TOP ENERGY®
Te Puna Hihiko

2024
ASSET MANAGEMENT PLAN

Introduction

It gives me great pleasure to present Top Energy's 2024 Network Asset Management Plan (AMP) Update. Our AMP is prepared in compliance with the Commerce Commission's Electricity Distribution Information Disclosure (Targeted Review Tranche 1) Amendment Determination 2022 and is the core asset management and operations plan for our electricity transmission and distribution network. It sets out our planned asset inspection, maintenance, development and replacement strategies, and the targeted service levels that we are planning to provide our consumers. This AMP Update should be read in conjunction with our comprehensive 2023 AMP that, except where modified by this Update, still underpins our asset management strategy. The regulatory schedules in Appendix 1 of this Update cover the planning period 1 April 2024 to 31 March 2034 (FYE2025-34) and replace the corresponding schedules in the 2023 AMP.

In November 2023 we celebrated the connection of Lodestone Energy's 23MW Kaitaia solar farm to our network. This solar farm, located about 5km northwest of Kaitaia, is currently the largest solar farm in the country. Construction has also commenced on Far North Solar's 20MW Pukenui solar farm, which we expect to connect to our network in late 2024. We also expect Ranui Generation to commence construction of the 24MW Twin Rivers solar farm, located southeast of Kaitaia, in late 2024 or early 2025.

The far north of our supply area has abundant potential for solar generation but, unfortunately, 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 on our 110kV circuit. However, once all three solar farms are connected, the capacity of this circuit will be fully utilised.

Over the two years FYE2022 and FYE2023, our supply area experienced extreme weather conditions, as confirmed by NIWA, culminating in Cyclone Gabrielle in February 2023. As a result of this extreme weather, our normalised unplanned SAIDI in FYE2023 was 514 minutes, well above our annual long-term average of just over 300 minutes. In the current FYE2024 year the weather has reverted to more normal conditions and, assuming no change over the remainder of the financial year, we expect our normalised unplanned SAIDI to be less than 10% above our annual long-term average, and well below the limit in the Commerce Commission's regulatory price-quality path.

The extreme weather highlighted the vulnerability of our critical 110kV Kaikohe-Kaitaia line to ground movement over the route of the line where it crosses the Maungataniwha Range. This is the same issue that closed State Highway 1 in August 2022 and the road has been closed ever since. Following Cyclone Gabrielle, we commissioned a geotechnical survey of the route of this line, which identified five structures at risk of a foundation failure. Two of these structures were redesigned and relocated in February 2024 and the other three structures are to be replaced in new locations in FYE2025.

Our annual consumer surveys have told us that most consumers connected to our network are generally happy with our supply reliability and the level of service we provide. Notwithstanding this, our owner the Top Energy Consumer Trust, and our Board are conscious of the fact that the extreme weather conditions we experienced during FYE2022-23 are likely to become more prevalent because of climate change. Failure to develop a network that is more resilient to such conditions could result in our reliability of supply deteriorating to the point where it starts to adversely impact economic development within our supply area. In FYE2023 we commenced a programme to improve the resilience and reliability of our 11kV network, which is the source of over 90% of the SAIDI impact of unplanned interruptions. At the time, it was expected that the improvement programme would last until FY2030, after which the focus of our capital expenditure would transition to increasing the capacity of our 11kV network to meet an expected localised growth in demand. Our Board has now decided to extend this programme beyond FYE2030 and has allocated further $12.33 million (based on FYE2025 prices) to extend this programme through to the end of this AMP planning period. This is new expenditure and expenditure in other areas has not been reduced to accommodate this.

We have now secured the route of our planned new 110kV line between Wiroa and Kaitaia. In doing this we have agreed with the three landowners who unsuccessfully appealed to the Supreme Court, that construction work across their properties would commence within ten years. We believe that it is in the national interest that this line is built, as it will enable the renewable solar generation potential in the north of our supply area to be more fully utilised. To this end our forecast capital expenditure now provides for the commencement of construction of the southern section of this line in FYE2031.

INTRODUCTION

The connection of small-scale behind-the-meter solar generation to our network continues apace and the penetration of such generation, as measured by the proportion of consumers hosting such systems, is higher than any other New Zealand EDB. By the end of FYE2022, a total of 7.3MW of such generation had been installed. In FYE2023 a further 2.4MW of such generation was installed and by the end of FYE2024 we expect another 2.1MW to have been installed, a 62% increase in installed capacity in just two years. We estimate that the total generation of small-scale behind-the-meter solar in FY2024 to be 18.8GWh, up from 14.8GWh in FYE2023. This equates to 5.7% of our expected 331GWh network electricity delivery volume in FYE2024, which is marginally below the actual 332GWh delivery volume in FYE2023.

If the connection of new behind-the-meter solar continues at its current rate, there is a risk that we may pass a tipping point where electricity delivery volumes though our network reduce. This will happen if the annual increase in behind-the-meter solar generation exceeds the growth in the electricity consumption by consumers connected to our network, including both behind the meter generation and electricity delivered through the network. Interestingly, up to about 90% of the small-scale solar installations connected over the last two years have had associated battery storage. This may be tempering the rate of growth in peak demand, which was lower than we expected in the 2023 winter. It may also be mitigating the technical issues that can emerge when a large quantity of solar generation is connected to a single low voltage circuit. We will continue to monitor this situation and the impact that it could have both on our business and on the management of our network assets.

We have yet to see significant growth in electricity demand resulting from decarbonisation of the economy. The penetration of battery electric vehicles and plug-in hybrids remains low. The few large industries in our supply area already use biomass as a heat source and we have had no enquiries from smaller industrial and commercial consumers that still use coal or bottled gas and want to convert to electricity. The Energy Efficiency and Conservation Authority (EECA) has released its Regional Energy Transition Accelerator (RETA) report for Northland. This indicates that, unlike many New Zealand EDBs, we are unlikely to see significant new demand from the electrification of heat sources currently using fossil fuels due to the ready availability of biomass in our supply area. Our 33kV subtransmission network has sufficient spare capacity to absorb our expected load growth and we have made provision in our capital expenditure forecast for the second half of the planning period to increase the network capacity as required to accommodate localised load growth in areas currently served by the 11kV distribution network.

In addition to the management of 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 on any other aspect of Top Energy's business and performance. Feedback can be provided through the Top Energy website https://topenergy.co.nz/i-want-to/get-in-touch/send-feedback or emailed to mailto: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 Asset Management Plan (AMP) Update documents Top Energy Network's forecast capital and operational expenditure in developing and maintaining its network assets over the ten-year period 1 April 2024 to 31 March 2034 (FYE2025-34) and 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. The commentary supporting the expenditure forecasts identifies material changes from the plans we detailed in the comprehensive AMP that we published on 31 March 2023 (our 2023 AMP). Accordingly, our 2023 AMP remains valid, except where amended by this Update.

This AMP Update was approved by our Board of Directors on 26 March 2024.

1.2 Resilience and Reliability

In FYE2023, we were non-compliant with the unplanned interruption quality thresholds in our RCP3 price-quality path, 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. Expert analysis of the impact of climate change indicates that it is likely that the frequency of major storm events will increase in coming years and that the intensity of such events will also increase. This highlights a need to increase the resilience of our network to severe weather events.

The rate at which we can do this is tempered by the sensitivity of our consumers to the cost of supply and the need to be mindful that the west of our supply area is one of the most economically deprived regions in the country. Our consumer surveys indicate that a majority our consumers do not see the need for significant investment in improving our reliability of supply, if the result is a material increase in the cost of electricity.

Notwithstanding this, after Board discussion with our owner, the Top Energy Consumer Trust, it was agreed that we should increase the level of investment in the network to increase its resilience to severe weather events, which would also improve our network reliability. The appropriate level of investment and improvement in resilience was assessed against the energy trilemma that our consumers face, both now and in the future. This investment will also increase the reliability of supply that we provide our consumers.

Our asset management strategy to achieve this increase in resilience and improvement in supply reliability continues the focus we commenced in FYE2023 on our 11kV distribution network, as interruptions caused by faults on this part of our system account for over 90% of our unplanned SAIDI and SAIFI impacts. This strategy includes an increased rate of asset replacement and renewal, and improvements to network architecture, particularly on the long rural feeders that characterise the distribution network supplying the sparsely populated rural parts of our supply area. In FYE2023 the faults on the ten worst-served 11kV feeders on our network caused 55% of our total normalised unplanned SAIDI.

1.3 Other Asset Management Drivers

1.3.1 Costs

We are finding that our unit costs are significantly higher than forecast in our 2023 AMP due to ongoing supply chain issues resulting from the Covid 19 disruptions, industry-wide skilled workforce shortages and a need to contract out some of the capital work on our 11kV network while we increase the capacity of Top Energy Contracting Services (TECS). In our expenditure forecasts, we have escalated the constant-price cost of most projects by 15% to accommodate this. In the case of large subtransmission projects, the cost escalation is even greater as it incorporates quoted budget prices for major equipment items.

1.3.2 Vulnerability of the 110kV Kaikohe-Kaitaia Line

The extremely wet weather experienced during FYE2023 caused significant ground slippage close to the route of our 110kV line where it crosses the Maungataniwha Range. As this line is our most critical asset, we commissioned a geotechnical survey of the line route, which identified several vulnerabilities. Therefore, in February 2024 we replaced two towers on the line with two-pole structures and redesigned foundations, located on more stable ground. A further three structures are to be replaced and relocated in FYE2025.

1.3.3 Power Transformer Condition

An external report on the condition of our substation power transformers found that the condition of some of our older power transformers is not as good as indicated by our regular oil testing and condition monitoring programme. It recommended that the replacement of some of our very old units be brought forward.

The two transformers in worst condition are the 33/11kV transformers at Pukenui and Taipa substations, which are both single transformer substations. We are planning to replace both transformers by FYE2030. Should either transformer fail before then, our contingency plan is to relocate a transformer from Moerewa or Kaeo respectively as a temporary measure.

In the meantime, we are planning to purchase a mobile transformer oil filtration plant in FYE2025, which will be used to treat the oil on our older transformers while they remain in service. This will first be used to treat the Pukenui and Taipa transformers to reduce the risk of a premature failure and then be used to treat other transformers, prioritised by the results of our condition assessments. We are also increasing the level of corrective maintenance across the power transformer fleet.

1.3.4 Impact of Decarbonisation on Asset Management Planning

1.3.4.1 Decarbonisation of Transport and Process Heat

We expect both increased penetration of the battery and plug-in hybrid electric vehicles and the reduced use of coal and bottled gas to increase the consumption of electricity by consumers connected to our network. However, while the extent and timing of this growth is still very uncertain, we don't expect it to have a major impact until towards the end of the planning period. We note that:

- Up to 95% of EV charging is currently done at home and we expect this to continue as the penetration of the EV fleet continues. This means that the increase in electricity consumption due to EV charging will be incremental and dispersed across the network, although higher growth rates can be expected on the eastern seaboard where the population is economically better off. Based on an analysis of available information, we estimate the current consumption of electricity for EV charging of light vehicles in our supply area to be 1.5GWh. We think this could increase to 22GWh by 2035.
- Given our remoteness and relatively low level of economic activity, we think the demand for electricity supply to heavy EV charging infrastructure will lag that of other parts of the country. To date we have not had any enquiries and we consider it unlikely there will be any requirement during the first half of the planning period.
- There are no major industries in our supply area that use coal or gas as a heat source. However, there are several medium-sized commercial and industrial loads that use either coal or bottled gas for heating. We anticipate that these users will decarbonise, but the timing and nature of their transition is highly uncertain. As biomass is readily available in our supply area, we think larger users may prefer to transition to biomass rather than electricity. Smaller users, such as rural hospitals, could install industrial heat pumps. EECA has now released its RETA report for Northland, which has confirmed that the decarbonisation of existing commercial and industrial heat sources is unlikely to result in significant new demand for electricity in our supply area.

1.3.4.2 Utility Scale Solar

In November 2023, we connected Lodestone Energy's new 23MW solar farm situated northwest of Kaitaia to our 33kV subtransmission network. At the time it was connected, it was the largest solar farm in New Zealand. Furthermore, construction work has now started on Far North Solar's 20MW Pukenui solar farm, located across the road from our Pukenui substation. We expect this to be connected before the end of CY2024. While construction has still to start on Ranui Generation's 24MW solar plant, located south-east of our Kaitaia transmission substation, we remain in contact with the developer and expect this to connect before the end of FYE2026.

1.3.4.3 Small Scale Solar

At the end of the current FYE2024 year, we expect that there will be almost 12MW of installed small-scale behind-the-meter solar generation connected to our network by almost 2,000 users. This equates to an uptake rate, which is a measure of the percentage of connected consumers with solar generation installed, of 5.8% which is higher than any other New Zealand EDB. This is shown in Figure 1.1.

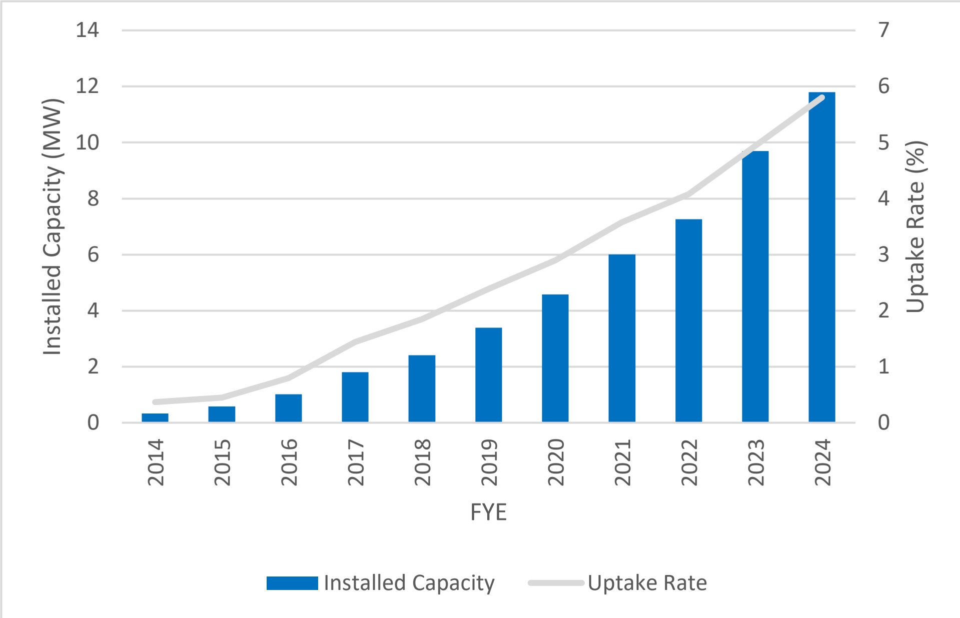

Figure 1.1: Installation of Small-Scale Photovoltaic Generation

Figure 1.2 shows our network peak demand, together with the total consumption of electricity in our supply area, including both electricity delivered through the network and the estimated aggregate output of connected small-scale solar generation. The figure shows that the growth in total electricity consumption is much higher than the growth in the volume of electricity delivered through the network, due to the almost exponential increase in the aggregate capacity of connected solar generation. It also shows that in FYE2024 our network peak demand was 76.7MW, down from 78.1MW the previous year. While the total consumption of electricity is estimated to increase by 1.1% to 350GWh in FYE2024, electricity delivered through the network is expected to decline marginally from 332GWh to 331GWh.

This shows the impact of the high levels of small-scale generation currently being connected to the network. If this continues to grow at its current rate, we could reach a tipping point where the connection of new solar generation capacity outstrips the growth in the demand for electricity. This could lead to ongoing declines in both network peak demand and delivery volumes.

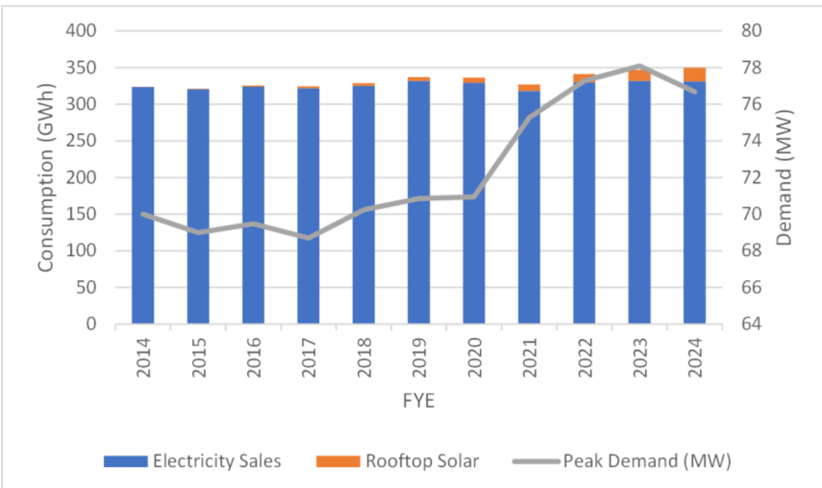

Figure 1.2: Peak Demand, Delivered Electricity Volumes and Estimated Small-Scale Solar Generation (FYE2014-24)

1.4 Impact of Climate Change

1.4.1 Increased Fire Risk

There are three zones within our supply area that are considered to be at high risk of wildfires, Cape Reinga, Ahipara and the Karikari peninsula. We have an extensive network within the Karikari peninsula, but in the other two areas the extent of our network is more limited. Before the start of each fire season, which extends from November to March, we survey our assets in these three areas to identify potential sources of ignition and take appropriate action to mitigate the risk. This generally involves targeted vegetation management.

Fire and Emergency New Zealand (FENZ) continually monitors the fire risk in all parts of our supply area and can declare a restricted fire season or a prohibited fire season at any time. When either a restricted or prohibited fire season is declared, we disable the auto reclose on all switchgear supply the affected area. If a fault occurs during a restricted fire season, we wait 15 minutes before trying to restore supply to allow reports from the public or emergency services to be received. If a fault occurs during a prohibited fire season, we will not try to restore supply until after the faulted line has been patrolled.

1.4.2 Sea-Level Rise / Flooding

Taipa substation is the most critical substation likely to be affected by sea level rise. Our long-term plan is to build new substations at Coopers Beach or Mangonui, and also at Tokerau Bay, to replace Taipa. We expect to build the Coopers Beach / Mangonui substation before the end of this AMP planning period.

Other substation assets which are low-lying are Kaeo and Omanaia substations. The risk to these sites is not as great as for Taipa, and is dependent on significant sea level rise, high tide and flooding all occurring simultaneously. To mitigate these risks flood remediation has been undertaken at Omanaia, and Kaeo substation has been elevated above any anticipated flood level.

1.4.3 Storms

The extreme weather events we experienced in FYE2022 and FYE2023 have highlighted a need to improve the resilience of our 11kV network. We have embarked on a programme of resilience improvement consisting of additional asset renewals, the optimisation of protection on our long rural feeders and the construction of interconnections between feeders. The Board has also approved additional capital expenditure over and above that provided in the 2023 AMP to allow the programme to be continued at an enhanced level after FYE2030. In addition to continuing the feeder optimisation and interconnection construction initiatives, the programme will be extended to include:

- Purchase of portable generation units and establishment of network connection points.
- Procurement of additional critical spares for the 110kV line.
- Undergrounding and the use of covered conductors in some critical areas with high exposure to vegetation faults.
- Increasing the number of pole replacements.

We are also planning to increase expenditure of vegetation management to further increase the resilience of the network to storm events.

1.5 Network Capacity

The capacity of our 110kV Kaikohe-Kaitaia transmission line will be fully utilised once all three utility-scale solar farms to be constructed in the north of our supply area are connected to the network. Furthermore, the N-1 transformer capacity of the Kaitaia 110kV substation will be exceeded, although the larger and newer of the two transformers at this substation has sufficient capacity to carry the load, should the smaller transformer fail. Failure of the larger transformer is unlikely as it is still relatively new and in good condition.

We have invested heavily in our 33kV subtransmission network over the last 10 years and our modelling has indicated that the current 33kV network backbone has sufficient capacity to accommodate an increase in demand of the magnitude forecast by Transpower through to 2040 and beyond. The exception to this is the supply into Wiroa, where the smaller of the two incoming circuits has insufficient capacity if the larger circuit fails at times of peak demand. We have planned to commence construction of the Wiroa 110/33kV substation in FYE2026 to remove this constraint.

As the consumption of electricity increases, we anticipate that there could be a need to increase the capacity of the network to meet localised demand growth in remote townships currently supplied by long 11kV feeders. This may involve extending the 33kV subtransmission network and constructing new zone substations to provide additional points of injection into the 11kV distribution system.

1.6 Delivery of the Work Programme

We have agreed with Top Energy Contracting Services the projects in our planned FYE2025 work programme that they will undertake. The remaining projects on the work programme will be bundled into a separate contract and outsourced by competitive tender. We have already gone to the market and sought expressions of interest for this contract.

The installation of the backup Ngawha generator transformer will be managed as a separate project and competitively tendered. We may also need to outsource some of our vegetation management to an external arborist.

1.7 Reliability Targets

As we expect the reliability of the network to improve due to the increased expenditure on improving the resilience of the 11kV network to severe weather events, we have revised our internal targets for the SAIDI and SAIFI impact of unplanned supply interruptions. The revised targets continue to use the normalisation measures used by the Commission for assessing compliance with the quality thresholds in its default price-quality path.

The new targets are shown in Tables 1.1 and 1.2 below.

FYE	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
New target	-	300	294	289	286	278	273	268	258	248	240
2023 AMP target	302	302	311	311	311	311	311	311	311	311	-

Table 1.1: Comparison of Revised Internal Unplanned SAIDI Targets with 2023 AMP Targets

FYE	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
New target	-	4.01	4.01	4.00	4.00	3.99	3.99	3.98	3.98	3.90	3.80
2023 AMP target	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	-

Table 1.2: Comparison of Revised Internal Unplanned SAIFI Targets with 2023 AMP Targets

Figures 1.3 and 1.4 below show how these revised targets compare with both the targets in the 2023 AMP and the historical performance of the network.

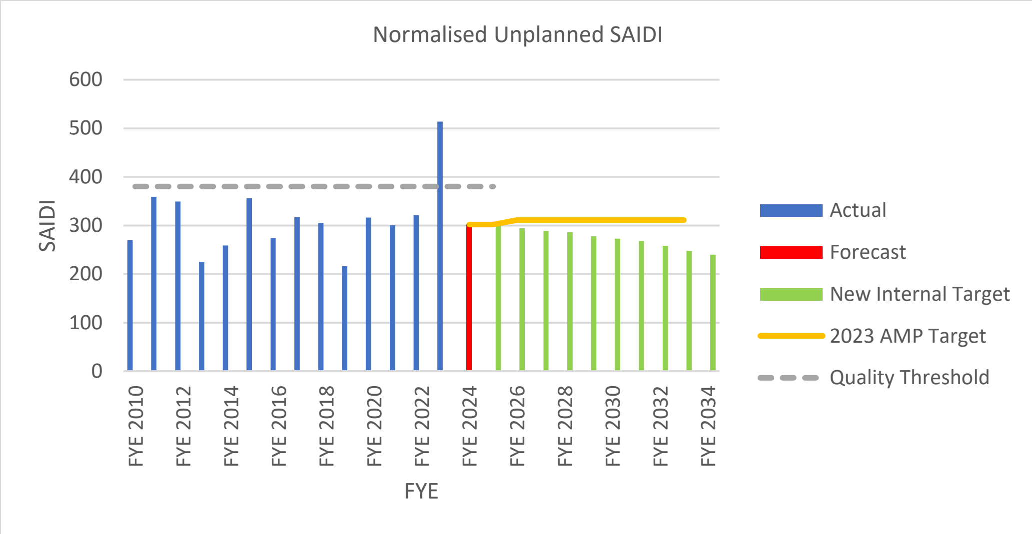

Figure 1.3: Historical and Target Unplanned SAIDI

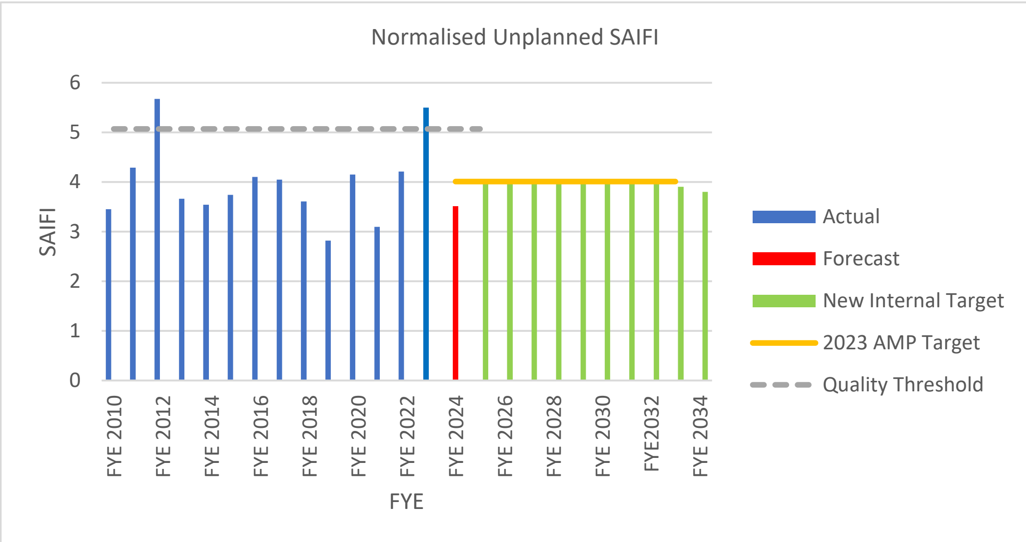

Figure 1.4: Historical and Target Unplanned SAIFI

1.8 Network Development

Table 1.3 and Figure 1.5 compare our forecast maintenance expenditure with the corresponding forecast in the 2023 AMP. These are constant price forecasts, with the current forecast expressed in FYE2025 dollars and the 2023 AMP forecast in FYE2024 dollars.

FYE	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
2024 AMP		30,626	24,943	22,104	21,529	21,792	20,505	21,032	21,944	21,032	21,032
2023 AMP	20,520	18,227	17,342	16,980	16,469	19,370	15,559	15,760	16,740	16,064	

Table 1.3: Comparison of the 2024 AMP Constant Price Forecast with 2023 AMP ($000)

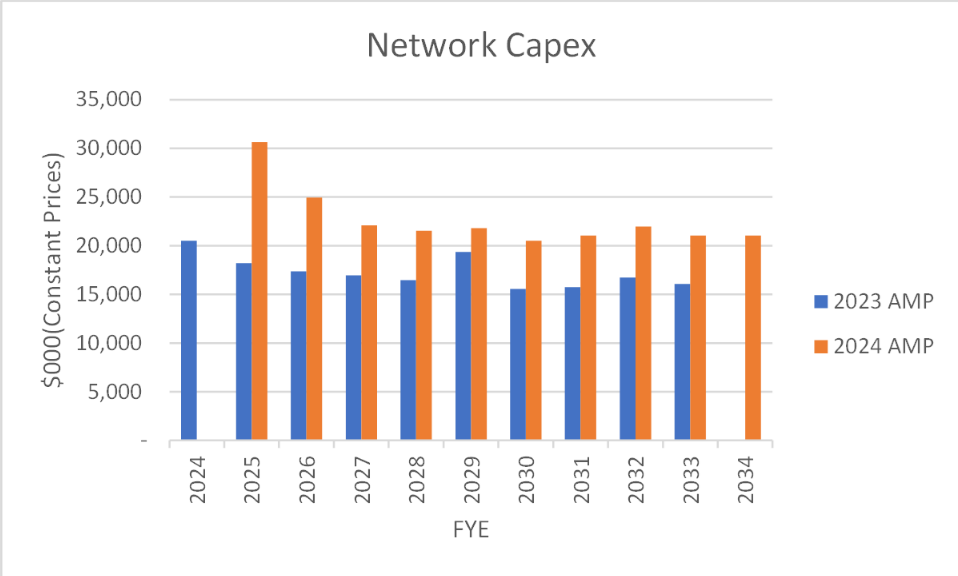

Figure 1.5 Comparison of Constant Price Network Capital Expenditure Forecast with 2023 AMP Forecast ($000)

The forecast includes the following projects that were not included in the 2023 AMP forecast.

- Backup generator transformer for the Ngawha OEC4 unit.
- Construction of the southern section of the Wiroa-Kaitaia 110kV line in accordance with Top Energy's agreement with the landowners who appealed the decision to grant a line route easement over their properties to the Supreme Court
- Construction of a new zone substation at Coopers Beach or Mangonui. Work relating to a new substation at Tokerau Beach is no longer included in the forecast.
- Extension of the programme to increase the resilience of the 11kV network beyond FYE2030. With the approval of the Board, we have included new expenditure in the forecast to extend this programme in response to Cyclone Gabrielle and the extreme weather events that we experienced in FYE2022 and FYE2023.
- Replacement of one of the 33/11kV power transformers at both Kaikohe and Kawakawa substations.

1.9 Network Maintenance

Table 1.4 and Figure 1.6 compare our forecast maintenance expenditure with the corresponding forecast in the 2023 AMP. These are constant price forecasts with the current forecast expressed in FYE2025 dollars and the 2023 AMP forecast in FYE2024 dollars. The difference between the two forecasts primarily reflects the difference between the actual costs we are currently experiencing and the assumptions we made in the 2023 AMP. We have also increased the volume of work we expect to undertake, particularly in vegetation management and the corrective maintenance of power transformers.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
2024 AMP		8,582	9,409	9,583	9,759	9,940	10,124	10,311	10,503	10,698	10,897
2023 AMP	7,463	7,540	7,577	7,615	7,653	7,692	7,731	7,769	7,809	7,847	

Table 1.4: Comparison of the 2024 AMP constant Price Forecast with 2023 AMP ($000)

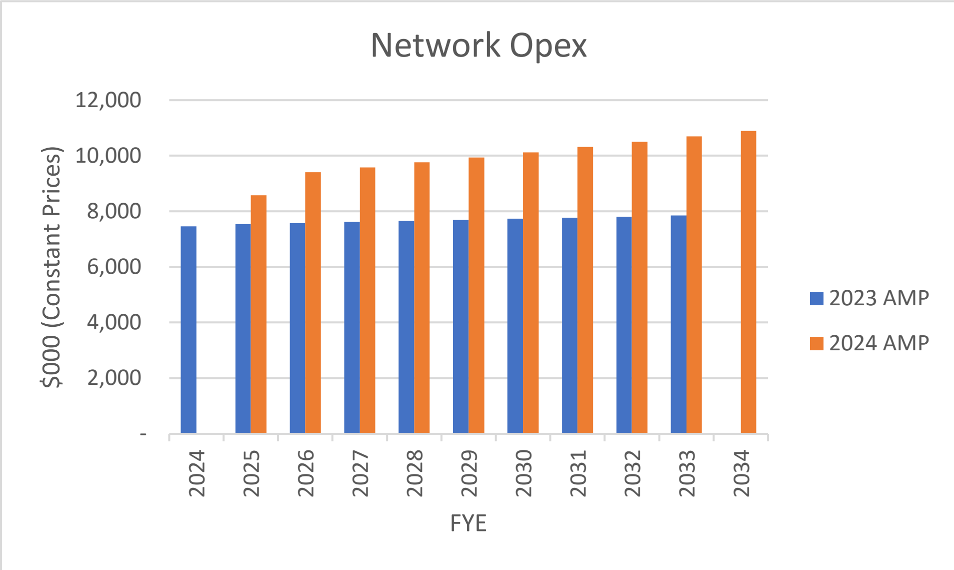

Figure 1.6 **Comparison of Constant Price Network Operational Expenditure with 2023 AMP Forecast**

2 Background

2.1 Purpose of this Document

This Asset Management Plan (AMP) Update documents how Top Energy Network currently plans to develop and maintain its network assets over the ten-year period 1 April 2024 to 31 March 2034 (FYE2025-34) and 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. For this planning period, rather than preparing a full AMP, we have chosen to prepare an AMP Update, which documents only the material changes to asset management plans documented in our last full AMP, which we published on 31 March 2023 (our 2023 AMP).

Accordingly, our 2023 AMP remains valid, except where amended by this Update. In particular, the regulatory schedules included in Appendix A cover the undated planning period and replace in full the corresponding schedules in the 2023 AMP. That said, there are no material changes to the Asset Management Maturity Assessment (AMMAT) presented in Schedule 13 of our 2023 AMP and we have therefore not included a revised schedule in this AMP Update.

This AMP Update was approved by our Board of Directors on 26 March 2024.

2.2 Resilience and Reliability

In FYE2023, we were non-compliant with the unplanned interruption quality thresholds in our RCP3 price-quality path. Our normalised unplanned SAIDI over the year 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. Over this time there were 13 significant storm events affecting our supply area, two of which triggered a formal declaration of a State of Emergency. Furthermore, a storm in August 2022 resulted in the loss of State Highway 1 through the Mangamuka Gorge. This road remains closed. The severity of this extreme weather compared to our historic weather patterns has been analysed by NIWA, and its reports are available on our website as attachments to our 2023 default price-quality path compliance statements.

Expert analysis of the impact of climate change indicates that it is likely that the frequency of major storm events will increase in coming years and that the intensity of such events will also increase. This highlights a need to increase the resilience of our network to severe weather events.

The rate at which we can do this is tempered by the sensitivity of our consumers to the cost of supply and the need to be mindful of the fact that the west of our supply area comprises one of the most economically deprived areas in the country. Our consumer surveys, discussed in Section 2.3 below, indicate that a majority our consumers do not see the need for significant investment in improving our reliability of supply, if the result is a material increase in the cost of electricity.

2.3 Consumer Surveys

As a consumer owned trust company, we look to our consumer feedback and customer surveys to quantify our plans and goals against their requirements to ensure their needs are met. As such we conducted three surveys in FYE2023 and FYE2024. From the perspective of price versus quality, survey respondents have been consistent in their key messaging which is:

- Consumers prefer to maintain the current pricing for the current level of service.
- Consumers should pay the same pricing regardless of where in the Far North they choose to live.

The surveys were conducted over periods where the quality of supply delivered by our network, as measured by raw (unnormalized) unplanned SAIDI has been significantly worse than experienced in previous years. In FYE2022, the network's raw unplanned SAIDI was 742 minutes, well over twice the average corresponding SAIDI over the previous four-year period FYE2018-21. In FYE2023 the raw SAIDI was 1,792 minutes, over five times the same four-year average.[1]

The primary cause of this abnormally poor supply reliability was the extreme weather experienced in both years. The severe weather in FYE2023 is discussed in Section 2.2.1 above.

The weather we experienced in FYE2022 was also abnormally severe compared to earlier years. It included two major SAIDI events, a short sharp storm on 3 August 2021 and Cyclone Dovi in mid-February 2022, which (until Cyclone Gabrielle in February 2023) had the most severe impact on our network reliability of any storm we have experienced since CY2014. The total annual rainfall in Kerikeri town as recorded by the Kerikeri Weather Station was 2,321mm, 65% higher than the average annual rainfall experienced during the previous four years and almost as high as the 2,560mm recorded in FYE2023.[2]

It is noteworthy that the weather has reverted to a more typical pattern in the current FYE2024 year and our normalised unplanned SAIDI is tracking toward a more typical year-end value circa 300 minutes, well below the 380-minute limit.

2022 Consumer Satisfaction Survey

In October 2022 we conducted our annual consumer satisfaction survey. This survey, which interviewed 350 consumers, was undertaken at a time when our unplanned SAIDI was tracking significantly higher than forecast, following several adverse weather events.

Price vs quality.

- 79% of consumers prefer to maintain their current pricing and level of service.
- 14% would rather see reduced pricing and service.
- 7% were open to paying more for an increased level of service.

Price vs location.

- 81% of consumers believe all people should pay the same price regardless of where they live.

Reliability.

- Only 5% of consumers rated overall reliability of power supply as poor.
- 10% thought we were not quick to respond to issues.
- 11% thought we did poorly minimising the number of outages.
- 10% of those surveyed thought we handled service enquiries poorly.

Price vs Quality Survey 2022

To ensure we had a good understanding of consumers' requirements around price and quality, we conducted a follow-up survey of 1,000 consumers in November 2022.

Reliability.

- Over two-thirds (67%) of consumers consider Top Energy's current power supply reliability to be acceptable, with almost one-third (32%) stating that the power supply has improved over the last 12 months.
- 80% of consumers experienced outages in the previous 12 months.
- 30% thought that two outages a year was acceptable.
- 30% thought that three to five outages per year was acceptable.

Price vs quality.

- 81% of consumers are not prepared to pay more for an improved service.

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[1] Raw SAIDI is a measure of the supply reliability experienced by consumers, as it does not normalise out the impact of severe weather events such as Cyclone Gabrielle. We have not included planned interruptions in this comparison as consumers are given advance notice of these interruptions.

[2] Weather conditions vary across our supply area and this data alone should not be taken as a quantitative measure of weather severity. However, in the absence of detailed analysis it is cited to illustrate the severity of the weather in FYE2022 compared to earlier years.

- 8% were open to paying more for an increased level of service.

2023 Consumer Satisfaction Survey

In October 2023, we again conducted our annual consumer satisfaction survey of 350 consumers with the following results:

Price vs quality.

- 78% of consumers would prefer to maintain current pricing and current levels of service (79% in 2022).
- 16% would prefer reduced pricing and service (14% in 2022).
- 6% were open to paying more for an increased level of service (7% in 2022).

Price versus location.

- 83% of consumers believe all people should pay the same price regardless of where they live.

Reliability.

- 7% of consumers rated the reliability of their power supply as poor.
- 10% thought we were not quick to respond to issues (10% in 2022).
- 12% thought we did poorly minimising the number of outages (11% in 2022).

Service

- 8% of those surveyed thought we handled enquiries poorly (10% in 2022).

These 2022 and 2023 survey results are remarkably consistent and suggest that our consumers are generally happy with their reliability of supply and the level of service we provide. Given these results and looking at various price-quality trade-offs, our Board consulted with our owner, the Top Energy Consumer Trust. After discussion it was agreed that, notwithstanding the survey results, we should increase the level of investment in the network to increase its resilience to severe weather events, which would also improve our network reliability. The appropriate level of investment and improvement in network resilience was assessed against the energy trilemma that our consumers face, now and in the future. As a result of this assessment, we have increased our planned investment in bolstering the resilience of our network to adverse weather events. As we expect this investment to also increase the reliability of the supply we provide our consumers, we have revised our internal reliability of supply targets to reflect a progressive improvement in supply reliability over the ten-year planning period of this AMP Update. These revised targets are shown in Section 3.

Our asset management strategy to achieve the increase in resilience and improvement in supply reliability continues the focus we commenced in FYE2023 on our 11kV distribution network, as interruptions caused by faults on this part of our system account for over 90% of our unplanned SAIDI and SAIFI impacts. This strategy includes an increased rate of asset replacement and renewal, and improvements to network architecture, particularly on the long rural feeders that characterise the distribution network supplying the sparsely populated rural parts of our supply area. In FYE2023 the faults on the ten worst-served 11kV feeders on our network caused 55% of our total normalised unplanned SAIDI.

2.4 Other Asset Management Drivers

2.4.1 Costs

We are finding that our unit costs are significantly higher than forecast in the 2023 AMP due to ongoing supply chain issues resulting from the Covid 19 disruptions, industry-wide skilled workforce shortages and a need to contract out some of the capital work on our 11kV network while we increase the capacity of TECS. In our expenditure forecasts, we have escalated the constant-price cost of most projects by 15% to accommodate this. In the case of large subtransmission projects, the cost escalation is even greater as it incorporates quoted budget prices for major equipment items.

2.4.2 Vulnerability of the 110kV Kaikohe-Kaitaia Line

The extremely wet weather experienced during FYE2023 caused significant ground slippage close to the route of our 110kV line where it crosses the Maungataniwha Range. This is the same problem that has closed SH1 since August 2022. As this line is our most critical asset, we commissioned a geotechnical survey of the route, which identified several vulnerabilities. Therefore, in February 2024 we replaced two towers on the line with two-pole structures and redesigned foundations located on more stable ground. A further three structures are to be replaced and relocated in FYE2025. The need to build access roads to the new tower locations has increased the cost and complexity of this work.

2.4.3 Power Transformer Condition

An external report on the condition of our substation power transformers found that the condition of some of our older power transformers is not as good as indicated by our regular oil testing and condition monitoring programme. It recommended that the replacement of some of our very old units be brought forward.

The two transformers in worst condition are the 33/11kV transformers at Pukenui and Taipa substations, which are both single transformer substations. We are planning to replace both transformers by FYE2030. Should either transformer fail before then, our contingency plan is to relocate a transformer from Moerewa or Kaeo respectively as a temporary measure – these are both lightly loaded two-transformer substations with new transformers.

In the meantime, we are planning to purchase a mobile transformer oil filtration plant in FYE2025, which will be used to treat the oil in our older transformers while they remain in service. Oil treatment will remove contaminants and moisture from the oil, which should reduce the rate of deterioration of the paper insulation of the transformer windings. The filtration plant will first be used to treat the Pukenui and Taipa transformers to reduce the risk of a premature failure and then be used to treat other transformers prioritised by the results of our condition assessments. Our other older transformers are at two transformer substations, where a premature failure is not as critical.

We are also planning to increase the level of corrective maintenance we perform on our power transformers. This includes tap changer contact maintenance, bolt tightening to prevent oil leaking through gaskets, painting, and corrosion management. We are developing a power transformer corrective maintenance plan that will prioritise this work across our fleet.

2.5 Impact of Decarbonisation on our Asset Management Planning

The Government has confirmed that it will retain the previous government's target of transitioning to net-zero carbon emissions by 2050. This means that, as a country, we must significantly reduce the use of fossil fuels as a source of energy. This section overviews what this might mean for the development and operation of our network.

2.5.1 Demand

Decarbonisation will require electrification of the vehicle fleet and transitioning away from fossil fuels in both industrial processes, and commercial/domestic installations where gas or coal is currently used as a source of heat. Transpower's October 2023 Whakamana I Te Mauri Hiko Monitoring Report concludes that New Zealand's economy remains on a path consistent with its "Accelerated Electrification" trajectory, which projects an increase in electricity demand of 68% by 2050. It notes that while annual electricity consumption (as measured by the demand for electricity that is met from both grid-connected generation and embedded generation such as rooftop solar) decreased by an average of 0.1% per year between 2012 and 2022, there are indications that this trend is likely to reverse. While there was little change in the peak demand on the transmission grid (as measured by the average of the 20 highest daily peaks each year) between 2015 and 2020, this has risen annually by 2% on average since 2021. We conclude that, going forward, an increase in the rate of growth of both peak demand and total electricity consumption on our network is highly likely, although a high level of uncertainty remains as to both the extent and timing of this increase. The impact of the Government's decision to cancel both the

Government Investment in Decarbonising Industry (GIDI) fund and EV purchase subsidy schemes, increases this uncertainty, but is likely to temper the increase in growth rates in the short term.

2.5.1.1 Decarbonisation of the Transport Fleet

Light Electric Vehicles

The number of light electric and plug-in hybrid vehicles registered in New Zealand for the first time in our supply area is relatively small but is increasing, as is shown in Table 2.1 below.

Calendar Year	BEV	Plug-in Hybrid
2018	34	7
2019	31	12
2020	15	4
2021	56	28
2022	91	100
2023	108	85
Total	**335**	**236**

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

If it is assumed that the average BEV does 12,000km per year and uses 18kWh of energy per 100km the total annual electricity consumption of these 335 BEVs would be around 0.72GWh. However, this estimate does not account for:

- Vehicles that were first registered in our supply area prior to 2018. We have no data on this, but these vehicles would primarily be Nissan Leafs with a relatively small battery capacity.
- Vehicles that were purchased second hand after having been first registered outside our supply area.
- Charging of vehicles registered outside our supply area.
- The efficiency of the charging process.

Accounting for these uncertainties would increase consumption. However, a subset of vehicles included in Table 2.1 would have been written off or transferred to addresses outside our supply area, which would offset some of this increase. Allowing for these uncertainties, an estimate of 1GWh for the total volume of electricity currently used for BEV charging seems reasonable.

Plug in hybrids typically have a much smaller battery capacity than a BEV. If it is assumed that the average PHEV consumes two-thirds the electricity of an equivalent BEV, an assumption broadly consistent with the road user charge discount to be applied to PHEVs under the Government's new EV road user charge policy, then we estimate the annual electricity consumption for charging plug-in hybrid vehicles to currently be around 0.5GWh.

Taking these factors into account, we think a reasonable estimate of the total annual electricity use within our supply area for charging BEVs could be currently about 1.5GWh. To put this into perspective, this is less than 0.5% of our current total electricity delivery volume and only around 8% of the estimated total annual electricity output of the small-scale solar generation connected to our network behind the meter (See Section 2.5.2.3).

If this estimate of 1.5GWh is extrapolated in line with MBIE's estimate of a required national EV fleet size of 1.5 million by 2035 if the Government's net zero target is to be met, the total electricity requirement for EV charging of light vehicles in our supply area would be 21GWh by 2035. This is a little more than 6% of our current electricity delivery volume and only 12% more than the estimated total generation output in FYE2024 of all the small-scale solar generation connected to our network.

Current estimates are that up to 95% of EV charging is done at home and the rest through public chargers. There are currently 13 public chargers scattered across our supply area, each rated at either 25kW or 50kW. These chargers are now considered too small for many modern EVs with large batteries, as the charging time is too long, and chargers rated at up to 300kW are being installed. Also, rather than the installation of several single chargers scattered across a supply area, installation of a smaller number of charging "hubs", each comprising two or more large chargers in a single location, is now being encouraged. The ChargeNet charging station in Kaiwaka is an example of this – it comprises two 300kW chargers and can charge up to four vehicles at the same time.[3]

We have had several enquiries relating to the installation of charging hubs in our supply area, but no firm applications. When applications are received, developers will need to pay a capital contribution to fund the provision of the required network capacity before the installation can proceed.

As most EV charging is done at home, growth in electricity demand due to EV charging will be incremental and dispersed across the network, primarily at residential points of connection. Growth will be driven by the penetration of EVs across the vehicle fleet. Installation of charging hubs and additional public DC chargers will reflect this demand rather than drive it. We expect new public EV charging facilities to be installed ahead of demand and at any one time most installed chargers will not be in use, as is currently the case. Hence, while network capacity will need to be provided to cater for the full rating of the charger, the load factor of each unit will be low and consequently the impact of each new unit on the growth of the total electricity delivery volume across the network will be relatively small.

Heavy Transport

While green hydrogen is being investigated as a fuel for heavy transport, it is likely that much of the heavy vehicle fleet will be electrified, unless a more energy efficient technology emerges for the manufacture of hydrogen.[4] In time, it is also likely that electricity will be used to power short haul water and air transport.

The electrification of heavy transport will be dependent on the availability of charging infrastructure. This will require the installation of charging stations, possibly with a capacity greater than 1MW, at strategic points across our network. There could also be a requirement for chargers at Kerikeri airport and the Opua marina.

Transport operators in some large New Zealand metropolitan areas have already announced firm plans to electrify their fleet, which has enabled EDBs in these areas to assess the impact on their networks and plan their network development accordingly. Given our remoteness and relatively low level of economic activity, we think the demand in our supply area for electricity supply to heavy EV charging infrastructure will lag that of other parts of the country. To date we have not had any enquiries and we consider it unlikely there will be any requirement during the first half of the planning period.

2.5.1.2 Electrification of Process Heat

There are no major industries in our supply area that use coal or gas as a heat source. However, there are several medium-sized commercial and industrial loads that use either coal or bottled gas for heating. We anticipate that these users will decarbonise, but the timing and nature of their transition is highly uncertain. Biomass is readily available in our area and is currently used as a heat source by the AFFCo freezing works and the wood processing industries that make up most of our industrial load. We think larger users may prefer to transition to biomass rather than electricity. Smaller users, such as rural hospitals, could install industrial heat pumps.

EECA has now released its RETA report for Northland, which has confirmed that the decarbonisation of existing commercial and industrial heat sources is unlikely to result in significant new demand for electricity in our supply area.

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3 This does not mean that the maximum charging hub demand is 1.2MW. If the demand of the two cars using a single charger exceeds the 300kW rating of the charger, the rate at which each car is charged is limited, so the 300kW rating of the charger is not exceeded.

4 Hydrogen is currently manufactured using an electrolytic process. The consumption of electricity in the manufacture of hydrogen is high and this reduces the overall efficiency of using hydrogen as a transport fuel.

2.5.2 Generation

2.5.2.1 Geothermal

Ngawha Generation Ltd's 57MW geothermal power station at Ngawha is embedded in our network and is situated approximately 7km from our Kaikohe GXP. Three units, OEC1-3 with a total capacity of 25MW, are connected directly to the 33kV bus at Kaikohe and the 4th unit, OEC4 rated at 32MW, is directly connected to the Kaikohe 110kV bus.

While the power station is technically embedded in our network, in practice it is operated as a second point of injection into the GXP and therefore has little impact on the operation or asset management of the rest of the network.

2.5.2.2 Utility Scale Solar

In November 2023 we celebrated the connection of Lodestone Energy's 23MW Kaitaia solar farm to our network. This solar farm, located about 5km northwest of Kaitaia, is currently the largest solar farm in the country. Construction has also commenced on Far North Solar's 20MW Pukenui solar farm, which we expect to connect to our network in late 2024. We also expect Ranui Generation to commence construction of the 24MW Twin Rivers solar farm, located southeast of Kaitaia, in late 2024 or early 2025.

Completion of all three solar farms will see a total of 67MW of utility-scale solar generation connected to the 33kV subtransmission network supplied from our Kaitaia 110kV substation. As this far exceeds the local consumer demand, particularly on a summer day at times of peak solar generation, most of this electricity will need to be exported south. This will fully utilise the capacity of our 110kV Kaikohe-Kaitaia circuit, and we are therefore currently unable to accept any more applications for the connection of utility scale generation to our existing network without imposing stringent conditions on generator operation.

Under certain weather conditions, there are likely to be large swings in generation output for the three generation farms that, while each will be connected to a different 33kV zone substation, will nevertheless experience similar weather conditions to the point where generation output from the three farms can be expected to rise and fall at about the same time. Before signing the connection agreements, we engaged an external consultant to model the impact of the expected swings in generation output on the quality of supply we provide consumers already connected to the network, and we are confident that this will remain within statutory limits. Nevertheless, management of such a large amount of intermittent generation relative to the load on the network will add a level of complexity to the management of the network and our control room operators are preparing for this.

2.5.2.3 Small Scale Solar

Figure 2.1 shows the increase in the installation of small-scale behind-the-meter solar generation on our network at the end of each year of the 11-year period FYE2014-24, based on Electricity Authority data. The figure shows that the installed capacity is increasing at an almost exponential rate. At the end of FYE2024, we expect that there will be 11.8MW of installed capacity connected to our network by almost 2,000 users. This equates to an uptake rate, which is a measure of the percentage of connected consumers with solar generation installed, of 5.8% which is higher than any other New Zealand EDB.

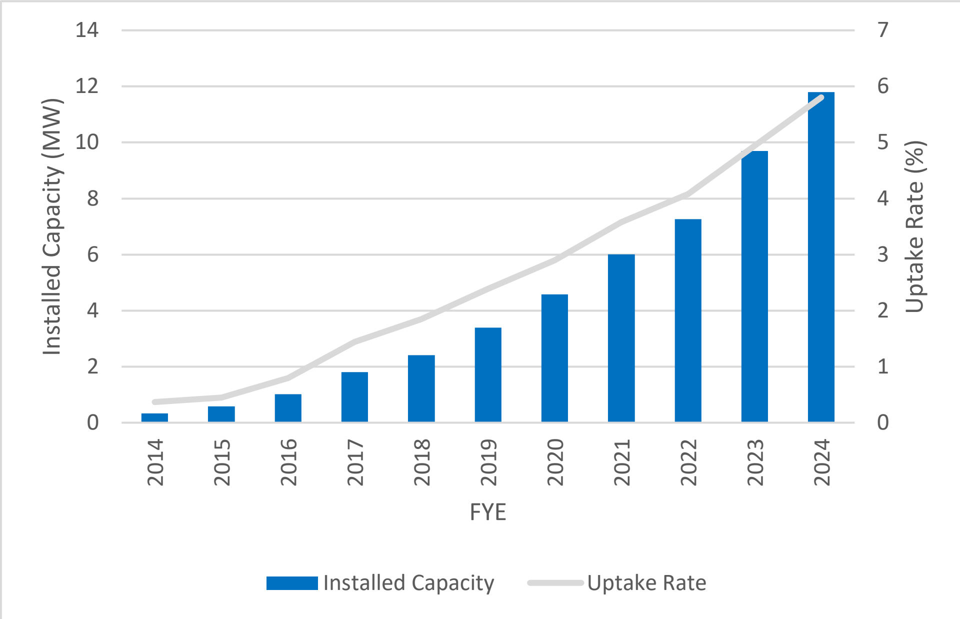

Figure 2.1: Installation of Small-Scale Photovoltaic Generation

The heat map in Figure 2.2 shows the location of this solar generation across our supply area. As might be expected, the concentration is highest around the more affluent and densely populated Kerikeri and Bay of Islands areas.

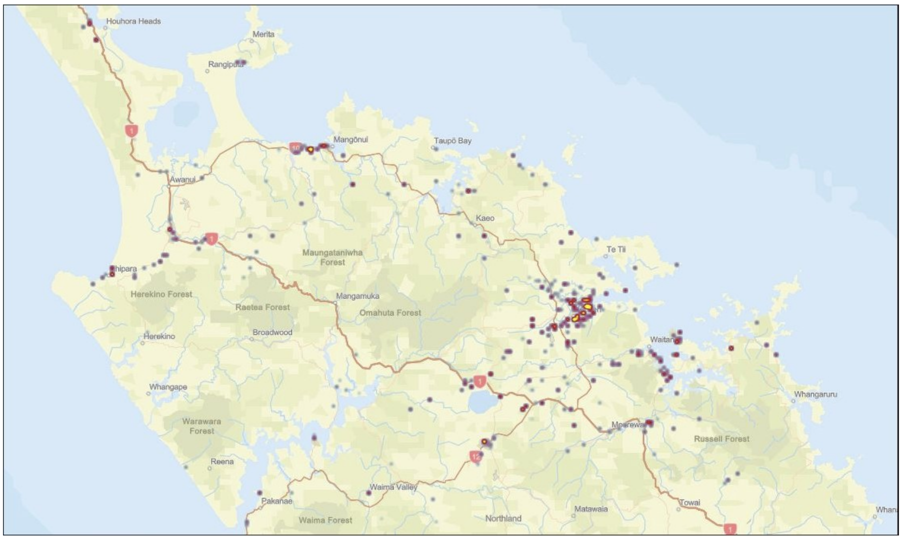

Figure 2.2: Concentration of Small-Scale Solar within our Supply Area

It is also clear from Figure 2.1 that the average size of these units is increasing. In the current FYE2024 year the average size of each new installation was 6.9kW. We limit the electricity injection into low voltage circuits to 5kW, but over the last two years or so, most new installations have included batteries. These have provided storage capacity, which allows the installation of larger units without breaching the export limit. They also allow the energy generated during the day to be stored and used at times of peak demand.

Figure 2.3 shows the peak demand and delivered electricity volumes disclosed to the Commission over the period FYE2014-24.[5] It shows that the growth in peak demand experienced during the CY2020-22 winters was not sustained in CY2023, which could in part be due to an increasing amount of storage

5 Figures for FYE2024 are estimates based on data currently available.

associated with newly installed rooftop solar generation. The demand profile shown in Figure 2.2 is such that it is hard to forecast our network peak demand going forward with a high level of confidence.

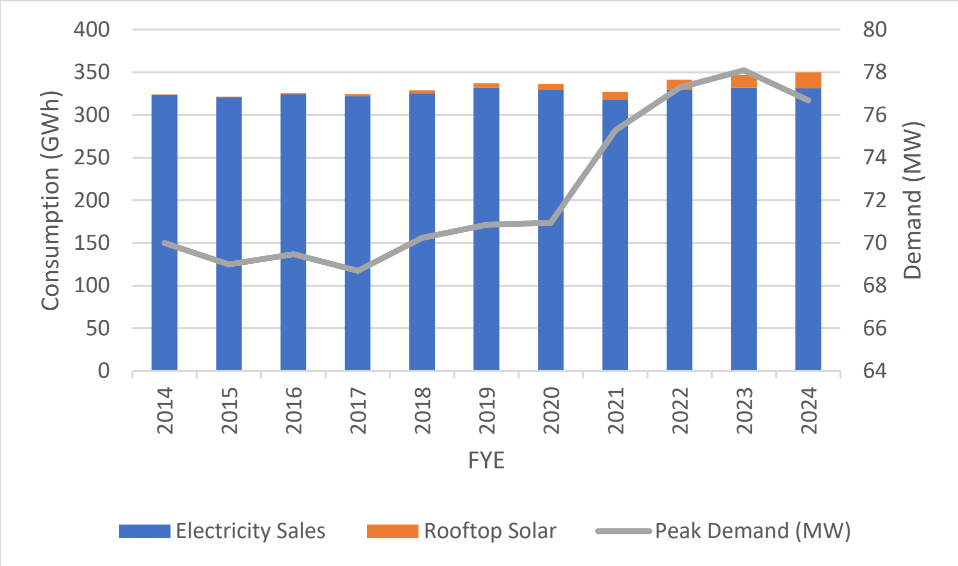

Figure 2.3: Peak Demand, Delivered Electricity Volumes and Estimated Small-Scale Solar Generation (FYE2014-24)

Figure 2.3 also shows the estimated annual output from small-scale solar generation relative to electricity volumes delivered through the network. While there was little growth in the total volume of electricity (sourced from both delivered energy and behind-the-meter local generation) used by consumers up until FYE2017, since then that has been a steady growth in annual consumption.

This is shown in more detail in Figure 2.4, which compares the total electricity consumption on our network (the sum of our electricity delivered and behind the meter solar generation) with the electricity delivery volumes from the network over the same FYE2014-24 period, with the y-axis magnified. It shows that since FYE2017 the growth in total electricity consumption has been significant – we estimate a compounding annual growth rate of just under 1.1%. However, over the same period our electricity delivery volumes increased by only 0.4% per year.

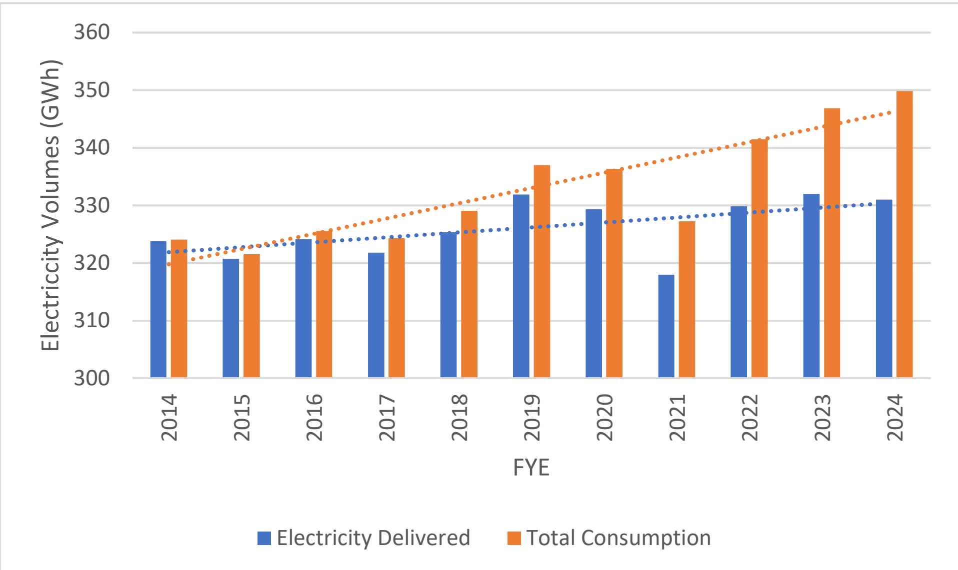

Figure 2.4: Electricity Volumes Delivered Compared to Total Consumption (note magnified scale of y-axis)

The 1.1% growth rate in total electricity consumption is much higher than the national growth rate disclosed by Transpower and discussed in Section 2.5.1. The fact that this growth rate is higher than the corresponding growth in electricity delivered from the network is due to the almost exponential increase in the installed capacity of small-scale solar generation, as shown in Figure 2.1. At the end of FYE2017 there was a total of 1.8MW small-scale solar generation connected to our network whereas, by the end of the current FYE2024 year, this is expected to have increased to 11.8MW, an annual growth rate of over 30%. There is a risk that, if the connection of small-scale solar continues to grow at its current rate, Top Energy will pass a tipping point where the annual increase in solar generation regularly exceeds the increase in total consumer demand for electricity.[6] This would result in a situation where Top Energy's electricity delivery volumes continue to decline, notwithstanding an overall increase in electricity consumption by consumers.

2.6 Impact of Climate Change on Asset Management

Section 7.6.1 0f our 2023 AMP discussed the probable impact of climate change in our supply area as forecast by the Ministry for the Environment, and the impact this might have on our network. In summary:

- Temperature rise is likely to result in an increased risk of wildfires, shortage of water and an increased demand for irrigation. There will be fewer extremely cold winter days, which could temper growth in demand over winter while the increased demand for water and irrigation could increase summer demand. We are already seeing increased water and irrigation demand – two irrigation schemes are currently being constructed near Kaikohe and a second water supply scheme for Kaitaia has recently been completed. Many of the prospective new loads discussed in Section 4.1.1 are irrigation pumps. The developing avocado industry on the Aopouri Peninsula has already seen the Pukenui substation move from a winter to a summer peak demand. Increased summer temperatures could also lead to an increased demand for air conditioning.
- New Zealand experienced an average rise in mean sea level of 1.7mm per year over the 20th century and the rate of rise is expected to increase. Initially this will manifest itself in increased flooding and erosion in coastal areas following severe weather events. Eventually low-lying coastal areas will be inundated to the extent that there will likely need to be a managed retreat. Government and the insurance industry are now starting to think about who should bear these costs. In the event of such a retreat, we would expect relocated consumers would be treated as new connections in accordance with our connections policy and our connection costs would be included in the cost of the retreat. However, we are unlikely to be compensated for the loss of assets,
- The intensity of ex-tropical cyclones and other severe weather events will increase and there will be more rain and higher wind speeds. This will increase the extent of flooding, vegetation contact and tree falls, as well as the potential for broken wires, fallen poles and damage to pole top hardware.

The sections below provide an overview of the steps we are taking to manage the impact of climate change.

2.6.1 Fire

Our lines can cause fire when vegetation grows into the line or when a spark ignites dry vegetation. The National Institute of Water and Atmospheric Research (NIWA) has identified Cape Reinga, Ahipara and its environs and the Karikari peninsula as the areas where our network is at greatest risk of igniting a wildfire during the fire season, which extends from November to March. We are also increasing our collaboration with Fire and Emergency New Zealand (FENZ), which continually monitors the fire risk in

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[6] This happened in the current year where we estimate the increase in total consumption was 3GWh. This was exceeded by an estimated increase in small scale solar generation of 4GWh.

all parts of our supply area and can declare a restricted fire season or prohibited fire season in any part of our area at any time.

Our approach to minimising the risk of our asset causing a wildfire is twofold:

- Prior to each wildfire season we will survey our lines in the three high-risk areas to identify potential sources of ignition and take appropriate action to minimize the risk. In most cases this will involve targeted vegetation management. Fortunately, the Karikari peninsula is the only high-risk area where our network is extensive – the extent of our network in the other two areas is more limited.
- When FENZ declares a restricted or prohibited fire season in any part of our supply area we will disable the auto reclose function on switchgear supplying the restricted area. This may involve sending out field personnel to manually disable the reclosers supplying SWER circuits. When a fault occurs in a restricted fire area, we will not restore supply within 15 minutes of the fault occurring to allow time for reports from the public or emergency services to be received. In a prohibited fire season, supply will not be restored until the line has been patrolled to establish to cause of the fault and confirm that it is safe to reliven.

2.6.2 Sea Level Rise / Flooding

Taipa Substation is the most critical asset likely to be impacted by tsunami or sea level rise. It is situated 250 metres from the Oruru River estuary and approximately 1.8m above mean high water level. The substation has now reached its full capacity and will eventually be replaced by two new substations, one at either Mangonui or Coopers Beach and the second at Tokerau Bay. We envisage that the Mangonui / Coopers Beach substation will be built during the planning period of this AMP.

Other low-lying zone substations are Kaeo and Omanaia. The risk to these sites is not as great as Taipa, and is dependent on significant sea level rise, high tide and flooding all occurring simultaneously. To mitigate these risks, flood remediation has been undertaken at Omanaia, and Kaeo substation has been elevated above any anticipated flood level.

We have an increased awareness of the flooding risk within different parts of our supply area, and we actively strive to mitigate this risk to the extent practicable when designing and building new infrastructure or replacing existing assets.

2.6.3 Storms

The extreme weather events we experienced in FYE2022 and FYE2023 have highlighted the need to increase resilience in our 11kV network and, as discussed in Section 2.3 above, our Board has resolved to allocate increase its planned funding on 11kV resilience improvement through to the end of this AMP planning period. In the next FYE2025 year, $4 million is forecast to be spent on proactive 11kV asset renewal and $5 million on other 11kV resilience improvement initiatives, including optimising the protection on our long 11kV feeders and the construction of interconnections between neighbouring feeders. Over the five-year RCP4 period, FYE2026-30, we have forecast a total expenditure of $27.6 million on proactive asset renewal and $13 million on other projects designed to improve network resilience and reliability of supply, primarily feeder protection upgrades and interconnections.

Over the four years of the planning period after the end of RCP4, we have allocated $12.33 million for resilience improvement initiatives that were not included in the 2023 AMP capital expenditure forecast. In addition to continuing the existing programme of feeder protection improvements and interconnection construction, we envisage that this extension to the resilience improvement programme would include:

- Purchase of portable generation units and establishment of network connection points.
- Procurement of additional critical spares for the 110kV line.
- Undergrounding and the use of covered conductors in areas of high exposure to vegetation faults.
- Increasing the number of pole replacements.

We are also planning to increase expenditure on vegetation management to further increase the resilience of the network to storm events.

2.7 Existing Network Capacity

As discussed in Section 2.5.2, the capacity of our 110kV Kaikohe-Kaitaia transmission line will be fully utilised once all three utility-scale solar farms in the north of our supply area are connected to the network. Furthermore, the N-1 transformer capacity of the Kaitaia 110kV substation will be exceeded, although the larger and newer of the two transformers at this substation has sufficient capacity to carry the load, should the smaller transformer fail. Transformer failures are unusual and, as this transformer is new and in good condition, the probability of a failure is low. These are generation constraints and do not limit the connection of additional consumer load. The winter rating of our 110kV Kaikohe-Kaitaia line is 68MVA whereas the peak consumer demand in our northern area is currently only 26MVA.

There is also a constraint on the supply capacity into our Wiroa substation. Wiroa is supplied at 33kV and, should there be a fault on the larger of the two incoming circuits at time of peak winter demand, we could experience low 11kV voltages on feeders supplied from our Kaeo and Waipapa substations. This constraint will be addressed by the construction of a new 110/33kV substation at Wiroa and this build is planned to start in FYE2026.

We have invested heavily in our 33kV subtransmission network over the last ten years and our modelling has indicated that, apart from the Wiroa constraint, the current 33kV network backbone has sufficient capacity to accommodate an increase in demand of the magnitude forecast by Transpower through to 2040 and beyond.

However, we supply several remote townships from long feeders on our 11kV distribution network. As the consumption of electricity increases, we anticipate that there will be a need to increase the capacity of parts of the 11kV network to meet localised demand growth in some of these towns. In some cases, this may be best achieved by extending the coverage of the 33kV subtransmission network to provide a new point of injection into the distribution system. While the location and timing of such demand growth remains unclear, we do not anticipate any requirement to extend the reach of the subtransmission network in the first half of the planning period.

2.8 Delivery of the Work Programme

Our plan to deliver our 2025 work programme is as follows:

- Our time-based asset inspections and the low voltage data capture project will be undertaken by staff contracted directly to Top Energy Network.
- We have an ongoing contract in place with Northpower for the maintenance of our transmission and zone substations and a separate contract covering our 110kV transmission line assets, including condition assessment and structure replacements.
- Vegetation management will be undertaken by TECS. We have increased our planned level of vegetation management in FYE2025 and will likely need to engage an external arborist to complete the work that TECS is unable to deliver.
- Construction of new zone substation assets are managed as separate projects and outsourced by competitive tender. In FYE2025, the only such project is the installation of the backup generator transformer at Ngawha.
- TECS undertakes fault response, maintenance work and defect remediation on our 33kV, 11kV and 400V assets.
- Prior to the beginning of the financial year, we discuss our planned capital works programme with TECS and agree the capital projects that they will undertake, given their expected delivery capacity and available skillset.
- Once the projects to be undertaken by TECS are confirmed, the remaining work will be bundled into a separate scope of work and let as a single competitively tendered contract. We have

already gone to the market and invited expressions of interest. The work will be competitively tendered by the external contractors that express interest and have the capacity and skills we need.

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. The targets in our 2023 AMP were based on the average reliability of the network over an historic ten-year period and assumed that this will be held at that level and not deteriorate over time. This meant that expenditure on maintenance and quality of supply initiatives would be limited to that needed to offset the natural deterioration in the condition of the network.

Our threshold breaches in FYE2023, together with the impact that supply interruptions during Cyclone Gabrielle had on our consumers, has highlighted a need to develop a network that is more resilient to severe weather conditions, given that the frequency and severity of major storms is predicted to increase due to climate change. Notwithstanding the results of our consumer surveys, which are discussed in Section 2.3, our Board looked at various price quality trade-offs and consulted with our owner, the Top Energy Consumer Trust as to the appropriate strategy in managing the resilience to severe weather events. The level of investment and improvement in network reliability was assessed against the energy trilemma that our consumers face, now and in the future.

As a result of this discussion, the Board has decided to continue with its current 11kV distribution network reliability improvement plan and increase its expenditure on the replacement of 11kV network assets. From FYE2030 it is also planned to implement a new programme to progressively develop a more resilient 11kV network architecture. The focus will be on the 11kV network, since typically over 90% of our network SAIDI is due to 11kV faults.

While this new expenditure is primarily focused on increasing the resilience of the network to severe weather, it is also expected to result in improved network reliability. We have therefore revised our strategy for setting network reliability targets and reverted to an approach that targets a progressive improvement in reliability over time. Our revised unplanned interruption targets will continue to use the Commission's normalised measures. The Commission has commenced the process of resetting the reliability threshold that will apply from RYE2026 and, should the revised thresholds be based on a different normalisation methodology, we will need to adjust our numerical targets accordingly.

Table 3.1 below compares the new normalised unplanned SAIDI targets with those in the 2023 AMP and Figure 3.1 compares these two sets of targets with our historic performance, assuming a consistent normalisation methodology.

FYE	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
New target	-	300	294	289	286	278	273	268	258	248	240
2023 AMP target	302	302	311	311	311	311	311	311	311	311	-

Table 3.1: Comparison of Revised Internal Unplanned SAIDI Targets with 2023 AMP Targets

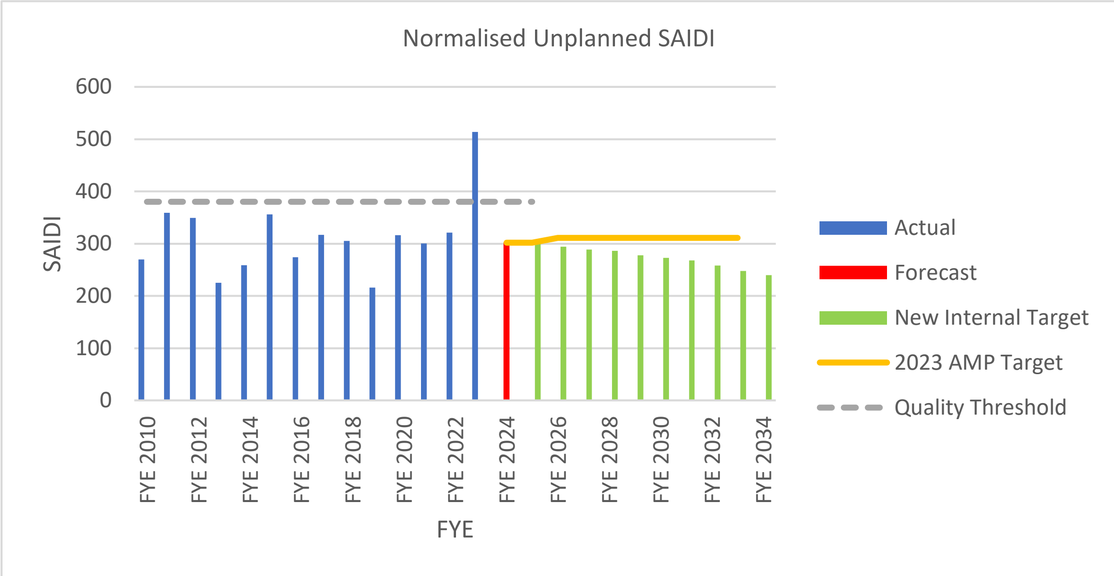

Figure 3.1: Historical and Target Unplanned SAIDI

Table 3.2 below compares the new normalised unplanned SAIFI targets with those in the 2023 AMP and Figure 3.2 compares these two sets of targets with our historic performance, again assuming a consistent normalisation methodology.

FYE	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
New target	-	4.01	4.01	4.00	4.00	3.99	3.99	3.98	3.98	3.90	3.80
2023 AMP target	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	-

Table 3.2: Comparison of Revised Internal Unplanned SAIFI Targets with 2023 AMP Targets

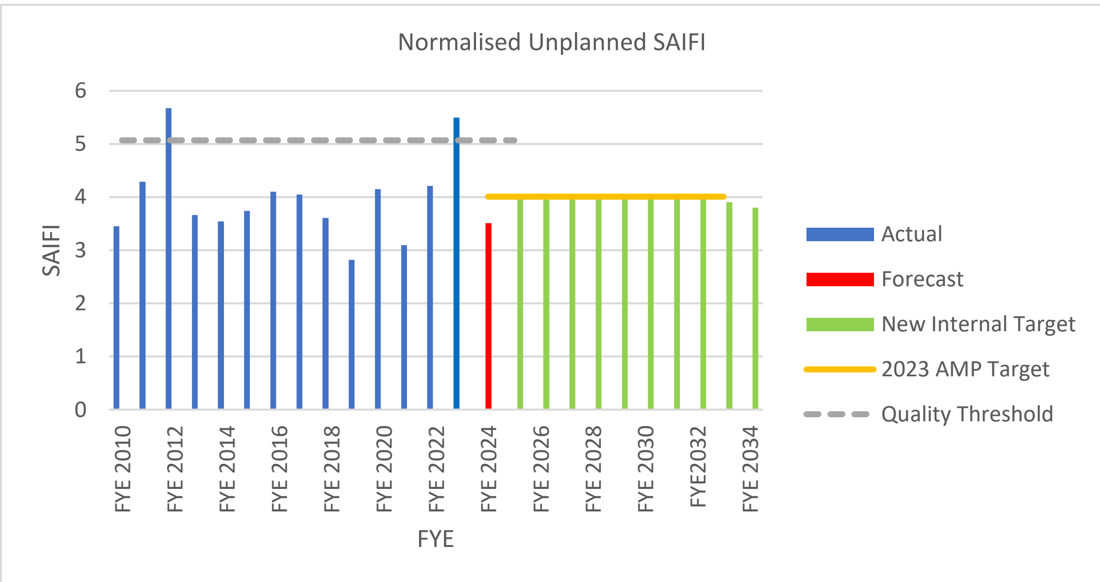

Figure 4.2: Historical and Target Unplanned SAIFI

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. While we think 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 so is not reflected in our delivery volumes. Growth in peak demand is also lower than forecast, possibly due in part to an increasing amount of battery storage associated with behind-the-meter solar generation.

4.1.1.1 New Loads

New connections that are either confirmed or in the pipeline include large irrigation pumps and the initial stage of a commercial gum extraction and processing plant northwest of Kaitaia. This development is expected to undergo a staged expansion over the next five years, which could lift the peak demand of the site to 3MVA. We are currently investigating how best to supply this load – while there is sufficient capacity on our Awanui feeder to supply the initial stage, a new feeder will be required if the expansion proceeds to its full extent.

We are also investigating a possible new wood processing plant with a potential load of 2.5MVA to be located close to our Pukenui substation, although we think this project is still undergoing feasibility assessment. There is also sustained interest in residential subdivision development, particularly around the Kerikeri and Waipapa areas. In our experience, the impact of new subdivisions on network demand tends to be incremental as large subdivisions are typically built in stages and houses within each stage are not all connected at the same time.

Our subtransmission infrastructure has sufficient capacity to accommodate these new loads, apart from the Pukenui substation transformer. This transformer is in poor condition and, as noted in Section 2.4.3, provision has been made in our capital expenditure forecast to replace it with a new 5/10MVA unit by FYE2030. This project may need to be brought forward if the wood processing plant goes ahead, but the cost would be partly funded by the capacity charge the developer would be required to pay (See Section 6.4.2).

4.2 Major Capital Projects Completed in FYE2024

Our expected FYE2024 capital expenditure on network assets is $22.9 million. The major projects covered by this expenditure are described below.

4.2.1 Customer Driven

We installed 2.8km of 33kV overhead line and 0.9km of 33kV underground cable to connect Lodestone Energy's new 23MW solar farm to our NPL zone substation.

4.2.2 System Growth

The Russell peninsula reinforcement project was substantially completed in FYE2022 but could not be commissioned due to supply chain issues, which delayed the delivery of critical electrical components. The project was finally commissioned in February 2024. It has:

- Enabled the load on Russell peninsula to be shared between two feeders. One feeder supplies Russell town and second the load along the Russell Road through to Rawhiti. This has not only increased the supply capacity into the peninsula but also increased the reliability of supply as not all consumers on the peninsula will be disconnected following a fault.
- Reduced the peak load on the Kawakawa substation by transferring approximately 1.5MW to Haruru. The two transformers at Kawakawa are both nearing the end of their life and, should

a transformer fail, the remaining transformer would otherwise have been overloaded at times of peak demand.

4.2.3 Asset Renewal and Replacement

We replaced two towers on our 110kV Kaikohe-Kaitaia line with new two-pole structures, which were relocated on more stable ground at a cost of $1.4 million, which included the construction of access tracks to the new structure sites. This project was in response to ground movement along the route of the line, caused by the extreme weather we experienced during FYE2023. A further three structures are to be replaced and relocated in FYE2025.

We also expect to spend $1.2 million on proactive 33kV line refurbishment and $4.34 million on 11kV line refurbishment and pole replacements.

Our total forecast FYE2024 capital expenditure on the proactive renewal and replacement of network assets is $7.4 million. Furthermore, we expect our reactive expenditure on the renewal and replacement of network assets in response to faults and the remediation of defects identified during our asset inspection programme to be $3.0 million.

4.2.4 Reliability of Supply

As part of the 11kV reliability improvement programme we:

- Installed new protection equipment on the South Rd, Horeke, Te Kao and Rangiahua feeders. This work is now 50% complete and will now be completed in FYE2025.
- Constructed an interconnection between the Whangaroa and Matauri Bay feeders. We still need to upgrade the conductor at the ends of the two feeders, as the existing conductor has insufficient capacity to carry the load of both feeders. This will be done in FYE2025-26.
- Installed the switchgear for the new 11kV injection point from the tertiary winding on the Kaitaia 110/33/11kV transformer. The 11kV cables connecting the switchgear to the South Road and Oxford St feeders will be installed in FYE2025.

We also commenced work on the installation of a backup generator transformer for the 32MW OEC4 generator transformer at Ngawha, including design and transformer procurement. This is a new project that was not included in the 2023 AMP.

4.3 FYE2025 Work Programme

4.3.1 Network Assets

Our planned capital expenditure on network assets in FYE2025 is $30.63 million, up 68% from the $18.23 million forecast in the 2023 AMP. A large part of this increase is due to the decision to install a backup generator transformer for the 32MW OEC4 unit at Ngawha power station. Our estimated FYE2025 expenditure on this project, which was not included in the 2023AMP, is $8.67 million. A breakdown of this work programme is given in Table 4.1 below.

Project	Cost ($000)	Comment
Customer Driven		
All projects	**3,427**	This includes the connection of the Pukenui solar farm to the Pukenui substation bus.
System Growth		
All projects	**752**	This includes two small projects to address localized capacity constraints within the 11kV network.
Asset Replacement and Renewal		

110kV structure replacements	953	This is a continuation of the project started in FYE2024 to address the risk of ground movement that was exposed by the extreme weather we experienced in FYE2023.
33kV line refurbishment	790	
11kV line refurbishment	2,857	
Concrete pole replacement	357	
Wood pole replacement	831	
Switchgear	812	
Transformers and regulators	428	
Protection and SCADA	402	
Reactive – fault response	1,152	
Reactive – corrective response	1,528	
Other	417	
Subtotal – Asset Replacement and Renewal	**10,529**	
Reliability, Safety and Environment		
Optimisation of 11kV feeder protection	1.627	Includes the installation of new and relocated protection devices and optimisation of protection settings on the Horeke, Herekino, Rangiahua, Te Kao, Whangaroa and South Rd feeders.
Feeder interconnections	2,533	South Rd–Rangiahua and Whangaroa–Matauri Bay feeders. Includes conductor upgrades and the installation of regulators to provide sufficient network capacity to carry the full load of both feeders.
Kaitaia 11kV injection point	833	Completion of project to provide injection points into the South Rd and Oxford St feeders from the tertiary winding of the Kaitaia 110/33/11kV transformer.
Communications system upgrades	727	
Substation protection upgrades	293	
Low voltage data capture	350	
Ngawha backup generator transformer	8,665	This project will provide a backup generator transformer for the 32MW OEC4 generator at Ngawha power station. This is a new project that was not included in the 2023 AMP. Generator transformers at the power station are network assets.
Other	890	Includes a range of projects, such as the installation of fault passage indicators and the installation of meters for monitoring harmonics
Subtotal – Reliability, Safety and Environment	**15,918**	
TOTAL FORECAST CAPEX – FYE2025	**30,626**	

Table 4.1: Breakdown of FYE2025 Work Programme

4.3.2 Non-Network Assets

Our planned capital expenditure on non-network assets in FYE2025 is $3.05 million, up 154% from the $1.20 million forecast in the 2023 AMP. This is primarily due to new projects that were not provided for in the 2023 AMP. These include:

- Hardware replacements.
- The power transformer oil filtration plant discussed in Section 2.4.3.
- Improvements to enhance the quality and space of inventory storage, as there is a shortage of covered storage areas to protect materials and equipment from the elements. We are planning to construct a new storage area at the Kaikohe substation to protect sensitive materials and equipment from degradation.

4.4 FYE2026-30 Capital Expenditure Forecast

We have considered this five-year period separately from the rest of the planning period, as it coincides with RCP4, and the Commission is currently resetting the price-quality path for this regulatory control period.

4.4.1 System Growth

Our forecast constant price system growth capital expenditure for RCP4 is $15,918k, down 11.9% from the $18,067k forecast in 2023.

Key changes from the 2023 AMP forecast include:

- The cost of the Wiroa substation build has increased from $10.8m to $14.9m. This includes the 15% escalation in labour and minor equipment costs, as well as updated budget prices for major equipment items.
- Replacement of the zone substation transformer at Taipa was included in the 2023 AMP system growth forecast. This project remains in the RCP4 capital expenditure forecast but has now been recategorized as an asset replacement project, based on the updated assessment of the condition of this unit. The constant price cost of this project in the 2023 forecast was $2.3m.
- The replacement of the old 110/33kV transformer at Kaitaia has been deferred to FYE2033-35.

4.4.2 Asset Replacement and Renewal

Our forecast total constant price asset renewal and replacement capital expenditure for RCP4 is $62,584k, up almost 48% from the $42,402k forecast in our 2023 AMP.

Key changes from the 2023 AMP forecast include:

- The provision for structure replacements on the 110kV Kaikohe-Kaitaia line has been increased to $3.8m, up 48% from $2.6m to accommodate the relocation of structures on this line. This includes the replacement and relocation of three structures where the line crosses the Maungataniwha Range to mitigate the risk of ground instability exposed by the severe weather experienced during FYE2022. This is in addition to the two structures replaced and relocated in February 2024.
- As noted above, the forecast now includes the replacement of the Taipa zone substation transformer, at a revised cost of $2.9m, up 26% from the estimated cost in the 2023 AMP.
- The forecast includes the replacement of the Pukenui transformer, at a cost of $2.0m. This project was not included in the 2023 AMP.
- The forecast also includes $32.3m for planned asset renewal and replacement of primary 11kV network assets, up 36% on the $23.7m forecast in 2023. This increase incorporates both cost

escalation and increases in work volumes and does not include reactive expenditure on the replacement of assets that fail in service or are identified as needing replacement by our asset inspection regime.

The forecast also includes $14.0m for the reactive replacement of assets that fail in service or are identified as needing replacement by our asset inspection regime.

4.4.3 Quality of Supply

Our forecast total constant price quality of supply capital expenditure for RCP4 is $17,623k, up 45% from the $12,168k forecast in our 2023 AMP. This reflects our decision to continue with the implementation of our 11kV reliability improvement plan, notwithstanding the new demands for additional expenditure on the renewal of subtransmission assets.

Key changes from the 2023 forecast include:

- The provision for protection improvements on our long 11kV rural feeders has increased to $4.0m, up 48% from the $2.7m forecast in 2023.
- The provision for the construction of interconnections between neighbouring feeders has increased to $6.8m, up 83% from the $4.3m forecast in 2023.
- Forecast expenditure on improved communication systems has increased to $2.0m, a 157% increase on the 2023 forecast expenditure of $771k. This expenditure is designed to improve the efficiency of our response to severe weather events.
- Forecast expenditure on additional remote controlled 11kV network switches, including new smart devices, has increased to $948k, up 63% from the $581k forecast in the 2023 AMP.

4.4.4 Non-Network Capital Expenditure

Our 2024 AMP forecast total constant price non-network capital expenditure for RCP4 is $9.6m, up 81% from the $5.3m forecast in 2023. This includes the following projects that were not provided for in the 2023 AMP.

- *Additional Advanced Distribution Management System (ADMS) capability*
  Our product vendor, GE, continues to develop this product, introducing new capabilities and features to support improved network performance and operational management. We have provided for the procurement of a Distributed Energy Resource Management System (DERMS), currently planned for FYE2028. This is expected to be a complex and relatively expensive software solution, requiring substantial professional services to design, configure and implement.
- *Geospatial Information System (GIS)*
  We are planning substantial enhancements to our GIS over the next 5 years to support the additional capabilities and features noted under ADMS above, and to improve our planning and efficient delivery of network and customer led projects.
- *Data Centre infrastructure*
  The cost of replacing our Disaster Recovery (DR) data centre with a containerised solution has increased. Also, the timing for replacing our Storage Area Network (SAN) has been brought forward due to substantial unbudgeted cost increases for support on our current model.

4.5 FYE2031-34 Capital Expenditure Forecast

Our total capital expenditure on network assets over the final four years of the planning period (FYE2031-34) is forecast to be $85 million in FYE2025 dollars. This expenditure includes:

- Construction of the southern section of the planned 110kV line between Wiroa and Kaitaia. A condition of the legal settlement with the three landowners who took legal action over the granting of line route easements across their properties is that construction of the line over the affected properties would commence within ten years. This project was not included in the 2023 AMP forecast.

- Replacement of the old 22MVA, 110/33kV transformer bank at Kaitaia substation with a new 40/60MVA transformer. This bank is in poor condition and installation of a larger transformer will give N-1 security to the utility scale solar capacity to be connected to the network in the Kaitaia region.
- Construction of a new 110/33kV substation at Coopers Beach or Mangonui. Doubtless Bay is currently supplied by the Taipa substation, which is currently operating at full capacity and is at risk from sea level rise. It is planned to replace it with two substations, one at either Coopers Beach or Mangonui and the second at Tokerau Beach on the Karikari peninsula. In the 2023 AMP it was anticipated that the first substation would be built at Tokerau Beach but, following a review of the relatively high load growth in the area, we now believe Coopers Beach or Mangonui to be the better location for the first substation.
- Replacement of one of the 33/33kV transformers at both the Kaikohe and Kawakawa substations.
- Ongoing investment in improving the resilience of the 11kV distribution network, as discussed in Section 2.6.3. This is new expenditure not included in the 2023 AMP and has been allocated in response to Cyclone Gabrielle and the extreme weather events we experienced in FYE2022 and FYE2023.

4.6 Total Forecast Capital Expenditure

Our total forecast capital expenditure on network assets, measured in constant price terms, over the ten-year planning period of this AMP has increased to $226.5 million, 31% higher than the $173.0 million forecast for the 2023 AMP planning period. This is shown in Table 4.2 and Figure 4.1. More than 15% of this increase is due to increased material and labour costs and the remainder reflects expenditure to address network capacity constraints and improve network resilience to the changing climate. The 2023 AMP forecast was measured in FYE2024 prices, whereas the current forecast uses FYE2025 prices.

FYE	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
2024 AMP		30,626	24,943	22,104	21,529	21,792	20,505	21,032	21,944	21,032	21,032
2023 AMP	20,520	18,227	17,342	16,980	16,469	19,370	15,559	15,760	16,740	16,064	

Table 4.1: Comparison of the 2024 AMP Constant Price Capital Expenditure Forecast with 2023 AMP Forecast ($000)

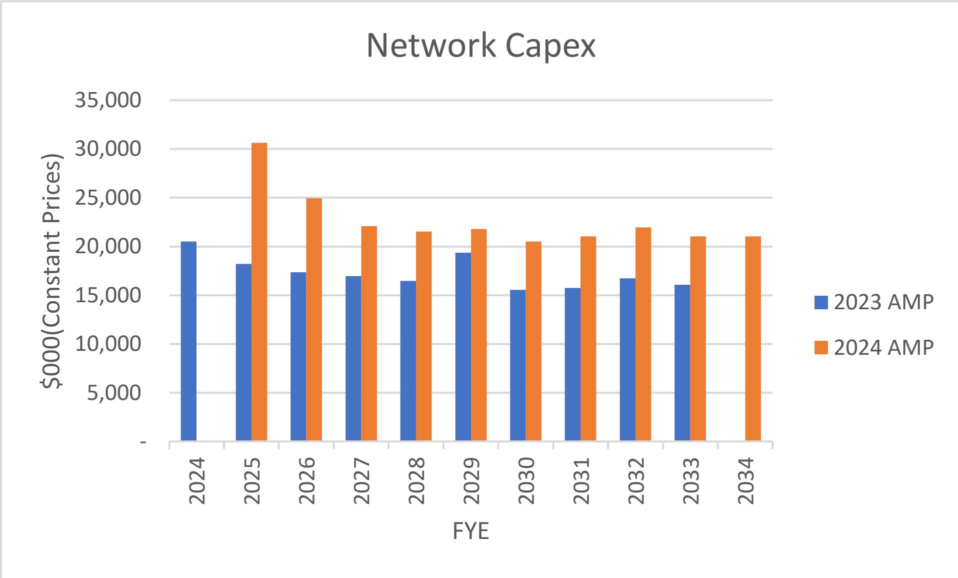

Figure 4.1 Comparison of Constant Price Network Capital Expenditure Forecast with 2023 AMP Forecast ($000)

5 Lifecycle Asset Management

5.1 Network Maintenance

Our total forecast operational expenditure on network maintenance, measured in constant price terms, over the ten-year planning period of this AMP has increased to $99.8 million, 30% higher than the $76.7 million forecast for the 2023 AMP planning period. This is shown in Table 5.1 and Figure 5.1. Approximately 15% of this increase is due to increased material and labour costs and the remainder reflects an increased maintenance programme to improve network resilience with the changing climate. The 2023 AMP forecast was measured in FYE2024 prices whereas this current forecast uses FYE2025 prices. The impact of this change has been much higher than we expected last year due to the lingering impact of Covid 19 and its consequent supply chain impacts, the state of the economy and the high level of inflation, the high cost of materials, the shortage of labour, particularly staff and contractors with the appropriate skills and experience. The uplift in expenditure is required to maintain a network that meets consumer needs now and in the future.

FYE	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
2024 AMP		8,582	9,409	9,583	9,759	9,940	10,124	10,311	10,503	10,698	10,897
2023 AMP	7,463	7,540	7,577	7,615	7,653	7,692	7,731	7,769	7,809	7,847	

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

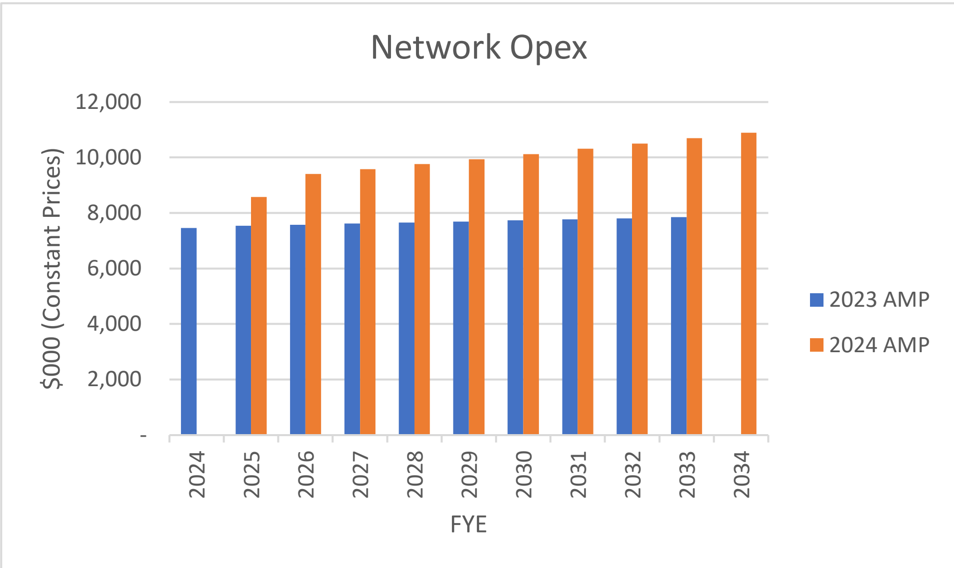

Figure 5.1 Comparison of Constant Price Network Operational Expenditure with 2023 AMP Forecast ($000)

In developing this updated forecast, we have also reviewed our approach to forecasting the required expenditure in the various operational expenditure categories. This is discussed in the sections below.

5.1.1 Service Interruptions and Emergencies

This expenditure is reactive. We experienced a much higher number of extreme weather events in FYE2023 than usual and the weather over the previous FYE2022 year was also worse than we normally experience, although not as bad as FYE2023. Consistent with most meteorological forecasts, we expect climate change to increase the frequency of severe weather events going forward. We also note that our fault response costs are often incurred at overtime rates. We have updated the 2024 AMP Update forecasts to reflect the median real value of our historical expenditure in responding to faults and emergencies.

5.1.2 Vegetation Management

An analysis of our inspection records indicates that the number of spans where the vegetation clearances violate the requirements of the Electricity (Hazards from Trees) Regulations 2004 is currently increasing at a rate of about 300 per year and our revised expenditure forecast provides for the vegetation management of an additional 330 spans per year. We are currently increasing our TECS resources and will likely need to engage external arborists to enable us to increase our annual vegetation management output to the required level.

5.1.3 Routine and Corrective Maintenance and Inspection

Our 2024 AMP forecast includes a new provision of approximately $200k per year for safety and compliance activities, including close approach monitoring, cable location etc., which we undertake at no cost to third parties. Historically we have only budgeted around $20k per year. The 2024 budget for this work is based on our actual annual expenditure. Going forward, this expenditure will be captured in a separate cost centre that will be categorised as routine maintenance.

We have also included a new provision in this forecast for inspection of our fibre assets and increased our forecast expenditure on the corrective maintenance of power transformers, as discussed in Section 2.4.3.

5.1.4 Asset Replacement and Renewal

In our 2024 AMP forecast we have provided additional expenditure for the remediation of defects identified in our asset inspection programme. At the present level of investment, the number of defects that need attention within a year is increasing at the rate of almost 300 per year. To address this, there needs to be a significant increase in asset replacement operational expenditure. We have also found instances of mould and moisture ingress in a few of our substations, highlighting a need to increase the level of non-routine maintenance on substation grounds and buildings to preserve the health of these assets and maintain a healthy environment for staff working on site.

5.2 System Operations and Network Support Expenditure

Our total forecast constant price system operations and network support expenditure over the AMP planning period is $87.04 million, up 14% from the $76.55 million in the 2023AMP. Much of this increase is due to increases in software expenditure, the drivers for which are discussed below.

- *Migration of IT Systems to the Cloud*
  Our Enterprise Resource Planner (ERP) and Asset Maintenance Management System (AMMS) vendor requires migration from on-premises to the cloud as its on-premises solution will no longer be supported. The most cost-effective long-term migration method requires a greenfield development. This substantial cost, under the current accounting standards, must be expensed. It was originally budgeted to be capital. The cloud license and software maintenance costs are more than double what we currently pay for the on-premises solution.

- *Accounting Standards*
  We continue to develop our Customer Relationship Management (CRM) system and other similar software as a service (SaaS) cloud-based systems to improve customer experience and internal workflow. These development costs were previously included in the capital expenditure forecast as a SAP upgrade. These costs are now being treated as operational expenditure to conform with the accounting standards for software as a service implementation.

- Enhancements to Existing Systems
  We have provided for additional licence, software maintenance and system support expenditure for existing systems to support improvements to information disclosure, customer

service, staff and public safety, and network reliability and performance that were not included in the 2023 AMP.

- *Cyber Security*
  Cyber security service providers continue to develop and introduce new products and capabilities to combat the ever-developing threat from malicious actors. We are planning to add many of these new products and capabilities, which were not provided for in the 2023 AMP.
- *New Systems*
  We have provided substantial additional licence, software maintenance and system support costs for new systems that were not provided for in the 2023 AMP.

6 Other Disclosures

6.1 Introduction

On 25 November 2022 the Commerce Commission issued its *Final Decision Paper – Tranche 1 of its Targeted Information Disclosure Review – Electricity Distribution Businesses.* This required narrative information on identified business processes to be uploaded onto our website by 30 June 2023. As this information was not covered by the director certification requirements that normally apply to regulatory information disclosures, it imposed an additional requirement that the information be certified by 31 March 2024. This could be done either by including the information in the AMP or in a separate director-certified document. We have chosen to include the information in this AMP Update.

We have updated and expanded on the information uploaded to our website in June 2023 and this updated information is provided below.

6.2 Notice of Planned and Unplanned Interruptions

6.2.1 Planned Interruptions

Planned outages are scheduled in advance and uploaded into the Outage Management System (OMS) module of our Advanced Distribution Management System (ADMS) by our network controllers. The OMS automatically displays upcoming planned outages on a map on our website, https://outages.topenergy.co.nz (note the tab for planned outages), as well as in Top Energy's Outage App which can be uploaded from the Google Play or Apple Stores. This map draws polygons around affected outages and users can click on these for additional information.

The OMS also generates a text or email to advise affected customers of the upcoming planned interruptions, where we have the relevant contact details. This message includes a link to the outage details on our website and a facility where users can opt in to receive further notifications of any changes in the status of the interruption. We are currently working on extending this facility to include notifying affected customers by mail where we do not have text or email contact information. Retailers are also notified of all planned outages through a dedicated business-to-business communication link.

We endeavour to give at least ten days' notice of a planned interruption but there are times when this is not possible – for example when an urgent safety issue is identified or where a permanent repair is required after a temporary repair has been made following a fault.

For small outages our contractors also drop cards advising of the outage into the letterboxes of affected consumers. For larger outages where a letterbox drop is not practical, Top Energy advertises the supply interruption using radio, social media and newspapers.

6.2.2 Unplanned Interruptions

We first become aware of an unplanned interruption when:

- The interruption is caused by the operation of a remotely monitored protection device. This will automatically log the interruption in the OMS; or
- A customer phones our call centre to advise a loss of power. The call centre advises our control room of the interruption, which is then manually entered into the OMS. The interruption is assumed to start at the time the first call is logged by the call centre.

The OMS has access to the connectivity of the network and can trace the affected consumers. It automatically records the extent of the fault on the active outages tab of Top Energy's outage website, which is updated in real time as more reports are received on the extent of the fault, or power is restored to consumers not directly affected through network reconfiguration.

The following information can be accessed from the active outages tab on Top Energy's outage website:

- The location and extent of the fault. The website displays a polygon around the location of affected consumers on a map of our supply area.
- The affected feeder and roads.
- The time the fault was reported.
- The cause of the fault (when known).
- The expected restoration time (when known).

Users can subscribe to be notified of outages by registering the address or ICP number of their point of supply. Subscribed users will automatically get notified by text or email of outages that affect their registered supply point and will also be notified when supply has been restored.

6.3 Voltage Quality

6.3.1 Monitoring of Low Voltage Quality

We now have approximately 60 data loggers installed on the low voltage circuits of selected distribution transformers. These transformers supply large commercial and industrial precincts, hospitals, certain high density housing developments and loads with a high density of behind-the-meter solar generation installed. The data loggers have online visibility on our intranet and historic data is stored to the cloud. They help us establish typical demand profiles and provide us with a better understanding of the performance of the network.

We may also install a data logger to monitor the quality of the low voltage network in response to a call from a consumer concerning a high or low voltage supply, or in response to a concern raised following a preventive maintenance inspection.

We are also negotiating with retailers and metering service providers to get access to their smart meter data, and, if these negotiations are successful, we plan to trial the Gridsight low voltage visibility and hosting capacity software platform, as discussed in Sections 5.10 and 8.3 of our 2023 AMP. Over time, we expect that this initiative will give us much greater visibility of the performance of the low voltage network and enable us to proactively identify issues that we expect to emerge as the penetration of small-scale solar generation and the use of the network for EV charging both increase.

https://topenergy.co.nz/assets/Top-Energy-2023-AMP-Final-signed.pdf

6.3.2 Low Voltage Data Capture Project

As noted in Section 8.3 of our 2023 AMP we have embarked on our low voltage data capture project. Funds have been allocated for this in our expenditure forecast, and it is envisaged the project will run through to FYE2027. The project involves experienced personnel physically inspecting every LV asset to ensure that the asset is accurately recorded in our GIS and asset maintenance database, and confirm its connectivity. The inspectors will also identify assets requiring maintenance, potential voltage non-compliances and overloads, and will raise defects to rectify these issues.

On completion of this project, we expect to have an accurate record of all our LV assets and their connectivity. This will extend the functionality of our ADMS and enable the Gridsight software platform to be extended across the whole network. We also expect the project to identify parts of the LV network where localised voltage compliance or overload issues could emerge as the penetration of behind-the-meter solar generation increases and at-home EV charging also increases.

6.3.3 Response to Identified Voltage Quality Issues

When a consumer calls the call centre and reports a power quality concern, the control room is notified. It assesses the concern and, if the nature and urgency of the issue warrants it, dispatches a fault person to investigate. If dispatching a fault person is not an appropriate response, or if the fault person investigates and is unable to rectify the issue, the concern is treated as a complaint and escalated to our network planning or maintenance section for investigation and action.

Voltage quality issues that are identified via internal inspection processes or by our contracting personnel also get escalated to either the maintenance or planning departments for investigation and rectification.

6.3.4 Consumer Communication

As customer-initiated voltage quality issues are treated as complaints, they are managed in accordance with the complaints process described in Section 6.5.2. The issue is recorded in Salesforce and monitored by the Executive Assistant through to completion. All communications to and from a customer get recorded in Salesforce. Further enhancements to Salesforce and communication protocols with customers are ongoing.

If resolution of the voltage quality issue involves a planned interruption, the notification process described in Section 6.3.1 would apply.

6.4 New Connections and Connection Alterations

6.4.1 Planning and Management of New and Altered Connections

All applicants for new and altered connections must complete the application form on Top Energy's website and pay the standard application fee.

For a simple connection, a quote is provided, generally within ten working days following receipt of the application fee. Once the quote is accepted and paid, an ICP number is allocated to the connection. Top Energy will install a meter and connect the installation within ten working days of being advised by the applicant's electricity retailer that the new installation is complete and ready for inspection and connection to the network.

For a more complex connection, where design is required to meet the applicant's requirements, more time is usually needed but indicative timeframes will be advised to the applicant once the application is accepted and before work commences. Once all design and construction is complete and the installation is ready for connection, the applicant must request its electricity retailer to arrange the network connection. The retailer then sends a request to Top Energy to inspect the installation, install a meter and connect it to the network.

Refer to Top Energy's website for more detailed information on the management of new connections.

https://toenergy.co.nz/i-want-to/get-connected

The process for managing alterations to existing connections is similar to the new connection process. Applicants must complete the same application form and pay the standard application fee.

Salesforce is used to manage the connection process from application to completion.

Top Energy conducts bimonthly surveys of applicants seeking connection to the network, to monitor their satisfaction with the connection process. This is in addition to our annual surveys that monitor consumer satisfaction with the services that we provide.

6.4.2 Costs

Where a suitable connection point is available at the applicant's boundary, new connections of up to 63 amps are priced on a fixed fee schedule, based on the number of phases required. The fee includes a capacity charge for the use of the capacity within the distribution transformer asset supplying the connection, an inspection fee, and a connection fee. Where a suitable connection is not available at the boundary, the applicant will also be required to pay a capital contribution to cover the cost of extending the network to provide a suitable connection point at the boundary. This will be charged to the applicant at cost.

Larger connections are individually priced and will include a capacity charge and, in most cases, a capital contribution. The capacity charge covers the use of existing network capacity, and the capital contribution covers the cost of providing any new capacity or network extension required to meet the applicant's requirements. The capacity charge is based on the applicant's requested maximum demand at the new connection point, and the capital contribution is based on the actual cost of the network extension or upgrade required.

The capacity charge is non-refundable but part of the capital contribution, calculated on a pro-rata basis, is refundable should a new customer connect to the network extension funded by a capital contribution within five years of the original payment being made.

We use standardised equipment and look for the most cost-effective designs for complex connections. Standardisation helps reduce costs and ensures consistent pricing.

Refer to Top Energy's Capital Contribution Guide for more information on capacity charges and capital contributions.

https://topenergy.co.nz/tell-me-about/the-network/capital-contributions

6.4.3 Communication

All communications with a connection applicant are recorded in Salesforce, Top Energy's work management software tool, which is regularly monitored for timely responses. Further enhancements to Salesforce and communication protocols with customers are ongoing.

6.4.4 Timeframes

As noted in Section 6.4.1 above, for simple connection applications where a connection point is already available at the applicant's boundary, Top Energy will provide a quote within ten working days and will endeavour to connect the installation within ten days of being advised by the applicant's retailer that the installation is complete and ready for inspection and connection.

More complex connections will take longer, depending on resource availability, the complexity of the design and the extent of any construction work required. Top Energy will provide applicants with indicative timeframes early in the process and will keep them updated as the application progresses. Procurement and shipping delays, adverse weather and the availability of contracting resources can all delay the completion of connection projects.

6.5 Customer Service

6.5.1 Customer Engagement

Every October we engage an external company to phone 350 customers across the Top Energy network.

We ask customer satisfaction questions around:

- Value for money.
- Reliability of service.
- Image and reputation.
- Communication.
- Price vs quality.

Every second month we also survey customers who have contacted us to connect to the network or report a fault.

We ask them to rate us on:

- Customer satisfaction.
- Net promoter score.
- Customer effort score.

6.5.2 Complaint Resolution

When a customer displays any dissatisfaction or concern about a service or goods provided by Top Energy, this is treated as a complaint and must be escalated to the Executive Assistant, who is responsible for managing our complaints resolution process. The person escalating the complaint must provide as much information as possible including:

- Date of complaint.
- ICP number (if possible).
- Street address.
- Contact details including phone number and email address.
- Customer / invoice number (if relevant).
- Details of the complaint.
- Desired outcome (if requested).

The EA will ensure that the complaint is acknowledged with the customer by phone or email (depending on their initial contact) and ensures a complaint case is raised in Salesforce. The customer is advised that, if for any reason we can't agree on a solution, they can contact Utilities Disputes on 0800 22 33 40, which is a free service that resolves complaints about utility providers.

The EA then investigates the complaint and tries to reach a resolution with the customer within 20 working days (within Utilities Disputes guidelines). If no resolution is reached within that time and more time is required for further investigation, we advise the customer an extension of a further 20 working days is required.

If no resolution can be reached, the customer is reminded of their right to contact Utilities Disputes.

All correspondence, including call records, is recorded in the Salesforce case.

6.6 Impact of New Connections on Network Operations or Asset Management Priorities

6.6.1 Demand

We monitor the impact of new demand at two levels. At a macro level, we look at the historic growth in demand at different points on the network and assess both the drivers of this demand and the extent to which these drivers are likely to be sustained moving forward. We also assess the impact of changing economic trends, such as decarbonisation of the economy and the electrification of the transport fleet, on the demand for electricity. We also regularly engage with external stakeholders associated with the economic development of our supply area, who provide a broad perspective on where growth might occur and what form it might take. For example, the Far North District Council can provide information on district plans, population growth, building consents, etc. This information is used to develop the load forecast in our AMP, which in turn underpins the network capacity expansion capital expenditure forecast in our AMP.

At the micro level we assess the impact of every new connection on the network supplying the proposed connection point to ensure the network has sufficient capacity to supply the new load. We look at the capacity of the distribution transformer to determine whether this needs to be uprated. If a network extension or capacity expansion is required, then this will need to be resourced and built into our work programme. This work also requires close coordination between our customer works team and network planning team, particularly where the connection application is complex.

Impact of Uncertainty

Over the last ten years Top Energy has invested heavily in increasing the resilience and capacity of its 33kV subtransmission network. The final phase of this programme is the new 110/33kV Wiroa substation, where construction is due to commence in FYE2026. When this project is complete the existing subtransmission network will have sufficient capacity to accommodate all realistic high demand growth scenarios through to 2040 and beyond,

Increases in demand may well require the localised capacity of the 11kV distribution network to be increased. Should the 11kV capacity shortfall be caused by the installation of the new block load any network augmentation required to meet the new demand would be funded by the developer in accordance with our capital contributions policy. We think that there is sufficient spare capacity in the 11kV network to meet organic load growth due to an aggregation of small new connections and additional demand from existing connections from, for example, EV charging until the second half of the planning period when there is provision in our capital expenditure forecast for 11kV network capacity augmentation.

6.6.2 Generation

Again, we need to distinguish between utility scale generation and small-scale behind-the-meter solar, given that it is likely that three solar generation plants with a combined capacity of 67MW will connect to the network by FYE2026. We look at each large generation project individually to establish:

- Whether the existing network has sufficient capacity to carry the load.
- The assets required to connect the proposed generation site to our network.
- Potential interaction between generators and the possibility of adverse impacts on the quality of the supply we provide consumers. We have engaged an external consultant to study the interactions between the three northern solar farms.
- The impact of the new generation on the harmonic levels within the network and their compliance with the relevant industry standards. This is a significant issue for large solar farms, which generate at direct current (DC) and require electronic inverters to convert this to the alternating current (AC) required by the network.
- The behaviour of the generation under fault or overload conditions and whether special operating conditions are required to manage this. The three solar plants will be required to disconnect from the network if the 110kV Kaikohe-Kaitaia circuit is out of service, and may be required to reduce their generation output if one of Transpower's two Kaikohe-Maungatapere circuits is out of service.
- The impact of the generation on the management of the network and the real time operation of the network by our control room staff. This includes ensuring that the control room has visibility of both the output of the generators and its impact on the network, and also that control room staff are appropriately trained and standard operating procedures are developed.

All applications for installation of new small-scale solar generation are assessed for their impact on the low voltage circuit to which they will be connected. We limit export to the grid to 5kW per installation. In recent times about 90% of the applications we have received have included associated battery storage, so the 5kW export limit has not significantly constrained the connection of larger installations. We have found that management of installed small-scale behind-the-meter solar generation has not been a major problem, although occasionally we have had to change the tap on a distribution transformer in response to an overvoltage complaint.

We have published on our website our Distributed Generation Connection Standard and Connection Management Standard. The website also notes that only inverters approved by the Clean Energy Council are permitted to connect to our network.

https://topenergy.co.nz/i-want-to/get-connected/distributed-generation-solar

Impact of Uncertainty

There is no spare capacity in the 110kV Kaikohe-Kaitaia circuit or the Transpower 110kV double circuit grid connection to accommodate additional utility scale generation and so we are unable to accept any new applications for connection of generation over 100kW in our northern area unless network upgrades are financially supported by the applicant or significant operating constraints are accepted.

When the anticipated new generation is connected, the N-1 capacity of the two Kaikohe-Maungatapere circuits will be exceeded during the daytime over summer. This constraint can be relieved by installing a runback scheme, which will allow both circuits to be fully utilised at the same time. Following the loss of one of the two circuits, the runback scheme will automatically reduce generation output, so the capacity of the second circuit is not exceeded. Incremental costs associated with the installation of the runback scheme will need to be covered by the newly connected and applying parties as part of their connection costs.

It is therefore strongly recommended that all parties considering installing distributed generation over 100kW engage in discussions with Top Energy.

This information is published on our website.

https://topenergy.co.nz/assets/Export-Congestion-Website-Jan-2024.pdf

The management of high levels of solar generation on low voltage circuits has been a problem in Australia and given that the penetration of small-scale solar generation in our supply area is higher than that of any other New Zealand EDB, this is likely to be an issue that we will need to address before most other New Zealand EDBs. We know where the solar generation is located as we maintain a heat map that tracks all known solar installations as applications are submitted and approved (See Figure 2.2). We also conduct targeted data logging on the low voltage side of distribution transformers that supply circuits with high levels of solar penetration.

As noted in Section 6.3, we are negotiating with retailers for access to smart meter data to give us much better visibility of the behaviour of our low voltage networks. We are also investigating potential benefits of developing standard low voltage circuit designs so that the behaviour of our low voltage system under different loading conditions can become more predictable.

6.6.3 Storage Capacity

We do not record the amount of battery storage capacity associated with small-scale solar generation. As noted above in Section 6.6.2, the amount of battery storage associated with small-scale solar installations dispersed across the network is increasing. This has had a positive impact as it has allowed installation of larger units without overloading the low voltage circuits.

On a larger scale, we are currently assisting a third party connect a 280kVA/80kWh battery energy storage system at our Taipa substation as a pilot project. The battery will be used for peak shaving and monitored from our control room, and the impact of this mode of operation on both our network and the battery itself will be assessed. Unfortunately, commissioning of this project has been delayed due to bad weather and design issues.

Impact of Uncertainty

As the penetration of battery storage increases and we gain more visibility of low voltage circuit behaviour, we may be able to compare the performance of circuits with similar levels of connected solar generation but different amounts of connected battery storage. This should allow us to better assess, and perhaps even quantify, the impact of battery storage on low voltage circuit behaviour.

6.7 Innovation

We are currently focused on improving the effectiveness of our asset management practices by increasing the completeness, accuracy, level of detail and accessibility of the information we have on our asset base. To this end we are trialling recently developed software packages, including DataFrame to improve the integrity of our asset data, and Gridsight to increase our visibility of the performance of our low voltage assets. We are also developing condition-based asset risk management models of our line and HV distribution switchgear assets to provide a more robust basis for identifying the optimum level of expenditure on asset renewal.

Furthermore, we are extending the functionality of our existing software by integrating our geographic information system and network load flow model to provide accurate model updates to enable improved network planning. We are also enabling our ADMS to model load flows within the network in real time to provide a tool that will allow our controllers to quantify the impact of different network reconfigurations in response to a contingency.

In the field, we are engaged in trials of smart fault passage indicators and battery energy storage systems. We are also exploring sophisticated protection systems that can isolate faults quickly and safely and pinpoint their location. This will reduce the number of customers impacted by a fault on the network and enable automatic recovery from faults and restoration of power more quickly.

The success of any trial we undertake is assessed against criteria that we identify at the start of the trial. As we aim to mitigate the risks of implementing new technology by being a fast follower rather than a leader, we also ensure that our assessment is consistent with outcomes achieved by other EDBs before the widespread implementation of any new technology.

We are actively involved with industry groups such as the Electricity Networks Association (ENA), the Electricity Engineers’ Association (EEA), WorkSafe New Zealand, and the Business Health and Safety Forum to better understand our regulatory and legislative environment and work collaboratively towards the achievement of shared objectives. We engage with other lines companies and digital technology providers where this helps us better serve our consumers, with better response times, power quality and network resilience.

9 Appendices

Appendix A – Asset Management Plan Schedules:

Schedule 11a	CAPEX Forecast
Schedule 11b	OPEX Forecast
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 2024 – 31 March 2034

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			FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029	FYE2030	FYE2031	FYE2032	FYE2033	FYE2034
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	5,527	3,427	3,295	2,590	2,713	2,767	2,822	2,879	2,936	2,995	3,055
11		System growth	195	752	4,469	4,769	5,123	2,552	625	4,553	6,076	6,914	6,353
12		Asset replacement and renewal	11,021	10,529	13,263	13,675	12,645	15,707	14,521	9,234	10,467	9,576	10,406
13		Asset relocations	-	-	-		-	-	-	-	-	-	-
14		Reliability, safety and environment:											
15		Quality of supply	5,215	7,253	3,549	3,118	3,513	3,747	5,807	8,208	6,992	6,395	6,583
16		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	962	8,665	2,142	-	-	-	-	-	-	-	-
18		**Total reliability, safety and environment**	6,177	15,918	5,691	3,118	3,513	3,747	5,807	8,208	6,992	6,395	6,583
19		**Expenditure on network assets**	22,920	30,626	26,718	24,152	23,994	24,773	23,775	24,874	26,471	25,880	26,397
20		**Expenditure on non-network assets**	1,200	3,047	2,198	2,014	2,307	2,020	2,028	2,068	2,109	2,152	2,195
21		**Expenditure on assets**	24,120	33,673	28,916	26,166	26,301	26,793	25,803	26,942	28,580	28,032	28,592
22													
23	*plus*	Cost of financing	100	500	200	100	250	350	350	100	100	100	100
24	*less*	Value of capital contributions	3,500	3,001	2,813	2,099	2,141	2,184	2,227	2,272	2,317	2,364	2,411
25	*plus*	Value of vested assets											
26													
27		**Capital expenditure forecast**	20,720	31,172	26,303	24,167	24,410	24,959	23,925	24,770	26,363	25,768	26,281
28													
29		Assets commissioned	19,917	22,599	34,159	19,590	32,137	20,177	28,845	17,550	22,589	25,998	21,814

sch ref												
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	5,527	3,427	3,076	2,370	2,434	2,434	2,434	2,434	2,434	2,434	2,434
34	System growth	195	752	4,172	4,365	4,597	2,245	539	3,850	5,037	5,619	5,062
35	Asset replacement and renewal	11,021	10,529	12,382	12,515	11,346	13,817	12,524	7,808	8,677	7,782	8,291
36	Asset relocations	-	-	-	-	-	-					
37	Reliability, safety and environment:											
38	Quality of supply	5,215	7,253	3,313	2,854	3,152	3,296	5,008	6,940	5,796	5,197	5,245
39	Legislative and regulatory	-	-	-	-	-	-					
40	Other reliability, safety and environment	962	8,665	2,000	-	-	-					
41	**Total reliability, safety and environment**	6,177	15,918	5,313	2,854	3,152	3,296	5,008	6,940	5,796	5,197	5,245
42	**Expenditure on network assets**	22,920	30,626	24,943	22,104	21,529	21,792	20,505	21,032	21,944	21,032	21,032
43	Expenditure on non-network assets	1,200	2,958	2,072	1,861	2,090	1,794	1,766	1,766	1,766	1,766	1,766
44	**Expenditure on assets**	24,120	33,584	27,014	23,965	23,619	23,586	22,270	22,797	23,710	22,798	22,798
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 2024 – 31 March 2034**

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		FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029	FYE2030	FYE2031	FYE2032	FYE2033	FYE2034
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	-	-	219	220	279	333	388	445	502	561	621
57	System growth	-	-	297	404	526	307	86	703	1,039	1,295	1,291
58	Asset replacement and renewal	-	-	881	1,160	1,299	1,890	1,997	1,426	1,790	1,794	2,115
59	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
60	Reliability, safety and environment:											
61	Quality of supply	-	-	236	264	361	451	799	1,268	1,196	1,198	1,338
62	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
63	Other reliability, safety and environment	-	-	142	-	-	-	-	-	-	-	-
64	**Total reliability, safety and environment**	-	-	378	264	361	451	799	1,268	1,196	1,198	1,338
65	**Expenditure on network assets**	-	-	1,775	2,048	2,465	2,981	3,270	3,842	4,527	4,848	5,365
66	Expenditure on non-network assets	-	89	126	153	217	226	262	302	344	386	429
67	**Expenditure on assets**	-	89	1,901	2,200	2,682	3,206	3,532	4,145	4,871	5,234	5,794
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*
74		**11a(ii): Consumer Connection**						
75		*Consumer types defined by EDB**	**$000 (in constant prices)**					
76		Utility scale solar	1,840	3,000	706			
77		Other	3,687	427	2,370	2,370	2,434	2,434
78		[EDB consumer type]						
79		[EDB consumer type]						
80		[EDB consumer type]						
81		**include additional rows if needed*						
82		**Consumer connection expenditure**	5,527	3,427	3,076	2,370	2,434	2,434
83	*less*	Capital contributions funding consumer connection	723	514	461	356	365	365
84		**Consumer connection less capital contributions**	4,804	2,913	2,615	2,015	2,069	2,069
85		**11a(iii): System Growth**						
86		Subtransmission						
87		Zone substations			4,172	4,365	4,597	2,245
88		Distribution and LV lines	195	752				
89		Distribution and LV cables						
90		Distribution substations and transformers						
91		Distribution switchgear						
92		Other network assets						
93		**System growth expenditure**	195	752	4,172	4,365	4,597	2,245
94	*less*	Capital contributions funding system growth						
95		**System growth less capital contributions**	195	752	4,172	4,365	4,597	2,245
96								

Company Name	**Top Energy**
AMP Planning Period	**1 April 2024 – 31 March 2034**

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		FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029	FYE2030	FYE2031	FYE2032	FYE2033	FYE2034
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	2,808	1,877	2,037	3,132	2,442	2,187					
101	Zone substations		660			829	3,092					
102	Distribution and LV lines	6,175	5,653	7,763	7,690	6,398	6,428					
103	Distribution and LV cables	150	134	133	138	141	141					
104	Distribution substations and transformers	970	830	634	650	632	663					
105	Distribution switchgear	882	906	766	782	791	789					
106	Other network assets	36	469	1,049	123	113	517					
107	**Asset replacement and renewal expenditure**	11,021	10,529	12,382	12,515	11,346	13,817					
108	*less* Capital contributions funding asset replacement and renewal											
109	**Asset replacement and renewal less capital contributions**	11,021	10,529	12,382	12,515	11,346	13,817					
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	1,075	1,627	603	829	860	901					
131	Interconnections	2,076	2,533	1,201	686	705	1,311					
132	Improved communication systems	372	727	184	346	713	644					
133	Remote controlled switches and smart devices			359	221	145						
	KTA 11kV injection point	341	833									
	Substation protection upgrades	181	293									
	Low voltage data capture	346	350									
134	110kV line property rights	428										
135	**include additional rows if needed*											
136	All other projects or programmes - quality of supply	396	890	966	772	729	440					
137	**Quality of supply expenditure**	5,215	7,253	3,313	2,854	3,152	3,296					
138	*less* Capital contributions funding quality of supply											
139	**Quality of supply less capital contributions**	5,215	7,253	3,313	2,854	3,152	3,296					
140												

Company Name	**Top Energy**
AMP Planning Period	**1 April 2024 – 31 March 2034**

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		FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029	FYE2030	FYE2031	FYE2032	FYE2033	FYE2034
141		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*					
142												

143 11a(vii): Legislative and Regulatory

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
144	*Project or programme**	**$000 (in constant prices)**					
145	[Description of material project or programme]						
146	[Description of material project or programme]						
147	[Description of material project or programme]						
148	[Description of material project or programme]						
149	[Description of material project or programme]						
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

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
158	*Project or programme**	**$000 (in constant prices)**					
159	Backup Ngawha generator transformer	962	8,665	2,000			
160	[Description of material project or programme]						
161	[Description of material project or programme]						
162	[Description of material project or programme]						
163	[Description of material project or programme]						
164	**include additional rows if needed*						
165	All other projects or programmes - other reliability, safety and environment						
166	**Other reliability, safety and environment expenditure**	962	8,665	2,000	-	-	-
167	*less* Capital contributions funding other reliability, safety and environment						
168	**Other reliability, safety and environment less capital contributions**	962	8,665	2,000	-	-	-
169							
170		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
171							

172 11a(ix): Non-Network Assets

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
173	**Routine expenditure**						
174	*Project or programme**	**$000 (in constant prices)**					
175	General	686	568	482	863	313	404
176	Software	514	317	760	393	273	542
177	Hardware		393	217	143	145	271
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**	1,200	1,278	1,459	1,399	731	1,217
183	**Atypical expenditure**						
184	*Project or programme**						
185	Replace 3PAR Switches		777				
186	Zone Tx Dryout System		107				
	Covered storage at Substation		194				
	Building Improvements		602				
	GIS				462		
187	ADMS DERMS					1,359	
188	Harware SAN						577
189	Hardware Data Centre			613			
190	**include additional rows if needed*						
191	All other projects or programmes - atypical expenditure						

Company Name	**Top Energy**
AMP Planning Period	**1 April 2024 – 31 March 2034**

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		FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029	FYE2030	FYE2031	FYE2032	FYE2033	FYE2034
192	**Atypical expenditure**	-	1,680	613	462	1,359	577					
193												
194	**Expenditure on non-network assets**	1,200	2,958	2,072	1,861	2,090	1,794					

Schedule 11b – Opex Forecast

	Company Name	**Top Energy**
	AMP Planning Period	**1 April 2024 – 31 March 2034**

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			FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029	FYE2030	FYE2031	FYE2032	FYE2033	FYE2034
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		1,781	1,562	2,157	2,244	2,334	2,429	2,527	2,629	2,735	2,846	2,961
11	Vegetation management		2,238	2,713	3,002	3,123	3,249	3,381	3,517	3,659	3,807	3,961	4,121
12	Routine and corrective maintenance and inspection		2,197	2,667	2,816	2,930	3,048	3,172	3,300	3,433	3,572	3,716	3,866
13	Asset replacement and renewal		1,647	2,069	2,201	2,274	2,349	2,427	2,508	2,591	2,678	2,768	2,861
14	**Network Opex**		7,863	9,011	10,176	10,571	10,980	11,409	11,852	12,312	12,792	13,291	13,809
15	System operations and network support		7,691	9,012	9,405	9,634	10,086	10,416	10,690	10,904	11,122	11,344	11,571
16	Business support		7,800	9,826	10,561	10,783	10,964	11,372	11,463	11,692	11,926	12,164	12,407
17	Non-network solutions provided by a related party or third party	*Not Required before DY2025*											
18	**Non-network opex**		15,491	18,838	19,966	20,417	21,050	21,788	22,153	22,596	23,048	23,508	23,978
19	**Operational expenditure**		23,354	27,849	30,142	30,988	32,030	33,197	34,005	34,908	35,840	36,799	37,787
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		1,781	1,488	1,994	2,034	2,075	2,116	2,158	2,202	2,246	2,291	2,336
24	Vegetation management		2,238	2,584	2,776	2,831	2,888	2,946	3,004	3,065	3,126	3,188	3,252
25	Routine and corrective maintenance and inspection		2,197	2,540	2,604	2,656	2,709	2,763	2,819	2,875	2,933	2,991	3,051
26	Asset replacement and renewal		1,647	1,970	2,035	2,061	2,088	2,115	2,142	2,170	2,199	2,228	2,258
27	**Network Opex**		7,863	8,582	9,409	9,583	9,759	9,940	10,124	10,311	10,503	10,698	10,897
28	System operations and network support		7,691	8,202	8,568	8,554	8,756	8,824	8,826	8,826	8,826	8,826	8,826
29	Business support		7,800	9,344	9,632	9,564	9,445	9,547	9,325	9,325	9,325	9,325	9,325
30	Non-network solutions provided by a related party or third party	*Not Required before DY2025*											
31	**Non-network opex**		15,491	17,546	18,201	18,118	18,201	18,371	18,151	18,151	18,151	18,151	18,151
32	**Operational expenditure**		23,354	26,127	27,610	27,701	27,960	28,311	28,275	28,462	28,654	28,849	29,048
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		760	986	1,085	1,139	1,196	1,256	1,319	1,385	1,454	1,527	1,603
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		-	74	163	210	259	313	369	427	489	555	625
47	Vegetation management		-	129	226	292	361	435	513	594	681	773	869
48	Routine and corrective maintenance and inspection		-	127	212	274	339	409	481	558	639	725	815
49	Asset replacement and renewal		-	99	166	213	261	312	366	421	479	540	603
50	**Network Opex**		-	429	767	988	1,221	1,469	1,728	2,001	2,289	2,593	2,912
51	System operations and network support		-	810	837	1,080	1,330	1,592	1,864	2,078	2,296	2,518	2,745
52	Business support		-	482	929	1,219	1,519	1,825	2,138	2,367	2,601	2,839	3,082
53	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
54	**Non-network opex**		-	1,292	1,765	2,299	2,849	3,417	4,002	4,445	4,897	5,357	5,827
55	**Operational expenditure**		-	1,722	2,532	3,287	4,070	4,886	5,730	6,446	7,186	7,950	8,739
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 2024 – 31 March 2034**

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.	0.05%	2.13%	5.56%	84.19%	3.23%	4.84%	4	1.40%
11	All	Overhead Line	Wood poles	No.	0.51%	11.93%	66.87%	16.18%	1.45%	3.07%	4	34.00%
12	All	Overhead Line	Other pole types	No.	-	-	-	28.57%	35.71%	35.71%	4	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1.62%	25.29%	29.93%	10.21%	22.74%	10.21%	2	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	8.33%	-	66.67%	25.00%	2	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	5.45%	94.55%	-	2	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	-	35.00%	65.00%	-	4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	66.67%	-	33.33%	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.	-	-	13.33%	60.00%	13.33%	13.34%	4	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	-	51.15%	41.95%	6.90%	4	-
30	HV	Zone substation switchgear	33kV RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	18.18%	-	9.09%	63.64%	9.09%	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	53.52%	46.48%	-	4	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	14.29%	-	31.43%	31.43%	22.86%	4	-
35												

Company Name	**Top Energy**
AMP Planning Period	**1 April 2024 – 31 March 2034**

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	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
36					**Asset condition at start of planning period (percentage of units by grade)**							
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	1.92%	15.38%	46.15%	15.38%	21.15%	4	3.80%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	10.48%	31.07%	24.06%	26.28%	6.53%	1.58%	2	1.50%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
42	HV	Distribution Line	SWER conductor	km	34.76%	22.51%	15.62%	16.86%	10.12%	0.14%	2	9.40%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.25%	3.06%	7.41%	47.46%	30.17%	11.65%	2	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	11.73%	24.80%	48.00%	3.47%	12.00%	2	-
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	66.67%	-	16.67%	16.67%	-	2	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	0.59%	-	2.95%	75.52%	2.95%	17.99%	4	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	7.87%	11.53%	13.91%	24.05%	21.75%	20.88%	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.	-	-	1.72%	75.54%	17.60%	5.15%	4	6.40%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.06%	0.55%	4.57%	88.06%	2.01%	4.76%	4	1.50%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	0.11%	1.11%	88.99%	1.67%	8.12%	4	1.40%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	6.06%	60.61%	30.30%	3.03%	4	4.80%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	5.56%	16.67%	5.56%	72.22%	1	27.00%
55	LV	LV Line	LV OH Conductor	km	10.89%	38.14%	24.32%	19.99%	6.37%	0.29%	2	-
56	LV	LV Cable	LV UG Cable	km	7.08%	16.86%	21.62%	34.63%	18.76%	1.05%	2	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	3.06%	20.91%	26.85%	44.95%	3.86%	0.37%	2	-
58	LV	Connections	OH/UG consumer service connections	No.	0.03%	0.35%	11.93%	74.12%	4.37%	9.20%	2	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	47.35%	-	-	17.96%	28.16%	6.53%	1	8.60%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	100.00%	-	-	1	5.80%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	68.29%	29.27%	2.44%	-	4	-
62	All	Load Control	Centralised plant	Lot	-	-	-	7.14%	7.14%	85.71%	2	-
63	All	Load Control	Relays	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
64	All	Civils	Cable Tunnels	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Schedule 12b – Capacity Forecast

Top Energy
1 April 2024 – 31 March 2034

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)	Installed firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
8			*Not Required after DY2024*	*Not Required after DY2024*	*Not Required after DY2024*	*Not Required after DY2024*	*Not Required after DY2024*	*Not Required after DY2024*	*Not Required after DY2024*	
9	Kaikohe	10	17	N-1	1	58%	17	61%	No constraint within +5 years	
10	Kawakawa	5	6	N-1	3	80%	6	91%	No constraint within +5 years	
11	Moerewa	3	5	N-1	3	68%	5	68%	No constraint within +5 years	
12	Waipapa	11	23	N-1	8	46%	23	61%	No constraint within +5 years	
13	Omanaia	3	-	N-0	2	-	-	-	Transformer	Transfer capacity includes 2MVA of onsite generation. Mobile transformer is available if needed.
14	Haruru	8	23	N-1	2	35%	23	35%	No constraint within +5 years	
15	Mt Pokaka	3	-	N-0	2	-	-	-	Transformer	Mobile transformer available if needed. Sufficient transfer capacity available to supply all small use consumers.
16	Kerikeri	8	23	N-1	6	36%	23	46%	No constraint within +5 years	
17	Kaeo	4	-	N-0	4	-	-	-	Subtransmission circuit	
18	Okahu Rd	10	12	N-1	4	83%	12	64%	No constraint within +5 years	1.5MVA to be transferred to Kaitaia transmission substation by winter FYE2026
19	Taipa	6	-	N-0	3	-	-	-	Subtransmission circuit	The transfer of the mobile substation to Taipa on a permanent basis has mitigated the exisitng transformer constraint and a larger transformer is plaaned to be installed by FYE2030. However the substation still has only one incoming transfmission circuit.
20	NPL	10	23	N-1	4	43%	23	43%	No constraint within +5 years	
21	Pukenui	2	-	N-0	2	-	-	-	Transformer	Transfer capacity includes onsite diesel generation. Mobile transformer available. A 3/5MVA transformer is planned for installation by FYE2030.
22	Kaikohe 110kV	48	39	N-1	25	123%	39	77%	No constraint within +5 years	The 25MVA of transfer capacity is from OEC1-3 at Ngawha power station, which bypass the transformers and inject power into the 33kV busbar. Approximately 27 MVA of the Kaikohe 110kV peak demand will be transferred to Wiroa when the 110/33kV Wiroa substation is commissioned. This is now expected by FYE2028.
23	Kaitaia 110kV	26	-	N-0	16	-	-	-	Subtransmission circuit	Transfer capacity is diesel generation in northern area. The installation of utility scale solar generation will fully utilise the 40/60MVA transformer should the smaller transformer fail. Approximately 1.5MVA of 11kV load will be supplied from this substation by FYE2026.
24	Wiroa 110kV	-	-	-	-	-	60	50%	No constraint within +5 years	New substation. 60MVA firm capacity from FYE2029.
25	[Zone Substation_17]					-			[Select one]	
26	[Zone Substation_18]					-			[Select one]	
27	[Zone Substation_19]					-			[Select one]	
28	[Zone Substation_20]					-			[Select one]	

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 2024 – 31 March 2034**

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*
	FYE2024	**FYE2025**	**FYE2026**	**FYE2027**	**FYE2028**	**FYE2029**
*Consumer types defined by EDB**						
Residential	340	360	370	380	390	400
Commercial	35	50	55	60	65	70
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
Connections total	375	410	425	440	455	470

**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	300	305	310	315	320	325
Capacity of distributed generation installed in year (MVA)	26	22	26	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	20	21	23	24	26	27
plus Distributed generation output at HV and above	57	57	57	57	57	57
Maximum coincident system demand	77	78	80	81	83	84
less Net transfers to (from) other EDBs at HV and above						
Demand on system for supply to consumers' connection points	77	78	80	81	83	84
Electricity volumes carried (GWh)						
Electricity supplied from GXPs	10	10	13	15	17	18
less Electricity exports to GXPs	124	157	211	216	220	222
plus Electricity supplied from distributed generation	483	516	570	575	580	585
less Net electricity supplied to (from) other EDBs						
Electricity entering system for supply to ICPs	369	369	372	374	377	381
less Total energy delivered to ICPs	331	332	334	336	338	340
Losses	38	37	38	38	39	41
Load factor	55%	54%	53%	53%	52%	52%
Loss ratio	10.3%	10.0%	10.2%	10.2%	10.3%	10.8%

Schedule 12d – Reliability Forecast

Company Name	**Top Energy**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Network / Sub-network Name	**Top Energy**

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)	245.9	245.9	245.9	245.9	245.9	245.9
12	Class C (unplanned interruptions on the network)	448.9	445.9	437.0	429.5	425.1	413.2
13	**SAIFI**						
14	Class B (planned interruptions on the network)	1.13	1.13	1.13	1.13	1.13	1.13
15	Class C (unplanned interruptions on the network)	3.94	3.94	3.94	3.93	3.93	3.92

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 FYE2025. Going forward, we have assumed an inflation rate of 4% per annum in FYE2026, 3% per annum in FYE2027 and 2% per annum thereafter. This reflects the high rates of inflation we are currently experiencing, but in the longer term we assume inflation will settle at about the mid-point of the Reserve Bank's 1-3% inflation target. Our calculations have also assumed higher labour rate increases over the CPI increases as described above. We do not consider an inflation rate assumption based on an analysis of 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 FYE2024. Going forward, we have assumed an inflation rate of 5% per annum in FYE2025, 3% per annum in FYE2026 and 2% per annum thereafter. This reflects the high rates of inflation we are currently experiencing, but in the longer term we assume inflation will settle at about the mid-point of the Reserve Bank's 1-3% inflation target. We do not consider an inflation rate assumption based on an analysis of industry-specific cost drivers is warranted given the high levels of uncertainty in the forecast.

In the short term we expect operational expenditure inflation to be higher than capital expenditure inflation as the proportion of labour costs is greater, but we do not expect this differential to be sustained.

Company Name:	Top Energy
For Planning Period Ended:	31 March 2034

Schedule 15 Voluntary Explanatory Notes

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

   1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, 2.5.2 and 2.6.6;

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

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

3. Provide additional explanatory comment in the box below.

Box 1: Voluntary 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-Kaitaia 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 subtransmission 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.

Our operational expenditure forecast provides for additional expenditure on vegetation management to ensure that the volume of work we undertake is sufficient to keep ahead of the rate of vegetation growth in our supply area.

Appendix B – Certification for Year Beginning Disclosures

TOP ENERGY
Te Puna Hihiko

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

26 March 2024

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