to do quantitative risk analysis, our focus has been on ensuring we understand asset condition well, while continually improving data and modelling – both key to realising value of quantitative risk assessment.

We are using the feedback from RCA to build our understanding of the occurrence (specific to our network) of plausible failure modes documented in our fleet strategies. We are using the learnings to inform our understanding of assessed asset condition and health - through RCA and other programs of testing, we are validating and refining our modelling inputs.

- **Align decision making with risk:** The fleet strategies capture all plausible failure modes and the impact, against our corporate risk framework. While we have not progressed the use of these assessments to quantify relative risk, through the fleet strategies we are using our understanding of risk to inform required OPEX and CAPEX budgets to manage that risk. This year we undertook a maturity assessment and independent review of the fleet strategies and plans documented to date, and have subsequently documented a roadmap for each fleet.

We will continue to concurrently build our failure data and mature our ability to identify trends, before we can comprehensively use failure information from RCA to inform forecasts. However, we are realising benefits of RCA through being proactive in our response. To date this has included sharing workmanship related issues with contractors, amendments to our design standards, introduction of alternate models for some equipment (where we identified a systemic type related failure modes) and working with suppliers to share RCA findings and learnings including the issuing of safety alerts/notices.

We acknowledge that evolving beyond age-based renewal planning to a health-based approach can enable significantly enhanced investment decision making for some fleets. We are using evidence from new/improved inspection programmes, maturing our AHI models and the feedback loop from RCA on asset failures, and through these initiatives we are driving informed investment plans that target maintenance and renewal needs, but also help to inform overall improvement in AM practices.

- **Define and monitor risk control effectiveness:** This year we launched a cross-business project to bolster the work being done to understand the root cause of asset failures, this involves a review of standards and processes as well as significant system improvements to enable effective and efficient use of the data, and insights coming from the RCA.
- **Define and Document investment approval process:** In RY25 we completed a piece of work to document a Business Case Template and manual for use at Aurora, leveraging the 'Better Business Case' model developed by Treasury. We are currently testing the template as a pilot application to a network project.

We have implemented the cost estimation tool which incorporates stage gates for major projects, and we are working towards a defined level of scope definition to be in place for all projects and programmes in the 10 year plan, by stage gate.

Each of our fleet strategies documents how we realise our AM objectives at a fleet level, including additional steps that we might need to take to meet those objectives.

To improve our knowledge of how assets are performing and failing which allows us to target investment and ensure solutions are addressing the relevant cause, we are improving our understanding of vegetation risks, and taking a targeted approach to tracking and proactively managing 'Cause Unknown's.

5.7. COST ESTIMATION PRACTICES

Cost estimation practices inform the business cases for asset management decisions, the expenditure forecasts that drive regulated revenue determinations and our cashflow projections and funding requirements. It is important therefore, for our cost estimation processes to be as accurate as possible.

We rate ourselves 4/5 for developing our cost estimation processes

| KEY ACTIVITIES / MILESTONES | RY22 | RY23 | RY24 | RY25 | RY26 |
|---|------|------|------|------|------|
| Enhanced unit rate estimation | | | | | |
| Improved management of unit rates | | | | | |
| Volumetric project scope breakdowns | | | | | |
| Major project cost breakdowns | | | | | |
| Establish contract unit rates | | | | | |
| Enhanced project cost estimation tool | | | | | |
| Improve project cost estimation tool | | | | | |
| Including a broader range of projects | | | | | |
| Improvements to our network opex models | | | | | |
| Informed 'Base' expenditure | | | | | |
| 'Step' expenditure review | | | | | |
| Review our 'Trend' assumptions | | | | | |
| Review the vegetation forecast model | | | | | |
| Capture vegetation programme information in our systems | | | | | |
| Develop a 'Base Step Trend' or 'bottom-up' forecast model | | | | | |

We have rated ourselves this score because:

- **Major project cost breakdown:** Our tender documentation is now set up to receive detailed pricing breakdowns. We will now document how we will use the cost data to inform the unit costs in our cost estimation book.
- **Continue to establish additional contract unit rates:** In addition to the more than 50 unit rates for maintenance and defect activities that were included in the agreements with our primary service provider in RY24, we have negotiated additional unit rates with our Field Service Providers for activities such as consumer pole replacements.
- **Including a broader range of projects in our cost estimation tool:** The cost estimation tool currently covers all zone substation work and some distribution reinforcement projects. In some cases, the tool is sufficiently developed and therefore only requires application to the broader range of projects. The major project cost estimation stage gate process and tool that was previously developed has been used again to develop our AMP25 forecasts. The development phase of this new process is complete and subject to continuous improvement.

- **Have enhanced access to vegetation programme information in our systems:** We now have enhanced access to vegetation programme information via new dashboards developed with our field service providers. We are capturing and reviewing vegetation related faults on our network, to enable improved visibility of the effectiveness of our programmes and risks in relation to hazard trees; helping to inform future investment requirements in light of potential regulatory change. During RY25, we documented a Vegetation Management Strategy, with a key focus on future information and system requirements.
- **Have developed a ‘Base Step Trend’ or ‘bottom-up’ forecast model:** We have set up the Base-Step-Trend model for Vegetation forecasting. We expect that the improved visibility of data from our field service providers and supporting systems, will enable enhanced forecasting of required expenditure going forward.

5.8. QUALITY ASSURANCE PRACTICES

It is important that all work undertaken to upgrade and maintain the electricity network meets the relevant regulatory standards and is delivered as efficiently and effectively as possible. Our increased work programme throughout the CPP Period means it is even more important to have robust quality assurance processes and resources in place.

We rate ourselves 5/5 for developing our quality assurance processes

| KEY ACTIVITIES / MILESTONES | RY22 | RY23 | RY24 | RY25 | RY26 |
|---|------|------|------|------|------|
| Works management capability improvements | | | | | |
| Develop and implement process improvements | █ | | | | █ |
| Continuous staff development | █ | | | | █ |
| Construction works quality assurance improvements | | | | | |
| Develop construction works review standard | | █ | | | |
| Extend scope of construction works reviews | | █ | █ | | |
| Incorporate quality assurance metrics into wider contractor performance metrics | | █ | | | |
| Review resourcing | █ | | | | |
| Staff training and development improvements | █ | █ | | | |

We have rated ourselves this score because we:

- **Continue to develop and implement process improvements relating to works management capabilities:** Early in RY25 we engaged Leva Advisory to provide a project health check. In addition, we asked KPMG to review our Works Pipeline and Tender processes to identify process improvements. These reports each provided recommended actions to improve our ability to deliver the significant workload more efficiently. We have stood up a progress sub-group within the team to implement actions from the two reports, such as merging our SharePoint document management sites between the Dunedin and Cromwell teams to provide consistent guidance between the two regions. The process subgroup will continue to meet regularly to identify and implement changes.

- **Continuous staff improvement in works management capability:** We have continued to train and upskill in the PRINCE2 methodology, with all current project managers having achieved Prince2 certification within 90 days of employment. In addition, safety observations continue to be performed by the team to extend the team’s health and safety construction knowledge. In addition, the project managers have completed NZS 3910:2013 Conditions of Contract training, with refresher training planned once the business implements the updated 2023 version. Our project managers also complete “Understanding National Utilities Code” and Inspector training for working on roads, and support is provided for those new to the electricity industry to complete the Electricity Supply Industry, Level 2 course.

6. ENGAGING WITH CONSUMERS

Consumers are at the heart of Aurora Energy. In this section, we detail how we have engaged with the consumers on our network throughout RY25, how we are taking into account the feedback that we are receiving, and our performance against Aurora Energy’s Customer Charter and Customer Service Incentive Payment Scheme.

6.1. ENGAGING WITH CONSUMERS AND KEY STAKEHOLDERS

We rate ourselves 5/5 for how effectively we have engaged with different consumers in each of our pricing regions

What does our rating mean?

- 1 – Did not engage with any consumers
- 2 – Engaged with consumers via less than three channels and not in all pricing regions / did not consider feedback
- 3 – Engaged with consumers via less than five channels and in all pricing regions / considered some feedback
- 4 – Engaged with consumers via less than ten channels and in all pricing regions / took into account feedback
- 5 – Engaged with a variety of consumers and stakeholders via more than ten channels and in all pricing regions / took into account feedback

We have rated ourselves this score because:

- We have an extensive communications and engagement plan that enables us to engage with many of our stakeholders and different groups of consumers across our entire network throughout the year, which we demonstrate below. We regularly review our plan to ensure it continues to meet both consumer and business needs.
- We have given effect to feedback received from consumers via various channels.
- Customer perceptions continue to improve, with results from the 2025 customer satisfaction survey showing year-on-year improvements in customer perceptions for performance, knowledge of and confidence in Aurora Energy.
- We continue to ‘get under the hood’ of survey results and despite the overall positive trends, we held focus groups in the areas where perception of our performance was not so positive. The general objective of these focus groups was to identify areas in which we can improve our service levels, communications and customer processes.
- We have worked proactively with our field service providers, who are often the face of Aurora Energy in the field, to share information about consumer needs and to improve customer experiences. Our interactions with field service providers have focused particularly on the

impact of planned power outages on consumers, and how together we can best mitigate the inconvenience and disruptions they can cause.

Stakeholder engagement

During RY25 we engaged with a wide variety of stakeholder groups:

- **General consumers:** We engaged with general consumers across our network by:
 - Publishing our newsletter, ‘Your Network, Your News’, which was inserted in community newspapers in Dunedin, Wānaka, Queenstown and Central Otago in May and November 2024. This newsletter provides consumers and stakeholders with updates on major projects and programmes of work being undertaken across the Aurora Energy network, and gives us a means of communicating other important messages to our community, such as public safety reminders, updates on changes relevant to the electricity sector and energy choices, pricing, sustainability and community engagements.
 - Publishing a full-page advertorial in community newspapers in Dunedin (The Star), Central Otago (Central Otago News), Wānaka (Wānaka Sun) and Queenstown (Mountain Scene), in August 2024 and February 2025.
 - Undertaking our public safety advertising campaign across several media channels that highlights and promotes public safety issues. The content is seasonal and changed each month.
 - Hosting stalls at the 2025 A&P shows at Lake Hayes, Central Otago (Omakau) and Wānaka, and the 2025 Brighton Gala Day in Dunedin, where we provided an opportunity for consumers to engage directly with Aurora Energy staff.
 - Hosting public forum events in October 2024 in Dunedin and Cromwell to engage on our RY24 ADR.
- **Business community:** We sponsored the inaugural ‘Electrify Queenstown’ event in June 2024. This was hosted by the Queenstown Chamber of Commerce and Destination Queenstown, with attendees from Central Otago also attending. We also hosted a Business After 5 event in September 2024 with Business South (the Chamber of Commerce) in Dunedin. The focus of our presentation was on how we can enable businesses to electrify their operations, and there was the opportunity for attendees to engage directly with members of our executive leadership and senior management team. We have been working with other Chambers of Commerce throughout Otago to see if we can host similar events with a focus on sustainability and the future of electricity.
- **Major customers:** Members of our executive leadership team and senior management team have engaged directly with major consumers on our network, and the Senior Relationship Manager has engaged on operational matters.
- **Councils:** Members of our executive leadership team have established positive and effective relationships with Queenstown Lakes District Council, Central Otago District Council and Dunedin City Council and engage with them when required. This follows an initial schedule of meetings some years ago to build awareness, knowledge and trust.
- **Consumers impacted by multiple planned outages:** Where consumers have been impacted by multiple planned outages due to bundled work programmes, we have directly corresponded

with them to provide information about what work is being done as well as our five-year investment programme. In situations where a significant amount of work is undertaken within a community, we have provided support to a local initiative that will benefit the wider community, as a thank you.

Stakeholder feedback

We provide consumers and key stakeholders with the opportunity to provide feedback on any aspect of our services, in person at any of our events, to us directly via our Customer Experience Team by phone or in writing, or via our website. For the most part, consumer feedback is specific to that individual's circumstances. We continue to receive complimentary feedback from consumers in relation to the timeliness of fault response, our work to upgrade and maintain the network, and the helpfulness of our customer experience team/fault response crews.

We did not receive any specific feedback from consumers or stakeholders on the RY24 Annual Delivery Report that we presented in October 2024. We also did not receive any feedback in relation to our pricing methodology disclosures that were published in early 2025. We did not undertake any specific consultation in relation to the pricing methodology disclosures in RY25 because in RY22, we undertook extensive pricing consultation.

We also gather feedback from consumers via annual customer satisfaction surveys as discussed above. We want to continue building on the positive customer engagement that we have established over recent years so also arranged for independent focus groups to be held in areas of the network where we know there is room for improvement.

Learning and insights from handling complaints

We actively use the insights gained from customer complaints to improve our service levels where possible. Historically, the majority of complaints have stemmed from both planned and unplanned outages experienced by consumers. Analysing these trends has helped us strengthen our customer service initiatives.

Our customer experience team also works to ensure that other parts of the business are taking into account the feedback we are receiving and learnings we are taking from complaints. Our goal is to minimise the impact of planned outages on consumers as much as possible, particularly for consumers located in areas where reliability does not meet current expectations.

The types of complaints that we have received in the greatest numbers during RY25 are, in most cases, similar to those that we received in RY24 and RY23. The highest number of complaints received were for voltage quality, with an increase in the number of complaints from the prior year. For the third year running, we have seen a reduction in the number of contractor behaviour related complaints as we continue to proactively engage with our contractors and provide feedback. The number of complaints related to the frequency of outages compared with the previous year remains the same, and we acknowledge the impact our five-year work programme has on consumers. We continue to refine the Customer Outage Guidelines, which are designed to mitigate the consumer impacts of planned work. The number of complaints for unsuitable timing of planned outages has reduced significantly from the prior year.

Reprioritised or substituted capital and operational expenditure projects and programmes

We rate ourselves 4/5 for any consultation that we have done with consumers on capital expenditure or operational expenditure projects or programmes that we propose to reprioritise or substitute.

We rated ourselves this score because, as signalled in our PPDP, information about reprioritisation was included in the May 2024 issue of Aurora Energy’s community newsletter ‘Your Network, Your News’. In addition to this, we continued to gauge the level of involvement consumers wanted to have if we needed to amend the five-year investment plan. The results showed the majority of respondents were satisfied with little involvement, so long as Aurora Energy let the public know about any changes. We undertook extensive consumer engagement during the development of our CPP application and this feedback, together with continuing to understand consumers’ views via our extensive consumer engagement schedule, continues to inform our decision making. We had ongoing targeted conversations during RY25 with councils and consumers who made growth-related enquiries and responded to meet their requirements where appropriate. We also engaged with key stakeholders in the Upper Clutha region in relation to options to support growth in the area.

6.2. OUR CUSTOMER CHARTER AND CUSTOMER SERVICE INCENTIVE PAYMENT SCHEME

We launched a new Customer Charter in August 2024, which incorporates our customer commitments and customer service incentive payment scheme. It replaced our original Charter that had been in place since 2017 and needed to be updated to better reflect the customer service attributes that consumers value. Please see section 5.3 for further detail on how we have improved awareness of the new Customer Charter.

We are committed to reporting on progress against the service levels in the new Customer Charter and have put a robust framework in place to ensure Aurora Energy is accountable for the promises we make to consumers.

Our Customer Charter outlines the service levels we are committed to, and how consumers may be compensated if we do not meet those service levels. It also outlines what we need from consumers so we can meet their expectations to deliver a safe, reliable and efficient electricity supply.

During RY25, service failure payments were made for the following:

- Failing to give at least ten working days’ notice, via a consumer’s electricity retailer, of a planned interruption (\$20 credit, inclusive of GST until the new Charter was launched on 20 August, when the credit increased to \$40). In RY25, we paid out \$37,635 (exclusive of GST) in respect of failing to meet this service commitment.
- Failing to restore power after an unplanned interruption within set service level timeframes (if it is safe to do so) – 4 hours for urban consumers and within 6 hours for consumers in all other areas¹ (\$50 credit, inclusive of GST, for residential consumers or one month’s line charges for

¹ Urban areas are defined as Dunedin, Mosgiel, Queenstown, Wanaka, Cromwell and Alexandra. The urban areas are defined as being within the 50km/h speed zone boundaries. Rural and remote-rural consumers are all consumers who live outside the urban areas.

non-residential). In RY25 we paid out \$117,825 (exclusive of GST) in respect of failing to meet this service commitment. This service failure payment is no longer part of our customer compensation arrangement and stopped being paid from 20 August 2024.

- Failing to respond to any power quality complaints within 7 working days of receipt (\$50 credit, inclusive of GST). In RY25, we did not make any credit payments for not meeting this commitment because we achieved the timeframe in all instances.

The following factors contributed to the service failure payments we made in RY25:

- The new outage management system introduced in 2022 has made a significant improvement in our outage notification processes. The number of missed retailer notifications has almost halved compared to RY24. (The slight increase in credit payments compared to RY24 reflects the credit value increasing from \$20 to \$40.)
- Restoring power within the service level timeframes for an unplanned interruption is not always possible when the location of the fault is remote or the fault repair is complex. The number of customers affected by unplanned interruptions outside the set service level timeframes in RY25 reduced by more than half compared to RY24. (The reduction in RY25 charter payments reflects fewer affected customers compared to RY24 and the removal of the service standard from the customer charter partway through RY25.)

7. FEEDER PERFORMANCE

We have 234 distribution feeders across our network. In this section we identify the worst performing feeders for RY25 and outline any plans for improvement of those feeders. The worst performing feeders have been defined by the Commerce Commission as being those feeders on our network that are in the top 90th percentile or higher due to that feeder's contribution to network SAIDI or network SAIFI during RY25. While this definition of worst performing feeders is useful at a high level, it does have limitations:

- The SAIDI and SAIFI associated with planned interruptions is combined with the SAIDI and SAIFI associated with unplanned interruptions, which can mask underlying network performance issues.
- There is no consideration given to the network topology/geography where urban networks are expected to outperform remote rural networks.
- Consumer experience (number and duration of interruptions experienced) is not accurately reflected.

As a result, several feeders have been identified as worst-performing due to the high proportion of planned SAIDI and SAIFI associated with that feeder. We have not provided specific improvement plans for these feeders unless they also have poor unplanned interruption performance. We acknowledge that planned interruptions are an inconvenience to consumers, and we continue to look for opportunities to improve our practices to minimise the impact of planned interruptions (see section 5.4 above). Our planned outage work is essential to achieving a safe network and safe work practices for our contractors. We believe that the investment we are making will reduce the probability of asset failure and therefore provide long-term unplanned reliability improvements for consumers.

Feeders with higher customer numbers will accrue higher SAIDI and SAIFI values in the event of an interruption. The worst-performing feeders identified here typically have higher consumer numbers (approximately 23% of our consumers are connected to these 30 feeders). Using network SAIDI and SAIFI to gauge feeder performance means that feeders with lower ICP counts do not feature. For this reason, we have developed our own internal metric for identifying reliability performance hotspots. For each feeder, we have identified target unplanned SAIDI and SAIFI values based upon circuit type and configuration, circuit length, and number of consumer connections, which is a method we believe enables us to better target our response to address customer impact.

In past years we have incorporated internal reliability performance reviews as part Feeder Performance reporting. This approach (Hotspot Programme) has aided the identification and a response to poorer performing parts of our network. The Hotspot programme identified the 10 worst performing feeders based on our internal metric. The approach has continued to evolve and is now incorporated into ongoing routine reviews of reliability performance, rather than an annual review. Refer to Appendix E of AMP 2025 for a summary of reliability performance improvements. This maturing of approach has seen us transition from an annual lagging review to a leading indication of emerging performance issues across the network, enabling us to be more proactive in the identification of emerging hotspots.

Table 1 below includes detail for each of the worst performing feeders identified using the Commerce Commission’s methodology. Planned and unplanned SAIDI/SAIFI have been colour coded to indicate their contribution to the worst performing feeder status. Red cells indicate that an individual planned or unplanned value was enough to trigger the threshold value for worst performing feeder. Orange cells indicate that both planned and unplanned values combined were required to trigger the threshold value.

Table 1: RY25 Worst Performing Feeder details

| FEEDER ID | PLANNED SAIDI | UNPLANNED SAIDI | PLANNED SAIFI | UNPLANNED SAIFI |
|-----------|---------------|-----------------|---------------|-----------------|
| AT7652 | 0.18 | 1.15 | 0.0030 | 0.0276 |
| AX167 | 3.04 | 2.04 | 0.0102 | 0.0209 |
| AX168 | 1.29 | 12.34 | 0.0034 | 0.1079 |
| AX169 | 2.42 | 1.11 | 0.0069 | 0.0113 |
| CE190 | 3.62 | 1.09 | 0.0135 | 0.0319 |
| CG5730 | 2.55 | 0.43 | 0.0083 | 0.0181 |
| CH2006 | 0.81 | 8.34 | 0.0048 | 0.0861 |
| CM821 | 2.96 | 2.03 | 0.0089 | 0.0260 |
| CM832 | 11.15 | 1.90 | 0.0243 | 0.0088 |
| CM838 | 0.77 | 1.60 | 0.0038 | 0.0205 |
| EK480 | 4.43 | 3.34 | 0.0132 | 0.0428 |
| ET5 | 3.05 | 0.13 | 0.0086 | 0.0027 |
| ET9 | 0.93 | 0.19 | 0.0102 | 0.0172 |
| FH5309 | 0.29 | 1.31 | 0.0026 | 0.0285 |
| FH5310 | 0.00 | 2.50 | 0.0000 | 0.0284 |
| FK7782 | 3.40 | 0.78 | 0.0135 | 0.0186 |
| FK7783 | 3.36 | 0.00 | 0.0112 | 0.0001 |
| FK7784 | 11.46 | 0.97 | 0.0249 | 0.0277 |
| GI12 | 2.76 | 0.02 | 0.0064 | 0.0035 |
| HB13 | 0.72 | 0.93 | 0.0128 | 0.0140 |
| MG3 | 3.24 | 0.00 | 0.0290 | 0.0007 |
| OM656 | 0.67 | 7.24 | 0.0049 | 0.0590 |
| OT2 | 5.85 | 0.66 | 0.0135 | 0.0104 |
| PC3 | 3.85 | 2.99 | 0.0094 | 0.0191 |
| QB2423 | 0.66 | 3.58 | 0.0020 | 0.0377 |
| RB4637 | 3.53 | 1.06 | 0.0104 | 0.0256 |
| WB3 | 3.38 | 0.07 | 0.0091 | 0.0005 |
| WK2755 | 2.48 | 2.79 | 0.0064 | 0.0382 |

| FEEDER ID | PLANNED SAIDI | UNPLANNED SAIDI | PLANNED SAIFI | UNPLANNED SAIFI |
|-----------|---------------|-----------------|---------------|-----------------|
| WK2757 | 1.83 | 0.91 | 0.0048 | 0.0252 |
| WK2758 | 0.87 | 2.04 | 0.0138 | 0.0325 |

Unplanned performance

For the 30 worst performing feeders identified in RY25 (Commerce Commission Approach), several have also exceeded our internal unplanned targets. Where we have identified the need for intervention our plan to improve feeder performance is provided alongside the feeder maps below.

In addition to feeder-specific improvements, we have also progressed some general reliability improvements:

- **Asset failures:** We capture failure information for all unassisted asset failures and review the information to help identify root cause. Where we identify common trends, we use these learnings to improve our strategies around asset inspection and renewals. Overall, we aim to reduce the impact of defective equipment on unplanned SAIDI/SAIFI.
- **Vegetation:** We have identified that an increasing proportion of vegetation SAIDI and SAIFI is due to trees outside the Growth Limit Zone. Due to limitations around the current Tree Regulations, we have limited authority to remove high risk trees on our network. To prepare for upcoming changes in these regulations, we have implemented a register of known hazard trees on our network.
- **Unknown Causes:** We have identified the risk of unknown outages on the network that recur until the root cause is correctly identified. In some cases, customers can experience loss of supply several times before the issue is addressed. We are now actively monitoring feeder performance to detect feeders that are experiencing multiple unknown outages within a short timeframe – we then conduct further analysis to determine whether further action is required.
- **Subtransmission Faults:** Several worst performing feeders in RY25 have experienced loss of supply due to faults on the subtransmission network. We have carried out further reviews and inspections on two Central Otago subtransmission circuits to address the frequency of unplanned outages.

Planned Performance

For efficiency purposes, much of our asset inspection and remediation programme is on a 5-year feeder rotation and when we enter an area, we often bundle large work packages on individual feeders to help reduce the overall number of planned outages required. The 5-year rotation can mean that some customers experience multiple outages within a single year, rather than having them spread evenly across multiple years. We also have planned outage guidelines in place to help limit the inconvenience placed on consumers. In general, we do not see high annual planned SAIDI/SAIFI values as an indicator of poor reliability, but we will monitor for any feeders that experience a large number of planned outages across several years.

Worst performing feeders

Dunedin city area



Feeder GI12 – Green Island

Worst performing status is due to high planned SAIDI/SAIFI so no improvement actions have been planned for this feeder.

Feeder HB13 – Halfway Bush

This feeder experienced two vegetation faults at the same location due to a row of hazard trees that are outside the growth limit zone. The cost of removing these trees may prove prohibitive, so we are looking at options to reconfigure the network to reduce the impact on customers if further tree faults occur.

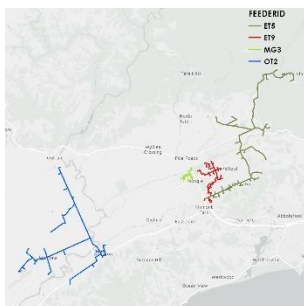
Feeder PC3 – Port Chalmers

This feeder experienced high unplanned SAIDI and SAIFI, but it did not exceed our internal expected unplanned performance for RY25. Unplanned circuit performance in past years has generally been caused by out of zone vegetation. We await further updates to the Tree Regulations to enable a more proactive approach to managing out of zone vegetation.

Feeder WB3 – Willowbank

Worst performing status is due to high planned SAIDI/SAIFI, so no improvement actions have been planned for this feeder.

East Taieri area



Feeder ET5 – East Taieri

Performance dominated by high planned SAIDI so no improvement actions have been planned for this feeder.

Feeder ET9 – East Taieri

This feeder experienced high unplanned SAIFI due to an isolated outage event in May 2024. Crews had identified an issue with a switch during planned works and the issue required a brief unplanned outage to the entire feeder to resolve. No performance improvement plans are in place.

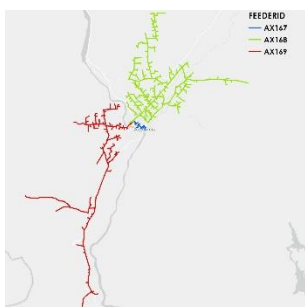
Feeder MG3 - Mosgiel

Performance dominated by high planned SAIDI so no improvement actions have been planned for this feeder.

Feeder OT2 – Outram

This large rural feeder did not exceed our internal interruption target, and the outages were due to a range of different causes. No improvement actions have been planned for this feeder.

Alexandra area



Feeder AX167 – Alexandra

This feeder experienced a single unplanned outage in RY25. Network configuration at the time of the fault meant that the feeder was supplying significantly more customers than normal, resulting in an increased SAIDI and SAIFI impact. No improvement actions have been planned for this feeder.

Feeder AX168 – Alexandra

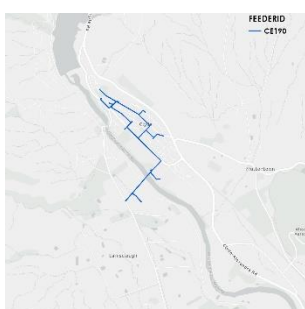
The feeder experienced several cause unknown outages earlier in the year. In September, we identified the issue as line clashing caused by a poorly designed line upgrade that was installed two years earlier. The issue was resolved.

Also in September 2024, we experienced a significant snow event on the network. We noted two line down events due to failed line splices – our new overhead inspection programme proactively identifies poor connections, enabling us to target this failure mode. The SAIDI impact from these events was exacerbated by poor weather conditions, and challenges locating and repairing several faults.

Feeder AX169 – Alexandra

Worst performing status was driven by a combination of planned and unplanned SAIDI. Unplanned performance was within our internal targets, so no actions have been planned.

Clyde/Earnsclough area

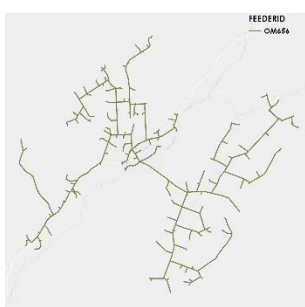


Feeder CE190 – Clyde/Earnsclough

In September 2024 we experienced a significant snow event on the network. During this snow event, this feeder experienced an unplanned interruption due to a failed line splice. These issues are now being proactively identified as part of our overhead inspection programme.

Two other major faults were due to switching errors during planned works which were quickly resolved however had high SAIFI impacts.

Omakau area

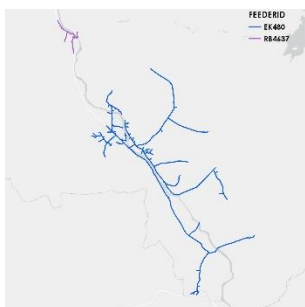


Feeder OM656 – Omakau

This feeder has been consistently one of the highest contributors to unplanned SAIDI/SAIFI in recent years. Due to the configuration of the circuit, previous efforts to improve performance have had limited impact. As a part of the RY25 upgrade of Omakau zone substation, we reconfigured this feeder into four separate feeders. Now rather than an outage on the circuit potentially resulting in a loss of supply to all consumers connected to the zone substation, outages on an individual feeder will only impact those ICPs connected to that feeder. However, the Omakau zone substation remains an N security substation supplied by a single sub-transmission circuit.

During RY25, a significant rain event saw extensive flooding in the area, which resulted in a pole becoming unstable due to rising river levels. The significant snow event in September also resulted in a failed conductor joint. We are working to identify and address conductor joint issues through our overhead inspection programme. For the OM33 sub-transmission circuit specifically, our early fault detection trial commenced in May 2024 and has helped to identify a number of defects on this line that have been addressed prior to failure. We continually monitor circuit performance to identify new defects as they emerge.

Roxburgh/Ettrick area



Feeder EK480 – Ettrick

One-third of the unplanned SAIDI impact on this feeder was due to vegetation outside of the growth limit zone. With owner agreement, we have cleared hazard trees on one site that has seen multiple faults. We expect that future changes to the Tree Regulations will help us to manage other high-risk sites in future.

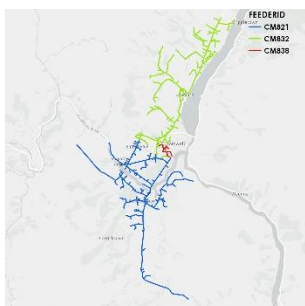
This feeder also experienced multiple outages due to faults on our subtransmission lines. We have carried out advanced inspections on our subtransmission lines from Alexandra to Roxburgh and have addressed identified issues.

Feeder RB4637 – Roxburgh

Similar to EK480, much of the unplanned impact on this feeder was due to subtransmission performance. We believe the issues to be resolved by follow-up inspection and repairs.

The only other feeder fault was due to fast-growing vegetation that had encroached the growth limit zone. We have seen very few in-zone vegetation faults in recent years, but we continue to identify areas for improvement in our vegetation management programme.

Cromwell area



Feeder CM821 - Cromwell

This feeder experienced two main faults in RY25. The first was due to a significant snow event that we experienced on the network in September 2024 – High SAIDI and SAIFI was accrued due to the challenging conditions and terrain when trying to repair the fault. The second fault was due to orchard netting that had become tangled in overhead lines due to high winds.

We consider these faults to be isolated events, and no improvement initiatives have been planned for this feeder.

Feeder CM832 – Cromwell

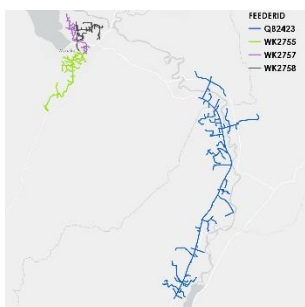
Performance dominated by a high planned SAIDI and SAIFI so no improvement actions have been planned for this feeder.

Feeder CM838 – Cromwell

CM838 is a short urban feeder with a low fault target. In RY25, the feeder experienced a cable fault. Network configuration at the time of the fault meant that the feeder was supplying significantly more customers than normal, resulting in an increased SAIDI and SAIFI impact.

There are multiple feeder reconfiguration projects identified in our AMP25 to address feeder security and growth in Cromwell in coming years.

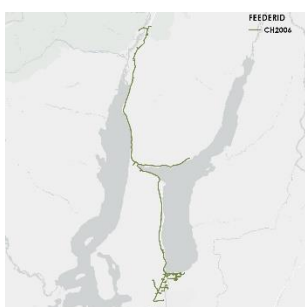
Wanaka area



Feeders WK2755, WK2757 and WK2758 – Wānaka

The network experienced a major fault on the Upper Clutha 66 kV lines in March 2025 which was a main contributor to unplanned performance of these Wānaka feeders. One Upper Clutha circuit was out for maintenance when the other circuit tripped, resulting in a widespread outage in the area. We take great care in scheduling planned outages on these lines to ensure necessary maintenance is completed while minimising any risk of customer outages.

We also had two equipment failures which generated high SAIDI/SAIFI impact on these feeders. WK2755 had a fault in July 2024 relating to a set of capacitor banks that failed in service. We have since implemented a solution to ensure that customers are not affected if the assets were to fail again. WK2758 had a set of links fail due to a clamp failure. These links have since been replaced by an air break switch.



Feeder CH2006 – Camp Hill

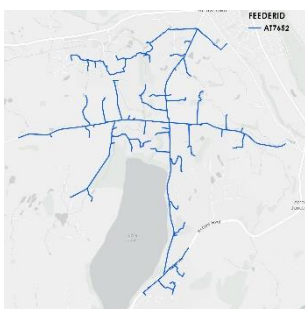
This feeder has seen an increase in unplanned performance in RY25, particularly since December 2024. The entire feeder lost supply four times in total – twice due to cable faults. The long rural section of the feeder that heads towards Makarora also experienced a high number of outages due to a mix of causes – defective equipment, vegetation and wildlife.

The Hāwea township has experienced significant growth in recent years, and as a result, this feeder now supplies over 1,100 ICPs. Given the recent performance issues, we are looking at means to reconfigure the feeder to reduce the number of customers affected by faults and enable faster restoration. We are also looking at adding another recloser in the rural section of the feeder to reduce the number of customers affected when outages occur in this area. Given the number of cable faults affecting this feeder, we are also undertaking additional asset inspections to reduce the likelihood of further faults.

Feeder QB2423 - Queensberry

The QB2423 feeder covers a large rural area and it has a high unplanned target as a result. We have seen no concerning trends in the feeder’s performance for RY25 and no specific improvement actions are planned.

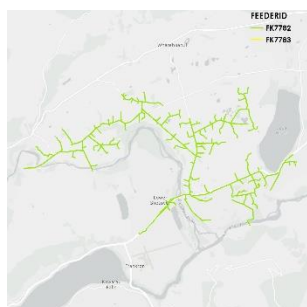
Arrowtown area



Feeder AT7652 – Arrowtown

This feeder shows no obvious trends of worsening performance that requires action. One of the major outages was due to a switching error during a planned job which also impacted the AT7632 feeder. We also saw two outages with unknown cause, but they were five months apart and unlikely to be associated.

Queenstown area

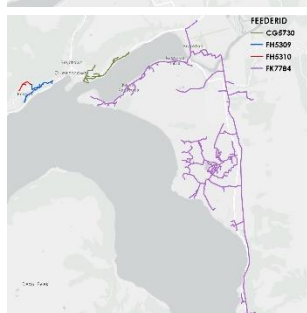


Feeders FK7782 and FK7783 – Frankton

Performance dominated by a high planned SAIDI so no improvement actions have been planned for these feeders.

Feeder FK7784 – Frankton

Performance dominated by a high planned SAIDI so no improvement plans are planned for these feeders. Unplanned SAIFI was high due to an oversized vehicle that required a short-notice disconnect to pass safely under our lines. 1,600 ICPs were affected for 3 minutes in total.



Feeders FH5309 and FH5310 – Fernhill

FH5309 and FH5310 were both affected by a substation-wide outage in April 2024. Due to works in the Fernhill substation at the time, these feeders had been reconfigured and were carrying over 1,800 ICPs when generally they only supply a few hundred ICPs each.

This event has been reviewed from an operational perspective and process improvements undertaken but no network improvement actions have been planned for the feeder.

Feeder CG5730 – Commonage

CG5730 is an urban underground feeder that generally experiences strong reliability performance. In RY25, the feeder experienced two significant faults – the first due to a car versus pole incident on a subtransmission line which briefly affected several feeders, and the second due to the urgent replacement of a defective ground-mounted switch. At this stage, we do not anticipate further issues on this feeder, but we will continue to monitor performance.



8. MID-PERIOD EXPERT REVIEW

In February 2024, Aurora Energy publicly disclosed two reports that had been prepared by independent experts (Farrierswier and Energy Networks Consulting) in relation to Aurora Energy’s progress in a number of areas during the CPP Period.

The following is a summary of the recommendations that were made by the independent experts and the actions that Aurora Energy has taken in response to those recommendations.

| RECOMMENDATION | ACTION TAKEN |
|---|---|
| Energy Networks Consulting | |
| Justify material changes in the approach to managing an asset type | Content has been included in chapter 11 of our Asset Management Plan. |
| Explain divergences between expenditure and the trend of the underlying investment driver. | Noted. We will consider this when preparing future regulatory disclosures. |
| Provide sufficient data on volumes and unit costs to provide a better understanding of whether Aurora is meeting its forecast delivery programs. | Asset replacement and renewal quantities and average cost are disclosed in each ADR and compared with equivalent forecasts in the PPDP, in accordance with Information Disclosure requirements determined by the Commerce Commission. We will continue to assess whether there is additional information on volumes and unit costs we can provide outside of the ADR and efficiently in the future. |
| Consistent use of project names and references between the various documents. | We have ensured that project names in this ADR match those used in the PPDP. |
| Expand communication to customers to discuss how and why reprioritisation and substitution of capital or operational expenditure was undertaken and the impact on network risk. | Noted. We considered this when preparing the May 2025 edition of YNYN. |
| Provide more information to explain differences in costs of monitoring the LV network compared to CPP Determination and how it relates to the roadmap initiatives. | Once ANSA's DG hosting and LV capex model has been developed, we will be able to consider the costs of monitoring versus CPP expenditure. |



| RECOMMENDATION | ACTION TAKEN |
|--|---|
| <p>Include further information when publishing power quality performance, including number of instances where standards were breached, areas affected, complaints information and percentage of network being monitored.</p> | <p>Noted. Aurora will consider this and the value of sharing statistics from our PowerQuality dashboard.</p> |
| <p>Improve communication of the LV quality issues identified and action being to address.</p> | <p>Aurora will consider how best to use existing customer facing mediums, including the website, subject to suitability and functionality, to communicate LV quality issues and action being taken to address those issues. Once the LV visibility platforms are set up, we will be better equipped to consider reporting on the scale and type of LV issues.</p> |
| <p>Update the Congestion Guide to ensure it reflects, and is consistent with, the Congestion Policy.</p> | <p>Aurora’s Congestion Guide will be considered upon completion of ANSA hosting and modelling project.</p> |
| <p>Clarify how the risk methodology is applied to each asset fleet to develop the forecast in the AMP.</p> | <p>Content has been included in chapter 11 of our Asset Management Plan.</p> |
| <p>Present the network risk profile to show the current state and future state.</p> | <p>Noted. Once we have progressed the Development Plan initiatives to mature in this space, we will consider how we can present the view across different asset categories.</p> |
| <p>Provide additional information on the development of asset management processes that are described as specific initiatives in the Development Plan.</p> | <p>Content has been included in chapter 6 and Appendix D of the 2025 Asset Management Plan.</p> |
| <p>Apply criticality factors to the remaining fleets for consistency.</p> | <p>Criticality factors have been applied to distribution switchgear. Remaining fleets have not been prioritised because there is low public safety risk. They will be considered as an improvement to internal fleet strategies, but are not prioritised at this stage.</p> |
| <p>Consider a path to fully quantify risk analysis. Aurora should also include the output of their updated risk framework in the AMP.</p> | <p>We will consider a path to fully quantify risk analysis. Concept plans and key artefacts were discussed in the 2025 Asset Management Plan.</p> |
| <p>Ensure that the ADRs and AMPs align with information in the Safety Delivery Plan on the volume of assets that represented key network safety risks. The information should also show how volumes have changed and the reason.</p> | <p>We will consider this in future AMPs, however, there is a timing difference between the reporting included in the ADR and the information being included in the AMP, which means that there will be variances, however, the models are the same source.</p> |
| <p>Farrierswier</p> | |
| <p>Simplify pricing consultation material, including a 1-2 page (graphic heavy) summary of main document and reconsider layout on website of consultation material.</p> | <p>Noted. We will consider this feedback when we conduct pricing consultations in the future.</p> |



| RECOMMENDATION | ACTION TAKEN |
|--|---|
| <p>Consider design of future consumer-focused surveys so that these are not limited to simple yes/no responses and there is opportunity for respondents to provide feedback beyond the questions asked.</p> | <p>Noted. We will consider this feedback when we conduct pricing surveys in the future.</p> |
| <p>Consider engaging (including the CAP and CVP) on a tariff strategy and pricing methodology update, and along with a detailed supporting paper(s) it prepares a high-level presentation to discuss with consumers prior to completing the questionnaire. We also recommend that the questionnaire be designed to be more open to enable consumers to provide their ideas on what Aurora’s tariff strategy and pricing methodology should comprise.</p> | <p>Noted. We will consider this feedback when we conduct pricing consultations in the future.</p> |
| <p>Consider providing changes and quantifying the difference by consumer (or tariff) class given that there can be different drivers for each.</p> | <p>We have considered this recommendation and do not intend to take any action. Consumer charges vary depending on how and when individual consumers choose to use electricity. It is misleading to publish average pricing changes by consumer category, when individual consumers within each category will be affected differently.</p> |
| <p>Consider some scenario analysis, with appropriate caveats, to provide quantitative information to consumers on how consumer bills may be impacted by its pricing methodology.</p> | <p>Our Pricing Methodology now includes worked examples for a typical household in each pricing area. In our RY26 Pricing Methodology we will include additional analysis to demonstrate how consumers could benefit from the uptake of off-peak prices.</p> |
| <p>Review the criteria or methodology it uses to determine prices for its non-standard contracts to describe the extent to which its criteria or methodology are consistent with the 2019 pricing principles for the RY25 pricing methodology.</p> | <p>We have one non-standard contract which has been reviewed and repriced in RY25. The methodology for the reprice will be documented in the RY26 Pricing Methodology.</p> |
| <p>Consider potential areas for improvement in relation to the cost of supply model.</p> | <p>Other than addressing minor corrections identified, we do not intend to further action this recommendation because we do not consider that there is value in doing so for consumers. We agree that the Cost of Supply Model is likely too complex for most consumers and are happy to assist consumers and stakeholders in understanding how their prices are set. Our webpage includes a 'Contact Us' link where consumers are able to request additional information. Minor corrections identified were corrected in the RY25 model.</p> |



| RECOMMENDATION | ACTION TAKEN |
|---|---|
| Where resources allow, consider using Customer Advisory Panel (CAP) and Customer Voice Panels (CVP) / and / or engaging with industry groups for its within period engagement. | We have considered this recommendation and do not intend to take any action. The CAP and CVP were established for a specific purpose during the development of the CPP application. As we have evolved as a business and strengthened relationships with key stakeholders and within the community, we have evolved and matured our engagement practices, which includes identifying alternative best practice engagement methods. |
| Be clear during engagement of the level of participation it is seeking from consumers under the International Association for Public Participation (IAP) IAP2’s Public Participation Spectrum | Noted. We will make this clear when undertaking future engagements. |
| Consider how current social media platforms are used / and / or explore other platforms as well. | We have a Social Media Standard, which outlines the channels and platforms used and why. This was reviewed in June 2024. |
| When including links in reports include direct links rather than to website homepage. | Noted. We will consider doing this when appropriate. At times, it is more appropriate to direct people to the website’s homepage. |
| When Aurora engages on a topic, all relevant webpages on its website include mention and links to the engagement. | Noted. We will ensure this practice is continued. |
| Make past information submitted to the CAP and CVP, and presentations /and/or handouts at shows and meetings, available on Aurora’s website, as well as outcomes of any public meetings / trade shows. | We have considered this recommendation and do not intend to take any action. We engage with major customers and stakeholders on a regular basis. In addition to this targeted engagement, we have included a question in our customer satisfaction survey to determine how much level of involvement customers want to have in any amendments to our five-year investment plans. Reprioritisation and substitution is included in the May issue of our community newsletter YNYN each year inserted in community newspapers across Otago. |
| For major projects above a certain threshold /and/or those that are likely to materially impact on service outcomes seek views from affected consumers or representative bodies if there is benefit from consumer input prior to decisions being made, or if consumers should have been informed prior to any change and the reasons why. | We have considered this recommendation and do not intend to take any action We engage with major customers and stakeholders on a regular basis. In addition to this targeted engagement, we have included a question in our customer satisfaction survey to determine how much level of involvement customers want to have in any amendments to our five-year investment plans. Reprioritisation and substitution is included in the May |



| RECOMMENDATION | ACTION TAKEN |
|----------------|---|
| | issue of our community newsletter YNYN each year inserted in community newspapers across Otago. |

9. THE RY25 NUMBERS

9.1. EXPENDITURE

In this section, we set out actual expenditure compared to the proposed expenditure in our PPDP. The tables disclose:

- capital and operational expenditure consistent with the Information Disclosure requirements (Information disclosure category); and
- projects and programmes where the actual expenditure exceeds the proposed expenditure by 20% or more and is \$1 million or more (Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)).

This information is disclosed for each pricing region and explanations for the disclosed variations to proposed expenditure are provided.

9.1.1. Dunedin pricing region

This section sets out actual expenditure compared to proposed expenditure for the Dunedin pricing region.

Table 2: Renewal Capex – Dunedin pricing region

| RENEWAL CAPEX | PPDP FORECAST \$ | ACTUAL \$ | VARIANCE |
|---|------------------|--------------|----------|
| Information disclosure category | | | |
| Asset replacement and renewal | \$38,407,324 | \$32,751,814 | -15% |
| Projects or programmes exceeding proposed expenditure under clause 1.7.1(a) | | | |
| Distribution conductor | \$3,204,661 | \$6,646,550 | 107% |
| Distribution cables | \$1,797,687 | \$3,388,800 | 89% |
| Zone substations | \$5,404,061 | \$7,692,868 | 42% |

Actual asset replacement and renewal capital expenditure was lower than the PPDP forecast due to the deferral of expenditure on subtransmission conductor. A major subtransmission project was impacted by resource constraints and cost escalation across the wider programme, necessitating the need to reprioritise. The multi-year project will re-commence in RY26.

Since setting out the PPDP forecast, the landscape has changed, and our asset management practices have matured. We have seen greater than forecast demand growth and cost increases well beyond expectations. However, with maturing asset management practices, we have been able to make informed adjustments to our plan. The adjustments have driven variances against the PPDP across the regions.

The unit rate cost of distribution conductor has increased. A leading cause of increased unit rates relates to the renewal of network assets in the roading corridor (conductor, along with most poles and crossarms), has been the significant and unforeseeable increases in the cost of traffic management. The expenditure for distribution cables is largely reactive in nature. It includes ongoing replacement of cast iron potheads which are a significant public safety risk. The zone substation expenditure is higher than forecast mostly due to expenditure related to projects that are yet to be commissioned. The programme of major zone substation renewals has been impacted by higher than forecast costs, and greater than forecast growth, across the network. These projects include Green Island zone substation renewal and Smith Street switchgear renewal.

Table 3: Growth and security Capex – Dunedin pricing region

| GROWTH AND SECURITY CAPEX | PPDP FORECAST \$ | ACTUAL \$ | VARIANCE |
|---|------------------|-------------|----------|
| Information disclosure category | | | |
| System Growth | \$172,806 | \$1,557,998 | 802% |
| Projects or programmes exceeding proposed expenditure under clause 1.7.1(a) | | | |
| Smith Street to Willowbank Inter-tie | - | \$1,287,807 | - |

System growth expenditure was above that forecast in the PPDP due to the Smith Street to Willowbank Inter-tie project. This project was originally forecast to be delivered earlier in the CPP Period, but timeframes were altered to coincide with Dunedin City Council's centre city upgrade.

Table 4: Other network Capex – Dunedin pricing region

| OTHER NETWORK CAPEX | PPDP FORECAST \$ | ACTUAL \$ | VARIANCE |
|---|------------------|-------------|----------|
| Information disclosure category | | | |
| Quality of Supply | - | \$6,231 | - |
| Legislative and regulatory | - | - | - |
| Other reliability, safety and environment | - | - | - |
| Consumer connection | \$2,695,775 | \$6,165,394 | 129% |
| Asset relocations | \$414,735 | \$966,267 | 133% |
| Projects or programmes exceeding proposed expenditure under clause 1.7.1(a) | | | |
| Consumer connection capacity event | \$2,695,775 | \$6,165,394 | 129% |
| Asset relocations | \$414,735 | \$966,267 | 133% |

Consumer connections expenditure in Dunedin was higher than forecast due to significant electrification projects that were not known at the time the forecast in the PPDP was developed.

Asset relocations expenditure was higher than forecast due to projects initiated by Waka Kotahi.

Quality of supply expenditure remained closely aligned to the PPDP forecast for RY25.

Table 5: Network Opex – Dunedin pricing region

| NETWORK OPEX | PPDP FORECAST \$ | ACTUAL \$ | VARIANCE |
|---|------------------|-------------|----------|
| Information disclosure category | | | |
| Routine and corrective maintenance and inspection | \$5,304,276 | \$6,074,620 | 15% |
| Service interruptions and emergencies | \$2,428,560 | \$1,917,993 | -21% |
| Vegetation | \$1,492,446 | \$1,757,964 | 18% |
| Asset replacement and renewal | - | - | - |
| Projects or programmes exceeding proposed expenditure under clause 1.7.1(a) | | | |
| Corrective | \$2,250,494 | \$3,622,827 | 61% |

RY25 routine and corrective maintenance expenditure was higher than forecast in the PPDP largely due to the re-phasing of expenditure associated with our consumer poles programme.

Service interruptions and emergencies expenditure was lower than forecast due to lower levels of reactive maintenance work than expected.

Our vegetation management expenditure was higher than forecast partly due to the increasing cost of traffic management and the proximity of our network to the roading network in Dunedin.

Table 6: Non-network Opex – Dunedin pricing region

| NON-NETWORK OPEX | PPDP FORECAST \$ | ACTUAL \$ | VARIANCE |
|---------------------------------------|------------------|--------------|----------|
| Information disclosure category | | | |
| System operations and network support | \$9,739,803 | \$10,265,740 | 5% |
| Business support | \$9,831,522 | \$8,761,477 | -11% |

Despite inflationary pressures throughout CPP period to date, total non-network operational expenditure remained closely aligned to the PPDP forecast for RY25.

9.1.2. Central Otago and Wānaka pricing region

This section sets out actual expenditure compared to proposed expenditure for the Central Otago and Wānaka pricing region.

Table 7: Renewal Capex – Central Otago and Wānaka pricing region

| RENEWAL CAPEX | PPDP FORECAST \$ | ACTUAL \$ | VARIANCE |
|---|------------------|--------------|----------|
| Information disclosure category | | | |
| Asset replacement and renewal | \$11,930,621 | \$21,050,719 | 76% |
| Projects or programmes exceeding proposed expenditure under clause 1.7.1(a) | | | |
| Poles | \$4,103,711 | \$6,097,693 | 49% |
| Distribution conductor | \$3,165,704 | \$4,764,718 | 51% |

| | | | |
|---------------------------|-------------|-------------|--------|
| Zone substations | \$1,111,223 | \$4,064,138 | 266% |
| Ground mounted switchgear | \$10,368 | \$1,946,227 | 18671% |

As we improve our view of asset condition, we are able to move away from age-based renewals, enabling informed decisions around investment trade-offs and optimised timing for interventions. While we navigate the change and adjust our modelling to reflect our maturing view, there will be variances to the forecast set in our PPDP.

Pole replacements in Central Otago and Wanaka were undertaken at a higher average cost. While we have seen significant upward pressure on unit rates, influenced by high traffic management costs, we also completed a high ratio of subtransmission poles in Central Otago during RY25. These poles are generally more costly to replace owing to access and complexity and have put upward pressure on the average cost of poles replaced in the region.

Our distribution conductor programme delivered higher levels of conductor length renewals than originally planned for RY25.

Zone substation expenditure is higher than forecast mostly due to expenditure related to projects that are yet to be commissioned. The programme of major zone substation renewals has been impacted by higher than forecast costs, and greater than forecast growth, across the network. Alexandra switchgear renewal project is ongoing.

Ground mounted switchgear forecast expenditure was higher in Central Otago and Wānaka owing to a reprioritisation of the plan. This category which includes low voltage enclosures and high voltage switch gear, was reprioritised to include higher cost, high voltage switch gear, not identified in the PPDP forecast.

Table 8: Growth and security Capex – Central Otago and Wānaka pricing region

| GROWTH AND SECURITY CAPEX | FORECAST \$ | ACTUAL \$ | VARIANCE |
|---|-------------|-------------|----------|
| Information disclosure category | | | |
| System Growth | \$7,127,295 | \$7,269,133 | 2% |
| Projects or programmes exceeding proposed expenditure under clause 1.7.1(a) | | | |
| Upper Clutha auto transformer replacement | \$899,251 | \$3,638,304 | 305% |

Overall system growth expenditure was closely aligned to that forecast in the PPDP.

Work on the Upper Clutha auto transformer replacement was brought forward from RY26, resulting in greater expenditure than forecast in the PPDP for that project in RY25.

Table 9: Other network Capex – Central Otago and Wānaka pricing region

| OTHER NETWORK CAPEX | PPDP FORECAST \$ | ACTUAL \$ | VARIANCE |
|---------------------------------|------------------|-----------|----------|
| Information disclosure category | | | |
| Quality of Supply | \$124,420 | \$424,443 | 241% |

| | | | |
|---|-------------|-------------|------|
| Legislative and regulatory | - | - | |
| Other reliability, safety and environment | - | - | |
| Consumer connection | \$7,568,907 | \$9,331,693 | 23% |
| Asset relocations | \$518,418 | \$2,216,000 | 327% |
| Projects or programmes exceeding proposed expenditure under clause 1.7.1(a) | | | |
| Consumer connection | \$7,568,907 | \$9,331,693 | 23% |
| Asset relocations | \$518,418 | \$2,216,000 | 327% |

Continued growth in Central Otago and Wānaka, together with escalating costs, meant our consumer connections expenditure was higher than forecast in the PPDP.

Asset relocation expenditure continues to be higher than the PPDP forecast mainly due to the Wānaka NZTA state highway intersection realignment project.

Quality of supply expenditure varied from the forecast in the PPDP due to expenditure on a new generator at the Camphill zone substation, which had not been planned at the time the PPDP was set. This was required in order to support growth in the region.

Table 10: Network Opex – Central Otago and Wānaka pricing region

| NETWORK OPEX | PPDP FORECAST \$ | ACTUAL \$ | VARIANCE |
|---|------------------|-------------|----------|
| Information disclosure category | | | |
| Routine and corrective maintenance and inspection | \$2,697,844 | \$4,662,607 | 73% |
| Service interruptions and emergencies | \$1,457,136 | \$1,418,201 | -3% |
| Vegetation | \$1,854,915 | \$1,667,707 | -10% |
| Asset replacement and renewal | - | - | - |
| Projects or programmes exceeding proposed expenditure under clause 1.7.1(a) | | | |
| Preventive | \$1,832,269 | \$2,369,490 | 29% |
| Corrective | \$865,574 | \$2,293,117 | 165% |

We spent more than originally forecast on routine and corrective maintenance and inspections to improve our asset information through improved inspection and data collection processes (preventive), including inspections to help us address reliability issues. As we inspect more assets and discover defects, we are in a position to undertake more remedial work (corrective) to extend their useful life/ enhance the reliability performance of our network. The re-phasing of expenditure associated with our consumer pole programme also contributed to higher than forecast corrective expenditure than planned in the PPDP. Service interruptions and emergencies and vegetation expenditure was closely aligned to the PPDP forecast for RY25.

Table 11: Non-network Opex – Central Otago and Wānaka pricing region

| NON-NETWORK OPEX | PPDP FORECAST \$ | ACTUAL \$ | VARIANCE |
|------------------|------------------|-----------|----------|
|------------------|------------------|-----------|----------|

| Information disclosure category | | | |
|---------------------------------------|-------------|-------------|-----|
| System operations and network support | \$4,643,161 | \$4,403,802 | -5% |
| Business support | \$3,879,281 | \$3,715,829 | -4% |

Despite inflationary pressures throughout CPP period to date, total non-network operational expenditure was closely aligned to the PPDP forecast for RY25

9.1.3. Queenstown region

This section sets out actual expenditure compared to proposed expenditure for the Queenstown pricing region.

Table 12: Renewal Capex – Queenstown pricing region

| RENEWAL CAPEX | PPDP FORECAST \$ | ACTUAL \$ | VARIANCE |
|---|------------------|-------------|----------|
| Information disclosure category | | | |
| Asset replacement and renewal | \$4,409,163 | \$9,751,957 | 121% |
| Projects or programmes exceeding proposed expenditure under clause 1.7.1(a) | | | |
| Poles | \$1,139,920 | \$2,385,043 | 109% |
| Distribution conductor | \$72,727 | \$1,354,714 | 1763% |
| Protection | - | \$3,581,986 | - |

As we improve our view of asset condition, we are able to move away from age-based renewals, enabling informed decisions around investment trade-offs and optimised timing for interventions. While we navigate the change and adjust our modelling to reflect our maturing view, there will be variances to the forecast set in our PPDP. The main driver of the variance in total asset replacement and renewal expenditure was the value of protection works undertaken at the Queenstown and Fern Hill zone substations. These works were not originally planned to be delivered during the CPP Period. As experienced in other pricing regions, distribution conductor and pole renewal in Queenstown, were undertaken at higher average costs than originally forecast.

Table 13: Growth and security Capex – Queenstown pricing region

| GROWTH AND SECURITY CAPEX | PPDP FORECAST \$ | ACTUAL \$ | VARIANCE |
|---|------------------|-------------|----------|
| Information disclosure category | | | |
| System growth | \$1,892,180 | \$1,859,468 | -2% |
| Projects or programmes exceeding proposed expenditure under clause 1.7.1(a) | | | |
| Frankton zone substation upgrade | \$684,213 | \$1,695,208 | 148% |

Overall system growth expenditure was closely aligned to that forecast in the PPDP.

The Frankton zone substation required more expenditure than was forecast in the PPDP due to an increase in the purchase cost of, and additional work required to strengthen the foundation at the

site to accommodate a larger transformer. Additional upgrades were also required to the SCADA system to support the modern protection relays used for the project.

Table 14: Other network Capex – Queenstown pricing region

| OTHER NETWORK CAPEX | PPDP FORECAST \$ | ACTUAL \$ | VARIANCE |
|---|------------------|-------------|----------|
| Information disclosure category | | | |
| Quality of Supply | \$124,420 | - | |
| Legislative and regulatory | - | - | |
| Other reliability, safety and environment | - | \$572,750 | |
| Consumer connection | \$3,732,612 | \$3,315,244 | -11% |
| Asset relocations | \$829,469 | \$4,671,200 | 463% |
| Projects or programmes exceeding proposed expenditure under clause 1.7.1(a) | | | |
| Asset Relocations | \$829,469 | \$4,671,200 | 463% |

A provisional sum for quality of supply expenditure was included in the PPDP, however this spend did not eventuate during RY25. Other reliability, safety and environment expenditure related to a project to strengthen the ripple injection system to work with new transformers installed by Transpower to maintain reliability in the region. This project was not planned at the time the PPDP was set.

Asset relocations expenditure was higher than forecast due to projects initiated by Kā Huanui a Tāhuna. The lower than forecast consumer connection expenditure was in part due to the existence of a competing network in the region.

Table 15: Network Opex – Queenstown pricing region

| NETWORK OPEX | PPDP FORECAST \$ | ACTUAL \$ | VARIANCE |
|---|------------------|-------------|----------|
| Information disclosure category | | | |
| Routine and corrective maintenance and inspection | \$1,567,743 | \$2,755,385 | 76% |
| Service interruptions and emergencies | \$971,424 | \$656,024 | -32% |
| Vegetation | \$590,520 | \$1,007,947 | 71% |
| Asset replacement and renewal | - | - | |
| Projects or programmes exceeding proposed expenditure under clause 1.7.1(a) | | | |
| Preventive | \$1,221,513 | \$1,536,521 | 26% |
| Corrective | \$346,230 | \$1,218,864 | 252% |
| Vegetation | \$590,520 | \$1,007,947 | 71% |

We spent more than originally forecast on routine and corrective maintenance and inspection to improve our asset information through improved inspection and data collection processes (preventive), including inspections to help us address reliability issues. As we advance our Inspection standards and discover more defects, we are in a position to undertake more remedial work

(corrective) to extend their useful life/enhance the reliability performance of our network. The re-phasing of expenditure associated with our consumer poles programme, along with corrective work required on our spare transformer following a fault at the Remarkables zone substation, also contributed to higher corrective expenditure than forecast in the PPDP.

Service interruptions and emergencies expenditure was less than forecast due to lower levels of reactive maintenance work than expected.

Vegetation costs were higher in Queenstown partly due to the increasing cost of traffic management and out-of-cycle work carried out in response to faults.

Table 16: Non-network Opex – Queenstown pricing region

| NON-NETWORK OPEX | PPDP FORECAST \$ | ACTUAL \$ | VARIANCE |
|---------------------------------------|------------------|-------------|----------|
| Information disclosure category | | | |
| System operations and network support | \$2,523,941 | \$2,755,458 | 9% |
| Business support | \$2,547,709 | \$2,351,694 | -8% |

Despite inflationary pressures throughout CPP period to date, total non-network operational expenditure was closely aligned to the PPDP forecast for RY25.

9.2. ASSET REPLACEMENT AND RENEWAL

This section sets out the number of primary assets that we have replaced and the average cost of replacing the assets during RY25 as part of our asset replacement and renewal expenditure.

The quantities in these tables do not represent all assets replaced. They instead represent:

- the number and costs of assets delivered under the asset replacement and renewal programme rather than our total expenditure programme; and
- the number and cost of assets determined using a primary-driver approach, which we explain further below.

In our PPDP, we forecasted the number of assets to be replaced and the average total cost of replacing those assets based on the primary asset being replaced. When replacing primary assets, we also replace other assets in and around the primary asset where it is either necessary or efficient to do so at that time.

This means the total average cost disclosed in the tables also reflects more than the replacement of the primary asset. It also includes the cost of associated assets replaced at the same time as the primary asset.

Box 10.2: Example Primary and Associated assets

When replacing poles under the pole programme, poles are the primary asset replaced. We may also replace other assets attached to the pole when replacing the pole because it is prudent and efficient to do so at that time. These replaced assets are associated assets. For example, if a pole-

mounted transformer is replaced when replacing the pole under the pole programme then the pole is a primary asset and therefore counted as a replaced asset in the quantities identified in this section. The pole-mounted transformer is an associated asset in this example and is therefore not counted in the quantities identified in this section, but its cost of replacement is included in the primary asset (pole) replacement cost. This is consistent with how the PPDP forecast was prepared.

This information is disclosed for each pricing region and asset portfolio.

9.2.1. Dunedin pricing region

This section sets out the number of primary assets that we have replaced and the average cost of replacing the assets in the Dunedin pricing region as part of our asset replacement and renewal expenditure during RY25. Explanations are provided to assist with understanding, including why the number of assets replaced may have varied from the PPDP forecast.

Table 17: Support structure assets replaced or renewed – Dunedin pricing region

| SUPPORT STRUCTURES ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|-----------------------------------|--|---------------|----------|
| Poles | Number of assets replaced | 549 | 219 |
| | Total average cost of replacing the assets | \$12,670 | \$29,114 |
| Crossarms | Number of assets replaced | 1144 | 254 |
| | Total average cost of replacing the assets | \$2,927 | \$7,431 |

As our asset risk management practices have developed throughout the CPP period, we have been able to use condition-based information instead of age-based information to inform our asset health modelling and renewal planning. For Dunedin, this has resulted in fewer poles and crossarms needing to be replaced than initially forecast.

Table 18: Overhead conductor assets replaced or renewed – Dunedin pricing region

| OVERHEAD CONDUCTOR ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|-----------------------------------|--|---------------|-----------|
| Subtransmission conductor | Number of assets replaced | 8.304 km | - |
| | Total average cost of replacing the assets | \$284,217 | - |
| Distribution conductor | Number of assets replaced | 20.788 km | 19.219 km |
| | Total average cost of replacing the assets | \$154,884 | \$289,444 |
| Low voltage conductor | Number of assets replaced | 30.444 km | 2.965 km |
| | Total average cost of replacing the assets | \$131,275 | \$411,048 |

We revised our overhead system inspection standard in RY24 and implemented a new inspection programme for overhead conductor. The new inspection programme, together with conductor testing informed a revised plan, which led to slightly lower distribution conductor replacement during RY25 and a change in the renewal pace for low-voltage conductor – we do not yet have a full

cycle of inspection data, but expect the trend of more favourable condition data to continue. The next stage of the multi year Waipori Subtransmission renewal project (forecast in PPDP for RY25) has been deferred to RY26.

Table 19: Cable assets replaced or renewed – Dunedin pricing region

| CABLE ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|-----------------------|--|---------------|-------------|
| Subtransmission cable | Number of assets replaced | 1.866 km | - |
| | Total average cost of replacing the assets | \$1,213,058 | - |
| Distribution cable | Number of assets replaced | 5.803 km | 0.946 |
| | Total average cost of replacing the assets | \$433,925 | \$3,468,062 |
| Low voltage cable | Number of assets replaced | 1.902 km | 0.379 |
| | Total average cost of replacing the assets | \$146,739 | \$554,081 |

A section of the Kaikorai Valley subtransmission cable was planned for renewal in RY25, but instead has commenced in RY26.

We replaced small portions of distribution and low voltage cables as reactive works, which was provided for in the forecast. The reactive works distort the disclosed average cost because of the relatively short lengths involved compared to a planned intervention of larger runs of cable. Furthermore, we continue to see upward cost pressure on civil/trenching work, especially where traffic management is involved.

Table 20: Zone Substation assets replaced or renewed – Dunedin pricing region

| ZONE SUBSTATION ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|-------------------------------------|--|---------------|----------|
| Power transformers | Number of assets replaced | 2 | - |
| | Total average cost of replacing the assets | \$1,578,931 | - |
| Indoor switchgear | Number of assets replaced | 13 | - |
| | Total average cost of replacing the assets | \$139,935 | - |
| Outdoor switchgear | Number of assets replaced | 2 | - |
| | Total average cost of replacing the assets | \$144,168 | - |
| Ancillary zone substation equipment | Number of assets replaced | - | 1 |
| | Total average cost of replacing the assets | \$131,665 | \$46,274 |
| Buildings and grounds | Number of assets replaced | 1 | - |
| | Total average cost of replacing the assets | \$1,008,170 | - |

The power transformers and building in the PPDP forecast were for the Willowbank substation rebuild. The Willowbank Zone Substation renewal has been deferred to RY27 due to reprioritisation of other zone substation projects (including Green Island and Smith Street).

The network configuration required to enable the Smith Street switchgear replacement project has resulted in a deferral of the projects to deliver the forecast indoor switchgear quantities for the Halfway Bush substation. These projects are forecast to be completed after the CPP period.

The outdoor switchgear in the PPDP forecast were for the Port Chalmers substation but have been deferred to coordinate with the replacement of the power transformers in RY27.

A piece of ancillary zone substation equipment was identified as needing to be replaced during RY25. This had not been identified at the time the PPDP was set.

Table 21: Distribution switchgear assets replaced or renewed – Dunedin pricing region

| DISTRIBUTION SWITCHGEAR ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|--|--|---------------|-----------|
| Ground mounted switchgear | Number of assets replaced | 32 | 17 |
| | Total average cost of replacing the assets | \$83,945 | \$149,736 |
| Pole mounted fuses | Number of assets replaced | 45 | 32 |
| | Total average cost of replacing the assets | \$5,275 | \$3,097 |
| Pole mounted switches | Number of assets replaced | 36 | 29 |
| | Total average cost of replacing the assets | \$15,182 | \$26,010 |
| Reclosers and sectionalisers | Number of assets replaced | - | 1 |
| | Total average cost of replacing the assets | \$85,731 | \$66,376 |
| Low voltage enclosures | Number of assets replaced | 213 | 37 |
| | Total average cost of replacing the assets | \$5,667 | \$20,313 |

Since the PPDP, we have reprioritised our plan including the replacement of ground mounted switchgear across all regions. This has resulted in fewer units being replaced in the Dunedin area compared to the number planned when the PPDP was developed.

We have slowed our pole mounted fuse replacement programme based on improved inspection results.

We paused our pole mounted switch replacement programme in RY24 due to a systemic issue with the reliability of the new switches being deployed. We validated and checked an alternative type and provider and the programme resumed in RY25, informed by improved information. This pause resulted in fewer pole mounted switches being delivered in RY25 than planned in the PPDP. Low voltage enclosure replacements have slowed as we have completed a full cycle of invasive inspections and are using that data to target replacements based on risk. The cost is higher than forecast because there are two different types of enclosures. The PPDP assumed we would primarily be replacing pillars and very few boxes, but this year we replaced more boxes than pillars which raises the total average cost across the low voltage enclosures fleet.

Table 22: Distribution transformers assets replaced or renewed – Dunedin pricing region

| DISTRIBUTION TRANSFORMERS ASSET CATEGORY | PPDP FORECAST | ACTUAL |
|--|---------------|--------|
|--|---------------|--------|

| | | | |
|--|--|----------|----------|
| Ancillary distribution substation | Number of assets replaced | 104 | 6 |
| | Total average cost of replacing the assets | \$4,623 | \$7,305 |
| Ground mounted distribution transformers | Number of assets replaced | 16 | 12 |
| | Total average cost of replacing the assets | \$50,748 | \$92,576 |
| Pole mounted distribution transformers | Number of assets replaced | 38 | 15 |
| | Total average cost of replacing the assets | \$32,592 | \$51,017 |

There were inherent limitations in the data available at the time we set the forecasts in our PPDP. This has resulted in fewer surge arresters in the ancillary distribution substation fleet, ground mounted transformers and pole mounted distribution transformers needing to be replaced than initially forecast.

Updated inspection information and our maturing asset management practices have enabled us to better identify transformers needing replacement. The higher-than-expected total average cost for ground mounted distribution transformers is because there are different sizes of transformers that can be replaced.

Table 23: Secondary systems assets replaced or renewed – Dunedin pricing region

| SECONDARY SYSTEMS ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|----------------------------------|--|---------------|----------|
| Protection | Number of assets replaced | 64 | - |
| | Total average cost of replacing the assets | \$20,633 | - |
| DC systems | Number of assets replaced | 8 | 2 |
| | Total average cost of replacing the assets | \$74,086 | \$6,253 |
| Remote terminal units | Number of assets replaced | - | 1 |
| | Total average cost of replacing the assets | \$111,729 | \$72,963 |

The forecast protection assets in the PPDP related to the South City zone substation, which were delivered earlier in the CPP Period than planned and the Willowbank zone substation, which has now been deferred to after the CPP Period.

The DC systems assets delivered varied from the forecast in the PPDP primarily due to a number of the assets having been delivered earlier in the CPP Period than planned.

The remote terminal unit replacement relates to work on the South Dunedin GXP, which was not forecast at the time the PPDP was set.

9.2.2. Central Otago and Wānaka pricing region

This section sets out set out the number of primary assets that we have replaced and the average cost of replacing the assets in the Central Otago and Wānaka pricing region as part of our asset replacement and renewal expenditure during RY25.

Table 24: Support structure assets replaced or renewed – Central Otago and Wānaka pricing region

| SUPPORT STRUCTURES ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|-----------------------------------|--|---------------|----------|
| Poles | Number of assets replaced | 324 | 294 |
| | Total average cost of replacing the assets | \$12,670 | \$20,477 |
| Crossarms | Number of assets replaced | 628 | 131 |
| | Total average cost of replacing the assets | \$2,927 | \$6,811 |

As our asset risk management practices have developed throughout the CPP period, we have been able to use condition-based information instead of age-based information to inform our asset health modelling and renewal planning. For Central Otago and Wanaka, this has resulted in fewer poles and crossarms needing to be replaced than initially forecast.

Table 25: Overhead conductor assets replaced or renewed – Central Otago and Wānaka pricing region

| OVERHEAD CONDUCTOR ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|-----------------------------------|--|---------------|-----------|
| Subtransmission conductor | Number of assets replaced | - | - |
| | Total average cost of replacing the assets | \$284,217 | - |
| Distribution conductor | Number of assets replaced | 20.535 km | 32.207 |
| | Total average cost of replacing the assets | \$154,884 | \$155,882 |
| Low voltage conductor | Number of assets replaced | 5.836 km | 0.422 |
| | Total average cost of replacing the assets | \$131,275 | \$141,461 |

Our revised inspection programme for overhead conductor has resulted in us reprioritising actual renewals for our conductor fleets. This has resulted in prioritising distribution conductor over low voltage conductor in the Central Otago and Wanaka region. The higher quantity of distribution conductor delivered in RY25 was also influenced by projects that had been forecast to be delivered in RY24.

Table 26: Cable assets replaced or renewed – Central Otago and Wānaka pricing region

| CABLE ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|-----------------------|--|---------------|-----------|
| Subtransmission cable | Number of assets replaced | - | - |
| | Total average cost of replacing the assets | \$1,213,058 | - |
| Distribution cable | Number of assets replaced | - | 0.494 |
| | Total average cost of replacing the assets | \$433,925 | \$668,104 |
| Low voltage cable | Number of assets replaced | - | - |
| | Total average cost of replacing the assets | \$146,739 | - |

We replaced small portions of distribution cable as reactive works. The nature of reactive works distorts the disclosed average cost due to high associated asset costs. The shorter lengths involved also have a higher cost per metre when compared to a planned intervention of larger runs of cable.

Table 27: Zone Substation assets replaced or renewed – Central Otago and Wānaka pricing region

| ZONE SUBSTATION ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|-------------------------------------|--|---------------|-----------|
| Power transformers | Number of assets replaced | - | - |
| | Total average cost of replacing the assets | \$1,578,931 | - |
| Indoor switchgear | Number of assets replaced | - | - |
| | Total average cost of replacing the assets | \$139,935 | - |
| Outdoor switchgear | Number of assets replaced | - | 1 |
| | Total average cost of replacing the assets | \$144,168 | \$459,868 |
| Ancillary zone substation equipment | Number of assets replaced | - | - |
| | Total average cost of replacing the assets | \$131,665 | - |
| Buildings and grounds | Number of assets replaced | - | - |
| | Total average cost of replacing the assets | \$1,008,170 | - |

The outdoor switchgear at the Roxburg zone substation had been forecast for RY22 but was deferred until RY25 to coordinate with other planned works. The total average cost for the outdoor switchgear that was replaced includes significant costs associated with enabling work including a design review of the protection systems and outage mitigation. The project also incurred costs for necessary insulator replacements.

Table 28: Distribution switchgear assets replaced or renewed – Central Otago and Wānaka pricing region

| DISTRIBUTION SWITCHGEAR ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|--|--|---------------|-----------|
| Ground mounted switchgear | Number of assets replaced | - | 19 |
| | Total average cost of replacing the assets | \$83,945 | \$152,322 |
| Pole mounted fuses | Number of assets replaced | - | 15 |
| | Total average cost of replacing the assets | \$5,275 | \$7,361 |
| Pole mounted switches | Number of assets replaced | - | 8 |
| | Total average cost of replacing the assets | \$15,182 | \$18,102 |
| Reclosers and sectionalisers | Number of assets replaced | - | 2 |
| | Total average cost of replacing the assets | \$85,731 | \$31,998 |
| Low voltage enclosures | Number of assets replaced | 2 | 18 |
| | Total average cost of replacing the assets | \$5,667 | \$4,346 |

We paused our pole mounted switch replacement programme in RY24 due to a systemic issue with the reliability of the new switches being deployed. We validated and checked an alternative type and provider and the programme resumed in RY25, informed by improved information. This pause

resulted in more pole mounted switches being delivered in RY25 than planned in the PPDP. The replacement of the remaining assets in these fleets was primarily undertaken as reactive works.

Table 29: Distribution transformers assets replaced or renewed – Central Otago and Wānaka pricing region

| DISTRIBUTION TRANSFORMERS ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|--|--|---------------|----------|
| Ancillary distribution substation | Number of assets replaced | 96 | 10 |
| | Total average cost of replacing the assets | \$4,623 | \$7,381 |
| Ground mounted distribution transformers | Number of assets replaced | - | 9 |
| | Total average cost of replacing the assets | \$50,748 | \$66,353 |
| Pole mounted distribution transformers | Number of assets replaced | 22 | 15 |
| | Total average cost of replacing the assets | \$32,592 | \$26,180 |

Updated inspection information and our maturing network risk assessment practices have enabled us to better identify what assets require replacing. There were inherent limitations in the data available at the time we set the forecasts in our PPDP. This has resulted in fewer surge arresters (ancillary distribution substation fleet) and fewer pole mounted distribution transformers needing to be replaced than initially forecast. Through our inspection programme, we identified a number of ground mounted transformers needing to be replaced that were not originally forecast.

Table 30: Secondary systems assets replaced or renewed – Central Otago and Wānaka pricing region

| SECONDARY SYSTEMS ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|----------------------------------|--|---------------|---------|
| Protection | Number of assets replaced | - | - |
| | Total average cost of replacing the assets | \$20,633 | - |
| DC systems | Number of assets replaced | 2 | 5 |
| | Total average cost of replacing the assets | \$74,086 | \$6,521 |
| Remote terminal units | Number of assets replaced | 1 | - |
| | Total average cost of replacing the assets | \$111,729 | - |

DC systems replacement varied from the forecast in the PPDP due to replacement of units on our mobile zone substation being required. This had been forecast for earlier in the CPP period but was deferred due to contractor availability.

The forecast remote terminal unit replacement related to work at the Cromwell zone substation which has been deferred to RY28.

9.2.3. Queenstown region

This section sets out the number of primary assets that we have replaced and the average cost of replacing the assets in the Queenstown pricing region as part of our asset replacement and renewal expenditure during RY25.

Table 31: Support structure assets replaced or renewed – Queenstown pricing region

| SUPPORT STRUCTURES ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|-----------------------------------|--|---------------|----------|
| Poles | Number of assets replaced | 90 | 94 |
| | Total average cost of replacing the assets | \$12,670 | \$25,902 |
| Crossarms | Number of assets replaced | 50 | 21 |
| | Total average cost of replacing the assets | \$2,927 | \$6,373 |

As our asset risk management practices have developed throughout the CPP period, we have been able to use condition-based information instead of age-based information to inform our asset health modelling and renewal planning. For Queenstown, this has resulted in fewer crossarms needing to be replaced than initially forecast.

Table 32: Overhead conductor assets replaced or renewed – Queenstown pricing region

| OVERHEAD CONDUCTOR ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|-----------------------------------|--|---------------|-----------|
| Subtransmission conductor | Number of assets replaced | 0.083 km | 0.850 |
| | Total average cost of replacing the assets | \$284,217 | \$649,930 |
| Distribution conductor | Number of assets replaced | 0.472 km | 5.696 |
| | Total average cost of replacing the assets | \$154,884 | \$242,066 |
| Low voltage conductor | Number of assets replaced | 0.414 km | 0.01 |
| | Total average cost of replacing the assets | \$131,275 | \$708,958 |

The forecast quantities in the PPDP were to accommodate possible reactive works. More subtransmission conductor and less low voltage conductor was actually replaced via reactive works than forecast. The distribution conductor that was delivered was carryover from prior years.

Table 33: Cable assets replaced or renewed – Queenstown pricing region

| CABLE ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|-----------------------|--|---------------|-------------|
| Subtransmission cable | Number of assets replaced | - | - |
| | Total average cost of replacing the assets | \$1,213,058 | - |
| Distribution cable | Number of assets replaced | 0.005 km | 0.114 |
| | Total average cost of replacing the assets | \$433,925 | \$1,067,105 |
| Low voltage cable | Number of assets replaced | 0.012 km | 0.022 |
| | Total average cost of replacing the assets | \$146,739 | \$1,937,243 |

We replaced small portions of distribution and low voltage cable as reactive works which were provided for in the forecast. The nature of reactive works distorts the disclosed average cost due to high associated asset costs. The shorter lengths involved also have a higher cost per metre when compared to a planned intervention of larger runs of cable.

Table 34: Zone Substation assets replaced or renewed – Queenstown pricing region

| ZONE SUBSTATION ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|-------------------------------------|--|---------------|--------|
| Power transformers | Number of assets replaced | 1 | - |
| | Total average cost of replacing the assets | \$1,578,931 | - |
| Indoor switchgear | Number of assets replaced | - | - |
| | Total average cost of replacing the assets | \$139,935 | - |
| Outdoor switchgear | Number of assets replaced | - | - |
| | Total average cost of replacing the assets | \$144,168 | - |
| Ancillary zone substation equipment | Number of assets replaced | - | - |
| | Total average cost of replacing the assets | \$131,665 | - |
| Buildings and grounds | Number of assets replaced | - | - |
| | Total average cost of replacing the assets | \$1,008,170 | - |

The power transformer forecast in the PPDP was at Arrowtown zone substation which has been deferred. This is informed by a wider network upgrade plan, and updated transformer condition information.

Table 35: Distribution switchgear assets replaced or renewed – Queenstown pricing region

| DISTRIBUTION SWITCHGEAR ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|--|--|---------------|-----------|
| Ground mounted switchgear | Number of assets replaced | 4 | 11 |
| | Total average cost of replacing the assets | \$83,945 | \$116,987 |
| Pole mounted fuses | Number of assets replaced | - | 168 |
| | Total average cost of replacing the assets | \$5,275 | \$1,558 |
| Pole mounted switches | Number of assets replaced | - | 3 |
| | Total average cost of replacing the assets | \$15,182 | \$23,326 |
| Reclosers and sectionalisers | Number of assets replaced | - | - |
| | Total average cost of replacing the assets | \$85,731 | - |
| Low voltage enclosures | Number of assets replaced | 2 | 18 |
| | Total average cost of replacing the assets | \$5,667 | \$5,504 |

The ground mounted switchgear was replaced as reactive works which were provided for in the forecast. Significant civil costs and generation costs impacted the total average cost.

The pole mounted fuses were delivered in an additional safety programme installing non spark during operation Denco fuses in fire risk zones. The total average cost is lower than forecast as the forecast was prepared based on the number of sites while asset register replacements count the actual number of fuses being replaced.

The pole mounted switches renewal programme was paused in RY24 as we identified a systemic issue with the reliability of the new switches being deployed. We have now approved a new alternative and are working through the backlog of switch replacements from RY24.

The low voltage enclosures were undertaken as reactive works.

Table 36: Distribution transformers assets replaced or renewed – Queenstown pricing region

| DISTRIBUTION TRANSFORMERS ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|--|--|---------------|----------|
| Ancillary distribution substation | Number of assets replaced | 13 | 30 |
| | Total average cost of replacing the assets | \$4,623 | \$8,053 |
| Ground mounted distribution transformers | Number of assets replaced | - | 3 |
| | Total average cost of replacing the assets | \$50,748 | \$62,587 |
| Pole mounted distribution transformers | Number of assets replaced | 1 | 1 |
| | Total average cost of replacing the assets | \$32,592 | \$9,977 |

There were inherent limitations in the data available at the time we set the forecasts in our PPDP. In the Queenstown pricing region this has resulted in more surge arresters in the ancillary distribution substation fleet and ground mounted distribution transformers needing to be replaced than initially forecast and one fewer pole mounted distribution transformer than was forecast. Total average cost is higher due to the nature of reactive work.

Table 37: Secondary systems assets replaced or renewed – Queenstown pricing region

| SECONDARY SYSTEMS ASSET CATEGORY | | PPDP FORECAST | ACTUAL |
|----------------------------------|--|---------------|---------|
| Protection | Number of assets replaced | - | - |
| | Total average cost of replacing the assets | \$20,633 | - |
| DC systems | Number of assets replaced | - | 1 |
| | Total average cost of replacing the assets | \$74,086 | \$1,963 |
| Remote terminal units | Number of assets replaced | 2 | - |
| | Total average cost of replacing the assets | \$111,729 | - |

A DC system asset that had not been forecast in the PPDP was replaced at the Queenstown zone substation.

The two remote terminal units that had been forecast for replacement in RY25 related to the Queenstown zone substation, which has now been included in a growth-related project, and the Arrowtown zone substation, which will now be delivered later than planned at the time the PPDP was set.



9.3. VEGETATION MANAGEMENT

Table 38 sets out the percentage of the network that we have either inspected or felled, trimmed, removed or sprayed in RY25 as part of our three-year vegetation management plan. RY25 was the third year of that three-year plan, which set out to inspect and maintain 100% of the overhead network across that period. Now that the vegetation is in a more manageable state, we are moving to a five-year plan to align with our overhead inspection cycle.

The proportion of a feeder maintained, which then contributes to our overall percentage, is determined by whether there are any outstanding maintenance tasks on that feeder as at 31 March. If no maintenance tasks were identified during an inspection of that feeder, and that inspection occurred during the regulatory year, we consider that feeder to be maintained.

This information is disclosed by pricing region.

Table 38: Vegetation management

| NATURE OF WORK | DUNEDIN | | CENTRAL OTAGO AND WĀNAKA | | QUEENSTOWN | |
|---|----------|--------|--------------------------|--------|------------|--------|
| | FORECAST | ACTUAL | FORECAST | ACTUAL | FORECAST | ACTUAL |
| Percentage of network inspected | 38% | 29% | 46% | 46% | 65% | 65% |
| Percentage of network felled, trimmed, removed or sprayed | 38% | 20% | 44% | 54% | 63% | 65% |

9.4. SAFETY-RELATED INCIDENTS

Table 39 outlines the number of safety-related incidents that occurred on our network in RY25 in relation to network assets, maintenance, or operational activities that created a safety risk to the public, an Aurora Energy employee, or one of our contractors.

This information is disclosed by pricing region. Further detail regarding safety-related incidents is found in section 4.2.

Table 39: Safety-related incidents

| | DUNEDIN | | CENTRAL OTAGO AND WĀNAKA | | QUEENSTOWN | |
|------------------------------------|---------|------|--------------------------|------|------------|------|
| | RY24 | RY25 | RY24 | RY25 | RY24 | RY25 |
| Number of safety-related incidents | 135 | 158 | 84 | 139 | 25 | 52 |

9.5. RELIABILITY

Table 40 sets our reliability performance for each pricing region on our network (Dunedin, Central Otago and Wānaka, and Queenstown). The figures in this table are also disclosed in Schedule 10 of our Annual Information Disclosures for the relevant year, available at <https://www.auroraenergy.co.nz/disclosures/>. These figures are our raw SAIDI and SAIFI for those pricing regions.

Table 41 sets out our reliability performance in relation to the quality compliance limits that are set out in the Aurora Energy Limited Electricity Distribution Customised Price-Quality Path Determination 2021 (CPP Determination). These are calculated:

- on a total network basis; and
- in accordance with the CPP Determination, which allows for the normalisation of unplanned SAIDI and SAIFI for major events, and the de-weighting of planned SAIDI where it meets additional notification requirements.

Table 40: Reliability – 5-year time series by pricing region

| | RY25 | RY24 | RY23 | RY22 | RY21 |
|-----------------|--------|--------|--------|--------|-------|
| Dunedin | | | | | |
| Planned SAIDI | 123.89 | 155.00 | 117.91 | 134.62 | 87.10 |
| Planned SAIFI | 0.43 | 0.68 | 0.44 | 0.79 | 0.59 |
| Unplanned SAIDI | 25.90 | 51.39 | 65.05 | 51.47 | 59.30 |
| Unplanned SAIFI | 0.40 | 0.78 | 0.97 | 0.72 | 1.01 |



| Central Otago and Wānaka | | | | | |
|--------------------------|--------|--------|--------|--------|--------|
| Planned SAIDI | 241.86 | 283.29 | 272.90 | 290.46 | 218.60 |
| Planned SAIFI | 0.77 | 0.87 | 0.88 | 0.92 | 0.99 |
| Unplanned SAIDI | 253.99 | 344.41 | 309.50 | 224.61 | 238.50 |
| Unplanned SAIFI | 2.99 | 4.52 | 5.18 | 3.33 | 2.72 |
| Queenstown | | | | | |
| Planned SAIDI | 199.89 | 308.59 | 236.58 | 298.17 | 193.70 |
| Planned SAIFI | 0.66 | 0.89 | 0.81 | 0.83 | 0.55 |
| Unplanned SAIDI | 84.65 | 150.20 | 267.98 | 248.36 | 137.60 |
| Unplanned SAIFI | 1.68 | 1.71 | 4.06 | 3.90 | 1.85 |

Table 41: Reliability – performance against the CPP Determination quality limits

| Total network | |
|---------------------------------|--------|
| Planned SAIDI assessed value | 90.08 |
| Planned SAIFI assessed value | 0.55 |
| Unplanned SAIDI assessed value | 77.24 |
| Unplanned SAIFI assessed value | 1.16 |
| Planned accumulated SAIDI limit | 979.80 |
| Planned accumulated SAIFI limit | 5.54 |
| Unplanned SAIDI limit | 124.94 |
| Unplanned SAIFI limit | 2.07 |

9.6. PLANNED INTERRUPTIONS

Table 42 sets out details on planned interruptions that we undertook during RY25.

Table 42: Planned interruptions

| METRIC | RY25 |
|---|------|
| Planned interruptions cancelled with more than 24 hours' notice, but less than 10 working days' notice | 75 |
| Planned interruptions cancelled without notice | 84 |
| Planned interruptions for which Aurora Energy gave additional notice | 1190 |
| Planned interruptions for which Aurora Energy did not give additional notice | 21 |
| Planned interruptions in which the interruption either started more than one hour before, or continued for more than one hour after, the period in which the interruption was notified to occur | 61 |
| Unplanned interruptions that Aurora Energy intentionally initiated to carry out work on our network that did not directly relate to a fault | 77 |

9.7. COMPLAINTS

Table 43 through Table 45 set out details on the number of complaints received by pricing region, by complaint type and ranked in order from greatest to smallest by number of complaints and type.

Table 43: Complaints – Dunedin pricing region

| COMPLAINT TYPE | NUMBER OF COMPLAINTS | AVERAGE TIME TO RESOLVE (BUSINESS DAYS) |
|--|----------------------|---|
| Voltage quality ¹ | 22 | 2 |
| Contractor behaviour or service ² | 3 | 11 |
| Network asset concerns | 2 | 14 |
| Connection policies | 2 | 13 |
| Damage to property ² | 2 | 5 |
| Vegetation management | 1 | 45 |
| Consumer poles | 1 | 24 |
| Duration of outage | 1 | 24 |
| Frequency of outages | 1 | 16 |
| Planned outage – Not notified | 1 | 16 |
| Planned outage – not performed as notified | 1 | 11 |
| Pricing | 1 | 1 |

¹ Type of complaint with the greatest number of complaints received in RY24

² Type of complaint with the third greatest number of complaints received in RY24

Note – the type of complaint with the second greatest number of complaints received in RY24 was damage to appliances. No complaints were received for this category in RY25.

Table 44: Complaints – Central Otago and Wānaka pricing region

| COMPLAINT TYPE | NUMBER OF COMPLAINTS | AVERAGE TIME TO RESOLVE (BUSINESS DAYS) |
|---|----------------------|---|
| Voltage quality ¹ | 22 | 2 |
| Contractor behaviour or service ² | 3 | 4 |
| Frequency of outages ² | 2 | 41 |
| Damage to property | 2 | 28 |
| Planned outage – not performed as notified | 2 | 23 |
| Duration of outage | 1 | 31 |
| Network asset concerns | 1 | 26 |
| Connection policies | 1 | 24 |
| Duration of outage | 1 | 31 |
| Network asset concerns | 1 | 26 |
| Planned outage – not notified | 1 | 20 |
| Planned outage – unsuitable timing ² | 1 | 2 |

¹. Type of complaint with the greatest number of complaints received in RY24

². Type of complaint with the second greatest number of complaints received in RY24 (3 categories with same number of complaints)

Table 45: Complaints – Queenstown pricing region

| COMPLAINT TYPE | NUMBER OF COMPLAINTS | AVERAGE TIME TO RESOLVE (BUSINESS DAYS) |
|---|----------------------|---|
| Voltage quality ¹ | 8 | 1 |
| Frequency of outages | 3 | 11 |
| Damage to property | 2 | 20 |
| Planned outage – not performed as notified ² | 2 | 16 |
| Contractor behaviour or service | 1 | 59 |
| Network asset concerns | 1 | 48 |
| Damage to appliances ¹ | 1 | 22 |
| Connection policies | 1 | 18 |

¹. Type of complaint with the greatest number of complaints received in RY24 (2 categories with same number of complaints)

². Type of complaint with the second greatest number of complaints received in RY24 (2 categories with same number of complaints (planned outage – unsuitable timing which did not receive any complaints in RY25))



APPENDIX A. COMPLIANCE MATRIX

The following table demonstrates how this Annual Delivery Report complies with Attachment B of the Determination.

| Determination Requirement | Attachment B of the Determination Reference | Statement Reference |
|---|---|---------------------|
| Aurora must include the following in an annual delivery report: | Clause 1 | |
| <i>Overall progress update from board of directors</i> | | |
| an overview from Aurora’s board of directors setting out— | Clause 1.1 | |
| Aurora’s overall progress in the following areas: | Clause 1.1.1 | |
| for each disclosure year except disclosure year 2022, Aurora’s progress in completing the capital expenditure and operational expenditure projects and programmes identified in Aurora’s project and programme delivery plan under clause 2.5.4(2); | Clause 1.1.1(b) | Section 2 |
| any actions Aurora is taking to ensure its capital expenditure and operational expenditure projects and programmes are completed as effectively and efficiently as possible; | Clause 1.1.2 | Section 2 |
| for each disclosure year except disclosure year 2022, in respect of any key capital expenditure and operational expenditure project or programme that Aurora is behind schedule in completing according to Aurora’s project and programme delivery plan under clause 2.5.4(2), the reason(s) why the project or programme is behind schedule, and any actions Aurora is taking to bring the project or programme back on track; and | Clause 1.1.3 | Section 2 |
| a summary of the network safety risks Aurora has successfully reduced; | Clause 1.1.4 | Section 2 |
| <i>Safety delivery plan reporting</i> | | |



| Determination Requirement | Attachment B of the Determination Reference | Statement Reference |
|--|---|---------------------|
| for each disclosure year except disclosure year 2022, a report on Aurora’s progress against the safety delivery plan under clause 2.5.4(3) containing the following information: | Clause 1.2 | |
| a visual representation of Aurora’s actual reduction or change in network safety risk, grouped by asset class, as a result of delivering capital expenditure or operational expenditure projects or programmes identified in Aurora’s project and programme delivery plan under clause 2.5.4(2); and | Clause 1.2.1 | Section 4.1 |
| in relation to the key network safety risks listed in the safety delivery plan,— | Clause 1.2.2 | |
| a summary of actions Aurora has taken to reduce those risks, with reference to the principle of reducing risk to ‘as low as reasonably practicable’; and | Clause 1.2.2(a) | Section 4.1 |
| for any identified risk that Aurora has not reduced to the extent planned, a description of how, and within what timeframe, Aurora plans to reduce the risk; | Clause 1.2.2(b) | Section 4.1 |
| <i>Progress in developing key processes and practices – disclosure years after disclosure year 2022</i> | | |
| for each disclosure year except disclosure year 2022, a summary, a self-assessment rating, and reason(s) for the self-assessment rating, of Aurora’s progress— | Clause 1.4 | |
| in ensuring the information Aurora publicly discloses under clause 2.4.5A(1) enables interested persons to understand how Aurora sets prices for each Aurora pricing region; and | Clause 1.4.1 | Section 5.1 |
| against each of the following areas in Aurora’s development plan under clause 2.5.4(1): | Clause 1.4.2 | |
| developing and improving its low voltage network practices referred to in clause 2.5.4(1)(a); | Clause 1.4.2(a) | Section 5.2 |
| engagement with consumers on Aurora’s customer charter, and consumer compensation arrangement; | Clause 1.4.2(b) | Section 5.3 |
| planning, management, and communication of planned interruptions to consumers; | Clause 1.4.2(c) | Section 5.4 |
| asset data collection and asset data quality practices referred to in clause 2.5.4(1)(d); | Clause 1.4.2(d) | Section 5.5 |

COMPLIANCE MATRIX



| Determination Requirement | Attachment B of the Determination Reference | Statement Reference |
|---|---|---------------------|
| asset management practices and processes referred to in clause 2.5.4(1)(e)(i) to (iii); | Clause 1.4.2(e) | Section 5.6 |
| practices for identifying and reducing safety risks referred to in clause 2.5.4(1)(e)(iv); | Clause 1.4.2(f) | Section 5.6 |
| cost estimation practices referred to in clause 2.5.4(1)(f); and | Clause 1.4.2(g) | Section 5.7 |
| quality assurance processes referred to in clause 2.5.4(1)(g); | Clause 1.4.2(h) | Section 5.8 |
| <i>Spending and work done on Aurora’s network</i> | | |
| for each disclosure year except disclosure year 2022, the key capital expenditure and operational expenditure projects and programmes that Aurora— | Clause 1.5 | |
| has delivered on time in the most recent disclosure year; | Clause 1.5.1 | Section 3 |
| has not yet completed, but which are on schedule in accordance with Aurora’s project and programme delivery plan under clause 2.5.4(2); | Clause 1.5.2 | Section 3 |
| has not completed on time, but had planned to complete in the most recent disclosure year; and | Clause 1.5.3 | Section 3 |
| has not commenced, but had planned to commence, in the most recent disclosure year; | Clause 1.5.4 | Section 3 |
| for each disclosure year except disclosure year 2022, the following information relating to capital expenditure and operational expenditure projects and programmes Aurora has undertaken in the disclosure year in each Aurora pricing region: | Clause 1.7 | |
| Aurora’s actual expenditure compared to the proposed expenditure in Aurora’s project and programme delivery plan under clause 2.5.4(2), with any variance expressed as the percentage difference between proposed and actual expenditure, together with the reason(s) for the variance, | Clause 1.7.1 | Section 9.1 |
| where the actual capital expenditure or operational expenditure— | Clause 1.7.1(a) | |

COMPLIANCE MATRIX



| Determination Requirement | Attachment B of the Determination Reference | Statement Reference |
|--|---|---------------------|
| exceeds the expenditure proposed in Aurora’s project and programme delivery plan under clause 2.5.4(2) by 20% or more; and | Clause 1.7.1(a)(i) | |
| is \$1 million or more; | Clause 1.7.1(a)(ii) | |
| for each of: | Clause 1.7.1(b) | |
| consumer connection; | Clause 1.7.1(b)(i) | Section 9.1 |
| system growth; | Clause 1.7.1(b)(ii) | Section 9.1 |
| asset replacement and renewal; | Clause 1.7.1(b)(iii) | Section 9.1 |
| asset relocations; | Clause 1.7.1(b)(iv) | Section 9.1 |
| quality of supply; | Clause 1.7.1(b)(v) | Section 9.1 |
| legislative and regulatory; and | Clause 1.7.1(b)(vi) | Section 9.1 |
| other reliability, safety and environment; | Clause 1.7.1(b)(vii) | Section 9.1 |
| for each of: | Clause 1.7.1(c) | |
| service interruptions and emergencies; | Clause 1.7.1(c)(i) | Section 9.1 |
| vegetation management; | Clause 1.7.1(c)(ii) | Section 9.1 |
| routine and corrective maintenance and inspection; | Clause 1.7.1(c)(iii) | Section 9.1 |
| asset replacement and renewal; | Clause 1.7.1(c)(iv) | Section 9.1 |
| system operations and network support; and | Clause 1.7.1(c)(v) | Section 9.1 |

COMPLIANCE MATRIX



| Determination Requirement | Attachment B of the Determination Reference | Statement Reference |
|--|---|---------------------|
| business support; | Clause 1.7.1(c)(vi) | Section 9.1 |
| asset replacement and renewal, including | Clause 1.7.2 | |
| the number of assets replaced compared to the number of assets Aurora planned to replace in its project and programme delivery plan under clause 2.5.4(2) in the relevant disclosure year, with reasons for variances; and | Clause 1.7.2(a) | Section 9.2 |
| for each asset type for which Aurora undertook asset replacement and renewal in the relevant disclosure year, the average total cost of replacing an asset of that type compared to the forecast average total cost of replacing the asset type in Aurora’s project and programme delivery plan under clause 2.5.4(2); | Clause 1.7.2(b) | Section 9.2 |
| compared to Aurora’s documented planning for vegetation management, the percentage of the network that Aurora has, as part of its vegetation management,— | Clause 1.7.3 | |
| inspected; and | Clause 1.7.3(a) | Section 9.3 |
| felled, trimmed, removed, or sprayed; | Clause 1.7.3(b) | Section 9.3 |
| <i>Quality information – for the network and Aurora pricing regions</i> | | |
| for each Aurora pricing region, in a time series form for each of the most recent five disclosure years, the— | Clause 1.8 | |
| planned SAIDI values; | Clause 1.8.1 | Section 9.5 |
| planned SAIFI values; | Clause 1.8.2 | Section 9.5 |
| unplanned SAIDI values; and | Clause 1.8.3 | Section 9.5 |
| unplanned SAIFI values; | Clause 1.8.4 | Section 9.5 |
| for each disclosure year except disclosure year 2022, in respect of each Aurora pricing region,— | Clause 1.9 | |

COMPLIANCE MATRIX



| Determination Requirement | Attachment B of the Determination Reference | Statement Reference |
|--|---|----------------------|
| a table with the following information on any complaints from consumers about Aurora’s supply of electricity distribution services in the most recent disclosure year: | Clause 1.9.1 | |
| the type of complaint, with Aurora determining the different types of complaint by the general subject matter to which the complaints relate; | Clause 1.9.1(a) | Section 9.7 |
| the number of each type of complaint; | Clause 1.9.1(b) | Section 9.7 |
| the average time to resolve each type of complaint; | Clause 1.9.1(c) | Section 9.7 |
| the top three types of complaints with the highest numbers of complaints and how they differ to the three types of complaints with the highest numbers of complaints from the previous disclosure year; and | Clause 1.9.1(d) | Sections 9.7 and 6.1 |
| a description of whether, and if so how, Aurora is using the learning and insights gained from handling complaints as a feedback loop to improve the quality and service levels of in supplying electricity distribution services; | Clause 1.9.1(e) | Section 6.1 |
| regarding the most recent disclosure year,— | Clause 1.9.2 | |
| the number of safety-related incidents in relation to network assets, maintenance, or operational activities that created a safety risk to the public, an Aurora employee, or an Aurora contractor; | Clause 1.9.2(a) | Section 9.4 |
| commentary on how the number of safety-related incidents compared against the previous disclosure year; and | Clause 1.9.2(b) | Section 4.2 |
| any corrective actions taken in respect of these incidents; | Clause 1.9.2(c) | Section 4.2 |
| for Aurora’s network, in respect of the most recent disclosure year, the— | Clause 1.10 | |
| planned SAIDI assessed value, unplanned SAIDI assessed value, planned accumulated SAIDI limit, and unplanned SAIDI limit; and | Clause 1.10.1 | Section 9.5 |
| planned SAIFI assessed value, unplanned SAIFI assessed value, planned accumulated SAIFI limit, and unplanned SAIFI limit; | Clause 1.10.2 | Section 9.5 |

| Determination Requirement | Attachment B of the Determination Reference | Statement Reference |
|--|---|---------------------|
| for each disclosure year except disclosure year 2022, the total number of each of the following: | Clause 1.11 | |
| planned interruptions cancelled with less than 10 working days' notice; | Clause 1.11.1 | Section 9.6 |
| planned interruptions cancelled without notice; | Clause 1.11.2 | Section 9.6 |
| planned interruptions for which Aurora gave additional notice; | Clause 1.11.3 | Section 9.6 |
| planned interruptions for which Aurora did not give additional notice; | Clause 1.11.4 | Section 9.6 |
| planned interruptions in which the interruption either started more than one hour before, or continued for more than one hour after, the period in which the interruption was notified to occur; and | Clause 1.11.5 | Section 9.6 |
| unplanned interruptions that Aurora intentionally initiated to carry out work on its network that did not directly relate to a fault; | Clause 1.11.6 | Section 9.6 |
| <i>Performance and engagement with consumers</i> | | |
| regarding Aurora's performance in supplying electricity distribution services to its consumers, — | Clause 1.12 | |
| a self-assessment rating, and reason(s) for the self-assessment rating, regarding each of the following: | Clause 1.12.1 | |
| for each disclosure year except disclosure year 2022, - | Clause 1.12.1(b) | |
| how effectively Aurora has engaged with different consumers in each Aurora pricing region | Clause 1.12.1(b)(i) | Section 6.1 |
| any consultation Aurora has done with consumers on capital expenditure or operational expenditure projects or programmes, Aurora proposes to reprioritise or substitute; | Clause 1.12.1(b)(ii) | Section 6.1 |
| summary of, — | Clause 1.12.2 | |
| for each disclosure year, — | Clause 1.12.2(a) | |

COMPLIANCE MATRIX



| Determination Requirement | Attachment B of the Determination Reference | Statement Reference |
|---|---|---------------------|
| whether, and if so how, Aurora has consulted with consumers on any proposed changes to its customer charter, consumer compensation arrangement, or additional pricing methodology disclosures under clause 2.4.5A; | Clause 1.12.2(a)(i) | Section 6 |
| any feedback from consumers on Aurora’s additional pricing methodology disclosures under clause 2.4.5A; and | Clause 1.12.2(a)(ii) | Section 6.1 |
| whether Aurora met its commitments under its customer charter and consumer compensation arrangement, and if not, the respects in which Aurora failed to do so, and the reasons for such failure; and | Clause 1.12.2(a)(iii) | Section 6.2 |
| for each disclosure year except disclosure year 2022 – | Clause 1.12.2(b) | |
| whether, and if so how, Aurora has improved consumer awareness of its customer charter and consumer compensation arrangement; | Clause 1.12.2(b)(i) | Section 6.2 |
| any payments Aurora has made in respect of each service level standard under Aurora’s consumer compensation arrangement; | Clause 1.12.2(b)(ii) | Section 6.2 |
| whether, and if so how, Aurora has taken account of consumers’ feedback on any aspect of its supply of electricity distribution services – for example, feedback on Aurora’s presentation of its summary of the key features of the most recent annual delivery report; and | Clause 1.12.2(b)(iii) | Section 6.1 |
| the different groups of consumers Aurora has engaged with; | Clause 1.12.2(b)(iv) | Section 6.1 |
| for each disclosure year except disclosure year 2022, the following information on Aurora’s supply of electricity distribution services to its worst-performing feeders: | Clause 1.12.3 | |
| using a map, or series of maps, of appropriate scale, the geographical location of each of Aurora’s worst-performing feeders; | Clause 1.12.3(a) | Section 7 |

COMPLIANCE MATRIX



| Determination Requirement | Attachment B of the Determination Reference | Statement Reference |
|--|---|---------------------|
| for the worst-performing feeders: | Clause 1.12.3(b) | |
| the planned SAIFI value(s); | Clause 1.12.3(b)(i) | Section 7 |
| the planned SAIDI value(s); | Clause 1.12.3(b)(ii) | Section 7 |
| the unplanned SAIFI value(s); and | Clause 1.12.3(b)(iii) | Section 7 |
| the unplanned SAIDI value(s); | Clause 1.12.3(b)(iv) | Section 7 |
| any plans Aurora has to improve supply of electricity distribution services on its worst-performing feeders. | Clause 1.12.3(c) | Section 7 |
| <i>Additional content required in annual delivery reports disclosed after mid-period expert report</i> | | |
| In addition to the content specified under clause 1 of this attachment, Aurora must include in the annual delivery report it publicly discloses for each of disclosure year 2025 and disclosure year 2026, a summary of any actions Aurora has taken as a result of any recommendations from the report or reports from one or more independent experts under clause 2.8.5A — for example, updating Aurora’s development plan under clause 2.5.4(1). | Clause 2 | Section 8 |

APPENDIX B. DIRECTOR CERTIFICATION

SCHEDULE 18

Certification for Disclosures Clause 2.9.5

We, Stephen Richard Thompson and Janice Evelyn Fredric, being directors of Aurora Energy Limited, certify that, having made all reasonable enquiry, to the best of our knowledge, the information prepared for the purposes of clause 2.5.5(1) of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

A handwritten signature in black ink, appearing to read "Stephen Thompson".

Stephen Richard Thompson

A handwritten signature in black ink, appearing to read "J E Fredric".

Janice Evelyn Fredric

27 August 2025

APPENDIX C. ASSURANCE REPORT

AUDIT NEW ZEALAND
Mana Arotake Aotearoa

Independent Assurance Report

**To the directors of Aurora Energy Limited and to the Commerce Commission
on the Annual Delivery Report
for the disclosure year ended 31 March 2025 as required by
The Electricity Distribution Information Disclosure (amendments related to IM
Review 2023) Amendment Determination 2024 [2024] NZCC 31**

Aurora Energy Limited (the company) is required to disclose certain information in an Annual Delivery Report under the Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024 [2024] NZCC 31 (the Determination), and to procure an assurance report by an independent auditor in terms of section 2.8.1 of the Determination.

The Auditor-General is the auditor of the company.

The Auditor-General has appointed me, Chantelle Gernetzky, using the staff and resources of Audit New Zealand, to undertake a reasonable assurance engagement, on his behalf, on whether certain information in the Annual Delivery Report prepared by the company for the disclosure year ended 31 March 2025 (the audited Disclosure Information) complies, in all material respects, with the Determination.

The Disclosure Information in the Annual Delivery Report for the 2025 disclosure year that falls within the scope of the assurance engagement, is the information required by clauses 1.5, 1.7, 1.8 and 1.10 in Attachment B of the Determination.

Opinion

In our opinion, in all material respects:

- as far as appears from an examination, proper records to enable the complete and accurate compilation of the audited Disclosure Information, have been kept by the company;
- as far as appears from an examination, the information used in the preparation of the audited Disclosure Information has been properly extracted from the company's accounting and other records, sourced from the company's financial and non-financial systems; and
- the audited Disclosure Information complies, in all material respects, with the Determination.

Basis for opinion

We conducted our engagement in accordance with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised), *Assurance Engagements Other Than Audits or Reviews of Historical Financial Information ("ISAE (NZ) 3000 (Revised)"),* and the Standard on Assurance Engagements (SAE) 3100 (Revised), *Compliance Engagements ("SAE 3100 (Revised)"),* issued by the New Zealand Auditing and Assurance Standards Board.

We have obtained sufficient recorded evidence and explanations that we required to provide a basis for our opinion.

Key assurance matters

Key assurance matters are those matters that, in our professional judgement, required significant attention when carrying out the assurance engagement during the current disclosure year. These matters were addressed in the context of our compliance engagement, and in forming our opinion. We do not provide a separate opinion on these matters.

| Key assurance matter | How our procedures addressed the key assurance matter |
|---|---|
| <p>Expenditure</p> <p>The value of actual capital and operational expenditure compared to the forecast expenditure under the company’s Project and Programme Delivery Plan is disclosed in section 8 of the Annual Delivery Report, as required by clause 1.7.1 in Attachment B of the Determination. During the disclosure year, the company carried out a significant number of individual network system projects that are either operational (network maintenance) or capital (asset replacement or network growth) in nature. Capital expenditure in the current disclosure year totalled \$74 million and operating expenditure totalled \$54 million. The overall total amount of expenditure is significant relative to the company’s total asset value of \$898 million.</p> <p>Expenditure is a key assurance matter due to the significant judgement by company personnel and the auditor to assess whether the expenditure is capital or operational in nature and meets the definitions set out in the Determination.</p> | <p>We have obtained an understanding of the compliance requirements relevant to the Annual Delivery Report as set out in the Determination.</p> <p>The procedures we carried out to satisfy ourselves that the capital expenditure and operational expenditure are correctly presented in the Annual Delivery Report included:</p> <ul style="list-style-type: none"> • assessing whether the company’s capitalisation policy was in line with NZ IAS 16, <i>Property, Plant and Equipment</i>; • evaluating and testing the controls over the classification of expenditure; • testing a sample of capital expenditure to invoices or other supporting information to determine whether the expenditure met the capitalisation criteria in the Determination and was capitalised to the appropriate asset category; • testing a sample of operational expenditure to invoices or other supporting information to confirm the classification is appropriate; and • comparing the actual expenditure to the forecast in the published Project and Programme Delivery Plan, and assessing the reasonableness of, and support for, the variance explanations. <p>Having completed these procedures, we have no matters to report.</p> |

| Key assurance matter | How our procedures addressed the key assurance matter |
|--|---|
| <p>Accuracy of the number and duration of electricity outages</p> <p>The company has a combination of manual and automated systems to identify outages and to record the duration of outages. This outage information is used to report the company's quality information for the network and for each of the company's pricing region, in a time series form for each of the most recent five disclosure years. If this information is inaccurate then the measures of the reliability of the network could be materially misstated.</p> <p>This is a key assurance matter because information on the frequency and duration of outages is an important measure of the reliability of electricity supply. Relatively small inaccuracies can have a significant impact on the reliability thresholds against which the company's performance is assessed.</p> | <p>We have obtained an understanding of the company's system to record electricity outages, and their duration. This included review of the company's definition of interruptions, planned interruptions, and major event days.</p> <p>Our procedures to assess the adequacy of the company's methods to identify and record electricity outages and their duration included:</p> <ul style="list-style-type: none"> • reviewing and testing the overall control environment; • performing an assessment of the reliability of the manual and automated processes to record the details of interruptions to supply; • obtaining internal and external information on interruptions to supply, to gain assurance that interruptions to supply were recorded. Internal and external information sources included works orders for contractors, media reports, and Board minutes; • testing a sample of interruptions to supply, to source records to conclude on their accuracy of calculation, and the appropriateness of the categorisation of the cause of the interruption and whether it was planned or unplanned, and that the cause of the interruptions is correctly categorised; • checking the SAIDI and SAIFI ratios were correctly calculated in accordance with the Determination and the IM Determination; • obtaining explanations for all significant variances to forecast; and • testing the accuracy of the number of connections to the Electricity Authority's register. <p>Having carried out these procedures, and assessed the likelihood of reported electricity outages and their duration being materially misstated in the Disclosure Information, we have no matters to report.</p> |

Directors' responsibilities

The directors of the company are responsible in accordance with the Determination for the preparation of the Disclosure Information in the Annual Delivery Report.

The directors of the company are also responsible for the identification of risks that may threaten compliance with the clauses identified above and controls which will mitigate those risks and monitor ongoing compliance.

Auditor's responsibilities

Our responsibilities in terms of clauses 2.8.1(1)(b)(vi) and (vii), and 2.8.1(1)(c), are to express an opinion on whether:

- as far as appears from an examination, the information used in the preparation of the audited Disclosure Information in the Annual Delivery Report has been properly extracted from the company's accounting and other records, sourced from its financial and non-financial systems;
- as far as appears from an examination, proper records to enable the complete and accurate compilation of the audited Disclosure Information in the Annual Delivery Report required by the Determination have been kept by the company and, if not, the records not so kept; and
- the company complied, in all material respects, with the Determination in preparing the audited Disclosure Information in the Annual Delivery Report.

To meet these responsibilities, we planned and performed procedures in accordance with ISAE (NZ) 3000 (Revised) and SAE 3100 (Revised), to obtain reasonable assurance about whether the company has complied, in all material respects, with the Disclosure Information in the Annual Delivery Report required to be audited by the Determination.

For the forecast information reported in the audited Disclosure Information, our procedures were limited to checking that the information agreed to the company's published Project and Programme Delivery Plan prepared and certified by the directors of the company in accordance with clause 2.9.5 of the Determination.

An assurance engagement to report on the company's compliance with the Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the requirements. The procedures selected depend on our judgement, including the identification and assessment of the risks of material non-compliance with the requirements.

Other information

The directors of the company are responsible for the other information. The other information comprises all of the information included in the Annual Delivery Report other than the audited Disclosure Information and our assurance report thereon.

Our opinion does not cover the other information, and we do not express any form of opinion or assurance conclusion thereon.

In connection with the reasonable assurance engagement of the audited Disclosure Information, our responsibility is to read the other information. In doing so, we consider whether the other information is materially inconsistent with the audited Disclosure Information, or our knowledge obtained in the reasonable assurance engagement, or otherwise appears to be materially misstated. If, based on our work, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Inherent limitations

Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error, or non-compliance with the Determination may occur and not be detected.

A reasonable assurance engagement throughout the disclosure year does not provide assurance on whether compliance with the Determination will continue in the future.

Restricted use of this report

This report has been prepared for use by the directors of the company and the Commerce Commission in accordance with clause 2.8.1(1)(a) of the Determination, and is provided solely for the purpose of establishing whether the compliance requirements have been met. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the company and the Commerce Commission, or for any other purpose than that for which it was prepared.

Independence and quality control

We complied with the Auditor-General's independence and other ethical requirements, which incorporate the requirements of Professional and Ethical Standard 1, *International Code of Ethics for Assurance Practitioners (including International Independence Standards) (New Zealand)* (PES 1), issued by the New Zealand Auditing and Assurance Standards Board. PES 1 is founded on the fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behaviour.

We have also complied with the Auditor-General's quality management requirements, which incorporate the requirements of Professional and Ethical Standard 3, *Quality Management for Firms that Perform Audits or Reviews of Financial Statements, or Other Assurance or Related Services Engagements* (PES 3), issued by the New Zealand Auditing and Assurance Standards Board. PES 3 requires our firm to design, implement and operate a system of quality management including policies or procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

The Auditor-General and his employees, and Audit New Zealand and its employees, may deal with the company on normal terms within the ordinary course of trading activities of the company. Other than any dealings on normal terms within the ordinary course of trading activities of the company, this engagement, the assurance engagement on the Disclosure Information, the assurance engagement on the Customised Price-Quality Path, the assurance engagement on the operating leases information and the depreciation of existing assets information, and the annual audit of the company's financial statements and statement of service performance, we have no relationship with, or interests in, the company.

A handwritten signature in black ink, appearing to be "Chantelle Gernetzky".

Chantelle Gernetzky
Audit New Zealand
On behalf of the Auditor-General
Christchurch, New Zealand
27 August 2025

