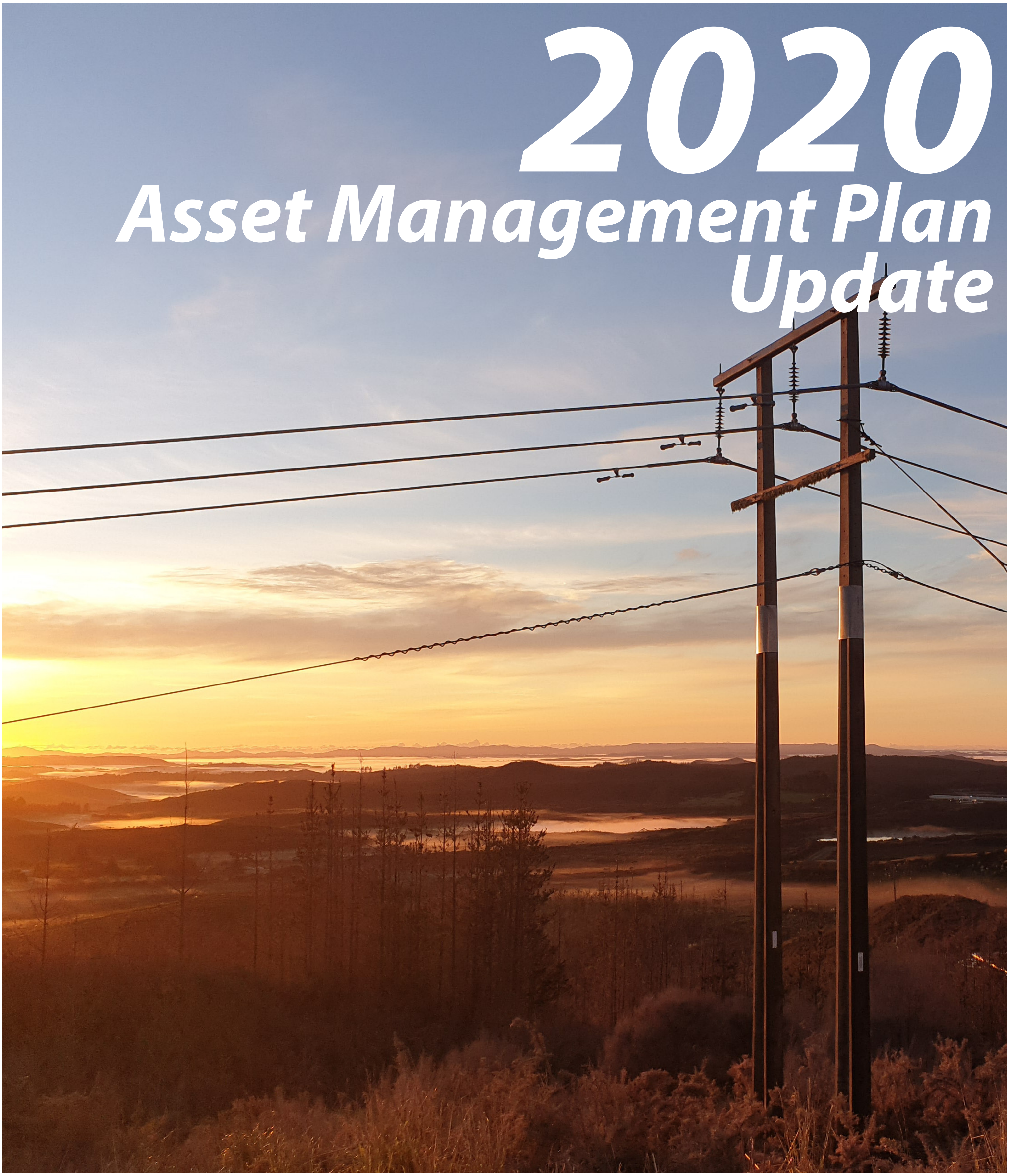
2020 Asset Management Plan Update



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TOP ENERGY®

TePuna Hihiko

Introduction

It gives me great pleasure to present this Update to Top Energy's 2019 Network Asset Management Plan (AMP). Our 2020 AMP Update has been prepared in compliance with the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 and includes updated regulatory schedules to cover the planning period commencing on 1 April 2020 and ending on 31 March 2030 (FYE 2021-30). It also documents material changes to the asset management strategies, levels of service, network development and lifecycle asset management plans described in our 2019 AMP and confirms that the strategies unchanged from our 2019 AMP are still appropriate. It is not a stand-alone document and should be read in conjunction with our 2019 AMP.

The 2019 AMP, as updated by this 2020 AMP Update, remains the core asset management planning and operations document for our electricity transmission and distribution network. It details our planned inspection, maintenance and capital replacement strategies for the next ten years, as well as the targeted service levels that we plan to deliver to our customers.

This is an exciting time for the Top Energy Group. Construction of the fourth generating unit (OEC4) at our Ngawha geothermal power station is well underway and we are on track to commission this unit in October 2020, eight months earlier than originally planned. We also have consent to construct a fifth unit (OEC5), and in the event that we decide to proceed, it could be commissioned by late 2025. If this expansion is completed, the generating capacity of the power station will increase from its current 25MW to more than 88MW and all of the electricity requirements for the Far North would be generated within our supply area. This would enable us to develop a more sustainable, cost-efficient infrastructure that provides higher-value services to our consumers. It should protect our consumers from the impact of rising transmission charges since, with the expansion of Ngawha, our transmission connection will primarily be used to export energy south and we expect the cost of this connection to be paid by the users of this exported energy.

We are also pleased that the Electricity Authority has exempted the new Ngawha units from the cross-ownership requirements of the Electricity Industry Act 2010 to allow the new generation unit to be embedded in our network rather than directly connected to the national transmission grid. This will avoid the construction of additional assets that would have provided no clear technical benefit and will consequently reduce the cost of electricity to consumers.

Our Board has approved a Strategy Map for the Top Energy Group, which sets out the Group's mission, vision and values, and underpins everything that we do. Each operating division within the Group has developed its own strategic vision, which interprets the Group's mission and vision for the business unit's activities and delivers on the Group's core values and high-level corporate objectives.

Top Energy Networks' mission is: *To provide a safe, secure, reliable, and fairly priced supply of electricity to consumers in the Far North.* Its vision is to: *Enable consumers to take greater control over their business and home energy supply needs by developing secure; two-way energy flow; load information and management solutions.*

Our ten-year asset management strategy through to FYE 2030 has been developed in accordance with this mission and vision and, being mindful of our corporate values and objectives, has addressed a range of strategic challenges. These include:

- *Providing a secure supply to the North*. We have now installed sufficient diesel generation in the Kaitaia area to supply all small-use consumers during maintenance shutdowns of the 110kV Kaikohe-Kaitaia line. When construction of the 110kV circuit between Wiroa and Kaitaia is completed in FYE 2030, supply to the north will become fully secure and we will be able to supply consumers in the Far North with renewable energy sourced from Ngawha under all reasonable network contingencies.

- *Connection of the expanded Ngawha power station*. We are constructing a new 110kV line to deliver the power generated by the OEC4 unit at Ngawha to our 110kV switchyard at Kaikohe substation. In the event that OEC5 is commissioned in 2025 we will have upgraded the injection voltage at Wiroa to 110kV, so the power station will be fully embedded into our network by being directly connected to both Kaikohe and Wiroa.

- *Improvement in supply reliability.* Protection upgrades completed in FYE2017 have substantially reduced the impact of 33kV subtransmission network faults on supply reliability. Our reliability improvement initiatives are now focusing on our 11kV distribution network. We have set ourselves a target of improving our supply reliability to a level comparable to that reported by similar rural New Zealand distribution businesses by the end of this AMP planning period and have developed a comprehensive reliability improvement plan to achieve this.

- *Maintenance.* We are transitioning from a largely age based process for prioritising maintenance and asset renewals to one based on the use of industry-standard asset health indicators. Asset health is a function of both asset condition, determined by our asset inspection programme, and asset criticality, which reflects the consequences of an in-service asset failure. This will over time lead to better targeting of our maintenance expenditure and a reduction in the SAIDI impact of faults due to asset failures.
- *Meeting the challenges of new technology.* We have installed an Advanced Distribution Management System (ADMS) that uses the latest available technology. When fully implemented, this will significantly increase the level of automation in our management of network outages and increase worker and public safety by reducing the risk of operator error. It will also be used to optimise the use of the diesel generation that we have added to our network. Over time, the system will be further developed to ensure that we are well positioned to embrace emerging technologies that are starting to change the face of our industry, for the benefit of all our stakeholders.

Our response to these and other challenges is further described in our corporate video, *Top Energy – Energy of the Future* which can be viewed on our website http://www.topenergy.co.nz.

The Commerce Commission has released its new price-quality path for the FYE 2021-25 regulatory period. This imposes a revenue cap rather than a price cap, which provides us with more certainty that we will have the resources to implement our network development plan. It also relaxes constraints on the impact of planned interruptions, which gives us more flexibility in planning maintenance work on the 11kV network. While we are now at the point where we do not need to interrupt supply to undertake maintenance work on our 33kV networks, we still need to interrupt supply to localised areas when undertaking 11kV network maintenance. Consumers have advance warning of planned interruptions and in our consumer surveys they have indicated tolerance of an increased number of planned interruptions in return for the development of a more reliable network. Over the FYE 2021-25 regulatory period, we expect to be able to increase the level of maintenance on the 11kV network without increasing the overall impact of planned interruptions above historic levels.

Uncertainty remains in other components of the regulatory environment. In particular:

- The Electricity Authority has still to grant an exemption for the new and existing diesel generation units from the cross-ownership requirements of the Electricity Industry Act 2010. This exemption has been applied for; however, until it is granted, we will be unable to run the installed generation across the northern part of our network, which will significantly decrease the reliability of supply to these consumers. We estimate that we will require eight planned shutdowns per annum of between eight and ten hours per shutdown.
- The Electricity Authority has still to finalize its review of transmission pricing. Its current proposal has indicated a significant increase in transmission prices for consumers in the north of the country. The expanded Ngawha power station will significantly reduce the extent that electricity consumed in our supply area is generated south of Auckland and we expect that this should protect our consumers from much of this increase. We remain opposed to the changes proposed by the Electricity Authority.
- The Electricity Authority is also requiring electricity distribution businesses to develop more cost reflective pricing policies. We are currently trialing new time-of-use tariffs and we are planning to review our pricing structures further in FYE 2021 and will need to take account of the outcomes of these trials and reviews.
- Industry response to the challenge of emerging technologies remains a source of debate, focused largely on the extent to which EDBs can recover the costs on implementing new technologies from regulated revenue. The FYE 2021-25 price-quality path decision has done little to clarify this issue.

We will keep a watching brief on these developments and their potential impact on our consumers and provide updates in subsequent AMPs.

Since FYE2010 we have put significant investment into the network and the value of our regulatory asset base (RAB), which was approximately $128 million in 2010, is expected to exceed $280 million by the end of FYE 2021. Over this period our annual capital expenditure has been significantly greater than depreciation. Since FYE 2015 our depreciation has averaged $8.5 million per annum while our average annual capex has exceeded $17.7 million. During the current year (FYE 2020) our capital expenditure, which includes the construction of a new 110kV line to connect the expanded Ngawha power station to our network, the installation of additional diesel generation in the Kaitaia area and the rebuilding of the Omanaia substation, is expected to be exceed $39 million. The difference between capital expenditure and depreciation has been funded by increasing prices to the limit allowed by our regulatory price path and significantly increasing debt. This investment has allowed us to resolve the security of supply issue on our 110kV and 33kV networks and significantly improve the resilience of our network. Looking forward over the period FYE 2021 to FYE 2030, we plan to continue to invest; however, we cannot increase prices above the new price path, and we have no further debt capacity, so we will have capital constraints. We are still working through the impact of these constraints and these are expected to be included in our full AMP next year. What is clear is that we cannot continue to make such significant investments in the network.

Our Board and Management are confident that we can still improve service outcomes to levels comparable to those experienced by consumers supplied by similar rural networks within New Zealand and we will therefore focus on achieving a price-quality balance that is affordable and in the best interests of the communities that we serve.

In addition to the development of the 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 participant's 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 this Asset Management Plan Update a succinct summary of the material changes to our 2019 AMP. We welcome your feedback on the update or any other aspect of Top Energy's business and performance. Feedback can be provided through the Top Energy website at http://www.topenergy.co.nz/contact-us-feedback.shtml or emailed to info@topenergy.co.nz.

Russell Shaw

Chief Executive, Top Energy Ltd

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Executive Summary

Purpose

This AMP Update documents changes to the asset management strategies set out in our 2019 AMP. Furthermore, it records the outcome of an internal review that confirms that: (i) apart from the documented changes; the network development plan set out in the 2019 AMP remains appropriately aligned with our internal targets for improving our network reliability; (ii) our network maintenance strategies will ensure that our network assets remain fit for purpose and (iii) no material changes to the network development and maintenance budgets are needed.

Supply Reliability

In resetting Top Energy's price-quality path for the FYE 2021-25 regulatory period, the Commerce Commission has set separate quality standards for planned and unplanned interruptions and has revised the way in which unplanned interruptions are normalised for quality assessment. We have reviewed our internal SAIDI and SAIFI targets in the light of these changes and replaced the targets in the 2019 AMP with separate targets for planned and unplanned interruptions.

Our new unplanned SAIDI and SAIFI targets are numerically the same as the unplanned interruption components of the targets in the 2019 AMP. However, in measuring our performance against these targets, we will normalise our raw performance using the Commission's revised normalisation methodology.

We have set new SAIDI and SAIFI targets for planned interruptions at a level where the consumer impact will be the same, on average, as the impact experienced over the ten-year period FYE 2010-19. While we have now reached a point where there is little need to schedule planned interruptions for maintenance work on our 110kV and 33kV network, setting targets based on the average historic impact of planned interruption across all voltages will allow us more flexibility in maintaining our 11kV distribution network, without subjecting consumers to a higher level of planned interruptions than they have historically experienced.

Our strategy for reducing the impact of unplanned interruptions has not changed, and by the end of the planning period we still expect to be able to deliver a level of reliability comparable to that provided by similar rural electricity distribution businesses.

Network Development

The following adjustments have been made to the network development plan set out in the 2019 AMP. There are no material changes to our forecast capital expenditure over the planning period as a result of these adjustments. Network reconfigurations described in the 2019 AMP that are designed to improve the resilience of our 11kV distribution network to faults will proceed.

Connection of Ngawha Power Station

The Electricity Authority has granted us an exemption that allows the Ngawha Power Station expansion to be embedded in our network rather than be directly connected to the Transpower grid at Kaikohe. This has not changed the connection of the first new unit (OEC4) but, should a second new unit be constructed, one outgoing 110kV circuit will be directly connected to Kaikohe and the second to Wiroa.

Diesel Generation

We no longer plan to deploy diesel generation at remote locations across our 11kV network. The generation that we proposed to deploy remotely is now being installed at Omanaia and Pukenui substations, which both have only one transformer and one incoming circuit. This change has no budgetary implications.

Innovation Pilot Projects

Following the release of the Commission's default price path decision for the regulatory period beginning on 1 April 2020, we are reviewing our approach to trialling new technologies and, pending the outcome of this review, have decided not to proceed with the innovation pilot projects identified in the 2019 AMP. Meanwhile we are focussing our efforts on customising our new ADMS system in order to fully utilise its potential to improve the effectiveness of our control room operation as we develop our capability as a Distribution System Operator.

Lifecycle Asset Management

Proactive Asset Renewal

The asset condition analysis included in our 2019 AMP did not take asset criticality into account. We have reviewed the asset renewal programme set out in our 2019 AMP and after a risk assessment are satisfied that no assets known to have a high risk of failing in service are critical to the performance of our network. A change to our asset renewal strategy to accelerate the replacement of non-critical assets known to be in poor condition would divert funds from the renewal of more critical assets and could limit the rate at which we can improve supply reliability. We note that the SAIDI impact of faults due to assets failing in service has progressively reduced from a high of 229.8 minutes in FYE 2014 to 66.5 minutes in FYE 2019.

Vegetation Management

We have reviewed our approach to vegetation management since the SAIDI impact of vegetation faults has trended upwards since FYE 2013. Our review has found that while the SAIDI impact has trended up, the SAIFI impact has trended down. The upward SAIDI trend is due to the number of vegetation faults located in remote network locations and therefore taking longer to fix. We will continue to monitor our expenditure on vegetation management and review whether our vegetation management strategy strikes the right balance in the attention we give to different parts of the network. Our approach is reliant on tree owners playing their part in managing vegetation and we will be monitoring this closely. If this does not occur, then we will be reviewing future spend levels. We are fully engaged with the Ministry of Business, Innovation and Employment's review of the Electricity (Hazards from Trees) Regulations 2003 to clarify where responsibilities lie.

1. Asset Management Strategy and Delivery

We strive to continually improve the manner in which we operate, to achieve our strategic business objective, while at the same time complying with all relevant legislation and providing a safe working environment for our staff. However, there are no material changes to the Asset Management Maturity Assessment (AMMAT) presented in Schedule 13 of our 2019 AMP. We have therefore not included a revised schedule in this AMP Update.

This AMP Update covers the ten-year planning period 1 April 2020 to 31 March 2030 and was approved by our Board of Directors on 31 March 2020.

Figure 1.1 compares our capital expenditure forecast for the planning period with that forecast in our 2019 AMP and Figure 1.2 provides a similar comparison for our forecast network operations and maintenance expenditure (excluding system operations and network support and business support expenditure).The figures show that there are no material changes to the forecast network capital expenditure, apart from a small inflation adjustment.

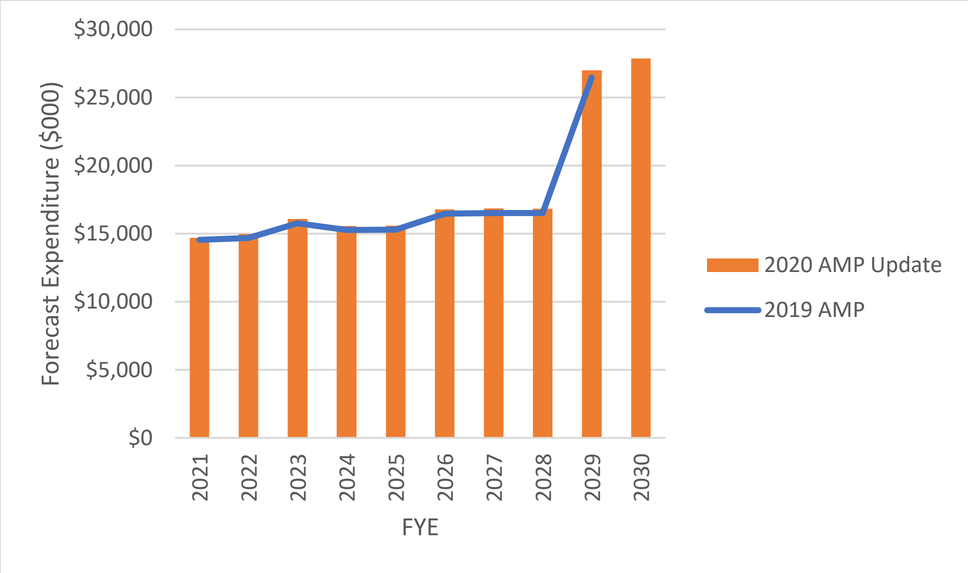

Figure 1.1: Comparison of Network Capital Expenditure Forecast with 2019 AMP (constant prices)

As can be seen from Figure 1.2, there is no material change to our network operational expenditure forecast apart from a small inflation adjustment.

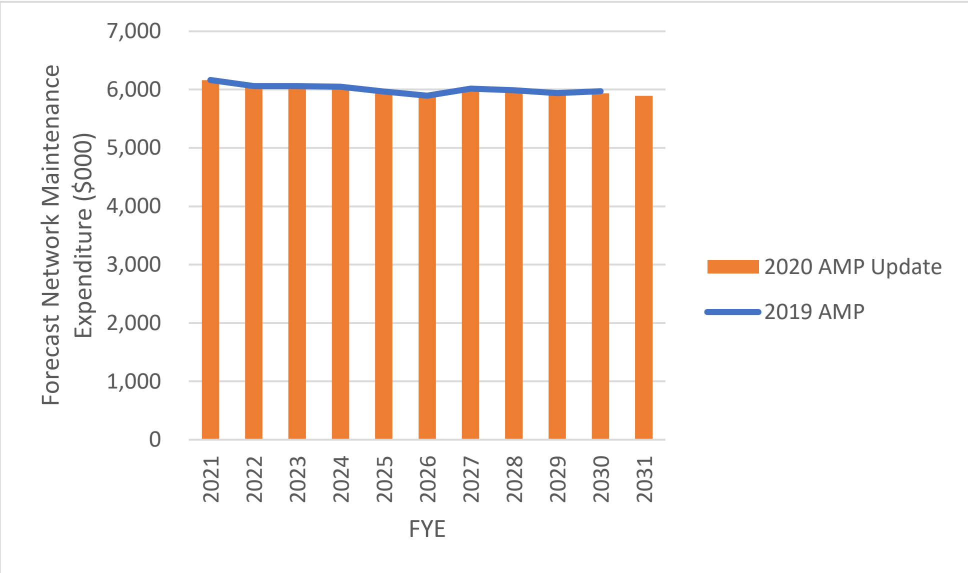

Figure 1.2: Comparison of Network Capital Expenditure Forecast with 2019 AMP (constant prices)

2. Supply Reliability

Summary

In resetting Top Energy's price-quality path for the FYE 2021-25 regulatory period, the Commerce Commission has set separate quality standards for planned and unplanned interruptions and has revised the way in which unplanned interruptions are normalised for quality assessment. We have reviewed our internal SAIDI and SAIFI targets in the light of these changes and replaced the targets in the 2019 AMP with separate targets for planned and unplanned interruptions.

Our new unplanned SAIDI and SAIFI targets are numerically the same as the unplanned interruption components of the targets in the 2019 AMP. However, in measuring our performance against these targets, we will normalise our raw performance using the Commission's revised normalisation methodology.

We have set new SAIDI and SAIFI targets for planned interruptions at a level where the consumer impact will be the same, on average, as the impact experienced over the ten-year period FYE 2010-19. While we have now reached a point where there is little need to schedule planned interruptions for maintenance work on our 33kV network, setting targets based on the average historic impact of planned interruption across all voltages will allow us more flexibility in maintaining our 11kV distribution network, without subjecting consumers to a higher level of planned interruptions than they have historically experienced.

Our strategy for reducing the impact of unplanned interruptions has not changed and by the end of the planning period we still expect to be able to deliver a level of reliability comparable to that provided by similar rural electricity distribution businesses. In particular, our reliability improvement strategy includes increasing the resilience of our 11kV network to major storm events by optimising our operational response to such events and continuing to implement a more resilient network design.

2.1 Unplanned

For internal management purposes, we measure and report supply reliability using normalised SAIDI and SAIFI measures, which are lower than the actual reliability experienced by our consumers. We use the normalisation methodology specified by the Commerce Commission for assessing compliance with our regulatory price-quality path. However, our internal reliability targets are more stringent than the limits specified by the Commission because the Commission's limits are set to ensure that we maintain reliability at historic levels, whereas our asset management objective is to progressively improve the reliability of the supply that we provide to our consumers.

We believe that reporting reliability against a normalised, rather than an actual, measure is more meaningful since normalisation reduces the impact of severe weather events. While such events adversely affect the reliability of the supply experienced by our consumers, their frequency and severity are outside our control. In reducing the sensitivity of the measure to the volatility of the external environment, the normalised measure provides a better reflection of underlying network reliability.

On 27 November 2019, the Commission set Top Energy's default price-quality path for the third regulatory period (DPP3), which starts on 1 April 2020 to and runs to 31 March 2025, and revised the quality limits with which we must comply. For DPP3 the Commission has:

- set separate reliability limits for planned and unplanned interruptions. For the current regulatory period, which ends on 31 March 2020, the Commission set a single SAIDI and single SAIFI limit, with each limit incorporating both planned and unplanned interruptions;
- changed the basis for normalizing unplanned interruptions from a calendar day to a rolling 24-hour period. Under the DPP2 normalization methodology, the Commission specified a boundary value and the maximum SAIDI and SAIFI impact of any calendar day was limited to the boundary value. Under the revised approach the Commission's boundary value limits the SAIDI and SAIFI over any 24-hour period, rather than a calendar day. Over a measurement year, the DPP3 normalization approach will report a lower normalized SAIDI and SAIFI than the DPP2 methodology for the same raw network performance.

Consistent with the Commission's decision to set separate limits for planned and unplanned reliability, we have now set separate internal targets for the impact of planned and unplanned interruptions. Notwithstanding the normalisation change, in setting our unplanned SAIDI and SAIFI targets we have not adjusted the unplanned components of the SAIDI and SAIFI targets and these remain unchanged as presented in Table 4.2 of the 2019 AMP. These are shown in Table 2.1.

FYE	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Normalised Unplanned SAIDI										
Unplanned 110kV	-	-	-	-	-	-	-	-	-	-
Unplanned 33kV	29	28	27	26	25	24	23	22	21	20
Unplanned 11kV	225	218	210	203	195	188	180	173	163	157
Total	**254**	**246**	**237**	**229**	**220**	**212**	**203**	**195**	**186**	**177**
Normalised Unplanned SAIFI										
Unplanned 110kV	-	-	-	-	-	-	-	-	-	-
Unplanned 33kV	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Unplanned 11kV	2.53	2.48	2.41	2.36	2.29	2.24	2.17	2.11	2.05	2.00
Total	**3.03**	**2.98**	**2.91**	**2.86**	**2.79**	**2.74**	**2.67**	**2.61**	**2.55**	**2.50**

Table 2.1: Internal Consumer Service Level Targets

As the revised approach to normalisation returns a lower normalised measure for the same raw performance, the targets in Table 2.1 reflect a marginally lower level of reliability than the targets in the 2019 AMP. We decided not to adjust the 2019 AMP targets to reflect the change in normalisation for the following reasons:

- Since we introduced our network development plan in FYE 2010, the only years where we have bettered our internal reliability targets have been FYE 2013 and FYE 2019, both years in which the weather was unusually benign. Furthermore, we are trending toward not meeting our internal reliability target for the current year (FYE 2020). This suggests that the buffer that we have incorporated into our historic targets to account for weather volatility has not been sufficient.
- For this analysis we have normalized our historic service levels using the DPP3 methodology for every year since FYE2009, as shown in Figures 2.1 and 2.2. The figures show a trend of improving reliability, which reflects the effectiveness of our network development plan. The targets in Table 2.1 are a continuation of this trend, as shown in Figures 2.1 and 2.2, and reflect the expected impact of our ongoing network development. With our targeted level of improvement, we anticipate that our raw network reliability will be comparable to that of similar rural EDB networks such as those of Eastland Energy and The Lines Company by the end of the planning period.

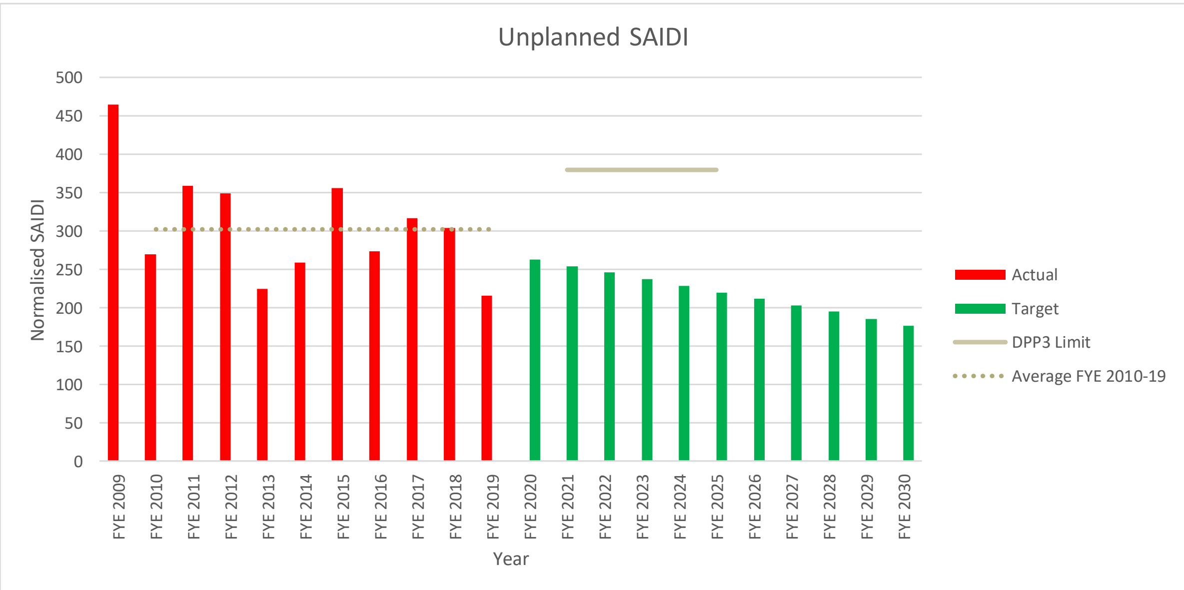

Figure 2.1: Actual and Targeted SAIDI

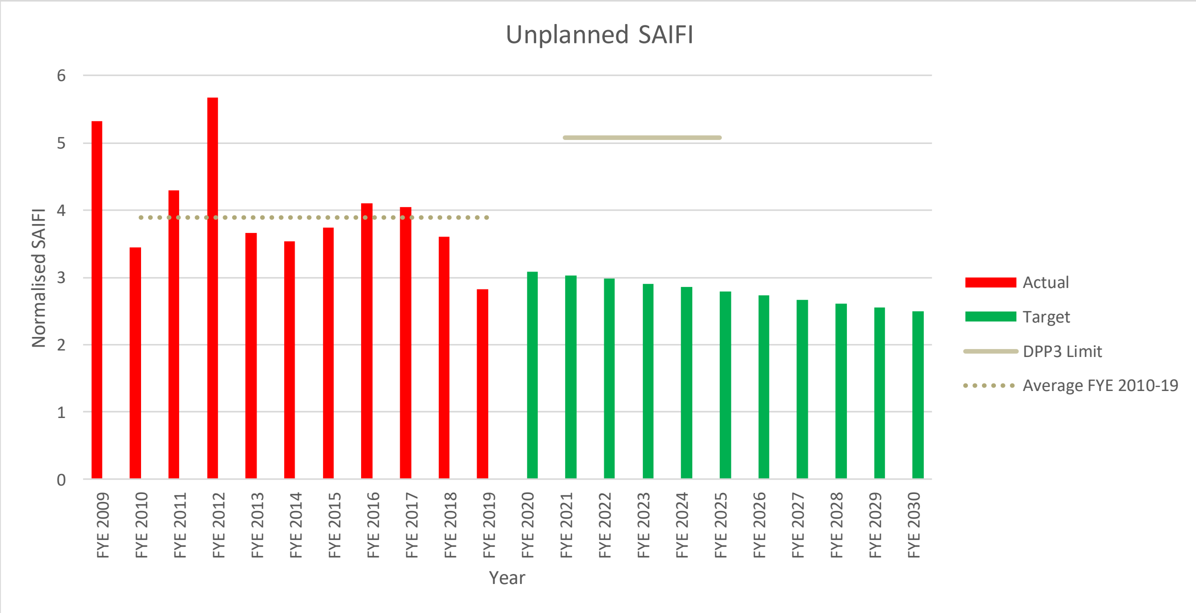

Figure 2.2: Actual and Targeted SAIFI

Our strategy for reducing unplanned 33kV SAIDI includes the refurbishment of the 33kV line to Omanaia, which is planned to be undertaken during FYE 2021 and FYE 2022 at a cost of $0.86 million and the now completed installation of generation at Omanaia and Pukenui, which are both single transformer substations supplied by a single incoming circuit. These generators will reduce the duration of interruptions caused by faults on these incoming circuits but will not prevent the interruptions from occurring as the generators will only be started after an interruption has occurred. We expect further incremental reductions in SAIDI over the planning period as we improve our fault response and become more experienced in the utilisation of our Advanced Distribution Management System (ADMS). We are also increasing our expenditure on the replacement of assets known to be approaching the end of their economic life, as discussed in Section 4.1.

2.1.1 Network Resilience to Storms

Our network development plan has increased the resilience of our 110kV and 33kV networks through the installation of backup diesel generation and the installation of upgraded protection on the 33kV network so that in most cases supply is uninterrupted following a fault. Increasing the resilience of the 11kV distribution network is more difficult due to the radial network design and the higher storm exposure due to the significantly greater circuit lengths. To increase the resilience of the 11kV network we are focusing on reducing the number of customers affected by a fault and developing a network that can be quickly reconfigured after a fault occurs to restore supply to most consumers before the fault is repaired.

Reducing the number of customers affected by a fault is most effectively achieved by reducing the number of consumers connected to a distribution feeder and we have achieved this in the north-east seaboard through the installation of new zone substations at Kerikeri and Kameo. Our capital expenditure forecast also provides for the installation by FYE2022 of a second feeder to supply consumers on the Russell peninsula – this means that only half the consumers on the peninsula will experience a supply interruption following a single fault. On long feeders the number of affected consumers can be reduced by the installation of automatic reclosers along the feeder to prevent consumers close to the source being interrupted by a remote fault. We have almost 120 reclosers on our network including those that protect single wire earth return (SWER) lines. Many of our spur lines are now fused at the point of connection to the main feeder backbones to prevent faults on the spur affecting the whole feeder.

Rapid restoration of supply prior to the repair of a fault can be achieved through the installation of interconnections between adjacent feeders and through the installation of remote-controlled switches in the field so that switching can be done remotely from the control room rather than locally at site. We now have a total of 250 remote control switches throughout our network we have provided $0.6 million for the installation of additional switches during the planning period. Our capital expenditure forecast also includes the installation of five new feeder interconnections at a total cost of $5.9 million. These are discussed in Section 3.3.

We also have documented operational procedures in place to optimise our response to major storm events. During such an event our capacity to respond is limited and so we need to prioritise our response. Our first priority to ensure that the network is safe, our second is to restore supply to as many consumers as possible and only then do we focus on the repair/remediation and stabilisation of network and consumer assets.

In preparing for a pending significant weather event, we monitor weather watches and warnings issued by Metservice to assess the potential impact on our network. We issue capability statement forms to our supporting teams including our PhonePlus call centre, Top Energy Contracting Services, Stores and Procurement. These statement lists are used to confirm their expected event response resource availability. If it appears that a severe weather event is likely, then representatives from these teams attend a pre event briefing and coordination meeting. The meetings purpose is to establish any expected shortfall in our response capabilities and identify options to address or minimise the impact of any resource or response limitations.

If the storm develops into a major event that exceeds our normal response capability, a "Full Response", as defined in the Top Energy Emergency Preparedness Plan (EPP) is declared. This puts the business on a major event footing where all planned and unnecessary work is suspended to allow full resourcing of the storm response, utilising all appropriate business resources.

Staff welfare and fatigue during such events are managed to ensure we can maintain a viable resource throughout the event. The Human Resources team, the Fault Supervisor and after-hours Fault Coordinators have the responsibility of this task, with support from the Network Controllers and the Duty Manager. Leadership and management during these events are managed by the business' operational managers and their teams with the out-of-hours support provided by the Rostered Duty Management team.

Public enquiries during events are handled by the normal resources and existing processes that are in place i.e. PhonePlus, complaints process, the Outage Centre and the outage app etc. Media enquiries during major events are handled and released in accordance with the Top Energy Media Protocol, with support from our media consultancy provider.

2.2 Planned Interruptions

As noted in Section 2.1.1, our 11kV distribution network is of a radial design, like that of most ECBs, and when an element of the network fails or is de-energised, supply to downstream consumers is interrupted. WorkSafe New Zealand's current position is that work should generally not be undertaken on live electrical equipment. Working within these constraints, we will be unable to increase the maintenance of our 11kV distribution network above the current level without increasing the number of planned 11kV network interruptions.

While planned interruptions are disruptive to consumers, they are less so than unplanned interruptions, because consumers are given advance notice of the interruption and can plan accordingly. With generation installed at Kaitaia, Omanaia, Pukenui and Taipa, planned interruptions should now normally only be required for work on the 11kV distribution network[1].

For DPP3, the Commission has not set an annual limit for the impact of planned interruptions but has set aggregated planned SAIDI and SAIFI limits for the whole regulatory period. As compliance will only be assessed at the end of the period, EDBs are free to use up this allowance at any time over the period. Our limit is 1,905.36 SAIDI minutes and 7.63 interruptions (SAIFI), which is calculated as three times our average annual planned SAIDI and SAIFI over the FY 2010-19 period aggregated for five years.

For internal management purposes we have set rounded annual planned SAIDI and SAIFI targets equal to our average performance over the FY 2010-19 period[2]. Given that there should be little need for planned interruptions on our transmission and subtransmission network, this will allow us to increase our level of maintenance on the 11kV

1 The one exception to this is the Junken Nissho mill. Insufficient generation has been installed at Kaitaia to supply the mill during an outage of the 110kV Kaikohe-Kaitaia line. An arrangement is in place with the customer to ensure the mill is shut down during a planned interruption of this line.

2 These are rounded down values. The reliability incentive scheme has a planned SAIDI component with a target SAIDI of 127.02. This is the neutral level, for which no reward or payment will apply.

network without increasing our consumers' exposure to planned interruptions above historic levels. These targets are shown in Table 2.2. Assuming the SAIDI target is met, the aggregate SAIDI impact of planned interruptions over the DPP3 regulatory period will be 625 minutes, less than one third of the 1,905.36 minutes set by the Commission.

FYE	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Planned SAIDI	125	125	125	125	125	125	125	125	125	125
Planned SAIFI	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Table 2.2: Targets for the Impact of Planned Interruptions

3. Network Development

3.1 Connection of Ngawha Power Station

Summary

The Electricity Authority has granted us an exemption that allows the Ngawha Power Station to be embedded in our network rather than be directly connected to the Transpower grid. This has resulted in changes to the development of our 110kV network in the southern area from the plan set out in our 2019 AMP. These changes have no budgetary implications.

Stage 1 of the Ngawha power station expansion (referred to internally as OEC4 as it will be the 4th generator at the site) is on track for commissioning in 2020 and will increase the generation capacity of the power station by 31.8MW. There is an option for a 5th and final generator (OEC5) to be built, and if were to proceed, it could be commissioned by late 2025.

In October 2019, the Electricity Authority granted Top Energy an exemption from the cross-ownership provisions of the Electricity Industry Act 2010, which means that we can now embed the new Ngawha generators within our network, rather than being required to connect them directly to the transmission grid at the Kaikohe grid exit point. We now plan that the expansion to the power station will form part of a 110kV loop circuit connecting Kaikohe and Wiroa, as shown in Figure 3.1. The loop will comprise the two circuits of the existing double circuit line between Kaikohe and Wiroa and a new double circuit 110kV spur line to the power station, presently under construction. As the new line will now be part of our shared transmission network rather than an asset dedicated to the power station, once commissioned it will be included in Top Energy Networks' regulatory asset base.

Initially OEC4 will connect directly to a new line bay in the Kaikohe 110kV switchyard through a single 110kV circuit utilising the new line and part of one circuit of the existing Wiroa line. The loop arrangement would be implemented after OEC5 was commissioned or after a 110/33kV substation at Wiroa is commissioned.

The development plan in the 2019 AMP included the replacement in FYE 2023 of the smaller 30MVA transformer at Kaikohe with a new 40/60MVA unit that would be connected by a tee connection to the existing Kaikohe-Kaitaia 110kV line, to free up a bay in the 110kV switchyard. We have now decided to install a new 110kV line bay in the Kaikohe switchyard and leave the existing transformer in place.

Apart from these near-term adjustments, there have been few changes to the network development plan set out in the 2019 AMP. In particular, our capital expenditure forecast still provides for the completion of the Wiroa-Kaitaia 110kV line by FYE 2030.

3.2 Diesel Generation

Summary

We no longer plan to deploy diesel generation at remote locations across our 11kV network as indicated in our 2019 AMP. The generation that we proposed to deploy remotely will now be installed at Omanaia and Pukenui substations, which both have only one transformer and one incoming circuit. This change has no budgetary implications.

As part of our strategy for security of supply, the 2019 AMP set out our plan to purchase 12 new generators being a mix of 1MW and 500kW machines, in addition to the three that had already been purchased and installed at our Kaitaia depot. It was envisaged that eight generators would be installed at a new generator farm at Bonnetts Rd, west of Kaitaia, three at our Kaitaia depot, and four would be relocatable units deployed across the 11kV network, primarily to provide resilience in the event of a fault.

In the event, 11 new generators were purchased. Eight are being installed at Bonnetts Rd and, instead of deploying generators across the 11kV network, two generators are being installed at our Omanaia substation and one at Pukenui. Reasons for this strategy change include:

- Omanaia and Pukenui are both single transformer substations. The presence of generation at these substations will enable supply to be restored more rapidly and reduce the urgency with which the mobile substation needs to be deployed should there be a transformer failure. The generation will also be used to avoid supply interruptions during maintenance outages of the incoming single circuit 33kV lines;
- Our operational experience with the Taipa generators is that there can be problems when starting generators remotely in response to an unplanned network failure. This experience has been incorporated into the selection of locations for our new generator fleet. Rather than installing generators in remote locations where communications are less reliable, less intensive monitoring is possible from the control room, and response time for repair or local start up is protracted, we are installing them at substations that are more accessible and have reliable communications links. Delayed start negates the benefit of generators as unplanned outage backup.

Notwithstanding this, it may be that in the future we decide to deploy a generator to provide network support on the remote 11kV network for planned interruptions. Under these circumstances, and with the ability to forward plan, it is likely that a hire generator would be deployed, then removed at the end of the work.

The Electricity Authority has still to grant an exemption for the new and existing diesel generation units from the cross-ownership requirements of the Electricity Industry Act 2010. This exemption has been applied for; however, until it is granted, we will be unable to run the installed generation across the northern part of our network which will significantly decrease the reliability of supply to these consumers. We estimate that we will require eight planned shutdowns per annum of between eight and ten hours per shutdown.

3.3 Distribution Network Reconfigurations

Summary

We have reviewed our network capital expenditure forecast for the first five years of the AMP planning period to ensure consistency with the reliability improvement implied by the unplanned interruption targets in Table 2.1. The review has confirmed that the network projects in the 2019 AMP are appropriate and that no material forecast changes are required.

Projects in our forecast for the first five years of the planning (FYE2021-25) period that are designed to increase the resilience of our network to faults through network reconfiguration are shown in Table 3.1. Network reconfigurations will not prevent faults occurring but will either reduce the number of consumers affected by a fault or enable supply to be restored more quickly to many consumers after a fault occurs.

Project	Implementation	Budget ($ million)	Comment
Russell Reinforcement	FYE 2022	1.48	The installation of a new 11kV cable between Okiato Pt and the Russell Rd intersection will enable the Russell Peninsula load to be shared between two feeders. This means that a single fault will only interrupt supply to half the feeders on the peninsula.
Feeder Interconnections	FYE 2022-26	4.75	The installation of additional interconnections between adjoining feeders allow load transfers between feeders after a fault occurs, reducing the time taken to restore supply to many consumers. Interconnections between the following feeders have been provided for over this period: Matauri Bay – Whangaroa Rangiahua --South Rd Rangiahua – Horeke Bulls Gorge – Moerewa Herekino-South Rd

Table 3.1: Planned Distribution Network Reconfigurations

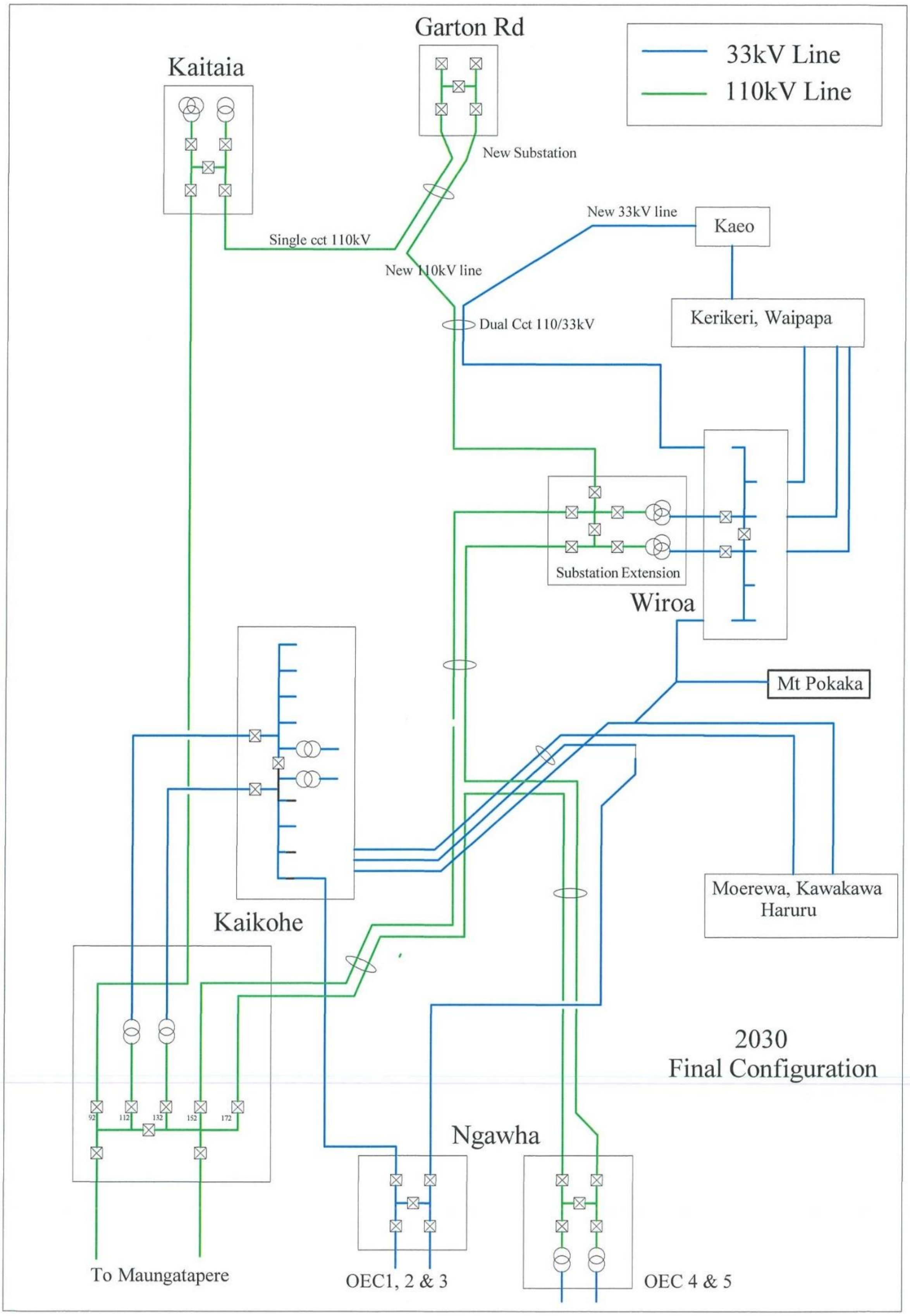

Figure 3.1: Planned/Anticipated 110kV Transmission Network Development

3.4 Innovation Pilot Projects

Summary

We have decided not to proceed with the innovation pilot projects identified in the 2019 AMP and will review our approach to the trialling of innovative technologies during FYE 2021. As the cost of these pilot projects was relatively small, we have not changed our total forecast expenditure.

Our 2019 AMP signalled our intention to initiate a range of new technology pilot projects, including the development of micro-grids supported by battery storage and the deployment of a static voltage compensator on the Russell feeder. We have decided not to proceed with the pilots as:

- Many other EDBs are, or have already been, actively undertaking new technology trials and the results of those trials are readily available. Typically, these trials are more extensive than Top Energy could entertain, and duplication of work already done is not good use of our capital resources;
- We have made a commitment in the AMP to undertake specific, long term remediation and maintenance work on the network in order to provide an improving level of service to our consumers, including improved reliability, resilience and security of supply. Funding for new innovative technology trials is well down the priorities list for funding and its inclusion cannot be justified in the foreseeable future; and
- While we will maintain our watching brief on the introduction of new technology, in general, we will be followers rather than leaders in this area and only adopt new technology after it has been well proven.

The Commission's DPP3 final decision provides an innovation project allowance, recoverable as a pass-through cost, which we could utilise for the implementation of innovation initiatives. The innovation project allowance available to us under this mechanism over the DPP3 regulatory period is $198,000. To qualify for this funding, we would need to meet certain conditions. In particular:

- We would need to match any drawdown from the project innovation allowance with a corresponding contribution from our own resources;
- Prior to starting the project, we would need to submit a report to the Commission from an independent engineer or suitable specialist. The report would need to confirm that the proposed project met the criteria set by the Commission;
- The Commission must approve the project based on its analysis of this report;
- On completion of the project we would need to provide the Commission with a report on the findings of the project. This report must also be publicly available on our website.

During FYE 2021 we plan to review our approach to innovation in the light of this new innovation framework and provision for the implementation of suitable innovation projects may be included in future expenditure forecasts. It is likely that any such initiatives will focus on the development and implementation of our ADMS system to optimise our effectiveness as a distribution system operator. The use of the ADMS system to more effectively manage the operation of our diesel generation after an unplanned 110kV interruption, or to black-start Ngawha after a sustained outage of the connection to the Transpower grid are possible areas of investigation.

3.5 Solar Penetration

As shown in Figure 3.2, there has been steady growth in the connection of solar generation to our network, with more 1.1 MW of new generation connecting to the network in the year to the end of January 2020. We have also received enquiries for the connection of large solar generation projects rated at about MAW and, as such, we are currently reviewing our embedded generation policy. We are planning to formally review the impact of solar generation on our network once our total solar penetration exceeds 5MW and if the growth in solar generation continues at its current rate this trigger point will be reached sometime during FYE 2021. Although there is no current impact on distribution, we will address in more detail the implications of increased solar penetration in our 2021 AMP.

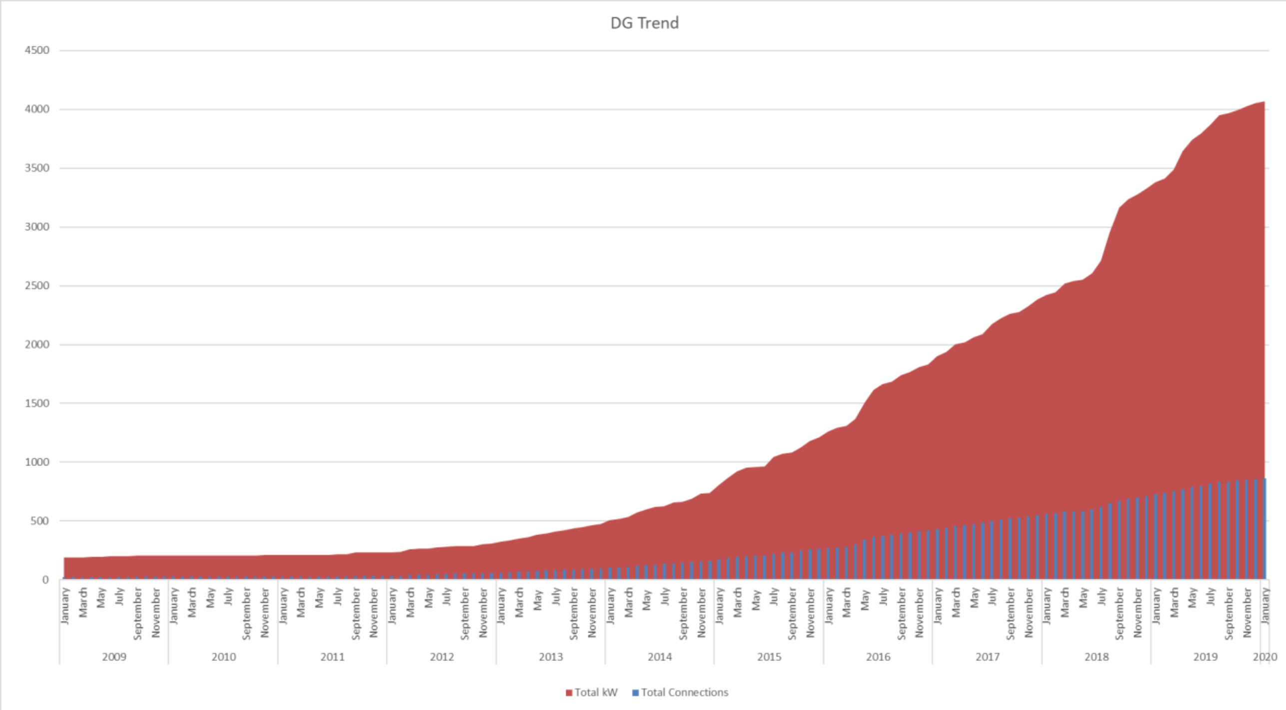

Figure 3.2: Growth in Network Solar Penetration

4. Lifecycle Asset Management

Prior to the completion of our 2019 AMP we undertook a comprehensive assessment of the health of the assets in the different asset classes within our network. The assessment was based on the criteria in the Energy Engineers' Association (EEA) Asset Health Indicator (AHI) Guide, using where possible the results of our asset inspection program. For assets such as cables, where an assessment of asset condition is not possible from a visual inspection, asset age was used as a proxy for condition. This exercise, which is based on asset condition rather than solely on asset age, has provided us with more accurate quantitative information on the health of our asset fleet and enabled us to develop an asset renewal budget that better targets assets in most need of replacement.

A limitation of the AHI approach is that asset health is determined only by the probability of failure. The EEA has recently extended this approach by developing a structured approach to the assessment of asset criticality, based on the consequences of asset failure. This information, when combined with our knowledge of the health of an asset, can be used to develop a two-dimensional assessment of asset risk, which is defined as the consequences to our business and our consumers if an asset fails. The overall objective is to base the decision to replace or renew an asset on the risk of an asset failure rather than purely on asset health.

The EEA criticality guide has only just been released and we have still to develop a structured approach to quantifying asset risk. In prioritising assets for replacement, we intuitively take criticality into account in that, all else being equal, assets where the consequences of failure are highest, are prioritised for replacement. Nevertheless, this is still a high-level, qualitative assessment.

We adopt a two-pronged approach to asset renewal, reactive and proactive. Reactive renewals are driven by the need to replace assets that have failed in service and by the need to replace individual assets that have been identified through our asset inspection programme as being defective to the point where they have a high risk of failure. The effort is the responsibility of our Network Maintenance Manager, who must also consider the consequences of failure when prioritising the replacement of assets known to be defective.

The proactive component of asset renewal is driven by our Network Planning Manager. Under this programme the replacement of assets or the refurbishment of parts of the network are aggregated into asset renewal projects for proactive implementation. For example, over the last few years the incoming 33kV lines supplying Taipa and Pukenui substations have both been refurbished and refurbishment of the 33kV line to Omanaia is currently being undertaken. Asset health and the consequence of asset failure are key inputs to the development and prioritisation of asset renewal projects.

4.1 Proactive Asset Renewals

Summary

In our 2019 AMP we incorporated the results of our asset inspection programme into our assessment of asset condition for the first time. This provided a more accurate assessment of the quantity and type of assets that have reached the end of their economic lives. We have reviewed our proactive asset renewal programme in the light of this revised assessment approach. We note that the SAIDI impact of faults due to assets failing in service has progressively reduced from a high of 229.8 minutes in FYE 2014 to 66.5 minutes in FYE 2019 and have confirmed that no assets currently in service and identified as having reached the end of their economic life are critical to safety, the reliability or performance of the network. A change in the asset renewal strategy set out in the 2019 AMP to accelerate the replacement of these assets would divert funds from the renewal of more critical assets and could constrain the rate at which we can improve our supply reliability.

While the planned reconfiguration strategies described in Section 3.3 are designed to make the network more resilient to faults that that do occur, our proactive network renewal strategy is designed to limit the incidence of interruptions due to defective equipment and ensure that the network remains fit for purpose. This expenditure is over and above our reactive capital expenditure on asset renewal, which arises from the replacement of assets that fail in service or are identified during asset inspection as requiring urgent replacement.

Over the past few years our proactive renewal strategy has largely focused on our subtransmission network, since subtransmission faults can interrupt supply to large numbers of consumers. The transformer at Omanaia substation has now been replaced with a new unit and, apart from refurbishment of the Omanaia circuit and the rebuild of the Waipapa substation, this work is now substantially complete. We are therefore increasing our expenditure on renewal of the 11kV distribution network.

The Waipapa substation rebuild has been deferred out to 2028. The objective of this project is to replace the 33kV and 11kV outdoor switchyards with indoor switchboards, primarily to reduce the safety risk in line with current industry practice, and to lower the transformers to ground level to reduce the earthquake risk. While the switchyard structures are old, they are still serviceable and key outdoor assets such as circuit breakers have already been replaced. Pending the start of the rebuild, all assets will be maintained in a serviceable condition and safety risks will continue to be managed using industry standard procedures.

Our 11kV asset renewal forecast is focused on the renewal of following assets:

- Wooden poles. These are a safety risk as deterioration usually occurs below ground level and is not apparent from a visual inspection. We still have more than 1,000 wooden poles on our network, of which approximately 25% are considered unreliable. We intend to replace all these wooden poles with concrete by the end of the planning period and will prioritize those known to be unreliable.

- Concrete poles. Concrete poles deteriorate much more slowly than wooden poles and deterioration generally occurs above ground level, so is apparent from a visual inspection. Our older concrete poles are "L" and "T" shaped, some of which have a known construction flaw where short pieces of reinforcing were welded together when the correct length was not available. Affected units have failed in service but the location of other flawed units is not known and cannot be determined by a visual pole inspection. We have approximately 31,500 concrete poles on our network, of which around 3% are considered potentially unreliable.

- Conductor: The majority of faults from conductor failure are due to the failure of steel, copper and small aluminum (mink) conductor that is now close to the end of its useful life. Approximately 0.7% of the almost 4,000km of circuit conductor on our network requires replacement and almost 50% of this deteriorated conductor is on our SWER network. We currently plan to replace approximately 10 cct-km conductor per year. Initially this work will be bundled into line refurbishment projects where 11kV lines in poor condition are fully refurbished. Accelerated replacement of this conductor is not considered justified as the conductor is located in remote, uneconomic network locations.

- Switchgear: While we plan to replace limited numbers of air-break switches and ring main units each year, most of the switchgear on our network that has reached end of life are drop-out fuse holders. There are more than 5,600 drop-out fuses on our network and more than 10% of these have been assessed as requiring replacement. Our documented risk management strategy, which includes component risk assessment, raises few safety or reliability concerns. Anodically, the failure modes are generally burnt off terminations, or fuses not clearing the holder as designed. As there is little safety risk, these assets are generally run to failure, rather than proactively replaced.

The 2019 AMP identified two substation transformers that had reached the end of their economic life and were at a heightened risk of failing in service. The 33/11kV transformer at Omanaia was replaced with a new unit in FYE 2020. The second transformer is the smaller 110/33kV transformer at Kaitaia. It was inherited from Transpower and is a bank of three single phase units with each phase in a separate tank. The larger 40MVA Kaitaia transformer is about four years old and still in as-new condition. The transformer it replaced has not been removed. There are therefore four spare single-phase units still at Kaitaia, which are available to be brought back into service if one of the three in-service units failed. Replacement of this old transformer bank is currently scheduled for FYE 2029.

Our strategy for ensuring that the network remains fit for purpose and for controlling the number of interruptions due to equipment failing in service includes completing the projects identified in Table 4.1 over the first five years of the planning period.

Project	Implementation	Budget ($ million)	Comment
33kV Omanaia line refurbishments	FYE 2021-22	0.86	Omanaia is the final subtransmission line to be refurbished under our programme of refurbishing all single circuit zone substation incomers.
11kV line reconstructions	FYE 2021-25	4.65	We plan to refurbish a number of 11kV lines that are known to be in poor condition and that have given rise to an excessive number of defective equipment faults. *This budget also provides for the proactive replacement of conductor and pole-top hardware.*
Switchgear	FYE 2021-25	2.41	This includes the proactive refurbishment and replacement of ring main units, air-break switchgear and drop-out fuses.
Poles	FYE 2021-25	6.33	This provision is for proactive pole replacements over and above those replaced under the 11kV line reconstruction programme.

Table 4.1: Forecast Expenditure on Major Proactive Asset Refurbishment and Replacements (FYE 2021-25)

4.2 Vegetation Management

Summary

We have reviewed our approach to vegetation management since the SAIDI impact of vegetation faults has trended upwards since FYE 2013. Our review has found that while the SAIDI impact has trended up, the SAIFI impact has trended down. The upward SAIDI trend is due to vegetation faults being in more remote network locations and therefore taking longer to fix. While we will continue to review whether our vegetation management strategy strikes the right balance in the attention we give to different parts of the network, and until the Ministry of Business, Innovation and Employment review of the Electricity (Hazards from Trees) Regulations 2003 results is known, no material increase in expenditure above current levels is forecast.

Because of the very high SAIDI impact of tree related faults experienced in FYE 2009 and FYE 2010, expenditure on vegetation management was increased in FYE 2011 to approximately $3 million per year. This had an immediate impact; our regulatory disclosures show that the SAIDI impact of tree related faults decreased from 134 in FYE 2009 and 109 in FYE 2010 to 45 in FYE 2011 and 57 in FYE 2012. Expenditure on vegetation management continued from FYE 2013 at a rate of around $2 million per year until FYE 2017 when it was reduced further to around $1.6 million per year. By that time a “first cut” as defined in the Electricity (Hazards from Trees) Regulations 2003 (tree regulations) had been completed across the network. It was thought that this had brought the vegetation management problem under control and the program could transition to a sustainable maintenance level. We also expected that tree owners would contribute to the cost of the program as provided for in the tree regulations. Our current forecast is for annual expenditure of $1.8 million per annum.

With this level of expenditure, while the SAIFI impact of tree related faults has continued to trend down, the SAIDI impact has increased, as shown in Figures 4.1 and 4.2. There are a number of reasons for this:

- A portion of our annual vegetation management expenditure is spent on the control of trees on our 110 kV and 33 kV line routes. However, as there are now very few tree related faults on these lines, the benefits of this expenditure are no longer reflected in an improvement in our tree-related fault performance. In any case, since the completion of the 33kV line protection upgrade in FYE 2017, most tree faults on the 33kV network would no longer result in a supply interruption.
- Vegetation management on the 11kV network is generally focused on feeder backbones, because these faults affect a larger number of consumers. Management of trees in the more remote, less economic parts of the network is more costly and has not had the same priority. While faults on the remote parts of the

network affect fewer consumers, they take longer to repair. This situation can be exacerbated during storm conditions, where the repair of close-in backbone faults, which may not be tree related, is prioritized. This effect was well illustrated in FYE2019, a relatively benign year weather-wise, when tree related SAIDI and SAIFI were both well down on previous years. However, the average time to repair a tree related fault (CAIDI) was very high, as shown in Figure 4.3.

- We have only been partially successful in getting tree owners to meet their obligations under the tree regulations. Our efforts to encourage compliance continue and we are still looking for ways to incentivise tree owners to meet their obligations. We are hoping that the upcoming review of the tree regulations by the Ministry of Business, Industry and Employment will assist in this regard. We also continue to review the focus of our vegetation management expenditure and, in particular, whether we have struck the right balance in the attention we give to the different parts of the network.

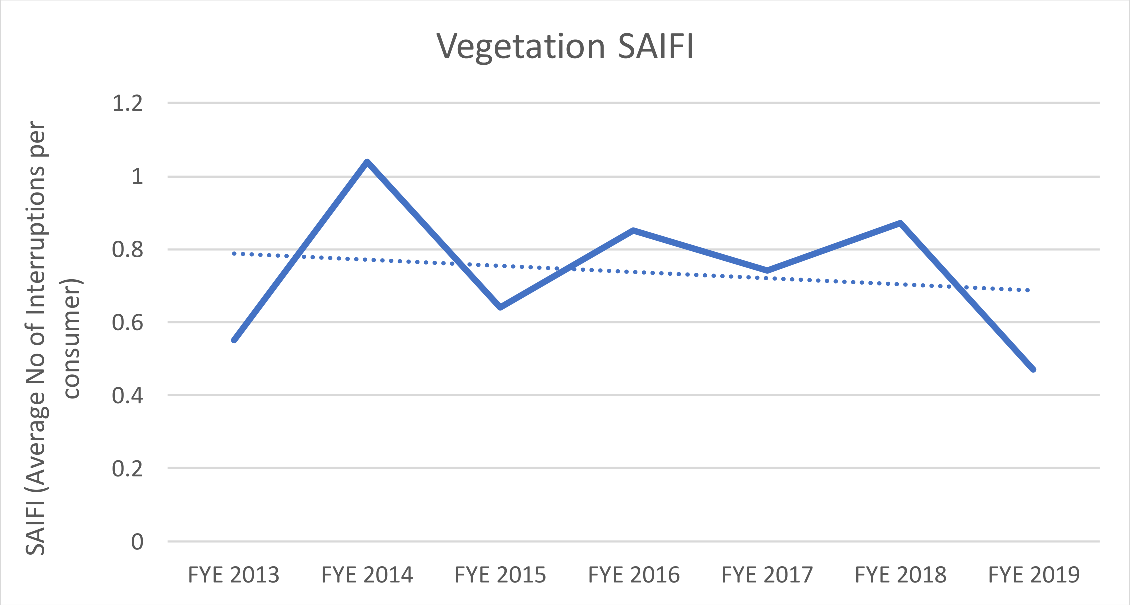

Figure 4.1: Vegetation Related SAIFI since FYE 2013

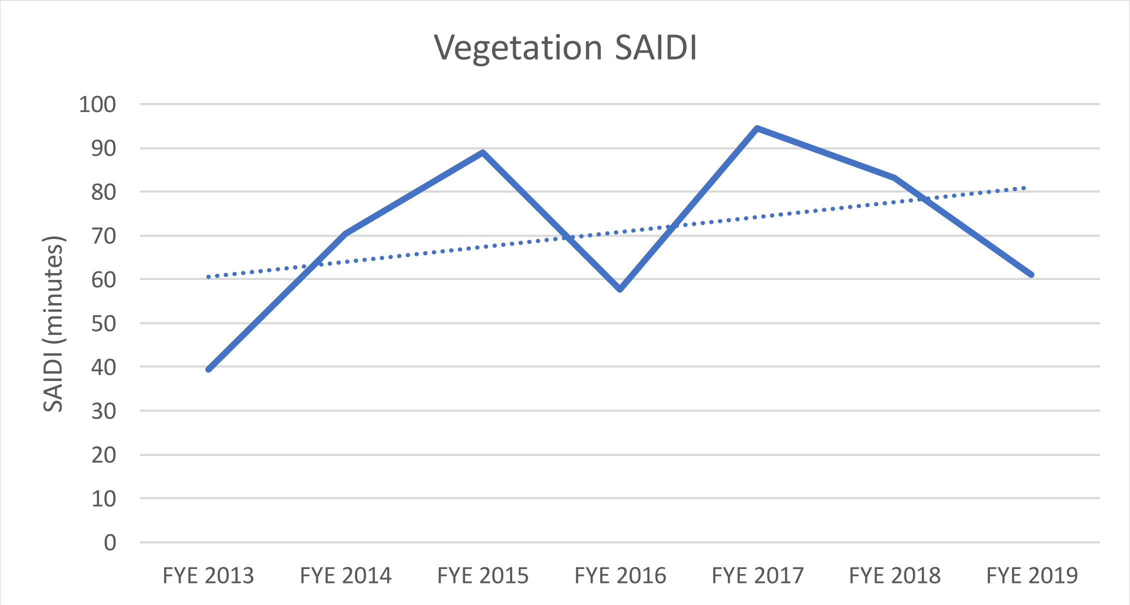

Figure 4.2: Vegetation Related SAIDI since FYE 2013

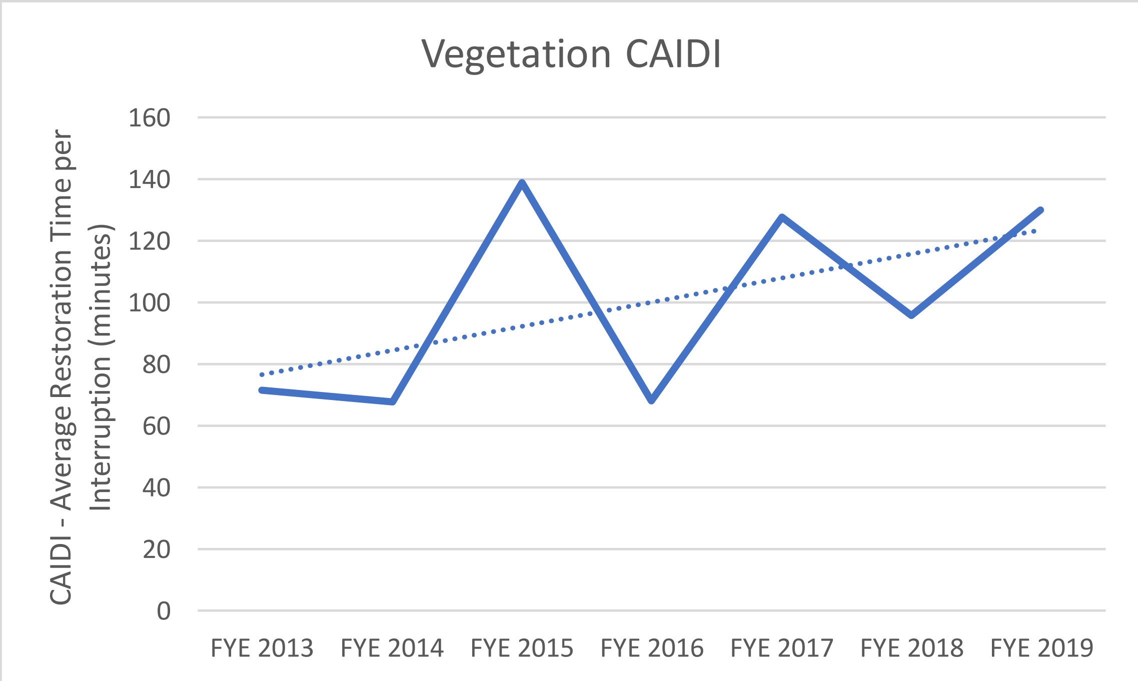

Figure 4.3: **Average Time to Repair a Vegetation Related Fault since FYE 2013**

5. 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

Company Name	**Top Energy**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

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

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref

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		for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10		Consumer connection	2,500	1,668	1,701	1,735	1,770	1,805	1,841	1,878	1,916	1,954	1,993
11		System growth	19,786	3,495	2,973	3,319	5,747	5,234	1,214	59	60	5,267	5,202
12		Asset replacement and renewal	5,793	5,821	6,609	8,171	6,196	7,667	6,743	6,322	6,521	6,748	6,702
13		Asset relocations											
14		Reliability, safety and environment:											
15		Quality of supply	11,507	1,274	2,699	3,593	2,662	2,352	8,318	9,288	5,976	14,976	15,522
16		Legislative and regulatory											
17		Other reliability, safety and environment											
18		**Total reliability, safety and environment**	11,507	1,274	2,699	3,593	2,662	2,352	8,318	9,288	5,976	14,976	15,522
19		**Expenditure on network assets**	39,586	12,258	13,982	16,818	16,375	17,058	18,116	17,548	14,473	28,945	29,419
20		Expenditure on non-network assets	1,100	153	938	520	531	541	552	563	574	586	598
21		**Expenditure on assets**	40,686	12,258	13,982	16,818	16,375	17,058	18,668	18,111	15,047	29,531	30,017
22													
23	*plus*	Cost of financing	100	300	102	104	106	108	110	113	115	117	120
24	*less*	Value of capital contributions	1,800	1,226	1,251	1,276	1,301	1,327	1,354	1,381	1,408	1,436	1,465
25	*plus*	Value of vested assets	10	10	11	11	12	12	13	13	14	14	15
26													
27		**Capital expenditure forecast**	38,996	11,342	12,845	15,658	15,192	15,851	17,438	16,856	13,768	28,226	28,686
28													
29		Assets commissioned	15,086	40,747	13,281	14,408	19,893	17,598	13,047	11,105	34,266	20,281	43,951
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		for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
32			**$000 (in constant prices)**										
33		Consumer connection	2,500	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668
34		System growth	19,786	3,495	2,915	3,190	5,415	4,835	1,100	52	52	4,496	4,353
35		Asset replacement and renewal	5,793	5,821	6,479	7,854	5,838	7,083	6,445	6,740	9,754	7,514	8,644
36		Asset relocations	-	-	-	-	-	-					
37		Reliability, safety and environment:											
38		Quality of supply	11,507	1,274	2,646	3,453	2,509	2,173	7,534	8,248	5,202	12,782	12,988
39		Legislative and regulatory	-	-	-	-	-	-					
40		Other reliability, safety and environment	-	-	-	-	-	-					
41		**Total reliability, safety and environment**	11,507	1,274	2,646	3,453	2,509	2,173	7,534	8,248	5,202	12,782	12,988
42		**Expenditure on network assets**	39,586	12,258	13,708	16,165	15,430	15,759	16,747	16,708	16,677	26,459	27,652
43		Expenditure on non-network assets	1,100	153	920	500	500	500	500	500	500	500	500
44		**Expenditure on assets**	40,686	12,411	14,628	16,665	15,930	16,259	17,247	17,208	17,177	26,959	28,152
45													
46	**Subcomponents of expenditure on assets (where known)**												
47		Energy efficiency and demand side management, reduction of energy losses											
48		Overhead to underground conversion											
49		Research and development											

Company Name	**Top Energy**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref												
50												
51		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
52	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
53	**Difference between nominal and constant price forecasts**	**$000**										
54	Consumer connection	-	-	33	67	102	137	174	210	248	286	325
55	System growth	-	-	58	129	331	399	114	7	8	772	849
56	Asset replacement and renewal	-	-	130	317	357	584	297	(418)	(3,233)	(766)	(1,941)
57	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
58	Reliability, safety and environment:											
59	Quality of supply	-	-	53	140	154	179	784	1,041	774	2,194	2,534
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
62	**Total reliability, safety and environment**	-	-	53	140	154	179	784	1,041	774	2,194	2,534
63	**Expenditure on network assets**	-	-	274	653	944	1,299	1,369	839	(2,204)	2,486	1,767
64	Expenditure on non-network assets	-	40,594	12,361	13,908	19,393	17,098	52	63	74	86	98
65	**Expenditure on assets**	-	(153)	(646)	153	444	799	1,421	903	(2,129)	2,572	1,865
66												

67		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
68	**11a(ii): Consumer Connection**						
69	*Consumer types defined by EDB**	**$000 (in constant prices)**					
70	All types	2,500	1,668	1,668	1,668	1,668	1,668
71	[EDB consumer type]						
72	[EDB consumer type]						
73	[EDB consumer type]						
74	[EDB consumer type]						
75	**include additional rows if needed*						
76	**Consumer connection expenditure**	2,500	1,668	1,668	1,668	1,668	1,668
77	*less* Capital contributions funding consumer connection	1,800	1,226	1,226	1,226	1,226	1,226
78	**Consumer connection less capital contributions**	700	442	442	442	442	442
79	**11a(iii): System Growth**						
80	Subtransmission	15,900	3,182	-	-	312	-
81	Zone substations	3,886	-	-	2,816	4,116	4,294
82	Distribution and LV lines	-	314	1,434	374	987	541
83	Distribution and LV cables	-	-	1,481	-	-	-
84	Distribution substations and transformers	-	-	-	-	-	-
85	Distribution switchgear	-	-	-	-	-	-
86	Other network assets	-	-	-	-	-	-
87	**System growth expenditure**	19,786	3,495	2,915	3,190	5,415	4,835
88	*less* Capital contributions funding system growth						
89	**System growth less capital contributions**	19,786	3,495	2,915	3,190	5,415	4,835
90							

Company Name	**Top Energy**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
91								
92		for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
93	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
94	Subtransmission		1,424	1,815	2,170	1,076	908	1,243
95	Zone substations		451	247	65	66	140	187
96	Distribution and LV lines		2,153	2,461	2,260	5,020	3,345	4,201
97	Distribution and LV cables		287	116	116	117	118	119
98	Distribution substations and transformers		1,131	387	386	388	390	392
99	Distribution switchgear		266	714	1,330	985	807	810
100	Other network assets		81	80	154	204	131	131
101	**Asset replacement and renewal expenditure**		5,793	5,821	6,479	7,854	5,838	7,083
102	*less* Capital contributions funding asset replacement and renewal							
103	**Asset replacement and renewal less capital contributions**		5,793	5,821	6,479	7,854	5,838	7,083
104								

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
105								
106		for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
107	**11a(v): Asset Relocations**							
108	*Project or programme**		**$000 (in constant prices)**					
109	[Description of material project or programme]							
110	[Description of material project or programme]							
111	[Description of material project or programme]							
112	[Description of material project or programme]							
113	[Description of material project or programme]							
114	**include additional rows if needed*							
115	All other project or programmes - asset relocations							
116	**Asset relocations expenditure**		-	-	-	-	-	-
117	*less* Capital contributions funding asset relocations							
118	**Asset relocations less capital contributions**		-	-	-	-	-	-
119								

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
120								
121		for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
122	**11a(vi): Quality of Supply**							
123	*Project or programme**		**$000 (in constant prices)**					
124	Kaikohe-Kaitaia line - property phase		400	222	360	46	46	-
125	Kaikohe-Kaitaia line - construction phase			-	-	-	-	689
126	11kV feeder interconnections			-	510	1,616	1,246	616
127	Kaitaia Generation		10,400	-	-	-	-	-
128	[Description of material project or programme]			525	-	-	-	-
129	**include additional rows if needed*							
130	All other projects or programmes - quality of supply		707	526	1,776	1,791	1,217	868
131	**Quality of supply expenditure**		11,507	1,274	2,646	3,453	2,509	2,173
132	*less* Capital contributions funding quality of supply							
133	**Quality of supply less capital contributions**		11,507	1,274	2,646	3,453	2,509	2,173
134								

Company Name	**Top Energy**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref							
135		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
136	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
137	**11a(vii): Legislative and Regulatory**						
138	*Project or programme**	**$000 (in constant prices)**					
139	[Description of material project or programme]						
140	[Description of material project or programme]						
141	[Description of material project or programme]						
142	[Description of material project or programme]						
143	[Description of material project or programme]						
144	**include additional rows if needed*						
145	All other projects or programmes - legislative and regulatory						
146	**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory						
148	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
149							
150		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme**	**$000 (in constant prices)**					
153	[Description of material project or programme]						
154	[Description of material project or programme]						
155	[Description of material project or programme]						
156	[Description of material project or programme]						
157	[Description of material project or programme]						
158	**include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment						
160	**Other reliability, safety and environment expenditure**	-	-	-	-	-	-
161	*less* Capital contributions funding other reliability, safety and environment						
162	**Other reliability, safety and environment less capital contributions**	-	-	-	-	-	-
163							
164		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
165	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme**	**$000 (in constant prices)**					
169	General	1,100	153	150	500	500	500
170	[Description of material project or programme]						
171	[Description of material project or programme]						
172	[Description of material project or programme]						
173	[Description of material project or programme]						
174	**include additional rows if needed*						
175	All other projects or programmes - routine expenditure						
176	**Routine expenditure**	1,100	153	150	500	500	500
177	**Atypical expenditure**						
178	*Project or programme**						
179	ADMS Stage 2 implementation			770			
180	[Description of material project or programme]						
181	[Description of material project or programme]						
182	[Description of material project or programme]						
183	[Description of material project or programme]						
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure						
186	**Atypical expenditure**	-	-	770	-	-	-
187							
188	**Expenditure on non-network assets**	1,100	153	920	500	500	500

Company Name	**Top Energy**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,762	1,435	1,438	1,441	1,443	1,445	1,446	1,447	1,447	1,447	1,446
11	Vegetation management	1,899	1,814	1,850	1,887	1,925	1,963	2,003	2,043	2,083	2,125	2,168
12	Routine and corrective maintenance and inspection	1,779	1,677	1,680	1,648	1,753	1,718	1,716	1,879	1,904	1,903	2,006
13	Asset replacement and renewal	961	1,283	1,309	1,335	1,362	1,389	1,417	1,445	1,474	1,504	1,534
14	**Network Opex**	6,401	6,209	6,277	6,311	6,483	6,516	6,581	6,814	6,909	6,979	7,154
15	System operations and network support	5,036	5,594	5,734	5,879	6,029	6,181	6,397	6,499	6,664	6,833	7,007
16	Business support	5,198	5,388	5,496	5,606	5,718	5,832	5,949	6,068	6,189	6,313	6,439
17	**Non-network opex**	10,234	10,982	11,230	11,485	11,747	12,013	12,346	12,567	12,853	13,146	13,446
18	**Operational expenditure**	16,635	17,191	17,507	17,796	18,230	18,528	18,927	19,381	19,761	20,125	20,600

19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,762	1,435	1,410	1,385	1,360	1,335	1,310	1,285	1,260	1,235	1,210
23	Vegetation management	1,899	1,814	1,814	1,814	1,814	1,814	1,814	1,814	1,814	1,814	1,814
24	Routine and corrective maintenance and inspection	1,779	1,677	1,647	1,584	1,652	1,587	1,554	1,669	1,658	1,624	1,679
25	Asset replacement and renewal	961	1,283	1,283	1,283	1,283	1,283	1,283	1,283	1,283	1,283	1,283
26	**Network Opex**	6,401	6,209	6,154	6,066	6,109	6,019	5,961	6,050	6,015	5,956	5,986
27	System operations and network support	5,036	5,594	5,622	5,651	5,681	5,710	5,794	5,771	5,801	5,832	5,863
28	Business support	5,198	5,388	5,388	5,388	5,388	5,388	5,388	5,388	5,388	5,388	5,388
29	**Non-network opex**	10,234	10,982	11,010	11,039	11,069	11,098	11,182	11,159	11,189	11,220	11,251
30	**Operational expenditure**	16,635	17,191	17,164	17,105	17,178	17,117	17,143	17,209	17,204	17,176	17,237
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance	309	340	340	340	340	340	340	340	340	340	340

37 ** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	28	56	83	110	136	162	187	212	236
43	Vegetation management	-	-	36	73	111	150	189	229	270	311	354
44	Routine and corrective maintenance and inspection	-	-	33	64	101	131	162	211	246	279	328
45	Asset replacement and renewal	-	-	26	52	79	106	134	162	191	220	250
46	**Network Opex**	-	-	123	245	374	496	620	763	894	1,022	1,168
47	System operations and network support	-	-	112	228	348	471	603	728	863	1,001	1,144
48	Business support	-	-	108	218	330	444	561	680	801	925	1,051
49	**Non-network opex**	-	-	220	446	678	915	1,164	1,408	1,664	1,926	2,195
50	**Operational expenditure**	-	-	343	691	1,051	1,411	1,784	2,171	2,558	2,948	3,363

Company Name	**Top Energy**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref												
7					**Asset condition at start of planning period (percentage of units by grade)**							
8												
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	No.	0.01%	2.74%	9.09%	78.86%	4.37%	4.94%	4	1.12%
11	All	Overhead Line	Wood poles	No.	-	15.09%	72.58%	3.05%	8.69%	0.59%	4	29.36%
12	All	Overhead Line	Other pole types	No.	-	-	-	75.00%	25.00%	-	4	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	1.88%	5.63%	74.79%	17.70%	-	2	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	60.90%	39.10%	-	2	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km					100.00%	-	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.				70.00%	30.00%		4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.				100.00%			4	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.				63.33%	36.67%		4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.			10.00%	58.33%	26.67%	5.00%	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.			0.53%	55.56%	39.15%	4.76%	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.	-	28.57%	-	-	71.43%	-	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	88.89%	11.11%	-	4	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	13.89%	-	69.44%	8.33%	8.33%	4	-
35												

Company Name	**Top Energy**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref												
36					**Asset condition at start of planning period (percentage of units by grade)**							
37												
38	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	2.22%	22.22%	55.56%	8.89%	11.11%	4	-
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	4.15%	6.86%	19.00%	44.21%	25.78%	-	2	2.82%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km	21.34%	17.00%	22.50%	20.69%	18.47%	-	2	4.43%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	0.05%	0.45%	7.76%	91.74%	-	2	-
44	HV	Distribution Cable	Distribution UG PILC	km	3.66%	13.15%	15.94%	67.25%	-	-	2	-
45	HV	Distribution Cable	Distribution Submarine Cable	km			100.00%				2	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	1.32%	0.53%	6.07%	77.84%	13.46%	0.79%	4	1.32%
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.	9.36%	14.30%	17.01%	24.47%	34.06%	0.79%	2	-
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	15.40%	36.09%	47.59%	0.92%	4	5.75%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.24%	0.12%	2.40%	85.39%	5.87%	5.99%	4	0.24%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.06%	0.57%	13.37%	75.75%	8.45%	1.81%	4	0.06%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	9.68%	64.52%	25.81%	-	4	4.84%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	40.00%	60.00%	-	-	4	-
55	LV	LV Line	LV OH Conductor	km	5.89%	17.65%	49.88%	18.56%	8.02%	-	2	-
56	LV	LV Cable	LV UG Cable	km	-	5.19%	14.58%	39.53%	40.70%	-	2	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.34%	6.51%	17.45%	41.58%	34.12%	-	2	-
58	LV	Connections	OH/UG consumer service connections	No.	-	0.70%	19.00%	54.80%	8.90%	16.60%	4	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	7.50%	-	1.50%	-	91.00%	-	4	7.50%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
61	All	Capacitor Banks	Capacitors including controls	No.	11.11%	2.22%	55.56%	20.00%	11.11%	-	4	11.11%
62	All	Load Control	Centralised plant	Lot	-	-	-	100.00%	-	-	4	-
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

Company Name	**Top Energy**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

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

sch ref

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

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Kaikohe	10	17	N-1	1	59%	17	58%	No constraint within +5 years	
10	Kawakawa	6	7	N-1	3	91%	7	71%	No constraint within +5 years	1.5MW to be transferred to Haruru in FYE2022.
11	Moerewa	3	5	N-1	2	67%	5	66%	No constraint within +5 years	
12	Waipapa	8	23	N-1	6	34%	23	33%	No constraint within +5 years	
13	Omanaia	3	-	N-0	3	-	-	-	Subtransmission circuit	Single transformer is an additional constraint. Transfer capacity includes 2MW of onsite generation.
14	Haruru	6	23	N-1	1	28%	23	39%	No constraint within +5 years	1.5MW to be transferred from Haruru in FYE2022
15	Mt Pokaka	3	-	N-0	1	-	-	-	Transformer	Mobile transformer available. Sufficient transfer capacity available to supply all small use consumers.
16	Kerikeri	7	23	N-1	6	31%	23	35%	No constraint within +5 years	
17	Kaeo	4	-	N-0	4	-	-	-	Subtransmission circuit	There will be only one incoming subtransmission circuit until the southern section of the 110kV line is completed, expected to be in FYE2030.
18	Okahu Rd	9	12	N-1	4	75%	12	79%	No constraint within +5 years	
19	Taipa	6	-	N-0	4	-	-	147%	Subtransmission circuit	Single transformer is an additional constraint. Transfer capacity is onsite diesel generation.
20	NPL	11	23	N-1	4	48%	23	48%	No constraint within +5 years	
21	Pukenui	2	-	N-0	1	-	-	-	Subtransmission circuit	Single transformer is an additional constraint. Transfer capacity is onsite diesel generation. Mobile transformer available. There is a single incoming subtransmission circuit
22	Kaikohe 110kV	48	55	N-1	25	87%	55	87%	No constraint within +5 years	Firm capacity includes the 25MVA of Ngawha generation that feeds directly into the 33kV bus, as this is base load generation.
23	Kaitaia 110kV	23	-	N-0	9	-	-	-	Subtransmission circuit	Transfer capacity is offsite diesel generation. There is only one incoming 110kV circuit.
24	[Zone Substation_16]					-			[Select one]	
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 forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name	**Top Energy**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

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

sch ref

sch ref								
7		**12c(i): Consumer Connections**						
8		*Number of ICPs connected in year by consumer type*				**Number of connections**		
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
11		*Consumer types defined by EDB**						
12		Residential	235	270	275	280	285	290
13		Other	100	125	135	140	145	150
14		[EDB consumer type]						
15		[EDB consumer type]						
16		[EDB consumer type]						
17		**Connections total**	335	395	410	420	430	440
18		**include additional rows if needed*						
19		**Distributed generation**						
20		Number of connections	200	260	340	440	570	740
21		Capacity of distributed generation installed in year (MVA)	1	33	2	2	3	4
22		**12c(ii) System Demand**						
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24		**Maximum coincident system demand (MW)** — for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
25		GXP demand	46	46	15	15	15	16
26	*plus*	Distributed generation output at HV and above	25	25	57	57	57	57
27		**Maximum coincident system demand**	71	71	72	72	72	73
28	*less*	Net transfers to (from) other EDBs at HV and above						
29		**Demand on system for supply to consumers' connection points**	71	71	72	72	72	73
30		**Electricity volumes carried (GWh)**						
31		Electricity supplied from GXPs	150	108	51	52	53	54
32	*less*	Electricity exports to GXPs						
33	*plus*	Electricity supplied from distributed generation	200	240	300	300	300	300
34	*less*	Net electricity supplied to (from) other EDBs						
35		**Electricity entering system for supply to ICPs**	350	348	351	352	353	354
36	*less*	Total energy delivered to ICPs	321	319	322	323	324	325
37		**Losses**	29	29	29	29	29	29
38								
39		**Load factor**	56%	56%	56%	56%	56%	55%
40		**Loss ratio**	8.3%	8.3%	8.3%	8.2%	8.2%	8.2%

Company Name	**Top Energy**
AMP Planning Period	**1 April 2020 – 31 March 2030**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

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

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9		for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
10	**SAIDI**							
11	Class B (planned interruptions on the network)		103.6	125.0	125.0	125.0	125.0	125.0
12	Class C (unplanned interruptions on the network)		325.6	274.0	266.0	257.0	249.0	241.0
13	**SAIFI**							
14	Class B (planned interruptions on the network)		0.69	0.50	0.50	0.50	0.50	0.50
15	Class C (unplanned interruptions on the network)		4.57	3.03	2.98	2.91	2.86	2.81

Company Name	Top Energy
For Year Ended	31 March 2021

Schedule 14a Mandatory Explanatory Notes on Forecast Information

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

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6

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

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

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

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

Our constant price forecast assumes FYE 2021 prices. We have assumed an annual inflation rate of 2% which is the mid-point of the Reserve Bank's target inflation range. Industry specific analysis of potential price movements is not considered justified given the forecast uncertainty.

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

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

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

Our constant price forecast assumes FYE 2021 prices. We have assumed an annual inflation rate of 2% which is the mid-point of the Reserve Bank's target inflation range. Industry specific analysis of potential price movements is not considered justified given the forecast uncertainty.

6.

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, Euan Richard Krogh and David Alexander Sullivan, 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 clause 2.6.1 and subclauses 2.6.3(4) and 2.6.5(3) 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.

Euan Richard Krogh	David Alexander Sullivan

31 March 2020

Note: This Asset Management Plan does not include any COVID-19 implications.

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