Firstlightnetwork®

Asset Management Plan Update

31 March 2025

MESSAGE FROM OUR CEO

Welcome to the Firstlight Network 2025 Asset Management Plan (AMP).

As we navigate the evolving energy landscape, we remain steadfast in our commitment to enhancing resilience, responding to the energy transition and balancing the energy trilemma. This AMP outlines our ongoing initiatives to improve the reliability of our network, ensuring that we can meet the needs of our customers now and in the future.

The past year has been challenging, due in large part to weather events and issues with out-of-zone vegetation that have tested the resilience of our network. Our Firstlight Network team has shown dedication and adaptability in providing electricity distribution services to our customers in Gisborne, Wairoa, and the East Coast.

We understand the importance of affordable electricity for consumers, and we are working hard to balance cost concerns with the need to maintain a resilient and reliable network. Price increases taking effect from 1 April this year will have a real impact on many in our communities.

Increased investment in our network is necessary to build more resilience in our region's network, maintain and replace assets built last century and adapt to the forecasted significant increase in electricity demand by 2050. This AMP Update describes the level and timing of investment that we plan to undertake. We know that most of our unplanned outages are on rural parts of the network, and we are spending approximately 75% of our capital expenditure in these areas to improve the reliability of the network. Without this investment, we risk higher prices in the future, less reliable electricity, and a network that cannot keep up with demand growth.

As we look ahead, we are excited about the opportunities that the energy transition presents in the communities we serve. We are committed to balancing affordability, security, and sustainability, and this AMP Update reflects our efforts to achieve these goals. We believe that by working together with our stakeholders, we can create a sustainable and resilient energy future for our customers.

Thank you for your continued support.

Goodeve

Paul Goodeve

CEO, Firstlight Network, part of Clarus

EXECUTIVE SUMMARY

2025 Asset Management Plan Update

Our Asset Management Plan (AMP) Update builds on our previous AMP disclosures and provides updated expenditure forecasts for the coming 10-year period. It summarises our work programme and reliability performance for the regulatory year ending 31 March 2025 and explains material changes to our investment plans since our 2024 AMP Update. Finally, this AMP Update describes our ongoing initiatives to improve the reliability and resilience of our network.

A safe and resilient network

Firstlight's electricity network spans the Gisborne, Wairoa, and the East Coast districts and connects the national electricity grid to our customers' homes and workplaces. The network provides residential and business customers a safe, secure, and reliable electricity distribution service. Firstlight is part of the wider Clarus Group.

Safety remains our foremost organisational priority, and we challenge ourselves to put safety and well-being at the heart of everything we do. We continue to take an uncompromising approach to safety and will act when we believe there are safety risks to the public, our staff, or service providers.

Network resilience is an urgent priority for us, as changing climate brings with it more frequent and more powerful storms and floods. Climate modelling and our own recent experiences suggest that extreme weather events will continue to increase in both frequency and intensity over the coming decades. Extreme weather adversely impacts the performance and safety of electricity assets. As a result, climate change poses ongoing risks to our network and its performance.

The impact of severe weather events will be compounded by deteriorating condition of ageing assets. We are continuing to address the impacts of severe weather, including progressively reinstating damaged subtransmission assets and progressing a range of reliability performance initiatives (as set out in Chapter 5).

Our assets and operational systems need to be more resilient to extreme weather and asset failure events. Firstlight is adapting its asset management approaches to improve resilience in the face of increasingly severe weather.

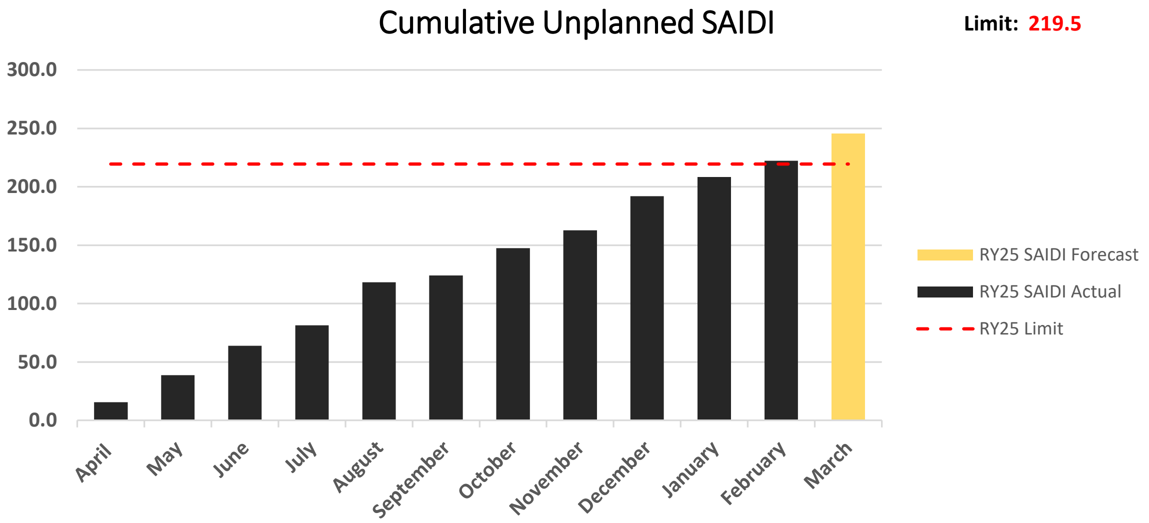
Reliability Performance

Delivering appropriate levels of service reliability is a priority for Firstlight. The levels of service our customers receive are influenced by a range of factors, including asset condition, weather, nearby vegetation, third-party activities, our capacity to respond to incidents, and network security.

The levels of reliability we can deliver today reflect historical trade-offs between cost and delivered levels of service. Improving service performance is often a long-term undertaking and has cost implications. We recognise that this trade-off needs to be based on our customer's preferences, while ensuring our network is safe.

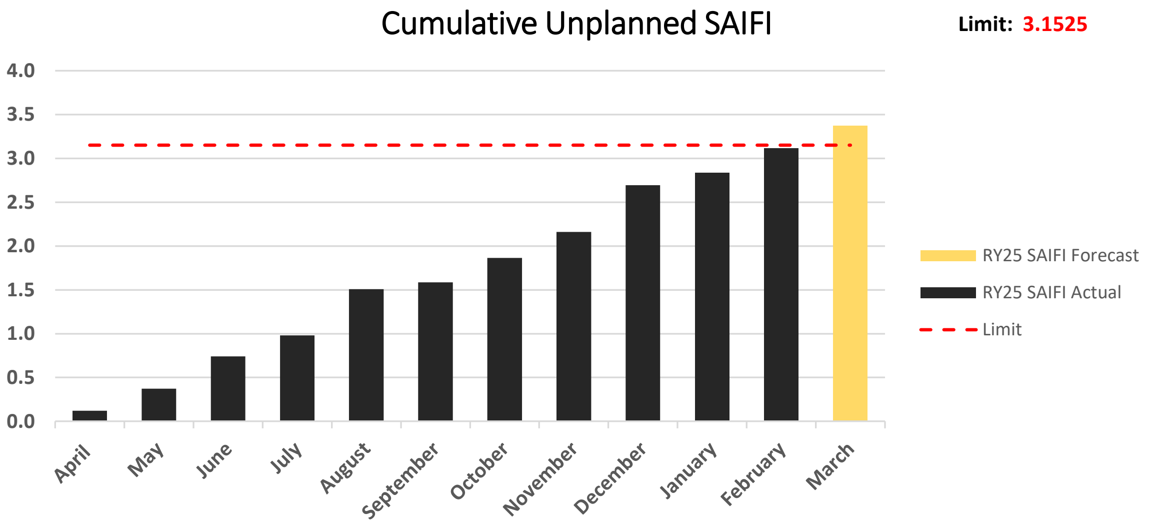
While the 2025 regulatory year has seen fewer extreme weather events, we have still experienced a number of wind and rain events. As the year progressed a range of factors (discussed in Section 3.4) have contributed to unplanned SAIDI ending the year considerably lower than the last two years but above our annual regulatory limit for unplanned SAIDI (as depicted below).

Cumulative unplanned SAIDI



Based on projections for the remainder of the regulatory year our unplanned SAIFI will also exceed the regulatory limit. The final outcome will depend on outages through the remainder of March.

Cumulative unplanned SAIFI



As discussed in Chapter 3, unplanned SAIFI has mainly been caused by a large number of vegetation-related outages (driven by high winds and out-of-zone trees) and equipment failures. Chapter 5 sets out a series of ongoing and planned improvement initiatives that we expect to improve reliability performance over the coming years.

Our investments focus on addressing reliability performance

Approximately 75% of our unplanned SAIDI occurs on rural parts of our network. In response to this, we have been directing over three quarters of our lifecycle Capex to these rural areas to improve reliability and to manage safety risk. This focused investment demonstrates our commitment to addressing the ongoing reliability challenges across our network.

Improving our Asset Management Capability

We believe strong asset management drives efficient delivery, and we're continuing to improve our asset management maturity. Capability development (e.g. embedding appropriate processes, systems, and techniques in our business) is essential, and the improvements that we have made in this area include:

- optimising inspection routes and tracking notifications to tree owners though the use of a new vegetation management dashboard
- analysing unplanned interruptions to determine the best locations to target inspections, install sectionalisers and load fault indicators
- analysing equipment failures and the equipment's health indicator, to understand the health and age of assets failing and whether corrective maintenance activities would have increased life cycle
- better analysis and visibility to the business of unplanned interruptions and making this available through centralised dashboards.

Recognising opportunities to improve our asset management and the need to address the network reliability challenges we, and the wider electricity distribution sector face, we will be reviewing our asset management improvement roadmap in RY26. We expect this to include further improvements, such as:

- aligning our asset management system and processes with ISO 55000
- undertaking a comprehensive review of our AMMAT scoring
- reviewing and updating all asset fleet plans
- identifying asset classes that we can utilise Repex modelling for AMP26 forecasts and asset health
- assessing any new functionality Maximo application suite can provide in our asset management system.

These improvements, which will inform our 2026 AMP, will support improved reliability outcomes and are being directed towards aspects of capability that can deliver the most benefits.

Section 3.3.1 sets out further examples of the capability improvements we are progressing.

2025 AMP Update Expenditure Forecasts

As a lifeline utility, it is critical that we invest prudently to ensure our assets are safe, reliable, and resilient in the longer term. Our renewal investments and operations and maintenance activities help to maintain the condition and performance of our assets and to prevent increases in risk. Our expected total capital expenditure (Capex) and operating expenditure (Opex) profiles over the AMP period are set out below.

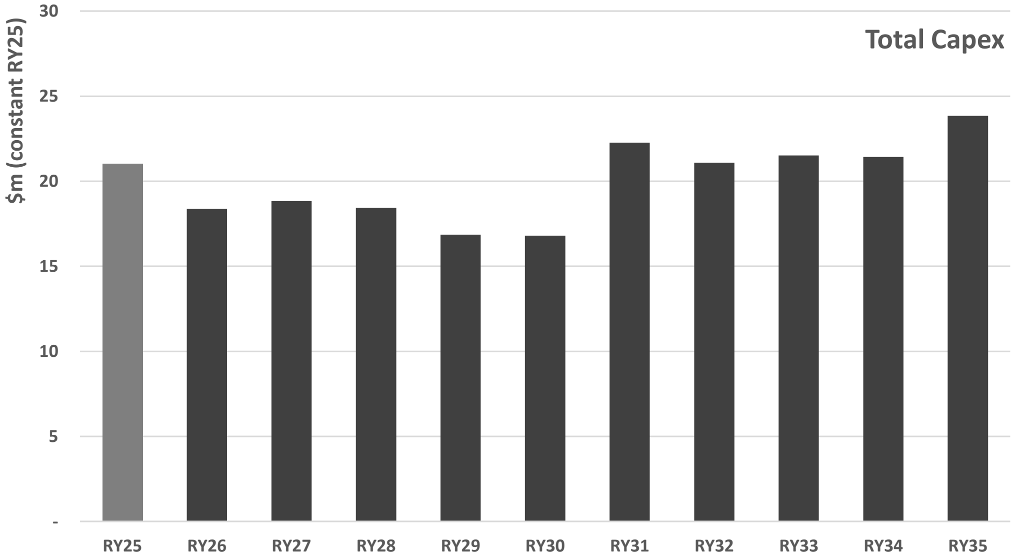
DPP4 Expenditure Allowances

Our expenditure forecasts have been developed to align with our default-price-quality path (DPP) allowances as determined by the Commerce Commission.[1] These allowances have been set below the amounts set out in our 2024 AMP Update and resulting changes to our investment plans are explained in Chapter 4.

Capital Expenditure

Firstlight believes that timely asset renewal and modernisation of our assets is an important foundation for delivering a safe and resilient network. The Capex forecasts in this AMP include targeted investments to deliver these outcomes.

Forecast Capex during the AMP Period (constant RY25)



Our planned Capex from RY26 through RY30 has been reprioritised to focus on asset renewal and investments to improve reliability. This will see a continuation of higher investment compared with historical levels. This demonstrates our commitment to maintaining required levels of Capex to address those assets impacting our reliability performance. During the remainder of the AMP period, we expect to lift investment during DPP5 and will set out details on these investments in our 2026 AMP.

During DPP4, most of our Capex relates to the renewal of our overhead assets, dealing with geohazards, and refurbishing ageing assets. Other renewal programmes are relatively stable over the period. The 10-year profile varies over time due to the presence of larger 'lumpy' investments and projects towards the beginning and end of the period. The timing of these works reflects the latest prudent timing for addressing the related needs.

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[1] Details on the decision can be found here.

Potential Need for Reopeners

Our Capex expenditure over the RY26 to RY30 period have been adjusted to align with the DPP allowances as determined by the Commerce Commission.[2] We have prioritised expenditure based on the degree to which it manages safety and reliability risk on the network.

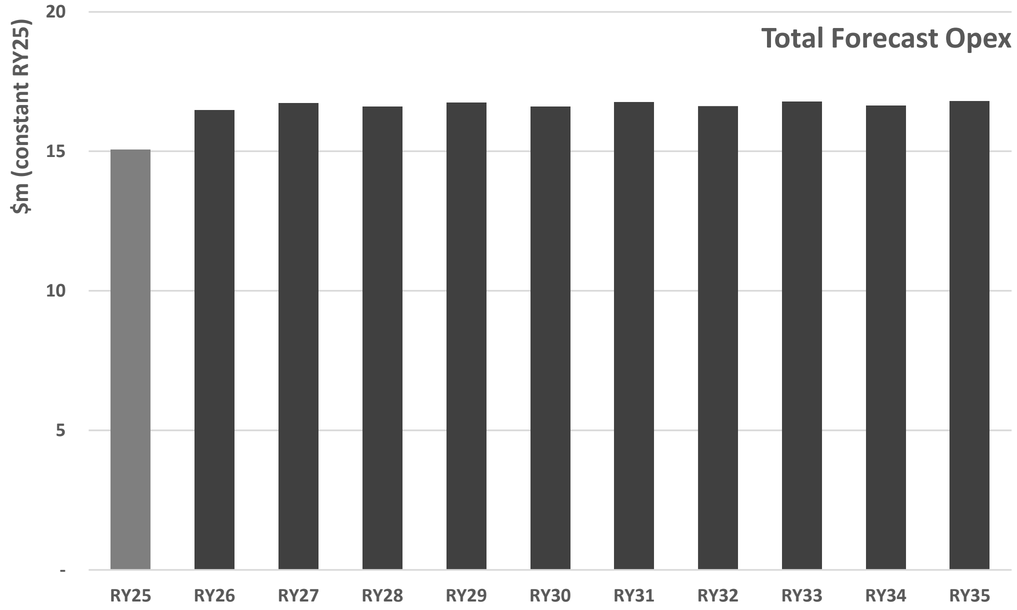
Several projects have been excluded from this AMP Update, due to available funding from DPP allowances and a degree of uncertainty surrounding the timing and/or scope of the projects. The need for these investments will continue to be monitored and reassessed as new information becomes available and may become candidates for regulatory reopeners.

We remain committed to making the necessary levels of investment to ensure a safe, reliable, and resilient distribution service for the communities we serve. Our expenditure in the coming years will be prioritised to support these outcomes.

Operating Expenditure

Our planned Opex during the AMP period is set out below.

Forecast Opex during the AMP Period (constant RY25) Updated Chart



Our planned Opex forecast is relatively stable from RY26 onwards through the AMP period and has been aligned to our DPP allowance in the initial years of the period. The amounts reflect the underlying levels of operations and maintenance, support costs, and people costs to manage our network. As we progress our renewal programs, we expect that reactive maintenance activity (e.g. repairs) will reduce over time. We have increased Opex on vegetation management activities to manage reliability performance.

Consistent with good practice, we are reviewing our maintenance and inspection programmes and plan to improve our maintenance regimes including enhanced data

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[2] Details on the decision can be found here.

capture for better analysis and work prioritisation. Further detail on these initiatives is set out in Chapter 5.

Concluding Comment

While managing within the constraints of our DPP allowances, we have developed Capex and Opex forecasts aimed at stabilising and gradually improving network resilience and reliability. Our expenditure priorities reflect recent network performance on our network and the increasing risks associated with escalating impacts of climate change and our ageing assets. The forecasts have been developed to support our improvement initiatives.

Our key expenditure driver continues to be providing a safe network that meets the needs of Gisborne, Wairoa, and East Coast communities, now and in the future.

1. INTRODUCTION

This AMP Update builds on our previous AMP disclosures and provides updated expenditure forecasts for the coming 10-year period. In addition, the AMP Update discusses our work program and reliability performance for the regulatory year ending 31 March 2025 and explains material changes to our investment plans.

1.1. Objectives of the AMP Update

This AMP Update covers the 10-year period from 1 April 2025 to 31 March 2035 and relates to the electricity distribution services supplied by Firstlight. The AMP meets the requirements of the Electricity Distribution Information Disclosure Determination 2012. Appendix B sets out how the AMP Update meets these requirements.

The AMP was approved by our Board on 28 March 2025.

1.2. Structure of the AMP Update

This document is structured as follows.

Table 1.1: Document Structure

CHAPTER		DESCRIPTION
1	**Introduction**	This chapter
2	**Overview of Firstlight**	Provides an overview of our business.
3	**Year in Review**	Discusses our work program and reliability performance for the regulatory year ending 31 March 2025.
4	**Expenditure Plans**	How our investment plans have changed since our 2024 AMP Update
5	**Reliability and Resilience Improvement Initiatives**	Our ongoing program to develop and implement reliability improvement initiatives.
APPENDICES		DESCRIPTION
A	**Disclosure Schedules**	AMP disclosure schedules required by the Commerce Commission
B	**Disclosure Requirements**	Sets out how the AMP Update meets Information Disclosure requirements
C	**Director's Certificate**	A copy of the AMP's director certification

2. OVERVIEW OF FIRSTLIGHT

This section introduces the Firstlight business and provides an overview of the organisation. It also provides information on our approach to asset management and our approach to stakeholder engagement.

2.1. Our Business

Firstlight Network Limited (Firstlight) owns and maintains the electricity distribution assets that supply Gisborne, Wairoa and the East Coast providing electricity to approximately 26,100 customers over an area of approximately 12,000km^2. These regions are geographically isolated with challenging topography and limited access. The network area is predominantly rural with two urban centres.

> **Clarus**
>
> Firstlight is part of the wider **Clarus Group**.[3] Clarus is one of New Zealand's largest energy groups with businesses that touch many aspects of the energy supply chain including Rockgas, Firstgas, Firstlight Network, First Renewables and Flexgas.

2.2. Asset Management Strategy

Our objectives as a business directly influences our approach to asset management through our overarching strategy to provide safe, reliable and cost-effective services to our customers. We believe that effectively delivering this strategy will ensure our business remains sustainable and lead to improving outcomes for the communities of Gisborne, Wairoa and the East Coast.

2.2.1. Network Objectives

Throughout this AMP Update, we describe how we will achieve the following important objectives for our customers and wider stakeholders:

- **Safety commitment**: the safety of our customers, staff, service providers and the general public is paramount.
- **Effective engagement**: by consulting with our stakeholders, particularly on our planned investments, and how we manage our network to deliver for customers. This means we need to provide clear descriptions of our key strategies and objectives.
- **Performance accountability**: provide visibility to stakeholders on how we are performing and provide information on the performance of our network.
- **Investment planning**: provide visibility of forecast investment programmes and upcoming medium-term construction works, with a clear rationale as to why planned investments are the best way to meet customer needs.

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[3] Further details available at the website https://clarus.co.nz/

- **Improving capability**: provide guidance and training on our asset management approach to staff and service providers to ensure common understanding and suitable resourcing.
- **Regulatory compliance**: ensure we meet our Information Disclosure obligations set by the Commerce Commission.

2.3. Stakeholder Engagement

This section provides an overview of Firstlight's engagement with stakeholders and how that engagement has shaped our decision making. We engage with regulators, retailers, stakeholders, and customers to ensure that we can meet the needs of our customers.

Firstlight recognises the importance of engaging with businesses and customers who rely on the safe and reliable delivery of electricity to support their businesses and households. Our focus is to engage with our stakeholders on the following topics:

- Understanding our customers' views and preferences for their energy supply and the transition to new solutions (e.g. EVs and PV)
- Firstlight connection policies and pricing methodologies
- Firstlight investment and asset maintenance strategies and key operational decisions
- Regulatory and government policy processes.

Delivering for our communities needs to be underpinned by meaningful, effective engagement with our customers and other stakeholders. We do so through a range of channels, actively consulting with them on what matters most to them and their experience in dealing with us.

- customer satisfaction surveys are run annually to test how well we are responding to their needs
- we actively engage with forestry owners to improve our shared understanding of how vegetation impacts our assets and how this risk can be managed
- our online safety centre provides information and advice on safety related issues
- outage communications through social media and our website for planned outages[4]
- iwi engagement
- our online 'home energy hub' provides information and advice on electricity bills
- stakeholders affected by major projects are consulted and their views are taken on board during the project planning phase

We recognise that affordability is a key concern, particularly for vulnerable customers. We continue to engage with customers to balance cost and service quality. As part of our annual customer surveys, it was a key finding that keeping the power on and getting it back on quickly is the most important part of our service, while keeping line charges low is increasing in importance. We will continue to increase stakeholder engagement through RY26 and incorporate these views to help inform future pricing and investment plans.

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[4] https://firstlightnetwork.co.nz/tell-me-about/outages

We continue to increase our efforts to work more closely and collaboratively with stakeholders, as part of this we welcome your feedback on this AMP.

2.3.1. Managing Diverging Interests

In the operation of any large organisation with numerous stakeholders and diverse interests, situations will inevitably arise where not all interests can be accommodated, or where conflicting interests exist. For example, different customers may place greater or lesser emphasis on price or quality.

From our perspective, situations of conflicting interests are best managed by:

- Clearly identifying and analysing stakeholder conflicts (existing or potential).
- Seeking solutions that are consistent with the principles found in industry codes and in relevant legislation or regulation.
- Communicating effectively with stakeholders so that all parties know where they stand.

In all instances of conflicting interests, we will strive to engage with stakeholders in a transparent manner to explain our decisions.

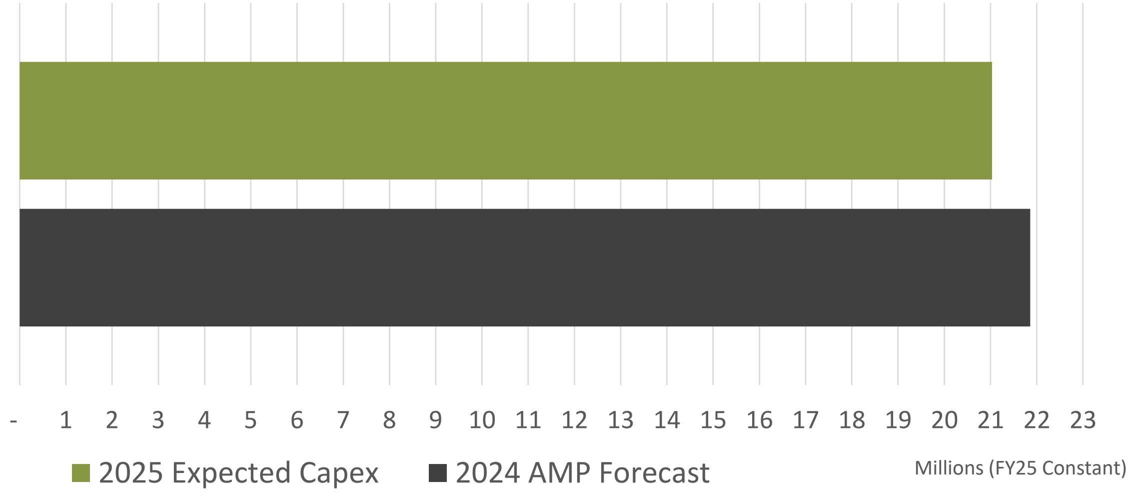
3. YEAR IN REVIEW

This section provides an overview of Firstlight's investments, main initiatives, and reliability performance over the past year ending 31 March 2025.

3.1. Capital Expenditure Summary

Firstlight remains focused on building and maintaining a safe and reliable electricity distribution network for customers across Gisborne, Wairoa and the East Coast. This focus is reflected in the work programme that was undertaken over the last 12 months.

Figure 3.1: Total expected Capex in RY25 versus forecast Capex in the 2024 AMP

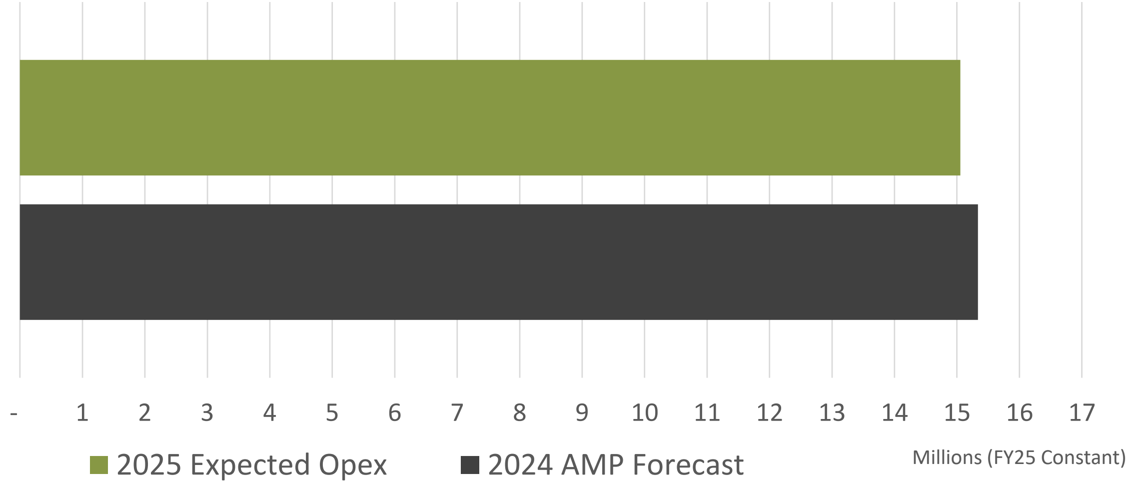


Our expected Capex during RY25 is likely to be just below our AMP 24 forecast. The eventual total will vary depending on completed works during March. We successfully maintained our accelerated pole replacement and rural automation programs during RY25. These have been prioritised to help improve our reliability performance. The main reason for the slightly reduced Capex was lower than expected customer connection volumes.

3.2. Operating Expenditure Summary

Firstlight remains focused on effectively operating and maintaining its assets to provide a safe and reliable electricity distribution network for our customers across Gisborne, Wairoa and the East Coast. This focus is reflected in the activities undertaken over the last 12 months.

Figure 3.2: Total expected Opex in RY25 versus forecast Opex in the 2024 AMP



Our expected Opex during RY25 will be in line with our AMP 24 forecast. The eventual total may vary depending on activity levels, including reactive maintenance, during March. These have been prioritised to help improve our reliability performance.

3.3. Significant Activities Undertaken in RY25

In this section we set out a summary of key investments and related activities during RY25.

3.3.1. Asset Management Capability Improvements

We believe strong asset management drives efficient delivery, and we're continuing to improve our asset management maturity. Capability development (e.g. embedding appropriate processes, systems, and techniques in our business) is essential, and the improvements that we have made in this area include:

- optimising inspection routes and tracking notifications to tree owners though the use of a new vegetation management dashboard.
- improving vegetation surveillance by deploying a mobile application to contractors and staff.
- Improving our pole forecasting and asset health by utilising Repex modelling.
- Updating our pole management plans against EEA timber pole condition assessment guide and updating the following:
  - pole fleet plans,
  - pole inspection standard,
  - pole inspection training,
  - deployment of a new mobile inspection app and inspection dashboard to improve condition data capture on poles, crossarms, insulators and conductors,
  - applying EEA defect rating scale to poles,
  - implementing EEA tagging practices.
- Analysing unplanned interruptions to determine the best locations to target inspections, install sectionalisers and load fault indicators.

- Analysing equipment failures and the equipment's health indicator, to understand the health and age of assets failing and whether corrective maintenance activities would have increased life cycle.
- better analysis and visibility to the business of unplanned interruptions and making this available through centralised dashboards.

Recognising opportunities to improve our asset management and the need to address the network reliability challenges we, and the wider electricity distribution sector face, we will be reviewing our asset management improvement roadmap in RY26. We expect this to include further improvements, such as:

- Aligning our asset management system and processes with ISO 55000.
- Undertaking a comprehensive review of our AMMAT scoring.
- Reviewing and updating all asset fleet plans.
- Identifying asset classes that we can utilise Repex modelling for AMP26 forecasts and asset health.
- Assessing any new functionality Maximo application suite can provide in our asset management system.

These improvements, which will inform our 2026 AMP, will support improved reliability outcomes and are being directed towards aspects of capability that can deliver the most benefits.

When developing our annual work programme, we assess the current and previous year's reliability, looking for trends across the network, such as equipment failures or vegetation-related outages. The analysis identifies our worst performing feeders, which we use to target our inspections, lifecycle and reliability Capex programs.

3.3.2. Network Automation Program

Our automation program aims to enhance network performance and customer outcomes by minimising the number of customers impacted during a fault, swiftly identifying fault locations, and reducing the extent of network isolation during repairs.

- Sectionalisers and auto-reclosers have been installed in strategic segments of the network to partition the system during faults, thereby maintaining connectivity for more customers.
- Load fault indicators have been deployed in rural and remote areas to reduce response times and to improve repair efficiency in those areas.
- In addition, ground-mounted oil switches have been replaced at key locations to minimise the scope of network isolation necessary for repairs.

Further work on our network automation program, including additional installations and replacements is planned for RY26.

The following table sets out the automation projects completed in RY25.

Table 3.1: Sectionalisers installed in RY25

SECTIONALISERS INSTALLED IN RY25			
A91 Whāngārā	H1219 Matā	J309 Whakaangiangi Road	W810 Mōrere
D3416 Tahora	H135 Tuakau Road	J3702 East Cape Road	W799 Ruakituri
D2703 Wharekōpae Road	H1726 Makarika Road	W958 Mahanga, Māhia	W5585 Raupunga
F423 Matawai	J1048 Waiomatatini Road	W900 Ōpoutama, Māhia	W3953 Mōhaka
W789 Mahanga YMCA Rd, Māhia	G1419 Anaura Road	W1015 Kotemaori	G1074 Arakihi Road
W1221 Māhia East Coast Rd, Māhia			
OVERHEAD LOAD FAULT INDICATORS INSTALLED IN RY25			
Lavenham/Kaimoe	Tāhaenui Blacks Pad 33kV	Puha-Ngātapa 50kV	Raupunga – 11kV
Lavenham/Tiniroto	Tolaga-Tokomaru Bay 50kV	Gisborne-Makaraka 50kV	Dalton/Huxley – 11kV
Lavenham/Brunton	Gisborne Hexton/Puha 50kV		
OIL SWITCH REPLACEMENTS INSTALLED IN RY25			
B766 Stout Street	B848 Oak Street	A342 Crawford Road	B1043 Solanders St.
B751 Stanley Road	W1070 Clyde Road, Wairoa	W294 McLean St, Wairoa	A400 Maki Street

3.3.3. Pole Replacement and Inspection Programme

During RY25, the replacement of poles has been a significant focus. This initiative not only enhances network safety for both the public and our workforce but also supports improved reliability by replacing outdated components such as crossarms, insulators, and joints. Over RY25, we expect 680 low voltage, distribution and subtransmission poles to be replaced.

Efforts are ongoing to optimise the volume of pole replacements, analyse the collected data, and explore the benefits of a dedicated crossarm replacement program. Considering the age of the poles, full replacement currently offers substantial benefits.

As outlined in the Improving Asset Management Capability (Section 3.3.1), we have been refining our approach to managing the lifecycle of poles.

Previous inspection standards did not fully align with industry guidelines, resulting in poles being identified for replacement if inspectors anticipated they would require replacement within five years. To improve our practices, we have adopted the EEA guideline to develop a new inspection procedure.

When planning pole replacements, we consider customer disruption, site location, and the need for track construction or helicopter support. We may proactively replace nearby poles nearing the end of their service life to improve efficiency and reduce future work.

We typically replace wooden poles with concrete poles and have installed 417 concrete poles in RY25. However, due to the varied terrain in our network, we install lighter wooden poles when necessary. We are also reviewing the use of composite poles, which offer a longer service life, to reduce reliance on wooden poles in the future.

3.3.4. Vegetation Management

Towards the end of RY24, we implemented a dedicated application to support our vegetation management and increase the efficiency and effectiveness of this key work program. RY25 is the first full year in which we've deployed the tool, which uses aerial, photo-based mapping for accurate tree location identification. Key features of the application include:

- Allows viewing landowner data, photos, and notices recorded against each tree
- Interfaces with LINZ land data for easy landowner identification
- Staff and contractors can record actions and gather information on-site, with data captured in real-time
- Uses a traffic light system to identify the status of trees and critical sites
- Improves contractor efficiency by providing precise site location and information.

An updated vegetation management plan was implemented in RY25, with a number of operational changes with the aim of:

- reducing unplanned SAIDI due to vegetation
- improving financial efficiency through optimal inspections and patrolling

The changes in practices include monthly strategic planning reviews to assess and adjust the patrols based on current data received through the new vegetation application and unplanned outage data. We are also able to measure the volume of trees cut per dollar spent, to measure the efficiency of the vegetation management plan.

Work is continuing on how engage with forestry owners and how we manage vegetation risk for out-of-zone trees within commercial forests.

Table 3.2: Overview of RY25 vegetation management activity

RY25 VEGETATION STATISTICS	
Feeders completely inspected	22
Feeders' vegetation cleared	7
Trees cut	24,654
1st cut notices issued	453
2nd cut notices issued	165
No interest declared	180
RY25 VEGETATION EXPENDITURE	
Emergent risk vegetation clearing (YTD end of January)	$102k
Planned vegetation clearing (YTD end of January)	$676k

3.4. Reliability Performance

This chapter discusses our reliability performance during the 2025 regulatory year. Consistent with the DPP framework, the main reliability measures we monitor are as follows:

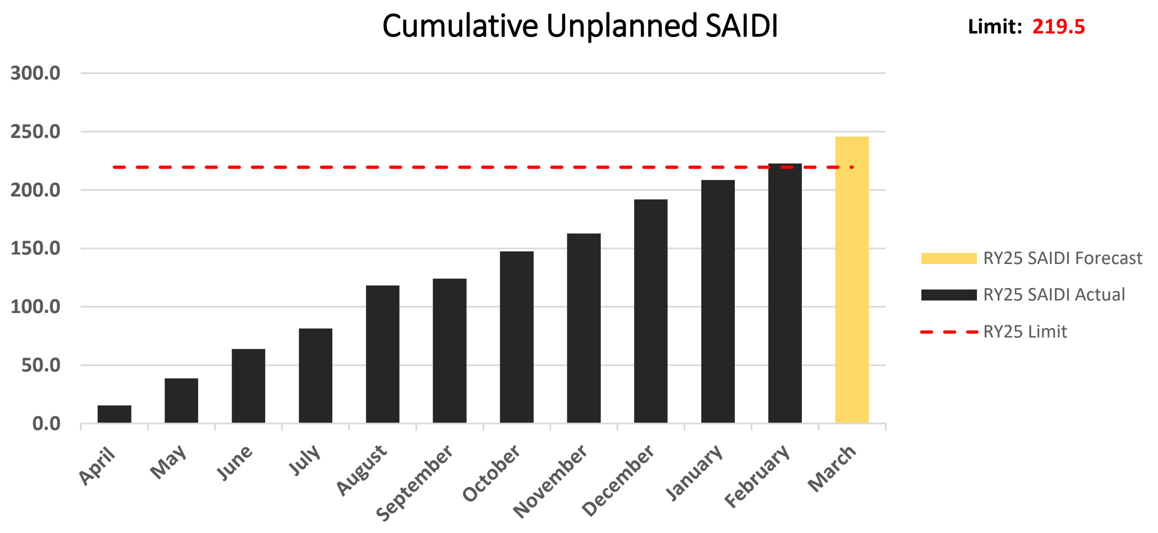
- Unplanned SAIDI
- Unplanned SAIFI
- Planned SAIDI
- Planned SAIFI

While the final performance figures for the 2025 regulatory year were not available at the time of publishing this AMP, we have set out expected outcomes for the year. As a result, the included statistics and analysis and subject to refinement and may change.

3.4.1. Unplanned SAIDI

While the 2025 regulatory year has seen fewer extreme weather events, we have still experienced a number of wind and rainstorms. As the year progressed a range of factors have contributed to unplanned SAIDI ending the year considerably lower than the last two years, however we have exceeded our annual regulatory limit for unplanned SAIDI (as depicted below).

Figure 3.3: Cumulative unplanned SAIDI



The key drivers for unplanned SAIDI during RY25 were vegetation exacerbated by high winds (39%), equipment failure (20%) and adverse weather (19%). Chapter 5 of this AMP Update sets out a series of ongoing and planned improvement initiatives that we expect to improve reliability performance over the coming years.

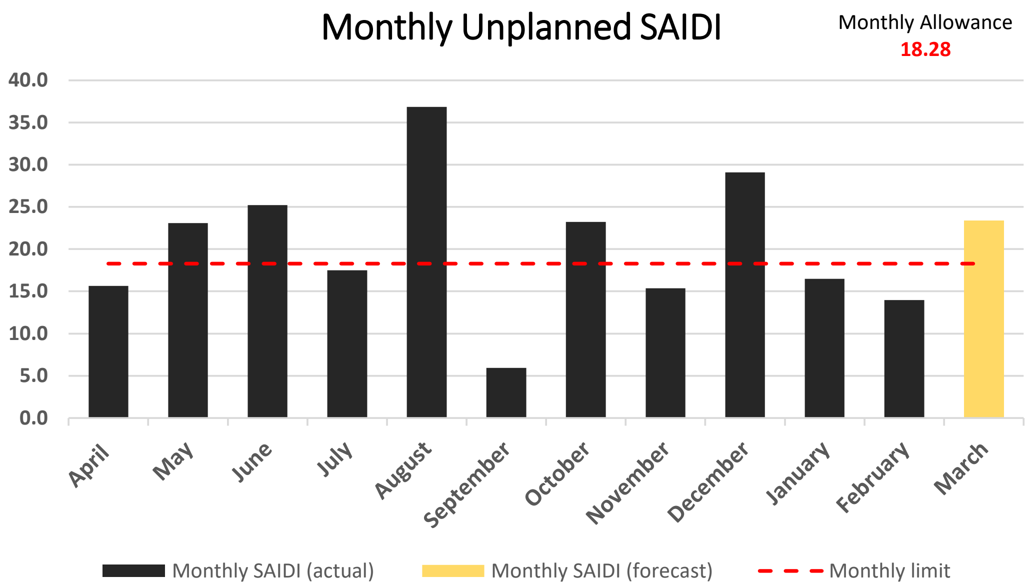
Reliability and Resilience Improvement Initiatives

Our reliability performance in RY25, and in recent years, provides further impetus to advance our reliability improvement initiatives. These initiatives are crucial to ensure we can comply with regulatory limits and deliver an appropriate level of service to our customers. By proactively progressing these initiatives, we aim to reduce unplanned outages and the likelihood of breaching our regulatory limits.

Monthly SAIDI Performance

As is typical practice, we monitor our monthly performance against a representative monthly 'allowance' (derived from our DPP limits).

Figure 3.4: Monthly unplanned SAIDI

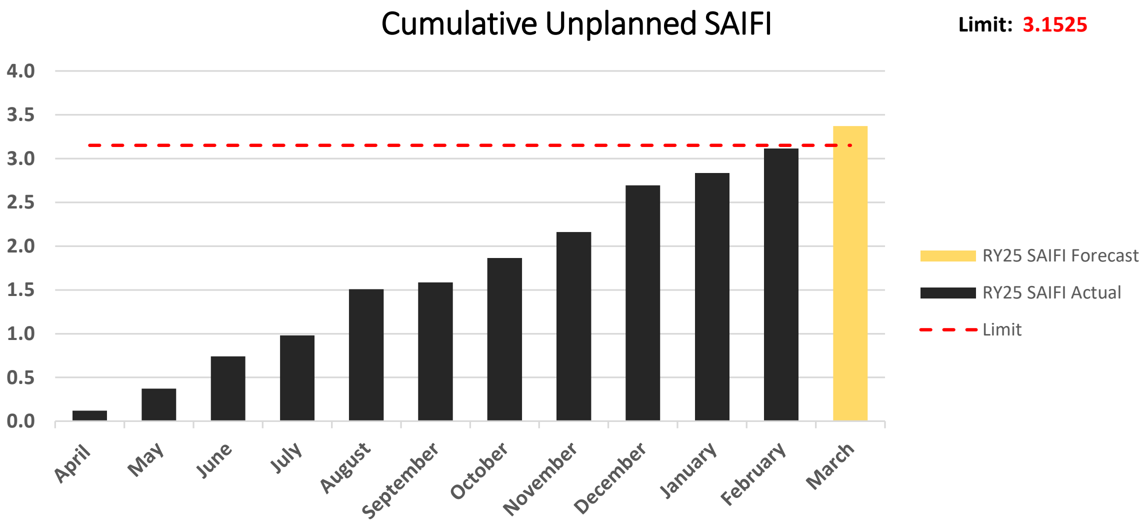


We discuss this monthly performance in Section 3.4.3.

3.4.2. Unplanned SAIFI

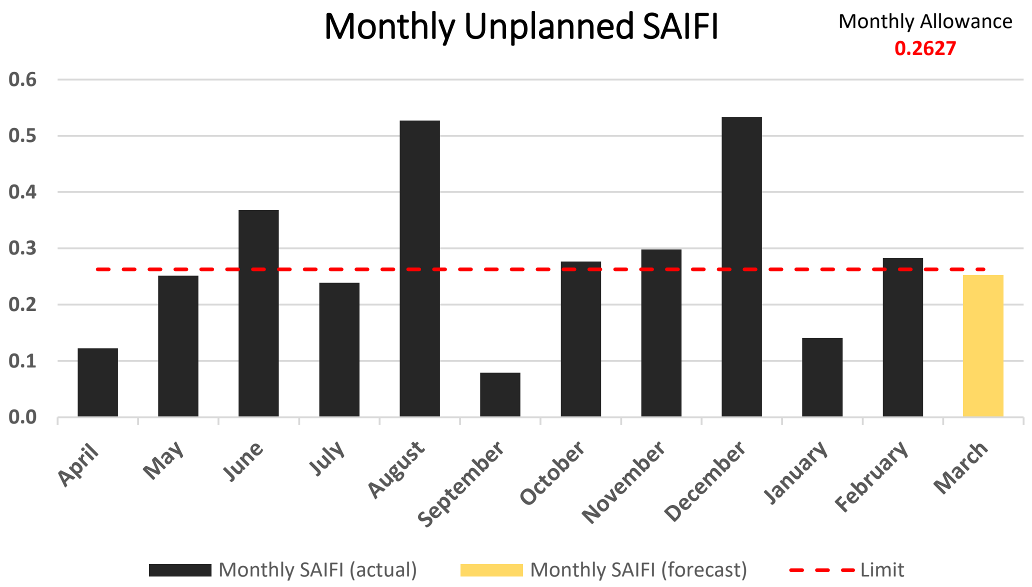
Based on our projections for the remainder of the regulatory period unplanned SAIFI expect to exceed our regulatory limit.

Figure 3.5: Cumulative unplanned SAIFI



The unplanned SAIFI breach has mainly been driven by vegetation-related outages made more frequent by poor weather.

Figure 3.6: Monthly unplanned SAIFI



We discuss this monthly performance in Section 3.4.3.

3.4.3. Drivers of Unplanned Outages in RY25

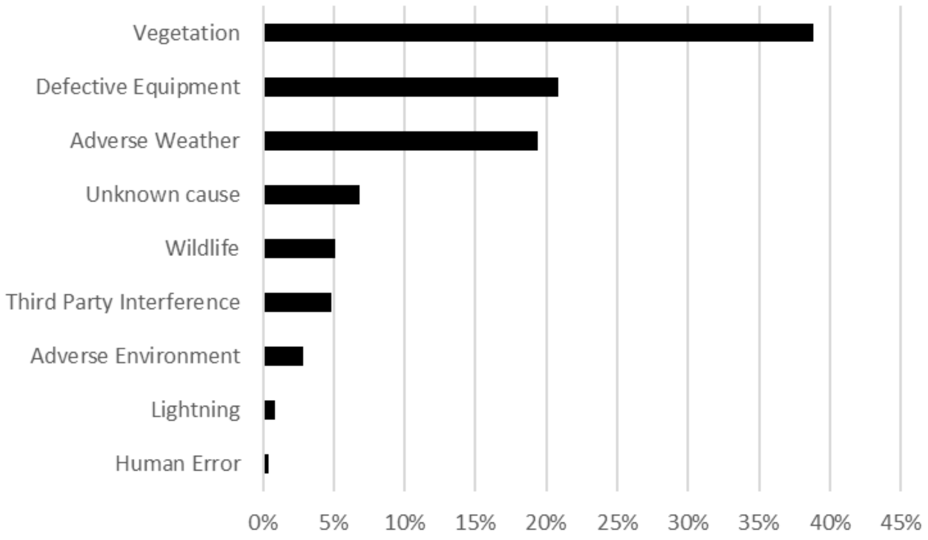
The main drivers of unplanned interruptions leading to unplanned SAIDI and SAIFI in RY25 are set out below.

Table 3.3: Unplanned outages with material SAIDI impacts during RY25

MONTH	OUTAGES	NORMALISED SAIDI	MAIN OUTAGE CONTRIBUTORS
April	35	16	– Third-party damage including car versus pole and a tree felled through our lines by landowner – Equipment failure at Tuai
May	74	23	– Equipment failure – Fuse fault in Valley Rd
June	79	25	– Trees through lines at two sites – Adverse weather in Nuhaka (wind)
July	47	19	– Fault at Parkinson St zone sub (unknown cause) – Equipment failure, lightning arrestor in Crawford Rd
August	102	37	– Tree through line at Tikitiki – Trees through multiple lines due to high winds
October	36	23	– Possum on subtransmission pole – Slip at Raupunga – Third-party damage
November	19	15	– Equipment failure – Third-party interference
December	57	27	– Adverse weather – Vegetation – High winds caused conductor clashing
January	22	16	– Adverse environment and weather – Vegetation – Equipment failures (ground mount transformer)
February	25	13	– Equipment failures (insulator and HV cable) – Third-party interference contributed

As depicted in the following chart, the key drivers for unplanned SAIDI during RY25 (up to end of February 2025) were vegetation exacerbated by high winds (39%), equipment failure (20%) and adverse weather (19%). We discuss the main drivers in more detail below.

Figure 3.7: Contribution of unplanned SAIDI (April to February)



Vegetation

This includes both in-zone and out-of-zone vegetation that leads to contacts with our equipment. This will become increasingly challenging due to higher wind speeds and more frequent storms. Approximately 90% of vegetation-related SAIDI is due to out-of-zone trees, the majority of which are not actively managed (i.e. non-plantation). It is likely that regulatory changes that address the management of out-of-zone trees would be required to effectively address these outages.

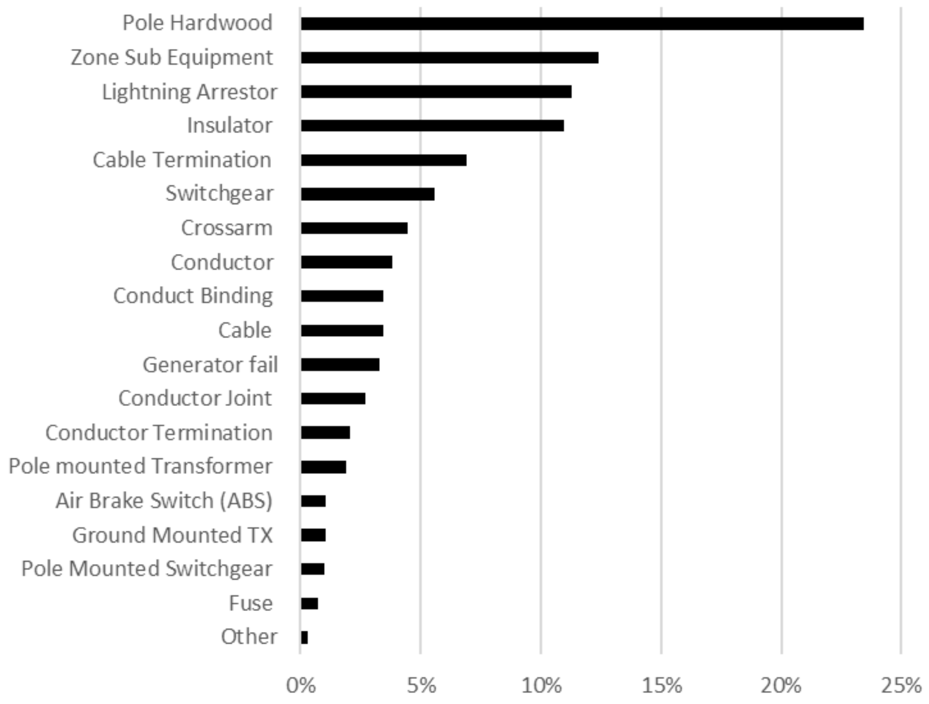
As discussed in Section 3.3.4 we continue to improve our approach to vegetation management. Over time we expect these improvements to reduce the impact of in-zone trees. However, the ongoing impacts of high winds on out-of-zone tree contacts remains a concern.

Equipment Failure

The following chart compares different types of equipment failures and their respective contributions to unplanned SAIDI.

Equipment failures contributed to interruptions, particularly issues with insulators and conductor bindings. To support our Strategic Reliability Management Plan (SRMP) and AMP 2026 forecasts we will undertake further analysis into equipment faults to determine patterns and potential mitigations for these faults. Ageing equipment is a key driver notably for pole-top equipment and associated conductor, which becomes increasingly prone to failure over time.

Figure 3.8: Main causes of equipment failure SAIDI (April to February)



Given the nature and scale of the overhead network it is typical that the most common interruptions are overhead assets which are more vulnerable to adverse weather and vegetation contacts. The impact of defects in remote locations is significant due to challenges associated with access and repair.

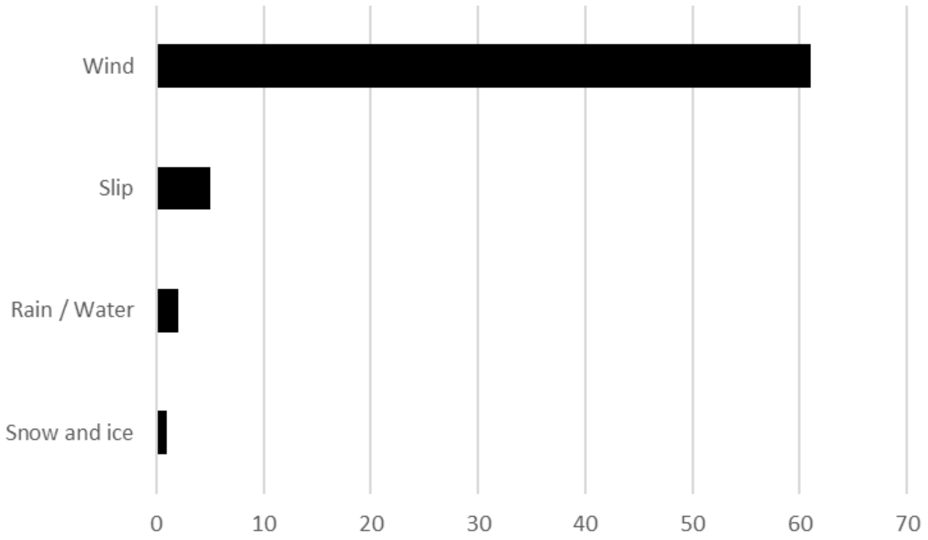
This information underscores the need for targeted asset management and renewal strategies, with a focus on higher-risk assets. Addressing ageing overhead assets requires effective inspections and a proactive approach to renewal, potentially with more resilient designs. This, together with our ongoing deployment of fault detection, improved field response, and the use of generators, will help reduce the future impact of equipment faults.

Based on these issues, several strategies and initiatives have been reflected within our reliability improvement initiatives. These are set out in Chapter 5.

Adverse Weather

Adverse weather continues to be significant contributors to unplanned outages. The ongoing impact of extreme weather (e.g. damaged foundations) can emerge and persist months after the event ends.

Figure 3.9: Outages due to adverse weather and environment cause (April to February)



The Gisborne and Wairoa regions are increasingly being impacted by adverse weather events. The increasing number of weather events is a key driver of unplanned interruptions and SAIDI on our network. High winds caused the majority of unplanned interruptions assigned to adverse weather. High winds can cause momentary trips as lines clash or momentary vegetation contact but then clear.

The resulting events lead to significant interruptions both through direct damage to assets (e.g. poles) and indirectly through impacts on fault restoration. Increasing rainfall leads to increased risk of slips impacting our assets. These conditions often result in damage to multiple assets leading to extended restoration times, especially in remote areas.

Our investment programmes during the DPP4 and DPP5 periods will include a focus on improving the ability of our network to withstand these events, and to increase operational capability to support our response.

Wildlife and third-party interference

Third-party incidents like vehicle damage to poles and conductor or cable strikes is a key driver of unplanned outages. These events continue to be a significant contributor to unplanned SAIDI. There has been numerous wildlife (e.g. birds/possums) incidents. Third-party interference tends to have a higher relative contribution due to the time required to ensure public and worker safety before rectification work can commence.

3.4.4. Planned SAIDI and SAIFI

We expect to meet our limits for both planned SAIDI and SAIFI during RY25. When undertaking our work programmes, we aim to ensure that we limit the necessary length and number of planned outages.

4. EXPENDITURE PLANS

This chapter sets out differences between our updated 2025 AMP Update forecasts and equivalent plans included in our 2024 AMP Update. Consistent with Information Disclosure requirements we have focused the discussion on "material"[5] changes.

Note the portfolios and fleets referred to below reflect our internal categorisation and may vary from those included in Schedules 11a and 11b.

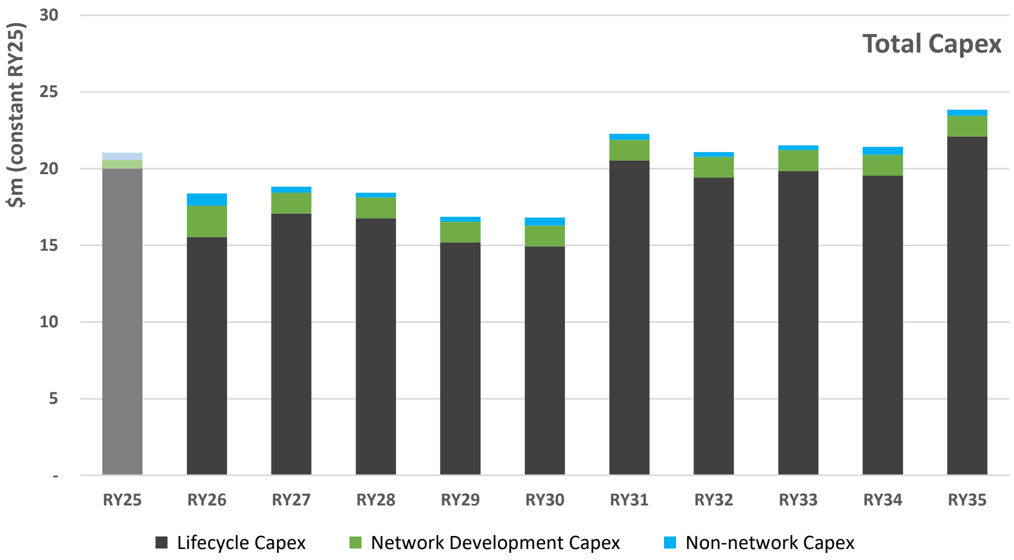
> **DPP4 Expenditure Allowances**
>
> Our expenditure forecasts have been developed to align with our DPP allowances as determined by the Commerce Commission. These allowances have been set below the amounts set out in our 2024 AMP Update. This has required reductions to our investment plans, which are explained below.

4.1. Overview of Total Capex

Consistent with our DPP allowances, and as part of our 'business-as-usual' internal planning and governance processes we have developed updated expenditure plans for RY25 and beyond. The chart below summarises our Capex forecasts over the period. To illustrate their respective priorities, this reflects the following Capex drivers:

- **Lifecycle**: includes asset renewal and investments focused on safety and reliability outcomes (RSE)
- **Network development**: includes connections and growth-driven investments
- **Non-network Capex**: investments to support our management of the network.

Figure 4.1: Forecast Capex during the AMP Period (constant RY25)



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[5] We have used a threshold for "material" consistent with our previous AMP Update disclosures.

This demonstrates our commitment to maintain required levels of Capex to address those assets impacting our reliability performance. We will support this important work through additional targeted inspections to ensure we address higher-risk assets, including poor condition poles.

4.2. Lifecycle Management Plans

Firstlight continues to improve its forecasting approaches to forecasts and incorporate condition-based asset health scores. The principal asset lifecycle strategy to mitigate the failure risks posed by ageing or poor condition assets on our network. This typically involves refurbishment of poor condition assets or replacement of H1 and H2 assets before end-of-life failure. Our approach is supported by new asset inspection standards and increased numbers of inspections.

When compared with our 2024 AMP Update forecasts, lifecycle management Capex over the 2025 AMP period is materially the same over their respective periods.[6]

4.2.1. Asset Replacement and Renewal

Asset fleet plans are being reviewed for major asset types to identify the issues, asset management strategies, and investment needs to maintain assets over their full lifecycle. A key consideration in these plans is the need to strengthen network resilience in response to the increasing impact of climate change. Our asset replacement and renewal forecasts have been refined to account for a range of factors, including our reliability performance, and updated asset information. The timing of planned projects has been reviewed, leading to modifications in the Capex profile.

Following prioritisation to align with our DPP allowance, our planned lifecycle Capex (ARR and RSE) has not been materially changed, and we have to improve the resilience and reliability of the network. During the remainder of the AMP period, we expect to lift investment during DPP5. Given their importance to managing risk on our overhead network, we will continue our accelerated pole replacement program and reliability focused investments such as feeder automation.

> **Forecasting asset renewal needs**
>
> We have begun to refine our approaches to forecasting asset health and to better align our expenditure forecasting methodology with typical industry good practice. An example is adopting a Repex-based methodology for assessing asset health and forecasting overall future asset replacement needs. We plan to use theses refined modelling approaches to inform future Schedule 12a disclosures, including those in our 2026 AMP.[7]

The table below provides further details on the main changes to our lifecycle management plans.

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[6] This relates to the overlapping period (nine years) between the respective AMP 24 and AMP 25 periods.

[7] Note, we have used a Repex based approach for poles in Schedule 12a of this AMP Update. Our existing DNO-based methodology has been used for the remainder.

Table 4.1: Material changes to our lifecycle management plans

PORTFOLIO	DESCRIPTION
Poles and crossarms	Pole replacements have been phased to maintain the accelerated replacement program in DPP4 and is expected to stabilise at lower volumes in DPP5 as we improve the overall health of this asset fleet. Additional investment is planned to proactively replace crossarms and associated equipment in DPP5.
Conductors	The conductor program was reforecast to allow further analysis and inspection data to be gathered. The program will begin in DPP5.
Cables	Like the conductor program, cables were reforecast to allow further analysis and inspection data to be gathered. The program will begin in DPP5.
Zone substations	Zone substations remain relatively stable, however an increase in expenditure is required over DPP5 to replace large 110Kv transformers in Wairoa.
Other network assets	We have reduced our generator renewal program to account for updated condition assessments and increased use of refurbishment.

4.3. Network Development Plans

This section sets out material differences between our updated 2025 AMP forecasts for growth and customer connections and the equivalent plans included in our 2024 AMP Update.

When compared with our 2024 AMP Update forecasts, network development Capex has decreased by approximately $34m over their respective periods.

4.3.1. Growth and Security

Based on Firstlight's overarching asset management strategy, system growth Capex forecast reflects expenditure drivers that are aligned to two distinct phases over the AMP period. During the upcoming DPP4 period we will primarily concentrate on bolstering the security and resilience of the network. Subsequently, the following DPP period will shift the focus towards expanding the capacity and capability of the network to accommodate additional demand for electricity in the evolving energy landscape.

We currently have a number of existing constraints on the network that may need to be addressed during the DPP4 AMP period. To address these, several growth projects are being assessed. These investments would help ensure we can manage and alleviate existing network constraints and prepare for expected future growth.

Potential Need for Reopeners

As discussed above, we have prioritised expenditure based on the degree to which it manages safety and reliability risk on the network. This has led to a shortfall in allowance for demand driven projects.

As a result, several projects have been excluded from this AMP Update due to the shortfall in allowance and uncertainty surrounding the timing and/or scope of these projects. The need for these investments will continue to be monitored and reassessed as new information becomes available and may become candidates for regulatory reopeners.

The table below sets out the main changes to our system growth plans, including projects that may require a reopener to proceed. While recognising that the mechanism and eligibility for reopeners is evolving, we will consider applying for the growth projects, indicated in the table below.

Table 4.2: Material changes to our system growth plan (constant RY25 $)

PROJECT	CHANGE	DESCRIPTION
Wairoa substation	Removed	This project has been removed from the AMP forecast due to the uncertainty of the load increase required and solution to address the increase in load.
Thermal upgrade	Removed	Phase 1 will be completed in RY26. Phase 2 has been removed from the AMP forecast; further analysis is required to confirm the required scope and related costs.
Massey substation	Removed	This project has been removed from the AMP forecast. At the time of developing our AMP forecasts, the required scope and scale of the project could not be confirmed until we have more certainty around the third-party load requests.

As investment needs evolve during the AMP period, we will investigate whether a reprioritisation of our plan can be achieved ahead of seeking a reopener of our allowance. Seeking to ensure affordability for customers by continuing to challenge projects or programmes where the driver for investment has changed/reduced.

4.3.2. Consumer Connections

Our AMP Update 2024 signalled a planned change to our capital contribution policy. The 2024 AMP forecast was then developed to reflect the anticipated policy change. However, upon review and given the ongoing deliberations and consultation on the policy in the sector, we have deferred the date of changes to our capital contribution policy to RY27.

4.4. Operating Expenditure

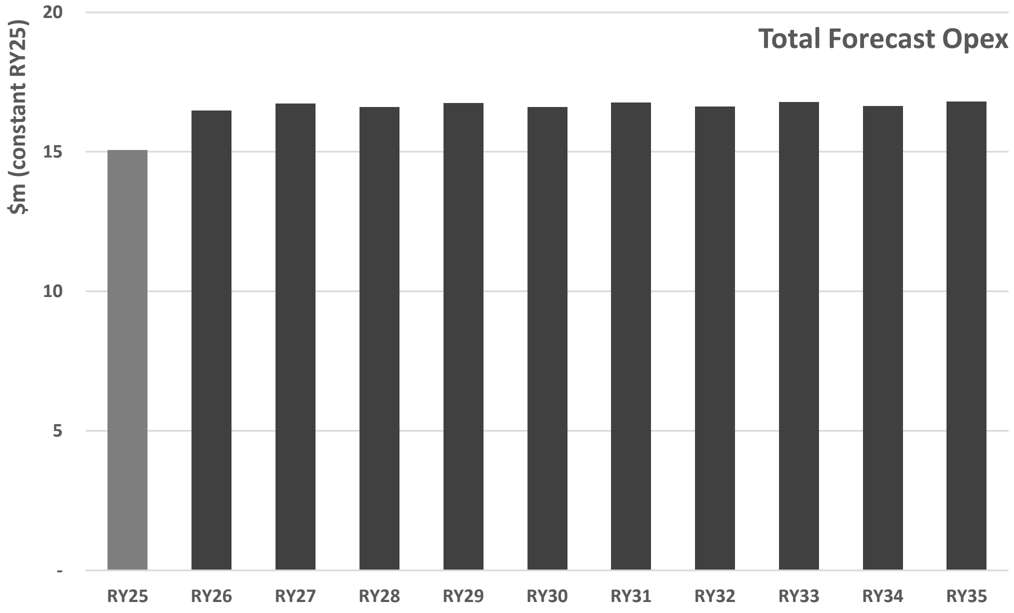
Firstlight has adopted a base-step-trend (BST) approach to forecast its Opex forecasts. For our 2025 AMP forecasts, we have used the latest available, confirmed actuals from RY24 as the base year, adjusted to 2025 dollars. This approach best reflects our prevailing operational environment, evolving business structure, and baseline activities.

Significant changes in expenditure, where they are known or anticipated, were incorporated as step changes. These encompassed network or operational changes, alterations to external drivers, and other material drivers expected to impact Opex.

Additionally, a trend component was integrated to account for the anticipated variations in outputs throughout the forecast period, for example forecast increase in ICPs.

Our planned Opex during the AMP period is set out below.

Figure 4.2: Forecast Opex during the AMP Period (constant RY25)



When compared with our 2024 AMP forecasts, total Opex has decreased by approximately $15m over their respective periods.[8]

> **DPP4 Opex Allowances**
>
> Our Opex forecasts have been constrained to align with our DPP allowances as determined by the Commerce Commission.[9] These allowances have been set below the amounts set out in our 2024 AMP Update.
>
> - Despite the overall reduction, we plan to increase our vegetation management activities and related Opex. This seeks to address the increasing impact of vegetation on our reliability performance.
> - The five remaining Opex categories have all been reduced when compared with our 2024 AMP forecast.

Explanations of material changes to forecast Opex in the upcoming AMP period are provided below.

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[8] This relates to the overlapping period (nine years) between the respective AMP 24 and AMP 25 periods.

[9] Details on the decision can be found here.

Table 4.3: Material changes to our Opex forecasts (constant RY25 $)

OPEX AREA	CHANGE	DESCRIPTION
SIE	**Reduced** by approx. 450k per annum	Our 2024 AMP included a step change in reactive maintenance in line with the increasing volumes of unplanned outages on the network. This step change was not approved as part of the DPP decision.
RCI	**Reduced** by approx. 350k per annum	Our 2024 AMP included increased expenditure to increase volume of inspections and to improve asset condition information. These improvements have been deferred to align with our DPP allowance. Despite the reduction, our updated forecast will ensure that our existing scheduled maintenance is completed. We will prioritise these activities based on safety and reliability.
Vegetation Management	**Increased** by approx. $150k per annum	We plan to increase our vegetation management activities and related Opex. This seeks to address the increasing impact of vegetation on our reliability performance.
SONS and Business Support	**Reduced** by approx. $1.1m per annum	Our non-network Opex forecasts for both SONS and business support have been reduced when compared with our proposed AMP 24 expenditure. This has been necessary to ensure sufficient network Opex while aligning with our DPP allowances as determined by the Commerce Commission.

5. RELIABILITY AND RESILIENCE IMPROVEMENT INITIATIVES

Firstlight breached its unplanned SAIDI quality standard in RY23 and RY24. It also expects to breach these in RY25. Recognising this, we continue to prioritise asset renewal and investment programmes that seek to improve reliability. Work is also underway to determine which pathway to compliance would be most appropriate for the consumers we serve. In the recent DPP decision, reflecting a higher WACC and increased level of investment in the network, Firstlight had one of the higher price increases to consumers. We are very mindful that additional increases and acceleration in expenditure, through for example a CPP, will mean further price increases for users of our network. We know that most (~75% of unplanned SAIDI) of our unplanned outages are on rural parts of the network and that we are spending approximately 80% of our capital in rural areas to improve the reliability of the network.

As we consider future investment needs, particularly as we experience more severe weather events, we are considering the trade-off between the required cost and the potential improvements to reliability and resilience. We will consult widely with communities and users of the network to establish the most appropriate balance.

5.1. Climate Change Risk Assessment

We are undertaking a climate change risk assessment to better understand the potential impacts of climate change on our assets and operations. By identifying and evaluating these risks, we aim to assess how the resilience of our network is likely to need to change and potentially adapted to ensure the long-term suitability of our infrastructure. This proactive approach will help us to:

- **Mitigate Risks**: By understanding the specific climate-related risks, we can implement measures to mitigate potential impacts on our network.
- **Enhance Resilience**: The assessment will provide insights into how we can adapt our operations and network to withstand future climate conditions.

The assessment will include three scenarios and two timeframes, identifying impacts and risks at a regional level for various asset types, with a focus on our critical infrastructure. The selected scenarios will align with three of the scenarios from The Aotearoa Circle Energy Sector Report.

5.2. Strategic Reliability Management Plan

Two unplanned outage reports[10] were produced for the prior two regulatory years, and another will be required for RY25. To ensure we manage all actions, recommendations and improvements, we are currently developing a Strategic Reliability Management Plan (SRMP) which we plan to complete in RY26. The SRMP will bring together all the work

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[10] The 2024 report can be found here, while the 2023 report can be found here.

completed so far, prioritise the work streams that will have the most impact to improve the network reliability.

The primary objective of Firstlight's SRMP is to improve the reliability of the network by preventing and limiting the impact of disruptions caused by ageing assets, weather events, and vegetation near our assets. SRMP initiatives will focus on our response capability and improving the network's ability to withstand events such as repeated strong winds and consistent heavy rain events, cyclones, floods, and landslips. The recent weather events over the past three regulatory periods have highlighted vulnerabilities within the network, prompting a comprehensive improvement program of our approach to ensuring reliability.

The SRMP will consolidate previous actions, recommendation and improvements into three categories.

To holistically manage the reliability of the network, we need to manage it on three different fronts. FNL needs to:

- **Respond:** when there is an outage to reinstate customers quickly
- **Prevent:** the outages from happening
- **Improve:** our understanding of outages and the underlying processes that we use to manage our network reliability.

Table 5.1: Overview of SRMP initiatives

CATEGORY	EXAMPLES
Respond	– Emergency response, – Callout response, – Mobile generation, – Critical spares, – Remote location access, – Communications, – Contractor management.
Prevent	– Renewing assets, – Network design, security and interference, – Network operation, automation and monitoring, – Connected Generation, – Reduce impact of adverse weather, – Identify and manage adverse environment, – Vegetation Management.
Improve	– LiDAR surveys, – Design standards, – Criticality or Risk based approach to asset replacement and inspections, – Ongoing Analysis of fault data, – Maintenance and inspection field data capture.

5.3. SRMP Initiatives

The initial focus of the improvement program is focused on minimising the number of customers impacted during an outage.

During RY25, this was supported by installing sectionalisers on key feeders, replacing seven oil switches to reduce the footprint of the isolation during an unplanned outage, and operating connected generation on feeders without the ability to back feed.

5.3.1. Respond

When an outage happens, our priority is reconnecting as many customers as possible safely and in a timely manner that doesn't lead to safety risks for our field crews and staff. To do this effectively we need to respond correctly when there is an outage. Ensuring we have trained field crews and staff in the right location, with the correct tools and equipment.

These are some of the initiatives to improve our response.

Table 5.2: Overview of SRMP Respond initiatives

RESPOND INITIATIVE	STATUS
Embed Coordinated incident management system (CIMS).	In progress
Continually reviewing and improving callout response capabilities and locations of field crews.	Ongoing
Mobilise field crews ahead of weather events to remote locations.	Implemented and reviewing
Install a dedicated emergency response room to manage large events and emergencies.	New
Deploy mobile generators to keep customers connected during fault restoration.	Implemented and ongoing

5.3.2. Prevent

Preventing an unplanned outage is about investing in replacing our assets and improving the operation of the network to prevent unplanned outages from happening. We plan to do this with targeted programs of asset replacements that that will prevent future unplanned outages by improving the assets condition and using current best practices for installation.

These are some of the initiatives to prevent unplanned outages.

Table 5.3: Overview of SRMP Prevent initiatives

PREVENT INITIATIVE	STATUS
Installation of sectionalisers to segment the network and minimise the number of customers affected during a fault.	In progress
Install load fault indicators to quickly dispatch fault crews and patrol the feeder.	In progress
Replace ground mount oil switches in strategic locations to reduce the size of network isolations when rectifying faults.	In progress

PREVENT INITIATIVE	STATUS
Replacing poles across our networks to ensure we operate a safe network, while improving the resilience of the network by using stronger poles and replacing crossarms, insulators and conductor bindings.	In progress
Sample inspecting previously inspected poles to compare the inspection standard against the new pole inspection standard.	In progress
Inspecting assets to assess the current condition and proactively replace equipment before failure.	In progress
Quickly identifying and removing in-zone vegetation.	In progress
Install additional connected generation in strategic locations to maintain supply to customers.	In progress

5.3.3. Improve

As we implement improvements to the network, we need to ensure we are making the correct choices. We continue to analyse and discuss the improvements and where it is possible, we will measure how many minutes we have improved our reliability. Improving our reliability requires multiple items to change and manage. These are some of the improvement initiatives we are focusing on.

Table 5.4: Overview of SRMP Improve initiatives

IMPROVE INITIATIVE	STATUS
Establish a comprehensive Strategic Reliability Management Plan.	Ongoing
Analyse the reliability impact on consumers, the type of consumer connected at the ICP and the reliability differences between urban and rural consumers.	New
Develop pathway to compliance scenarios and understand the impact to the network and consumers for each scenario.	New
Analyse the effectiveness of the changes we make on the network to improve reliability.	Initiated
Change our design and operating standards to work within the adverse environment in which we now operate and that our network must adapt to when exposed to higher wind speeds, flood zones and geohazard risks.	In progress
Review the effectiveness of the pole inspection and replacement program to understand if there is a benefit of a crossarm and insulator programme.	New
Update pole field data inspection requirements to provide better condition assessment of the pole, crossarm, insulator and conductor health.	In progress
Review and analyse the worst performing feeders and unplanned outages to understand trends.	On going
Improve our current risk-and criticality-based practices, ensuring routine maintenance inspection and asset renewal programmes are focusing on high-risk areas and assets critical to network reliability.	New
Continue to strengthen engagement with tree owners, local communities and businesses to collaboratively manage vegetation.	On going
Leverage LiDAR technology to identify vegetation-related risks.	Under development
Engage on and advocate for larger clearance zones (Tree Regulations).	On going

APPENDICES

APPENDIX A. DISCLOSURE SCHEDULES

This appendix includes the following Information Disclosure schedules:

- Schedule 11a: report on forecast Capital Expenditure
- Schedule 11b: report on forecast Operational Expenditure
- Schedule 12a: report on asset condition
- Schedule 12b: report on forecast capacity
- Schedule 12c: report on forecast network demand
- Schedule 12d: report on forecast interruptions and duration
- Schedule 14a: commentary on differences between forecast Capex (schedule 11a) and Opex (schedule 11b) in nominal and constant prices

Schedule 11a: report on forecast Capital Expenditure

Company Name	**Firstlight Network**
AMP Planning Period	**1 April 2025 – 31 March 2035**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref														
7			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8													
9		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	357	1,083	1,113	1,144	1,175	1,206	1,239	1,273	1,308	1,344	1,380
11		System growth	444	2,004	1,066	1,095	1,124	1,155	1,186	1,219	1,252	1,286	1,321
12		Asset replacement and renewal	18,736	14,300	16,171	17,447	15,036	16,302	23,451	22,750	23,913	24,182	28,194
13		Asset relocations	75	76	78	80	82	84	87	89	91	94	96
14		Reliability, safety and environment:											
15		Quality of supply	566	1,547	1,675	626	1,762	661	331	340	349	358	368
16		Legislative and regulatory	8	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	614	103	106	109	112	115	354	364	374	384	394
18		**Total reliability, safety and environment**	1,188	1,650	1,782	735	1,874	776	685	703	723	742	763
19		**Expenditure on network assets**	20,800	19,112	20,209	20,501	19,291	19,523	26,648	26,034	27,287	27,648	31,755
20		**Expenditure on non-network assets**	474	817	416	346	355	595	464	385	396	663	516
21		**Expenditure on assets**	21,274	19,930	20,625	20,847	19,646	20,118	27,111	26,419	27,682	28,310	32,271
22													
23	*plus*	Cost of financing											
24	*less*	Value of capital contributions	238	980	742	763	783	804	826	849	872	896	920
25	*plus*	Value of vested assets											
26													
27		**Capital expenditure forecast**	21,036	18,950	19,883	20,084	18,863	19,314	26,285	25,570	26,810	27,414	31,351
28													
29		Assets commissioned	19,984	23,242	19,920	20,127	19,040	19,320	25,641	25,714	26,756	27,427	31,032
30			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31													
32			**$000 (in constant prices)**										
33		Consumer connection	357	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050
34		System growth	444	1,944	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005
35		Asset replacement and renewal	18,736	13,869	15,249	16,016	13,440	14,188	16,652	15,565	16,000	15,700	17,989
36		Asset relocations	75	73	73	73	73	73	73	73	73	73	73
37		Reliability, safety and environment:											
38		Quality of supply	566	1,500	1,580	575	1,575	575	280	280	280	280	280
39		Legislative and regulatory	8	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	614	100	100	100	100	100	300	300	300	300	300
41		**Total reliability, safety and environment**	1,188	1,600	1,680	675	1,675	675	580	580	580	580	580
42		**Expenditure on network assets**	20,800	18,536	19,058	18,819	17,243	16,991	19,361	18,274	18,709	18,409	20,698
43		Expenditure on non-network assets	474	793	393	318	318	518	393	318	318	518	393
44		**Expenditure on assets**	21,274	19,329	19,450	19,137	17,561	17,509	19,754	18,592	19,027	18,927	21,091
45													
46		**Subcomponents of expenditure on assets (where known)**											
48		Energy efficiency and demand side management, reduction of energy losses											
49		Overhead to underground conversion											
50		Research and development											
52													

Difference between nominal and constant price forecasts

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	$000										
Consumer connection	-	33	63	94	125	156	189	223	258	294	330
System growth	-	60	61	90	119	150	181	214	247	281	316
Asset replacement and renewal	-	431	921	1,431	1,596	2,115	6,798	7,184	7,912	8,481	10,205
Asset relocations	-	2	4	7	9	11	13	16	18	21	23
Reliability, safety and environment:											
Quality of supply	-	47	95	51	187	86	51	60	69	78	88
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	3	6	9	12	15	54	64	74	84	94
Total reliability, safety and environment	-	50	102	60	199	101	105	123	143	162	183
Expenditure on network assets	-	576	1,151	1,682	2,048	2,532	7,287	7,760	8,578	9,239	11,057
Expenditure on non-network assets	-	25	24	28	38	77	71	68	78	145	124
Expenditure on assets	-	601	1,175	1,710	2,086	2,610	7,358	7,828	8,656	9,384	11,180

Commentary on options and considerations made in the assessment of forecast expenditure

EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15

11a(ii): Consumer Connection

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
*Consumer types defined by EDB**	$000 (in constant prices)					
General	357	1,050	1,050	1,050	1,050	1,050
**include additional rows if needed*						
Consumer connection expenditure	357	1,050	1,050	1,050	1,050	1,050
less Capital contributions funding consumer connection	238	950	700	700	700	700
Consumer connection less capital contributions	119	100	350	350	350	350

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	232	150	-	-	-	-
Zone substations	113	1,194	-	-	-	-
Distribution and LV lines	-	150	225	225	225	225
Distribution and LV cables	-	240	360	360	360	360
Distribution substations and transformers	99	210	420	420	420	420
Distribution switchgear	-	-	-	-	-	-
Other network assets	-	-	-	-	-	-
System growth expenditure	444	1,944	1,005	1,005	1,005	1,005
less Capital contributions funding system growth						
System growth less capital contributions	444	1,944	1,005	1,005	1,005	1,005

97			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
98								
99		**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**					
100		Subtransmission	4,822	3,382	1,923	202	3,446	3,191
101		Zone substations	1,779	821	1,998	753	1,146	1,841
102		Distribution and LV lines	6,736	7,200	7,297	7,056	6,528	6,835
103		Distribution and LV cables	377	175	175	175	524	524
104		Distribution substations and transformers	1,532	757	757	757	757	757
105		Distribution switchgear	1,485	744	744	744	744	744
106		Other network assets	2,004	790	2,355	6,329	295	295
107		**Asset replacement and renewal expenditure**	18,736	13,869	15,249	16,016	13,440	14,188
108	*less*	Capital contributions funding asset replacement and renewal						
109		**Asset replacement and renewal less capital contributions**	18,736	13,869	15,249	16,016	13,440	14,188
110								

111			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
112								
113		**11a(v): Asset Relocations**						
114		*Project or programme**	**$000 (in constant prices)**					
115		General	75	73	73	73	73	73
116								
117								
118								
119								
120		**include additional rows if needed*						
121		All other project or programmes - asset relocations						
122		**Asset relocations expenditure**	75	73	73	73	73	73
123	*less*	Capital contributions funding asset relocations						
124		**Asset relocations less capital contributions**	75	73	73	73	73	73
125								

126			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
127								
128		**11a(vi): Quality of Supply**						
129		*Project or programme**	**$000 (in constant prices)**					
130		Generators	60	1,000	1,000	-	1,000	-
131		Rural Automation / Reclosers	257	100	100	175	175	175
132		LV Monitoring	95	200	200	200	200	200
133		Load Fault Indicators	153	200	200	200	200	200
134								
135		**include additional rows if needed*						
136		All other projects or programmes - quality of supply			80			
137		**Quality of supply expenditure**	566	1,500	1,580	575	1,575	575
138	*less*	Capital contributions funding quality of supply						
139		**Quality of supply less capital contributions**	566	1,500	1,580	575	1,575	575
140								

11a(vii): Legislative and Regulatory

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	*Project or programme**	$000 (in constant prices)					
	**include additional rows if needed*						
	All other projects or programmes - legislative and regulatory	8					
	Legislative and regulatory expenditure	8	-	-	-	-	-
less	Capital contributions funding legislative and regulatory						
	Legislative and regulatory less capital contributions	8	-	-	-	-	-

11a(viii): Other Reliability, Safety and Environment

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	*Project or programme**	$000 (in constant prices)					
	**include additional rows if needed*						
	All other projects or programmes - other reliability, safety and environment	614	100	100	100	100	100
	Other reliability, safety and environment expenditure	614	100	100	100	100	100
less	Capital contributions funding other reliability, safety and environment						
	Other reliability, safety and environment less capital contributions	614	100	100	100	100	100

11a(ix): Non-Network Assets

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Routine expenditure						
*Project or programme**	$000 (in constant prices)					
Buildings	62	222	22	22	22	22
Vehicles	182	143	143	143	143	143
ICT	93	322	197	122	122	322
Other Assets	137	106	31	31	31	31
**include additional rows if needed*						
All other projects or programmes - routine expenditure						
Routine expenditure	474	793	393	318	318	518
Atypical expenditure						
*Project or programme**						
**include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	-	-	-	-	-	-
Expenditure on non-network assets	474	793	393	318	318	518

Schedule 11b: report on forecast Operational Expenditure

Company Name: **Firstlight Network**
AMP Planning Period: **1 April 2025 – 31 March 2035**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.

sch ref													
7			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8													
9	**Operational Expenditure Forecast**		**$000 (in nominal dollars)**										
10	Service interruptions and emergencies		3,178	3,314	3,406	3,496	3,593	3,693	3,795	3,899	4,007	4,118	4,231
11	Vegetation management		1,967	1,956	2,006	2,054	2,106	2,159	2,213	2,269	2,326	2,385	2,445
12	Routine and corrective maintenance and inspection		3,178	3,204	3,444	3,363	3,615	3,536	3,800	3,716	3,994	3,905	4,197
13	Asset replacement and renewal		60	162	166	170	174	179	183	188	193	197	202
14	**Network Opex**		8,384	8,636	9,022	9,082	9,488	9,567	9,991	10,072	10,519	10,605	11,075
15	System operations and network support		1,650	3,044	3,227	3,304	3,388	3,474	3,561	3,651	3,743	3,837	3,933
16	Business support		4,636	4,926	5,051	5,171	5,302	5,437	5,573	5,713	5,857	6,004	6,155
17	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	388	401	411	421	431	442	-	-	-	-	-
18	**Non-network opex**		6,675	8,371	8,689	8,896	9,121	9,353	9,135	9,364	9,600	9,841	10,089
19	**Operational expenditure**		15,059	17,007	17,711	17,978	18,609	18,919	19,126	19,437	20,119	20,446	21,164
20			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
21													
22			**$000 (in constant prices)**										
23	Service interruptions and emergencies		3,178	3,211	3,218	3,226	3,234	3,241	3,249	3,257	3,265	3,272	3,280
24	Vegetation management		1,967	1,895	1,895	1,895	1,895	1,895	1,895	1,895	1,895	1,895	1,895
25	Routine and corrective maintenance and inspection		3,178	3,104	3,254	3,104	3,254	3,104	3,254	3,104	3,254	3,104	3,254
26	Asset replacement and renewal		60	157	157	157	157	157	157	157	157	157	157
27	**Network Opex**		8,384	8,366	8,524	8,381	8,539	8,397	8,555	8,412	8,570	8,428	8,586
28	System operations and network support		1,650	2,949	3,049	3,049	3,049	3,049	3,049	3,049	3,049	3,049	3,049
29	Business support		4,636	4,772	4,772	4,772	4,772	4,772	4,772	4,772	4,772	4,772	4,772
30	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	388	388	388	388	388	388	-	-	-	-	-
31	**Non-network opex**		6,675	8,109	8,209	8,209	8,209	8,209	7,821	7,821	7,821	7,821	7,821
32	**Operational expenditure**		15,059	16,475	16,733	16,591	16,748	16,606	16,376	16,233	16,391	16,249	16,407
33	**Subcomponents of operational expenditure (where known)**												
35													
36	Energy efficiency and demand side management, reduction of energy losses												
37	Direct billing*												
38	Research and Development												
39	Insurance												
41	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*												
42													
43			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
44													
45	**Difference between nominal and real forecasts**		**$000**										
46	Service interruptions and emergencies		-	104	188	270	359	452	546	643	742	845	951
47	Vegetation management		-	61	111	158	211	264	318	374	431	490	549
48	Routine and corrective maintenance and inspection		-	100	190	260	361	432	546	612	740	802	943
49	Asset replacement and renewal		-	5	9	13	17	22	26	31	36	41	45
50	**Network Opex**		-	270	498	701	949	1,170	1,437	1,660	1,949	2,177	2,489
51	System operations and network support		-	95	178	255	339	425	512	602	693	788	884
52	Business support		-	154	279	399	530	665	801	942	1,085	1,233	1,384
53	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	13	23	32	43	54	-	-	-	-	-
54	**Non-network opex**		-	261	480	687	912	1,144	1,314	1,543	1,779	2,020	2,268
55	**Operational expenditure**		-	531	978	1,387	1,860	2,313	2,750	3,203	3,728	4,197	4,757
56													
57	**Commentary on options and considerations made in the assessment of forecast expenditure**												
58	*EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.*												

Schedule 12a: report on asset condition

Company Name **Firstlight Network**

AMP Planning Period **1 April 2025 – 31 March 2035**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref												
7					**Asset condition at start of planning period (percentage of units by grade)**							
8												
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	No.	0.2%	0.5%	2.0%	3.2%	94.1%		2	1.1%
11	All	Overhead Line	Wood poles	No.	7.9%	12.0%	22.3%	13.8%	44.0%		2	22.9%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-		2	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	0.03%	1.11%	0.69%	2.67%	95.49%		2	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	5.76%	94.24%		2	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	3.92%	96.08%		2	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km							N/A	
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km							N/A	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km							N/A	
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km							N/A	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km							N/A	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km							N/A	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km							N/A	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km							N/A	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	10%	50%	30%	10%		2	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.			80.00%	20.00%			2	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-		N/A	
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	-	-	100.00%		2	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-		N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	-	-	100.00%		2	-
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-		N/A	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-		N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	2.13%	-	-	10.64%	87.23%		2	2%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	9.26%	5.56%	-	15.74%	69.44%		2	10%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	23.08%	-	-	-	76.92%		2	25%
35												

36					Asset condition at start of planning period (percentage of units by grade)							
37	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	2.94%	23.53%	73.53%		2	3%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2.78%	0.19%	0.65%	8.15%	88.23%		2	
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km	-	-	-	-	100.00%		2	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	4.01%	-	-	8.73%	87.25%		2	5%
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	4.20%	58.13%	37.67%		2	0.5%
45	HV	Distribution Cable	Distribution Submarine Cable	km							3	
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	4.44%	6.67%	-	13.33%	75.56%		2	5%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	6.67%	13.33%	66.67%	13.33%		2	5%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	5.44%	2.22%	1.70%	12.36%	78.29%		2	7%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	1.37%	-	2.74%	6.85%	89.04%		2	2%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	3.24%	0.36%	1.08%	17.27%	78.06%		2	5%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	4.32%	2.66%	2.04%	6.95%	84.02%		2	7%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.51%	0.17%	1.19%	4.61%	93.52%		2	2%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	-	100.00%		2	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.							N/A	
55	LV	LV Line	LV OH Conductor	km	2.02%	0.18%	1.31%	9.50%	86.99%		2	1.5%
56	LV	LV Cable	LV UG Cable	km	5.21%	-	-	18.72%	76.07%		2	2%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	-	-	-	100.00%		2	-
58	LV	Connections	OH/UG consumer service connections	No.	4.08%	42.02%	32.43%	13.56%	7.92%		2	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	4.03%	30.65%	21.77%	19.35%	24.19%		2	25%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	11.36%	37.55%	21.84%	19.66%	9.59%		2	20%
61	All	Capacitor Banks	Capacitors including controls	No.		100.0%					2	-
62	All	Load Control	Centralised plant	Lot		100.0%					2	-
63	All	Load Control	Relays	No.	6.56%	12.66%	77.05%	1.50%	2.23%		2	5%
64	All	Civils	Cable Tunnels	km							N/A	

Schedule 12b: report on forecast capacity

Company Name **Firstlight Network**
AMP Planning Period **1 April 2025 – 31 March 2035**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and constraints for each zone substation. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

			Not Required before DY2025	*Not Required before DY2025*	*Not Required before DY2025*	*before DY2025*	*before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	
8	*Existing Zone Substations*	**Current peak load (MVA)**	**Current peak load period**	**Installed operating capacity (MVA)**	**Current security of supply classification (type)**	**Current constraint type**	**Current available capacity (MVA)**	**Peak load period +5 yrs**	**Available capacity +5 yrs (MVA)**	**Security of supply classification +5 yrs (type)**	**Peak load period +10 yrs**	**Min. available capacity +10 yrs (MVA)**	**Max. available capacity +10 yrs (MVA)**	**Security of supply classification +10 yrs (type)**	**Forecast constraint type**	**Year of any forecast constraint**	**Constraint primary cause**	**Constraint solution type**	**Constraint solution progress**	**Temporary constraint solution remaining lifespan**	**Explanation**
9	TeAraroa	0.8	Winter	1.3	N-1 switched	Security	1.7	Winter	1.7	N-1 switched	Winter	1.5	1.7	N-1 switched	Security	10+	Not applicable	Not applicable	Not applicable	> 3 years	Security constraint supported by generation
10	Ruatoria	1.5	Winter	2.0	N-1 switched	Security	3.5	Winter	3.5	N-1 switched	Winter	3.1	3.5	N-1 switched	Security	10+	Not applicable	Not applicable	Not applicable	> 3 years	Security constraint supported by generation & adjacent substations
11	Tokomaru Bay	1.0	Winter	1.2	N-1 switched	Security	1.5	Winter	1.5	N-1 switched	Winter	1.2	1.4	N-1 switched	Security	10+	Not applicable	Not applicable	Not applicable	> 3 years	Security constraint supported by adjacent substations
12	Tolaga Bay	1.2	Winter	1.8	N-1 switched	Security	3.8	Winter	3.7	N-1 switched	Winter	3.5	3.7	N-1 switched	Security	10+	Not applicable	Not applicable	Not applicable	> 3 years	Security constraint supported by generation & adjacent substations
13	Kaiti	7.8	Winter	8.0	N-1 switched	Security	4.7	Winter	4.3	N-1 switched	Winter	0.9	3.8	N-1 switched	Security	10+	Distribution back-up circuit capacity	Network upgrade	Planning stage	Not applicable	Security constraint supported by adjacent substations. Backup circuits near capacity. New substation in planning stage that will allow rebalancing of loads and restore security.
14	Port	7.7	Spring	8.0	N-1 switched	Security	4.8	Spring	4.4	N-1 switched	Spring	1.1	4.0	N-1 switched	Security	10+	Distribution back-up circuit capacity	Network upgrade	Planning stage	Not applicable	Security constraint supported by adjacent substations. Backup circuits near capacity. New substation in planning stage that will allow rebalancing of loads and restore security.
15	Gisborne	57.0	Winter	60.0	N-1	Security	3.0	Winter	0.1	N-1	Winter	50.5	57.0	N	Capacity	10+	Subtransmission circuit	Network upgrade	Implementation stage	> 3 years	TUAI to Gisborne 110kV Circuit Thermal upgrade work is being carried out & voltage support work is planned. Generation support available during peak load periods (N-1 switched)
16	Carnarvon	14.3	Winter	23.5	N-1 switched	Security	9.2	Winter	8.5	N-1	Winter	2.3	7.7	N-1	No constraint	None	Distribution back-up circuit capacity	Network upgrade	Planning stage	Not applicable	Security constraint supported by adjacent substations. Backup circuits near capacity. New substation in planning stage that will allow rebalancing of loads and restore security.
17	Parkinson	8.2	Winter	12.5	N-1	No constraint	5.5	Winter	5.2	N-1	Winter	2.2	4.8	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
18	Makaraka	7.5	Winter	7.0	N-1 switched	Security	5.3	Winter	4.5	N-1 switched	Winter	1.7	3.6	N-1 switched	Security	10+	Distribution back-up circuit capacity	Network upgrade	Planning stage	Not applicable	Security constraint supported by adjacent substations. Backup circuits near capacity. New substation in planning stage that will allow rebalancing of loads and restore security.
19	Patutahi	4.0	Winter	5.0	N-1 switched	Security	8.5	Winter	8.3	N-1 switched	Winter	6.5	8.0	N-1 switched	Security	10+	Not applicable	Not applicable	Not applicable	Not applicable	Security constraint supported by adjacent substations
20	Pehiri	0.5	Autumn	1.3	N-1 switched	Security	2.0	Autumn	2.0	N-1 switched	Autumn	1.9	2.0	N-1 switched	Security	10+	Not applicable	Not applicable	Not applicable	Not applicable	Security constraint supported by adjacent substations
21	Ngatapa	0.5	Winter	1.5	N-1 switched	Security	2.0	Winter	2.0	N-1 switched	Winter	1.9	2.0	N-1 switched	Security	10+	Not applicable	Not applicable	Not applicable	Not applicable	Security constraint supported by adjacent substations
22	Puha	2.1	Winter	1.5	N-1 switched	Security	2.9	Winter	2.9	N-1 switched	Winter	2.9	2.9	N-1 switched	Security	10+	Not applicable	Not applicable	Not applicable	> 3 years	Embedded hydro generation connection through distribution feeder. Security constraint supported by generation
23	JNL	2.1	Spring	5.0	N-1 switched	Security	10.7	Spring	10.7	N-1 switched	Spring	10.2	10.7	N-1 switched	Security	10+	Not applicable	Not applicable	Not applicable	Not applicable	Security constraint supported by adjacent substation
24	Matawhero	4.5	Autumn	12.8	N-1	No constraint	8.3	Autumn	7.8	N-1	Autumn	4.7	7.3	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
25	Tuai	0.7	Spring	5.0	N	Security	4.3	Spring	4.3	N	Spring	4.1	4.3	N	Security	10+	Distribution back-up circuit capacity	Undecided	No active planning	> 3 years	No distribution backup circuit. Portable generation used for extended outages.
26	Kiwi	4.5	Autumn	6.5	N	Security	2.0	Autumn	2.0	N	Autumn	2.0	2.0	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Waihi Hydro generation infeed
27	Wairoa	11.0	Autumn	12.5	N-1	Security	1.5	Autumn	1.2	N-1	Autumn	0.0	0.9	N-1	Capacity	10+	Zone substation transformer	Network upgrade	Planning stage	> 3 years	Constraint supported by generation. Investigation work has started on reconfiguration of the Wairoa network.
28	Blacks pad	1.4	Summer	1.5	N-1 switched	Capacity	0.1	Summer	0.0	N-1 switched	Summer	0.0	0.0	N-1 switched	Security	10+	Zone substation transformer	Network upgrade	Planning stage	> 3 years	Peak loads during holiday periods and supported by generation. Long term plan for a new substation in Mahia with interim plan to increase capacity of the Black's pad substation transfomer.
29	Tahaenui	0.8	Winter	1.0	N-1 switched	Security	0.7	Winter	0.7	N-1 switched	Winter	0.5	0.7	N-1 switched	Security	None	Not applicable	Not applicable	Not applicable	Not applicable	Security constraint supported by adjacent substations
30	Waihi	4.5	Winter	6.5	N	Security	2.0	Winter	2.0	N	Winter	2.0	2.0	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Waihi Hydro generation infeed

[1] *Extend table as necessary to disclose all capacity and constraint information by each zone substation*

Schedule 12c: report on forecast network demand

Company Name	**Firstlight Network**
AMP Planning Period	**1 April 2025 – 31 March 2035**

SCHEDULE 12c: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref								
7		**12c(i): Consumer Connections**						
8		*Number of ICPs connected during year by consumer type*				**Number of connections**		
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10								
11		*Consumer types defined by EDB**						
12		Domestic/Residential	20,607	20,808	21,012	21,217	21,425	21,635
13		Commercial	5,353	5,405	5,458	5,512	5,566	5,620
14		Large Commercial	146	148	149	151	152	154
15		Industrial	5	5	5	5	5	5
16								
17		**Connections total**	26,111	26,366	26,624	26,885	27,148	27,414
18		**include additional rows if needed*						
19								
20								
21								
22		**Distributed generation**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
23		Number of connections made in year	106	106	106	106	106	106
24		Capacity of distributed generation installed in year (MVA)	1	1	1	1	1	1
25		**12c(ii) System Demand**						
26			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
27		**Maximum coincident system demand (MW)**						
28		GXP demand	65	65	66	67	68	69
29	*plus*	Distributed generation output at HV and above	6	6	6	6	6	6
30		**Maximum coincident system demand**	70	71	72	73	74	75
31	*less*	Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
32		**Demand on system for supply to consumers' connection points**	70	71	72	73	74	75
33		**Electricity volumes carried (GWh)**						
34		Electricity supplied from GXPs	305	306	307	309	311	312
35	*less*	Electricity exports to GXPs	-	-	-	-	-	-
36	*plus*	Electricity supplied from distributed generation	17	17	18	19	20	21
37	*less*	Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
38		**Electricity entering system for supply to ICPs**	322	323	325	328	331	333
39	*less*	Total energy delivered to ICPs	294	295	298	300	302	305
40		**Losses**	28	28	28	28	29	28
41								
42		**Load factor**	52%	52%	52%	52%	51%	51%
43		**Loss ratio**	8.6%	8.7%	8.5%	8.6%	8.7%	8.5%

Schedule 12d: report on forecast interruptions and duration

Company Name	**Firstlight Network**
AMP Planning Period	**1 April 2025 – 31 March 2035**
Network / Sub-network Name	**Gisborne & Wairoa**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref							
8		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	101.1	101.1	101.1	101.1	101.1	101.1
12	Class C (unplanned interruptions on the network)	230.4	230.4	230.4	230.4	230.4	230.4
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.67	0.67	0.67	0.67	0.67	0.67
15	Class C (unplanned interruptions on the network)	3.31	3.31	3.31	3.31	3.31	3.31

Company Name	**Firstlight Network**
AMP Planning Period	**1 April 2025 – 31 March 2035**
Network / Sub-network Name	**Gisborne**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref							
8		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	70.7	70.7	70.7	70.7	70.7	70.7
12	Class C (unplanned interruptions on the network)	161.2	161.2	161.2	161.2	161.2	161.2
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.50	0.50	0.50	0.50	0.50	0.50
15	Class C (unplanned interruptions on the network)	2.48	2.48	2.48	2.48	2.48	2.48

Company Name	**Firstlight Network**
AMP Planning Period	**1 April 2025 – 31 March 2035**
Network / Sub-network Name	**Wairoa**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	30.3	30.3	30.3	30.3	30.3	30.3
12	Class C (unplanned interruptions on the network)	69.1	69.1	69.1	69.1	69.1	69.1
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.16	0.16	0.16	0.16	0.16	0.16
15	Class C (unplanned interruptions on the network)	0.83	0.83	0.83	0.83	0.83	0.83

Schedule 14a: Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.
2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

The difference between constant RY25 and nominal prices capital expenditure forecasts is based on the approach used by the Commerce Commission in the EDB DPP4 Final Determination, released 20 November 2024

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

Our approach for operational expenditure is equivalent to the approach for capital expenditure, described above.

APPENDIX B. DISCLOSURE REQUIREMENTS

This compliance matrix provides a look-up reference for each AMP-related Information Disclosure requirement.

Table B.1: Disclosure requirements checklist

REGULATORY REQUIREMENTS		AMP REFERENCE
2.6	**ASSET MANAGEMENT PLANS AND FORECAST INFORMATION**	
2.6.3	Subject to clause 2.6.4, an EDB may elect to complete and publicly disclose an AMP update, as described under clause 2.6.5, before the start of a disclosure year, instead of an AMP, as described under clause 2.6.1(1), unless the start of that disclosure year is- (1) one year after the start of the DPP regulatory period; or (2) two years before the start of the next DPP regulatory period.	Disclosure year 2025 does not meet the requirement for a full AMP, and we have elected to publish an AMP Update.
2.6.4	An EDB must not complete and publicly disclose an AMP update instead of an AMP if it has not previously publicly disclosed an AMP under clause 2.6.1.	Firstlight's most recent, previous disclosure was its 2023 AMP.
2.6.5	For the purpose of clause 2.6.3, the AMP update must— (1) Relate to the electricity distribution services supplied by the EDB; (2) Identify any material changes to the network development plans disclosed in the last AMP under clause 11 and clause 17.5-17.7 of Attachment A or in the last AMP update disclosed under this clause; (3) Identify any material changes to the lifecycle asset management (maintenance and renewal) plans disclosed in the last AMP pursuant to clause 12 of Attachment A or in the last AMP update disclosed under this section; (4) Provide the reasons for any material changes to the previous disclosures in the Report on Forecast Capital Expenditure set out in Schedule 11a and Report on Forecast Operational Expenditure set out in Schedule 11b; (5) Identify any changes to the asset management practices of the EDB that would affect a Schedule 13 Report on Asset Management Maturity disclosure; and (6) Contain the information set out in the schedules described in clause 2.6.6.	(1) Confirmed in Chapter 1 (2) included in Chapter 4 (3) included in Chapter 4 (4) included in Chapter 4 (5) Changes made since publishing our 2024 AMP Update would not materially impact our AMMAT assessment. We will undertake an updated assessment as we develop our 2026 AMP. (6) See 2.6.6 below

REGULATORY REQUIREMENTS		AMP REFERENCE
2.6.6	Each EDB— (1) must, except as provided in subclause 2.6.6(2), before the start of each disclosure year, complete and publicly disclose each of the following reports by inserting all information relating to the electricity distribution services supplied by the EDB for the disclosure years provided for in the following reports— (a) the Report on Forecast Capital Expenditure in Schedule 11a; (b) the Report on Forecast Operational Expenditure in Schedule 11b; (c) the Report on Asset Condition in Schedule 12a; (d) the Report on Forecast Capacity in Schedule 12b; (e) the Report on Forecast Network Demand in Schedule 12c; (f) the Report on Forecast Interruptions and Duration in Schedule 12d; (2) must, before the start of each disclosure year, complete and disclose to the Commission the Report on Cybersecurity Expenditure Forecast in Schedule 11c by inserting all information relating to the electricity distribution services supplied by the EDB for the disclosure years provided for in that report; and (3) must, if the EDB has sub-networks, complete and publicly disclose the Report on Forecast Interruptions and Duration set out in Schedule 12d by inserting all information relating to the electricity distribution services supplied by the EDB in relation to each sub-network for the disclosure years provided for in the report.	(1) This information is included in Appendix A. (2) Provided separately (3) This information is included in Appendix A.
2.7	**EXPLANATORY NOTES TO DISCLOSED INFORMATION**	
2.7.2	Before the start of each disclosure year, every EDB must complete and publicly disclose the Mandatory Explanatory Notes on Forecast Information in Schedule 14a by inserting all relevant information relating to information disclosed in accordance with clause 2.6.6.	This information is included in Appendix A.
2.9	**CERTIFICATES**	
2.9.1	Where an EDB is required to publicly disclose any information under clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2, the EDB must at that time publicly disclose a certificate in the form set out in Schedule 17 in respect of that information, duly signed by 2 directors of the EDB.	A copy of the certificate is included in Appendix C.

APPENDIX C. DIRECTOR'S CERTIFICATE

We, Mark Adrian Ratcliffe and Fiona Ann Oliver, being directors of Firstlight Network Limited certify that, having made all reasonable enquiry, to the best of our knowledge

a) The following attached information of Firstlight Network Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Firstlight Network Limited's corporate vision and strategy and are documented in retained records.

Mark Adrian Ratcliffe	
Director Name:	Signature
Fiona Ann Oliver	
Director Name	Signature

26 March 2025

FIRSTLIGHT NETWORK®