ASSET MANAGEMENT PLAN

2025

TOP ENERGY®
Te Puna Hihiko

Introduction

It is my pleasure to present Top Energy's 2025 Network Asset Management Plan (AMP) Update. Our AMP, prepared in compliance with the Commerce Commission's Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024, outlines our strategies for asset inspection, maintenance, development, and replacement, along with the targeted service levels for our consumers.

This Update should be read alongside our comprehensive 2023 AMP, which still underpins our asset management strategy, except where modified by the 2024 AMP Update or this Update. The regulatory schedules in Appendix 1 cover the planning period from 1 April 2025 to 31 March 2035 (FYE2026–35) and replace the corresponding schedules in the 2024 AMP Update.

This year, 2025, marks the commencement of the DPP4 regulatory period, with a new default price-quality path for electricity distribution businesses (DPP4) beginning on 1 April 2025. No significant changes were made to our CAPEX allowance; however, our total OPEX allowance for the period fell short of our forecast requirement by 12.0%. Notwithstanding the Commission's reduction in the OPEX allowance used in setting the DPP, we will continue our risk-based approach to determine the operational expenditure requirement for the network. This will result in a continued overspend of our operational budget through BAU operations in an economic climate characterised by rising material and labour costs. This ongoing issue needs to be addressed by the regulators.

To mitigate this shortfall, we have continued to invest in Top Energy Group's Ngāwhā Generation plant, which provides a dividend and enables us to maintain customer pricing at the same level as ten years ago.

Top Energy plays a crucial role in ensuring that the electricity transmission and distribution infrastructure serving the Far North will continue to adequately support communities in the future, where there will be substantially higher electricity demand due to the decarbonisation of the economy.

During the year, Top Energy successfully converted 100% of its lending into Green Loans. We developed a Green Finance Framework that aligned with the APLMA/LMA/LSTA Green Loan Principles and ICMA Green Bond Principles, meeting the eligible criteria of Renewable Energy — Electrical Grids and Storage and Renewable Energy — Generation. The establishment of this Framework is part of our wider commitment to sustainability, as reported in Annual Sustainability Reports over the last three years. Initiatives have included supporting small-scale, behind-the-meter, and large-scale solar generation, lowering the network cost per connection, establishing energy hardship programmes, and increasing locally hired trainees.

Top Energy network investment over the upcoming AMP planning period remains focussed on improving network reliability on our 11 kV distribution network, with transmission and sub-transmission works in the latter half of the period. Timing for this is dependent on decarbonisation and electrification developments.

In FYE2023, we launched a comprehensive programme to improve the reliability and resilience of our 11kV network, contributing to over 90% of unplanned System Average Interruption Duration Index (SAIDI) impact. This programme will extend to the end of the AMP planning period. Alongside the unplanned outage improvement programme, we are also looking to optimise planned activities and implement SAIDI mitigation techniques. This will minimise customer impact and enhance overall customer experience. We also continue to identify and prioritise high-risk asset defects through our maintenance programme.

The extreme weather in FYE2022 and FYE2023 highlighted our critical 110kV Kaikohe-Kaitāia line's vulnerability to ground movement over the Maungataniwha Range. In response to Cyclone Gabrielle, we conducted a geotechnical survey identifying five structures at risk of foundation failure. The most vulnerable poles were relocated through FYE24 and FYE25. The line remains a critical asset for the Far North region, with an annual maintenance programme to address end-of-life and poor-condition pole structures. Reconductoring is planned in the DPP5 period.

INTRODUCTION

We have yet to observe substantial growth in electricity demand due to decarbonising the economy. The adoption rate of battery electric vehicles (EVs) and plug-in hybrids (PHEVs) remains low. Although the uptake of hybrid vehicles continues to increase, the adoption rate for EVs and PHEVs has slowed.

In February 2024, the Energy Efficiency and Conservation Authority (EECA) published its Regional Energy Transition Accelerator (RETA) report for Northland. The report indicated that, unlike many other New Zealand Electricity Distribution Businesses (EDBs), we are unlikely to experience significant new demand from the electrification of heat sources currently using fossil fuels. This is due to the prevalent availability of biomass in our supply area. Supporting this is the fact that, to date, we have not received any inquiries from smaller industrial and commercial consumers that currently use coal or bottled gas, intending to switch to electricity. We anticipate the next customers likely to invest in electrification will be the Northland Region Corrections Facility.

In November 2023, we celebrated the connection of Lodestone Energy's 23MW Kaitāia solar farm, the largest solar farm in the country, to our network. Construction continues on Far North Solar's 20MW Pukenui solar farm, with an expected network connection in mid-2025. Rānui Generation has also commenced construction of the 24MW Twin Rivers solar farm, located southeast of Kaitāia, which is expected to be commissioned in late 2025.

The far north of our supply area has abundant potential for solar generation; however, with constraints on the transmission network, we cannot accept any more connection applications without imposing significant operating constraints. As the maximum generation output of these three solar farms far exceeds the local consumer demand, the excess generation must be exported south via our 110kV circuit. This circuit will be fully utilised by the end of 2025, when all three solar farms are commissioned and operational.

In the short term, we have made an application to Transpower for a run-back scheme, to increase our export capacity. We are also engaged in a working group with Northpower and Transpower in a joint submission for the support of an "Energy Bridge" to enable the upgrade of transmission lines by all three parties to support generation growth in the region and increase capacity to export south. As the benefit of this work is towards New Zealand holistically, specifically Auckland, it is proposed that it is funded so that the customers of the Northland region are not relied upon to recover the build costs when they are not the primary beneficiaries. The new Top Energy owned line this would fund, would also provide resilience to the existing 110 kV Kaitāia line and provide N-1 security to better enable maintenance work on either line without the reliance on our diesel generation fleet.

The connection of small-scale behind-the-meter solar generation to our network continues apace. The penetration of such generation is measured by the proportion of consumers hosting such systems and is higher than that of any other New Zealand EDB. By the end of FYE2022, a total of 7.3MW of such generation had been installed. By FYE2025, this figure had increased to 13.4 MW, representing 6.3% of our network installation control points (ICPs).

We estimate the total generation of small-scale behind-the-meter solar in FY2025 to be 22.5GWh, up from 18.8GWh in FYE2024. This equates to 6.8% of our expected 330GWh network electricity delivery volume in FYE2024.

As the uptake of small-scale distributed energy resource (DER) continues, there may be a requirement to curtail and manage these loads at peak times to balance generation with consumption. Currently, we are only able to manage the grid-scale generation in the pursuit of a fair and equitable operating environment. So that we are able to load-shed and curtail across all scales of generation, we encourage the development of a New Zealand standard for solar installation to allow control and curtailment of domestic solar as well as grid generation.

Data access and network visibility are essential for managing load and outage processes. Efforts are being made to gather data and enhance our low-voltage (LV) visibility. However, obtaining smart meter data is challenging and costly through the Metering Equipment Providers (MEPs). This issue is found across the country and supported in the "Ara Ake EDB Challenge" paper, published in October 2024.

Given this challenge, and the current sufficient network capacity that does not necessitate immediate load management, we will focus on monitoring transformer and LV assets and continue the field-based data capture program for the next five years. A Distributed Energy Resource Management System

(DERMS) solution will be implemented in DPP5 (FYE2031-35), which will require a higher level of data from the smart meters.

In addition to managing our network assets, we continue to develop the safety and asset management culture within Top Energy. We actively participate in industry safety initiatives, which require staff engagement at all levels, and have the added benefit of sharing participants' experiences from across the industry. To succeed, the Company and all staff must maintain a proactive role in training, competency, peer support and guidance, and monitoring industry issues.

We hope that you find that this AMP Update shows that we continue to exercise prudent stewardship of our network assets for the long-term benefit of all our stakeholders and, in particular, the electricity consumers who rely on our network to meet their energy needs. We welcome your feedback on our asset management plans, or any other aspect of Top Energy's business and performance. Feedback can be provided via the Top Energy website https://topenergy.co.nz/i-want-to/get-in-touch/send-feedback or emailed to info@topenergy.co.nz

Russell Shaw

Chief Executive, Top Energy Ltd

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1. Executive Summary

1.1 Purpose of the Document

This document updates our current Asset Management Plan, published on 31 March 2023 and updated in our 2024 Update. It documents only the material changes to the plans presented in these two earlier documents. The regulatory schedules included in Appendix A cover the updated 10-year planning period from 1 April 2025 to 31 March 2035 and replace in full the corresponding schedules in the 2024 AMP Update.

This AMP Update was approved by our Board of Directors on 25 March 2025.

1.2 Resilience and Reliability

In FYE2023, we were non-compliant with the unplanned interruption thresholds in our RCP3 price-quality path, but in FYE2024 and FYE2025, the reliability of our network has improved significantly. In FYE2024, our normalised unplanned System Average Interruption Duration Index (SAIDI) was 292.29, and we are currently on track to achieve a normalised unplanned SAIDI of 255 in FYE2025, well under our internal target of 300 as reflected in the AMP and our Statement of Corporate Intent. Our normalised unplanned System Average Interruption Frequency Index (SAIFI) in FYE2024 was 3.31, and we expect it to be about the same this year. Again, this is well under our internal target of 4.01

While this improved performance can be partially attributed to more benign weather conditions, it also reflects the success of our reliability improvement programme, which commenced in FYE2023 and continues apace.

The failure of the 220kV transmission tower at Glorit in June 2024 exposed the vulnerability of Northland's electricity supply to the resilience of its backbone transmission grid. We are collaborating with Northpower and Transpower in a Resilience, Reliability, and Energy Bridge Working Group to explore opportunities for enhancing resilience and addressing future capacity constraints. This collaboration focuses on identifying opportunities for new or upgraded transmission assets to address the region's demand envelope, accommodate new generation, and develop solutions for loss of supply events. For Top Energy, this involves a proposal for our new 110 kV line from Wiroa to Kaitāia, which will provide increased capacity and a backup for the existing 110 kV single circuit line. It also includes an upgrade of Transpower's Kaikohe-Maungatapere grid connection.

1.3 EV Charging

Z Energy has installed the first two 180KW superfast EV chargers in our supply area at its Taipa service station, and BP has installed a 75kW charger at Waipapa. This brings the total number of public EV chargers to 17, with an aggregate capacity of 1.01MW. However, only 23 battery electric vehicles and 14 plug-in hybrids were first registered to addresses in our supply area in CY2024, the lowest numbers since 2020. This undoubtedly reflects the removal of the government subsidy on the purchase cost of new EVs and plug-in hybrids and the imposition of road user charges on EVs.

1.4 Generation

Construction of the Pukenui solar farm is almost complete and construction of the Twin Rivers solar farm has commenced. Both solar farms are expected to be fully operational by the end of FYE2026. The total capacity of utility-scale solar connected to our northern network will then be approximately 67MW, and the transmission capacity of our 110kV line between Kaikohe and Kaitāia will be fully committed.

In the 12 months ending 31 December 2024, a further 2.05MW of small-scale solar was connected to our network, consistent with the last two years when approximately 2MW was connected each year. This brings the total connected capacity to 13.6MW. We continue to have the highest penetration of small-scale solar connected to our network of any New Zealand EDB.

In late November 2024, SolarZero, which owned about 1.4MW of this small-scale solar through rental contracts with our consumers, went into liquidation and stopped connecting new customers. Although arrangements are in place for existing customers to continue to be supported, we expect this to moderate the growth rate of new connections in the short term.

1.5 Level of Service

1.5.1 Unplanned Interruptions

On 20 November 2024, the Commerce Commission issued its Electricity Distribution Services Price-Quality Path Determination 2025, which specified the normalisation methodology and quality threshold limits for the regulatory period 1 April 2025 – 31 March 2034 (DPP4). This confirmed that there would be no change to the normalisation methodology from DPP3, although it made minor reductions to our boundary values and annual compliance thresholds for unplanned interruptions. As these changes are not expected to have a material impact on normalisation outcomes, we have not changed our internal targets for unplanned System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). We are progressively investing to improve our network reliability over the ten-year planning period, and our internal targets reflect this, as shown in Table 1.1.

FYE	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
SAIDI	294	289	286	278	273	268	258	248	240	233
SAIFI	4.01	4.00	4.00	3.99	3.99	3.98	3.98	3.90	3.80	3.75

Table 1.1: Unplanned SAIDI and SAIFI Targets

We forecast that our FYE2025 SAIDI results will be around 255 minutes, with our year-to-date results showing significant improvements in our major SAIDI contributors.

Our main contributors to outage events and SAIDI are:

- **Defective Equipment –** We have seen a reduction in defective equipment failures in FYE2025, forecasted at 59.06 minutes, as a result of our defective equipment replacement works and renewal programme. This is a 52% reduction from the FY21 to FY24 average.
- **Vegetation –** We have also seen a reduction in both event count and SAIDI impact of Vegetation, helped by benign weather and the continued vegetation cut programme. Forecasted to be 38.38 SAIDI minutes at FYE2025, a 47% reduction from the FY21 to FY24 average.
- **Unknown –** Forecasted at 44.72 minutes for FYE2025, this is a reduction of 23% from the FY21 to FY24 average. Additional focus is being put into reducing the number of unknown contributors through follow-up patrols after the event to establish the cause and data analysis of protection devices.

1.5.2 Planned Interruptions

The Commission's DPP4 Determination confirmed that the Commission will continue to assess planned SAIDI and SAIFI measures against the regulatory threshold only once. This will be at the end of the regulatory period and the assessment would be against the aggregated values of the measures for all 5 years of that period. It also confirmed that assessing planned SAIDI values would continue to allow the raw SAIDI measures to be reduced by 50% if more stringent requirements relating to the notification of affected consumers are met. This reduction, which does not apply to SAIFI, typically results in a reduction of about 30% of the raw value.

The Determination confirmed that this assessed planned SAIDI, with notified interruptions de-weighted, would continue to be a component of the Quality Improvement Scheme (QIS), and set an annual QIS target of 172.72. This is significantly higher than the previous target of 127.02. This revised target is much closer to what we are currently achieving.

We will continue to monitor the impact of planned interruptions and set annual planned SAIDI and SAIFI targets. The SAIDI measure will be the assessed value, with interruptions meeting the enhanced notification requirements de-weighted, while the SAIFI measure will be the raw value. These targets are shown in Table 1.2.

	Target (FYE2026-35)	Former Target
Annual planned SAIDI (assessed)	170	125
Annual planned SAIFI (raw)	1.0	1.0

Table 1.2: Annual Planned SAIDI and SAIFI Targets

We have now appointed an Outage Coordinator within the control centre team to coordinate the scheduling of planned interruptions and reduce their impact on consumers. This role will holistically consider all planned work, including capital projects, maintenance, and customer requests. They will also coordinate outage-related activities where possible and identify opportunities to mitigate the impact of planned outages on users of our network.

1.6 Network Demand

We have reviewed the network demand forecast in the 2023 AMP and consider it to still provide a reasonable basis for forecasting our network capacity expansion requirements, apart from an error in the forecast demand at the Pukenui substation which is corrected in Table 1.3.

FYE	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Pukenui	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.1	3.2

Table 1.3: Corrected Pukenui Zone Substation Demand Forecast (MVA)

While the overall consumption of electricity by consumers connected to our network is growing at a rate of over 1% per year, this growth is largely offset by the increase in behind-the-meter solar generation and is not reflected in our delivery volumes. We also experienced a reduction in network peak demand to 71MW over the CY2024 winter – well below the 77MW we experienced in the CY2023 winter. The reasons for this are unclear but could include the impact of behind-the-meter solar generation, the recessionary economic environment, the high level of energy poverty in many parts of our supply area, and milder weather conditions.

No significant new block loads on our network have been confirmed or have emerged over the last year. On the other hand, no block loads have been formally withdrawn. Although we are less confident that some will proceed due to the challenging economic environment.

1.7 Network Capital Expenditure

Over the ten-year planning period of this AMP Update, we forecast a total capital expenditure of $230.4 million in FYE2026 constant prices. This forecast is shown in Table 1.4 and in Figure 1.1 is compared with the constant price capital expenditure forecast in our 2024 AMP Update. Apart from FYE2026, the increase shown in Figure 1.1 is due to the constant price base year adjustment from FYE2025 to FYE2026. The additional expenditure in FYE 2026 is due to higher than anticipated cost increases, the need to carry over work that was included in our FYE2025 work plan (that will not be

completed by the end of the year) and additional costs that we expect to incur in completing the installation of the backup Ngāwhā generator transformer.

FYE	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
2025 AMP		28,785	23,216	22,610	22,886	21,534	22,088	23,046	22,087	22,089	22,087

Table 1.4: Constant Price Network Capital Expenditure Forecast ($000, FYE2026)

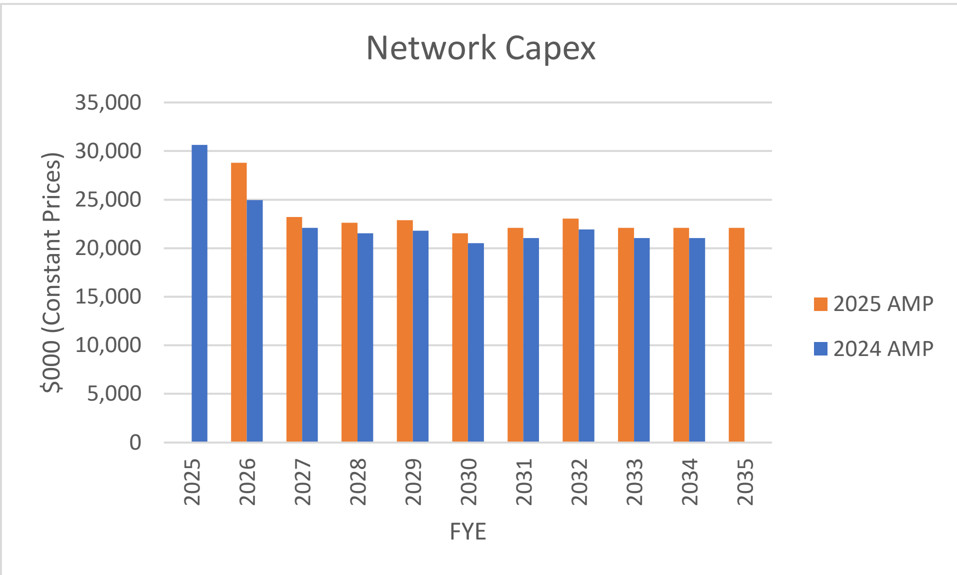
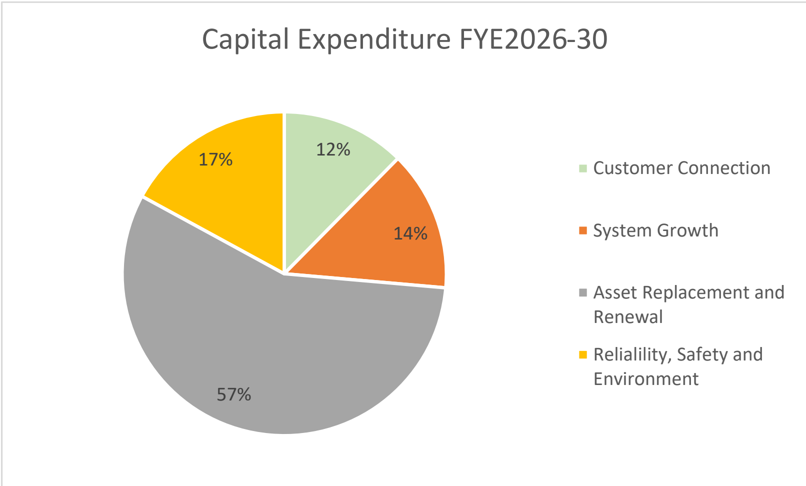


Figure 1.1: Comparison of Network CAPEX Forecast with 2024 AMP Update Forecast

Our capital expenditure forecast reflects our focus on improving resilience and reliability in the short term, transitioning to growth-related expenditure in the latter part of the period to accommodate expected growth in demand for electricity as the economy's decarbonisation accelerates. This transition is shown in Figure 1.2.



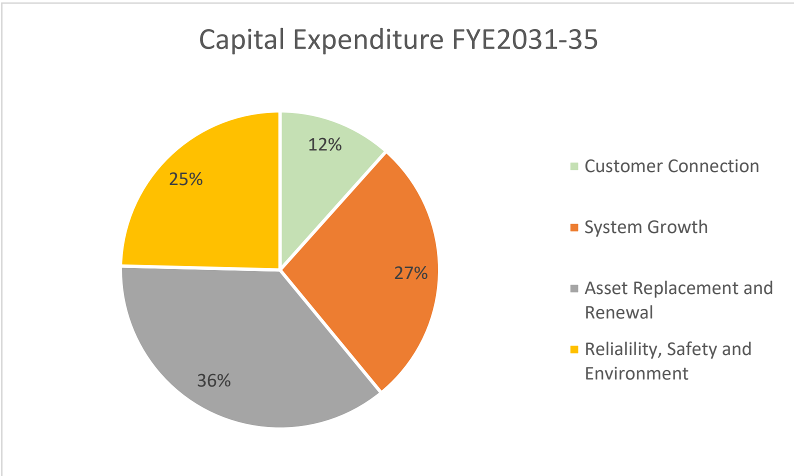


Figure 1.2: Capital Expenditure Breakdown FYE2026–30 and FYE 2031–35

Our FYE2026 work plan includes:

- $4.1 million in customer-driven expenditure, largely driven by the connection of the Pukenui and Twin Rivers solar farms.
- $3.9 million on the first stage of construction of our new 110/33kV Wiroa substation.
- $12.4 million on the replacement and renewal of network assets.
- $4.9 million on projects designed to improve the resilience and reliability of the network.
- $3.4 million completing the installation of the backup Ngāwhā generator transformer.

1.8 Network Maintenance

Over the 10-year planning period of this AMP Update, we expect to spend $108.7 million on network maintenance, as shown in Table 1.5. We have not changed our forecast expenditure in nominal terms and the increases shown in Figure 1.1 are due to inflation because of the constant prices being reset to a different base year. The constant price forecast in the 2024 AMP was based on FYE2024 prices, whereas the forecast below is in FYE2026 prices, to be consistent with our capital expenditure forecast. Therefore, the uplift shown in Figure 5.1 below is due to two years of inflation rather than the typical one year.

FYE	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
2025 AMP		10,176	10,161	10,347	10,540	10,735	10.933	11,136	11,344	11,555	11,866

Table 1.5: Comparison of the 2024 AMP constant Price Forecast with 2023 AMP ($000)

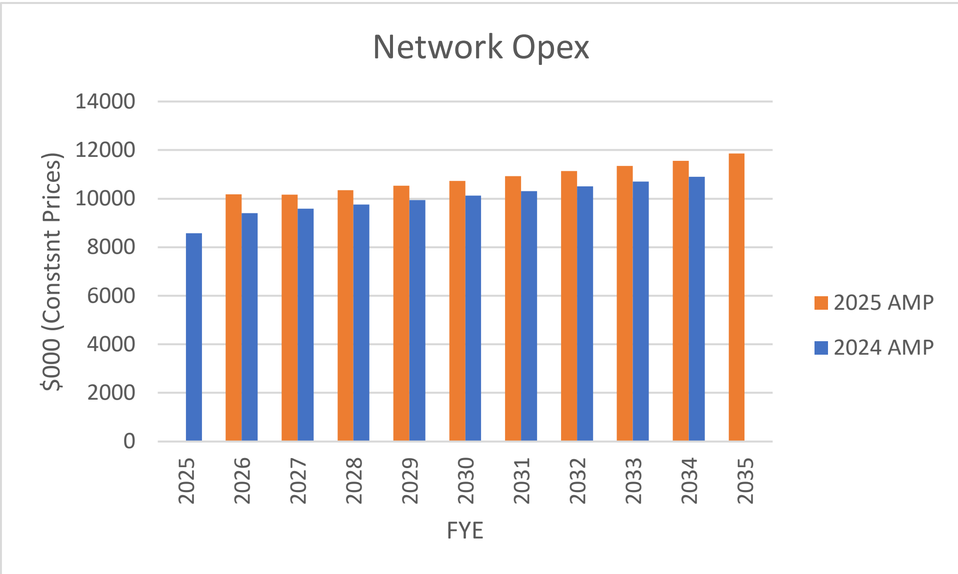


Figure 1.1 Comparison of Constant Price Network Operational Expenditure with 2024 AMP Forecast ($000)

1.8.1 Service Interruptions and Emergencies

Over the last year, we experienced an epidemic of faults on the Rangiahua and Horeke feeders due to swans and waterfowl from Lake Ōmāpere flying into our lines. We have installed bird diverters on the affected feeders, which have mitigated the problem.

1.8.2 Vegetation Management

The Electricity (Hazards from Trees) Amendment Regulations 2024 came into force on 17 October 2024. The most significant change is an extension of the growth limit zone to be “clear to sky”, transmission and sub-transmission lines with uninsulated conductors and also for all lines with a span length greater than 150 metres. There is no other change to the size of the growth limit zones and no material changes to the other requirements of the Regulations. The impact of the new regulations on our vegetation management effort is unlikely to be significant.

We are currently reviewing our approach to vegetation management. While this review is in its early stages, it could mean:

- A more proactive approach to educating and engaging with tree owners – with the objective of preventing issues from arising, rather than just reacting to issues after they occur.
- Outsourcing of work that can be more efficiently done using specialised equipment.
- A more aggressive approach to recovering costs from tree owners, to the extent provided for in the Regulations.
- The selective use of group fusing to minimise the number of consumers affected by a tree contact fault.

1.8.3 Power Transformer Maintenance

As indicated in our 2024 AMP Update, we have purchased a mobile oil treatment plant. This has now been used to treat the Pukenui and Taipa transformers and one Kaikohe transformer. It will be used to treat the oil of our other power transformers by rotation, prioritised by condition.

2. Background

2.1 Purpose of this Document

Our current Asset Management Plan (AMP), which was published on 31 March 2023 and updated in our 2024 AMP Update, documents how Top Energy Network plans to develop and maintain its network assets. It has been prepared in accordance with Sections 2.6.3 and 2.6.5 of the Electricity Information Disclosure (Targeted Review Tranche 1) Amendment Determination 2022. This year, rather than preparing a full AMP, we have chosen to prepare a second AMP Update, which documents only the material changes to the asset management plans documented in our 2023 AMP and our 2024 AMP Update.

Accordingly, our 2023 AMP and our 2024 AMP Update remain valid, except as amended by this Update. In particular, the regulatory schedules included in Appendix A cover the undated 10-year planning period 1 April 2025 to 31 March 2035 and fully replace the corresponding schedules in the 2024 AMP Update. As there are no material changes to the Asset Management Maturity Assessment (AMMAT) presented in Schedule 13 of our 2023 AMP, we have therefore not included a revised schedule in this Update.

This AMP Update was approved by our Board of Directors on 25 March 2025.

2.2 Resilience and Reliability

2.2.1 Distribution Network

In FYE2023, we were non-compliant with the unplanned interruption quality thresholds in our RCP3 price-quality path. Our annual normalised unplanned SAIDI was 513.96 compared to a limit of 380.24, and our normalised unplanned SAIFI was 5.50 compared to a limit of 5.07.

These non-compliances were largely due to the extreme weather experienced over the period, beginning with Cyclone Fili in April 2022 and concluding with Cyclone Gabrielle in February 2023. During this time, 13 significant storm events affected our supply area, two of which triggered a declaration of a formal State of Emergency.

The reliability of our network improved significantly in FYE2024 and FYE2025. In FYE2024, our normalised unplanned SAIDI was 292.29, and we are currently on track to achieve a normalised unplanned SAIDI of 255 in FYE2025. This is well under our internal target of 300, as reflected in the AMP and our Statement of Corporate Intent. Our normalised unplanned SAIFI in FYE2024 was 3.31, and we expect it to be about the same this year. Again, this is well under our internal target of 4.01.

While this improved performance can be partially attributed to more benign weather conditions, it also reflects the success of our reliability improvement programme, which commenced in FYE2023. Under this programme, we have:

- Transferred consumers in Russell township from the Russell Express feeder to Joyces Rd. This has halved the number of consumers affected by a fault on the Russell peninsula. At the same time, it has allowed us to provide for load growth on the peninsula by transferring about 1.5MW of load from the heavily loaded Kawakawa substation to our Haruru substation, where there is ample spare capacity.
- Interconnected the ends of the Whangaroa and Matauri Bay feeders. This has enabled supply to rapidly be restored to consumers outside of a faulted switching zone on either feeder. In FYE2026 we will upgrade the conductor on 35 spans at the end of the Whangaroa feeder to allow the interconnection to be fully utilised at times of peak demand.

As we progress this reliability improvement programme, we anticipate that it will deliver further reliability improvements by:

- Establishing a new 11kV injection point using the 11kV winding of the 110/33/11kV transformer at the Kaitāia substation. This will create five new feeders and is on track for commissioning in FYE2026.
- Optimising the number, location, and grading of protection devices on our long rural feeders to minimise the number of customers that experience a supply interruption when a fault occurs.
- Increasing the number of normally open interconnections between adjacent feeders. This will improve our ability to restore supply to consumers located downstream of a fault location before a fault is repaired.

We plan to replace five structures during a planned shutdown of the 110kV Kaikohe-Kaitāia line scheduled for early March 2025. This line is our most vulnerable asset. Ground subsidence near the line during Cyclone Gabrielle in February 2023 revealed the fragility of parts of the line route, with the section that crosses the Maungataniwha Range being most at risk.[1] During our planned FYE2024 shutdown, we installed two structures on this line in new locations, identified by a geotechnical survey, as having more stable ground.

We also continue to implement a range of smaller reliability improvement initiatives to reduce the SAIDI impact of faults on the 11kV distribution system. These include:

- Installation of new reclosers and sectionalisers to optimise protection on long rural feeders. In FYE2025, this work was completed on the South Road, Horeke, Te Kao, Herekino, and Whangaroa feeders.
- Installation of group fusing on 11kV spurs. This limits the impact of faults on spurs to customers directly connected to the spur.
- Installation of additional remote-controlled switches across the 11kV network to allow reconfiguration of the network remotely from our control room following a fault. This will reduce the time required to locate and isolate a faulted line section before repairs can commence.

Our programme to refurbish lines that have reached the end of their economic life and to replace other critical assets in poor condition continues apace. Over the five-year DPP4 regulatory period (FYE2026-30), asset replacement comprises more than 50% of our forecast capital expenditure on network assets.

2.2.2 Transmission Grid

The failure of the 220kV transmission tower at Glorit in June 2024, exposed the vulnerability of Northland's electricity supply to the resilience of its backbone transmission grid. There are two issues:

- **Security of supply –** While the Ngāwhā geothermal power station and our backup diesel generation has sufficient capacity to supply Top Energy's consumer demand, the geothermal power station cannot operate without a connection to the transmission grid. If this supply is lost, the power station will shut down and cannot restart until the connection to the grid is restored. Our diesel generators can be used to supply power to most consumers in our northern area, and did so during the Glorit event, but they have insufficient capacity to supply consumers in the southern part of our network. Utility-scale solar generation cannot provide support as its output is not controllable, and the dynamic response of the diesel generators is too slow to respond to rapid fluctuations in generated output.
- **Capacity –** There is insufficient transmission capacity to accommodate the connection of additional generation. While there is significant demand for the connection of further utility-scale solar generation to our network, we are unable to accept new connection applications since the transmission capacity available to export the electricity south is fully committed.

[1] Ground subsidence during the cyclone closed State Highway 1 nearby and this road has only recently been reopened.

We are collaborating with Northpower and Transpower in a Resilience, Reliability, and Energy Bridge Working Group to explore opportunities for enhancing resilience and addressing future capacity constraints. The energy bridge component focuses on identifying opportunities for new or upgraded transmission assets by the three organisations to address the region's demand envelope, accommodate current and potential new generation, and develop solutions for loss of supply events. For Top Energy, this involves a proposal to construct our new 110 kV line from Wiroa to Kaitāia, which will provide increased capacity and a backup for the existing 110 kV single circuit line. It also includes an upgrade of Transpower's Kaikohe-Maungatapere grid connection.

In parallel, the three organisations are investigating short, medium, and long-term initiatives to improve the networks' reliability and resilience. For Top Energy, this includes our SAIDI glide path improvement initiatives, particularly our 11kV reliability improvement plan. These projects aim to enhance the overall resilience and reliability of the Top Energy Network, ensuring a stable and secure energy supply for our consumers.

2.3 Consumer Surveys

We conducted two formal consumer surveys from September to November 2024. The first was our annual consumer satisfaction survey, while the second was a repeat of the survey we conducted in 2022, seeking consumers' views on the appropriate balance between price and quality. The results were broadly in line with those of our previous surveys and discussed in some detail in Section 2.3 of our 2024 AMP Update. We will continue to monitor these issues.

2.4 EV Charging

The Government abolished the subsidy on the purchase price of battery electric and plug-in hybrid vehicles on 1 January 2024 and removed the exemption on the payment of road user charges by battery electric vehicles from 1 April 2024. As seen in Table 2.1, this has significantly reduced the number of light electric and plug-in hybrid vehicles registered in New Zealand for the first time to addresses in our supply area. While we expect to see some recovery in 2025 and beyond, a return to the growth rate in registrations seen before 2024 seems unlikely in the short term.

Calendar Year	BEV	Plug-in Hybrid
2018	34	7
2019	31	12
2020	15	4
2021	56	28
2022	91	100
2023	108	85
2024	23	14
Total	**358**	**250**

Table 2.1: Registration of Light Electric Vehicles in our Supply Area.

Three new public EV chargers were installed in our supply area in 2025: a 75kW unit at the BP service station in Waipapa and two 180kW units at the Z service station in Taipa. The two new chargers at Taipa are our first two superfast chargers and reflect the current trend of installing several superfast chargers at a single charging hub rather than dispersing smaller units across multiple single-charger locations. This is in response to the longer range of modern EVs, the time taken to fully charge EVs with large batteries using a small charger, and the frustration experienced by drivers when they arrive at a charging station to find that it is already in use and there is no nearby alternative.

There are now a total of 17 individual DC chargers in our supply area, with an aggregate capacity of just over 1MW, as shown in Table 2.2.

Location	Operator	Size (kW)
Waipapa	BP	75
Taipa	Z Energy	180
Taipa	Z Energy	180
Waitiki Landing	ChargeNet	50
Waitiki Landing	ChargeNet	25
Houhora	ChargeNet	25
Kaitāia (Te Ahu)	ChargeNet	50
Kaitāia (PAK'nSAVE)	ChargeNet	50
Kaitāia (Warehouse)	ChargeNet	25
Coopers Beach	ChargeNet	50
Opononi	ChargeNet	50
Waipapa (Mitre 10)	ChargeNet	50
Waipapa (Warehouse)	ChargeNet	25
Kerikeri	ChargeNet	50
Paihia	ChargeNet	25
Kawakawa	ChargeNet	50
Kaikohe	ChargeNet	50
Total		**1,010**

Table 2.2: Public DC Electric Vehicle Chargers

2.5 Generation

2.5.1 Utility-Scale Solar

Construction of the 20MW Pukenui solar farm adjacent to our Pukenui substation is now almost complete. Commissioning is expected to commence in March 2025 and be completed in April or May. Construction of the 24MW Twin Rivers solar farm has also commenced and this power station should be fully commissioned by mid-FYE2026.

Completion of these two projects will mean that the total capacity of utility-scale solar connected to our northern network will be approximately 67MW, and the transmission capacity of our 110kV circuit between Kaikohe and Kaitāia will be fully committed.

2.5.2 Small Scale Solar

The connection of behind-the-meter, small-scale solar installations to our network continues apace. In the 12 months ending 31 December 2024, 305 of our consumers connected a total of 2.05MW additional small-scale solar generation capacity to the network, This is consistent with the last two years, when approximately 2MW a year was connected and brings the total connected capacity to 13.6MW. We continue to have the highest penetration of solar generation of any New Zealand EDB, with 6.5% of our consumers now having small-scale solar.

In late November 2024, SolarZero, which owned about 1.4MW of this small-scale solar through rental contracts with our consumers, went into liquidation and stopped connecting new customers. Although arrangements are in place for existing customers to continue to be supported. We expect this to moderate the growth rate of new connections in the short term, but the extent of this impact is unclear at this stage.

3. Level of Service

3.1 Unplanned Interruptions

We set our internal supply reliability targets to reflect the performance of the network given the expected outcomes of our investments in increasing network resilience and reliability. While these targets are set independently of the Commerce Commission, they nevertheless use the normalised SAIDI and SAIFI measures used by the Commission to monitor the reliability of our network under its default price-quality regime.

On 20 November 2024 the Commerce Commission issued its Electricity Distribution Services Price-Quality Path Determination 2025, which specified the normalisation methodology and quality threshold limits for the regulatory period 1 April 2025 – 31 March 2034 (DPP4). This confirmed that there would be no change to the normalisation methodology from DPP3, although it made minor reductions to the boundary values, setting the limit above which SAIDI and SAIFI can be normalised. It also made minor changes to the annual compliance thresholds. These changes are shown in Table 3.1.

	DPP4 (FYE2026-30)	DPP3(FYE2021-25)
SAIDI Boundary Value	26.78	27.92
SAIFI Boundary Value	0.1689	0.2284
SAIDI Compliance Threshold	399.25	380.24
SAIFI Compliance Threshold	4.8196	5.0732

Table 3.1: Revised SAIDI and SAIFI Boundary Values and Compliance Thresholds

The lower boundary values may result in some reduction to our annual normalised SAIDI and SAFI, all else being equal, but their impact in most years is unlikely to be material, given the small number of events that are normalised in any year. We have, therefore, not changed the internal SAIDI and SAIFI targets set out in our 2024 AMP update and shown in Table 3.2.

FYE	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
SAIDI	294	289	286	278	273	268	258	248	240	233
SAIFI	4.01	4.00	4.00	3.99	3.99	3.98	3.98	3.90	3.80	3.75

Table 3.2: Unplanned SAIDI and SAIFI Targets

Figures 4.1 and 4.2 compare the unplanned SAIDI and SAIFI performance from FYE2010 with the planning period targets shown in Table 3.2. The quality thresholds shown are the thresholds that will trigger a Commerce Commission investigation. The Commission has initiated an investigation into our asset management practices following our FYE2023 breach of both the SAIDI and SAIFI thresholds. This is ongoing.

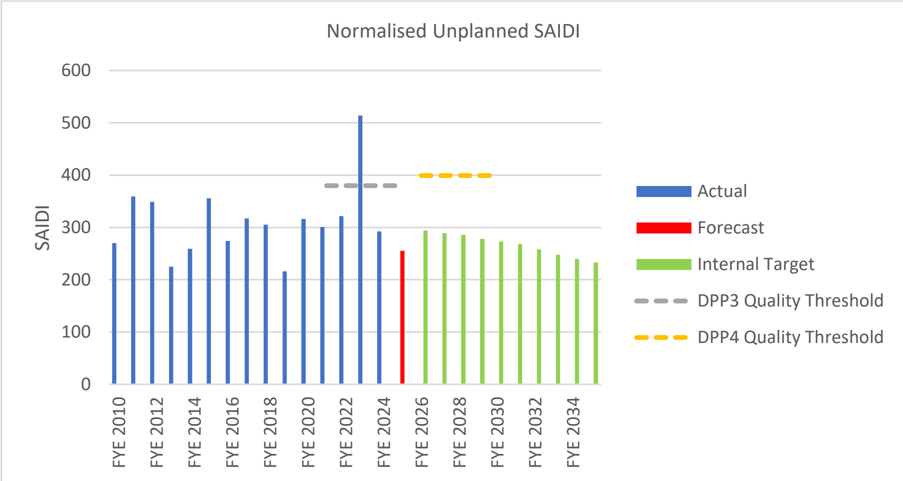


Figure 3.1: Historical and Target Unplanned SAIDI

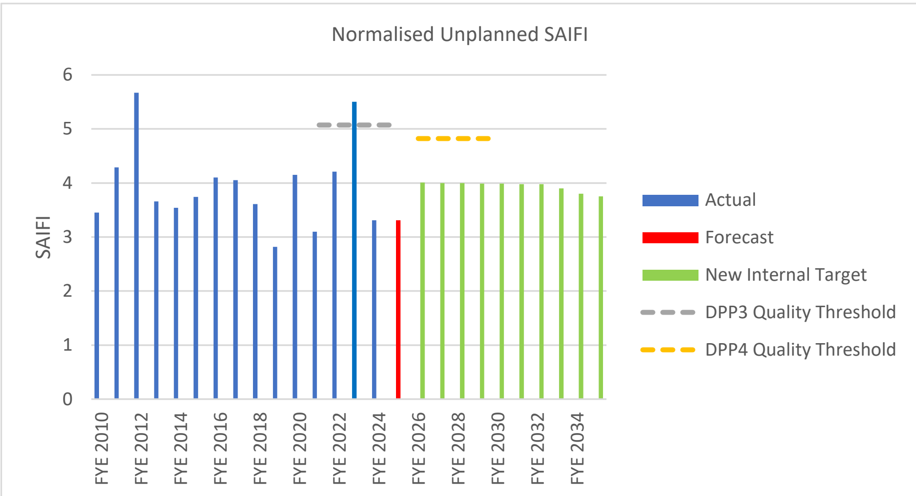


Figure 3.2: Historical and Target Unplanned SAIFI

In FYE2024 the normalised unplanned SAIDI was 292.29 SAIDI minutes and SAIFI was 3.31. These were both lower than the Commerce Commission's quality thresholds of 380.24 SAIDI minutes and 5.07 SAIFI interruptions, and lower than the 302 minutes unplanned SAIDI and 4.01 SAIFI targets in our Statement of Corporate Intent.

- There were two major SAIDI events in FYE2024, one storm at the end of April and spilling into May 2023, and Cyclone Lola in October 2023. Due to the impact of normalisation, these two events did not make a significant contribution to our normalised SAIDI/SAIFI measures – their total normalised SAIDI impact was 17.8 minutes.
- During FYE2024, there were 35 interruptions, outside of major events, with a SAIDI impact of greater than 2 minutes. Together these interruptions had a SAIDI impact of 120 minutes, which accounted for 41% of our total normalised Unplanned SAIDI for the year.
- The normalised unplanned SAIDI due to faults on the 33kV sub transmission network was 30.83 minutes, 10.5% of the total network Unplanned SAIDI of 292.3 minutes. As a result of the investment in the sub transmission network, sub transmission faults are no longer a major contributor to our normalised network SAIDI. Going forward, we are aiming to reduce the annual normalised unplanned SAIDI on our sub transmission network to below 20 minutes.
- The normalised SAIDI impact of faults on our 11kV distribution network in FYE2024 was 261.5 minutes, down 46% from the FY2023 impact of 480.1 minutes.

We are forecasting that our FYE2025 SAIDI results will be around 255 minutes, with our year-to-date results showing significant improvements in our major SAIDI contributors:

Our main contributors to outage events, and SAIDI are:

- **Defective Equipment –** (33.23% of total SAIDI FYE2024). We have seen a reduction in defective equipment failures in FYE2025, forecasted at 59.06 minutes, as a result of our defective equipment replacement works and renewal programmes as described in section 4.2.3. This is a 52% reduction from the FY21 to FY24 average.
- **Vegetation –** (24.14% of total SAIDI FYE2024). We are taking a risk-based approach to our vegetation strategy, as described in 5.1.2. This, alongside favourable weather through 2024, has resulted in a reduction in FYE2025 in vegetation-related events. This is forecasted to be 44.77 SAIDI minutes at year end, a 47% reduction from the FY21 to FY24 average.
- **Unknown –** (15.64% of total SAIDI FYE2024). These incidents are when we were able to restore power without being able to determine the initial cause during line patrols – typically the result of objects such as vegetation debris, wildlife, or unreported third-party interference.

  Unknown cause events are forecasted at 38.38 minutes for FYE2025, this is a reduction of 23% from the FY21 to FY24 average. Additional focus is being put into reducing the number of unknown contributors through follow-up patrols after the event to try to establish the cause and data analysis of protection devices.

3.2 Planned Interruptions

In its Electricity Distribution Services Price-Quality Path Determination 2025, the Commerce Commission confirmed that for DPP4 it would continue to assess planned SAIDI and SAIFI only once, at the end of the regulatory period. This assessment would be against the aggregated values for all five years of the period. It also confirmed that in assessing planned SAIDI values against the threshold, it would continue to allow the raw SAIDI value to be reduced by 50% if more stringent requirements relating to the notification of affected consumers are met. This reduction, which does not apply to SAIFI, typically results in a reduction of around 30% of the raw value.

The 2025 Determination changed our 5-year aggregated planned interruption thresholds from those that applied in DPP3. These changes are shown in Table 3.3.

	DPP4 (FYE2026-30)	DPP3(FYE2021-25)
5-year planned SAIDI limit	1,727.59	1,905.36
5-year planned SAIFI limit	8.5279	7.7526

Table 3.3: Revised Planned SAIDI and SAIFI Aggregated Thresholds

Nevertheless, we still set annual planned SAIFI targets for internal management purposes. Our current planned SAIDI target was set in our 2023 AMP. This was based on the SAIDI target set by the Commission for the quality incentive scheme that applies for the current DPP3 regulatory period (FYE2021-25). As planned, SAIFI is not a component of the quality incentive scheme. The SAIFI target was based on the planned SAIFI we expect to achieve in a typical year.

In its DPP4 Determination, the Commission reset our quality incentive scheme target to 172.72, a significant increase on the previous target of 127.02. This reflects the change in the industry safety regulations, which now prohibits the use of live line work procedures except in exceptional circumstances, as well as the increased amount of maintenance we are undertaking as we implement our 11kV reliability improvement plan. We have therefore adjusted our planned internal planned SAIDI target to reflect this. In assessing our performance against this target, we will continue to apply the planned SAIDI assessment criteria set out in the DPP4 Determination. This allows us to reduce the raw SAIDI impact of a planned interruption by 50% if enhanced retailer and customer notification criteria are met and the interruption is fully completed within the notification window. Typically, we find that application of this criteria reduces the measured raw SAIDI value over a year by about 30% for assessment purposes when aggregated over a year.

Planned SAIFI is not included in the quality incentive scheme and the Commission does not provide for any reduction in the measured raw value for assessment purposes. Our planned SAIFI target is, therefore, the raw value measure and has not changed from the current target of 1.0. This is is slightly below the annual planned SAIDI we have achieved when we introduced our 11kV reliability improvement programme.

Our internal annual targets for planned interruptions are shown in Table 3.4 below.

	Target (FYE2026-35)	Former Target
Annual planned SAIDI (assessed)	170	125
Annual planned SAIFI (raw)	1.0	1.0

Table 3.4: Annual Planned SAIDI and SAIFI Targets

3.2.1 Changes to the Default Distributor Agreement

As a result of changes made by the Electricity Authority to the Default Distributor Agreement, we are now required to credit retailers our daily charge for all supply interruptions of individual ICPs lasting more than 24 hours. We can readily identify and extract the affected ICPs from our Advanced Distribution Management System (ADMS) data and have been able to comply with this new requirement without any major changes to our asset management software.

In another change, we are now required to schedule planned interruptions to “minimise disruption to consumers” rather than “with consideration to minimise disruption…”. While this might seem a minor wording adjustment, it requires us to demonstrate that we actively consider the impact such interruptions are likely to have on individual consumers when scheduling planned interruptions.

In the past, our construction delivery team managed planned outages independently, addressing timing and impact mitigation as needed. To enhance the consumer experience and reduce the impact of maintenance activities and planned outages, we have transferred the coordination of these outages to the Network Control Centre, guided by a newly appointed Outage Coordinator.

This role will take a comprehensive look at all planned work, including capital projects, maintenance, and customer requests. The Outage Coordinator will coordinate outage-related activities and identify opportunities to mitigate the impact of planned outages users of our network.

4. Network Development Planning

4.1 Network Demand

We have reviewed the network demand forecast in the 2023 AMP and consider that it still provides a reasonable basis for forecasting our network capacity expansion requirements over the planning period for this 2024 AMP Update. This is apart from an error in the forecast demand at Pukenui substation, which is corrected in Table 4.1.

FYE	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Pukenui	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.1	3.2

Table 4.1: Corrected Pukenui Zone Substation Demand Forecast (MVA)

While the overall consumption of electricity by consumers connected to our network is growing at a rate of over 1% per year, this growth is largely offset by the increase in behind-the-meter solar generation and, therefore, is not reflected in our delivery volumes. Our peak demand over the CY2024 winter was only 71MW, well below the 77MW peak demand we experienced in the CY2023 winter. The reasons for this are unclear, but could include the impact of behind-the-meter solar generation, the recessionary economic environment, the high level of energy poverty in many parts of our supply area, and milder weather conditions. It is unclear whether this sudden drop in demand is an isolated occurrence or indicative of a more sustained trend.

4.1.1 New Loads

Apart from the completion of the initial 750kVA stage of a commercial gum extraction and processing plant northwest of Kaitāia, no significant new block loads on our network have been confirmed or have emerged over the last year. On the other hand, no block loads have been formally withdrawn, although we are less confident that some will proceed due to the difficult economic environment.

The number of connections to our network continues to increase at a rate of about 300 or 1% a year. In the short term, we expect any growth in network demand to be incremental.

4.2 Major Capital Projects Completed in FYE2025

We expect to have spent around $30 million capital expenditure on network assets in FYE2025. The major projects covered by this expenditure are described below.

4.2.1 Customer Driven

We have completed the connection of the Far North solar farm to the 33kV bus at Pukenui substation and are in the process of installing a 33kV underground circuit to connect the Twin Rivers solar farm to the 33kV bus at our Kaitāia substation. This work will need to be completed in time for the commissioning of the Twin Rivers solar farm in mid-FYE2026.

4.2.2 System Growth

We have now transferred half the load on the Russell peninsula from the Kawakawa zone substation to the more lightly loaded Haruru substation. We had been developing this project in stages for several years, but the final commissioning was delayed, pending the delivery of key components. We have also commenced the design of the 110/33kV Wiroa substation, where construction is scheduled to start in FYE2026. By the end of FYE2025, we expect to have spent $300,000 on the upgrading of heavily loaded conductor “hot spots” on the 11kV network

4.2.3 Asset Renewal and Replacement

We expect to have spent more than $10 million on asset renewal and replacement by the end of FYE2025. This will include:

- $1 million on the 110kV Kaikohe-Kaitāia transmission line for the replacement of five poor condition, or "at risk" structures during a shutdown scheduled for 1st and 2nd March 2025.
- $0.5 million on the refurbishment and rebuilding of 33kV sub-transmission lines.
- $7 million on the refurbishment and rebuilding of our 11kV distribution lines. This includes proactively replacing old copper and steel conductors, wooden and substandard concrete poles, and replacing pole-top assets on distribution line sections where a fault will have a significant SAIDI and SAIFI impact or public safety risk. It also includes the reactive replacement of assets in response to network faults and remediating defects identified through our asset inspection programme.

We continue to develop our condition-based asset risk management models and have now reached the point where most of our field asset classes have been modelled. Zone substation assets have not yet been modelled.

The model ranks the health of each individual asset on a score of 1 (as new) to 10 (end of life), where asset health is the probability of the asset failing in service weighted by criticality, or the potential consequence of, such a failure. The individual asset scores can then be aggregated to give a broader picture of the overall health of each asset class and how this would change over time if different interventions were applied. Inputs to the model include a wide range of parameters that can be expected to affect asset health – such as age, condition, and environmental factors likely to impact the rate of deterioration. As well as parameters related to criticality – such as the impact of the asset failure on the operation of the network and the likelihood of the failure causing a public safety hazard. The biggest challenge in the model's application is the completeness and accuracy of our data, causing many assets from being accurately modelled. We have initiatives to improve our asset data quality in response to this.

We anticipate that the model will eventually allow us to develop a more structured approach to optimising our asset renewal and replacement capital expenditure. We intend to use the models to inform the plan for the renewal and replacement of assets that will be included in our 2026 AMP.

4.2.4 Reliability of Supply

We expect to have spent up to $15 million on proactive reliability of supply initiatives by the end of FYE2025. About $8.5 million will be spent on a backup generator transformer for our 32MW OEC4 generator at the Ngāwhā power station. While the power station is owned by Ngāwhā Generation Ltd, its associated high-voltage assets are part of our network, and we are concerned that a transformer failure could put the generating unit out of service for up to two years. The transformer would also be used as backup for a second 110kV generating unit at Ngāwhā, if this is built.

We expect around $4 million to have been spent on our 11kV reliability improvement plan. This includes:

- $900,000 on constructing a new 11kV injection point using the 11kV tertiary winding of our 40/60/80MVA 110/33/11kV transformer at Kaitāia substation. This will add five new feeders to the network. By the end of FYE2025, we expect to have completed the installation of all the high-voltage assets associated with this project, but commissioning of the new injection point will be delayed until the associated secondary assets are installed and tested in FYE2026.
- $1.6 million on interconnections between the Matauri Bay and Whangaroa feeders, as well as the Rangiahua and South Rd feeders. The Matauri Bay-Whangaroa connection is complete, apart from the upgrade of 35 conductor spans at the end of the Whangaroa feeder to enable the interconnection to be fully utilised at times of high network demand. This work is in the FYE2026 work plan. Landowner negotiations over the line route have delayed the interconnection between Rangiahua and South Rd feeders, but we expect this project will also be completed in FYE2026.

- $1.5 million on optimising Horeke, Herekino, Rangiahua, Te Kao, Whangaora and South Rd feeder protection. These are all long rural feeders with a high SAIDI impact.

Our low voltage data capture project continues, and we expect to have spent $365,000 by the end of FYE2025. Like many other EDBs, the quality of our data on the capacity and connectivity of our low-voltage assets is poor compared to the data on the assets that make up our higher-voltage networks. The data capture project, which will extend to FYE2027, is designed to remedy this. It is planned that this data will be used in the following ways:

- It allows for centralised operation and access control to the low-voltage network to mirror the processes, controls, and situational awareness already in place to manage the high-voltage network. This transition will be implemented in stages as definitive areas of the low-voltage network have been verified and labelled in the field and in our digital operational systems.
- It will be input into our ADMS to provide a real-time network connectivity model that will enable the low-voltage network to be actively managed. This will be gradually developed to the point where it will provide visibility of supply interruptions down to the individual consumer or ICP level.
- It will be used as a planning tool to identify constraints on the low-voltage network proactively. As noted in our 2023 AMP, we are planning to trial the Hiko LV platform and have had discussions with Hiko to this effect. The platform claims to provide a model of the LV network that would provide the following benefits:
    - By monitoring consumer consumption patterns, the software would use artificial intelligence to identify consumers with EV chargers, behind-the-meter solar installations and battery storage. This would enable us to monitor their impact on the low voltage networks to which they are connected and identify current or emerging constraints.
    - The software can identify broken neutrals, which are a cause of electric shocks and a significant consumer safety problem.
    - It would enable us to identify consumers with a voltage outside the regulatory technical envelope and provide better data with which to design solutions.
    - It would allow us to optimise the tap change settings of individual distribution transformers.

To maximise the benefits of LV visibility, we require access to individual ICPs' engineering data. We have held discussions with metering service providers on our network but have not been able to access the data for what we consider a reasonable cost. The Electricity Authority is aware of this industry-wide problem, and we are hopeful that a regulatory solution will emerge that will overcome this roadblock.

4.3 FYE2026 Work Programme

4.3.1 Network Assets

Our planned capital expenditure on network assets in FYE2026 is $28.79 million, up 15% from the $24.94 million forecast in the 2024 AMP. A large part of this increase is due to a $1.42 million increase in the expected FYE2024 completion cost of installing the backup Ngāwhā generator transformer. The balance of the increase is a carryover of work in our current FYE2025 work plan, that we do not expect to be completed by the end of the financial year, and a 5% uplift in project costs due to inflation.

Project	Cost ($000)	Comment
Customer Driven		
All projects	4,147	This includes the connection of the Twin Rivers solar farm to the Kaitāia substation bus. This will complete installation of solar farm connections. Customer driven capital expenditure is expected to revert to more normal levels from FYE2027.
System Growth		
Wiroa substation	3,898	This is the first stage of the construction of the new 110/33kV Wiroa substation.
Asset Replacement and Renewal		
110kV structure replacements and other 110kV asset maintenance (incl. CB222 replacement at Kaitāia)	1,121	
Replace 110kV CB 122 at Kaitāia	214	
33kV line refurbishment	993	
11kV line refurbishment (incl. SWER)	3,927	
Concrete pole replacement	388	
Wood pole replacement	831	
Switchgear	512	
Transformers and regulators	1,134	
Protection Communications and SCADA	396	
Reactive – fault response	1,221	
Reactive – corrective response	1,682	
Subtotal – Asset Replacement and Renewal	12,419	

Project	Cost ($000)	Comment
Reliability, Safety and Environment		
Optimisation of 11kV feeder protection	603	Includes the installation of new and relocated protection devices and optimisation of protection settings on the Opononi and Oruru feeders and the installation of group fusing on spur lines.
Feeder interconnections	1,955	South Rd–Rangiahua and Matauri Bay-Whangaroa feeders. Includes conductor upgrades and the installation of regulators to provide sufficient network capacity to carry the full load of both feeders.
Communications system upgrades	933	
Remote controlled switches and smart devices	216	
Low voltage data capture	350	
Ngāwhā backup generator transformer	3,420	This will complete the project to provide a backup generator transformer for the 32MW OEC4 generator at Ngāwhā power station. Generator transformers at the power station are network assets.
Other	846	Includes a range of projects, such as the installation of fault passage indicators and minor network power quality upgrades.
Subtotal – Reliability, Safety and Environment	8,323	
TOTAL FORECAST CAPEX – FYE2025	28,785	

Table 4.1: Breakdown of FYE2025 Work Programme

4.3.2 Non-Network Capital Expenditure

Our planned capital expenditure on non-network assets in FYE2026 is $2.26 million. This is a 9% increase from the $2.07 million forecast in the 2024 AMP, primarily relating to the upgrade of the Top Energy office security system upgrade.

4.4 FYE2027-35 Capital Expenditure Forecast

4.4.1 Network Capital Expenditure

We have not made any material changes to the constant price forecast presented in our 2024 AMP Update apart from a 5% uplift to reflect an inflationary cost increase between FYE2025 and FYE2026. The projects in the forecast and their timing remain unchanged.

4.4.2 Non-Network Capital Expenditure

Our 2026 AMP forecast total constant price non-network capital expenditure for RCP4 is $8.22m, a 14% reduction from the $9.6m forecast in 2023. This is primarily due to the deferral of the following System Implementations:

- The Distributed Energy Resource Management System (DERMS) was previously planned for FYE2028. It is now planned for FYE2030–FYE2033 as it is not currently expected to be required until the latter half of the AMP planning period. We continue to enhance our access to accurate and quality data, including smart meter data and transformer loggers, to enable a DERMS system in the future.
- Automatic Power Restoration System (APRS), previously planned for FYE2028, deferred to FYE2034. We do not believe we will realise the value in this function until we have additional mesh connectivity in our MV network.

4.4.3 Total Forecast Network Capital Expenditure

Our total forecast capital expenditure on network assets, measured in constant price terms, over the 10-year planning period of this AMP has increased to $230.4 million, 2% higher than the $226.5 million forecast for the 2024 AMP planning period. This is shown in Table 4.2 and Figure 4.1. As noted in Section 4.3.1 above, our FYE2026 forecast has increased by 15% over the 2024 AMP forecasts. Going forward, constant prices have been expressed assuming an FYE2026 base year, with an inflationary uplift of more than 5% over the FYE2025 constant prices in the 2024 AMP. These increases have been offset by the abnormally high FYE2025 capital expenditure, which has dropped out of the comparison.

FYE	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
2025 AMP		28,785	23,216	22,610	22,886	21,534	22,088	23,046	22,087	22,089	22,087
2024 AMP	30,626	24,943	22,104	21,529	21,792	20,505	21,032	21,944	21,032	21,032	

Table 4.2: Comparison of the 2025 AMP Constant Price Capital Expenditure Forecast with 2024 AMP Forecast ($000)

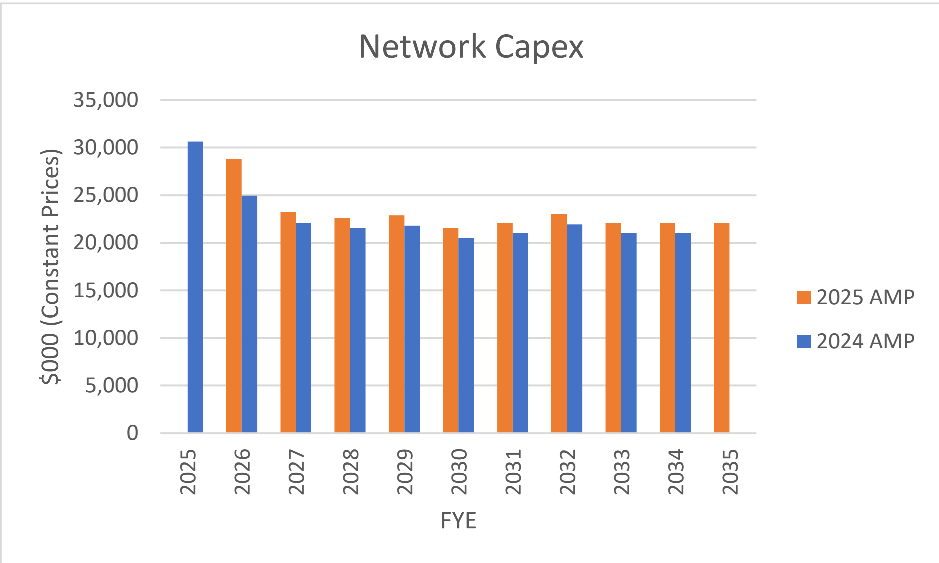
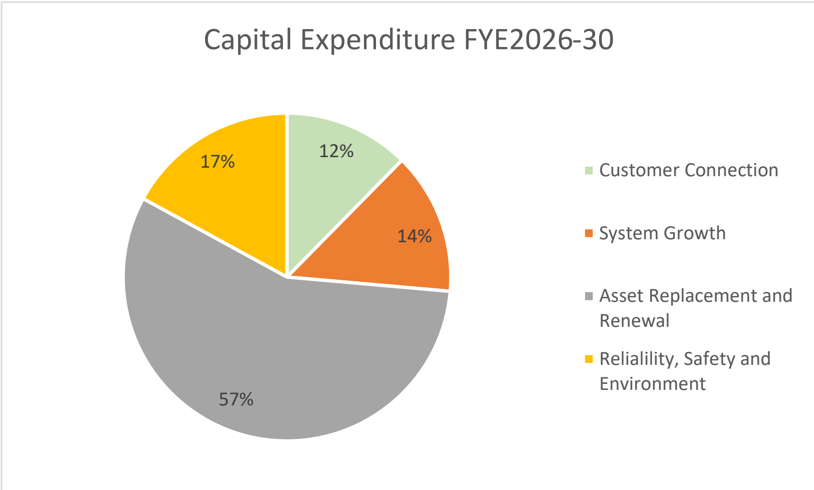


Figure 4.1 Comparison of Constant Price Network Capital Expenditure Forecast with 2023 AMP Forecast ($000)

Figure 4.2 compares the breakdown of our capital expenditure forecast for the first half of the planning period (FYE2026–30) with our anticipated breakdown over the second half of the period. This reflects our current focus on expenditure designed to increase the resilience and reliability of the network. Over the next five years, we expect this expenditure to be almost three-quarters of our capital expenditure budget. We anticipate this will reduce to 60% over the second half of the period as expenditure on system growth increases to accommodate the expected increase in demand as decarbonisation of the economy accelerates.



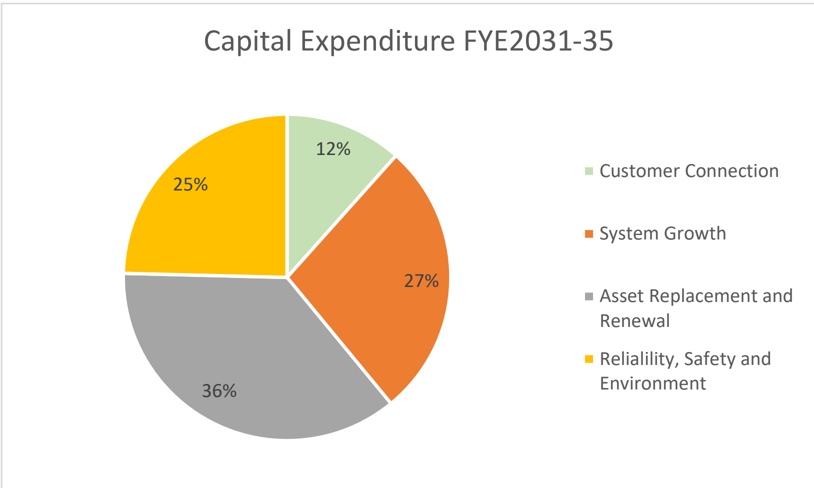


Figure 4.2: Capital Expendditure Breakdown FYE2026–30 and FYE 2031–35

5. Lifecycle Asset Management

5.1 Network Maintenance

Over the ten-year planning period our total forecast network maintenance expenditure is $108.8 million, up 9% on our 2024 AMP ten-year forecast. The network maintenance forecast in our 2024 AMP was significantly higher than the 2023 forecast. This is due to the high inflation rate over the last three years and an increased maintenance programme designed to improve network resilience in response to the changing climate. Due to this increase, we have not changed our forecast expenditure in nominal terms this year. The 9% increase is due to inflation since the constant prices have been reset to a different base year. The constant price forecast in the 2024 AMP was based on FYE2024 prices, whereas the forecast below is in FYE2026 prices, to be consistent with our capital expenditure forecast. The uplift is, therefore, due to two years inflation, rather than the normal one year.

Table 5.1 and Figure 5.1 compare our forecast with the forecast in our 2024 AMP.

FYE	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
2025 AMP		10,176	10,161	10,347	10,540	10,735	10,933	11,136	11,344	11,555	11,866
2024 AMP	8,582	9,409	9,583	9,759	9,940	10,124	10,311	10,503	10,698	10,897	

Table 5.1: Comparison of the 2024 AMP constant Price Forecast with 2023 AMP ($000)

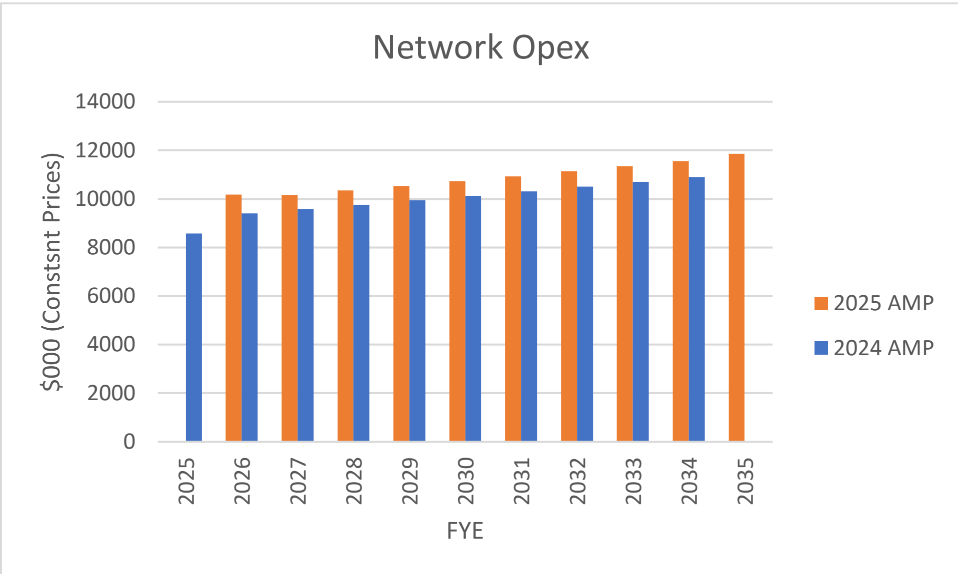


Figure 5.1 Comparison of Constant Price Network Operational Expenditure with 2024 AMP Forecast ($000)

Figure 5.2 provides a breakdown of the total 2025 AMP operational expenditure, as shown in Table 5.1, into the Commerce Commission's regulatory expenditure categories. Unlike capital expenditure, we do not expect this breakdown to change significantly over the planning period.

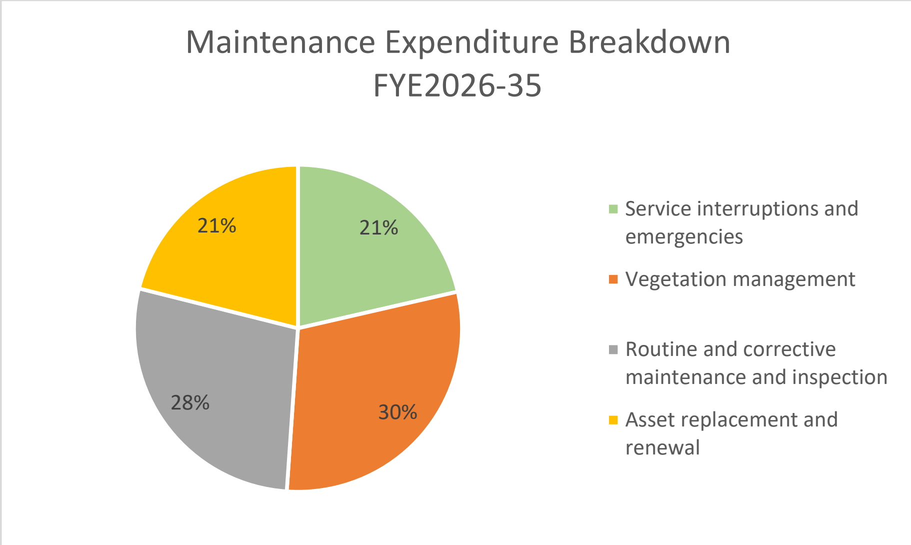


Figure 5.2 Breakdown of Network Maintenance Expenditure FYE2026–35

5.1.1 Service Interruptions and Emergencies

This expenditure is reactive, with no significant material change to budget.

Over the last year, we experienced an epidemic of faults on the Rangiahua and Horeke feeders due to swans and waterfowl from Lake Ōmāpere flying into our lines. We have installed bird diverters on the affected feeders, which have mitigated the problem.

5.1.2 Vegetation Management

Our transmission and sub-transmission lines are surveyed annually for vegetation clearance, while distribution lines are inspected on a two-year cycle. Identified vegetation issues are reported and logged through our Field Recording Electronic Device (FRED) – the mobile platform through which field data on our network assets is captured into SAP.

The surveys categorise the vegetation risk on each span of the network according to the vegetation risk categories defined in Table 5.2.

Risk Category	Description	Criterion
P_0	Contact	Vegetation has grown through the lines or there is visible burning.
P_1	Growth limit zone	Vegetation breaches the grown limit zone defined in the Electricity (Hazards from Trees) Regulations 2003.
P_2	Notice zone	Vegetation breaches notice zone defined in the Electricity (Hazards from Trees) Regulations 2003.
P_3	Potential hazard	Vegetation is present and may eventually become a higher priority.

Table 5.2: Vegetation Risk Categories

All P_0 and P_1 issues identified in our transmission and sub-transmission line surveys are cleared annually.

On our 11kV distribution network, we quantify the vegetation risk on each individual span in accordance with the risk categories in Table 5.2 and then aggregate this data to the feeder level on the basis of the total number of spans on the feeder in each category. The previous year's feeder SAIDI then weights this vegetation risk score to prioritise our vegetation management effort.

Overlaid on this management plan, we take a reactive approach to vegetation clearance on those parts of the network where the vegetation risk is known to be high. Cape Reinga, Ahipara and the Karikari Peninsula are areas where the fire risk, as categorised by Fire and Emergency NZ (FENZ), frequently rises to extreme levels and vegetation clearance in these areas is prioritised over summer. We monitor fire risk on the NIWA/FENZ website and are in close contact with FENZ regarding this issue. We also prioritise vegetation clearance where we become aware of a public safety risk.

The Electricity (Hazards from Trees) Amendment Regulations 2024 came into force on 17 October 2024. The most significant change is an extension of the growth limit zone to be "clear to sky", transmission and sub-transmission lines with uninsulated conductors and also for all lines where the span length is greater than 150 metres. There is no other change to the size of the growth limit zones and no material changes to the other requirements of the Regulations. The impact of the new regulations on our vegetation management effort is unlikely to be significant.

Our budgeted expenditure on vegetation management in FYE2026 is $3.0 million. Up from our actual expenditure of $2.2 million in FYE2024.

We are currently reviewing our approach to vegetation management. While this review is in its early stages it could mean:

- A more proactive approach to educating and engagement with tree owners with the objective of preventing issues from arising rather than just reacting to issues after they occur.
- Outsourcing of work that can be more efficiently done using specialised equipment.
- A more aggressive approach to the recovery of costs from tree owners to the extent provided for in the Regulations.
- The selective use of group fusing to minimize the number of consumers affected by a tree contact fault.

5.1.3 Routine and Corrective Maintenance and Inspection

Our budgeted expenditure on routine and corrective maintenance and expenditure in FYE2026 is $2.8 million, compared to actual expenditure of $2.4 million in FYE2024.

5.1.3.1 Power Transformer Maintenance

As indicated in our 2024 AMP Update, we have purchased a mobile oil treatment plant. This has now been used to treat the transformers at Pukenui and Taipa as well as one transformer at Kaikohe. It will be used to treat the oil of our other power transformers by rotation, prioritised by condition. Purification of the transformer oil should slow the rate of deterioration of the paper insulation, which could reduce the probability of an unexpected transformer failure.

5.1.4 Asset Replacement and Renewal

Our budgeted expenditure on asset replacement and renewal, where the expenditure cannot be capitalised, is $2.2 million. Up from our actual expenditure of $1.5 million in FYE2024. This largely reflects an increase in the rate at which we remediate defects identified by our asset inspection programme.

5.2 System Operations and Network Support Expenditure

There is no material change in System Operations and Network Support Expenditure.

6. Appendices

6.1 Appendix A – Asset Management Plan Schedules:

Schedule 11a	CAPEX Forecast
Schedule 11b	OPEX Forecast
Schedule 11c	Cybersecurity Expenditure
Schedule 12a	Asset Condition
Schedule 12b	Capacity Forecast
Schedule 12c	Demand Forecast
Schedule 12d	Reliability Forecast
Schedule 14a	Mandatory Explanatory Notes on Forecast Information
Schedule 15	Voluntary Explanatory Notes

Schedule 11a CAPEX Forecast

Company Name	**Top Energy**
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			FYE2025	FYE2026	FYE2027	FYE2028	FYE2029	FYE2030	FYE2031	FYE2032	FYE2033	FYE2034	FYE2035
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	3,500	4,147	2,590	2,714	2,768	2,823	2,880	2,937	2,996	3,082	3,245
11		System growth	400	3,898	4,769	5,090	2,552	625	4,554	6,029	6,914	5,877	12,781
12		Asset replacement and renewal	10,800	12,419	13,674	12,678	15,801	14,660	9,417	10,690	9,847	10,989	6,358
13		Asset relocations											
14		Reliability, safety and environment:											
15		Quality of supply	6,300	4,901	3,121	3,513	3,651	5,667	8,024	6,816	6,122	6,450	4,540
16		Legislative and regulatory											
17		Other reliability, safety and environment	8,500	3,420									
18		**Total reliability, safety and environment**	14,800	8,321	3,121	3,513	3,651	5,667	8,024	6,816	6,122	6,450	4,540
19		**Expenditure on network assets**	29,500	28,785	24,154	23,994	24,772	23,775	24,875	26,473	25,878	26,398	26,924
20		**Expenditure on non-network assets**	3,047	2,262	2,300	1,516	1,075	770	3,997	3,237	2,609	2,645	2,170
21		**Expenditure on assets**	32,547	31,047	26,453	25,510	25,848	24,545	28,871	29,709	28,487	29,043	29,094
22													
23	*plus*	Cost of financing	100	200	100	250	350	350	350	350	350	350	350
24	*less*	Value of capital contributions	3,000	3,295	2,100	2,142	2,184	2,228	2,272	2,317	2,364	2,411	2,459
25	*plus*	Value of vested assets											
26													
27		**Capital expenditure forecast**	29,647	27,952	24,454	23,619	24,013	22,667	26,949	27,742	26,473	26,982	26,984
28													
29		Assets commissioned	22,299	33,702	19,778	31,892	24,013	22,667	26,949	27,742	26,473	26,982	26,984
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	3,500	4,147	2,489	2,557	2,557	2,557	2,557	2,557	2,557	2,579	2,662
34		System growth	400	3,898	4,584	4,796	2,358	566	4,044	5,249	5,901	4,918	10,485
35		Asset replacement and renewal	10,800	12,419	13,143	11,947	14,598	13,278	8,362	9,306	8,404	9,195	5,216
36		Asset relocations	-	-	-	-	-	-					
37		Reliability, safety and environment:											
38		Quality of supply	6,300	4,901	2,999	3,311	3,373	5,133	7,125	5,934	5,225	5,397	3,724
39		Legislative and regulatory	-	-	-	-	-	-					
40		Other reliability, safety and environment	8,500	3,420	-	-	-	-					
41		**Total reliability, safety and environment**	14,800	8,321	2,999	3,311	3,373	5,133	7,125	5,934	5,225	5,397	3,724
42		**Expenditure on network assets**	29,500	28,785	23,216	22,610	22,886	21,534	22,088	23,046	22,087	22,089	22,087
43		Expenditure on non-network assets	3,047	2,262	2,210	1,429	993	697	3,549	2,818	2,226	2,213	1,780
44		**Expenditure on assets**	32,547	31,047	25,426	24,039	23,879	22,231	25,637	25,864	24,313	24,302	23,867
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													

Company Name	**Top Energy**
AMP Planning Period	**1 April 2025 – 31 March 2035**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

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sch ref		FYE2025	FYE2026	FYE2027	FYE2028	FYE2029	FYE2030	FYE2031	FYE2032	FYE2033	FYE2034	FYE2035
53		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
54												
55	**Difference between nominal and constant price forecasts**	**$000**										
56	Consumer connection	-	-	101	157	211	266	323	380	439	503	583
57	System growth	-	-	185	294	194	59	510	780	1,013	959	2,296
58	Asset replacement and renewal	-	-	531	731	1,203	1,382	1,055	1,384	1,443	1,794	1,142
59	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
60	Reliability, safety and environment:											
61	Quality of supply	-	-	121	203	278	534	899	882	897	1,053	816
62	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
63	Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
64	**Total reliability, safety and environment**	-	-	121	203	278	534	899	882	897	1,053	816
65	**Expenditure on network assets**	-	-	938	1,384	1,887	2,241	2,787	3,427	3,791	4,309	4,837
66	Expenditure on non-network assets	-	-	89	87	82	73	448	419	382	432	390
67	**Expenditure on assets**	-	-	1,027	1,471	1,968	2,314	3,234	3,846	4,174	4,741	5,227
68												
69	**Commentary on options and considerations made in the assessment of forecast expenditure**											
70	*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*											
71												
72												

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
73			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
74		**11a(ii): Consumer Connection**						
75		*Consumer types defined by EDB**	**$000 (in constant prices)**					
76		All types	3,500	4,147	2,489	2,557	2,557	2,557
77								
78								
79								
80								
81		**include additional rows if needed*						
82		**Consumer connection expenditure**	3,500	4,147	2,489	2,557	2,557	2,557
83	*less*	Capital contributions funding consumer connection	3,000	3,295	2,018	2,018	2,018	2,018
84		**Consumer connection less capital contributions**	500	852	471	539	539	539
85		**11a(iii): System Growth**						
86		Subtransmission						
87		Zone substations	150	3,898	4584	4796	2358	566
88		Distribution and LV lines	250					
89		Distribution and LV cables						
90		Distribution substations and transformers						
91		Distribution switchgear						
92		Other network assets						
93		**System growth expenditure**	400	3,898	4,584	4,796	2,358	566
94	*less*	Capital contributions funding system growth						
95		**System growth less capital contributions**	400	3,898	4,584	4,796	2,358	566
96								

		Company Name	Top Energy
		AMP Planning Period	1 April 2025 – 31 March 2035

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

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sch ref		FYE2025	FYE2026	FYE2027	FYE2028	FYE2029	FYE2030	FYE2031	FYE2032	FYE2033	FYE2034	FYE2035
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	1,800	2,344	3,230	2,566	2,409	1,789					
101	Zone substations	200	235	-	871	3,247	966					
102	Distribution and LV lines	8,000	6,888	8,111	6,819	6,807	8,242					
103	Distribution and LV cables		145	150	153	154	156					
104	Distribution substations and transformers	300	1,569	691	578	1,014	1,152					
105	Distribution switchgear	400	948	832	841	846	853					
106	Other network assets	100	290	130	120	120	120					
107	**Asset replacement and renewal expenditure**	10,800	12,419	13,143	11,947	14,598	13,278					
108	*less* Capital contributions funding asset replacement and renewal											
109	**Asset replacement and renewal less capital contributions**	10,800	12,419	13,143	11,947	14,598	13,278					
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	[Description of material project or programme]											
116	[Description of material project or programme]											
117	[Description of material project or programme]											
118	[Description of material project or programme]											
119	[Description of material project or programme]											
120	**include additional rows if needed*											
121	All other project or programmes - asset relocations											
122	**Asset relocations expenditure**	-	-	-	-	-						
123	*less* Capital contributions funding asset relocations											
124	**Asset relocations less capital contributions**	-	-	-	-	-						
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	11kV feeder protection improvements	1,500	682	871	903	947	818					
131	Interconnections	1,700	1,955	720	740	1289	2,951					
132	Improved communication systems	700	933	363	748	676	103					
	Remote controlled switches and smart devices		137									
	Low Voltage data capture	400	350	305								
133	Kaitaia 11kV injection point	1,000										
134												
135	**include additional rows if needed*											
136	All other projects or programmes - quality of supply	1,000	844	740	919	461	1,261					
137	**Quality of supply expenditure**	6,300	4,901	2,999	3,311	3,373	5,133					
138	*less* Capital contributions funding quality of supply											
139	**Quality of supply less capital contributions**	6,300	4,901	2,999	3,311	3,373	5,133					
140												

Company Name	Top Energy
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)

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sch ref		FYE2025	FYE2026	FYE2027	FYE2028	FYE2029	FYE2030	FYE2031	FYE2032	FYE2033	FYE2034	FYE2035
141		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*					
142												
143	**11a(vii): Legislative and Regulatory**											
144	*Project or programme**	**$000 (in constant prices)**										
145												
146												
147												
148												
149												
150	**include additional rows if needed*											
151	All other projects or programmes - legislative and regulatory											
152	**Legislative and regulatory expenditure**	-	-	-	-	-	-					
153	*less* Capital contributions funding legislative and regulatory											
154	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-					
155												
156		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*					
157	**11a(viii): Other Reliability, Safety and Environment**											
158	*Project or programme**	**$000 (in constant prices)**										
159	Backup Ngawha generator transformer	8,500	3,420									
160												
161												
162												
163												
164	**include additional rows if needed*											
165	All other projects or programmes - other reliability, safety and environment											
166	**Other reliability, safety and environment expenditure**	8,500	3,420	-	-	-	-					
167	*less* Capital contributions funding other reliability, safety and environment											
168	**Other reliability, safety and environment less capital contributions**	8,500	3,420	-	-	-	-					
169												

Company Name	Top Energy
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).

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sch ref		FYE2025	FYE2026	FYE2027	FYE2028	FYE2029	FYE2030	FYE2031	FYE2032	FYE2033	FYE2034	FYE2035
170		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*					
171												
172	**11a(ix): Non-Network Assets**											
173	**Routine expenditure**											
174	*Project or programme**	**$000 (in constant prices)**										
175	General	657	279	567	485	444	402					
176	Software	317	1,265	1,644	943	550	295					
177	Hardware	393	618									
178	[Description of material project or programme]											
179	[Description of material project or programme]											
180	**include additional rows if needed*											
181	All other projects or programmes - routine expenditure											
182	**Routine expenditure**	1,367	2,162	2,210	1,429	993	697					
183	**Atypical expenditure**											
184	*Project or programme**											
185	Replace 3PAR Switches	777										
186	Zone Tx Dryout System	107										
187	Covered storage at Substation	194										
188	Building Improvements	602										
189	Substation Security		100									
190	**include additional rows if needed*											
191	All other projects or programmes - atypical expenditure											
192	**Atypical expenditure**	1,680	100	-	-	-	-					
193												
194	**Expenditure on non-network assets**	3,047	2,262	2,210	1,429	993	697					

Schedule 11b OPEX Forecast

	Company Name	Top Energy
	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			FYE2025	FYE2026	FYE2027	FYE2028	FYE2029	FYE2030	FYE2031	FYE2032	FYE2033	FYE2034	FYE2035
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		2,097	2,157	2,244	2,334	2,429	2,527	2,629	2,735	2,846	2,961	3,189
11	Vegetation management		2,682	3,002	3,123	3,249	3,381	3,517	3,659	3,807	3,961	4,121	4,306
12	Routine and corrective maintenance and inspection		2,591	2,816	2,930	3,048	3,172	3,300	3,433	3,572	3,716	3,866	4,010
13	Asset replacement and renewal		2,109	2,201	2,274	2,349	2,427	2,508	2,591	2,678	2,768	2,861	2,960
14	**Network Opex**		9,479	10,176	10,571	10,980	11,409	11,852	12,312	12,792	13,291	13,809	14,465
15	System operations and network support		9,707	9,864	10,227	10,439	10,451	10,647	10,965	11,199	11,611	11,848	12,255
16	Business support		9,826	10,250	11,201	10,848	11,135	11,091	11,864	11,841	12,078	12,319	12,566
17	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
18	**Non-network opex**		19,533	20,114	21,428	21,287	21,586	21,738	22,829	23,040	23,689	24,167	24,821
19	**Operational expenditure**		29,012	30,290	31,999	32,267	32,995	33,590	35,141	35,832	36,980	37,976	39,286
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		2,097	2,157	2,157	2,199	2,244	2,289	2,334	2,381	2,429	2,478	2,616
24	Vegetation management		2,682	3,002	3,002	3,062	3,124	3,185	3,249	3,314	3,381	3,448	3,532
25	Routine and corrective maintenance and inspection		2,591	2,816	2,816	2,872	2,930	2,989	3,048	3,110	3,172	3,235	3,290
26	Asset replacement and renewal		2,109	2,201	2,186	2,214	2,242	2,272	2,301	2,331	2,362	2,394	2,428
27	**Network Opex**		9,479	10,176	10,161	10,347	10,540	10,735	10,933	11,136	11,344	11,555	11,866
28	System operations and network support		9,707	9,864	9830	9837	9655	9644	9737	9749	9910	9914	10053
29	Business support		9,826	10,250	10766	10222	10287	10045	10535	10308	10308	10308	10308
30	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
31	**Non-network opex**		19,533	20,114	20,596	20,059	19,941	19,689	20,272	20,058	20,218	20,222	20,361
32	**Operational expenditure**		29,012	30,290	30,756	30,406	30,481	30,423	31,204	31,194	31,562	31,777	32,228
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		1,012	1,012	1,062	1,115	1,171	1,230	1,291	1,356	1,423	1,495	1,569
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		-	-	87	135	185	238	295	354	417	483	573
47	Vegetation management		-	-	121	187	257	332	410	493	580	673	774
48	Routine and corrective maintenance and inspection		-	-	114	176	242	311	385	462	544	631	720
49	Asset replacement and renewal		-	-	88	135	185	236	290	347	406	467	532
50	**Network Opex**		-	-	410	633	869	1,117	1,379	1,656	1,947	2,254	2,599
51	System operations and network support		-	-	397	602	796	1,003	1,228	1,450	1,701	1,934	2,202
52	Business support		-	-	435	626	848	1,046	1,329	1,533	1,770	2,011	2,258
53	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
54	**Non-network opex**		-	-	832	1,228	1,645	2,049	2,557	2,982	3,471	3,945	4,460
55	**Operational expenditure**		-	-	1,243	1,861	2,514	3,167	3,937	4,638	5,418	6,199	7,058
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 Asset Condition

Company Name	**Top Energy**
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.	0.06%	0.44%	4.72%	85.98%	2.73%	6.07%	4	3.33%
11	All	Overhead Line	Wood poles	No.	0.65%	5.89%	62.80%	26.26%	1.12%	3.28%	4	64.39%
12	All	Overhead Line	Other pole types	No.	-	-	-	42.86%	17.86%	39.28%	4	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	16.21%	46.87%	10.16%	25.84%	0.92%	2	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	45.83%	-	9.15%	45.02%	2	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	2.61%	97.39%	-	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.	-	-	-	50.00%	50.00%	-	4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	100.00%	-	-	4	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	1.92%	84.62%	13.46%	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	6.67%	48.89%	31.11%	13.33%	4	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	-	53.45%	41.95%	4.60%	4	-
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.	-	22.22%	-	11.11%	55.56%	11.11%	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	39.44%	60.56%	-	4	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	14.29%	-	45.71%	37.14%	2.86%	4	-
35												

Company Name	**Top Energy**
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												
35												
36					Asset condition at start of planning period (percentage of units by grade)							
37												
38	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	2.17%	17.39%	54.35%	19.57%	6.52%	4	5.12%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3.19%	23.39%	34.73%	28.55%	9.88%	0.26%	2	1.44%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km	20.06%	34.21%	16.97%	15.86%	12.90%	-	2	14.29%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.12%	0.95%	3.91%	56.45%	33.92%	4.65%	2	-
44	HV	Distribution Cable	Distribution UG PILC	km	0.15%	10.32%	19.61%	57.70%	11.76%	0.46%	2	-
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	51.35%	-	24.56%	24.09%	-	2	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	0.66%	-	3.32%	72.09%	3.99%	19.94%	4	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.							N/A	
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	7.29%	10.51%	12.86%	22.92%	20.55%	25.87%	4	-
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	100.00%	4	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	1.76%	72.69%	18.06%	7.49%	4	8.77%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.08%	0.52%	3.10%	89.46%	1.85%	4.99%	4	1.09%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	1.19%	87.15%	1.51%	10.15%	4	1.59%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	5.26%	50.00%	26.32%	18.42%	4	7.89%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	5.88%	23.53%	-	70.59%	1	5.00%
55	LV	LV Line	LV OH Conductor	km	4.61%	27.91%	34.70%	25.00%	7.41%	0.37%	2	-
56	LV	LV Cable	LV UG Cable	km	6.17%	15.17%	20.47%	37.78%	19.84%	0.57%	2	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	3.54%	21.03%	26.92%	46.00%	2.37%	0.14%	2	-
58	LV	Connections	OH/UG consumer service connections	No.	0.03%	0.30%	8.96%	76.92%	3.56%	10.23%	2	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	47.13%	-	-	18.03%	28.28%	6.56%	1	18.67%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	100.00%	-	-	1	-
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	68.29%	29.27%	2.44%	-	4	-
62	All	Load Control	Centralised plant	Lot	-	-	-	92.86%	7.14%	-	2	-
63	All	Load Control	Relays	No.							N/A	
64	All	Civils	Cable Tunnels	km							N/A	

Schedule 12b Capacity Forecast

Company Name	**Top Energy**
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**

sch ref	*Existing Zone Substations*	Current peak load (MVA)	*Not Required before DY2025* Current peak load period	*Not Required before DY2025* Installed operating capacity (MVA)	*Not Required before DY2025* Current security of supply classification (type)	*Not Required before DY2025* Current constraint type	*Not Required before DY2025* Current available capacity (MVA)	*Not Required before DY2025* Peak load period +5 yrs	*Not Required before DY2025* Available capacity +5 yrs (MVA)	*Not Required before DY2025* Security of supply classification +5 yrs	*Not Required before DY2025* Peak load period +10 yrs	*Not Required before DY2025* Min. available capacity +10 yrs (MVA)	*Not Required before DY2025* Max. available capacity +10 yrs (MVA)	*Not Required before DY2025* Security of supply classification +10 yrs (type)	*Not Required before DY2025* Forecast constraint type	*Not Required before DY2025* Year of any forecast constraint	*Not Required before DY2025* Constraint primary cause	*Not Required before DY2025* Constraint solution type	*Not Required before DY2025* Constraint solution progress	*Not Required before DY2025* Temporary constraint solution remaining	Explanation
8																					
9	Pukenui	2	Winter	5	N-1 switched	No constraint	3	Winter	3	N-1 switched	Winter	3	3	N-1 switched	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	Single transformer substation but backup available from a 1.25MVA onsite generator and load transfer to NPL substation. Replacement transformer planned for FYE 2030 could be sized to accommodate new block load.
10	NPL	10	Winter	23	N-1	No constraint	13	Winter	13	N-1	Winter	10	13	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
11	Okahu Rd	10	Winter	12	N-1	No constraint	1.5	Winter	4.2	N-1	Winter	4	5	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	2.5MVA of existing load to be transferred to Kaitaia 11kV substation in FYE2026.
12	Taipa	6	Winter	6	N	No constraint	0.5	Winter	4.2	N	Winter	4	10	N-1	Capacity	4	Zone substation transformer	Network upgrade	Planning stage	> 3 years	Mobile substation and 4MVA of onsite generation provide temporary relief. New 10MVA transformer planned for FYE2030. Substation to be relocated in FYE2032, which when complete will provide full N-1 security.
13	Kaeo	4	Winter	10	N-1	No constraint	6	Winter	6	N-1	Winter	4	6	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
14	Waipapa	11	Winter	23	N-1	No constraint	12	Winter	9	N-1	Winter	6	8	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
15	Kerikeri	8	Winter	23	N-1	No constraint	15	Winter	12	N-1	Winter	7	10	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
16	Mt Pokaka	3	Winter	5	N	No constraint	2	Winter	2	N	Winter	1	2	N	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
17	Omanaia	3	Winter	5	N-1 switched	No constraint	2	Winter	2	N-1 switched	Winter	1	2	N-1 switched	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	Switching to onsite generation
18	Kaikohe	9	Winter	18	N-1	No constraint	9	Winter	7	N-1	Winter	3	6	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
19	Moerewa	4	Winter	5	N-1	No constraint	1	Winter	1	N-1	Winter	0	1	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	Potential for substation to be offloaded through a network configuration should a constraint emerge
20	Kawakawa	5	Winter	1	N-1	No constraint	1	Winter	1	N-1	Winter	0	1	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	through a network configuration should a constraint emerge
21	Haruru	7	Winter	23	N-1	No constraint	16	Winter	15	N-1	Winter	10	14	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	
22	Kaitaia 11kV	-	Winter	-			0	Winter	7.4	N-1 switched	Winter	7.5	10	N-1	No constraint	None	Not applicable	Not required	Not applicable	Not applicable	Commissioning planned FYE2026. Second 110/33/11kV transformer planned for FYE2034 will provide security upgrade from "N-1 switched" to "N-1".
23																					
24																					
25																					
26																					
27																					
28																					

29 [1] *Extend table as necessary to disclose all capacity and constraint information by each zone substation*

Schedule 12c Demand Forecast

Company Name	**Top Energy**
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

12c(i): Consumer Connections

Number of ICPs connected during year by consumer type

	Number of connections					
	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
*Consumer types defined by EDB**						
Residential	300	300	300	300	300	300
Commercial	30	30	30	30	30	30
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
Connections total	330	330	330	330	330	330

**include additional rows if needed*

Distributed generation

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
Number of connections made in year	320	325	325	325	325	325
Capacity of distributed generation installed in year (MVA)	2	46	2	2	2	2

12c(ii) System Demand

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	Maximum coincident system demand (MW)						
	GXP demand	14	15	17	18	19	21
plus	Distributed generation output at HV and above	57	57	57	57	57	57
	Maximum coincident system demand	71	72	74	75	76	78
less	Net transfers to (from) other EDBs at HV and above						
	Demand on system for supply to consumers' connection points	71	72	74	75	76	78
	Electricity volumes carried (GWh)						
	Electricity supplied from GXPs	10	10	11	12	13	15
less	Electricity exports to GXPs	145	210	260	260	260	260
plus	Electricity supplied from distributed generation	500	570	620	620	620	620
less	Net electricity supplied to (from) other EDBs						
	Electricity entering system for supply to ICPs	365	370	371	372	373	375
less	Total energy delivered to ICPs	330	331	332	333	334	335
	Losses	35	39	39	39	39	40
	Load factor	59%	59%	57%	57%	56%	55%
	Loss ratio	9.6%	10.5%	10.5%	10.5%	10.5%	10.7%

Schedule 12d Reliability Forecast

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

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)	260.0	240.0	240.0	240.0	240.0	240.0
12	Class C (unplanned interruptions on the network)	247.0	309.0	306.0	300.0	292.0	287.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	1.15	1.00	1.00	1.00	1.00	1.00
15	Class C (unplanned interruptions on the network)	3.31	4.09	4.08	4.08	4.07	4.07

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 clause2.7.2. 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

Constant prices are for FYE2026. Going forward, we have assumed an inflation rate of just over 4% per annum in FYE2026, and 2% per annum thereafter. We do not consider an inflation rate assumption based on an analysis of different industry-specific cost drivers is warranted given the high levels of uncertainty in the forecast.

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

Constant prices are for FYE2026. Going forward, we have assumed an inflation rate of just over 4% per annum in FYE2026, and 2% per annum thereafter. We do not consider an inflation rate assumption based on an analysis of different industry-specific cost drivers is warranted given the high levels of uncertainty in the forecast.

Company Name: Top Energy

For Planning Period Ended: 31 March 2035

Schedule 15 Voluntary Explanatory Notes

1. This schedule enables an EDB to provide, should it wish to-

2. Additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, 2.5.2 and 2.6.6;

3. Information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.

4. Information in this schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

5. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Our capital expenditure forecast has been prepared on the basis that:

- Construction of the southern section of the 110kV Wiroa-Kaitāia line will commence in FYE2031 in accordance with the legal settlement with the three property owners who appealed the Crown’s decision to allow Top Energy to compulsorily acquire the line easement.

- Construction of the 110/33kV Wiroa substation will commence in FYE2026 and commissioning of the first transformer will be completed in FYE2028.

- Given our available network capacity and forecast rate of growth in demand, our capital expenditure will largely focus on improving the reliability and resilience of the 11kV distribution network. Nevertheless, we anticipate there will be a need to extend the coverage of the 33kV sub-transmission network towards the end of the planning period to accommodate localised load growth in areas that are currently served at 11kV.

- There is a need to address the condition of our power transformers. This includes increasing the level of routine maintenance and bringing forward the planned replacement of some units.

6.2 Appendix B – Certification for Year-beginning Disclosures

Certification for Year-beginning Disclosures

Pursuant to Schedule 17

Clause 2.9.1 of section 2.9

Electricity Distribution Information Disclosure Determination 2012

We, David Alexander Sullivan, and Jon Edmond Nichols, being directors of Top Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge –

a) The following attached information of Top Energy 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 Top Energy Ltd's corporate vision and strategy and are documented in retained records.

____________________ ____________________

D A Sullivan J E Nichols

31 March 2024

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New Zealand

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