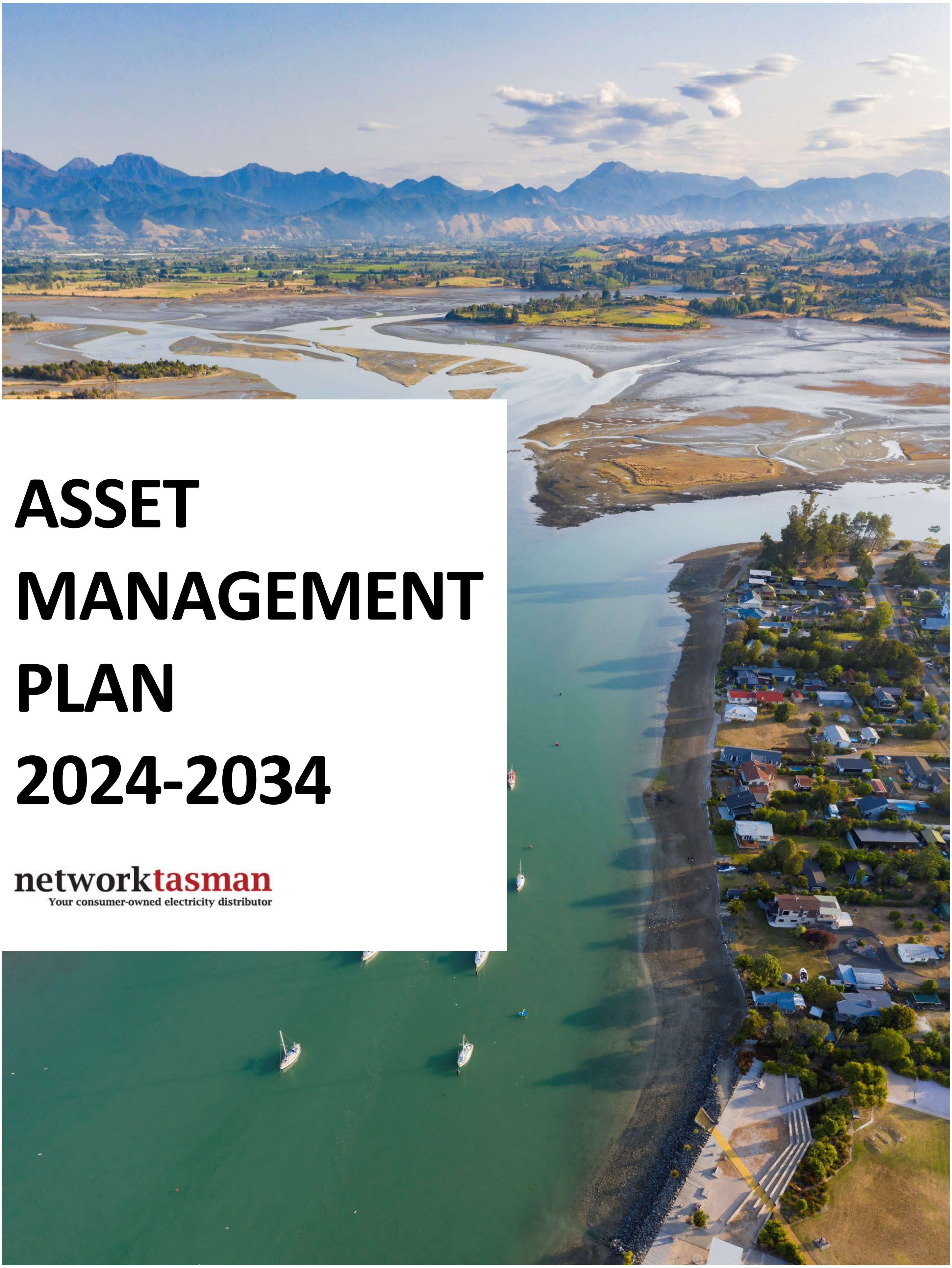


ASSET MANAGEMENT PLAN 2024-2034

networktasman
Your consumer-owned electricity distributor

Contents

1. EXECUTIVE SUMMARY

1.1 OVERVIEW AND PLAN PURPOSE

The Network Tasman Limited (NTL) electricity network distributes power to approx. 42,000 end use consumers in an area of 10,800 sq. km in the north-western corner of the South Island of New Zealand. The coverage area is shown in the map of Appendix A.

This *Network Tasman Asset Management Plan* (AMP) documents the current asset management practices used by NTL as part of developing an optimised management strategy for its electricity network assets. It outlines the present state of the electrical distribution system and presents a plan for the future maintenance and development of the network. This document is updated annually and will be continually refined.

The AMP incorporates regulatory information disclosure requirements in tabular form. The tables provide a standardised presentation of AMP information. These tables are appended to the document in Appendix N.

The primary objective of the plan is to provide a systematic approach to the planning of programmes, the implementation of which will ensure that the network assets are being effectively and efficiently maintained, enhanced and developed to satisfy stakeholder requirements.

The plan provides information on the implementation of programmes including how the company will organise and resource itself to ensure that the programmes are implemented in a timely and effective manner.

The period covered by this plan is for ten years beginning on 1 April 2024 and extending to 31 March 2034. The date of this revision of the plan is 31 March 2024. This document was approved by the NTL board of directors on 31 March 2024.

The next review of this plan will be issued on 31 March 2025.

1.2 CORPORATE OBJECTIVES AND ASSET MANAGEMENT DRIVERS

NTL is owned by the Network Tasman Trust on behalf of consumers as defined in the *Network Tasman Trust Deed*.

The drivers for the asset management process are derived from the *Statement of Corporate Intent* (SCI) of the company. This includes the vision and mission statements of NTL and the key objectives of the company.

The key business objectives arising from the vision and mission statements are as follows:

- To deliver safe, reliable and high quality network services to consumers that are in broad alignment with consumer and/or consumer group expectations of reliability and price as revealed by the consumer consultation process.
- To improve operational efficiency and effectiveness.
- To ensure regulatory compliance of the network and operations.
- To consider and adopt new technologies where appropriate.
- To facilitate the decarbonisation of the Nelson/Tasman economy.
- To increase consumer value.

Six asset drivers have been identified which define the scope and need for all asset management work. The drivers are:

- Safety (of workers, contractors and the general public)
- Consumer service (provision for adequate capacity and reliability), based on both direct consultations with large customers and use of consumer surveys and suitable proxies for estimating the requirements of the mass market.
- Economic efficiency

- Environmental responsibility
- Regulatory Compliance
- Risk management

The drivers will be both internally and externally set. Development of the network will be condition and performance based.

1.3 STATUS OF PROGRAMMES AND PROJECTS

This plan provides a long term indication of asset management requirements. Specific work programmes and projects will be drawn from this plan for inclusion in future annual business plans.

Specific projects greater than $100,000 in value are subject to board approval on an individual business case basis.

The inclusion of a particular project in this plan does not imply that the project will proceed.

The implementation timing of capital projects in this plan is influenced by outturns of growth in particular areas. The advent and development of modern technologies such as distributed generation and battery storage may have a significant effect on the implementation and timing of the capital expenditure projects in this plan. Growth in new loads such as electric vehicle (EV) charging and industrial process heating electrification may also have an impact. In this environment, the company is looking to apply new technologies to defer large capital projects where it is practicable and economical to do so.

The potential impacts of climate change on the distribution network assets are also considered in the plan. These may include coastal inundation and increased frequency of major storms.

Covid-19 has affected the manufacture and delivery of some types of network distribution equipment, resulting in extended delivery times and shortages. This may continue through the early years of the plan and delay the completion of some projects. Forward ordering of critical items for some projects was undertaken during 2020-2022.

1.4 ASSET MANAGEMENT SYSTEMS AND INFORMATION

A number of information subsystems are operated by NTL providing data inputs to the asset management process. These are as follows:

Geographic Information System (GIS)

- Central asset datastore for asset location
- Substation database
- Consumer connection database
- Asset condition survey database

Load survey database

- Outages and faults databases
- Outage information and statistics
- Component failure records
- Trend analysis

Network loadflow model

- Network voltage profiles
- Network configuration and load modelling
- Fault analysis

Customer consultation exercises

- Direct consultation with large customers
- Mass market surveys

1.5 NETWORK CONFIGURATION AND ASSET DESCRIPTION

The plan covers the network assets of NTL which comprise:

- Subtransmission lines, support structures and underground cables
- Distribution lines, support structures and underground cables
- Substations including all plant and equipment within the substation such as transformers, switchgear and SCADA (Supervisory Control and Data Acquisition) remote terminal units.
- Protection relays and voltage regulators
- Control centre – SCADA master station and associated communications systems
- Load control facilities

The network is divided into five bulk supply regions as indicated in Appendix A.

Traversing the Stoke, Golden Bay and Motueka regions is a 66kV subtransmission network that runs from the Stoke 66kV GXP (grid exit point) to a zone substation in Motueka and three 66kV substations in Golden Bay at Upper Takaka, Cobb and Motupipi.

The basic asset statistics of the Network Tasman network are summarised in the following table:

Network Tasman Distribution System	No.
Subtransmission Substations	2
Zone Substations	14
Ripple Injection Transmitters	5
66kV + 33kV Networks (km)	323
22kV + 11kV + 6.6kV Networks (km)	2,204
400V Networks (km)	1,207
Distribution Substations	4,696
Overall Peak Load (system demand for supply to consumer ICPs)	126
Annual Energy Delivered (MWh entering system for supply to consumer ICPs)	684,000
Annual System Load Factor	69%

The location of the assets is broadly indicated in the network layout maps of Appendix A. These maps show the location of the HV subtransmission and HV distribution throughout the area.

The *Asset Management Plan* does not cover Network Tasman's non-electricity distribution business related assets.

1.6 SERVICE LEVEL OBJECTIVES

Reliability targets have been reviewed and set following analysis of historical fault data, network studies and visits to other similar networks. The resulting targets represent achievable outcomes for networks of the nature of the NTL network.

In the 2019 AMP review, consideration of the 10-year copper conductor replacement programme was made and this led to an increase in the planned SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) targets of 25 and 0.16 respectively. The planned SAIDI target increased to 100 points and the planned SAIFI target increased to 0.7 for the next ten years.

Service level targets are in line with and justified by consumer consultation.

Recent consumer consultation undertaken consisted of:

- Direct and detailed consultation with 30 of our largest consumers.
- Assessment of mass market satisfaction via mass market survey and consultation with consumer groups. The report of the latest mass market survey is attached as Appendix K.

Asset performance targets in terms of SAIDI and SAIFI for the period of the plan are as follows:

SAIDI

		Transpower Planned	Transpower Unplanned	Total Transpower	NTL Planned	NTL Unplanned	NTL Total	Overall SAIDI
Actual	2009/10	0	79	79	62	85	147	226
	2010/11	48	18	66	48	129	177	243
	2011/12	14	1	15	52	107	159	174
	2012/13	32	7	39	36	93	129	168
	2013/14	10	17	27	53	75	128	155
	2014/15	0	30	30	58	122	180	210
	2015/16	9	0	9	102	84	186	195
	2016/17	8	13	21	70	115	185	206
	2017/18	16	238	254	71	161	232	486
	2018/19	17	0	17	106	134	240	257
	2019/20	8	4	12	102	83	185	197
	2020/21	11	0	11	116	87	203	214
	2021/22	5	22	27	65	113	178	205
Actual	2022/23	24	6	30	154	121	275	305
Forecast	2023/24	12	1	13	107	128	235	248
Target	2023/24	10	5	15	100	75	175	190
	2024/25	10	5	15	100	75	175	190
	2025/26	10	5	15	100	75	175	190
	2026/27	10	5	15	100	75	175	190
	2027/28	10	5	15	75	75	150	165
	2028/29	10	5	15	75	75	150	165
	2029/30	10	5	15	75	75	150	165
	2030/31	10	5	15	75	75	150	165
	2031/32	10	5	15	75	75	150	165
	2032/33	10	5	15	75	75	150	165

SAIFI

		Transpower Planned	Transpower Unplanned	Total Transpower	NTL Planned	NTL Unplanned	NTL Total	Overall SAIFI
Actual	2009/10	0.00	0.85	0.85	0.27	1.46	1.73	2.58
	2010/11	0.27	0.14	0.41	0.27	1.37	1.64	2.05
	2011/12	0.05	0.03	0.08	0.32	1.06	1.38	1.46
	2012/13	0.09	0.36	0.45	0.33	1.15	1.48	1.93
	2013/14	0.03	0.70	0.73	0.28	1.05	1.33	2.06
	2014/15	0.00	0.44	0.44	0.22	1.17	1.39	1.83
	2015/16	0.08	0.00	0.08	0.39	1.20	1.59	1.67
	2016/17	0.03	0.3	0.33	0.28	1.28	1.56	1.89
	2017/18	0.05	1.60	1.65	0.28	1.03	1.31	2.96
	2018/19	0.05	0.00	0.05	0.43	0.91	1.34	1.39
	2019/20	0.11	0.05	0.16	0.36	0.88	1.24	1.40
	2020/21	0.03	0.00	0.03	0.33	0.85	1.18	1.21
	2021/22	0.01	0.08	0.09	0.24	1.15	1.39	1.48
Actual	2022/23	0.05	0.05	0.10	0.56	1.17	1.73	1.83
Forecast	2023/24	0.05	0.02	0.07	0.35	1.21	1.56	1.63
Target	2023/24	0.03	0.12	0.15	0.70	1.07	1.77	1.92
	2024/25	0.03	0.12	0.15	0.70	1.07	1.77	1.92
	2025/26	0.03	0.12	0.15	0.70	1.07	1.77	1.92
	2026/27	0.03	0.12	0.15	0.70	1.07	1.77	1.92
	2027/28	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2028/29	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2029/30	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2030/31	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2031/32	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2032/33	0.03	0.12	0.15	0.54	1.07	1.61	1.76

CAIDI

		Transpower Planned	Transpower Unplanned	Total Transpower	NTL Planned	NTL Unplanned	NTL Total	Overall CAIDI
	2009/10	0	93	93	225	58	85	88
	2010/11	178	129	161	178	94	109	119
	2011/12	280	33	187	163	101	115	119
	2012/13	356	19	87	109	81	87	87
	2013/14	333	24	37	189	71	96	75
	2014/15	0	68	68	264	104	129	115
	2015/16	112	0	112	262	70	117	117
	2016/17	267	43	64	250	147	119	109
	2017/18	320	149	154	254	156	177	164
	2018/19	340	0	340	246	147	179	185
	2019/20	73	80	75	283	94	149	141
	2020/21	367	0	367	351	102	172	177
	2021/22	500	275	300	270	98	128	139
Actual	2022/23	480	120	300	275	103	159	167
Forecast	2023/24	240	50	186	306	106	151	152
Target	2023/24	333	40	100	143	70	99	99
	2024/25	333	40	100	143	70	99	99
	2025/26	333	40	100	143	70	99	99
	2026/27	333	40	100	143	70	99	99
	2027/28	333	40	100	139	70	93	94
	2028/29	333	40	100	139	70	93	94
	2029/30	333	40	100	139	70	93	94
	2030/31	333	40	100	139	70	93	94
	2031/32	333	40	100	139	70	93	94
	2032/33	333	40	100	139	70	93	94

Asset effectiveness targets are as follows:

Service Criterion	Key Performance Indicator	Annual Target 2021/22 to 2032/33	Actual 2022/23	Forecast 2023/24
Supply Quality	Number of proven voltage complaints	10	6	6
Contractual Performance	Breaches of UOSA	0	0	0
Environmental Effectiveness	Incidents of non-compliant emission from network	0	0	0
Safety	Staff and contractor serious harm incidents	0	0	0
Safety	Public injury incidents.	0	0	0
Safety	Public property damage incidents	0	0	0
Safety	Incidents with potential for public injury	70	86	84
Safety	Incidents with potential for public property damage	5	0	0

Asset efficiency targets are as follows:

Service Criterion	Key Performance Indicator	Annual Target 2021/22 to 2032/33	Actual 2022/23	Forecast 2023/24
Thermal Efficiency	Network losses	6%	5.6%	5.0%
Transformer Utilisation	KVA peak demand/distribution transformers	30%	26%	26%
Operating Efficiency	Cash operating costs per consumer	<$350	$307	$343

1.7 ASSET MAINTENANCE AND RENEWALS PLAN

NTL has the view that overhead distribution lines can be operated and maintained on an ongoing basis in perpetuity so that the lines never become unserviceable and they remain in such an overall condition that the probability of failure of any line is held constant.

Over the years the network has been maintained to a high standard. When this is combined with the significant renewal that has also taken place in many areas as a result of capital works and new line extensions, the result is that the NTL system is in good overall condition at present. This conclusion is supported by the low rates of faults resulting from network defects experienced (long term average approx. 1.1 faults per 100km of line per annum).

During 2017, Network Tasman commissioned external consultants Mitton ElectroNet to undertake an independent review of the condition of the distribution network and of the systems in place at Network Tasman to manage the condition of the network. This review confirmed that the network is generally in good condition. Any deficiencies in the network asset noted by the consultants were already identified and discussed within the current AMP. Some recommendations for further improvement were made by Mitton ElectroNet, and these have been considered and incorporated into the AMP. Another external review of the asset management systems and network condition will be considered within three years.

NTL has categorised its asset maintenance activities into two categories for the purposes of reporting and budgetary control. These are:

- Routine Maintenance – ongoing work aimed at maintaining individual component asset function and serviceability rather than enhancing life. Typical activities being - replacing blown fuses, cleaning components, tightening hardware, restraining conductors, etc.
- Renewals – component replacements at or near end of life.

The distribution network is 70% overhead by circuit length. The overhead distribution is 95% based on concrete poles that are well manufactured to a conservative design. These poles are expected to have a long service life in the benign Nelson environment. Aside from a small number of poles in relatively short sections of coastal line and in estuaries, and approx. 400 poles that are known to have been poorly made and are now spalling, there are no signs to date that even the oldest poles on the network are reaching end of life. Civil engineers, with the assistance of the University of Canterbury, have assessed the life of most concrete poles at 150 years.

Iron rail poles on the network, however, are reaching end of life and all will be replaced with concrete poles or treated softwood poles within the next few years. There are a small number of treated softwood poles dating back to the 1970s. The oldest of these may be reaching end of life. Condition testing of these will commence within the time frame of this plan.

Crossarms on the network have varying life from 15 to 45 years. The condition of in-service crossarms is assessed individually as timber quality is highly variable even within individually supplied batches of crossarms. Local conditions of aspect and rainfall are also life determining factors for individual crossarms. Crossarm renewal occurs through replacement and this is currently taking place at approx. 1,200 replacements per year.

Line hardware is mainly of porcelain and galvanised steel that has a very long life in the Nelson/Tasman environment. Some specific items have identified failure mechanisms (e.g. two-insulator dropout fuses and “kidney” strain insulators) and replacement strategies for these are underway.

Overhead line conductor in service is mainly copper, steel reinforced aluminium (ACSR), or all aluminium conductor (AAC). Over recent years, the incidence of conductor breakage in light copper conductors appears to have increased. This conductor is reaching the end of its life, being brought about through metallurgic ageing and annealing particularly in areas where clashing faults have occurred in the past. A 10-year programme to replace light copper conductors on all high voltage lines is included in this plan and this is underway. This programme commenced in the 2017/18 year.

No major problems with the aluminium conductors exist except in the west coast section of Golden Bay where corrosive and windy conditions exist. Conductor life is significantly shorter in this area. A conductor replacement project in the area has recently been completed.

Galvanised steel conductor installed in the 1940s and 1950s is still in place on some rural spur lines. This is reaching end of life due to corrosion and is being replaced with ACSR.

The underground cables on the network are mainly paper or more recently cross linked polyethylene (XLPE) insulated copper or aluminium for high voltage and PVC or XLPE insulated aluminium for low voltage. All cables have been carefully installed in bedding fines and all are operated within prudent loading limits. Testing of local cable bedding materials has revealed lower than previously assumed thermal resistivity. Partial discharge testing of the insulation of 33kV cables has been undertaken in recent years and this procedure is planned to be expanded to include critical 11kV feeder cables in the future.

Some loss of mechanical protection has been identified in lower capacity paper lead HV cables, due to corrosion of the outer steel tape armouring, however it is believed that this will not critically degrade the performance of the cables in the short term unless these cables are disturbed. This group of cables is being monitored and the oldest of these cables are now 45 years old. Network Tasman has developed a 10-year replacement programme for these cables and this programme commenced in 2021.

The 66kV subtransmission system is based on a combination of hardwood poles, concrete poles and lattice towers. These are all in good condition.

The network contains twelve 33/11kV zone substations of capacity ranging from 3MVA to 23MVA, two 66/11kV zone substations, and one 66/33kV subtransmission substation of capacity 20MVA. There is also one 66/6.6kV substation connecting a hydro generator. All are in good condition and are well designed for normally expected electrical and seismological duty. Fire risk at the substations is managed by design.

There are twenty-two NTL owned 33/11kV three-phase power transformers, four 66/11kV three-phase transformers and two 66/33kV transformers in service at these substations. The power transformers range in age from 2 to 64 years. All are monitored by annual dissolved gas analysis test and diagnosis.

A programme of insulation testing and winding reclamping of the older power transformers is underway. Transformers on the network have been conservatively loaded and have not experienced high numbers of through faults. To date, seven 33/11kV transformers manufactured prior to 1980 have undergone a midlife refurbishment and are expected to see out a 70-year life. Tap changers on the two oldest units (circa 1959) have been replaced with modern equivalents in conjunction with transformer refurbishment. Further midlife refurbishments are planned as power transformers reach 40 years in service.

High voltage circuit breakers (CBs) consist of ten 66kV outdoor ground mounted CBs, three indoor 33kV switchboards, twenty-one pole mounted 33kV CBs, eight indoor 11kV switchboards and seventy 11kV pole mounted reclosers and sectionalisers. Partial discharge testing has been carried out on the indoor 11kV and 33kV switchboards and this has verified good insulation condition. The fault duty of all equipment is within ratings. Pole mounted reclosers are now all of the vacuum interrupter type with oil, SF6 or solid insulation.

There are 270 ground mounted field high voltage ring main switches in service. These are either encapsulated vacuum or oil switches. The oil switches manufactured prior to 1988 were subject to a weakness in the design that resulted in intermittent operational problems. These have all been replaced. There are no high voltage oil fuse switches on the network.

An issue with the earth switches in one type of ground mounted 11kV switch has arisen during 2023. This will result in the early replacement of approx. 25 switch units. A replacement program is under investigation at present.

The network contains 4,537 distribution substations ranging in size from 5kVA to 1MVA. A small number of in-service transformer failures occur each year, mainly as a result of lightning strikes. A distribution transformer renewal programme, targeting the replacement of in-service transformers that are older than 60 years, is in place.

As a public safety improvement initiative, the use of platform substations has been discontinued. A programme to remove existing platform substations, based on risk of public access to platforms, has been set up and this commenced in 2017/18.

During 2021, a condition based risk management system project was commenced. This is a software based information system that incorporates condition and age data to form a health index for each asset and combines this with a failure consequence to derive a risk index for the assets expressed in annual failure cost terms. The system can be used to assess and rank the cost benefits of individual or collective maintenance/renewal strategies.

The project is in the data collection and validation process at present.

Budget forecast summaries for the classes of Maintenance and Renewals are given in Appendix F. Emergency repairs are included in these forecast summaries.

1.8 NETWORK DEVELOPMENT PLANS

Within Network Tasman's area there are five bulk supply regions and each of these has a different growth rate. There is steady growth in the Stoke and Motueka bulk supply regions and steady but slower growth in the Golden Bay and Murchison regions. The Kikiwa region has shown significant growth in the past few years due to land use change to hop processing.

A steady increase in base domestic and small commercial load annually over the whole region is expected of approx. 5GWh and 1.3MW per annum for the period of this plan. This growth excludes large consumer specific load increases.

The growth projection includes the effects of heat pump installations that are now replacing wood burner heating in the district. It also includes the effects of distributed generation and load management. Residential electric vehicle charging is a new load that is developing. Information on how this will affect network loading is limited at present. Electric vehicles are still small in number in the area at present but are expected to increase over time. Home vehicle charging is expected to impact low voltage distribution circuits initially.

The potential effects of electric vehicle charging on the network have been studied and it has been identified that older overhead LV networks may need to be reinforced if vehicle charging reaches significant levels, particularly if vehicle charging occurs at peak domestic load times. The design capacity for new residential LV networks has also been reviewed in light of potential future EV home charging loading (ref Section 5.8.2 p65). Network Tasman is monitoring the growth of EVs in the district and the charging patterns emerging in the network. Off-peak charging will be encouraged through the promotion of line tariffs that reward domestic consumers who charge their vehicles during the night.

The NTL network is generally of low consumer density (average 12 consumers/km line). Network constraints reached tend to be primarily end of line voltage related rather than component current capacity related.

In order to meet the load growth projected, a year by year plan of specific and non-specific network development projects has been formulated and is underway. This programme has been formulated from a step by step process of network development planning which includes the identification and elimination of network constraints as the loadings increase in line with projected growth over the planning period. The development projects include some specific upgrades to the 33kV subtransmission system, additional zone substations and some specific reinforcements of the 11kV distribution system. Non-specific development costs include expenditure items that are not cost recovered from new consumers or land developers under current policy. Distribution transformers and switchgear needed for distribution network extensions are the major items within this category.

NTL relies heavily on the bulk supply of electricity from the major hydro generators in the south of the South Island and at times generation from the North Island transmitted southward over the inter-island DC link. South Island bulk generation is transmitted to the Nelson region over 220kV lines. Transmission capacity from Christchurch to Nelson was upgraded in 2006 by approx. 50% with the stringing of a third 220kV circuit on existing double circuit towers from Islington to Kikiwa. Constraints exist, however, in the transmission capacity from Twizel to Islington in Christchurch. Transpower New Zealand is currently implementing a series of tactical upgrades of the existing four circuits feeding power into the Islington bus. There is also a planned programme of strategic transformer upgrades and additional voltage support device installations. This development plan is expected to avoid the requirement for any major new transmission lines until at least 2030.

The major system growth driven development project coming up is the new Brightwater GXP substation. This GXP will supplement the Stoke GXP as a second source of bulk supply to Nelson City and the Waimea districts. Although this will not be a NTL asset, the project will impose increased transmission costs on Network Tasman and its consumers. The development is expected to be required around 2027. Initiatives to cost effectively defer the development have been investigated. The substation will be built by Transpower and at present the lead time to design and construct the substation is four years.

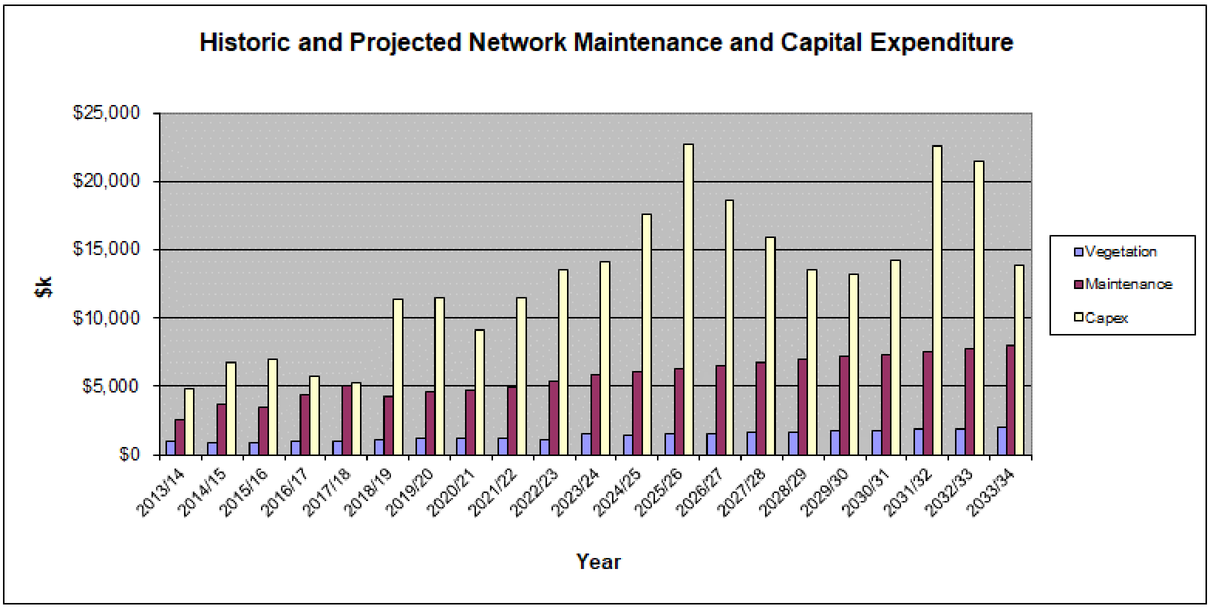
Apart from the specifically identified network development projects, allowance has been made for network line extensions to new consumers in both urban subdivisions and in rural areas. The *Capital Contributions Policy* was revised during 2022, and capital development contributions from prospective new customers in remote areas of the network are required. Current policy does not require capital contributions for transformers or items of high voltage switchgear from developers or intending consumers. Details of NTL's *Capital Contributions Policy* are available on the website at www.networktasman.co.nz

A summary of projected development costs by major asset category and by year for NTL is given in Appendix D to this document. A list of specific development projects is given in Appendix E.

The major capital projects for the next ten years are:

- Capacity upgrade of Motueka zone substation (growth).
- Construction of new grid exit point substation at Brightwater.
- Upgrade of subtransmission capacity to Motueka and Golden Bay.
- Extension of 33kV network to a new substation at Wakefield.
- Light copper HV overhead conductor replacement programme.
- Smallcross sectional area (csa) PILC (paper insulated lead covered cables)copper HV underground cable replacement programme.
- End of life distribution transformer renewal programme.

The chart below shows the overall levels of expenditure on the distribution network since 2013/14, together with the projected expenditure to 2032/33.



The chart shows that capital expenditure averaged around $6m per year up to 2018/19. Renewal of overhead lines (mainly copper conductor replacements) commenced that year.

Significantly increased capital expenditure is expected for the next ten years (averaging approx. $17m per year) during which time a number of upgrades to existing substations are planned and a new major GXP substation (2026-27) will be developed. A major capital project to increase the capacity of the subtransmission system supplying Motueka and Golden Bay occurs at the end of the 10-year planning period.

Overhead line conductor replacements and some underground cable replacements will also continue through this period.

Meanwhile, network maintenance continues at a steady rate of approx. $7m per year, mainly consisting of crossarm and pole hardware replacements. Vegetation maintenance expenditure is also shown in the chart, generally averaging approx. $1.5m per year. Vegetation expenditure is accepted as a significant operational overhead and NTL views it as an important and necessary component of operating a high reliability network.

1.9 RISK MANAGEMENT

A risk assessment and risk management study of the distribution network was first undertaken by the company in 1998. This study has been reviewed and updated in conjunction with each AMP review. The background environment of risk of loss of electricity supply has not substantially changed since the original 1998 study. The results of this review work are included in Appendix I.

Treatment of the identified risks is covered with reference to capital expenditure projects within this *Asset Management Plan* and also with reference to the document *Network Tasman Disaster Readiness and Response Plan* (refer Appendix L) for those risk events that are treated through deployment of a specific contingency plan.

Network Tasman's disaster readiness and response was reviewed by consultants Mitton ElectroNet during 2017. This review considered the *Disaster Readiness and Response Plan* (DRRP) and also operational matters that would arise in the immediate and short term aftermath of a major event. A number of improvement recommendations were made and many of these have been implemented. The implementation of these recommendations will improve NTL's overall resilience to natural disasters such as major earthquakes.

Aside from risks of non-supply due to failure of the NTL distribution network, there is risk of failure of the transmission network and in particular risk due to failure at TPNZ Stoke substation which is the major GXP from which NTL takes most of its supply. Transpower has undertaken a risk management study to identify and document the significant risks of loss of supply from this substation. NTL considers the risk of loss of supply from this substation a significant driver of the proposed new GXP capital project development at Brightwater.

The company operates a public safety management system. Incorporated in this system is a public safety risk management committee. Duties of the committee include:

- Establishing and maintaining a public safety hazard register.
- Investigating all reported public safety incidents and near misses.
- Collating and reporting public safety key performance indicators (KPIs) to the board.
- Regularly reviewing public safety hazards and implementing risk mitigation strategies.

1.10 PERFORMANCE GAP ANALYSIS AND IMPROVEMENT PLANS

SAIDI from unplanned outages is forecast to be over target for 2023/24 (115 against target 75). The year included commonly occurring outage events such as car vs pole events, bird strikes and some equipment failures including a number of underground cable failures. There were two significant 33kV outages which resulted in very high SAIDI counts. There was also a tornado event in April 2023.

The SAIDI target for planned outages was increased in 2016 to account for additional shutdowns from a reduction in live line maintenance work, and again in 2018 to account for unavoidable additional shutdowns brought about by the HV light conductor replacement programme. This programme will run for a further five years. Higher planned outage SAIDI to complete the programme, as well as the normal network maintenance programme, is inevitable.

Planned outage SAIDI for 2023/24 is also over target (forecast 120 against target 100). This reflects a year of catch-up work undertaken that had been disrupted by previous Covid-19 lockdowns and procurement issues.

The long term trend of network reliability performance (aside from major storm events) is generally of improvement and the operational benefits of capital investments into upgraded network capacity made over the past 10 years are now being realised. Such investments have included the provision of additional backup circuits in the 33kV network and the shortening of 11kV feeders through the provision of additional feeder circuits and zone substations.

Strategies to further address network reliability are to continue with the proposed developments in this plan, and to bring forward some of the cost effective reliability improvement measures such as installing fault indicators, trefoiling lines etc.

Consultation with consumers undertaken during 2022 indicates that there are no major concerns with respect to the supply reliability delivered or with the line price paid.

This survey found an overall 96% level of satisfaction across the customer base taking into account supply reliability, supply quality, outage response, communication and price paid, with 65% of customers stating that no level of price increase would be justified to improve network performance. Another consumer survey is to be undertaken during 2024.

Network Tasman believes that the asset management planning and processes it has deployed are serving the company and its consumers well, and that in many areas they follow industry best practice.

GIS based information systems support the execution of cost effective and efficient system maintenance, asset renewals and vegetation management programmes. The results have been sustained low rates of faults combined with low cash operating costs.

Areas for AMP process improvement are based around filling some holes in datasets and completing and implementing the CBRM (Condition based risk management) asset management system to provide additional backup information and verification of AMP expenditure levels.

1.11 DEPLOYMENT OF NEW TECHNOLOGIES

1.11.1 Photovoltaic (PV) Distributed Generation

Distributed generation in the form of solar PV has high uptake in Nelson when compared with other areas of New Zealand, but the current overall penetration level is not high enough to affect network operations at present. However, solar PV growth in the area is ongoing. The company has undertaken considerable study in conjunction with industry groups to model the effects of future high levels of PV in the network and identify strategies now that will maximise the hosting capacity available whilst maintaining equity and fairness to all users of the network. NTL has introduced standard operating settings for all PV inverters connected to its network. These settings avoid overvoltage conditions arising from high levels of distributed generation into the network and maximise the generation that can be accommodated.

1.11.2 Advanced Electronic Meters

Network Tasman has completed a rollout of advanced electronic meters (smart meters) throughout its network supply area.

In this rollout, older technology electronic and electromechanical meters were replaced with smart meters on consumers' switchboards. Approximately 75% of consumer installations in the NTL network now have an advanced electronic meter.

The "smart meters" incorporate remote two way communications capability. This rollout was undertaken primarily for electricity retailers. The rollout, however, also provides Network Tasman with enhanced capability to monitor conditions on its network in real time and offer opportunities for NTL to improve the performance of its network and its service to consumers. These opportunities include but are not limited to:

- Proactive voltage correction through analysis of voltage information available from smart meters.
- Reduction in consumer fault callouts through manual polling of voltage at the consumer's meter.
- Advance detection of network defects such as poor electrical connections through voltage exception reporting from smart meters.
- Improved back feed management following network outage.

Network development planning tools are also now being developed. These include:

- LV feeder circuit loading
- Distribution transformer capacity utilisation
- Consumer type load profiling (including DER battery storage and EV owning consumers)

Maximising the network benefits will continue to be a key priority for the company over the next few years.

1.12 DECARBONISATION

Network Tasman has undertaken significant work in preparation for the decarbonisation of industry and transportation in the Nelson/Tasman areas. Further work in this area is ongoing.

1.12.1 Industrial Process Heating

Studies have been undertaken by DETA Consulting to identify the likely substitution fuel and impact on the distribution network of industries which operate fossil fuelled boilers to raise hot water or steam. The results of this work have shown that considerable use of wood pellets in the Nelson area is preferred by many boiler operators, mainly due to lower capital changeover costs and lower fuel costs than electricity. However, the long term availability of wood pellets is uncertain.

This leaves only a small number of mainly urban boilers at present planning to go electric. The situation remains fluid, however, and we will continue to monitor the situation with ongoing dialogue with boiler owners.

1.12.2 Impact of EV Charging on LV Networks

Investigative work into the likely changes to loads and load diversity in LV networks has been undertaken during 2021. ANSA Ltd, provided analysis of smart meter data from hundreds of meters in urban subdivisions in the area, firstly to check how closely our LV diversity formulae models on existing suburban domestic loads and secondly, to estimate what future load diversity formulae we could expect under various home EV charging behavioural scenarios.

The load diversity equations are a fundamental input into the design of LV reticulation.

This body of work complemented and expanded work undertaken by ANSA in 2019 for NTL, where the hosting capacity of its existing LV networks was determined along with the identification of the constraints in the networks likely to arise as EV penetration increased.

Changes to, and incremental costs of LV reticulation needed to accommodate high penetration of EV chargers into our reticulation systems under the various charging behaviour patterns have been identified. Variations in charging behaviour have included the variation in the size types and capacities of home chargers that could become prevalent in the future.

The work identifying the incremental reticulation costs has also provided useful input into determining the value of flexibility services in the Network Tasman area.

1.12.3 Centralised Control of Home Battery Systems

As reported in the 2021 AMP, Network Tasman has completed trials of remote control of distributed battery systems via the mechanism of ripple control and the company is now in a position to be able to develop and offer a reward tariff for the utilisation of domestic scale batteries.

However, no further work has been undertaken in this area, after it was identified that the majority owner of distributed battery systems in our network was already using the battery system to respond to our time of use tariff pricing signals. This was heartening to discover as a network owner seeking to minimise peak loads on its network.

Aggregated distributed solar energy generation and battery energy storage that can reliably affect peak load reduction or load levelling are now being made available to the electricity distribution sector as flexibility services. These services have the potential to economically defer major grid upgrade projects. Network Tasman will evaluate the deployment of these services to defer or substitute grid development projects on case by case bases in the future.

Network Tasman is keeping a close watch on developments in this space generally and is keeping itself fully informed.

1.12.4 Grid Scale Battery Systems

Large scale network connected battery storage systems have been installed in other distribution networks in New Zealand. Network Tasman is keeping a watching brief on the operation and economics of these systems as a means of voltage support or as an alternative option for traditional network reinforcement. Future network development project business cases will fully analyse the opportunity for solving network development or renewal issues using this technology.

During 2022/23, NTL issued a request for “expression of interest” to potential providers of non-network solutions that could defer the development of a major new GXP substation at Brightwater.

2 BACKGROUND AND OBJECTIVES

2.1 *ASSET MANAGEMENT PLAN PURPOSE*

The purpose of this *Asset Management Plan* is to document the asset management practices employed by NTL in order to define and carry out an optimised lifecycle management strategy for the electricity distribution assets managed by the company in the interests of its stakeholders.

The AMP was first produced in 1994 and has been continuously and progressively developed. It is the company's key network planning document. The AMP is intended to meet the requirements of the Electricity Information Disclosure Requirements and to provide a technical document that communicates the asset management practices of NTL to its stakeholders.

The AMP is based on currently available information and the experience and skills of NTL staff. It is reviewed annually to incorporate improved asset information and improved knowledge of stakeholder expectations and interests. The document includes an indication of the likely development path of the network based on current information, however it is not intended that any external parties place any reliance on the implementation or timing of specific projects.

2.2 *CORPORATE OBJECTIVES*

NTL is owned by the Network Tasman Trust on behalf of consumers as defined in the *Network Tasman Trust Deed*.

The business focus and direction of NTL is guided by its vision and mission as set out below.

Vision
To be a successful network services company for the benefit of our consumers.

Mission
To own and operate efficient, reliable and safe electricity networks and other complementary businesses while increasing consumer value.

Key business objectives are therefore to:

- deliver reliable and high quality network services to consumers that are in broad alignment with customer and/or customer group expectations of reliability and price as revealed by the customer consultation process.
- improve operational efficiency and effectiveness.
- ensure regulatory compliance of the network and operations.
- increase consumer value.

2.3 *ASSET MANAGEMENT PLANNING DRIVERS*

To achieve the key business objectives, a rigorous approach to managing the distribution network assets is required. The business objectives therefore set the drivers for the AMP.

These drivers are identified as follows:

2.3.1 Safety

Safety of workers, contractors and the general public is paramount in all operations of the company. In order to ensure ongoing safety, the asset management process will:

- specify works to maintain assets in a safe condition.
- design and construct new assets to appropriate safety standards.
- operate and work using appropriate safety procedures in compliance with health and safety in employment legislation and electricity industry safety standards.
- develop and operate appropriate risk management practices.

2.3.2 *Consumer Service*

Consumers require an electricity supply that is safe, reliable, efficient and cost effective. The asset management approach incorporates a means to identify and satisfy consumer requirements. It also develops an understanding of available service level options and associated costs.

2.3.3 *Economic Efficiency*

Investments in the network assets are made with the long term aim of maintaining or increasing consumer owner value. Asset management processes will:

- provide economic cost benefit analysis for major projects.
- tender major project work to competent contractors to achieve competitive prices.
- optimise the trade-off between maintenance and renewal expenditure.
- provide a means of planning and prioritising maintenance and renewal expenditure.
- optimise network operation in order to minimise network losses and maximise network utilisation.

2.3.4 *Environmental Sustainability*

NTL is committed to managing its business in an environmentally sustainable manner for the benefits of its consumers, community, shareholders and staff. NTL's commitment is set out in its *Environmental Sustainability Policy*.

Our *Environmental Sustainability Policy* provides for:

- Stakeholder consultation in our decision making where material trade-offs exist between environmental, social and financial issues.
- Sustainable use of natural resources to protect the biosphere by the use of natural resources in a sustainable way.
- Reduction and disposal of waste by minimising waste, especially hazardous waste, and wherever practicable reuse or recycle materials in our operations.
- Wise use of energy.
- Risk reduction by understanding the risks to the environment that our operations pose and, based on those risks, prioritise our efforts to eliminate or minimise potential environmental hazards caused by our operations.
- Restoration of the environment.
- Commitment of management resources.

Particular environmental objectives identified include:

- Avoiding discharge of contaminants into the environment.
- Avoiding noise.
- Avoiding, remedying or mitigating any adverse effects on the environment.

2.3.5 *Regulatory Compliance*

The AMP document and process is part of NTL's drive to operate in a manner compliant with all relevant legislation. The key legislation relating to electricity distribution network management in New Zealand is:

- Electricity Act 1992 and amendments 1993, 1997, 2000, 2001, 2001(1), 2001(2)
- Electricity Reform Act 1998 and amendments
- Electricity (Hazards from Trees) Regulations 2003
- Electricity (Safety) Regulations 2010
- Electricity Information Disclosure Requirements 2004 and amendments
- New Zealand Electrical Codes of Practice
- Resource Management Act 1991
- Electricity Governance Rules
- Health and Safety at Work Act 2016
- Climate Change (Zero Carbon) Amendment Act 2019

2.3.6 Risk Management

In order to deliver the key business objectives in a sustainable manner, it is necessary that the asset management process incorporates a full understanding of the risks of adverse events impacting on achievement of the key business objectives.

A risk approach to asset management will incorporate:

- establishment of risk context
- identification of risks
- assessment and treatment
- process to monitor and review

2.4 PLANNING PERIOD AND PERIOD REVIEWS

The planning period of this AMP is 1 April 2024 to 31 March 2034.

This document was approved by the board of NTL on 25 March 2024.

The AMP will be reviewed on an annual basis based on the financial year to incorporate up-to-date information and plan improvements. The next review of the plan is expected to be issued on 31 March 2025.

2.5 STAKEHOLDERS

The needs and interests of the stakeholders of NTL are identified through direct and indirect consultation. Direct consultation with stakeholders takes place via meetings with individuals and groups such as retailers, major customers and organisations such as Federated Farmers etc. Indirect consultation occurs via feedback from meetings of the Network Tasman Trust and from mass market customer surveys.

The major stakeholder interest tension that forms a driver for the asset management function is the supply price/quality trade-off. Trust beneficiaries require an adequate return on assets employed whilst consumers require a safe, reliable and sustainable network operation. Balancing this trade-off is the primary function of the asset management process.

Feedback from consumers/stakeholders is formally sought through direct consultation. The consultation process was last undertaken during 2022. The report from this consultation is given in Appendix K.

Other less formal but equally important indirect means of consultation with company stakeholder consumers comes through interface with staff during day to day operations of the company. Both field and office based staff liaise with consumers, landowners, retailers, electrical contractors, developers and suppliers on an almost daily basis. Any issues arising from such operations are considered and reviewed by management and this consideration forms a major input into policy development. Conflicts between stakeholder interests inevitably arise from time to time and these are managed through company policy development. Company policy is signed off at CEO and Board level.

An example is the tension that exists between developers wishing to subdivide land and complete residential or commercial developments and existing consumers. A level of contribution from developers is required to cover the utilisation of upper network capacity that has previously been made available by existing consumers or other developers. In order to manage and resolve these conflicting interests a *Capital Contributions Policy* has been introduced. This and other important company policy documents affecting stakeholders are publicly available on the company website.

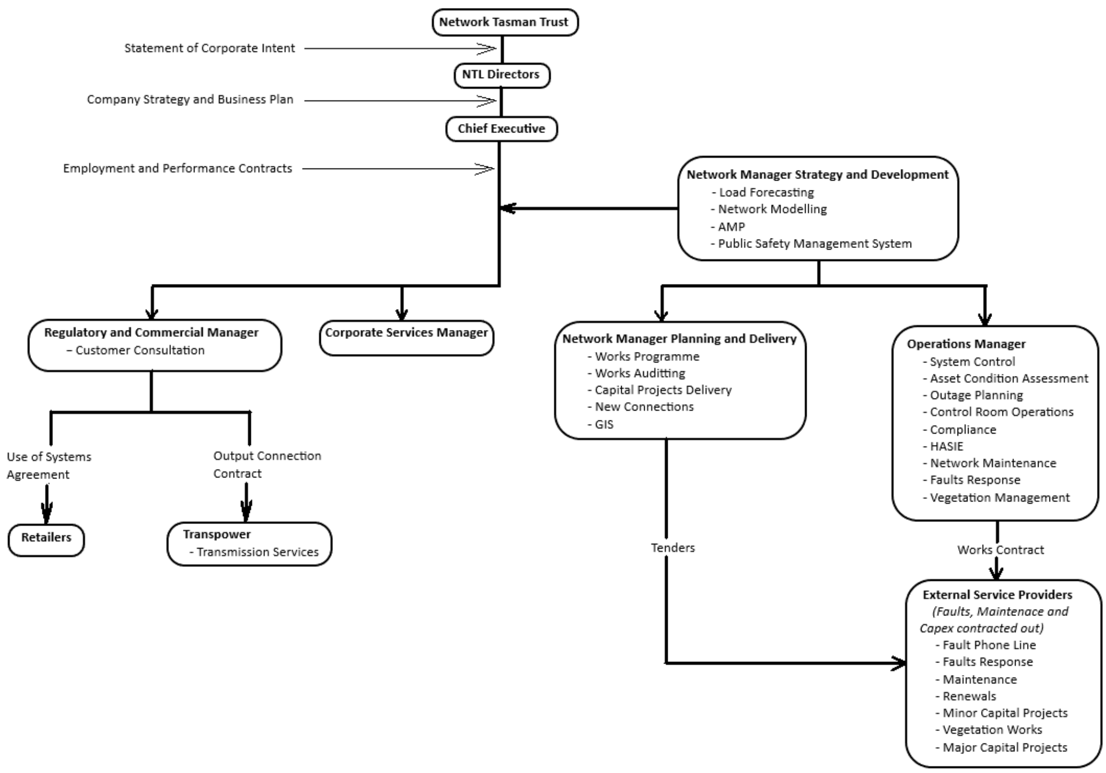
Key stakeholders and their interest in NTL are generally summarised below.

Stakeholder		Interest
Customers:	Retailers	Reliability of supply
	Direct supplied consumers	Quality of supply
	End use consumers	Price of services
	Developers	Company operational efficiency
	Electrical contractors	Capital Contributions Policy
		Safety
Suppliers:	TPNZ	Utilisation of provided services
	Electrical contractors service providers	NTL financial viability
Other:	Local authorities	Underground conversion policy
	Other utility operators and landowners	Network planning
	Community groups	
	Government	Environmental performance
		Regulatory compliance
		Corporate citizenship
Company:	Trust beneficiaries	
	Network Tasman Trust	Financial performance
	Directors	Operational performance
	Management	Quality of employment
	Staff	

2.6 *ACCOUNTABILITIES AND RESPONSIBILITIES*

Accountabilities and responsibilities in respect of network operations and management are summarised in the chart below.

FIGURE 1: ACCOUNTABILITIES AND RESPONSIBILITIES OF PARTIES



The Network Tasman Trust holds shares in the company on behalf of the consumers who are the trust beneficiaries. The trust is made up of six trustees, five of whom are elected by the consumers and one who is appointed by the three largest consumers. The trust has the role of appointing the directors of the company and approving the *Statement of Corporate Intent*, which is the guiding document of the company. The trust, as representatives of the consumers, also has a role in feeding back the views of consumers to the company on such matters as price and performance. This is an indirect means of consumer consultation that has a significant influence over the asset management planning process.

NTL has seven directors, who have an overall governance role of the company and who are legally accountable for the company. The AMP, annual business plan and budgets are prepared by the management team and approved by the board of directors. Company performance is managed through a performance plan agreed between the board and company management.

Asset management outcomes are reported to the board through monthly management reports and through the process of the annual AMP reviews. Monthly information to board members includes analysis of all network outages for the month and a running summary of overall network performance for the year. Updates on AMP projects underway are also included in the monthly information to directors.

As a part of the AMP review process, a study and analysis on network reliability by feeder against that expected following AMP project implementation is updated in a report to directors each year.

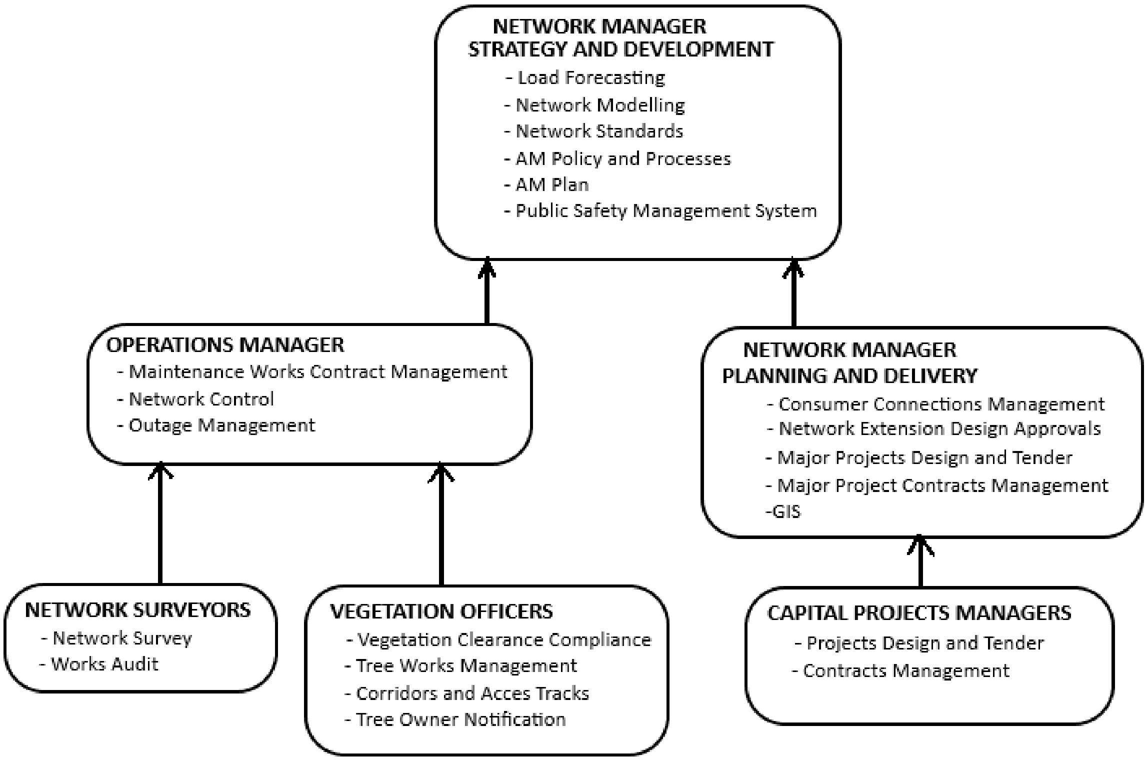
Also, as part of the review process, any policy developments through the year affecting the AMP, or any recommendations from external reviews or audits, are discussed and incorporated into the AMP as appropriate. Such plan developments are highlighted in the final presented draft.

The AMP review is presented to the board and discussed for final approval annually in time for regulatory disclosure.

The management team of NTL has responsibility for the day to day management of the company and its assets and for implementing company policy. The Network Manager – Strategy and Development is responsible for the annual production of the AMP. The plan is also reviewed by company management before finalisation.

The asset management functions and processes are undertaken and overseen within the company by a number of staff under the oversight of the Network Manager – Strategy and Development. Asset management functions within NTL are shown in Figure 2.

FIGURE 2: ASSET MANAGEMENT FUNCTIONS WITHIN NETWORK TASMAN



Network planning, system analysis and design for projects are all completed by NTL staff. Consultants are deployed in specialist areas such as risk management studies, network security policy formulation and in projects involving major civil and structural engineering. All major capital expenditure projects are put out to tender for construction. Once contracts are awarded, most construction projects are managed by NTL staff.

A contract for the provision of a faults response service, all asset maintenance works and minor capital works was retendered during 2020/21 and awarded to Delta Utility Services Ltd. This five-year term contract commenced on 1 June 2021. Delta Utility Services has held this contract previously.

The Network Manager - Strategy and Development is responsible for the outcomes of the services contracts and for the cost performance of the network operation against budget. Contractor performance is monitored through regular meetings with the contractors at an operational level and at a management level. An alliance partnership regime is in place where both principal and contractor work together to achieve the most effective and efficient outcomes within the terms of the contract.

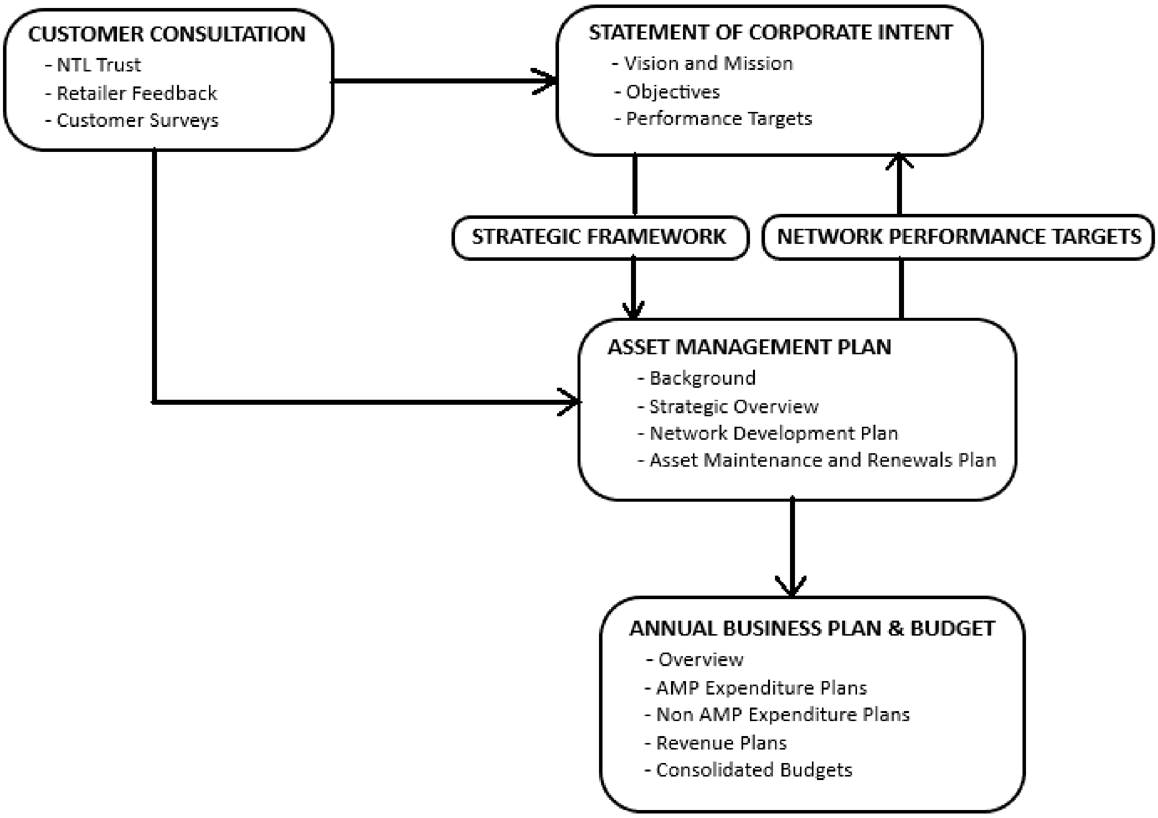
Document approvals and levels of expenditure delegation are given in the following table:

DOCUMENT/EXPENDITURE LEVEL	APPROVAL AUTHORITY
Statement of Corporate Intent	NTL Trust
Asset Management Plan	Board
Annual Business Plan and Budget	Board
Expenditure >$100,000	Board
Expenditure >$20,000 and <$100,000	CEO
Expenditure <$20,000	Managers

2.7 AMP INTERACTION WITH CORPORATE GOALS AND BUSINESS PLANNING

The management of the electricity distribution network in the Nelson/Tasman area (excluding the inner Nelson city serviced by Nelson Electricity Ltd) for the consumer owners of the company, is the major business activity of NTL. Although NTL also operates a number of other business activities outside of the electricity network management business, the greater part of the company's expenditures and revenue streams are based on the electricity network business. As a result of this, the primary strategic focus of the company is on the management and performance of the electricity distribution network.

FIGURE 3: AMP INTERACTION WITH OTHER CORPORATE DOCUMENTS



The vision and mission of the company (refer section 2.1) are translated into corporate goals that are network performance focussed. The goals specified in the company's *Statement of Corporate Intent* are the performance goals of the AMP. The relationships of stakeholders and accountabilities and responsibilities for this process are represented in Figure 1 and described in section 2.6.

The capital expenditure projects and network operations and maintenance activities as outlined in this plan form the major part of the annual business plan of the company.

2.8 ASSET MANAGEMENT INFORMATION SYSTEMS

The following information systems are employed by NTL for use as input to the asset management process.

2.8.1 Geographic Information Systems

A computer-based Geographic Information System contains records for all distribution network assets, including attribute data on the location, age and type of all equipment employed on the network. The GIS comprises the main datastore for all network management activity. It is used for most operational functions of the company.

The GIS system incorporates information from subsystem databases that are maintained on an ongoing basis. These subsystems are:

- The Substation/Transformer database – this database records the parameters of all distribution substation sites (approx. 4,500) and holds earth test and loading records for the sites. The database also tracks the location, specifications and test records of all transformers.

- The Consumer Network Connection Points (NCP) database – this database records the capacity parameters and start dates of all end use consumer connections to the distribution network. The database is maintained at NTL and is used for the reconciliation of line charge revenue.

- The Network Maintenance database – this database records all network survey condition assessments against each pole, service box, distribution substation or ground mounted switchgear. Information collected on mobile digital devices and proforma sheets and during the continuous line surveys is entered. Maintenance contracts are later generated using GIS tools in conjunction with the survey information. Maintenance works within the database are signed off when completed in the field by the entry of date of completion information. The database is also used for statistical reporting and identification of trends in component failures, and in the determination of component life cycles.

- The Network Load Survey database – this database records all network loading data from maximum demand recording devices that are positioned at strategic points on the network. This information is used in network development planning.

2.8.2 Outages and Faults Database

A database of all planned and unplanned outages on the high voltage network is kept and updated at the time of restoration of supply, by network operations staff in the control room. Detailed information is stored against each outage including the time, area, number of consumers affected and the reason for the outage - whether it was planned or unplanned. Fields are set up to allow easy summary information extraction and determination of network performance statistics.

Network reliability information is required to be disclosed annually under the Electricity Information Disclosure regulations. Process and procedures are in place to ensure that records for this purpose are complete and accurate. Full details of these procedures and processes are given in Appendix M. These processes and procedures utilise the consumer and network information within the GIS system to identify the consumers affected by any outage. The sections of network affected in any outage are identified from switching records.

Faults on the low voltage network are recorded in a second database. This information is kept to allow for contractor performance monitoring, summary statistics, the identification of recurring faults and trend analysis.

2.8.3 Network Load Flow Model

A network load flow model of the high voltage distribution system is kept and this is used for performance analysis of the network under various loading conditions. The results of this modelling are used in the formulation of the *Network Development Plan*.

2.8.4 SCADA System

The SCADA system has remote stations at the major zone substations, subtransmission substations, GXP substations, ripple injection plants and field autoreclosers/sectionalisers. The system allows for the remote monitoring and control of loads at substation and feeder level, with data stored at the master station computer in the control room at our head office.

Historical trend information on substation and feeder loadings is used in the network load survey process and in the formulation of the demand forecast.

2.8.5 Vegetation Database

During 2005/6, a vegetation notification database system was instigated. This records vegetation notification activities meeting the requirements of the Electricity (Hazards from Trees) Regulations 2003.

This database continues to form the basis of vegetation management activity. This database may be linked to the Geographic Information System in the future.

2.8.6 Customer Consultation Database

Two key means of customer consultation occurs:

- Direct, detailed consultation with the 30 or so largest customers.
- Mass market surveys of consumer satisfaction with supply reliability as assessed by several proxies.

The most recent customer consultation outcomes are given in Appendix K.

2.8.7 Condition Based Risk Management System (CBRM)

This software system combines age and condition information on assets with asset criticality and failure consequence information to determine a monetarised asset risk score. The system is under construction at present and will inform and support asset management decisions in the future.

2.9 INFORMATION SYSTEMS GAP ANALYSIS

The datasets described above have a high degree of accuracy and completeness. All datasets have a level of accuracy and completeness that is adequate and appropriate for their purposes.

Data accuracy limitations exist in the year of manufacture of some specific assets. In particular, many poles have no recorded date of manufacture and, in these cases, a year of manufacture has been derived from other records such as the year of line construction, on the assumption that the poles used in the line construction were manufactured in the same year.

As the asset renewal and maintenance regime is condition based down to a high level of asset disaggregation, this limitation does not affect the effectiveness and performance of the maintenance systems. Also, the assumptions made do not significantly affect long term renewals expenditure projections as any errors brought about by these assumptions are very small with respect to the overall error within the expenditure projections.

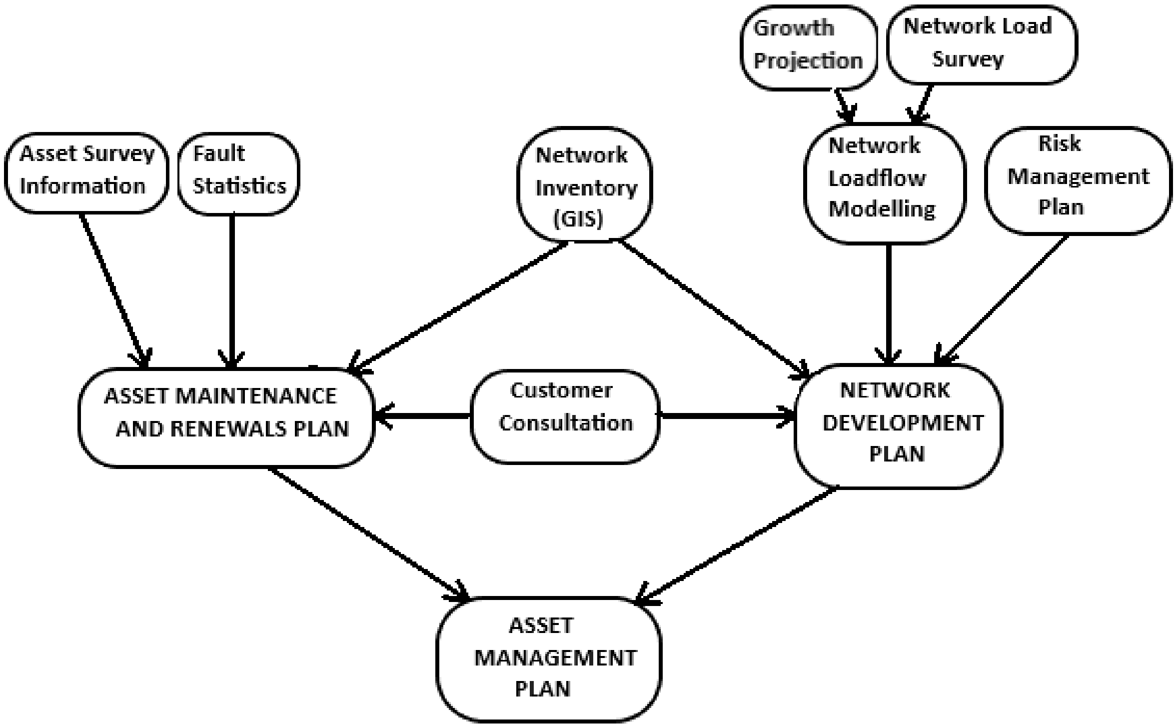
Although spatial positioning accuracy is sufficient for operational purposes, positioning information is improved on an ongoing basis as information comes to hand from land surveys etc.

2.10 ASSET MANAGEMENT PLAN FORMULATION AND STRATEGIC REVIEW PROCESS

2.10.1 AMP Formulation

Figure 4 represents the information inputs and flows into the AMP formulation and review process.

FIGURE 4: ASSET MANAGEMENT PLANNING INFORMATION SYSTEM



2.10.2 Asset Condition Information

The company's Network Maintenance database, which holds information from ongoing field asset surveys, supplies prioritised asset maintenance works information needed to form the annual *Asset Maintenance and Renewals Plan*. This forms the basis of the annual works programme which is forwarded to Delta Utility Services Ltd who complete the works under contract.

Trend information from the faults outages database is used to prioritise work activities in cases where repeat fault patterns are identified from the historical faults information.

The GIS system is used in works planning to locate and geographically group works activities so that the contractor may efficiently plan the work.

2.10.3 Network Development

The network development plan is built up using a load flow model of the network as a basis. Field load survey data from the distribution substations max demand database is used to check the distribution of loads modelled across the network. The model is then enhanced with load growth projections from the demand forecast and following this, network constraints or areas of non-compliance with voltage standards are identified.

A series of development project options is generated to remove the identified network constraints or correct the projected voltage profile. This series of options is then considered collectively to form a view of the most likely overall medium to long term development path. Consideration of technical effectiveness, economic efficiency, ongoing compliance with the network security standard and management of risk of non-supply are part of the process of formulation of the medium to long term *Network Development Plan*.

The *Asset Maintenance and Renewals Plan* and the *Network Development Plan* are brought together in the AMP document.

2.10.4 Stakeholder Interests

Specific stakeholder interests are considered during the AMP formulation and annual review. Such items include periodic reviews of the undergrounding policy and project priorities in conjunction with the two territorial authorities, and reviews of vegetation management policy. Budgets for the 10 years going forward are developed from this.

Wider stakeholder issues raised by the Network Tasman Trust or feedback from customer consultation will also be considered at this stage. Such issues may include review of capital development contributions policy.

Stakeholder interests are accommodated within asset management practices through:

- Load forecasting
- Network planning
- Network security standards
- Network design and construction standards
- Environmental policy implementation
- Safety management processes
- Fostering of local contracting marketplace
- Clear contracts with counterparties
- Use of professional advice where required

Conflicts between stakeholder interests and asset management requirements exist and must be managed. Examples of this are specific priorities of underground conversion undertaken or the overall level of underground conversion undertaken.

Conflicting stakeholder interests are managed through:

- Consideration of stakeholder needs as part of high level planning process
- Cost benefit analysis of major network investments
- NTL's objective to operate "as a successful business" (Energy Companies Act requirement)
- Board level policy development

2.10.5 Strategic Review Process

The AMP and its associated budgets provide the major inputs to the company's strategic and business plans. Company strategic and business plans are reviewed annually following completion of the annual AMP review.

The AMP and business plan budgets are reviewed from a company financial perspective. This involves updating the business financial models in order to form a picture of the medium and long term financial future of the organisation.

At this time, the organisational capabilities and capacity to implement the company AMP and business plan projects are also reviewed. The company structure and resourcing model is considered in light of the network development, renewal and maintenance expenditure levels and time profiles.

Maintenance and renewal works are contracted out to a primary service provider under the works contract. The work levels for the five years of the contract are discussed with the works contractor in order that medium term contract resource planning can take place. This includes contractor competency and training requirements.

All major capital works are tendered to local or national service providers. Most projects are planned and designed using in-house resources. If the planning or design requirements of the capital works plan exceeds the capabilities or capacity (due to workload) of the in-house resource, then consideration is given to contracting external design and project management services for particular projects.

Also, during the annual strategic planning process, a review of company performance against targets is undertaken, together with a benchmarking review of the company performance against all other lines companies in New Zealand.

The company performance review draws on data from monthly reliability reports, proven voltage complaints, review of the company's financial performance against budget targets and other performance measures in this plan. The benchmarking review utilises gazetted information disclosure data including operational and financial performance information. The results of these reviews are fed back into company strategic targets and may trigger review of AMP performance targets and the company's *Statement of Corporate Intent*.

Annual company performance against SCI targets is fed back to the wider company stakeholders via the company's annual report. A summary of the annual report is sent out to all consumers.

3 NETWORK CONFIGURATION AND ASSET DESCRIPTION

3.1 NETWORK CONFIGURATION

The area covered by the NTL network is shown in the map of Appendix A. There are five bulk supply regions. These are supplied from four Transpower grid exit points (GXPs). Transpower GXPs exist at substations at Stoke (33kV and 66kV), Kikiwa (11kV) and Murchison (11kV). Maps showing the five bulk supply regions are given in Appendix A.

The overall maximum demand on the Network Tasman distribution system for 2023/24 was 154MW. The winter weather was mild. The total electricity delivered to consumer ICPs (installation control points) was 650GWh. The overall load factor was 63%.

There are 11kV line interconnections between the Stoke, Motueka and Kikiwa area systems, however the load transfer capability between any supply region is limited to only 300-500kW due to the fact that they are end of rural overhead 11kV feeder interconnections only.

Details of line and cable lengths by voltage are given in Section 3.3. The network is 30% underground by circuit length overall.

3.1.1 Stoke Bulk Supply Region

This region is the major load region of the NTL network, containing approx. 29,000 consumer connections. There are two direct supply 33kV consumers being Nelson Electricity Ltd (33MW) and Nelson Pine Industries Ltd (16MW). The main suburban townships in this region are Stoke and Richmond, with other semi-rural centres at Atawhai, Brightwater, Wakefield and Mapua.

The GXP is at Transpower's Stoke substation from which a load of 129MW is supplied at 33kV. This figure includes Nelson Electricity's load which is supplied from this GXP substation as well as NTL's. The firm capacity of this GXP is currently 141MVA. NTL demand from the substation is 96MW. Nelson Electricity's coincident peak demand from Stoke is 33MW. Stoke is the only GXP in the area from which this load can be served. There is therefore a heavy reliance on this GXP.

Within this bulk supply region, NTL has ten 33/11kV substations at Wakapuaka, Founders Park, Annesbrook, Songer Street (Stoke), Richmond, Hope, Lower Queen Street (Richmond Industrial), Eves Valley (Brightwater Industrial), Brightwater, and Mapua. A schematic diagram and geographic layout of the Stoke bulk supply region subtransmission system is given in Appendix A. Most of the zone substations in this GXP region have switched N-1 subtransmission security. The total energy delivered to NTL from this GXP is 511,400MWh, giving an annual load factor of 61%.

The region contains a mainly overhead 33kV subtransmission network and a partially underground 11kV and 400V distribution network. The 33kV network provides open ring supply to the larger urban zone substations and a single line supply to rural and dedicated industrial zone substations. The 11kV networks in the region are run as open rings in the urban area, with significant sections underground. Rural 11kV networks are mainly single line overhead radial feeders.

The load characteristic has a continuous base load resulting from the 24-hour a day operation of the Nelson Pines Industries MDF plant. A mix of other industrial/commercial and domestic load is superimposed on this. The peak load period is driven by winter domestic space heating with a peak period occurring in June and July.

3.1.2 Motueka Bulk Supply Region

The Motueka region encompasses the town of Motueka and its environs. There are approx. 7,900 consumer connections spread throughout this area. The township has four 11kV feeders supplying it from the Motueka substation. A further four overhead line feeders from Motueka substation feed out into the rural hinterland of mainly horticultural farming and lifestyle blocks. The resort centre of Kaiteriteri is included in this bulk supply region. As with Stoke, the 11kV system is run in open rings for the township area and mainly single line overhead supplies to the rural areas with very limited backup circuits.

The GXP for this bulk supply region is at Stoke substation at 66kV. Two 66kV circuits from Stoke substation supply the Motueka zone substation and the Motupipi substation in Golden Bay. Motueka bulk supply region has peak offtake of 21MW. The firm capacity of the Motueka zone substation is 23MVA.

The load is a mix of domestic, horticulture and food processing. The combination results in a long peak load period running from February through to September. The total annual energy delivered is 106,400MWh, giving an annual load factor of 58%.

3.1.3 Golden Bay Bulk Supply Region

In Golden Bay, Network Tasman has a subtransmission substation (66/33kV) at Motupipi. The Transpower GXP for the region is the 66kV connection at the Stoke substation. NTL also has two 33/11kV zone substations within the Golden Bay bulk supply region at Takaka (Takaka) and Collingwood (Swamp Road).

Golden Bay contains approx. 3,600 consumer connections including one large industrial load at the Fonterra Takaka dairy factory. The 33kV network consists of two single line feeders, one supplying each of the 33/11kV zone substations. The zone substations are simple two transformer substations with pole mounted 11kV feeder auto-recloser switchgear.

The 11kV systems are radial overhead lines mainly with minimal alternate routes beyond the limits of the Takaka township. The line to the west coast from Collingwood traverses some very remote coastal terrain with very light consumer density. The harsh coastal environment of this line creates high maintenance overheads for this line and supply restoration difficulties following fault outages.

The peak load in this bulk supply region is 7.5MW. As the Motupipi substation has a single line 66kV supply from Upper Takaka, this supply region has no firm capacity. The area has a domestic load profile characteristic with winter peak that is modified by the effect of the dairy industry and by summer holiday activity. The overall load in the region has its peak period over summer and early autumn. The total annual energy delivered is 40,020MWh, giving an annual load factor of 60%.

3.1.4 Kikiwa Bulk Supply Region

The Kikiwa bulk supply region is supplied at 11kV with a peak load of 3.4MW. Firm capacity of 4MW with manual switching is available from the GXP at Transpower's Kikiwa substation. The supply area contains approx. 1,100 consumer connections including a timber processing factory. There are two small centres at Tapawera and St Arnaud which are 20km and 40km respectively from the bulk supply point. Three overhead line feeders supply the area from Kikiwa substation. The country traversed by these feeders is mountainous and remote. Pole mounted autoreclosers are utilised to limit the extent of fault events on these lines. One of the feeders is now operating at 22kV.

The load characteristic for the Kikiwa bulk supply region is a mix of domestic and dairying operations including significant irrigation during dry summers. Recently hop growing has become prominent in the area. This load has a short operating period during February for the kiln drying of harvested hops.

The peak period on the GXP is typically February to April. The total annual energy delivered is 14,400MWh, giving an annual load factor of 49%.

3.1.5 Murchison Bulk Supply Region

This region has a small township at Murchison that is surrounded by four river valleys. The GXP substation at Matiri is close to the load centre at Murchison and it has a peak load of approx. 3MW. The substation has a single three-phase transformer, therefore there is no firm capacity available. In the event of a transformer failure, temporary diesel generation would be deployed until the Transpower mobile substation could be deployed to the site.

Consumers supplied from the substation number approx. 900. Three radial 11kV overhead feeder lines distribute power away from this substation in four directions. The longest 11kV spur feeder in the NTL network runs from Matiri to Springs Junction, a run of 80km.

The load characteristic for Murchison is similar to Kikiwa with a mix of domestic and dairy farming being the dominant drivers. However, irrigation is less than in Kikiwa. The peak loading occurs in late summer and early autumn. The total annual energy delivered is 12,800MWh, giving an annual load factor of 49%.

3.2 ASSET JUSTIFICATION AND NETWORK OPTIMISATION

All networks are optimised for the loads that they supply. The distribution system has been developed around the main load centres initially and then extended out into the surrounding districts during the 1950s and 1960s. Underground conversion of many suburban main roads and commercial centres only occurred during the period 1972 to 1987. Most suburban streets that were formed prior to 1970, however, have retained the original overhead reticulation. Underground conversion of the main township centres and main suburban thoroughfares is largely complete.

Backup capacity in most parts of the network is appropriate for the type of load serviced in line with our design security standard, however there are a small number of load sections that do not have design standard backup capacity. Capital expenditure is planned to bring all networks up to the design security standard.

Distribution substations of capacity 100kVA and greater are fitted with maximum demand indicators and transformers are regularly relocated to maximise transformer capacity utilisation.

There are no areas in the network that have experienced material loss of load rendering stranded network assets, however there are a number of identifiable sections of uneconomic supply.

All new urban subdivisions since 1970 have been reticulated underground, however extensions to rural lifestyle blocks have tended to be overhead line to the 11kV substation with underground cable from substation to dwelling. The engineering standards of the major territorial authorities in the area now require rural 11kV extensions to be underground by default, and there is increasing public pressure to minimise additional overhead line construction.

Embedded generation exists within the Golden Bay and Motueka regions. Privately owned hydro plants are at Cobb (32MW), Pupu Valley (250kW), Onekaka (900kW), Brooklyn (200kW), Upper Takaka (400kW) and Mt Ella (200kW). The Cobb power station is directly connected to the 66kV subtransmission network and generation from it generally exceeds the offtake load (Motueka + Golden Bay bulk supply regions). This means that powerflows at the Stoke 66kV GXP are into the grid rather than away from it at most times.

A 5MW hydro scheme is operational at Lake Matiri near Murchison. It is owned by Southern Generation Ltd. The station connects with NTL's network at the Transpower Murchison GXP. Other small hydro generation projects are planned in the area.

Solar photovoltaic generation exists in the network with approx. 740 mostly domestic scale sites. Total installed domestic scale PV is approx. 2,200kW. A 1.2MW solar farm exists at Uruwhenua in Golden Bay. This generation feeds into NTL's Upper Takaka zone substation via a connection to one of the 11kV distribution feeders.

3.3 ASSET DESCRIPTION

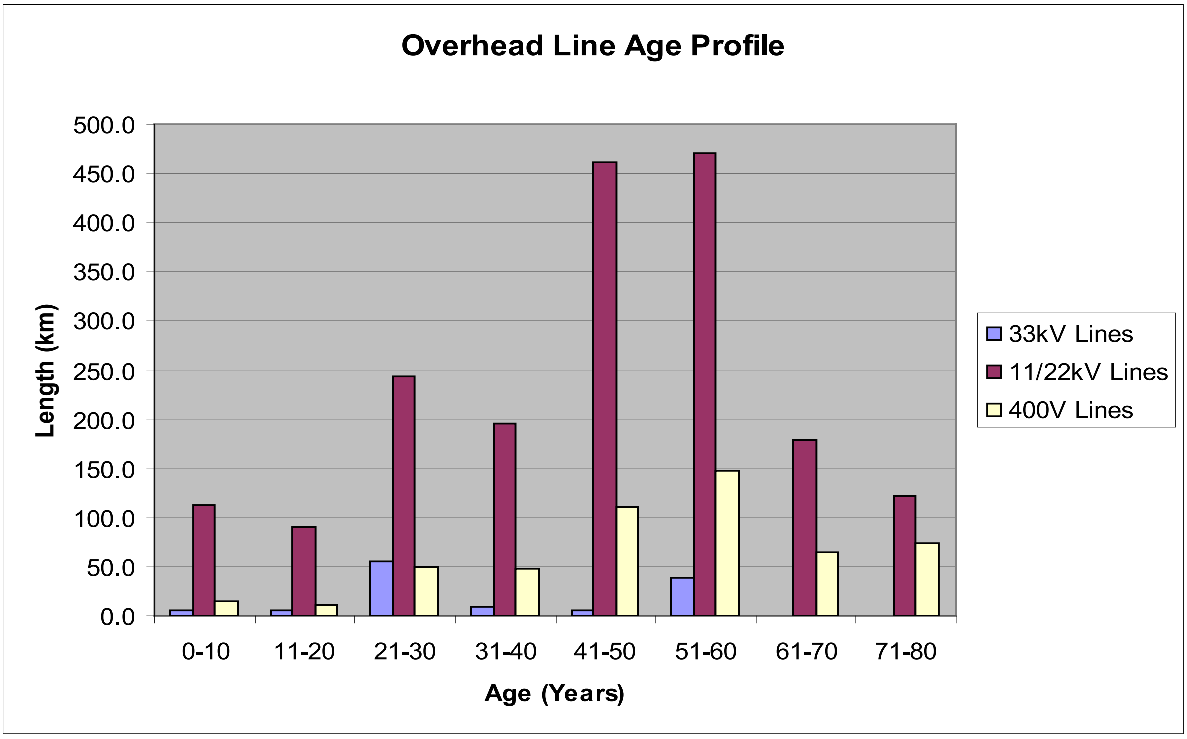
All distribution assets employed in the NTL network are listed by category in this section. The reader's attention is drawn to the map at Appendix A showing the main 11kV distribution network overlaid on a topological map.

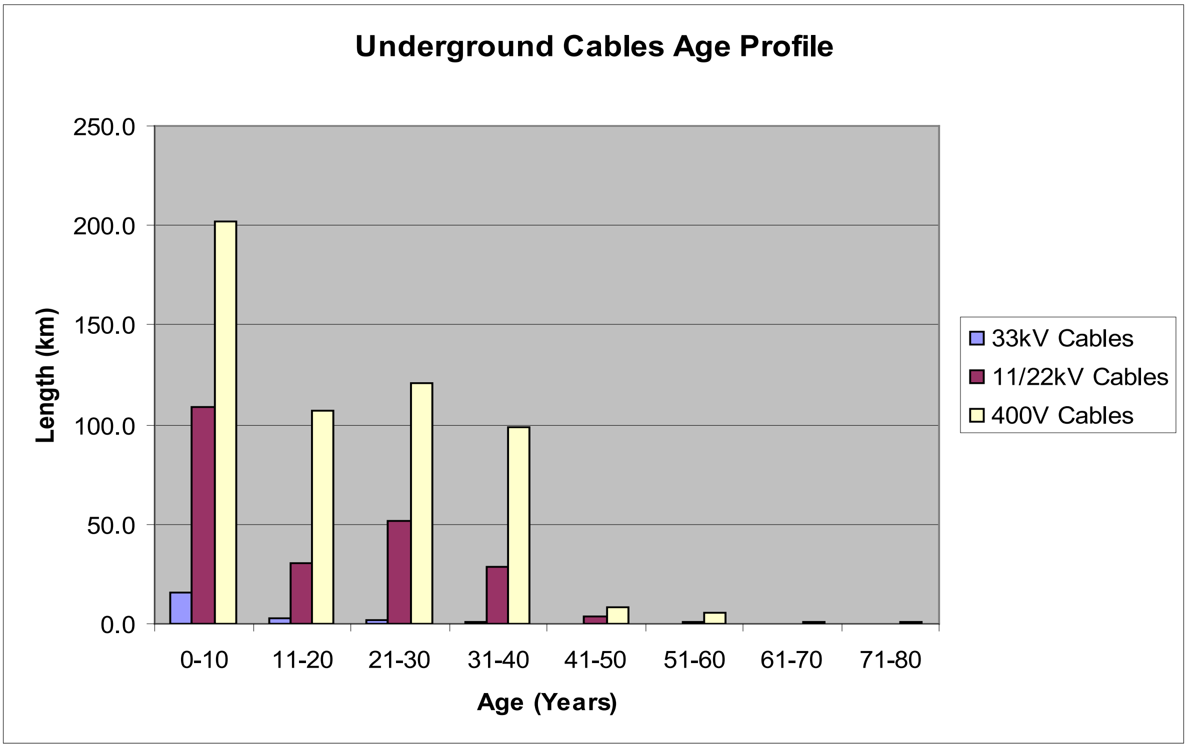
Distribution Lines (km)

	400V Line	400V Cable	6.6kV Line	6.6kV Cable	11kV Line	11kV Cable	22kV Line	22kV Cable	33kV Line	33kV Cable	TOTAL	Underground %
Stoke	222.0	543.3	0.0	0.0	582.5	224.6	0.0	0.0	89.9	41.1	**1703.4**	47
Motueka	143.1	109.2	0.0	0.0	357.2	60.1	0.0	0.0	1.2	0.0	**670.7**	25
Golden Bay	59.2	50.5	14.1	0.0	387.3	10.1	0.0	0.0	32.9	0.3	**553.4**	11
Kikiwa	30.8	13.6	0.0	0.0	250.3	3.2	18.8	12.5	0.0	0.0	**329.1**	9
Murchison	28.3	7.5	0.0	0.0	185.7	3.1	94.7	0.0	0.0	0.0	**319.3**	3
	483.4	**724.1**	**14.1**	**0.0**	**1763.0**	**301.1**	**113.5**	**12.5**	**123.0**	**41.4**	**3576.0**	30

66kV Subtransmission Lines (km)

Circuit	Length (km)	Year Constructed
Stoke-Upper Takaka	60.3	1944
Stoke-Cobb	69.9	1957
Upper Takaka-Cobb	9.5	1944
Upper Takaka-Motupipi	18.5	1944
Total	**158.2**	





Zone Substations

Substation	Transformers	Firm Capacity (MVA)	Offtake Max Demand (MW)	Outgoing 11kV Feeders	Meets Security Std
Annesbrook	2 x 11.5/23MVA	23	19.4	9	Yes
Hope	2 x 10MVA	10	11.0	8	Yes
Songer St	2 x 11.5/23MVA	23	18.9	8	Yes
Lower Queen St	2 x 15/30MVA*	30	16	8	N/A**
Eves Valley	2 x 5MVA	5	3.8	1	Yes
Takaka	2 x 5/7.5MVA	7.5	4.8	4	Yes
Swamp Rd	2 x 3MVA	3	2.8	2	Yes
Brightwater	2 x 7.5/15MVA	15	7.3	4	Yes
Founders	2 x 7.5/15MVA	15	3.6	4	Yes
Mapua	2 x 10MVA	10	6.2	4	Yes
Richmond	2 x 11.5/23MVA	23	17.1	8	Yes
Motueka	2 x 11.5/23MVA	23	20.5	8	Yes
Upper Takaka	2 x 6MVA	6	0.9	1	Yes
Wakapuaka	2 x 7.5MVA	7.5	3.4	4	No

*Owned by connected large industrial consumer
**Security level at preference of consumer

Subtransmission Substations

Substation	Transformers	Firm Capacity (MVA)	Max Demand (MW)	Meets Security Std
Motupipi	4 x 1ph 6.6MVA	20	7.5	No
Cobb	2 x 40MVA*	40	32	Yes

*Owned by connected generation company

Ripple Injection Transmitters

Plant	Generator	Coupling Cell	Controller	Year
Stoke	Enermet SFU-K	Indoor 33kV	Enermet/Abbey EPL	1990
Motueka	Enermet SFU-K	Indoor 11kV	Enermet/Abbey EPL	1983
Motupipi	L+G SFU-K	Outdoor 33kV	Enermet/Abbey EPL	1984
Kikiwa	L+G SFU-K	Indoor 11kV	Enermet/Abbey EPL	2013
Murchison	L+G SFU-K	Indoor 11kV	Enermet/Abbey EPL	2013

Power Transformers – Current Year 2024

Substation	Unit	Serial No.	Transform Voltage (kV)	MVA	Make	Year	Age	Year Refurbished
Hope	T1	58542	33/11	10	Brush	1958	66	2010
Hope	T2	58541	33/11	10	Brush	1958	66	2004
Annesbrook	T1	M0235A	33/11	11.5/23	Wilson	2003	21	NA
Annesbrook	T2	M0235B	33/11	11.5/23	Wilson	2003	21	NA
Songer St	T1	17761	33/11	11.5/23	Tyree	1976	48	2017
Songer St	T2	18716	33/11	11.5/23	Tyree	1987	37	NA
Eves Valley	T1	400131-1	33/11	5	ABB	2005	19	NA
Eves Valley	T2	400131-2	33/11	5	ABB	2005	19	NA
Brightwater	T1	18396	33/11	7.5/15	Tyree	1983	41	NA
Brightwater	T2	18715	33/11	7.5/15	Tyree	1987	37	NA
Founders	T1	18552	33/11	7.5/15	Tyree	1985	39	NA
Founders	T2	18827	33/11	7.5/15	Tyree	1988	36	NA
Takaka	T1	P0872A	33/11	5/7.5	Wilson	2009	15	NA
Takaka	T2	M9854A	33/11	5/7.5	Wilson	1999	25	NA
Swamp Rd	T1	644581	33/11	3	TJ	1977	47	1995
Swamp Rd	T2	691959	33/11	3	TJ	1970	54	1996
Motupipi	T1	3011200037	66/33	15	CG Pauwels	2021	3	NA
Motupipi	T2	3011200038	66/33	15	CG Pauwels	2021	3	NA
Mapua	T1	68352	33/11	10	Brush	1967	57	2005
Mapua	T2	68362	33/11	10	Brush	1967	57	2005
Richmond	T1	M0602B	33/11	11.5/23	Wilson	2007	17	NA
Richmond	T2	M0602A	33/11	11.5/23	Wilson	2007	17	NA
Motueka	T5	VN1456	66/11	11.5/23	ABB	2018	6	NA
Motueka	T6	VN1457	66/11	11.5/23	ABB	2018	6	NA
Upper Takaka	T1	P1423-01	66/11	6	Wilson	2015	9	NA
Upper Takaka	T2	P1423-02	66/11	6	Wilson	2015	9	NA
Wakapuaka	T1	1LVN1810000311	33/11	7.5	ABB	2018	6	NA
Wakapuaka	T2	1LVN1810000312	33/11	7.5	ABB	2018	6	NA
						Max Age (Yrs)	66	
						Avg Age (Yrs)	28.1	

Outdoor 66kV Switchgear – Current Year 2024

Unit	Type	Make	Year Manufactured	Age
Motupipi T1	Vacuum	AE Power	2012	12
Motupipi T2	Vacuum	Meiden	2021	3
Motueka 62	SF6	ABB	1990	34
Motueka 82	SF6	ABB	1990	34
Upper Takaka 172	SF6	ABB	1990	34
Upper Takaka 192	SF6	ABB	2007	17
Upper Takaka 202	SF6	ABB	1990	34
Upper Takaka 222	SF6	ABB	1992	32
Cobb 72	SF6	ABB	1992	32
Cobb 82	SF6	ABB	1992	32
			Max Age (Yrs)	34
			Average Age (Yrs)	26.4

Outdoor 33kV Switchgear – Current Year 2024

Unit	Type	Make	Year Manufactured	Age
Hope T1	Bulk Oil	Takaoka	1981	43
Hope T2	Bulk Oil	Takaoka	1981	43
Annesbrook T1	Bulk Oil	Takaoka	1982	42
Annesbrook T2	Bulk Oil	Takaoka	1982	42
Songer St T1	Bulk Oil	Takaoka	1976	48
Songer St T2	Bulk Oil	Takaoka	1976	48
Lower Queen St T2	Vacuum	McGraw Edison	1985	39
Lower Queen St T3	Vacuum	McGraw Edison	1997	27
Founders T1	Vacuum	Nulec N Series	1998	26
Founders T2	Vacuum	Nulec N Series	1998	26
Eves Valley	Vacuum	McGraw Edison	1985	39
Brightwater T1	Vacuum	McGraw Edison	1985	39
Brightwater T2	Vacuum	McGraw Edison	1985	39
Railway Reserve	Vacuum	McGraw Edison	1985	39
Takaka T1	Vacuum	Nulec N Series	2008	16
Takaka T2	Vacuum	Nulec N Series	2008	16
Motupipi T1	Vacuum	Eaton VFI	2022	2
Motupipi T2	Vacuum	Eaton VFI	2022	2
Motupipi BS 1	Vacuum	Eaton VFI	2022	2
Motupipi BS 2	Vacuum	Eaton VFI	2022	2
Takaka Feeder	Vacuum	Eaton VFI	2022	2
Collingwood Feeder	Vacuum	Eaton VFI	2022	2
Statcom Feeder 1	Vacuum	Eaton VFI	2022	2
Statcom Feeder 2	Vacuum	Eaton VFI	2022	2
Three Bros Corner	Vacuum	Nulec N Series	2005	19
Hope Feeder	Vacuum	McGraw Edison	1985	39
Waahi Taakaro	Vacuum	Nulec E Series	2020	4
Matiri Hydro	Vacuum	Nulec N Series	2020	4
			Max Age (Yrs)	48
			Average Age (Yrs)	23.4

Indoor 33kV Switchgear

Unit	Type	Make	Year Manufactured	Age
Mapua Incomer 1	SF6	Fluair 400	2005	19
Mapua BS	SF6	Fluair 400	2005	19
Mapua T1	SF6	Fluair 400	2005	19
Mapua T2	SF6	Fluair 400	2005	19
Richmond Incomer 1	Vacuum	Tamco	2006	18
Richmond Incomer 2	Vacuum	Tamco	2006	18
Richmond BS	Vacuum	Tamco	2006	18
Richmond T1	Vacuum	Tamco	2006	18
Richmond T2	Vacuum	Tamco	2006	18
Wakapuaka Incomer 1	Vacuum	ABB Unigear	2019	5

Wakapuaka Incomer 2	Vacuum	ABB Unigear	2019	5
Wakapuaka Feeder 1	Vacuum	ABB Unigear	2019	5
Wakapuaka BS	Vacuum	ABB Unigear	2019	5
Wakapuaka T1	Vacuum	ABB Unigear	2019	5
Wakapuaka T2	Vacuum	ABB Unigear	2019	5
			Max Age (Yrs)	19
			Average Age (Yrs)	13.1

Outdoor 11kV Pole Mounted Switchgear

	No.	Average Age Est
Recloser McGraw Edison KF	2	43
Recloser McGraw Edison KFE	4	40
Recloser Nulec U Series	71	16
Sectionaliser Nulec U Series	2	8
Total	79	

Outdoor 11kv Ground Mounted Switchgear

	No.	Average Age Est
Magnefix 1T	1	48
Magnefix 2K1T	57	24
Magnefix 3K1T	94	22
Magnefix 4K1T	5	13
ABB SD3	125	19
ABB SD	50	18
Halo 3LBS	17	6
Halo 4LBS	14	6
Halo 2LBS+2CB	2	5
Xiria	2	14
Total Units	367	

Indoor 11kV Switchgear – Current Year 2024

Substation	Feeder	Type	Make	Year Manufactured	Age
Annesbrook	Tahuna	Vacuum	Reyrolle LMVP	2001	23
Annesbrook	Stoke	Vacuum	Reyrolle LMVP	2001	23
Annesbrook	Aerodrome	Vacuum	Reyrolle LMVP	2001	23
Annesbrook	Bishopdale	Vacuum	Reyrolle LMVP	2001	23
Annesbrook	Wakatu	Vacuum	Reyrolle LMVP	2001	23
Annesbrook	Pascoe St	Vacuum	Reyrolle LMVP	2001	23
Annesbrook	Bolt Rd	Vacuum	Reyrolle LMVP	2001	23
Annesbrook	Moana	Vacuum	Reyrolle LMVP	2001	23
Annesbrook	Merton Place	Vacuum	Reyrolle LMVP	2019	5
Annesbrook	T1 Incomer	Vacuum	Reyrolle LMVP	2001	23
Annesbrook	T2 Incomer	Vacuum	Reyrolle LMVP	2001	23
Annesbrook	Bus Section	Vacuum	Reyrolle LMVP	2001	23
Annesbrook	Local Service	Fuse Sw	Reyrolle LMVP	2001	23
Founders	Akersten	Vacuum	Reyrolle LMVP	1998	26
Founders	Hira	Vacuum	Reyrolle LMVP	1998	26
Founders	Atawhai	Vacuum	Reyrolle LMVP	1998	26
Founders	Spare	Vacuum	Reyrolle LMVP	1998	26
Founders	T1 Incomer	Vacuum	Reyrolle LMVP	1998	26
Founders	T2 Incomer	Vacuum	Reyrolle LMVP	1998	26
Founders	Bus Section	Vacuum	Reyrolle LMVP	1998	26
Founders	Local Service	Fuse Sw	Reyrolle LMVP	1998	26
Hope	Richmond West	Vacuum	Reyrolle LMVP	2016	8
Hope	Waimea West	Vacuum	Reyrolle LMVP	2016	8
Hope	Appleby	Vacuum	Reyrolle LMVP	2016	8
Hope	Paton Road	Vacuum	Reyrolle LMVP	2016	8

Hope	Gladstone Road	Vacuum	Reyrolle LMVP	2016	8
Hope	Wensley Road	Vacuum	Reyrolle LMVP	2016	8
Hope	Waimea East	Vacuum	Reyrolle LMVP	2016	8
Hope	Future 2	Vacuum	Reyrolle LMVP	2016	8
Hope	T1 Incomer	Vacuum	Reyrolle LMVP	2016	8
Hope	T2 Incomer	Vacuum	Reyrolle LMVP	2016	8
Hope	Bus Section	Vacuum	Reyrolle LMVP	2016	8
Hope	Local Service	Vacuum	Reyrolle LMVP	2016	8
Lower Queen St	Estuary	SF6	ABB Safesix	1985	39
Lower Queen St	Queen St	SF6	ABB Safesix	1985	39
Lower Queen St	Swamp Rd	SF6	ABB Safesix	1985	39
Lower Queen St	Furnaces	SF6	ABB Safesix	1985	39
Lower Queen St	Refiners	SF6	ABB Safesix	1985	39
Lower Queen St	Chip Mill	SF6	ABB Safesix	1985	39
Lower Queen St	MDF East	SF6	ABB Safesix	1997	27
Lower Queen St	Lumber Plant	SF6	ABB Safesix	2001	23
Lower Queen St	T1 Incomer	SF6	ABB Safesix	1985	39
Lower Queen St	T2 Incomer	SF6	ABB Safesix	1985	39
Lower Queen St	T3 Incomer	SF6	ABB Safesix	1985	39
Lower Queen St	Bus Section	SF6	ABB Safesix	1985	39
Mapua	Mahana	Vacuum	Reyrolle LMVP	2005	19
Mapua	Mapua	Vacuum	Reyrolle LMVP	2005	19
Mapua	Upper Moutere	Vacuum	Reyrolle LMVP	2005	19
Mapua	Spare	Vacuum	Reyrolle LMVP	2005	19
Mapua	T1 Incomer	Vacuum	Reyrolle LMVP	2005	19
Mapua	T2 Incomer	Vacuum	Reyrolle LMVP	2005	19
Mapua	Bus Section	Vacuum	Reyrolle LMVP	2005	19
Mapua	Local Service	Fuse Sw	Reyrolle LMVP	2005	19
Songer St	Main Road	Vacuum	Reyrolle LMVP	2003	21
Songer St	Aldinga	Vacuum	Reyrolle LMVP	2003	21
Songer St	Polstead	Vacuum	Reyrolle LMVP	2003	21
Songer St	Monaco	Vacuum	Reyrolle LMVP	2003	21
Songer St	Nayland	Vacuum	Reyrolle LMVP	2003	21
Songer St	Saxton E	Vacuum	Reyrolle LMVP	2003	21
Songer St	Saxton W	Vacuum	Reyrolle LMVP	2003	21
Songer St	Isel	Vacuum	Reyrolle LMVP	2003	21
Songer St	T1 Incomer	Vacuum	Reyrolle LMVP	2003	21
Songer St	T2 Incomer	Vacuum	Reyrolle LMVP	2003	21
Songer St	Bus Section	Vacuum	Reyrolle LMVP	2003	21
Songer St	Local Service	Fuse Sw	Reyrolle LMVP	2003	21
Richmond	King St	Vacuum	Reyrolle LMVP	2006	18
Richmond	Waverley St	Vacuum	Reyrolle LMVP	2006	18
Richmond	Talbot St	Vacuum	Reyrolle LMVP	2006	18
Richmond	McGlashen Ave	Vacuum	Reyrolle LMVP	2006	18
Richmond	Lower Queen St	Vacuum	Reyrolle LMVP	2006	18
Richmond	Beach Rd	Vacuum	Reyrolle LMVP	2006	18
Richmond	Champion Rd	Vacuum	Reyrolle LMVP	2006	18
Richmond	Darcy St	Vacuum	Reyrolle LMVP	2006	18
Richmond	T1 Incomer	Vacuum	Reyrolle LMVP	2006	18
Richmond	T2 Incomer	Vacuum	Reyrolle LMVP	2006	18
Richmond	Bus Section	Vacuum	Reyrolle LMVP	2006	18
Richmond	Local Service	Fuse Sw	Reyrolle LMVP	2006	18
Brightwater	Redwood Valley	Vacuum	Reyrolle LMVP	2013	11
Brightwater	Higgins Road	Vacuum	Reyrolle LMVP	2013	11
Brightwater	Ellis St	Vacuum	Reyrolle LMVP	2013	11
Brightwater	Spring Grove	Vacuum	Reyrolle LMVP	2013	11
Brightwater	T1 Incomer	Vacuum	Reyrolle LMVP	2013	11
Brightwater	T2 Incomer	Vacuum	Reyrolle LMVP	2013	11
Brightwater	Bus Section	Vacuum	Reyrolle LMVP	2013	11
Brightwater	Local Service	Fuse Sw	Reyrolle LMVP	2013	11
Motueka	Kaiteriteri	Vacuum	Reyrolle LMVP	2006	18
Motueka	Wildman Road	Vacuum	Reyrolle LMVP	1997	27

Motueka	Tasman	Vacuum	Reyrolle LMVP	1997	27
Motueka	Queen Victoria	Vacuum	Reyrolle LMVP	1997	27
Motueka	Dovedale	Vacuum	Reyrolle LMVP	1997	27
Motueka	Brooklyn	Vacuum	Reyrolle LMVP	1997	27
Motueka	Whakarewa	Vacuum	Reyrolle LMVP	1997	27
Motueka	Pah St	Vacuum	Reyrolle LMVP	2006	18
Motueka	T5 Incomer	Vacuum	Reyrolle LMVP	1997	27
Motueka	T6 Incomer	Vacuum	Reyrolle LMVP	1997	27
Motueka	Bus Section	Vacuum	Reyrolle LMVP	1997	27
Wakapuaka	Glenduan	Vacuum	Reyrolle LMVP	2019	5
Wakapuaka	Hira	Vacuum	Reyrolle LMVP	2019	5
Wakapuaka	Marybank	Vacuum	Reyrolle LMVP	2019	5
Wakapuaka	Spare	Vacuum	Reyrolle LMVP	2019	5
Wakapuaka	Local Service	Vacuum	Reyrolle LMVP	2019	5
Wakapuaka	T1 Incomer	Vacuum	Reyrolle LMVP	2019	5
Wakapuaka	T2 Incomer	Vacuum	Reyrolle LMVP	2019	5
Wakapuaka	Bus Section	Vacuum	Reyrolle LMVP	2019	5
				Max Age (Yrs)	39
				Avg Age (Yrs)	19.7

Regulators

	Type	Year
Pokororo	McGraw Edison Autobooster 100A 2 Cans	
Cooks Corner	McGraw Edison VR32 100A 2 Cans	1993
Kaiteriteri	McGraw Edison Autobooster 100A 2 Cans	
Old House Road	McGraw Edison Autobooster 100A 2 Cans	
Frog Flat	Hawker Siddeley 130A	
Maruia	McGraw Edison VR32 100A 3 Cans	
Kotinga 11/6.6kV Transformer	Crompton Parkinson 3 x 1ph 350kVA	
Kikiwa 22/11kV Transformer	Wilson three-phase Autotransformer 5000kVA	2005
Kohatu 22/11kV Transformer	Wilson Double Wound 3000kVA	2005
Tutaki Capacitor Bank	2 x 150kVA Steps	2002
Motupiko Capacitor Bank	8 x 300kVA Steps	2002
Howard Capacitor Bank	4 x 150kVA Steps	2008
Bainham Capacitor Bank	4 x 150kVA Steps	2011
Hira Capacitor Bank	4 x 150kVA Steps	2012
Maruia Capacitor Bank	4 x 150kVA Steps	2013
Matariki Capacitor Bank	4 x 150kVA Steps	2014
Mangles Capacitor Bank	4 x 150kVA Steps	2014
Sunrise Valley SVG	Static VAR Compensator 300kVA	2018

Air Break Isolators

	No.	Average Age Est
66kV	38	30
33kV	106	37
22kV	7	17
11kV	667	33
Total	818	

HV DDO Line Fuses

	No.	Average Age Est
33kV	4	40
22kV	8	17
11kV	739	30
Total	751	

Mobile Generators

1 x 1000kVA Diesel	Trailer Mounted	2001
1 x 500kVA Diesel	Skid Mounted	2013
1 x 300kVA Diesel	Skid Mounted	2013
1 x 150kVA Diesel	Skid Mounted	2013
1 x 1000kVA Diesel	Trailer Mounted	2020

Network kWh Metering Nil

Distribution Substations

	Fenced Enclosure	Padmount	Kiosk	Overhead Platform	Overhead Single Pole	Total
Stoke	20	626	21	221	1,228	**2,116**
Motueka	8	135	2	157	756	**1,058**
Golden Bay	2	37	2	52	741	**834**
Kikiwa	2	14	0	17	354	**387**
Murchison	0	4	0	17	280	**301**
TOTAL	**32**	**816**	**25**	**464**	**3,359**	**4,696**

There are five types of distribution substation:

1. Fenced enclosure – Concrete foundation pad with open bushing ground mounted transformer. Underground cables incoming and outgoing with HV fuse protection typically DDO at remote end of HV cable. Outdoor 11kV termination, transformer, and LV fusing all enclosed by perimeter fence. Transformers 50kVA to 1000kVA.

2. Padmount – Concrete prefabricated transformer pad, with compact composite transformer/substation bolted down. Underground cables incoming and outgoing. Transformer has lockable HV and LV cubicles and at either end. HV cubicle houses HV cable terminations, switchgear and HRC transformer fusing. LV cubicle houses low voltage fuse board, max demand indicator panel and streetlight controls.

3. Kiosk – Small concrete block building housing ground mount transformer, HV switchgear and HRC fuses, LV fuse board and streetlight controls etc.

4. Overhead platform – Steel platform between concrete poles supporting transformers up to 300kVA in size. Open bushing transformer, drop leads on HV side from DDO fuses connected to overhead line. LV disconnector and fuses mounted on pole.

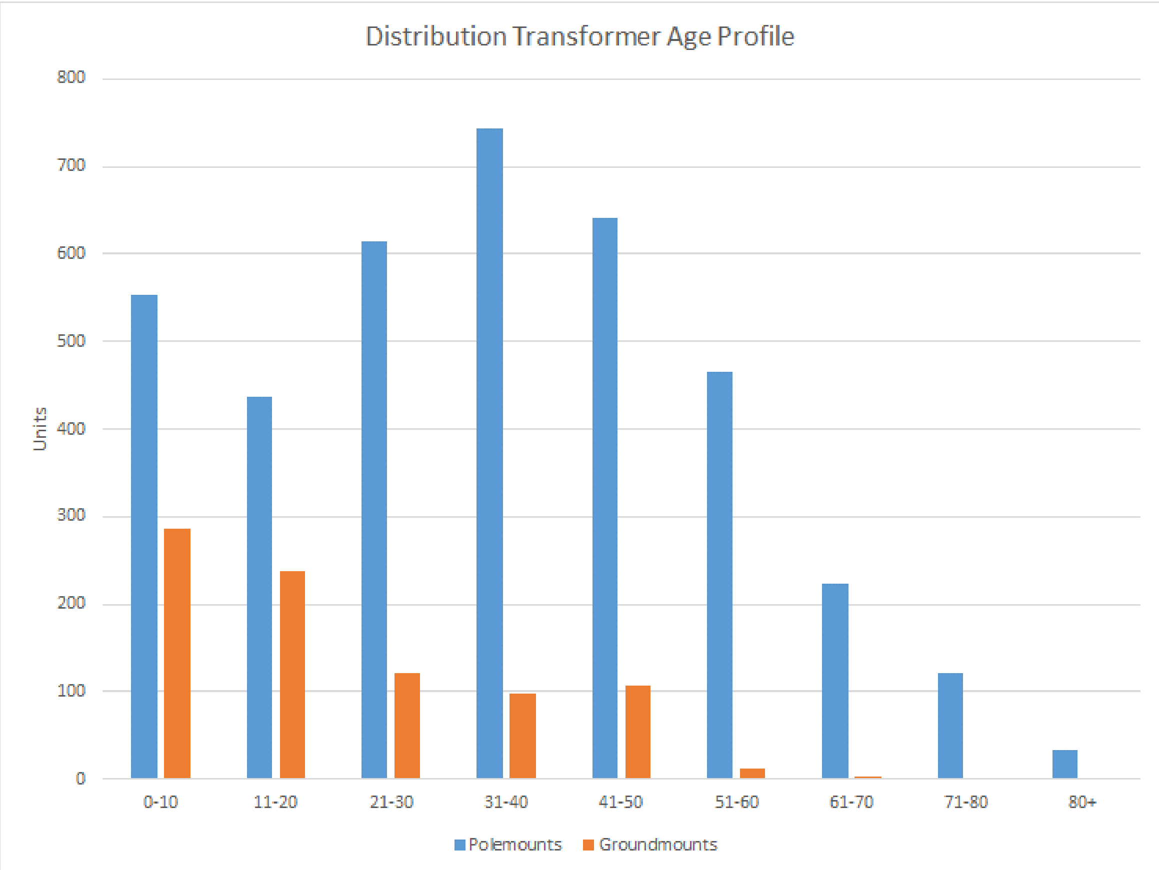
5. Pole – Single pole supporting hanger bracket transformer up to 75kVA. Drop leads to exposed bushings on HV side from DDO fuses. Low voltage fusing mounted on low voltage crossarm.

Distribution Transformers – Units

	0-15kVA	16-30kVA	31-50kVA	51-100kVA	101-300kVA	301-500kVA	>500kVA	Total
Stoke	416	346	345	279	530	139	61	**2,116**
Motueka	261	213	214	181	149	23	17	**1,058**
Golden Bay	338	193	136	115	48	3	1	**834**
Kikiwa	191	81	59	32	22	1	1	**387**
Murchison	149	67	42	28	14	1	0	**301**
	1,355	**900**	**796**	**635**	**763**	**167**	**80**	**4,684**
Working Stock	21	21	8	3	3	0	0	**56**
Emergency Stock	26	26	7	14	6	2	3	**84**
Total Units	**1,402**	**947**	**811**	**652**	**772**	**169**	**83**	**4,836**

Distribution Transformers – Capacity (kVA)

	0-15kVA	16-30kVA	31-50kVA	51-100kVA	101-300kVA	301-500kVA	500kVA+	Total
Stoke	6,091	9,845	17,250	24,175	131,800	69,500	52,500	**311,161**
Motueka	3,731	5,940	10,700	16,150	33,700	11,150	15,250	**96,621**
Golden Bay	4,726	5,650	6,800	9,750	10,637	1,500	1,000	**40,063**
Kikiwa	2,696	2,205	2,950	2,650	4,600	500	750	**16,351**
Murchison	2,114	1,835	2,100	2,250	3,150	500	0	**11,949**
	19,358	**25,475**	**39,800**	**54,975**	**183,887**	**83,150**	**69,500**	**476,145**
Working Stock	259	630	400	225	700	0	0	**2,214**
Emergency Stock	390	780	350	1,175	1,600	1,000	2,750	**8,045**
Total kVA	**20,007**	**26,885**	**40,550**	**56,375**	**186,187**	**84,150**	**72,250**	**486,404**



3.3.1 Low Voltage Networks

The urban LV networks in this region are a mixture of overhead along one side of the street and underground along both sides of the street. Urban LV networks from distribution transformers are run in open rings with limited transfer capability from one substation to another. The urban LV network is approx. 50% underground.

The rural LV networks tend to be mainly overhead, with underground only in newer rural subdivisions. Generally rural LV networks are not contiguous.

LV networks are designed to a standard capacity that is based on the After Diversity Maximum Demand (ADMD) of consumer loads on the network. This ensures that all LV networks are designed and priced to a consistent standard. Over the years, this standard design capacity has been altered once or twice as the ADMD of residences has changed. Recently, investigative work has been carried out to estimate the hosting capacity of electric vehicle charging in the LV networks. This has identified that the modern underground LV networks have greater hosting capacity than the older mainly overhead LV networks.

Further changes to the design capacity standard will be considered in light of EV uptake in the future.

Further information on the low voltage network is given in the Network Lines and Cables table and Age Profile charts at the beginning of this section.

3.3.2 Service Boxes

There are three types of service boxes on our network. These are all concrete pillar, concrete base and all PVC. In total, there are 13,809 service boxes with an average age estimate of 25 years.

3.4 NETWORK VALUATION

The Regulatory Asset Base value of the network is as follows:

Asset Class	**Actual 31-Mar-2023 ($000)**	**Forecast 31-Mar-2024 ($000)**
Distribution Cables	67,097	68,307
Distribution Lines	30,976	34,137
Distribution Subs and Transformers	31,170	34,687
Distribution Switchgear	11,329	11,941
Other Network Assets	13,349	13,776
Subtransmission Cables	12,040	12,187
Subtransmission Lines	8,997	10,621
Zone Substations	31,388	36,979
Non-network Assets	3,443	3,675
TOTAL	**209,789**	**226,311**

4 NETWORK PERFORMANCE

The performance of the network is measured in terms of asset performance, asset effectiveness and asset efficiency. These are discussed in this section.

4.1 *ASSET PERFORMANCE*

4.1.1 Supply Reliability

Supply reliability is measured and summarised in terms of consumer minutes lost each year due to network outages both planned and unplanned, and also in the number of consumer interruptions there are. Dividing the latter figure into the former yields the average duration of supply interruptions.

The industry standard performance indices are SAIDI, SAIFI and CAIDI. These are defined as follows:

SAIDI – System Average Interruption Duration Index

$$\text{SAIDI} = \frac{\text{Total Annual Consumer Minutes of Non-Supply}}{\text{Total Number of Consumers}}$$

SAIDI is a measure of the number of minutes that a consumer on the network can expect to be without supply each year.

SAIFI – System Average Interruption Frequency Index

$$\text{SAIFI} = \frac{\text{Total Annual Consumer Supply Interruptions}}{\text{Total Number of Consumers}}$$

SAIFI is a measure of the number of times each year that a consumer on the network can expect the supply to go off.

CAIDI – Consumer Average Interruption Duration Index

$$\text{CAIDI} = \frac{\text{Total Annual Consumer Minutes of Non-Supply}}{\text{Total Annual Consumer Supply Interruptions}}$$

CAIDI is a measure of the average duration in minutes of supply interruption.

The historical trends in supply reliability of the NTL network and the targets for the future are shown in Appendix C. The charts show SAIDI performance broken down by type of outage (Planned/Unplanned, Transpower Grid/Network Tasman Distribution), and by outage cause.

Analysis of the charts reveals the following points:

- The breakdown of causes of unplanned outages shows that the major causes of outages are external events such as vehicle collisions, bird strikes to overhead lines, contractors' cranes or tree felling interference. SAIDI from such sources averages 40 points each year. The second largest source of unplanned outage minutes on the NTL network is from equipment faults which has averaged 20 minutes per year.

- Methods of reducing network outage consequence and network susceptibility to external interference have been considered and many have been implemented. The capital works plan contains a number of ongoing network enhancements aimed at reducing the frequency, extent and duration of unplanned outages. The strategies include breaking up feeder circuits, installing more line circuit breakers, introducing automation, increasing conductor spacing, identification and elimination of failing line hardware etc.

- Tactical relocations of assets such as poles are considered and implemented where practicable in cases where individual assets have been struck multiple times. Network Tasman undertakes regular advertisements providing members of the public with safety information on living and working around its assets in public spaces.

- Analysis of reliability within each supply region reveals, as expected, that the reliability of supply in rural areas is less than that in the urban areas. In particular, the Kikiwa and Murchison bulk supply regions suffer the poorest reliability, this being a function of the remoteness of the load centres from the supply substation, the very low consumer density in these areas and the lack of alternative supply circuits.

- Planned outages on the distribution network have increased in the past few years due to less live line work being done on light copper conductors for safety reasons. Means of improving planned SAIDI from planned work will include deployment of temporary generators where practicable.

- The 10-year programme of light copper conductor replacements will require more than previously experienced planned outages to complete.

- Two of the supply regions are dependent upon single transformer supply sites (Murchison and Motupipi). Shutdowns of the whole supply region are required to complete transformer maintenance activity at these sites. Motupipi substation is currently in the process of being upgraded to a two-transformer site.

4.2 ASSET EFFECTIVENESS

4.2.1 Supply Quality

Supply quality relates to the voltage delivered at the end use consumers' connection point over the range of loads that the consumer has contracted for delivery. The tolerances are mainly specified within the Electricity Safety Regulations 2010 and in various industry codes of practice.

The parameters of supply quality are:

- Voltage magnitude and variation
- Harmonic level
- Level of interference

NTL aims to supply all end use consumers with supply quality that meets or exceeds the relevant regulatory standards. In order to achieve this, it designs and develops the network to meet allowable maximum voltage drop standards for worst case loading scenarios. These design standards are incorporated both into the design and construction standards for network extensions and into the company's upper network planning processes.

In order to achieve the required voltage tolerance at each consumer network connection point (NCP), it is necessary to allocate the voltage drops across all components of the network between the last voltage regulated supply point and the consumer's NCP.

A chart detailing design regulation across network components is attached as Appendix H.

This chart shows the design maximum voltage drops at minimum and maximum loads for each of the high voltage lines, transformers and low voltage lines. This allocation is designed to provide standard voltage at the consumer's ICP with a tolerance of +5/-3%. This tolerance is tighter than the current regulatory standard of +/-6%, however it is chosen as a design standard to give +/-5% at the consumer's switchboard. It also makes allowance for abnormal system conditions or error. It has also been empirically proven to give correct voltage for the expected range of conditions on the NTL network.

There are a small number of supplies in the rural area that are still operating on original low voltage supply lines that were designed for low capacity electricity supply. Typically, these are old dwellings connected to light overhead low voltage distribution lines. Over the years, the houses have been modernised with appliances added and new electric hot water systems installed. The increased load on these systems results in excessive voltage drop and maloperation of appliances. Other voltage complaints arise from faulty connections within the low voltage distribution.

Network Tasman now continuously monitors the voltage at most consumers' switchboards through the use of advanced electronic meters. These meters report sustained voltage excursions allowing the company to investigate proactively and at an early stage.

The key performance indicator for adherence to the supply quality standards is the number of proven voltage complaints that come about each year.

4.2.2 Contractual Performance

NTL has specified standards for fault outage response within its *Use of Systems Agreement* (UOSA) which is the basis of the contract with its energy retailer consumers. The network configuration and fault response systems are designed around meeting these targets for expected fault outage situations. The response standards for restoration of supply after general network fault notification are six hours for urban consumers and 10 hours for rural consumers.

4.2.3 Environmental Performance

NTL seeks to take a responsible approach to management of the electricity distribution network in the local environment. It will seek to avoid, remedy or mitigate any adverse effects on the environment including discharge of contaminants, unreasonable noise or unreasonable visual impact. It will design and operate its network with this aim in mind.

One measure of environmental performance has been selected. This is the number of incidents of non-compliant emissions. This includes contaminant spill incidents. The target for this measure is zero.

4.2.4 Safety

An important driver of the asset management process is safety. NTL aims to design, construct, operate and maintain its electricity distribution assets in a manner that ensures safety for all stakeholders and the general public.

Five measures of safety performance are used as follows:

The first is the number of serious harm incidents with contractors and staff whilst working on the electricity distribution network.

The second is the number of injury or serious harm incidents experienced by members of the public in conjunction with the electricity network operation as reportable under the Electricity Act 1992.

The third is the number of significant property loss or damage incidents experienced by a member of the public.

The target level for each of these measures is zero.

Two additional measures of public safety performance are used as indicators to gauge the potential for public safety events and for the identification of trends in this area. These are as follows:

- Reported incidents that had the potential for serious harm to any member of the public.
- Reported incidents that had the potential for significant damage to any property of members of the public.

The four public safety measures are key performance indicators that have been recommended by the Electricity Engineers Association for incorporation into public safety management systems. The use of these recommended KPIs will allow alignment with other industry participants for the purposes of benchmark comparison.

The company has reporting processes in place to ensure the complete and accurate collection of data.

4.3 ASSET EFFICIENCY

4.3.1 Thermal Efficiency

NTL aims to operate a thermally efficient system. Although energy losses are inevitable, it is environmentally and economically responsible for ensuring that system losses are kept as low as possible. Losses are derived from thermal losses in lines and transformers and also from unmetered supplies. Historically, the loss percentage (net energy imported/exported over energy imported) has run at approx. 5-6%.

4.3.2 Distribution Transformer Capacity Utilisation

Capacity utilisation is measured and reported annually under the Information Disclosure Regulations. This is a measure of how well assets employed in the system are utilised. NTL aims to hold or improve its current utilisation.

4.3.3 Financial Efficiency

NTL's mission is to own and operate efficient, reliable and safe electricity networks and other complimentary businesses while increasing consumer value. In order to do this, it needs to carefully manage costs. A measure of financial efficiency of the distribution network operations is required.

Network costs are required to be disclosed by lines companies every year under the Electricity (Information Disclosure) Regulations. This allows NTL to benchmark its financial performance against all other lines companies in New Zealand. Due to the differences in costs of operating and maintaining networks of varying urban/rural mix, benchmarking exercises need to consider consumer density (consumers/km line).

Total costs include all direct and indirect costs of operating and maintaining the electricity distribution network. The mix of direct and indirect costs may vary between distribution network companies depending on company structure and also on how many functions are contracted out. Depreciation charges may also vary depending on the age and size of networks and on valuations. To remove benchmarking variance brought about from these sources the measure of "total cash operating costs per consumer" has been selected as an indicator of financial efficiency.

This measure will give shareholders an indication of trends in NTL's financial efficiency given its other service measures, and also of its position against lines companies in New Zealand.

NTL has an objective to be a first quartile industry performer in this measure.

4.4 PERFORMANCE OBJECTIVES

4.4.1 Asset Performance

The performance targets for all planned and unplanned interruptions on the NTL network for the period of this plan are as follows:

SAIDI

		Transpower Planned	Transpower Unplanned	Total Transpower	NTL Planned	NTL Unplanned	NTL Total	Overall SAIDI
Actual	2009/10	0	79	79	62	85	147	226
	2010/11	48	18	66	48	129	177	243
	2011/12	14	1	15	52	107	159	174
	2012/13	32	7	39	36	93	129	168
	2013/14	10	17	27	53	75	128	155
	2014/15	0	30	30	58	122	180	210
	2015/16	9	0	9	102	84	186	195
	2016/17	8	13	21	70	115	185	206
	2017/18	16	238	254	71	161	232	486
	2018/19	17	0	17	134	106	240	257
	2019/20	8	4	12	102	83	185	197

	2020/21	11	0	11	116	87	203	214
	2021/22	5	22	27	65	113	178	205
Actual	2022/23	24	6	30	154	121	275	305
Forecast	2023/24	12	1	13	107	128	235	248
Target	2023/24	10	5	15	100	75	175	190
	2024/25	10	5	15	100	75	175	190
	2025/26	10	5	15	100	75	175	190
	2026/27	10	5	15	100	75	175	190
	2027/28	10	5	15	75	75	150	165
	2028/29	10	5	15	75	75	150	165
	2029/30	10	5	15	75	75	150	165
	2030/31	10	5	15	75	75	150	165
	2031/32	10	5	15	75	75	150	165
	2032/33	10	5	15	75	75	150	165

SAIFI

		Transpower Planned	Transpower Unplanned	Total Transpower	NTL Planned	NTL Unplanned	NTL Total	Overall SAIFI
Actual	2009/10	0.00	0.85	0.85	0.27	1.46	1.73	2.58
	2010/11	0.27	0.14	0.41	0.27	1.37	1.64	2.05
	2011/12	0.05	0.03	0.08	0.32	1.06	1.38	1.46
	2012/13	0.09	0.36	0.45	0.33	1.15	1.48	1.93
	2013/14	0.03	0.70	0.73	0.28	1.05	1.33	2.06
	2014/15	0.00	0.44	0.44	0.22	1.17	1.39	1.83
	2015/16	0.08	0.00	0.08	0.39	1.20	1.59	1.67
	2016/17	0.03	0.30	0.33	0.28	1.28	1.56	1.89
	2017/18	0.05	1.60	1.65	0.28	1.03	1.31	2.96
	2018/19	0.05	0.00	0.05	0.43	0.91	1.34	1.39
	2019/20	0.11	0.05	0.16	0.36	0.88	1.24	1.40
	2020/21	0.03	0.00	0.03	0.33	0.85	1.18	1.21
	2021/22	0.01	0.08	0.09	0.24	1.15	1.39	1.48
Actual	2022/23	0.05	0.05	0.10	0.56	1.17	1.73	1.83
Forecast	2023/24	0.05	0.02	0.07	0.35	1.21	1.56	1.63
Target	2023/24	0.03	0.12	0.15	0.70	1.07	1.77	1.92
	2024/25	0.03	0.12	0.15	0.70	1.07	1.77	1.92
	2025/26	0.03	0.12	0.15	0.70	1.07	1.77	1.92
	2026/27	0.03	0.12	0.15	0.70	1.07	1.77	1.92
	2027/28	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2028/29	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2029/30	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2030/31	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2031/32	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2032/33	0.03	0.12	0.15	0.54	1.07	1.61	1.76

CAIDI

		Transpower Planned	Transpower Unplanned	Total Transpower	NTL Planned	NTL Unplanned	NTL Total	Overall CAIDI
Actual	2009/10	0	93	93	225	58	85	88
	2010/11	178	129	161	178	94	109	119
	2011/12	280	33	187	163	101	115	119
	2012/13	356	19	87	109	81	87	87
	2013/14	333	24	37	189	71	96	75
	2014/15	0	68	68	264	104	129	115
	2015/16	112	0	112	262	70	117	117
	2016/17	267	43	64	250	147	119	109
	2017/18	320	149	154	254	156	177	164
	2018/19	340	0	340	246	147	179	185

	2019/20	73	80	75	283	94	149	141
	2020/21	367	0	367	351	102	172	177
	2021/22	500	275	300	270	98	128	139
Actual	2022/23	480	120	300	275	103	159	167
Forecast	2023/24	240	50	186	306	106	151	152
Target	2023/24	333	40	100	143	70	99	99
	2024/25	333	40	100	143	70	99	99
	2025/26	333	40	100	143	70	99	99
	2026/27	333	40	100	143	70	99	99
	2027/28	333	40	100	139	70	93	94
	2028/29	333	40	100	139	70	93	94
	2029/30	333	40	100	139	70	93	94
	2030/31	333	40	100	139	70	93	94
	2031/32	333	40	100	139	70	93	94
	2032/33	333	40	100	139	70	93	94

4.4.2 Asset Effectiveness

The performance targets in the area of asset effectiveness are as follows:

Service Criterion	Key Performance Indicator	Annual Target 2022/23 to 2033/34	Actual 2022/23	Forecast 2023/24
Supply Quality	Number of proven voltage complaints	10	6	6
Contractual Performance	Breaches of UOSA	0	0	0
Environmental Effectiveness	Incidents of non-compliant emission from network	0	0	0
Safety	Staff and Contractor serious harm incidents	0	0	0
Safety	Public injury incidents	0	0	0
Safety	Public property damage incidents	0	0	0
Safety	Incidents with potential for public injury	70	86	84
Safety	Incidents with potential for public property damage	5	1	0

4.4.3 Asset Efficiency

The performance targets in the area of asset efficiency s are as follows:

Service Criterion	Key Performance Indicator	Annual Target 2022/23 to 2033/34	Actual 2022/23	Forecast 2023/24
Thermal Efficiency	Network losses	6%	5.6%	5.0%
Transformer Utilisation	KVA distribution transformers/peak demand	30%	26%	26%
Financial Efficiency	Cash operating costs per consumer	<$350	$307	$343

All of the service level targets are measurable from existing business systems in place. These are subject to audit. Many of these service level targets are required to be disclosed annually under electricity industry information disclosure regulations.

4.5 JUSTIFICATION FOR SERVICE LEVEL TARGETS

4.5.1 Asset Performance

Unplanned Outages – Reliability

The reliability performance targets are derived from a combination of studies of historical performance, consideration of future works, network analysis, benchmarking with other lines companies of similar characteristics and from consultation with consumer groups that has been undertaken by the company over a long period of time.

The process of setting unplanned event targets firstly considered historical performance by feeder to establish expected frequency rates of fault outage. Outages caused by defective equipment are approx. 20% of the total unplanned outages and are stable at this level.

Network unreliability is now dominated by external causes and historical rates provide useful information as a basis for the development of future targets. Adjustments were made for the effects of improvements brought about by targeted maintenance regimes, capital works and improved vegetation clearance that have now been deployed.

The results of this were then incorporated into a network feeder reliability analysis taking into account the expected effects brought about by growth in customer numbers and by the implementation of capital development projects as detailed in the *Network Development Plan*.

This analysis is reviewed annually.

The 2023 analysis results show that medium term targets for unplanned events of SAIDI of 75, SAIFI of 1.07 and CAIDI of 70 are appropriate and achievable.

The results of the historical performance analysis for unplanned outages showing the contributions by feeder to annual SAIDI statistics is given in Appendix J.

This chart shows that aside from approximately seven feeders, most feeders contribute 0-3 SAIDI points per year to the total.

The worst performing feeders are of two types. Firstly, 33kV feeders, which have a low fault incidence but a high number of SAIDI points per fault. This is due to there being a large number of consumers supplied. Secondly, very long rural 11kV feeders. Due to their length they have a high incidence of faults, and each fault tends to have a reasonably high number of SAIDI points involved due to the time taken to determine the fault source and make repairs on a distant line.

Fault outage data over the past five years, shows that our average unplanned SAIDI over the period is 98 points. This average, however, includes the effects of extreme weather events and earthquakes. The average unplanned SAIDI, discounting extreme events, is 77.

The list of major projects over the next five years and their expected effect on the performance of the feeders is given in the table below:

Project	Year	Feeders affected	Improvement effected	SAIDI benefit
Motueka substation upgrade – additional transformers, switchboard and 11kV feeders.	2022-24	Whakarewa, Queen Victoria	Additional urban feeders reduces extent of existing urban feeders.	1
New feeder Hope sub to Swamp Rd	2024-25	Lower Queen St, Appleby	Additional industrial feeder reduces extent of existing industrial feeders.	0.5
Hope Substation upgrade	2024-25	N/A	Capacity upgrade.	0
Brightwater GXP and new 33kV feeders	2026-27	Hope 33kV, Railway Reserve 33kV	33kV feeders shortened/broken up. Full N-1 security provided for major urban zone substations.	1
TOTAL				**2.5**

The worst performing feeders are subject to improvement through the implementation of AMP capital projects programmed in the next five years, these being mainly the installation of additional reclosers to reduce the areas affected by fault events. Assuming that the rate of fault incidence remains constant for the foreseeable future, these AMP projects should result in a reduction of overall unplanned SAIDI to approx. 75 points.

Given the topology of the NTL network, improvement in unplanned outage performance beyond the current level is not possible without considerable additional capital expenditure into rural network infrastructure. Performance returns per unit capital invested in additional infrastructure would be low.

Less capital intensive investments into operational improvements in unplanned outage restoration, however, have the potential to yield cost effective results.

Planned Outages – Availability
NTL's target SAIDI from planned outages was increased from 75 to 100 in 2019, to take account of the shutdowns required to complete the 10-year light copper conductor replacement programme which commenced in 2018.

This programme will require significant additional planned shutdowns over this period. Generators are planned to be utilised as far as is possible during the conductor replacement operations, but as the conductor being replaced is the primary means of distribution, an increase in planned outages for consumers supplied by the reconductored lines is inevitable.

The national average SAIDI figure for planned and unplanned is 192 points. Network Tasman's corresponding target for the period of this plan is 175 points.

4.5.2 Asset Effectiveness

Supply Quality
Consumer feedback indicates that consumers are happy with the quality of supply that they receive in terms of flicker level, sags/surges etc. and that they would not wish to pay more for improved supply quality, but would not wish to see the existing standard of supply quality drop.

The measure of proven voltage complaints each year is a direct measure of supply quality.

The level of this measure varies between 5 and 10 per year. Targeting a continuation of this level is therefore justified.

Contractual Performance
NTL has processes in place to ensure that all responses required by its UOSA normally occur automatically under all but the most extreme circumstances. NTL has succeeded in operating without breaching UOSA standards for some years in the past. The target of zero breaches is therefore achievable. Consumer feedback suggests a continuation of current performance and price rather than a reduction of performance and price. This provides the justification for this KPI target.

Environmental Performance

Network Tasman operates its network with very low levels of emissions. The target level selected is based on continuation of high levels of environmental performance in line with historical performance. Feedback from stakeholders is that they have an expectation that the environmental performance of the company should not degrade over time. This justifies the target of zero.

Safety

The target levels selected are based on continuation of high levels of safety in line with historical performance. The worker safety targets are linked to the performance contract between NTL and its principal works contractor Delta Utility Services Ltd. This justifies the target level set.

4.5.3 Asset Efficiency

Thermal Efficiency

NTL aims to operate a thermally efficient system. Although energy losses are inevitable, it is environmentally and economically responsible for ensuring that system losses are kept as low as possible. There is a law of diminishing returns in the pursuit of loss reduction. System modelling and analysis has shown that bringing losses below 5% would require significant capital investment into replacing the existing transformer stock with lower loss transformers and reconductoring long lines in rural networks. The very large expenditures involved cannot be justified on the basis of incremental loss reduction.

Continued financial performance for stakeholders requires that the company makes capital investments that show appropriate returns. Setting a target for the continuation of existing losses at 6% is therefore sensible and justified.

Capacity Utilisation

Capacity utilisation is measured and reported annually. This is a measure of how well assets employed in the system are utilised. NTL's targets are below the industry average for this measure which is 30%. NTL aims to improve its current utilisation. There are a number of underutilised larger transformers in the network which can be economically changed out for lower capacity transformers

The target levels set are in accordance with this goal and are justified.

Financial Efficiency

The target level selected is based on the projected costs of continuation of the operating efficiency service levels targeted and assumes continuation of the current company structure and existing economic environment. NTL aims to maintain or improve its relative industry position over the period of this plan, and has a long term strategic goal of being in the industry first quartile for financial efficiency. Targets going forward include adjustment for inflation.

4.5.4 Consumer Consultation

Following process of feedback from consumer consultation work to date, and via the Network Tasman Trust, the resulting service levels are believed to be in line with consumer expectations and appropriate given the geography, network layout, weather conditions and consumer distribution of the Tasman area. In order to match supply reliability to customers' expectations, NTL assesses customer satisfaction with their existing supply reliability by both direct and indirect means. In addition, large customers are explicitly asked if they would like additional supply reliability.

Consumer consultation undertaken to date, including a survey undertaken during 2022, indicates that NTL consumers are happy with both the reliability and quality of electricity supply and with the price paid. An overall network performance satisfaction rate of 96% was recorded in the latest survey, with the majority of consumers (73%) stating that any increase in price would be too much to pay for an improvement in current performance. Further details of the 2022 consumer consultation outcomes are given in Appendix K.

The reliability and financial efficiency level targets outlined in this section of the plan are also corporate objectives of NTL. The same service level targets are listed in the *Network Tasman Statement of Corporate*

Intent. The company SCI is available on our website https://www.networktasman.co.nz/annual-reports-disclosures

Performance measures of the company are set in conjunction with the Network Tasman Trust, which owns the company on behalf of the consumers through the SCI.

5 NETWORK DEVELOPMENT PLAN

5.1 INTRODUCTION

This section outlines the plans of capital expenditure on the NTL network for the 10-year period 2023-2033. The plan is based on demand growth rates for the NTL network as outlined in Appendix B. The resulting development project plan is based on maintaining the security design standard and network performance standards of the previous section whilst accommodating this load growth projection.

The development planning process has the overall aim of developing the network in a timely manner and in a fashion that maintains the levels of supply quality, reliability and security required for our consumers. This aim is aligned with the corporate objectives of the company as discussed in Section 2.2.

5.2 NETWORK DEVELOPMENT POLICIES

NTL aims to develop its distribution network in order to maintain quality, reliability and security of supply in line with the standards specified in this document.

Prudent asset management planning takes a long term view of network development to ensure that the following criteria are met:

- Financial and technical risk is managed through optimised asset utilisation achieved through long term planning.
- Environmental effects of distribution network assets are minimised.
- Asset lifecycle costs are minimised and asset quality is maintained to ensure ongoing reliability.

5.2.1 Formulation of Network Development Projects and Development Path

The process of formulation of network development projects comes from network analysis studies in the light of expected load growth. During this process, future network loading scenarios are modelled using loadflow software and network constraints and regions of non-compliant voltage are identified.

Section 5.9 discusses the detailed network constraints identified from this projected network loading analysis.

A series of development project options is generated to remove the identified network constraints or correct the projected voltage profile. This series of options is then considered collectively to form a view of the most likely overall medium to long term development path. Consideration of technical and economic efficiency, ongoing compliance with the network security standard and management of risk of non-supply are part of the process of formulation of the medium to long term *Network Development Plan*.

Section 5.9 details the resulting likely network development path and its constituent projects by layer of the network supply hierarchy.

5.2.2 Prioritisation of Network Development Projects

Capital projects are generally prioritised using the following criteria:

1. Development or renewal projects that are being undertaken to remove or mitigate a significant public safety hazard.

2. Development or renewal projects that are being undertaken to remove or mitigate a high risk of uncontrolled loss of supply to existing consumers.

3. Development projects that are required to provide supply capacity for new consumers.

4. Development projects that are being undertaken to generally improve supply reliability.

5. Development projects that are being undertaken to generally improve supply security in line with the NTL security standard.

Depending on actual load growth outcomes against predicted load growth timing, the risk profile and ranking of various projects may change over time and sometimes over a relatively short time period, eg. as a result of unexpected large industrial load. Such developments will cause a revision of the capital works plan and may result in a change in the priority order and time that specific development projects are finally implemented.

A sudden change in network conditions brought about by the unexpected failure or early end of life of one or more major items of plant may also result in reprioritisation of capital projects.

The *Network Development Plan* is reviewed each year as part of the *Asset Management Plan* review. The *Network Development Plan* projects are priority reviewed through the following process:

1. Complete demand forecast review process (refer section 5.8)

2. Run load flow and system analysis to identify network constraints and order of occurrence.

3. Review *Network Development Plan* and proposed projects and their timing and order of implementation in light of results of steps 1 and 2.

4. Review public safety hazard register.

5. Review network security against security policy.

6. Finalise project priority in light of step 5 using capital project prioritisation criteria.

5.2.3 Capital Expenditure Approval Process

The NTL capital expenditure policy requires that capital expenditure projects above $100,000 in value are individually approved by the board of directors. In order to gain approval, a comprehensive business case must be developed. Business cases include an analysis and evaluation of alternative options for the project. Alternatives considered may be asset based solutions such as line upgrades, additional circuits, network reconfiguration or voltage support techniques such as regulators or capacitors. Non-asset based alternatives are also considered in project business plans and these may include load control measures, distributed generation, flexibility services etc.

Project business cases consider projects in the context of both short term and long term network development strategy.

5.3 NON-ASSET SOLUTION POLICY

Evaluation of appropriate non-asset solutions is included in the network planning and business case development processes. In particular, where large lumps of capital investment are required to meet short term peak loads, then the deployment of demand side management techniques such as ripple control of storage loads and, more recently, flexibility services are considered.

NTL aims to develop a network that is constraint free under normal conditions and under the failure conditions defined by its security standard. Existing network constraints are listed in Section 5.9. NTL is of the view that the distribution network asset operates to an extremely high level of reliability and availability which can be difficult to replicate by deployment of non-network solutions. Having said this, it will consider non-network solutions other than load management systems under its direct control in cases where the reliability of the non-asset solution is comparable with that of the network upgrade solution, and when failure of the non-asset solution will not affect NTL's ability to meet its obligations to supply consumers other than the operator of the non-asset solution.

At the high level network planning stage, deployment by consumers of home energy management systems and small distributed generation and the effects of these on network loadings are considered. Such developments have had application in the Nelson area, but to date the overall effect of the developments on network demand has been minor. Forward planning is also cognisant of current and likely developments in demand side solutions.

For each of the major upgrade projects in this plan, all options including non-asset solutions are considered in the business case for the project. Options typically considered include voltage support via switched capacitors, use of regulators, feeder distribution voltage change, local generation, load division by provision of additional feeders etc.

The company assesses the availability of non-asset solutions that may have practical significance for each project. These are typically location specific and may take the form of localised distributed generation. Such solutions are assessed for their ability to reliably and practically address the network constraint through being able to generate at the times of system constraint. The costs of operating are also taken into account.

5.4 DISTRIBUTED GENERATION POLICY

NTL has an open access policy and welcomes the connection of all forms of distributed generation on its network. NTL will also comply with the requirements of the Electricity Industry Participation Code for the connection of distributed generation. There are many examples of distributed generation operating within the NTL network at present, including photovoltaic solar generators and micro hydro plants.

Prior to the connection of new distributed generation, it is necessary for studies of the operating conditions of the new generator at the point of connection with the distribution network to be completed. These studies identify issues that may affect existing network assets or other users of the network. Examples include asset overload or introduced effects such as excessive voltage rise or voltage disturbance creating interference with other connected consumers' supplies.

Operation of the generating plant under network fault conditions and provision of means to isolate the generation during times of network maintenance are also required to be understood and managed.

Deployment of NTL operated local generation is considered as an alternative to incremental distribution asset as a part of the network development planning process. This is an option particularly applicable when seasonal peak loads occur such as in holiday areas or seasonal/temporary loads such as crop harvesting. NTL owns and operates five mobile diesel generators ranging in size from 150kW to 1MW.

Network Tasman's current policy is to apply line charges only to load taking ICPs. Small scale distributed generation ICPs currently, therefore, do not attract line charges. Any capital investment in the network needed to accommodate an incremental generator must be funded by the generator. During the process of establishment of a generating ICP, a point of connection defining the boundary between NTL's network and the generator's installation will be agreed. This point will generally be a point of electrical isolation between the two systems.

Further information for prospective operators of distributed generation in NTL's area can be found in the *Network Tasman Distribution Code*. This is available on NTL's website www.networktasman.co.nz.

5.4.1 Network Development Planning

Network development planning aims to continuously develop the network in a timely fashion, so that it can economically and efficiently support the loads to be placed on it. In planning the network, the following criteria are applied:

- Voltage regulation to be at all times within acceptable limits (refer section 4.2).
- System security to be consistent with security design standard (refer section 5.7).
- Urban subtransmission and zone substations planned using standard capacities –
- (subtransmission 23-34MVA, zone substations 23MVA, and distribution feeders 6MVA).
- Rural networks planned around economic selection of conductors and components.
- Adaptation to and mitigation of the effects of climate change.
- Compliance with all applicable acts and regulations.
- Mechanically and electrically safe.
- Minimised environmental impact.
- Economic viability.

5.4.2 Capacity Determination for New Assets

The capacity of new upper network components (33kV subtransmission circuits, zone substations, 11/22kV distribution feeder circuits) is determined by consideration of the following initial criteria:

- Current and likely future electrical loading under normal and contingency conditions.
- Current and likely future fault level.
- Likely mechanical loading, i.e. wind and snow and seismic strength.
- Likelihood of incorporation into future network rearrangement, e.g. ring circuits or conversion to main feeder.

All new and upgraded 11kV and 400V installations are designed and constructed in accordance with a published design and construction standard.

The Network Tasman design and construction standards prescribe the design process to be followed in order to determine appropriate component capacities for new reticulation such as residential and industrial subdivisions. The design and construction standards also prescribe standardised and approved components matching the determined capacities of all types of components. Examples are standardised LV and HV aerial conductors, standardised LV and HV underground cables etc.

5.5 NETWORK SECURITY POLICY

The network security policy provides for higher reliability in urban networks than rural areas and in particular a higher standard of security for urban industrial and commercial power supply. Additionally, individual customers and/or customer groups can be provided with additional supply security if they are willing to pay for the additional assets required.

In order to effect this, a design standard for the components of the supply system is needed. This standard must take into account the expected rates of failure of the network components, represented by mean time between failure (MTBF), expected mean time to repair (MTR), and also the number of consumers likely to be affected by a component failure.

The NTL network security design standard incorporates the above parameters for the following components of its network:

- 66kV and 33kV subtransmission lines and cables
- Zone substations
- 22kV and 11kV lines and cables
- Distribution transformers
- 400V overhead lines and underground cables

Overhead lines at all voltages have a higher failure rate than underground cables, but they have a much shorter repair time. Typically, an overhead line fault can be located and repaired within four hours, whereas a cable fault may take up to 36 hours or more to locate and repair. Also, typically, the higher the operating voltage of the line or cable the more consumers are affected.

Zone substation transformers are the most capital intensive and technologically specialised components on the distribution network. Faults within them can take days or even months to rectify. They are also typically items that supply large numbers of consumers. Therefore, a high level of redundancy is needed for these components. Where this is not built into the ‘in-service” network then contingency plans for the loss of such units are required. The failure rate of these units is generally very low.

Distribution substation transformers are much smaller and technically less complex than zone substation transformers. Failed distribution transformers can be replaced by spares within a few hours.

5.6 SECURITY DESIGN STANDARD

The standard for the design and operation of the NTL network is represented by the chart below. This standard allows for supply to be restored to all consumers following any single failure contingency within approx. 18 hours.

Double contingency failure events are not incorporated into the NTL standard. Such events are dealt with by the company's risk management and disaster readiness and response plans.

The security design standard is a long term network objective. Timing for the implementation of development projects to comply with this standard will be subject to economic, location, growth forecasts and alternative contingency evaluation on a case by case basis. The inclusion of any project in the 10-year Network Development Plan is subject to business case evaluation and no reliance should be placed on any project proceeding.

Group Peak Demand (GPD)	Load Classification	Customer Impact	Security Level	Time to restore first contingency	Time to restore second contingency
Over 10MVA	Major Urban Zone Substation	Over 4,000	N-1 (note 1)	100% GPD immediate restore	100% GPD in repair/switching time
5-10MVA	Minor Urban Zone Substation	2,000-4,000	N-1 (note 2)	100% GPD restore within 3 hours	100% GPD in repair/switching time
Up to 5MVA	Urban Distribution Feeder	Up to 1,500	N-1 (note 2)	100% GPD restore within 3 hours	100% GPD in repair/switching time
2-5MVA	Rural Zone Substation	1,000-2,000	N	50% GPD restore within 3 hours 100% GPD restore within 6 hours	100% GPD in repair/switching time
Up to 2MVA	Rural Distribution Feeder	Up to 1,000	N	100% GPD restore within 6 hours	100% GPD in repair/switching time
Up to 1MVA	Remote Rural Distribution Feeder	Up to 500	N	50% GPD restore within 6 hours. 100% GPD within 12 hours	100% GPD in repair/switching time
Up to 500kVA	Urban LV Network	Up to 300	N	100% GPD restore within 6 hours	100% GPD in repair/switching time
Up to 200kVA	Rural LV Network	Up to 50	N	100% GPD restore within 12 hours	100% GPD in repair/switching time

Note 1: Denotes full N-1 contingency with break for automated switching.
Note 2: Denotes N-1 contingency with break for manual switching.

Exceptions to the above standard are:

1. The 33kV supply from Stoke to the Lower Queen Street substation (17MVA) is a dedicated supply circuit to Nelson Pine Industries and it has an N only security level supply, as agreed with the consumer.

2. The 33kV supply to Mapua substation (6MVA, 2,400 consumers) incorporates a four core cable circuit, with each core spaced approx. 150mm from the others. Three cores are required for service and there is a spare core. In the unlikely event of two cores being damaged coincidentally, then an outage of up to 20 hours would result.

3. The Motupipi subtransmission substation (6MVA) is supplied by a 18km long single circuit overhead 66kV line from Upper Takaka. An insulator failure on this line could take up to 6 hours to repair.

4. The Wakapuaka substation (3MVA, 1,400 consumers) is supplied by a 8km long overhead line traversing difficult access hill country. An insulator failure on this line could take up to 12 hours to repair.

5. The Swamp Road substation (2.6MVA, 1,000 consumers) at Collingwood is supplied by a 26km long single circuit overhead 33kV line. An insulator failure on this line could take up to 6 hours to repair.

5.7 DEMAND FORECAST

The fundamental requirement for long term network planning is a sound demand forecast. The risks to NTL's asset management programme associated with a poor demand forecast includes, amongst other things: the potential for over or under investment, inability to meet demand, severely underutilised assets and the potential for significant optimisation of assets in future valuations with corresponding impacts in price movements and financial performance. This AMP is based on a comprehensive demand forecast using the most current information available.

5.7.1 Information from Local Territorial Authorities

Population forecasts provided by the Local Territorial Authorities (LTAs) should form the basis of any forward projections in demand since it is the LTAs that should have the best information to provide forecasts based on known and promoted development.

Actual population growth is influenced by the availability of land, land zoning, provision of services and other infrastructure. Local authority strategic plans therefore have a fundamental influence on the shape of future population projections as do private landowners since once land is rezoned, it is not necessarily immediately redeveloped.

Tasman District Council and Nelson City Council have jointly published a *Future Development Strategy (FDS)* which is a 30 year (2022-2052) plan of expected residential and industrial development by area. This can be viewed at www.fds.nelsontasman.govt.nz. In order to meet projected housing demand from population growth, the FDS prioritises intensification of housing development in Nelson, Richmond, Brightwater Wakefield, Mapua and Motueka and also provides for managed green field expansion around these centres.

Growth information from this document has been incorporated into NTL's load forecast.

Both territorial authorities have also published climate change maps. These indicate potential areas of inundation from varying levels of sea level rise. This information may influence future zoning developments in the district and also areas of future load growth/retreat in the longer term.

Specific areas of load growth include:

- Ongoing residential growth over the next decade in the Richmond south area, expanding westward and southward towards Hope and in the Brightwater and Wakefield townships. The Mapua area and coastal zone between Richmond and Motueka is also expected to show continued strong growth as a domestic housing area enjoying a semi-rural coastal environment with reasonable proximity to Motueka and Richmond.

- Most flat land close to Nelson city has been absorbed into residential subdivisions of relatively low load density housing. Richmond and Stoke are seen as ideal areas for retirement and many people move into the region from other larger cities. This has resulted in the development of a number of large rest homes.

- Further residential subdivision developments are expected for Nelson in Marsden Valley and also in the Maitai and Dodson Valleys.

- Industrial load growth in the region is expected to continue in the Tahunanui area and in Richmond on the western side. Typically, this will take the form of light manufacturing, seafood processing and packaging, fruit packing, cold storage and timber processing.

- The central Motueka area is expected to show moderate growth. Greenfield residential developments are expected in the Lower Moutere area and hills to the south of Motueka township. The Kaiteriteri/Marahau area is a popular holiday resort and retirement area, and subdivision of coastal land for permanent and holiday residences here is ongoing and expected to continue. Hotel and accommodation developments are expected in the area as well.

- In Golden Bay, like Kaiteriteri, subdivisions for holiday homes and retirement investments are expected near the coastal areas of Pohara, Tata and Collingwood.

- Hop farming has increased substantially in the Tasman district in the past two years as a result of a rising demand both nationally and internationally for Nelson hops. Hop processing is an annual short period load in February/March only. Hop processing has a high demand with a very low load factor. As a result, it has a high impact on rural supply feeders but it has poor asset utilisation and very poor economics when expensive line upgrades are required. Due to these economic factors, NTL limits the supply capacity that it makes available to rural hop processing operations to cover motor loads only and encourages rural hop processing operators to look to alternative fuels for heating.

- Development of dairy farms, including new irrigation, has occurred in the rural areas of Golden Bay, Tadmor, Korere, Murchison, Matakitaki and Maruia in the last decade. This wave of development has now been completed. Some dairy operations have recently been converted into hops.

5.7.2 Decarbonisation

Decarbonisation of the transport and the industrial heat sectors of economy are new factors that need to be considered in electricity demand forecasting. NTL has undertaken studies and investigations to try to establish the likely magnitude and timing of demand from these areas.

Electricity distribution businesses (EDBs) across New Zealand are aware that they have a key role to play as their networks enable the decarbonisation and electrification of society, particularly in the transport and industrial sectors. As EDBs confront this challenge, they recognise the importance of providing clear signals to their customers, communities and other stakeholders, of the likely medium to long term implications of this transition. It is important for stakeholders to understand that this is not ”just” an electric vehicle story – different EDBs will experience increased demands for investment in their networks for a range of different reasons. The following paragraphs describe what are anticipated to be the most significant sources of this demand that Network Tasman anticipates will occur over the next three decades, out to 2050. It should be noted that for many EDBs, ongoing ”business as usual” maintenance and renewal of their existing distribution network is, and will continue to be, a very significant driver of investment, however this is not presented here as it is not a ”new” driver of investment of the type the sector wishes to highlight.

Lastly, readers should appreciate that while certain elements of the transition are well understood and reasonably well fixed (e.g. the net zero by 2050 target), other elements which may have a significant impact on EDBs (e.g. the uptake of electric vehicles and adoption home enhanced EV charging systems) are still uncertain. Network Tasman has made an educated assessment of what might be expected on their network, but there are significant uncertainties and assumptions built into this. The EDB sector will, via its association with the Electricity Networks Association, be developing a more rigorous and structured set of demand forecasts and scenarios out to 2050 in the coming months.

<u>Industrial Process Loads</u>
Electrification of industrial process heating is likely to create some new large spot loads in both urban and rural areas. During 2021, DETA Consulting completed a consultative study with owners of industrial boilers in the area to gauge the potential network development impacts of these. At a high level, all but one site could be electrified with a moderate level of capital investment into the network required.

In the Nelson area, wood pellet fuel will in many cases offer an attractive alternative due to the lower capital cost of boiler alterations needed, and the current relatively low cost of the fuel in relation to electricity.

Electric boiler replacements have the potential to affect upper network planning in both the short and longer terms. To date, conceptual planning and costing has been provided for a few cases where boiler owners have indicated that electricity will be the likely replacement fuel. Planning takes account of the grade of heat required. Boilers operating at 80 degC or below can typically be served by heat pumps. Boilers operating at above 100 degC require direct heating such as electrode boilers. Further work is ongoing.

The load forecast and programme of network capital development in this plan is based on the best information held by NTL at the time of plan revision. This plan therefore represents NTL's view of the most likely path of load growth and of network development.

Electric Vehicles

Electric vehicle charging may become a significant distributed load within the planning period. To date, however, there has not yet been significant development of this load in the Nelson area. Electric vehicle ownership in the region, however, is increasing year on year. There are approx. 150 electric vehicles in the Tasman district at present of which 70% are purely electric.

NTL is aware of the uptake drivers for electric vehicles. The demand for public charging stations has increased in the past two years and this trend is expected to continue. Rural charging stations in particular will present electricity supply challenges requiring innovative solutions.

We are keeping a watching brief on international electric vehicle technology developments and on the implications for overseas electricity networks where they are appearing.

Existing Low Voltage Networks

High levels of uptake of electric vehicles have the potential to radically alter load profiles and impose high network capital investment costs if vehicle charging is not aligned to network off-peak usage. Load management influencing initiatives such as off-peak charging tariffs may offer a cost effective option for consumer electric vehicle charging. Network Tasman operates a day/night domestic tariff that allows night charging at considerably reduced rates.

Investigative work has been undertaken to identify the potential impacts of this new load type on existing low voltage distribution networks. Older overhead low voltage distribution networks in particular are expected to require capital investment, especially if charging occurs coincident with existing peak loads on these networks.

Communication to electric vehicle owners of the potential impacts on the electricity supply system (including both generation and distribution) and on the environment of charging at peak times may be undertaken by the company. Electric vehicle owners will also be encouraged to take advantage of day/night pricing plans offered by retailers. Network Tasman has recently moved to residential day/night line tariffs to retailers to support this.

Clustered home based vehicle charging occurring in the evening in winter may impact low voltage distribution circuits in the next few years. NTL is monitoring the uptake and clustering of electric vehicles on its network.

New Low Voltage Networks

During 2021, studies were undertaken to check the peak load and diversity formulae that are a fundamental part of LV network design against actual. Scott Lemon, of ANSA, analysed smart meter data derived from hundreds of suburban domestic installations. The work firstly verified the existing formulae and then by overlaying various EV charging load profiles, new load diversity formulae that incorporate possible future home EV charging behaviours and penetrations were derived.

The variations in charging load profiles considered included the effects of variations in the size, capacity and types of chargers that could become prevalent in homes in the future. At this stage, it is not possible to know with certainty how home charger sizing or level of charging automation will pan out, but the work undertaken has considered the range of chargers that are possible within typical single-phase supply residences, i.e. up to 7.4kW. Home charger capacities beyond this limit will typically require multi-phase supply, which given that subdivisions and residences in New Zealand are mainly reticulated single-phase, there will be a significant capital cost implication/barrier for home chargers above 7.4kW in capacity.

Studies identifying the design differences and incremental costs of subdivision LV reticulation that will be EV ready were concluded during 2022. NTL's network design and construction standards have been updated and will apply to all new urban subdivision reticulation installed from 1 April 2023.

Opportunities may exist for cooperative use of the energy storage of the vehicle with some consumers. This is an area that NTL may also seek opportunities in.

Energy Storage and Load Management

NTL operates peak load management for the purpose of minimising the peak loads on its network and is also involved in a joint load control initiative by other upper South Island lines companies to limit the peak loading on the transmission network supplying power to the upper South Island in emergency situations. Load management strategy operates to remove domestic and commercial water heating load at the times of system peak in order to minimise peak loadings. These loads are restored when the peak load periods have passed.

Domestic storage water heating constitutes a large energy storage element in the NTL network. Network Tasman has approx. 120MWh of storage available to it in the form of deferrable domestic water heating, and this is used to great effect for peak load reduction and load levelling through ripple control. On the peak load days (winter weekdays), the storage and SCADA load control system facilitates achieving a managed peak load that is constant from approx. 7.30am until 10.30pm, without significant limitation of hot water service to consumers. This is world class load management.

In practice, the action of load management causes peak loadings of parts of the lower network (i.e. on zone substations and 11kV feeders) to occur after the overall GXP peaks have occurred. This is due to variations in load mix across individual feeders and zone substations, so that those with higher proportions of domestic type load, and therefore more controllable load, will experience highest loads when the water heating is being restored. This effect is also accounted for in the formulation of the load forecast.

The demand forecast, detailed in Appendix B, takes account of the effect of load management and, as a result, the GXP peak loads do not contain controlled loads – up to 15MW (10% of total peak distribution network load) of domestic and commercial water heating is switched off at these times. This means that peak distribution network loadings are reduced by approx. 10% through the operation of the load management system.

Domestic and network scale batteries, however, are another energy storage medium that may become economic and available to the company in the future for network load management purposes.

In light of this, Network Tasman has been undertaken a trial with domestic scale battery systems, whereby the battery system is temporarily controlled by the company to be charged during the night and early morning, to be discharged into the network at times of peak loading the following day. A trial battery storage system has been installed at the company's Hope office for set up and testing. Trials of remote control of the battery have been successful and the company is now in a position to consider offering battery system owners a consumer tariff option where line charge reduction rewards are made available in return for temporary use of the battery system.

During 2021, however, it was identified in discussions with the majority battery system supplier in the area, that although domestic solar/battery systems are set up to maximise the self-consumption of solar energy generated at the site, they also respond to the pricing signals in our time of use tariffs. This means that there is no significant advantage for NTL to roll out a new reward tariff at present. Further work on a controlled battery storage tariff has therefore been put on hold.

Large scale network connected battery storage systems have been installed in other distribution networks in New Zealand. Network Tasman is keeping a watching brief on the operation and economics of these systems as a means of voltage support or as an alternative option for traditional network reinforcement. Future network development project business cases will fully analyse the opportunity for solving network development or renewal issues using this technology.

Flexibility Services

Flexibility service providers (aggregators of home battery storage) may be in a position to offer generation or load shifting services to NTL in the near future, as an alternative or deferment option to network capital reinforcement. Network Tasman would consider adopting such services where they are technically and economically appropriate.

Any flexibility service adopted must meet the technical requirements (including the reliability and availability) of the network reinforcement solution and must provide a NPV positive return over the network reinforcement solution in order that NTL's stakeholders' long term needs are met. The safety and environmental sustainability of the services offered are also key considerations.

During 2022/23, NTL issued a request for "expressions of interest" to potential providers of non-network solutions (Flexibility Services), to identify potential deferment for a major grid exit point substation development.

Energy Efficiency

The advent of modern energy efficient home appliances and the steady replacement of older appliances with these higher efficiency appliances appears to be having a significant effect on average household consumption, such that the annual average consumption in the Nelson area has fallen from approx. 7,400 units per annum to approx. 6,800 units per annum over the last ten years. However, the effect on household peak demand is less pronounced. photovoltaic generation is also contributing to the effect of reduced annual average household consumption but with a lesser reduction in average peak demand. The trend of reducing annual average household consumption is expected to continue.

5.7.3 Distributed Generation

The total uptake of small scale distributed generation, such as solar panels and small wind turbines, is progressing at a steady rate in the Nelson area. There are approx. 2,000 installed photovoltaic generation sites on the network at present representing 5% of total ICPs. This is the highest percentage of ICPs with solar generation in New Zealand. Total installed solar and wind generation across the network is 7MW or 5% of the total network load.

Solar PV generation has a negative effect on consumption with no effect on peak network loading. This is due to the timing of domestic load peak demand which is on winter weekday evenings after sunset.

Solar generation, therefore, has a significant effect on incremental growth in consumption. Ongoing growth in PV distributed generation will have a detrimental effect on system load factor. This has been a driver of line tariff changes recently implemented.

Modelling of the potential effects on the distribution network of various future PV generation scenarios is being undertaken at present. Steps to avoid potential network voltage management problems due to high solar PV penetration levels in the future have been taken and are ongoing. These include ensuring that generation in LV networks is within the capacity limits of the networks and that it is balanced across the three phases of the supply. Inverter configuration settings that will maximise the hosting capacity of the network for distributed generators have also been identified and implemented.

The demand forecasts in this plan also include the effects of existing small embedded hydro generators (refer section 3.2 for details of these). The net effect of the embedded hydro generators is a reduction of peak load of approx. 8% of the Golden Bay region load and 1% of the Motueka region load. The net effect of the small embedded hydro generation on the overall NTL peak load is a reduction of approx. 1%.

The Cobb power station (32MW) is directly connected to Network Tasman's 66kV subtransmission network. It is therefore not embedded within the distribution and as such does not reduce peak distribution system loads.

Experience with new distributed generators to date has shown that generation can be unpredictable for some years even after commissioning has been completed.

5.7.4 Demand Forecast Methodology

Step 1. Identify Population Growth by District

NTL's demand forecast is based on historic feeder loadings which are extrapolated using LTA planning document information for each area unit/district. This information is also combined with any known specific development initiatives to refine the high, medium and low population forecasts for each area unit/district.

Step 2. Translate District Population Growth to Network Feeder Growth

After diversity peak demands of 2.8kW per connection are assumed at 11kV feeder level. Domestic load is very weather dependent and the Nelson/Tasman district peaks occur in winter. These are dominated by domestic space heating requirements on the cold cloudy days.

The peak domestic load outturn in any particular year is highly dependent on how cold the weather is through the period June-August. Experience shows that there is an approx. 7% variation between the peak demands of a warm winter and a cold winter. Warm winters can mask the "latent" load that builds up with ongoing domestic load growth. Network Tasman takes a "prudent" approach by using after diversity peak demands recorded from cold winters when building up the demand forecast.

A lower network forecast is firstly developed by combining 11kV feeder load forecasts into zone substation forecasts and then 33kV feeder load forecasts by combining zone substation forecasts.

This is then adjusted for industrial spot load information and planned load transfers in order to derive individual feeder demand forecasts and zone substation demand forecasts.

Consumer expansion projects have major effects on the timing of capital expenditure in this plan. The advance information received from consumers has in the past sometimes proved unreliable, both from a load magnitude point of view and from a timing point of view.

The growth plans of large consumers and any changes that they make can have a major influence on whether or not the capital expenditure plan eventuates in practice. Individual load expansions greater than 2MW are defined as large expansions that are treated specifically. The unexpected development of large expansions may cause significant changes to individual projects and a review of the programme of subsequent projects.

Distributed generation developments are incorporated when known generation patterns have emerged. When generation patterns are known, they are incorporated into the load forecast as a negative load at their point of injection at the time of system peak. A factor is applied to generator maximum output depending upon its historic availability and probability of being available at the time of system peak. Then, as the load matrix is built up, the effect of each distributed generator on the peaks at each level of the network is accounted for.

Step 3. Combine Upper Network Growth to develop Regional Demand Forecasts

Finally, GXP forecasts are developed from the consolidated 33kV feeder forecasts. Diversity across the elements is allowed for at each combining step. Following diversity allowances in the forecast development process, the after diversity peak demand per new domestic connection decreases to approx. 2.0kW at GXP substation level.

5.7.5 Demand Forecast 2024-2034

Summarised demand forecasts for the overall network, each GXP and for all existing zone substations are shown in the tables of Appendix B.

5.8 DEVELOPMENT PLAN – DETAIL

5.8.1 Network Classifications

Proposed network upgrades are outlined in detail in this section under the following classifications:

- Transpower GXPs
- Primary distribution network (33kV)
- Zone and subtransmission substations
- 11kV feeders
- Distribution transformers
- Urban low voltage lines
- Rural low voltage lines
- SCADA/load management system/communications
- Ripple injection system
- Distributed generation

5.8.2 Transpower GXP and Transmission Line Upgrades

The transmission capacity from Christchurch to Nelson was significantly upgraded with the commissioning of a third 220kV transmission circuit between Islington and Kikiwa in 2005. The Stoke GXP substation firm capacity was also increased with a major 220/33kV supply transformer and 33kV switchboard redevelopment in 2013.

At current growth rates, it is expected that further capital investment into the Transpower network in the Nelson area will be required over the planning period of this document in order to maintain security of supply.

During 2009, a transmission "roadmap" was formulated in conjunction with Transpower. Following load flow studies of the network under projected loading scenarios, a list of development projects and approximate timings has been formulated.

In particular:

<u>New 220/33kV GXP at Brightwater (2025-2027)</u>

In around 2027, the load on the Stoke 33kV bus is likely to reach the firm capacity of the supply. Due to the limitations in bringing further load out from the Stoke GXP in its valley positioning in a growing residential housing area, a second GXP will be required. This should be sited near the load centre of the incremental growth which will be to the south of Stoke. Connections from this substation to the existing 33kV network can be made. Land was purchased for the site in 2005 and the site was designated as a GXP substation site in 2016.

This project has a design and construction lead time of four years and it is a very high cost development. Development of this substation will be a cooperative effort between Transpower and Network Tasman. The project timing is dependent on peak demands on the Stoke GXP. The peaks generally occur on winter weekdays. During mild winters the peaks are significantly lower, however NTL and Transpower maintain "prudent" forecasts which allow for the expected cold winter peak demands.

A single new large industrial development or the closure of an existing large industrial load in the Stoke 33kV GXP supply region could also impact the project timing.

Decarbonisation of industry and transport is expected to accelerate load growth in the future. Transpower have recently experienced unprecedented demand for new and upgraded GXPs across the country. This has led to a revision in the lead time for this development to be extended from three to four years.

<u>Additional Transmission Capacity Southern Lakes Generation to Christchurch</u>

Transpower is at present implementing tactical upgrades to existing lines and a programme of transformer capacity upgrades and voltage support device installations. These are expected to delay the requirement for major new transmission lines until at least 2030.

5.8.3 33kV Subtransmission Network Upgrades

The 33kV network is designed to the standard that each zone substation in the urban area has sufficient firm capacity in 33kV supply circuits to carry the peak load on the substation. This is made available by the provision of alternative circuits that can be switched into service in the event of a primary circuit line or cable failure. However, some rural zone substations have no 33kV supply line backup.

In general, all 33kV overhead lines can be repaired within half a day in the event of insulator failure or single pole failure. Wider spread damage tends to be much more catastrophic but far less likely. Most 33kV cables can be repaired within 24 hours after the faulted section has been located.

The substations with firm capacity (switched) in 33kV supply are Annesbrook, Songer St, Richmond, Hope, Founders and Brightwater. The substations without firm capacity in 33kV supply are Lower Queen St (supplying NPI) and rural substations Mapua, Eves Valley, Takaka, Swamp Road and Wakapuaka.

Eight specific 33kV network development projects have been identified. These are:

1. Installation of a 33kV underground cable between Founders and Wakapuaka substations (2023-24). This cable will parallel the existing 33kV overhead line supply to the substation which runs through heavily forested hill country and relegate this supply line to a backup supply. Although currently meeting our security design standard, the existing single line supply is threatened by high and increasing forest fire risk brought about by very dry summers. The cable will allow the backup overhead circuit to be shut down during extreme fire risk periods without loss of supply to consumers.

2. Reconductoring of the Hope substation to Railway Reserve/Clover Road 33kV circuit (4.4km). By 2027 it is expected that the Hope substation load will have reached the point that N-1 security in 33kV supply to this substation from Brightwater GXP will no longer be available at peak load times, and the security standard will not be met. The estimated cost of this project is $0.85m.

3. Reconductoring of the Motupipi to Collingwood 33kV circuit (26km). This circuit is expected to become capacity constrained by approx. 2027. The estimated cost of this project is $1.7m.

4. Installation of four new 33kV feeder cable circuits linking new Brightwater GXP substation with existing 33kV network in the Brightwater area (2026-27). The estimated cost of this project is $7.2m. These cable circuits will provide a switched firm supply for the Eves Valley, Hope, Brightwater and Mapua zone substations. The 33kV network in the Stoke area will also be reconfigured so that a no-break firm capacity 33kV supply is provided for the larger urban substations.

5. Replacement of a section of double circuit 33kV line in Marsden Rd, Stoke. In this project the double circuit configuration will revert to standard single circuit flat configuration utilising a 600A aluminium conductor. The project cost is estimated at $250,000 and it is currently programmed for 2028.

6. The installation of a new 600A 33kV cable in the Railway reserve between Neale Avenue and Annesbrook substation, together with reconductor of the overhead line circuit along the railway reserve in the same area to 600A conductor. This project will increase the firm capacity of 33kV supply to Annesbrook substation to 34MVA. This estimated cost of the project is $700,000. The project is timed to be completed by 2034 ready for the Annesbrook substation upgrade in 2035.

7. Reconductoring of the Hope substation to Railway Reserve/Eden Road 33kV circuit (2.9km). This project will increase the resilience of the network by increasing the transfer capacity available from Brightwater GXP and Stoke GXP. This project is currently timed for 2033. The estimated cost of this project is $0.35m.

8. Extension of 33kV network from Brightwater to Wakefield in preparation for zone substation construction at Wakefield (approx. 2035/36). The estimated cost of this extension is $4.5m.

5.8.4 66kV Subtransmission Network Upgrades

On 1 December 2014, the 66kV subtransmission system and substations at Cobb, Upper Takaka and Motueka were transferred from Transpower to Network Tasman.

Ongoing load growth will create the need for voltage support on the 66kV network under contingent conditions. This will take the form of a Static VAR Compensator (SVC) to be installed at Motupipi (2024) and capacitor banks at Motueka substation (2025).

Toward the end of the planning period, the load on the 66kV network is expected to reach the firm capacity of the supply. At this time a major upgrade to the supply will be necessary in the form of an upgrade in voltage of the Stoke to Motueka section of the 66kV network lines to 110kV. The existing 110/66kV transformation will in effect be relocated from Stoke to Motueka.

This project will be of a significant cost (circa $25-30m) and preliminary design work and costing is currently underway.

Given the magnitude and timing of this development, non-network alternatives such as distributed generation and battery storage may play a part in this development, either as a temporary or longer term solution.

5.8.5 Zone and Subtransmission Substation Upgrades

As a result of projected load growth, a number of existing zone substation supply areas will require substation supply capacity augmentation prior to the end of the planning period.

<u>Motueka Substation</u>

A capital project to replace the two 10/20MVA transformers at the substation and increase the capacity from the substation was completed during 2018/19. In this project, two new transformers were installed each with nominal continuous rating of 23MVA.

The replaced 10/20MVA transformers have now been refurbished and are now planned to be returned to service at Motueka substation as third and fourth transformers, in order to meet ongoing load growth in the Motueka area.

An additional 11kV switchboard and two additional 11kV feeder circuits are also planned for this substation. These circuits will run to the central and northern parts of the Motueka township, relieving the load on the existing township feeder circuits.

This upgrade project replaces a previously planned new substation at Riwaka. Development of this new substation was predicated on expected load growth in the northern part of the Motueka supply area, particularly at Kaiteriteri and Marahau. This load growth, however, has not eventuated. In the meantime, residential load growth has taken place in central Motueka and in the horticulture areas to the south. Climate maps published by the territorial authority also indicate that future growth and development of the Motueka area will most likely occur to the south-west of the township rather than to the north.

Rather than build a new substation to the north, it is now more prudent to expand the capacity of the existing substation. A project to install the refurbished transformers and the new switchboard is now in the detailed planning stage and is expected to be completed by the winter of 2025. This project will improve both the security of the supply and the capacity of supply available from the substation.

<u>Swamp Road Substation (Collingwood)</u>

The transformer protection at Swamp Road substation (Collingwood) relies on remote signalling of the 33kV feeder protection at Motupipi. This necessitates total loss of supply to the substation for a transformer or HV bus fault. It also hampers switching for transformer maintenance.

A project to install 33kV circuit breakers for each of the two transformers at the substation in the form of ground mounted 33kV vacuum CB ring main units and associated cable interconnections is proposed. This has an estimated cost of $650,000.

This project will improve supply security and marginally improve target service levels through reduced planned and unplanned outage times. The project is planned to be completed during 2024/25.

Later in the planning period, load growth in the Collingwood district may reach the firm capacity of the supply from the substation which is limited by the capacity of the transformers. A project to replace the existing 3MVA units with 5MVA units is planned for 2027/28.

Hope Substation

The Hope substation was first commissioned in 1960 and extended in 1967. The two power transformers at the substation were refurbished in 2004 and 2010. The substation is sited on land that has been designated by NZTA for future use as a highway.

The substation 11kV switch room has recently been replaced and relocated to a site adjacent to the designation. The new switchboard includes additional feeder circuit breakers in preparation for planned new feeder circuits accommodating load growth in the Richmond west and south areas.

In approx. 2026, it is expected that the Hope substation will be upgraded to 23MVA firm capacity by installing two new 11.5/23MVA units at the new site. A new 33kV switch room will also be installed.

Annesbrook Substation

In around 2035 a capacity upgrade of Annesbrook substation is expected. The substation firm capacity would be expanded to 34MVA by the installation of an indoor 33kV switchboard, a third transformer and an additional 11kV switchboard.

Wakefield Substation

The Brightwater substation is the main supply for the Brightwater and Wakefield areas. A project to upgrade the substation to full N-1 capacity has been completed.

In the longer term (at or beyond the horizon of this plan), further load growth at Wakefield and Brightwater will generate the need for a zone substation at Wakefield. Land at Wakefield has been purchased and designated for this purpose.

A summary of proposed zone substation transformer movements and purchases is outlined below:

2024/25	Install two refurbished 66/11kV 10/20MVA transformers at Motueka substation.
2025/26	Install two new 11.5/23MVA transformers at Hope substation.
2027/28	Replace transformers at Swamp Road substation with new 5MVA units.
2034/35	Upgrade Annesbrook substation with additional new 23MVA transformer.
2035/36	Construct new substation at Wakefield utilising two new 7.5/15MVA transformers.

5.8.6 11kV Feeder Upgrades

NTL operates a radial 11kV system generally without backup for rural areas. In the urban areas, open loops are built to allow alternative feed routes in the event of cable circuit failures.

HV feeder upgrades are identified through loadflow modelling of the 11kV feeder network. A continuous model of the HV network down to 11kV distribution lines is kept. The voltage profiles on this network can be obtained for various present and anticipated future loading conditions, and areas likely to require reinforcement can be identified at an early stage. Reinforcement projects are then identified and the implementation timing of these optimised from operational and economic viewpoints.

Reinforcement projects are required in order to meet anticipated load growth, to meet the design supply security standard and to maintain network supply quality and reliability performance.

New 11kV feeders and existing feeder reinforcements identified in the bulk supply regions and reasonably expected to be required in the time frame of this plan are as follows:

Stoke Region 11kV feeders

1. Installation of an interconnecting cable in Marsden Valley to link with the Montebello subdivision with associated switchgear in order to eliminate a section of network that is currently supplied by single cable spur and does not meet the design security standard. This project is planned for 2024/25 with an estimated cost of $250k.

2. Installation of a new feeder circuit from Mapua substation to the Stafford Drive/Aranui Road corner. This is to split Ruby Bay from the central Mapua feeder reducing the load on this feeder. This project is planned for 2025/26 with an estimated cost of $300k.

3. Reconductoring of overhead line from the Brightwater substation southward along Higgins Road to Bird Lane. This project is required to provide a full backup feeder circuit to the Wakefield load area and to reduce voltage drop. This project is scheduled for 2026/27. It has an estimated value of $500k.

4. Installation of a new feeder from Mapua substation to Horton Road. The new feeder will provide capacity for expected residential subdivision development in the Tasman area. This project is planned for 2027/28 with an estimated cost of $3m.

5. Installation of a new feeder from Brightwater substation to interconnect with the Ellis Street feeder at the intersection of Ellis Street and SH6. The new feeder will reduce load on the Ellis Street Feeder which serves central Brightwater and provide a backup supply to it. The project is planned for 2027/28 and has an estimated cost of $800k.

6. Installation of a new feeder circuit from Hope substation to connect with overhead lines in Swamp Road, Richmond. This is to support expected industrial load development in the Lower Queen Street industrial area. This project is planned for 2028/29 with an estimated cost of $1.7m.

7. Installation of an additional feeder CB at Richmond substation and two underground cables to create a ninth outgoing feeder circuit. This additional feeder is expected to be needed by 2032 as residential load in the Saxtons Rd East/Hill St North area develops. This project is planned for 2031/32 with an estimated cost of $600k.

8. Load growth in the industrial area of Bolt Road Tahunanui and/or at Nelson Airport may generate the need for an extension of the Bolt Road feeder circuit through to the intersection of Bolt Road and Trent Drive. This project will allow improved load sharing between the Bolt Road and Airport feeder circuits. The project is planned for 2032/33 with an estimated cost of $150k.

Motueka Region 11kV Feeders

Central Motueka

The township of Motueka is supplied from the Motueka zone substation via four 11kV feeders. The Motueka zone substation is situated approx. 3km away from the town centre. Significant load growth has occurred on the existing urban feeders in the past five years and this is expected to continue.

An upgrade to the 11kV feeder capacity into central Motueka is now underway. Two additional underground cable circuits have been run from the zone substation into the urban area. These will be supplied from the new switchboard at the substation to interconnect with existing urban feeder circuits and redistribute load.

Marahau

The Marahau area is supplied via a single 11kV cable installed across the tidal estuary. The shifting sand channels in the estuary have reduced the cover on the cable in places. This creates risk of damage to the cable from trailing boat anchors or shortened cable life from corrosion. A replacement cable installation run around the road is being considered. Alternative options would be considered in a business case analysis.

<u>Golden Bay Region 11kV Feeders</u>

Industrial load growth in Golden Bay has slowed in the last two years with no further development in dairy and irrigation expected in the time frame of this plan. Although one or two rural feeders are operating near their capacity, most have capacity available for the expected growth in the area which is primarily in residential subdivision and tourism.

No significant 11kV feeder upgrades are planned.

<u>Kikiwa Region 11kV Feeders</u>

Rotoiti/Kawatiri/Glenhope

The Rotoiti/Glenhope area is supplied from Kikiwa substation via a single line running southward from the substation to St Arnaud, down the Buller River to Kawatiri and then over hill country to Glenhope via Lamb Valley.

The St Arnaud area has shown only moderate growth with additional holiday properties at St Arnaud used during the winter skiing season and over the Christmas break period.

Voltage profiles over the line show that the supply along it is within regulatory tolerance at all points.

Should further major development at St Arnaud occur then further investment, possibly taking the form of a line upgrade to 22kV, may be required. EV rapid charging demand may necessitate this upgrade.

This development will be subject to full business case economic analysis and to final overall approval by the NTL board.

Korere/Tadmor

The Korere feeder from Kikiwa substation supplies the Korere and Tadmor areas. This feeder is a 50km long 11kV feeder. Significant dairying development has occurred in the Tadmor area. Some reconductoring of the feeder has taken place and two capacitor banks are in place at strategic points on the feeder to support peak load voltage.

Hops are now being planted in the area replacing previous grazing land. Hop processing is becoming a significant load. Further dairying and hop processing development in the future is possible. EV rapid charging at Kohatu is also possible. This may generate the need for partial rural line upgrades to 22kV.

This development will be subject to full business case economic analysis and to final overall approval by the NTL board.

<u>Murchison Region 11kV Feeders</u>

Maruia/Springs Junction

The Maruia valley and Springs Junction are supplied from the Murchison substation GXP via the longest single line radial feeder on the network which is 80km long. Two voltage regulators and a capacitor bank are sited at strategic points along this line to support the line voltage.

In parallel with these developments a two stage system upgrade is underway. In the first stage (2004/5-2006/7) the line has been reinsulated to 22kV.

When further load growth in the area requires it, a step by step process over five years to upgrade the operating voltage of the line to 22kV is to be undertaken. During this process an 11/22kV transformer and 22kV distribution transformers will be installed allowing progressive re-energisation of the line at 22kV from the Springs Junction end. The total cost of this upgrade project is estimated at $2.2m.

In the meantime, the line is operating at full capacity. Springs Junction, at the end of the line, is a significant node on the highway network between Nelson, Christchurch and the West Coast, being at the junction of SH7 and SH65. The capacity limitation of the feeder line is currently constraining the installation of rapid EV charging at this highway node. Funding of the 22kV upgrade would be a major consideration in order for EV charging (or any other load development) to proceed at Springs Junction.

This development will be subject to full business case economic analysis and to final overall approval by the NTL board.

Longford/Mangles
During 2011, applications for irrigation system load were received in the Tutaki/Mangles area on the Longford 11kV feeder. Capacitor banks were installed at Tutaki and at Mangles in order to support voltage in the area to accommodate these new loads. Significant further load growth on this feeder may generate the need for further feeder capacity upgrading which would likely take the form of 22kV conversion.

This development will be subject to full business case economic analysis and to final overall approval by the NTL board.

5.8.7 Urban Low Voltage Lines

Considerable infill development has occurred and is ongoing in some urban areas. This is coming about through the subdivision of former 1000 sq. m and larger sections down to smaller lots of around 450 sq. m. In some cases, both the back and front areas of some properties have been subdivided to provide land for two additional low cost houses.

New cables from these new houses have been run out to the existing reticulation which in most of these areas is still the original overhead lines. This has resulted in some sections of line in urban areas being loaded well over their original design. Some expenditure in these areas to relieve these overload situations is expected and has been allowed for in the plan.

A study into the potential impacts of electric vehicle charging in the urban area has been undertaken. This has identified that the underground LV networks constructed since the late 1980s can support significant vehicle charging load. The older overhead LV networks will become capacity constrained at low levels of vehicle charging load and will require capital upgrades if vehicle charging load (particularly at existing high load times) develops in them. At this stage, vehicle charging load is at low levels. NTL will monitor the uptake and location of vehicle charging in its network.

All LV networks can support night only (11pm to 7am) based charging to relatively high penetration levels. Distribution pricing options signalling this are in place, which will be adequate in the interim. It is expected that eventually smart charging with EVs scheduled over the night period will be required to avoid a new peak at 11pm.

Relief methods include installing intermediate transformers in existing overhead lines, or running new circuits underground on the opposite side of the street to the existing overhead lines. An allowance of $150,000 per year has been made for this type of upgrade in the plan.

5.8.8 Rural Low Voltage Lines

There are a number of long rural low voltage supply lines feeding multiple consumers and long supply lines to single consumers that require upgrading so that regulation voltage is supplied at each rural NCP. Typically, these are brought to our attention through consumer complaints of low voltage.

Upon investigation of the complaint an upgrade of the supply is required, taking the form of a new transformer installed closer to the consumer, or an increase in the size of the low voltage conductor that supplies the consumer(s).

Ten proven low voltage complaints are allowed for each year, at an average cost to rectify of $7,000. This leads to a budget of $70,000 for the rectification of rural low voltage complaints.

The nature of these cases is that they are not specifically predicted at the beginning of each year, however, once underway, they become specified upgrade projects. A budget of the total expected costs of all cases is therefore allowed at the budgeting stage.

5.8.9 SCADA/Load Management System

The SCADA master station is an up-to-date PC based system that is optimally specified to meet the needs of a distribution network operator of NTL's size and type. The system incorporates enhanced load management and monitoring and control of remote field devices such as voltage regulators and reclosers. It also facilitates remote access via laptops.

The system is called iPower which is supplied and developed in New Zealand by Catapult Software. It is built on a Windows based GEC industrial process software platform called iFix. The system deploys dual redundant servers with automatic failover.

The master station hardware and software are updated from time to time as new releases of the system are made available by the vendor. It is not expected that the SCADA system will require any other major development or full scale replacement in the time frame of this plan.

Expansion of the system to complete incorporation of all zone substations on the network is planned over the time frame of this plan. A fibre optic communications system has been extended to all zone and grid exit substations in the Stoke and Motueka bulk supply regions.

A microwave radio link provides communications with the major outstations in Golden Bay. This has recently been extended in conjunction with the Motupipi substation upgrade project.

5.8.10 Remote Control of 11kV Field Autoreclosers

All field autoreclosers are now automated with control integrated into the company's SCADA system. Communication with these devices is by intermittent polling over a mesh radio network.

Further recloser installations are planned for Golden Bay on the Pohara and East Takaka 11kV feeders in order to improve the fault response and overall reliability of these feeders.

An additional recloser installation is also planned near Mapua in order to reduce outage frequency for a growing residential area that is currently supplied from a predominantly rural supply feeder.

5.8.11 Ripple Injection System Upgrades

A ripple control system consists of one ripple transmitter which injects signals into the reticulation system and many ripple receivers located on consumer switchboards. The receivers, when detecting the particular signal code they are programmed to respond to, then switch the loads that are connected to them on or off.

The main purpose of the ripple control system is to utilise the storage available in some types of loads in a way that allows the overall peak demand on the transmission and distribution networks to be reduced. This is done by taking control of all these storage type loads (via the mechanism of ripple control) and ensuring that they are turned off when the uncontrollable loads (i.e. the rest of the system) are at their greatest.

In this way the overall peak on the network can be reduced in comparison to what would be run without the benefit of ripple control. Our aim is to ensure that all our chargeable peak demands contain no controllable loads i.e. that at the time that any peak load is run no water heaters or controllable space heaters are on. To a large extent this aim is achieved.

The primary justification for employing a ripple control system is based on the costs of providing peak capacity or, more correctly, the avoided costs of providing peak capacity. These costs can be divided into two groups. The first of these is the cost of providing transmission capacity to carry the peak load to the Nelson region. These costs ultimately manifest themselves in Transpower transmission charges. Past Transpower pricing indicated that the incremental cost of new demand on the system is approx. $200/kW/year.

The second group of costs are those of providing distribution capacity within the region. These costs are in capital servicing for heavier lines and transformers. The estimated cost for incremental demand on the network can be approximated from the current average cost.

The replacement value is approx. $300m to supply a load of 150,000 kW. This translates to $2,000/kW replacement capital, or $140/kW/year assuming a 7% per annum cost of capital. Adding these two component costs together gives a total avoided cost of $340/kW/year. At present the load control system reduces our overall peak loading by approx. 15,000kW. Therefore, the ripple control system is saving NTL $5.1m in avoided capital charges per year.

The NTL network has five ripple control transmitters in operation, one operating in each bulk supply area. All of these are modern static frequency transmitters that are monitored and remotely controlled via SCADA.

5.8.12 Fault Indicators

Interest and research into overhead line fault indicators, that can deliver high sensitivity and reliability in the detection of weak earth faults on the rural overhead line network, is ongoing. This level of sensitivity and reliability is required to match the protection schemes that are currently in place. It is also envisaged that future overhead line fault indicators would report back into the SCADA system via the mesh radio network. Such capability will enable a degree of automation of fault identification and isolation.

5.8.13 Emergency Generation

Network risk management studies have identified the need to provide relocatable generation as a temporary contingency in the event of two types of network fault.

The first of these is the case of an 11kV cable fault in a section of spur network containing up to 450kVA of load in up to two distribution substations. As cable fault location and repairs can take up to 36 hours to complete, local generation is needed until the cable fault repairs can be effected, in order to meet urban supply restoration time limits of six hours.

Three transportable generators fitted with cables ready to be connected to the low voltage switchboard of a distribution substation were purchased during 2013/14.

The second case is a contingency to allow supply restoration to rural spur networks within 12 hours in the event of 11kV cable failure. Five such spur sections have been identified on the network with loadings of up to 1100kVA.

A containerised 1250kVA generator was purchased and a trailer constructed for this generator during 2002/3. Aside from its emergency power supply function, this generator is also utilised for peak load management during the winter and for alternative power supply during shutdowns on rural feeder trunk lines.

A second trailerised 1250kVA generator has been purchased and commissioned. This generator will be deployed to supplement the existing generators during HV light copper replacement outages and as a backup supply for the small single transformer GXPs at Kikiwa and Murchison. It will also be deployed for peak load management.

5.8.14 Reactive Voltage Support

As the load in the Motueka and Motupipi bulk supply regions increases, the firm capacity of the 66kV subtransmission network is encroached. The capacity constraint is voltage based and can be boosted by the installation of reactive voltage support at Motupipi and Motueka substations.

Projects to install a static VAR compensator (SVC) at Motupipi (2024) and a capacitor bank at Motueka substation (2028) are planned. A budget capital allowance of $2m and $1.0m have been allocated for these projects.

5.8.15 Overhead to Underground Conversion

A previous overhead to underground conversion programme based on NCC, TDC and NTL's priorities, with NTL determining the final programme, has now been completed. The final project was completed during 2020 in Ellis Street, Brightwater.

Under current policy, small underground conversion projects may arise from time to time where major street upgrade works are being undertaken by NCC or TDC, where it is cost effective and practicable for NTL to underground lines in conjunction with the works and at NTL's sole discretion. Alternatively, ducts may be installed for future underground conversion.

5.8.16 Climate Change Based Adaption

Sea level rise as a result of global warming could threaten distribution assets in low lying areas particularly during storm surge events during the period of this plan.

Identified assets most vulnerable to sea level rise are service boxes and padmount transformers in the low lying coastal areas of Monaco, Ruby Bay and Beach Road, Richmond with underground reticulation. Assets in the areas have experienced inundation in the past during weather events combining spring tides with low barometric pressure.

Adaptation strategy is to raise these assets up onto mounds where possible. Relocation of these assets is generally not practicable as the assets are required in situ for the ongoing supply of electricity to consumers. Ultimately sea level rise may render properties in these areas uninhabitable, at which time the reticulation would be abandoned.

The following assets are identified as vulnerable at this stage:

Area	Padmount Substations	Service Boxes
Monaco	SM8	17
Ruby Bay	N/A	2
Beach Rd, Richmond	R211, R254	11

5.9 NEW CONSUMER GENERATED NETWORK EXPENDITURE

5.9.1 Background

Tasman District has experienced steady population growth in recent years. This has created a growing demand for residential land and in turn provides a stimulus for the business sector as the local economy expands.

Combined, both sectors are demanding greater line function services, initially as new connections, and then followed closely by business requiring greater capacity.

Land subdivision activity has resulted in approx. 600 new connections per year.

For capital expenditure planning purposes, the following distribution of new consumer connections has been assumed to be connected each year:

2022/23 to 2032/33	Urban Connections	Rural Connections
STOKE	475	26
MOTUEKA	125	23
GOLDEN BAY	15	17
KIKIWA	0	12
MURCHISON	0	7
TOTAL	**615**	**85**

5.9.2 Distribution Transformers

Distribution transformers are generally provided free issue by Network Tasman to reticulation developments and industrial expansions.

The current average expenditure on distribution transformers (11kV/415V) for developments is $1.73m. These provide capacity for residential consumers and increased business demand. Typical applications are urban/rural residential subdivisions, industrial subdivisions, central business district areas and sporadic rural sites.

Whether or not a transformer is required for a subdivision or individual customer will depend on the capacity requested, the proximity of the LV network and whether or not there is any unutilised capacity in that circuitry and its transformer to meet the demand requested.

Urban residential customers have an after diversity maximum (ADMD) of 3kW at low voltage distribution transformer level. Urban transformer utilisation typically has an overall average of 50%.

With approx. 615 new urban connections requiring 3,690kVA of transformer capacity, NTL can expect to invest $450,000 annually on typically 200kVA and 300kVA padmount transformers, where density allows 50-80 customers to be connected to single substations.

Rural subdivisions by contrast are less densely populated (typically >2000m2 lots) thus requiring more substations with smaller transformer capacity. Where only single lots are created by subdivision, a single dedicated transformer is often required (15kVA is minimum size purchased). On average in Stoke, Motueka and Golden Bay, rural consumers are provided with 12kVA of transformer capacity resulting in a very low utilisation factor. Transformer costs rise from $122/kVA for urban connections to $445/kVA for rural, leading to an overall $455,000 capital cost for rural transformer purchases to supply 85 new rural consumers per year.

Kikiwa and Murchison have respectively 12 and 7 new connections per annum on average. Apart from the odd subdivision at Tophouse/St Arnaud, almost all connections require a dedicated 15kVA transformer. At approx. $5,700 per unit, the annual transformer cost is $108,000 for both regions.

Large commercial and industrial consumers typically requiring 300kVA to 1000kVA create the remaining user group. Annually approx. 20 new transformers are purchased at a cost of $720,000. For safety and convenience reasons, a recent trend has been a move away from fence enclosure type industrial substations to padmount substations.

5.9.3 Switchgear

Consumer generated network extensions and alterations often create the need for additional 11kV switchgear to meet operational requirements and security standards. Normally these occur in the meshed section of the network to maintain N-1 security for urban and industrial subdivisions. Typical examples are pole mounted isolators at cable terminations and ground mounted ring main units at the confluence of three or more cables.

The annual budget is $400,000 per year for this equipment.

5.9.4 Urban Subdivisions

Provided the reticulated works are vested with NTL, then NTL will provide up to 100% contribution towards 11kV materials on qualifying subdivisions. This includes: padmount transformers including installation, 11kV cables and switchgear, except for some isolators and associated fixtures. On vesting and livening, NTL may also pay a further contribution per electrically connected lot as consideration for vesting.

5.9.5 Rural Supplies

Rural subdivisions and industrial connections are largely funded by the developer but vested with NTL.

Estimated replacement costs for rural connections is on average, $8,000 per connection. Total value with an average 85 new connections over all GXP regions amounts to $680,000 per annum.

All assets vested to NTL that are on private land are protected by registered easements.

5.10 MAJOR NETWORK DEVELOPMENT PROJECTS 2024/25

Refer to the table in Appendix D showing total capital expenditure by year over the planning period.

This section details the major network development projects planned for the 2024/25 year. Unless otherwise stated, business cases for these projects have been approved by the NTL board.

Specific details of the projects are as follows:

5.10.1 Founders Substation to Wakapuaka 33kV Cable Completion

This development has been undertaken to improve the security of supply to the Wakapuaka substation and mitigate forest fire risk during dry summers. This risk is brought about by the route of the existing 33kV supply to Wakapuaka substation through heavily forested hill country.

This project gained final NTL board approval during 2022 and commenced during 2023. Alternatives considered in the business case included:

- Overhead line route relocation
- On site Diesel Generation

The overall capital cost of this project is $5.5m. The project implementation is spanning two financial years with approx 50% expended in each year.

This project will have no incremental improvement effect on target service levels but it will serve to maintain existing supply quality and reliability while accommodating current and future load growth.

5.10.2 Motueka Substation Upgrade and Additional Feeder Circuits Stages 2

Residential growth and expansion of the Motueka township area is ongoing. By approx. 2024 the existing 11kV feeders will have increased such that the N-1 security level will have been reached.

To remedy this, a project to return two refurbished transformers to the substation as third and fourth transformers, to install an additional 11kV switchboard and to run two additional 11kV feeder circuits into the township has been approved and is now being implemented.

This project has a total estimated value of $8.9m. It is a three-year project with a second and third year value of $6m

The project gained NTL board approval in 2021. Options considered in the business case for this development included major deployment of embedded generation in the Motueka township.

This project will have no incremental improvement effect on target service levels but it will serve to maintain existing supply quality and reliability at current levels whilst accommodating load growth.

5.10.3 33kV Circuit Breaker Installation Swamp Road Substation 2024/25

The transformer protection at Swamp Road substation (Collingwood) relies on remote signalling of the 33kV feeder protection at Motupipi. This necessitates total loss of supply to the substation for a transformer or HV bus fault. This also hampers switching for transformer maintenance.

A project to install 33kV circuit breakers for each of the two transformers at the substation in the form of ground mounted 33kV vacuum CB ring main units and associated cable interconnections is proposed. This has an estimated cost of $650,000.

This project will improve supply security and marginally improve target service levels through reduced planned and unplanned outage times.

The project business case for board approval is currently being developed.

5.10.4 Upgrade of Hope Substation to 23MVA Firm Capacity 2024/25 and 2025/26

Load growth in south Richmond and Hope is projected to exceed the firm capacity of Hope substation in 2023. A project to upgrade the firm capacity by replacing the 10MVA transformers with 2 x new 23MVA rated units is proposed. The project will also include the installation of an indoor 33kV switchboard in a new switchroom building adjacent to the existing 11kV switchroom. The project will also complete the relocation of the Hope substation away from the NZTA roadway designation where it now sits.

Options to be considered in the business case for this project will include:

- Project deferment by embedded generation.
- Project deferment by battery storage installation.

This project is a two-year project and has an estimated total cost of $5m. The first year (2023/24) detailed design will be undertaken at an estimated cost of $0.5m.

The project will have no incremental improvement effect on target service levels but it will serve to maintain supply quality and reliability at current levels whilst accommodating load growth.

5.11 MAJOR NETWORK DEVELOPMENT PROJECTS 2025/26 – 2028/29

Refer to Appendix D, detailing all capital expenditure identified as likely to occur in the four years 2025/26 to 2028/29 inclusive.

These projects are all subject to business plan approval. The major projects and the alternative options to be considered prior to approval of these are as follows:

5.11.1 Brightwater GXP 33kV Interconnecting Cables – 2025/26 and 2026/27

The prudent load forecast for the Stoke 33kV bus is 141MVA for the winter of 2026. This load exceeds the firm capacity of the supply from the GXP. An alternate supply from a new Transpower 220/33kV GXP at Brightwater is proposed. Transpower will construct this GXP on land purchased and designated for the substation by Network Tasman.

The substation will be connected to the existing 33kV network via four new 33kV underground cables which will run from the substation switchboard out to four strategic points of connection with the existing overhead line network.

This cable installation project will be undertaken over two years while the GXP substation is being constructed. It has an estimated cost of $7.2m.

The business case for the installation of the cables is a part of the business case for the substation development.

Alternative options considered in the business will be based on economic deferment of the large capital cost of the substation and will include:

- Deployment of peak load flexibility services
- Peak load reduction by diesel generation.
- Peak load reduction by battery storage.

This project will not improve target service levels. It will maintain target service levels in the face of increased load.

5.11.2 Marahau Estuary Feeder Cable Replacement – 2025/26

Consumers at Marahau are supplied by a single HV cable that runs across the Otuwhero Inlet. This was installed in 1988 replacing an overhead line that crossed the tidal estuary. This cable was installed by moleplough but it's cover varies with sand movements in the estuary. It is also exposed to damage from anchors from watercraft that moor in the estuary.

It is proposed to replace the cable with a land based cable following the roadway around the estuary to improve the safety and security of the supply to Marahau.

This renewal project has an estimated cost of $800k. The project business case will include options of:

- Replacement with an over land based overhead line.
- Local generation.

The project will have no incremental improvement effect on target service levels but it will serve to maintain existing supply quality and reliability at current levels whilst accommodating future load growth.

5.11.3 Collingwood 33kV Feeder Reconductor – 2026/27

The Collingwood 33kV feeder is a single overhead line running 26km from the Motupipi substation to supply the 33/11kV Swamp Road substation. This substation supplies approx. 800 consumers in northern Golden Bay.

The load on the substation has low growth but the conductor is reaching the end of its life. The conductor is planned to be replaced with a slightly higher capacity conductor in 2026/27.

This renewal project has an estimated cost of $1.7m.

5.11.4 Capacitor Banks - Motueka Substation 2027/28

As a tactical development to defer a major upgrade of the 66kV supply to Motueka and Golden Bay, it is proposed to install additional voltage support to the network in the form of capacitor banks connected at 11kV at Motueka Substation. These are required to support the voltage at times of peak load in Motueka when the network is operating at N security – one of the 66kV circuits supplying the area being out of service for maintenance or forced outage.

The project has an estimated cost of $1.0m.

Alternative options to be considered in the business case will include:

- Load levelling by distributed or grid battery storage, and/or
- Local generation.

This project will have no incremental improvement effect on target service levels but it will serve to maintain existing supply quality and reliability at current levels whilst accommodating load growth.

5.11.5 New Horton Road 11kV Feeder Cable – 2027/28

A major housing development planned near the Tasman township will require an upgrade of the 11kV supply capacity in the area to maintain supply security standards. This will likely take the form of a new feeder circuit breaker and underground cable circuit from Mapua substation, running a distance of approx. 7km.

Options to be considered in the business case for this project will include:

- 11kV feeder supply from Motueka substation.
- Project deferment by embedded generation.
- Project deferment by battery storage installation.

This project has an estimated cost of $3m.

The project will have no incremental improvement effect on target service levels but it will serve to maintain existing supply quality and reliability at current levels despite the effects of load growth.

5.11.6 New 11kV Feeder Cable and CB – Brightwater Substation to Ellis Street/SH6 Corner 2027/28

Ongoing residential and industrial development in central Brightwater is causing the load on the single feeder supplying the area to reach the point that for supply security reasons a second feeder from the Brightwater substation is required. This will require an additional circuit breaker at the substation and a run of 11kV cable to interconnect with the existing feeder at the eastern end of Ellis Street in Brightwater.

This project has an estimated cost of $800,000.

Alternative options to be considered in the business case will include:

- Load transfer to upgraded feeders from Hope substation,
- Load levelling by battery storage, and/or
- Local generation.

This project will have no incremental improvement effect on target service levels but it will serve to maintain existing supply quality and reliability at current levels despite the effects of load growth.

5.11.7 Upgrade Swamp Road Substation Transformers to 5MVA – 2027/28

Load growth in the Collingwood rural region may cause the firm capacity of supply (3MVA) from Swamp Road substation to be exceeded in approx 2028. In order to accommodate this, a project to upgrade the transformer capacity to 5MVA firm is proposed. This project has an estimated cost of $900k.

Alternative options to be considered in the business case will include:

- Load transfer via upgraded feeders from Takaka substation,
- Load levelling by battery storage, and/or
- Local generation.

This project will have no incremental improvement effect on target service levels but it will serve to maintain existing supply quality and reliability at current levels whilst accommodating load growth.

5.11.8 New 11kV Feeder Cable Hope Substation to Swamp Road, Richmond – 2028/29

Due to industrial load growth in the Lower Queen Street area, it is expected that an additional 11kV feeder circuit from Hope substation along SH60 to connect with overhead lines at the Swamp Road intersection will be required for feeder capacity reasons. A feeder circuit breaker on the Hope 11kV switchboard is available for this circuit. This project has an estimated cost of $1.7m.

Alternative options to be considered in the business case will include:

- New 11kV feeder from Richmond substation,
- Load levelling by battery storage, and/or
- Local generation.

This project will have no incremental improvement effect on target service levels but it will serve to maintain existing supply quality and reliability at current levels despite the effects of load growth.

5.11.9 66kV to 110kV Line Upgrade Stoke to Motueka 2028/29 to 2031/32

By approx 2033, the load on the 66kV system supply the Motueka and Golden regions is projected to have reached the limits of N-1 supply security of this system. Tactical voltage support projects deployed at Motupipi and Motueka substations in order to defer this development by this time are likely to have been exhausted.

The next step in network reinforcement is a major one, involving a system voltage upgrade from 66kV to 110kV. There are two major upgrade components, firstly the re-insulation of the two overhead line circuits between Stoke GXP and Motueka zone substation and secondly the establishment of a 110/66kV step down substation at Motueka.

The line upgrade can be expected to take four years to complete. Therefore the first stage could commence in 2028/29.

The total cost of this development is approx $30m, $10m for the line upgrade and $20m for the substation.

Alternative options to be considered in the business case will include options for further deferment:

- Special protection schemes
- Load levelling by grid/distributed battery storage, and/or
- Local generation.

This project will have no incremental improvement effect on target service levels but it will serve to maintain existing supply quality and reliability at current levels whilst accommodating load growth.

6. ASSET RENEWAL AND MAINTENANCE PLAN

6.1 PLANNING CRITERIA AND ASSUMPTIONS

It is NTL's view that electricity distribution network assets can be operated, maintained and progressively renewed on an ongoing basis in perpetuity so that the overhead lines, cables and other equipment never become unserviceable and overall they remain in a such a condition that the probability of failure of any line is held constant.

Inputs and drivers used to develop the maintenance plan include the following:

- Asset survey
- Condition driven maintenance and renewal (CDM) - from asset data base
- Equipment replacement programme
- Regulatory compliance
- Equipment obsolescence
- Safety considerations

The performance standards and monitoring process provides an ongoing indication of the health of the network and basis for the matching of maintenance and capital expenditure to stakeholder expectations.

The total projected network asset operations and maintenance expenditure over the ten years of the plan by asset class is given in Appendix F. The projected expenditure for asset maintenance and non-capitalised renewal is summarised by category in the following table:

ASSET MAINT & RENEWAL EXP $k	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2033/34**
Faults and Emergency Maintenance	1,227	1,276	1,315	1,355	1,396	1,438	1,482	1,526	1,572	1,620
Routine and Preventive Maintenance	2,647	2,755	2,838	2,923	3,012	3,103	3,196	3,293	3,392	3,495
Refurbishment and Renewals Maintenance	2,208	2,297	2,366	2,438	2,511	2,587	2,665	2,746	2,829	2,914
Total	**6,082**	**6,328**	**6,519**	**6,716**	**6,919**	**7,128**	**7,343**	**7,565**	**7,793**	**8,029**

N.B. Figures include adjustment for asset growth (1.5% p.a.) and inflation (3% p.a.for first 3 years and 2% p.a for subsequent years).

The mode of maintenance of the system is primarily condition based whereby individual components making up lines are replaced when their condition and serviceability has deteriorated to the point that it creates an unacceptably high risk of failure. Since the service life of the various types of components varies widely (e.g. timber crossarms 15-45 years, porcelain line hardware in excess of 50 years), a composite line may never reach the point where it has reached the end of its life. Over a long period of time all components of the line may have been replaced at least once, however the line at no point in time was unserviceable or significantly less serviceable than a new line. True ageing of the composite overhead line network is therefore minimal and difficult to identify.

There is not expected to be any significant technology developments in the immediate future in the industry that will have a significant impact on network component performance in the macro sense. Any technological gains are seen as being complementary to the existing equipment and such improvements will operate in addition to the existing equipment.

Most extensions to the system have been underground over the last two decades, and it is expected that this will reduce the need for maintenance in the longer term. It is also apparent that over a period of time there has been a significant contribution to the renewal of the system from the continual alterations needed to accommodate additional consumers or to meet changing consumer needs.

6.2 ASSET RENEWAL AND REFURBISHMENT POLICY

Network Tasman's asset renewal and refurbishment policy is to replace or refurbish components just prior to end of life. Lifecycle renewals are ongoing under the regime of inspection and maintenance that the company is operating. As most network components have few or no moving parts, end of life is determined by age based degradation of materials such as insulation deterioration, metal fatigue or rusting, timber rotting etc. Technological items such as relays, switchgear and SCADA components are replaced for reasons of obsolescence rather than wearing out.

Although there is an expected service life for all components, there is significant variation within component classes of actual age at end of life. This means that the "wave" of replacements of a particular type of component typically does not have the same time profile as the "wave of initial installation". The overall effect is a significant flattening of the original installation profile for renewal.

Only a few assets or components of assets undergo refurbishment, due to the nature of the network asset being made up of a large number of replaceable components that individually are of low value. The exceptions to this are power transformers and large distribution transformers. These are subject to refurbishment policies aimed at extending the life of the asset by undertaking midlife refurbishment.

In-service failures of components on the network account for less than 10% of all HV outage events and approx. 20% of annual unplanned outage minutes. Any component types that have failed in service a number of times are investigated for the failure mechanism. When this is identified and ascertained, all items of the same type are isolated and programmed for progressive replacement. In this way, individual component failure rates are kept very low and it is difficult to obtain consistent figures for failure rates of individual components over time.

Other activities that significantly contribute to ongoing asset renewal include:

- Underground conversion of lines either by line company or private landowner.
- Line relocations for land development or roadworks.
- Replacements of damaged assets from vehicle collisions.

Details of asset renewal and refurbishment policies by individual asset type are given in section 6.6.

6.3 ASSET CLASS

The assets of the network are broken down into the following classes:

- Pole Structures
- Overhead Conductors 66kV, 33kV, 11kV, 400V
- Underground Cables 33kV, 11kV, 400V
- Distribution Substations
- Distribution Transformers
- Service Boxes
- Air Break Switches
- Ground Mounted Switchgear
- Pole Mounted Switchgear
- HV Line Fuses 33kV, 11kV
- Circuit Fuses 400V
- Field Regulators and Capacitors
- Zone Substations
- Power Transformers
- SCADA
- Communication Networks
- Public Lighting
- Ripple Injection Plants
- Network Meters
- Connection Assets

These asset classes are the basis of the asset layers of the GIS system and they also provide the framework for the network asset register. All items of plant are individually identifiable within these classes.

6.4 ASSET MAINENANCE AND RENEWAL CATEGORIES

In this plan the following categories have been used:

- Faults and Emergency Repairs
- Routine and Preventative Maintenance
- Refurbishment and Renewals

6.4.1 Faults and Emergency Repairs

These are unanticipated repairs/replacement work arising from network equipment failures, accidents, storms and other external influences which cause outages, weaken or impair service, or reduce asset life. The category includes all work needed to restore the network to its pre-incident strength and capacity.

Works during emergency repairs may constitute either premature maintenance and/or premature renewal. If an asset classed as a network component is completely replaced during the repair the activity is treated as a renewal.

A list of typical emergency repair activities is given in Appendix G.

6.4.2 Routine and Preventative Measures

This is regular ongoing work, annual or other regular longer time cycle, aimed at maintaining the existing composite assets rather than enhancing the life of them. The work is not intended to change the service potential, although this may, to a minor degree, be a result of this work.

Typical examples of this are tree trimming, service box maintenance, cleaning, also tightening line hardware, changing crossarms, rebinding conductors and replacing fuse links.

A list of typical routine maintenance activities is given in Appendix G.

6.4.3 Refurbishment and Renewals Maintenance

Refurbishments and Renewals are mainly component life extending refurbishments or complete replacements such as pole structure replacements including crossarms and line hardware.

Refurbishment of equipment is generally only undertaken to extend the life of major capital items such as power transformers. Most other single items are more economically replaced rather than refurbished.

Renewals are typically replacement works that arise near the end of an asset's expected life. As previously stated, the process of ongoing maintenance and replacement of the individual components making up a line network ensure that the overall line network is never significantly aged or reduced in service potential.

A list of typical renewals maintenance activities is given in Appendix G.

6.5 ASSET INSPECTION AND CONDITION MONITORING

The company has two staff members in the field to assess maintenance and renewal requirements. The entire network is subject to a condition driven survey cycle that involves inspection of every asset at least every five years.

The routine surveys confirm the view that the system is in a good state of repair. The entire network has now been inspected over many cycles with the bulk of the identified work being timber crossarm renewals with some pole replacements.

Urban and rural inspections are generally made from the ground. Remote rural inspections are sometimes made by helicopter. Drone cameras are also used in specific instances where close up views are necessary. The table below summarises the routine inspection regimes in place.

	Inspection Type	Period
Pole Structures	Visual	5 Yearly
Overhead Conductors	Visual and Thermographic	5 Yearly
Insulators	Visual and Corona Discharge	5 Yearly
Pole Mounted Switchgear	Visual and Thermographic	5 Yearly
Pole Mounted Switchgear	Operational Test	Monthly
Air Break Switches	Visual and Thermographic	5 Yearly
Distribution Substations >100kVA	Visual and MDI Reading	Yearly
All Distribution Substations	Visual and Earth Test	5 Yearly
Field Line Regulators	Operational Test	6 Monthly
Zone Substations	Visual Inspection	Monthly
Zone Substations	Switchgear Maintenance and Protection Operational Test	2 Yearly
Power Transformers	Tap changer Operational Test	Monthly
Power Transformers	Tap changer Oil and Contacts	2 Yearly
Power Transformers	DGA Oil Sample Test	Yearly
Ground Mounted Switchgear	Visual and Oil Sample Test	5 Yearly
Service Boxes	Visual	5 Yearly
Underground Cables 33kV	Partial Discharge Test	5 Yearly
Underground Cables 11kV Major Feeder	Partial Discharge Test	5 Yearly
Ripple Injection Plants	Operational Test	Monthly
Ripple Injection Plants	Supplier Service Inspection	Yearly
SCADA Master Station	Supplier Service Inspection	Yearly

All maintenance work identified from the routine field inspections in the above table is entered into the Network Maintenance database. Each task of maintenance or renewal work is referenced to the specific asset via a unique asset identifier. Maintenance works contracts are later formulated from the information in this database and assigned to the principal maintenance contractor.

Following completion of the maintenance works by the maintenance contractor, an independent auditor inspects the works in the field. Any incomplete works or remedial works are reported back to Network Tasman. All task audit inspections are recorded against the original task in the database. This provides an audit trail from when the maintenance task is initially identified from the routine field inspection, through to its issue to the contractor, task completion and invoicing by the contractor and finally its audit inspection and completion.

A comprehensive GIS system has been developed that includes all network components. This has links to the network maintenance database and allows the recording of all survey and completed maintenance activity for each individual component. The GIS system provides a convenient and efficient means of geographically selecting maintenance works tasks from the database to form contract works packages. These works packages are assigned to the contractor for completion in the field. The maintenance database is then updated upon completion of each works task. The database, therefore, also becomes a historical record of all maintenance activities undertaken at each pole site on the network.

Network Tasman is in the process of implementing a condition based risk management system (CBRM). This is a software system that takes in the available condition and age information for each asset to come up with a health indicator, and combines this with a consequence of failure assessment again derived from information on the asset's criticality in the network, and it's time to repair etc. The system output is a monetarised risk assessment for the entire network system. This allows for objective support for targeting of maintenance expenditure and for the determination of appropriate longer term network maintenance budgets.

6.6 LIFECYCLE ASSET MAINTENANCE AND RENEWAL POLICIES BY ASSET CLASS

6.6.1 Pole Structures

The NTL overhead line network is based on purpose designed concrete poles. There are approx. 28,000 poles in the NTL network, 95% of which are a reinforced concrete type that have been manufactured by the company and its predecessors since the 1930s. They have proven to give excellent service and, in the relatively benign conditions of Nelson/Tasman province, they have a very long life.

The design strength rating of these poles (despite some minor design alterations over the years) has been confirmed as being conservative and poles that have been in service for 55 years have shown to have strengths well beyond their design rating, even after considerable concrete spalling has occurred.

A graph of the historical development of the network shows that rapid expansion took place in the period 1950-1970 when the reticulation system was initially rolled out. Since that period many overhead feeder lines have been rebuilt to accommodate heavier conductors. Others have been replaced by underground cables during a period of underground conversion of the central townships and main urban highways. This took place in the period 1970-1987.

Reinforced concrete poles that have been correctly manufactured with good quality raw materials have a long life. There are many examples of 70-year-old poles on the network that are not cracking or spalling and show no signs of deterioration. Loss of strength, even in heavily spalled poles, is not evident. Strength testing has shown that the poles have better than their initial design strength even after one side has almost completely spalled. Concrete poles are generally therefore replaced for aesthetic and public safety reasons (risk of being struck by a falling piece of concrete) rather than for loss of strength.

Pole replacements due to spalling tend to be variable over the age distribution of poles. The onset of spalling (and therefore premature end of life) comes about mainly by reason of poor manufacture. Some batches of poles were produced with insufficient cover over one side of the reinforcing cage. Some others are believed to have been produced using reinforcing that was rusted through being transported on ships as deck cargo.

Approx. 1,200 reinforced concrete poles have been scheduled for replacement over the period of this plan. This represents 4% of the total pole population.

Research into the expected life of the reinforced concrete poles has been undertaken. This research utilised the engineering resources of local civil engineering companies and the University of Canterbury. Research undertaken to date indicates that reinforced concrete poles that are not within 30km of the coast will achieve a life of greater than 150 years.

The performance of pre-stressed concrete poles in estuary situations was brought into focus with the early failure (approx. 15 years in service) of some poles on the line supplying Best Island. It was ascertained that salt water ingress into these poles results in rapid rusting of the steel wires within the pole leading to catastrophic failure of the pole. The short life of reinforced concrete poles in estuary situations was also identified in the pole life research project. They are an inappropriate pole type for these locations. A programme to replace all concrete estuary poles with class A marine treated pine poles is now nearing completion.

The manufacture of reinforced concrete poles was discontinued in 2005. At this time the reinforcing steel had become prohibitively expensive. All new concrete poles installed on the network are now of pre-stressed construction. These are a stronger pole than the reinforced concrete pole, however they have the disadvantage of having no residual strength following breakage, for example from vehicle impact.

The remaining 5% of poles in the NTL network are either iron rail poles, from the original Nelson railway, or treated pine softwood poles. The railway iron poles date back to the 1950s and are now showing signs of reaching end of life in some areas.

A proactive iron rail replacement programme is operating. Iron rail poles that have maintenance scheduled on them (for example to change the crossarm) are replaced with a concrete or treated softwood pole. Also, as lines are being upgraded (e.g. larger conductor installed), all iron rails in the line section are replaced with a concrete pole as part of the upgrade. There are approx. 100 of these still in service on the network. All remaining iron rail poles in the network are expected to have been replaced by 2026.

The treated pine poles on the network were installed during the period 1975 to 1985 mainly in spur lines in the rural area. They were identified at the time as being a cost effective pole for use in rural line extensions, however the quality of them proved inconsistent and this led to ongoing problems with twisting and splitting, and so their use was generally discontinued. They are now used only in special situations such as high salt areas, estuaries and where access necessitates deployment of helicopters. Treated pine poles in service on the network are still relatively new and they are monitored during survey rounds. A testing programme for these poles is to be introduced in 2023/24. Few are expected to require replacement within the time horizon of this plan. A stack of replacement treated pine poles is kept for difficult access situations.

Pole Routine and Preventative Maintenance

Pole maintenance is limited to patching reinforced concrete poles in cases where cover concrete has been damaged by impact rather than due to quality of manufacture.

Straightening and strengthening of pole footings by re-blocking and re-compacting the footing is also considered maintenance.

Pole Refurbishment and Renewals

Most repair works undertaken on poles result in replacement of the pole. No poles are refurbished. As discussed above, pole replacement programmes are underway for spalling reinforced concrete poles and all iron rail poles. Spalling reinforced concrete pole replacements are budgeted to continue at a steady rate for the time horizon of this plan.

All pole replacements are treated as renewals and as capital expenditure under company policy.

6.6.2 Line Hardware

Line hardware consists of all pole structure subcomponents other than the poles themselves. Items include crossarms, insulators, strain insulators, guy wires and anchors, brace straps, dropout fuses and cutouts.

Crossarms

The timber crossarms in use in the NTL system are mainly Australian hardwood arms of varying types. The quality of these has varied within batches and across varieties such that the life spans of crossarms is highly variable. The service life can vary from 15 to 45 years with an average of around 25 years. Factors influencing crossarm life are aspect and level of shading from the sun, as well as the propensity for lichen growth on crossarms, particularly in the southern regions of our network.

Crossarm condition is generally assessed by visual inspection from the ground, initially looking for end splitting, shrinkage, corrosion of the upper surface of the crossarm and signs of dry rot.

The current average condition of crossarms is good. The present replacement rate is approx. 1,200 crossarm changes per year. This is consistent with the crossarm average life.

Replacement crossarms are now “purple-heart” hardwood material.

Hardware

Most line hardware is of galvanised steel or porcelain material that has proved to have a very long life in the Nelson environment.

In the west coast region of Golden Bay, however, the environmental conditions are extremely corrosive, being an area of high and steady salt laden westerly winds with regular light showery rain. This leads to severe corrosion of line hardware, particularly where dissimilar metals are used in the same components. Line hardware that is specified as corrosion resistant is trialled in the area.

Line Hardware Routine and Preventative Measures

Line hardware and crossarm maintenance activity consists of tightening crossarms and hardware only.

Line Hardware Refurbishment and Renewals

Most line hardware and crossarm activity involves replacement of the component. Such activity is ongoing across the network at a steady rate (approx. $1.1m per annum) for the period of this plan.

No items of line hardware are refurbished.

Specific component types, that have been identified as reaching the end of their service life and for which specific replacement strategies are underway, are as follows:

- Dominion dropout (DDO) fuses of the two piece insulator construction with a galvanised steel and cement insulator mounting have been found to fail particularly in cold, moist environments. Moisture entry into the mountings of the insulator posts is prone to freezing, with a resultant expansion and fracturing of the insulator mounting. The DDO normally retains its electrical insulating strength, however its mechanical strength is severely reduced. The mounting failure becomes apparent when the fuse is operated by a faultman, in that it falls apart when the fuse candle is reinserted after fuse link replacement. Units of this type are being identified during line surveys and replaced.

- Band clamp type dominion dropout fuses also have a failure mechanism whereby ice induced expansion of the band insulator mounting leads to loosening and eventual mechanical failure of the DDO. These units are also scheduled for replacement as they are identified.

- In the salt laden air environment of the north-west coastal strip, dropout fuses are known to corrode in the hinge area, defeating the dropout function of the fuse. This causes the candle to remain in situ following fuse element ruptures and the candle becomes a highly resistive conductor. Reports of low voltage or burning HV fuse candles alert faultmen to the problem. 11kV dropout fuses incorporating stainless steel fittings and preload spring systems are now used as replacements in these remote areas.

- Prior to 1995, the grease tube and line tap connector were commonly used for tapping copper tails onto aluminium lines. These have proved to be an unreliable method of connection and the procedure has now been discontinued. A compression joint is now made in all cases. Where other linework is taking place in an area, all grease tube and aluminium line tap connections are replaced. All remaining 11kV connections of this type will be identified for replacement during future line surveys. It is anticipated that it will take a number of years to change all 400V connections of this type.

- Porcelain strain insulators of the “kidney” type have been found to be failing in areas prone to lightning. The failure mode is a pinhole puncture through the porcelain when a high voltage impulse from a lightning strike occurs. This pinhole may not result in immediate failure of the insulator at normal service voltage, however it significantly reduces the insulation strength and often leads to later failure in misty or wet conditions. Kidney insulators are now scheduled for replacement during maintenance survey.

6.6.3 Overhead Line Conductor

Overhead line conductor in use on the network is copper, ACSR or all aluminium conductor. There are also short sections of galvanised steel conductor still in use on some rural HV spur lines.

Careful inspection and monitoring of the condition of the conductor at points subject to vibration, resulting in fatigue failure of strands, will be required to determine the reliability of these lines. Vibration testing to date indicates that aeolian vibration levels are generally low on the network, possibly aided by a policy of conductor installations at reduced tensions.

Conductor renewal is, however, now required for light copper lines in the network. Older light copper conductors are reaching end of life. Over the life of the conductor, vibration fatigue and annealing from passing fault currents results in loss of tensile strength. This is evidenced by an increased occurrence of conductor breakages when conductors are clashed together or otherwise abnormally stressed. However, there have been no incidences of conductor breakage under normal static loading conditions.

A programme to replace approx. 210km of light copper conductors on the network over ten years is entering its sixth year.

The standard ACSR conductor has a very limited life in the coastal conditions of Westhaven. Salt particles are driven into the conductor creating a chemical and abrasive attack on the aluminium strands. This deterioration is also enhanced by any conductor vibration in the crosswinds.

A major renewal project of the Westhaven lines was completed during 2010/11.

Conductor Routine and Preventative Maintenance
This consists mainly of re-sagging and/or rebinding line conductors. Any conductor repairs generated from conductor clashing also falls into this work category. There is a small budget each year for this activity (refer Appendix F).

Conductor Refurbishment and Renewals
Conductor renewal has been proceeding over recent years with the replacement of steel (originally galvanised) conductor that has rusted to failure, and has reached the end of its economic life.

A programme of replacement of 7/064 and lighter copper HV conductors over a 10-year period commenced in 2017/18. Conductor installation records and historical records of conductor breakages have been used to prioritise this replacement programme. Under the programme, approx. 21km of light copper conductor has been planned to be replaced each year.

Conductors that are removed from service are generally disposed of. No conductor refurbishment takes place.

Conductors are also often replaced prior to end of life for load growth reasons. Refer to the *Network Development Plan* for further details of conductor upgrade projects.

6.6.4 HV Underground Cables

In general, the underground cable network is in good condition. It has been carefully installed in fine bedding material and it is operated prudently within conservative loading limits.

The HV cables are mainly mass impregnated non-draining (MIND) oil impregnated paper lead technology, with a small amount of cross linked polyethylene cable in some areas. Paper lead insulation was the preferred technology due to its worldwide proven performance and long life as a high voltage insulation until 2015, when production of paper lead cables ceased in New Zealand and the cables became prohibitively expensive.

Cross linked polyethylene (XLPE) insulation has been deployed for all new HV cables since 2016.

HV Underground Cables Routine and Preventative Maintenance
Preventative Maintenance activity for HV underground cables consists of periodic visual inspection of cable terminations and partial discharge testing of 33kV and major 11kV feeder cables. Cable terminations in switchgear or transformer enclosures are cleaned when external tracking has been identified during inspection rounds.

HV Underground Cables Refurbishment and Replacement
In-service HV cable failures in the past few years have highlighted an issue with small csa (35 sq. mm and below) steel tape and wire armoured cables installed during the 1980s and up until 1997. The steel armouring has significantly corroded during the approx. 20 years in service to the point that the mechanical protection that the armouring provided has all but disappeared, leaving a thin layer of lead as the only protection against water ingress to the insulation. This exposes the cables to increased risk of damage from external sources such as tree roots etc. Excavations around these cables are also more hazardous. NTL has highlighted the enhanced risk situation with contractors in the area, reinforcing compliance with operational procedures when working in close proximity. Cable failure rates are also being closely monitored.

All sections of 16mm and 35 sq. mm HV cable have been individually identified and a replacement programme targeting these cables has been created. This programme commenced in 2021 and will continue for twenty-five years at a steady rate of approx. 2km per year, over which period all affected cable will have been replaced with PVC/HDPE sheathed XLPE insulated cable. The replacement programme will prioritise cables that are known to have completely lost the armour covering as identified from previous excavations and faults.

The costs of this replacement project are included in the capital works budgets of Appendix D.

Pitch filled cast iron case cable terminations known in the industry as “pitch potheads” were in common usage in the 1970s. These have a propensity to rupture and eject hot material when faulted, particularly if not protected by fast acting fuses. Over the past 30 years most pitch potheads have been removed from network and in 2023, 13 remain in service. These are all on low capacity cables and are protected by dropout fuses.

Pitch potheads are being replaced with modern “heat shrink” cable terminations which are less prone to explosive failure. The 13 pitch potheads will be replaced over the next few years.

6.6.5 Subtransmission and Zone Substations

The network contains one 66/33kV substation, two 66/11kV substations and ten 33/11kV substations of capacity ranging from 3 to 23MVA.

All substations are in good condition and are well designed for normal expected electrical duty. Monthly operational checks are completed and defects picked up in this process are remedied immediately.

Seismic strengthening of some switch room buildings to bring them up to appropriate standards has been completed.

Power Transformers

There are twenty-two 33/11kV three-phase transformers in service ranging in capacity from 3MVA to 11.5/23MVA. The oldest of these are two 10MVA units at 64 years.

There are two three-phase 66/11kV power transformers in service at each of Motueka and Upper Takaka substation. These are all relatively new units (circa 2018 and 2015).

There are two 66/33kV three-phase transformers in service at Motupipi substation. These were installed new during a recently completed upgrade of this substation.

Two 66/11kV transformers (ex Motueka substation) have been refurbished and are planned to be returned to service at Motueka in a substation capacity upgrade project.

Power Transformer Routine and Preventative Maintenance

The transformers, tap changers and switchgear at all substations are maintained on a biannual basis. Oil samples are taken from the in-service transformers for dissolved gas analysis every year and the results of these are checked for trends.

Oil acidity and moisture content is monitored carefully and oil is treated before it reaches the point that it may significantly compromise winding insulation life. Due to the N-1 design standard deployed for zone substation transformers, few units have been operated for significant periods beyond 70% of their nameplate rating. As a result of these practices, it is expected that the insulation of the power transformers is still in good condition.

The on-load tap changers on all power transformer units are opened up biannually and checked for wear etc. At this time, contacts are dressed or replaced and the tap switch is serviced. Although original parts can no longer be purchased for the older tap changers, it is possible to have them manufactured if required. The economics of having to replace many parts within a few years brings about the economic end of life for the older tap changers.

Power Transformer Refurbishment and Replacement

Network Tasman has an age based refurbishment and replacement policy for power transformers. Under this policy, a midlife refurbishment is undertaken after 40 years of service. Power transformers are planned to be finally retired from service after approx. 65 years.

The five oldest 33/11kV power transformers on the network have undergone midlife refurbishment. Paper insulation strength tests undertaken during the refurbishments confirmed that the insulation was in good condition for all of these units and that the expected 65-year service life would be attained from the transformers following refurbishment.

Further policy based midlife refurbishments of power transformers are scheduled in the capital programme of this AMP.

The oldest transformers on the network at Hope substation will be retired when the substation is upgraded in 2025.

There are no other age based replacements of power transformers within the time horizon of this plan.

66kV Switchboards

There are outdoor overhead 66kV switching structures at Motupipi, Upper Takaka, Cobb and Motueka substations. These are gantry based structures comprising 66kV isolators, 66kV circuit breakers, current transformers and voltage transformers.

These structures are all in good condition. The 66kV circuit breaker at Motupipi is a vacuum/dry air insulated type. This circuit breaker was new in 2012 having replaced the previous SF6 unit which had a slow gas leak.

All other 66kV circuit breakers in service on the network are of the SF6 type.

66kV Switchboard Routine Maintenance

Maintenance requirements for these switchboards are minimal, consisting mainly of visual inspections, intermittent circuit breaker and isolator operational checks and circuit breaker gas level monitoring checks.

66kV Switchboard Refurbishment and Renewals

Refurbishment and renewal of 66kV switchboard equipment constitute significant capital works. There are no plans to replace or refurbish the 66kV switchboard equipment in the time frame of this plan, however should any CBs develop significant gas leaks, then they may be removed from service and refurbished. Further analysis and determination of the lifecycle situation with the 66kV SF6 circuit breakers is to take place during the next few years.

33kV Switchboards and Reclosers

There are ten outdoor overhead 33kV switching structures, comprising overhead buswork, isolators, lightning arrestors and circuit breakers. The switchboards are monitored with thermal imaging during winter on a biannual basis.

The circuit breakers are either bulk oil or vacuum type, the oldest circuit breakers being circa 1981. These are inspected on a biannual basis. Very few fault clearing operations have occurred on these circuit breakers.

The Mapua, Wakapuaka and Richmond substations have indoor 33kV switchboards. The Mapua switchboard has SF6 CBs and the Richmond and Wakapuaka switchboards are both encapsulated vacuum type.

There are four 33kV field reclosers that are not at zone substations. These are all vacuum interrupter type.

33kV Switchboard Routine and Preventative Maintenance
Maintenance requirements for these switchboards are minimal, consisting mainly of visual inspections, intermittent operational checks and gas level checks. These are undertaken biannually.
33kV Switchboard Refurbishment and Renewals
High voltage switchboards are major capital items. Refurbishment and renewal are significant capital works.

The 33kV circuit breakers at Motupipi substation are older bulk oil circuit breakers. These will be replaced as part of a major upgrade of the substation currently taking place.

The 33kV circuit breakers at Annesbrook, Songer Street and Hope substations are early 1980s Takaoka bulk oil type. The Annesbrook and Songer CBs are planned for replacement in 2024/25. The 33kV switchboard at Hope substation is proposed to be replaced in conjunction with a zone substation capacity upgrade and relocation in 2024/25. All CBs will be replaced with vacuum interruption/non-SF6 gas insulated types.

Further information is provided in section 5.9.4.

11kV Indoor Switchboards
There are nine vacuum switchboards (circa 1997, 1998, 2001, 2003, 2005, 2006, 2013, 2016 and 2020) and one SF6 indoor switchboard (circa 1985). These switchboards are all in good condition, have sufficient fault duty and are regularly serviced.

11kV Switchboards Routine and Preventative Maintenance
The maintenance requirements of the modern vacuum and SF6 switchboards are minimal. All switchboards are inspected, cleaned and tested on a biannual basis. Partial discharge testing is also undertaken on a biannual basis. Partial discharge testing of all switchboards to date has revealed no unusual discharge activity.

11kV Switchboards Refurbishment and Renewal
11kV switchboard refurbishments or replacements are major capital works.
All oil interruption technology 11kV CB switchboards have been replaced with modern encapsulated vacuum technology switchboards in the last 15 years. The 11kV SF6 CBs at Lower Queen Street substation are scheduled to be replaced with vacuum type in 2024/25.

There are no planned refurbishments or renewals of any of the vacuum switchboards in the period of this plan.

Protection Relays
The protection relays are a mixture of electromechanical and electronic devices. Most substations have all electronic protection relays. Some have a mixture of digital electronic and electromechanical.

The remaining electromechanical protection relays are associated with the older (1980s) 33kV and 66kV transformer circuit breakers. Although these relays are ageing, there have been no signs to date of failure or critical degradation. Renewal of these relays will be undertaken for reasons of obsolescence rather than end of service life.

The modern digital protection relays now offer much greater functionality within one unit. Some digital relays will be replaced within the timeframe of this plan, having reached the age in service that the manufacturer recommends their replacement.

All protection relays are tested for functional operation and timing accuracy biannually in conjunction with other substation maintenance.

Oil Management
il handling procedures and facilities at all zone substations have been upgraded incorporating the provision of oil spill kits. Oil containment systems have been installed at all zone substations aside from Hope. Hope substation transformers are to be replaced and retired in 2025/26 and new transformer pad/bunds will be built in conjunction with this project.

6.6.6 Air Break Switches

There are 788 air break isolators in service on the NTL network. These comprise 66kV, 33kV, 22kV and 11kV isolators and include both side swing and rocker arm types.

<u>Air Break Switch Routine and Preventative Maintenance</u>

Air break switch maintenance is carried out with the switch in situ and consists of periodic thermographic surveys, operating mechanism adjustments and arc controlling flicker adjustments. Air break switch maintenance is also initiated from reports from lines staff of operating problems.

Bolted connections on overhead 11kV air break switches have previously been made using galvanised bolts and Belleville washers. These have severely corroded within five years of service, resulting in failure of these connections in service.

A programme to replace all bolted connections with friction welded bimetal connectors fastened with stainless steel bolts and washers is underway. Over a period of 10 to 15 years the complete replacement will be made. The worst connections are being identified by annual thermographic surveys of the HV network now being undertaken each winter.

<u>Air Break Switch Refurbishment and Replacement</u>

Air break switches that are of the minimum 400A rating and no older than 40 years are refurbished if this can be economically achieved. Refurbishment consists of contact and flicker assembly renewals and individual insulator change outs where it is possible to undertake these.

Air break switches of rating less than 400A and/or older than 40 years are scheduled for replacement in the network maintenance database.

Mahanga 11kV air break switches manufactured prior to 2014 have an insulator moisture ingress problem that can result in cracking of the porcelain insulators and corrosion of the metal fittings, a mechanism that is exacerbated in areas where temperatures drop below 0 degC. An insulator replacement programme for these switches is now underway. Under this programme, switches released from service are refurbished and the porcelain insulators are replaced with polymer insulators. All pre-2014 Mahanga 11kV air break switches are being changed out for a refurbished air break switch.

6.6.7 Pole Mounted 11kV Switchgear (Autoreclosers and Sectionalisers)

There are 81 11kV distribution pole mounted autoreclosers and sectionalisers in service on the NTL network.

These are mainly Schneider U series encapsulated vacuum type but also include 6 McGraw Edison KF and KFE oil insulated/vacuum type reclosers.

<u>Pole Mounted Switchgear Routine and Preventative Maintenance</u>

This is limited to monthly operational field checks and battery replacements. If any switchgear should fail an operational test, then it is brought into the workshop for analysis and any further testing. Line connections are also checked periodically through thermographic surveys.

<u>Pole Mounted Switchgear Refurbishment and Replacement</u>

All oil interruption technology reclosers and sectionaliser units have been subject to a replacement programme that was completed during 2016/17. Under this programme, 64 reclosers and sectionalisers were upgraded to modern automated encapsulated vacuum type. These are all SCADA controlled, facilitating improved fault outage response and providing a corresponding improvement in network availability.

The fleet of reclosers and sectionalisers is now modern and will not require refurbishment or replacement in the 10-year time horizon of this AMP.

6.6.8 Ground Mounted HV Switchgear

There are three main types of ground mounted 11kV switchgear in service on the network. These are the Hazemeyer Magnefix type, the ABB SD oil switch type and the Halo encapsulated vacuum switch type.

Ground Mounted Switchgear Routine and Preventative Maintenance

The Magnefix switchgear is a compound insulation switchboard with air insulated switch contacts. Due to the propensity for the surface of this equipment to track, particularly when in moist air, these units are installed only within transformer enclosures where the heat generated from the transformer keeps the units dry. This also ensures that no sunlight is normally incident upon them. Maintenance of these units consists of a periodic surface cleaning and link contact inspection and cleaning. Under these installation conditions, it is believed that these units will give at least a 45-year service life. A small number of units will reach this age within the time horizon of this plan and these will be planned for replacement.

The ABB SD oil switchgear is deployed in banks of 11kV switches. All are oil insulated and also rely on oil for their arc breaking capability. All units are series 2 type and there are no fuse switch (HV fuse in oil) units in the network. Maintenance consists of periodic inspection for corrosion and leaks in the metal cases and checking of internal oil levels. The oil within each switch unit is also tested for moisture ingress. From time to time the units may also be repainted. The oldest of these units is circa 1988.

The Halo encapsulated vacuum switchgear, like the ABB SD type, is deployed in banks of free-standing switches. As they are an air sealed unit, maintenance is minimal, other than periodic cleaning of the outside.

Ground Mounted Switchgear Refurbishment and Replacement

The use of HV fuses in oil has been discontinued following an incidence of “fuse candling”. This resulted in the catastrophic failure of the switch unit. There are now no HV oil fuse switches in the NTL distribution network.

The series 2 ABB SD oil switchgear is now no longer in production. The “Halo” type encapsulated vacuum switchgear has been adopted as standard for all 11kV free-standing ground mounted switch applications. These have the facility for future SCADA monitoring and control.

An issue with the earth switches on pre-2019 Halo switch units has come to light. This has resulted in a ban on operating these earth switches until the Halo units can be replaced with a post 2019 unit. This affects some 25 switch banks on the system. A replacement program for these units is currently being investigated.

There are no other refurbishment or replacement plans for ground mounted switchgear in the time frame of this plan.

6.6.9 Distribution Substations

There are currently 4,696 distribution substations on the network. These are in five standard types being single pole substations, multiple pole platform substations, kiosks, padmounts and fenced enclosures.

The substations are maintained in good condition and the loadings are monitored, with few having been allowed to exceed their nameplate rating for significant periods. All substations of capacity 100kVA and above are fitted with maximum demand indicators. These are read and reset annually. Substations below 100kVA are fitted with fuses on the low voltage side, limiting the load that can be drawn from them.

Fenced enclosure substations were a common style in the past for industrial sites. These are now gradually being phased out for new installations or upgrades, as large padmount types are now readily available, and these require less space.

Platform substations are no longer being installed. A programme of replacement of existing platform substations with padmount type substations, where there is a risk of public interference with or access to the substation, has been commenced. This will continue through the period of this plan. These replacements are prioritised on risk of public access to the platform.

During 2018, the platform substations were assessed for seismic strength. A number of remedial actions were identified that, if implemented, would bring the population of platform substations up to a minimum 67% NBS. A five-year programme of seismic strengthening of remaining platform substations to bring them up to 67% NBS commenced in 2019.

The earth mats at all distribution substations are tested every five years. Periodically earth mats at some sites are upgraded to improve safety. A budget of $60,000 per year is allocated for these works.

6.6.10 Distribution Transformers

The age profile of the distribution transformers on the network is shown in the chart of Section 3.3.

The life of distribution transformers has been found to be highly variable. The degree and length of time at high load is a significant factor in determining the life of a transformer. There are many other factors affecting life, however, such as overvoltage on the supply, fault passages and exposure to lightning. The latter exposure varies according to location.

Older transformers typically fail finally during a lightning storm. Lightning storms are intermittent in the Nelson area and only five to ten transformers are permanently damaged during major storms each year, however not all such failures are old transformers.

The overall in-service failure rate of transformers has been very low over the past 10 years at approx. 150kVA per year. The in-service failure rate of transformers is not expected to rise.

Many transformer change outs occur as a result of load increase beyond the transformer’s capacity rating. Transformers of 100kVA and above have maximum demand indicators fitted. Transformers below 100kVA have load limiting fuses fitted on the low voltage side. Transformer upgrade takes place when two subsequent annual readings of 10% over nameplate rating are recorded, or when load limiting fuses are repeatedly ruptured due to overload.

Load increases resulting from new consumer connection applications or existing connection upgrades also generate proactive transformer change outs.

Distribution Transformer Routine and Preventative Maintenance

Distribution transformers are maintained when they are released from service on the network for reasons of load increase/decrease or substation relocation due to underground conversion etc.

Distribution transformer maintenance consists of tank rust removal and repainting, oil treatment if oil acidity or moisture content has reached the point that insulation degradation is resulting, and tightening of internal connections.

The annual budget for distribution transformer maintenance is approx. $120,000.

Distribution Transformer Refurbishment and Renewals

An age based renewal policy and replacement programme for distribution transformers commenced in 2008/9.

Under this policy, distribution transformers that have been returned to store as a result of load capacity change out or in-service failure are retired and replaced if they are older than 50 years. Those that are less than 50 years old will be inspected and tested and if okay, repainted, oil treated and returned to service.

In-service distribution transformers that are older than 65 years are scheduled for replacement within 5 years.

A renewals budget provision of $510,000 per year over the term of this plan has been allocated.

6.6.11 LV Underground Cables

The LV cables are mainly 70 sq. mm, 95 sq. mm, 185 sq. mm or 240 sq. mm stranded aluminium conductor three or four core cables with either PVC or XLPE insulation. There are no paper insulated low voltage cables on the network. As with the HV cables, they are well bedded in fines such as crusher dust and protected from overload through conservatively rated HRC fusing.

LV Underground Cables Routine and Preventative Maintenance

The strong UV conditions experienced in the Nelson area have caused cracking and deterioration of XLPE insulated cable tails when low voltage cables are terminated to overhead line. For all new cable to overhead line terminations, the tails are now covered with UV resistant heat shrink. Existing terminations are covered as they are identified during survey rounds.

LV Underground Cables Refurbishment and Renewals

There are no end of life replacements of any LV cables planned in the time horizon of this AMP.

6.6.12 Service Boxes

There are 13,809 service boxes in place on the network. There are three main types. These are all concrete pillar box type (1970 to 1978), concrete base/PVC lid type (1979 to 1985) and all PVC type (1985 to present).

In general, the service boxes are in good condition with no identifiable age based deterioration. They have a moderate ongoing maintenance overhead, however, due to the fact that they are prone to damage from vehicle interference.

Services Boxes Routine and Preventative Maintenance

The PVC type service box lids often require re-securing after they have been struck by vehicles. Sometimes damage in these cases extends to necessitating fuse board repairs as well, or complete replacement of the box. In each case, an assessment is made as to whether or not the box should be protected by bollards or relocated to avoid repeat incidents.

Service boxes are subject to a five-yearly safety inspection programme.

Some boxes have been buried or made inaccessible by local landowner landscaping activities. An annual amount of $20,000 is provided in the 400V underground lines maintenance budget for this type of remedial work.

Service Boxes Refurbishment and Replacement

A plan for the bulk replacement of the early concrete pillar service boxes will be considered in the next few years. This will be undertaken for public and worker safety improvement reasons.

6.6.13 Connection Point Assets

These are mainly low voltage fuses, carriers and bases. To date, most outdoor units have been porcelain as these give the best service in the Nelson UV conditions. Replacement of re-wireable links with HRC cartridge fuses is ongoing as fuses fail or as LV crossarms are replaced. The HRC type fuse has advantages of more stable and accurate fusing performance and longer life. All new connections deploy HRC cartridge fusing.

6.6.14 Ripple Control Transmitters

There is one ripple control transmitter within each bulk supply region. All of these are solid state injection plants. All are in good condition and monitored annually. Ripple injection frequencies are 475Hz for the Stoke, Motueka and Golden Bay bulk supply regions and 233Hz for Kikiwa and Murchison.

The core convertor equipment at the Stoke and Motueka ripple injection plants was renewed during 2020.

The convertor equipment at Motupipi was upgraded during 2016.

6.6.15 Network Communication Systems

The network operation utilises two NTL owned communications systems. These are the SCADA communications network and the VHF radio telephone network.

The SCADA communications network comprises fibre optic, mesh radio and microwave links from zone substations, ripple injection plants and field switches to the control centre at Hope.

Five point-to-point microwave radio links connect the substations at Upper Takaka, Cobb and Motupipi in Golden Bay to the Hope control centre. Further microwave radio links are planned to be set up to extend SCADA communications to other substations in Golden Bay during 2024/25.

A mesh radio communications network was installed in 2015 allowing improved communications to 69 field autoreclosers and sectionalisers distributed across the network. This system is expandable to incorporate more distribution automation devices in the future. The mesh radio system replaces three E-band data repeater channels.

The VHF radio telephone network comprises E-band FM repeaters at four sites. Approx. 90% of the network area is covered by these repeater sites. The repeaters are managed and maintained by a contracted communications company, but the equipment is owned by Network Tasman.

6.7 VEGETATION

The Electricity (Hazards from Trees) Regulations 2003 became fully effective on 1 July 2005. These regulations require power companies to survey lines and advise tree owners when their trees are encroaching power lines. In the first encroachment, the tree is given a trim at the line company's cost. For subsequent encroachments, the tree owner has the option of arranging and funding trimming of the tree him/herself or declaring no interest in the tree, at which point the line company may trim or remove the tree at its discretion.

NTL has introduced a formal tree owner notification operation and administration system to meet the requirements of these regulations. Three vegetation notifying staff perform regular patrols of the overhead network to identify and notify tree owners of their obligations and options under the regulations. A steady routine has been reached where the network is fully patrolled every 24 months. This return period has been identified as being appropriate given the typical growth rates of species in the Nelson environment.

NTL's area enjoys a mild climate. Rural land use in the area includes forestry, horticulture and pastoral farming. There is also a high and increasing number of small lifestyle blocks in the area. Landowners place a high value on trees and vegetation. Many of the rivers in the area have banks supported by species such as willow and poplars. Much of the approx. 2,600km of overhead line traverses private land, both urban and rural.

The result of these environmental conditions is that vegetation management is a significant ongoing part of operations for NTL. This has been recognised over a number of years and policy has been evolved to deal with it in an effective and efficient manner. This has involved identifying the parties concerned and, within the legal framework, identifying the responsibilities of each and then setting drivers so that optimal decisions are made by the parties.

As part of its risk management processes, NTL surveys its network for the risks of damage from unstable trees within fall distance of its network. Such trees are not covered by the Electricity (Hazards from Trees) regulatory notification process, however they remain significant risks. NTL seeks to recover losses from damage to its network caused by trees falling through lines. Claims against tree owners for damages resulting from outages caused by trees falling through lines are also possible from other consumers.

In cases where fall distance tree hazards exist, the owner of the tree is made aware of the hazard and the potential liabilities. Advice on options of mitigating the risks is also given. As an option for the tree owner to consider, NTL offers a felling service for identified hazardous trees that is free of charge to the tree owner.

6.7.1 Line Corridors

There are sections of line on private property that traverse land that is not farmed or otherwise specifically managed by the landowner. Typically, this land has been destocked and left to revert to bush. Gorse and broom often take hold in such cases and, in the Nelson climate, these species thrive. If left untreated, within a few years gorse will grow to 4 to 5 metres in height and become impenetrable.

In order to maintain access to the lines and avoid creating fire risks should the vegetation encroach the overhead conductors, NTL takes a proactive approach to managing these areas as line corridors. Experience has shown that the most cost effective management strategy is to keep line corridors open with vegetation within kept at a low level. This requires treating the areas regularly with low cost methods such as hand cutting and aerial or ground spraying. The long term aim is to encourage grass cover and/or low and slow growing native species.

6.7.2 Forestry Corridors

Forestry corridors are a special subset of line corridors.

NTL has been working with major forest owners to formulate an operating policy that makes the best use of the skills and knowledge of both the forest owner and the line company to manage the risks of power lines coexisting with forestry blocks.

The result has been an operating agreement that considers a corridor of land of general dimensions 20-30m either side of the line. The interest/no interest principle is applied to this corridor where the forest owner decides which trees he has an interest in, and all others are passed to the line company to manage. Following establishment of the line corridor, the ongoing maintenance of it is the responsibility of the line company.

The operating agreement does not assign liability in the case of forest fire, it merely serves as a joint process to lower the risks of forest fire for all parties.

In the summer of 2018/19, a major forest fire occurred in the Tasman District under dry and windy conditions that had prevailed for the summer months. The fire was confined to forested land with no significant impact on Network Tasman's distribution network. Although this event was not caused by the electricity distribution network, it raised NTL's awareness of the risks and potential consequences of a fire when the conditions reach the dryness of the 2018/19 summer. In windy conditions, line clashes or windborne debris depositing on lines can result in arcing, including ejection of hot metal with sufficient energy to set fire to the dry vegetation below the lines.

NTL works in conjunction and cooperatively with Fire and Emergency New Zealand, monitoring the fire risk levels across its network and responding with mitigation initiatives to reduce the probability of a fire starting from its operations when the fire risk reaches certain trigger points. Such mitigation initiatives include worksite precautions by its contractors and switching off automatic reclosing functions of circuit breakers. Other risk mitigation initiatives such as replacing re-wireable drop out fuse links with sparkless HRC types at high risk sites are also being considered. Residual risk always remains however, which can only be fully eliminated by switching off the power supply.

6.7.3 Access Tracks

NTL has many access tracks on private land in order to access poles that are typically part of hill country lines. The maintenance of these is generally the subject of individual agreement with affected landowners. The standard of maintenance is all weather access for four-wheel drive vehicles. Maintenance activities include water table and cutoff clearing, and track spraying. This work is put out to contract outside of the lines maintenance contract.

6.7.4 Vegetation Management Expenditure

Budgeted vegetation expenditure is given in the maintenance expenditure projection table of Appendix F. The figures going forward over the time period of this plan are based on information held at the time of writing.

Five vegetation management budget categories are identified. These are:

- Regulatory free trims – all free trims arising from the Electricity (Hazards from Trees) Regulations 2003.
- Regulatory removals - all removals arising from the Electricity (Hazards from Trees) Regulations 2003.
- Fall distance hazard removals – removals of trees identified as significant fall hazards to overhead lines.
- Line corridors – maintenance of line corridors.
- Access tracks – maintenance of access tracks.

Vegetation expenditure has stabilised after many years of concentrated effort aimed at achieving long term lowest cost vegetation management. A previous backlog of tree clearance and removal work has been cleared and a steady state has been reached.

It is unlikely that tree management costs will decrease significantly from the forecast levels as the regulations require that the lines company offers a free trim or removal for all trees not previously attended. As new vegetation is continuously appearing, there is an ongoing overhead for the lines company.

Increased costs of working in the vegetation management area have come about through traffic management requirements. More costs are possible through pending revisions of tree clearance codes of practice and regulations.

An independent review of vegetation management policy and practice was completed during 2017. This review concluded that NTL vegetation expenditure levels are in line with similar networks in New Zealand and that its policy and practice are aligned with good industry practice.

7. NON-NETWORK ASSETS

This section provides a summary of non-network assets. These are material assets that are necessary and used for the purpose of management of the electricity distribution network.

7.1 NON-NETWORK ASSET DESCRIPTION

Network Tasman's material non-network assets are listed in the following table:

Type	Sub Type	Description
IT and Technology Systems	Network Modelling Software	Power Factory Loadflow
	Geographic Information System (GIS)	ESRI ArcGIS
	Overhead Line Design Software	Power lines Pro
Asset Management Systems	NTL Hope Main Office	Office building including PC Computer Network Hardware
	Contractors Depot – Hope	Office building and workshops
	Contractors Depot – Takaka	Office building and workshops
	Contractors Depot – Murchison	Office building and workshops
	Motor Vehicles	1 x Toyota FJ Cruiser 4WD – Line Survey
		2 x Suzuki Vitara – Vegetation Survey
		1 x Mitsubishi 4WD – Access Tracks Survey
		1 x Nissan Leaf – Office
		2 x Toyota Hilux 4WD – Technicians
		1 x Mitsubishi Outlander – Office
	Plant Tools and Equipment	1 x GPS/Ruggedised Laptop
		2 x Portable Power Monitors

7.2 NON-NETWORK ASSET DEVELOPMENT, MAINTENANCE AND RENEWAL POLICIES

7.2.1 Development

Network Tasman's asset management practices are now mature and well bedded in to steady operations. All procedures are supported by developed information systems that have been evolved over many years. There is no specific plan for further investment into systems development, however it is NTL's policy to monitor technological developments in the field of asset information collection and process automation. Any identified non-network asset development project will be carefully analysed and must show operational and economic justification via a business case to the board.

7.2.2 Maintenance and Renewal

Non-network assets are maintained in good working order during their expected economic life. At the end of their economic life, non-network assets are replaced unless they are rendered obsolete or redundant due to a development initiative.

The following replacements/renewals are budgeted:

Asset Replacement $k	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Vehicles, Plant and Equipment, Computer Hardware and Software	950	900	900	900	900	900	900	900	900	900

N.B. Figures are in 2024 dollars and do not include inflation adjustment

8. RISK MANAGEMENT AND NETWORK RESILIENCE

8.1 RISK MANAGEMENT OVERVIEW

8.1.1 Distribution Network

Sections 5.5 to 5.7 of the AMP detail the network design issues related to maintaining a prudent level of security of supply, in order that the operating reliability of the network is kept at levels consistent with good customer service yet delivered at a reasonable price. The attainment of an optimum balance of operating cost against network supply quality and reliability is the primary focus and objective of this plan.

The risks of loss of supply for all sections of the network are assessed in the Network Risk Analysis of Appendix I. This analysis identifies and considers the risks of loss of supply resulting from both network equipment failures and from external influence events. External influence events are typically high impact low probability (HILP) events such as major storms, floods and earthquakes. The influence of climate change on loss of supply risk at zone substation level is also assessed in this analysis.

Treatment options of the identified risks take the form of network capital works projects to reduce exposure to the risk and/or mitigate the impact. HILP events are generally dealt with through planned responses to manage with the aftermath of these events. Details of HILP event responses are provided in Network Tasman's disaster readiness and response plan (DRRP) which is appended as Appendix L.

The purpose of the DRRP is to set out and document clearly established readiness and response plans relating to Network Tasman's distribution network which will be implemented in the event of either natural disasters or catastrophic events related to the failure of the distribution network or the Transpower transmission network.

Risk events not directly resulting in loss of supply, such as oil spills, are also treated through documented contingency plans in the DRRP.

8.1.2 Transmission and Bulk Supply

Although this AMP is primarily focussed on the distribution network asset owned by NTL, risks of loss of supply to consumers include risks of failure of the Transpower transmission system to deliver supply capacity to the NTL grid exit points (GXPs).

NTL has a high degree of reliance on supply from Transpower GXPs in its network and there is very limited transfer capacity between GXPs. The Stoke 33kV GXP, in particular, carries the major load, including Nelson city.

Total or partial loss of transmission capacity to the GXPs or loss of energy supply capacity are grid emergency events. The primary response to sudden decrease in grid supply capacity is automatic under frequency load shedding (AUFLS). AUFLS tripping is a mechanism to arrest falling system frequency in order to avoid total system blackout.

Network Tasman is required to set up two 16% blocks of load that will be automatically disconnected when the system frequency falls through threshold values. This is achieved by tripping feeders that supply residential load primarily.

Where grid emergency events result in prolonged restriction in supply capacity, a rolling outage management plan is deployed. Network Tasman is required by regulation to maintain a Security of Supply Participant Outage Plan. This plan is posted on Network Tasman's website.

8.2 NETWORK RESILIENCE STRATEGY

Network resilience is maintained and developed at Network Tasman through the following:

- Network security – NTL reviews its network layout, levels of redundancy and ability to resupply from alternative sources. Specifically, NTL limits the load on single line feeder circuits that cannot normally be repaired under single contingency event scenarios within 24 hours, to that load which can be supplied by a transportable generator. Once these load limits have been reached on these spur circuits, then permanently available alternative supply circuit routes are developed.

- Equipment standardisation – NTL has standardised the design of lines and substations and standardised the componentry used in their construction across its network, ensuring that all equipment deployed is also used by other networks in the country.
- Earthquake resilience – major earthquake is the key risk identified in the Risk Analysis. NTL designs all new facilities to seismic strengths in line with infrastructure importance level and is progressively upgrading its structures to provide earthquake resilience.
- Business Continuity Plan reviews – NTL maintains and reviews a business continuity plan which includes review of Information and Communications Technology (ICT) systems resilience. The business continuity plan also reviews pandemic response and recovery.
- Control centre resilience – NTL operates an alternative relocatable temporary control centre. This system is tested annually by operating the control centre function from it for a number of days. Learnings from these temporary operations are considered for ongoing improvements. Further details are given in section 5.4 of the DRRP.
- Business operating resilience – NTL also reviews its ability to function without access to its business and ICT systems.
- Regional emergency coordination – NTL works with the Nelson/Tasman civil defence emergency management (CDEM) group and is a lifeline utility under the CDEM Act. Further details are given in Section 4 of the DRRP.
- Key alliances – NTL maintains alliances with other South Island lines companies and has an agreement to share resources under emergency conditions.

9. PERFORMANCE MEASUREMENT, EVALUATION AND IMPROVEMENT

9.1 *FINANCIAL AND PHYSICAL PERFORMANCE*

9.1.1 Last Completed Financial Year

The information disclosure regulations require that the results from the last completed financial year are compared against that which was planned. At the time of writing of this plan, this is the 2022/23 financial year.

These are as follows:

CAPITAL EXPENDITURE ($k)	Actual 2022/23	Budget 2022/23	% Variance 2022/23
Customer Connection	1,141	1,175	-3%
System Growth	3,416	5,340	-36%
Reliability, Safety and Environment	2,697	6,515	-59%
Asset Replacement and Renewal	6,091	7,040	-13%
Asset Relocation	0	500	-100%
ASSET MANAGEMENT CAPITAL EXPENDITURE	**13,540**	**20,570**	**-34%**

OPERATIONAL EXPENDITURE ($k)	Actual 2022/23	Budget 2022/23	% Variance 2022/23
Routine and Preventative Maintenance	2,593	2,377	+9%
Refurbishment and Renewals Maintenance	1,545	2,125	-27%
Service Interruptions and Emergencies	1,444	1,388	+4%
Vegetation Management	1,224	1,115	+10%
ASSET MANAGEMENT OPERATIONAL EXPENDITURE	**6,806**	**7,005**	**-3%**

NON NETWORK OPEX ($k)	Actual 2022/23	Budget 2022/23	%Variance 2022/23
System Operations and Network Support	3,467	3,449	+1%
Business Support	2,727	2,343	+16%
NON NETWORK OPERATIONAL EXPENDITURE	**6,194**	**5,792**	**+7%**

The above variances were discussed in the 2023 AMP review.

Progress against Plan for First Year of 2023/2024 Asset Management Plan

Network Tasman has a 31 March end of financial year. This means that at the time of review of the AMP, final financial results for the first year of the previous AMP are not available. As a proxy, forecast figures based on the 10 months completed are used in this performance review section.

The financial progress against plan for network capital projects and maintenance and operations expenditure is summarised in the following tables:

CAPITAL EXPENDITURE ($k)	Forecast 2023/24	Budget 2023/24	%Variance 2023/24
Customer Connection	1,336	1,175	+14%
System Growth	2,183	8,440	-74%
Reliability, Safety and Environment	4.318	4,400	-2%
Asset Replacement and Renewal	6,247	6,510	-4%
Asset Relocation	3	500	-99%
ASSET MANAGEMENT CAPITAL EXPENDITURE	**14,087**	**21,025**	**-33%**

OPERATIONAL EXPENDITURE ($k)	Forecast 2023/24	Budget 2023/24	%Variance 2023/24
Routine and Preventative Maintenance	2,767	2,218	+25%
Refurbishment and Renewals Maintenance	2,324	1,824	+27%
Service Interruptions and Emergencies	1,346	1,728	-22%
Vegetation Management	1,514	1,237	+22%
ASSET MANAGEMENT OPERATIONAL EXPENDITURE	**7,951**	**7,005**	**13%**

NON NETWORK OPEX ($k)	Forecast 2023/24	Budget 2023/24	%Variance 2023/24
System Operations and Network Support	3,964	3,449	+15%
Business Support	2,950	2,343	+27%
TOTAL OVERHEADS	**6,914**	**5,792**	**+19%**

9.1.2 Network Development Projects

The completion status at near year end of the network development projects planned for 2023/24 is summarised as follows:

Specific Development Projects					
Network Enhancement Project	**Year**	**Estimated Cost**	**Region**	**Expenditure Class**	**Completion Status**
RTU Takaka Substation	2024	$25,000	Golden Bay	Reliability	Deferred
RTU Upper Takaka Substation	2024	$30,000	Golden Bay	Reliability	Deferred
New Recloser Pohara B Line and relocate Sunbelt Recloser	2024	$40,000	Golden Bay	Reliability	Deferred
Motupipi Substation Upgrade Stage 3	2024	$1,000,000	Golden Bay	Renewal	Completed
Refurbish T1 Transformer Brightwater	2024	$200,000	Stoke	Renewal	Deferred
Motueka Substation Upgrade Stage 2	2024	$6,000,000	Motueka	System Growth	Deferred
SCADA Master Station Renewal	2024	$100,000	Stoke	Renewal	Completed
Protection Relay Replacements, Founders, Songer St, Richmond, Annesbrook	2024	$270,000	Stoke	Renewal	Deferred
11kV Feeder Cable and CB Brightwater substation to Hotel corner	2024	$800,000	Stoke	System Growth	Deferred
33kV CB's Swamp Road Substation	2024	$650,000	Golden Bay	Reliability	Deferred
Founders to Wakapuaka 33kV Cable Stage 1	2024	$2,800,000	Stoke	Reliability	Completed

During 2023/24, major network development projects undertaken included:

- Motupipi Substation upgrade
- Founders to Wakapuaka Sub 33kV Cable installation Stage 1
- Detailed Design for Motueka Substation Upgrade
- SCADA Master Station Renewal.

Residual Covid-19 procurement problems delayed the commencement and completion of some major capital projects during 2023/24. Delays in the delivery of other major components sourced from overseas, e.g. HV switchgear, occurred during 2023. A nationwide industry shortage of experienced and skilled staff is also impacting resource availability in some work areas.

The budget for underground conversion is a provisional allowance for opportune small underground conversions or duct installations that may come about if unplanned council or NZTA excavation works are occurring in streets that have overhead reticulation. This allowance was not used during 2023/24.

All projects not started during 2023/24 are now planned to be started during 2024/25. The deferment of projects will not compromise the safety or security of the network.

9.1.3 Network Extensions

Customer driven network extensions continued during 2023/24. An increase of 640 ICP's is expected to occur compared with the long term average increase of 700.

9.1.4 Network Operations and Maintenance

Service interruptions and emergency repairs expenditure is forecast to be under budget for the year ($1.346m vs budget $1.728m). Other than a tornado there were no major storm events during the year.

Planned network maintenance expenditure for the network is forecast to be over budget for the year ($5.091m vs $4,042m).

Ongoing network maintenance and renewal activity completed during the year included pole, crossarm and line hardware replacements, trefoiling of 11kV circuits in some areas, tree trimming and removals and overhead line corridor reinstatement. Many testing programmes occur on a continuous basis, e.g. distribution substation earth testing and switchgear and regulator operational tests.

9.1.5 Vegetation

Vegetation management expenditure for the 2023/24 year is forecast to be over budget. The very dry summer of 2018/19 has resulted in a noticeable increase in standing dead trees across the district. These have become threats to supply security where they are in fall distance of lines and are being dealt with as they are identified.

Extraordinary storm damage repairs to access tracks has also occurred during 2023/24 causing budget exceedance.

Tree notifications during 2023/24 were mainly eighth round notifications under the Electricity (Hazards from Trees) Regulations 2003. Tree trimming obligations for Network Tasman are dropping but tree removals are increasing as many land tree owners elect to declare “no interest” in trees that they have previously had trimmed under first free trim provisions.

New commitments to provide free trims apply to trees growing out to the sides of lines that were not previously notifiable. Many trees have branches reaching out that make them notifiable after 5-10 years of growth.

The budget for 2024/25 is increased from the 2023/24 budget. This is partly brought about by higher levels vegetation works but mainly due to increased contracting costs – labour and fuel costs and also traffic management costs.

9.2 SERVICE LEVEL AND ASSET PERFORMANCE

Reliability Performance against target for the 2023/24 year are forecast near year end as follows:

	Target	Forecast
SAIDI Planned	100	107
SAIDI Unplanned	75	128
SAIFI Planned	0.70	0.35
SAIFI Unplanned	1.07	1.21
CAIDI Planned	139	306
CAIDI Unplanned	70	106

Planned outages for the 2023/24 year are forecast to be a little over budget. Shutdowns remain at a high level to undertake copper conductor replacement,

Going forward, planned outages are not expected to return to the previous levels until the conductor replacement programme is completed. Portable diesel generators will be deployed where practicable to minimise the impact of these works, however the nature of conductor replacement work is such that shutdowns of consumer supplies are inevitable since it is the means of distributing even locally generated electricity power that is being replaced.

Unplanned outages are forecast to be well over target for the year. This forecast includes the impact of two major 33kV faults and a tornado that occurred in April 2023. These three events together constituted 81 points of the total forecast 128.

Network defects caused approx. 50% of outage minutes for the year. Historically this has averaged 20%. The two major 33kV faults were both caused by network defects and have been the major cause of this change.

The trend of reliability performance for the past five years is given in Appendix C.

Other service levels targeted for 2023/24 were as follows:

Service Criterion	Performance Indicator	Target	Forecast
Supply Quality	Number of proven voltage complaints	10	6
Operating Efficiency	Breaches of UOSA	0	0
Operating Efficiency	Network losses	6%	5.0%
Operating Efficiency	Faults per 100km line	6	4.8
Operating Efficiency	Peak demand/kVA distribution transformers	30%	26%
Financial Efficiency	Cash operating costs per consumer	<$350	$343
Environmental Effectiveness	Incidents of non-compliant emission from network	0	0
Environmental Effectiveness	Incidents of contaminant spill from network	0	0
Safety	Staff and contractor serious harm incidents	0	0
Safety	Public injury incidents	0	0
Safety	Public property damage incidents	0	0

All service levels other than distribution transformer utilisation (peak demand/kVA distribution transformers) are forecast to be in line with targets. The deterioration in distribution transformer utilisation is believed to be due to high levels of incremental rural load, particularly domestic rural lifestyle subdivision developments, dairy farming and hop processing. All of these types of load require relatively high and dedicated distribution transformer capacity. The dairy farming and hop processing loads are generally not operating at the times of overall system peak. This tends to add to overall distribution transformer capacity but significantly reduces overall transformer utilisation.

It has been noted that there are also a number of industrial sites in the network that have not realised the peak loads predicted at the time of initial development. This has led to underutilised transformer capacity at these sites. It may be economic to change out these transformers for smaller units. Opportunities for this will be considered on a case by case basis.

9.3 GAP ANALYSIS AND IMPROVEMENT PLANS

With the declaration of climate emergencies by NCC and TDC, climate change has been formally recognised as a change in the AMP environment. However, the timing and specificity of impacts carry considerable uncertainty at this stage. An additional planning assumption has been considered and added in this review of the plan (refer section 10).

Developments in the disruptive technologies of photovoltaic (PV) distributed generation, consumer based battery storage and electric vehicles are not yet significantly impacting network operations. At higher levels of penetration, however, possibly occurring at the end of the 10-year planning horizon, the potential for network voltage management issues exists. NTL is at the forefront of PV hosting at present in New Zealand and it has been actively involved in research and modelling of future uptake scenarios and network conditions. It has identified and taken steps to ensure that the network hosting capacity for disruptive technologies is maximised.

Electric vehicle charging is expected to become a significant new load in the future. Investigative work is being undertaken at present to identify the potential network impacts of this new load type. Older overhead low voltage distribution networks in particular are expected to require capital investment, especially if charging occurs coincident with existing peak loads on these networks.

Network Tasman has completed a rollout of advanced electronic meters (smart meters) throughout its network supply area. This involved a replacement of existing legacy electromechanical and early electronic meters. The rollout was primarily undertaken to provide a high functioning metering service for electricity retailers, however the advanced electronic meters also provide increased capability for Network Tasman to monitor conditions on its network in real time. Improvements in customer service arising from this have included:

- Proactive voltage correction through analysis of voltage information.
- Reduction in consumer fault callouts through manual polling of voltage at the consumer's meter.
- Remote data logging capability allowing preliminary voltage enquiry analysis without site visit.
- Improved back feed management following network outage.

Attainment of further network performance and consumer service improvements from the advanced meter deployment will be a key focus for the company over the next two to three years.

Development of the network is running in line with load growth and associated development projects as detailed in the plan. High operating efficiency in terms of reduced network losses, reduced faults per 100km and reduced proven voltage complaints are a direct result of the major capital projects completed during the last few years and which are ongoing.

Some major capital projects were deferred and others were not started due to contracting resource limitations.

Network reliability performance underlying extreme weather or non-repeating events is also generally improving and the operational benefits of recent capital investments into upgraded network capacity are now being realised. Such investments have included the provision of additional backup circuits in the 33kV network and the shortening of 11kV feeders through the provision of additional feeder circuits. Network reliability remains ahead of the national average.

The frequency of extreme weather events has increased in recent years. NTL includes all outage events in its reliability reporting. Regulatory reporting largely discounts such events for the determination of regulatory breach. The extreme weather events have therefore impacted reported reliability statistics. When the effects of the extreme weather events are separated out, the reliability statistics reveal a very good network performance.

It is neither economically justifiable, practicable nor prudent to design and build the distribution network so that it is immune to the effects of major storm events.

The long term target for unplanned outages of 75 SAIDI is in line with international best performance for rural, primarily radial networks. Improving the inherent reliability beyond this level would be expensive to achieve, as it would require that significant additional supply circuits are built in to the system. Such investment is unlikely to be justified.

Reliability analysis by feeder first undertaken during 2006 and annually updated since, shows that the worst performing feeders have been either long overhead 33kV feeders or the longest rural 11kV feeders (refer Appendix J). The analysis also shows steady improvement in inherent network reliability with the implementation of the capital works programme. The poorest performing feeders are subject to capital works in the *Network Development Plan*, the implementation of which will improve the reliability of these feeders.

Other strategies to further improve reliability are ongoing. These include installing fault indicators, trefoiling lines etc. These measures are targeted at reducing the outage customer minutes arising from third party incidents such as bird strikes.

9.3.1 Overall Quality of Asset Management Planning

NTL believes that the asset management planning and processes it has deployed are serving the company and its consumers very well, and that in most areas they follow industry best practice.

The condition based maintenance systems that are in place combined with GIS provide comprehensive information that allows maintenance to be scheduled and executed by its works contractor in an efficient manner. The process provides for excellent risk management in that expenditure can be targeted and prioritised to minimise failure risk and optimise network performance. Maintenance expenditure therefore returns very high value. The results have meant sustained low rates of faults combined with low cash operating costs when benchmarked against industry peers.

The need for end of life renewals of some network components is recognised and the planning and implementation of programmes for these is underway. Failure modes are well understood and there is a good understanding of involved risk. The historical decisions taken to construct the network with long life concrete poles has meant that the requirement for pole replacements is not yet with us and should not be an issue for many years yet. The underground network is also relatively young due to the late entry into underground reticulation.

Systems to cater for load growth in the network have performed well. The implementation of the AMP development programme has, to date, significantly boosted the capacity of the network and provided an appropriate level of security for consumer loads. Growth rates are monitored and further plans are in place to ensure that the network is developed in a logical step by step and cost efficient manner to cater for reasonably expected future growth in the area. Planning takes into account innovations such as distributed generation.

The condition of the network and the asset management practices deployed by NTL were independently reviewed by consultants Mitton ElectroNet during 2017. This review concluded that the overall network was in good condition and that the asset management processes in place were sound. A number of recommendations for improvement were made and these have been implemented.

Areas with potential for improvement in asset management processes are based on further improving information systems both in the office and in the field. Developments in the quality of information held and improving the ability to access the information will lead to refinements in the timing of asset programmes and improved risk decision making. This should lead to reduced overall asset management cost.

Future developments in asset management activity at NTL are therefore now focussed in the information technology area.

10. PLANNING ASSUMPTIONS

10.1 SIGNIFICANT ASSUMPTIONS

This plan has been prepared in a manner consistent with the existing ownership, structure and business activities of Network Tasman. No changes to the existing business are planned and all information is based on this continuance.

The significant assumptions made in this *Asset Management Plan* that have a material impact on forecast expenditure are identified as follows:

10.1.1 Legislative and Regulatory Framework

Electricity Act 1992

The AMP assumes that there will be no change to the company's obligation to maintain supply to existing consumers, nor any major changes to the existing legislative and regulatory required conditions of supply to consumers during the period of the plan. The Electricity Act 1992 requires that uneconomic lines are continued to be operated.

This assumption has a significant impact on expenditure forecasts for NTL due to the number and extent of uneconomic lines in the NTL network. Since the legislation requires the company to effectively operate and maintain such lines in perpetuity, ongoing maintenance and renewals must be budgeted for. Maintenance includes not only the line hardware but also the line corridor and its access. It is estimated that forward maintenance expenditure projections would be reduced by up to 30% if the requirement to maintain supply through uneconomic lines was discontinued.

10.1.2 Stakeholder Needs

This plan assumes that the desires of the company's stakeholders, as identified by stakeholder surveys, do not materially alter for the period of the plan. These needs and desires relate to:

- The specified levels of reliability and quality of electricity supply.
- The specified levels of safety and security of the network.
- The current pricing policies.

The main source of information for developing this assumption is feedback received from consumer surveys (refer Appendices K and L).

If stakeholders required less reliability and quality of supply, then all projects listed under the category of reliability could be cancelled and some of the system growth category projects would be deferred. This translates to approx. 25% of the forecast capital expenditure.

If stakeholders required a greater level of reliability and quality of supply, then the capital expenditures forecast in this plan would need to be significantly increased.

10.1.3 Regional Economic Activity

The plan assumes that economic activity in the region will continue to be based on primary production, including fishing and forestry, hops and wine.

The AMP assumes land use development will happen at a steady gradual rate, and that this rate will not significantly deviate from past trends. Land subdivided for residential development will occur in line with recent trends in terms of density etc.

ICP number growth is assumed to be at 1.5% or approx. 700 new connections per year, which is the average for the preceding five years. Overall load growth is expected to be 1.3% per year.

The principal sources of information for developing these assumptions are:

The local territorial authority's long term plans

Industrial customers
Local business organisations

If regional economic activity were to decrease such that there was no growth in electricity demand, then the forecast expenditures of this plan would decrease by approx. $5.5m per year or 66%.

10.1.4 Growth Funding

The plan assumes that the growth based projects will continue to be funded from the combination of contributions from developers and additional income from increased consumer demand, in line with the company's *Capital Contributions Policy*. Details of this policy are available on the company website.

This assumption is based on experience, to date, that the company has with developing its network under a number of capital contribution regimes and on discussions with developers and local authorities with respect to each.

The principal sources of information for developing the assumption are network costing models including ODV (optimised deprived value) valuations built up by NTL.

If growth based projects were not partially funded from developer contributions as under the *Capital Contributions Policy*, then the forecast capital expenditures of this plan could be expected to increase by approx. $1.2m per annum or 15%.

10.1.5 Technological Developments in the Electricity Distribution Industry

The AMP assumes that during the period of the plan, there will be no significant advances in the core technology of electricity distribution that could render the existing network obsolete. Solar PV generation with battery storage, in particular, are expected to complement or augment the grid supply but not replace it. Any technological gains adopted are expected to be complimentary to existing equipment and such improvements will operate in addition to the existing equipment.

This assumption is based on the technical history of electricity distribution and on ongoing vigilance of industry developments.

Principal sources of information from which this assumption has been derived are scientific and electrical engineering journals and publications.

10.1.6 Distributed Generation

The plan assumes that distributed generation will continue to develop in the region, with no significant changes to the rates of uptake experienced to date.

This assumption is based on government policy statements and current regulations around the connection of distribution generation by consumers.

The principal sources of information for developing this assumption are:

- Government policy statements
- Electricity governance rules
- Discussions with local suppliers and developers of distributed generation systems and schemes

10.1.7 Climate Change

The purpose of the Climate Change Response (Zero Carbon) Amendment Act 2019 is to:

(i) provide a framework by which New Zealand can develop and implement clear and stable climate change policies that —

(ii) contribute to the global effort under the Paris Agreement to limit the global average temperature increase to 1.5° Celsius above preindustrial levels; and

(iii) allow New Zealand to prepare for, and adapt to, the effects of climate change.

The act established a Climate Change Commission to provide advice to the government to enable the preparation of emissions budgets and emissions reduction plans. Emissions reduction targets are likely to have varying economic effects on differing sectors and regions within New Zealand which, at this stage, cannot be accurately quantified. Decarbonisation of the economy could result in significantly increased demands on electricity networks requiring very high levels of capital investment.

The Climate Change Commission final report of 31 May 2021 calls for 20% of the vehicle fleet to be electric by 2025. NTL has identified, through studies of its low voltage networks, that investment into older LV networks will likely be needed at these uptake levels. This AMP review allows for increased capital expenditure into LV networks in the latter half of the plan.

This AMP assumes that the frequency of storms will be at double historical rates. Sea level rise is assumed to be 40mm over the 10-year period of the plan. Adaption strategies at present include identifying and elevating assets threatened by sea level rise (refer section 5.9.16).

Climate change mitigation initiatives are targeted at reducing pollution and production of greenhouse gases. Network Tasman has adopted a policy of avoiding the deployment of SF6 as an insulating gas within its network. It deploys encapsulated vacuum or dry air insulated technology based switchgear for new and replacement equipment rather than SF6 wherever practicable. NTL is measuring its carbon footprint and aims to reduce this over time.

Climate change assumptions are based on the information provided to date by the local territorial authorities and generally available predictions. The assumptions carry considerable uncertainty.

Network Tasman will monitor environmental, economic and political factors that influence these assumptions carefully in future AMP reviews.

10.1.8 Supply from the National Grid

The plan assumes that the existing supply capacity continues to be available at all Transpower GXPs and that future projected demands are available to the Nelson area via the national grid. In particular, a new GXP at Brightwater, supplementing and diversifying the supply from the Stoke GXP, is assumed to be developed during the period of this plan.

This assumption is based on government policy statements and Transpower network planning and pricing policies.

The principal sources of information for developing this assumption are:

- Government policy statements
- Electricity governance rules
- Transpower annual planning report

10.2 FACTORS THAT MAY AFFECT AMP OUTCOMES

The factors that may lead to a material difference between the prospective information of this plan and the corresponding actual information recorded in future disclosures are:

- Regulatory requirements may change requiring NTL to achieve different service standards or different design or security standards. This may also impact on the availability of funds for asset management.
- Consumers' preferences for supply reliability or willingness to pay for differing levels of service may change.
- The incidence of natural events such as earthquakes, floods, major wind or snow storms which cause major damage to the network.
- Higher than expected coastal inundation and storm surge resulting from high levels of climate change induced sea level rise and storm incidence.
- NTL ownership could change and different owners could have different service and expenditure objectives than those embodied in this AMP.

- The rate of growth in demand could significantly increase or decrease within the plan period.
- Load patterns within each GXP region could change resulting in movement from winter to summer peaks and vice versa.
- Significant embedded generation capacity may be commissioned within the network supply area.
- Unexpected large loads may appear, requiring supply. Uncertainty with future decarbonisation strategies may significantly affect load forecasts and development plans.
- Existing large consumers may significantly reduce load.
- There could be major unforeseen equipment failure requiring significant repair or replacement expenditure.
- More detailed asset management planning undertaken over the next few years may generate development and maintenance requirements which significantly differ from those currently provided for.

The assumptions made in relation to these sources of uncertainty are listed in 9.1 above and detailed in various sections of this plan.

The potential effect of these sources of uncertainty on the prospective information in this plan is as follows:

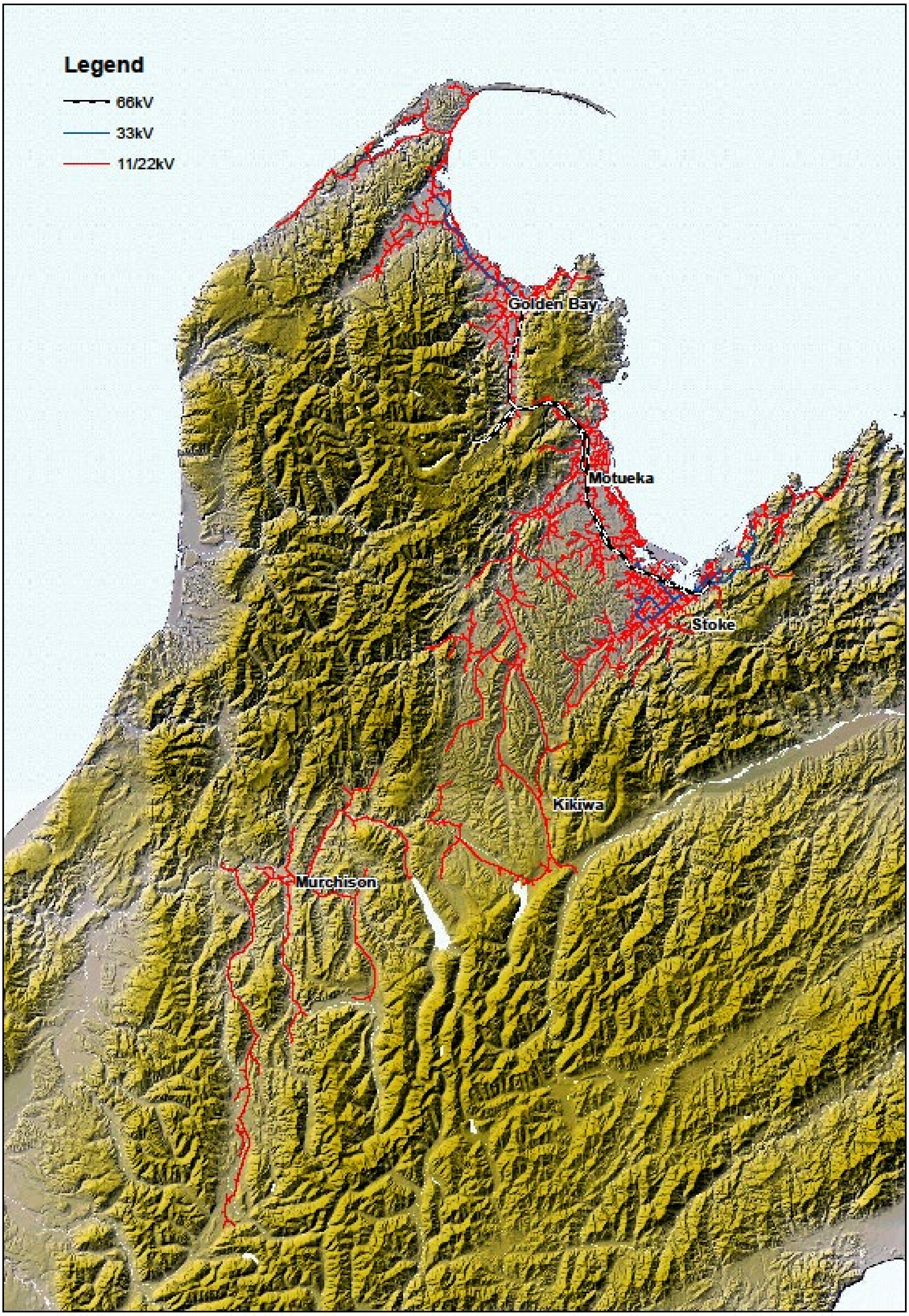
Source of Uncertainty	Potential Effect of Uncertainty	Potential Impact of Uncertainty
Regulatory Requirements	It is unlikely that any of the requirements will reduce, thus the most likely impact is an increase in forecast expenditure to meet possible increased standards. It is not possible to quantify this possible impact.	Low
Ownership	Different owners could have different service and expenditure objectives than those embodied in the AMP, resulting in either higher or lower service targets and associated expenditures.	Medium
Customer Demands	Customers could change their demands for service and willingness to pay, resulting in either higher or lower service targets and associated expenditures.	Medium
Natural Disaster	Equipment failure and major repairs and replacements required which are not currently provided for.	Low, Medium High depending on severity
Climate Change	Asset relocation and/or fortification required as a result of climate change effects.	Low, Medium High depending on severity
Demand Growth	Higher or lower demands require greater or lesser capacity across the system as currently projected. The most likely implication is that the existing expenditure forecast is either accelerated or delayed. The magnitude of this potential shift is unlikely to be more than five years either way.	Low
Load Profile	Seasonal shifts in demand could require planned capacity upgrades to be accelerated or delayed. The magnitude of this potential shift is unlikely to be more than five years either way.	Low
New Large Loads	Large new loads will impact on demand growth. The implications of uncertainty for demand growth are noted above. Specific new investments may also be required to meet large new loads.	Low
Load Reductions	Reduction in load from large customers generally provides additional capacity for the remainder of the network. Thus, existing expenditure projections may be deferred.	Low
Equipment Failure	Equipment failure and major repairs and replacements which are not currently provided for.	Low due to business continuity planning
Further Detailed Planning	Development and maintenance requirements differ from those currently predicted for the later five years of the planning period, particularly for the 22kV, 11kV and 400V networks.	Low (applies mainly to years 6-10 of the plan)

LIST OF APPENDENCIES

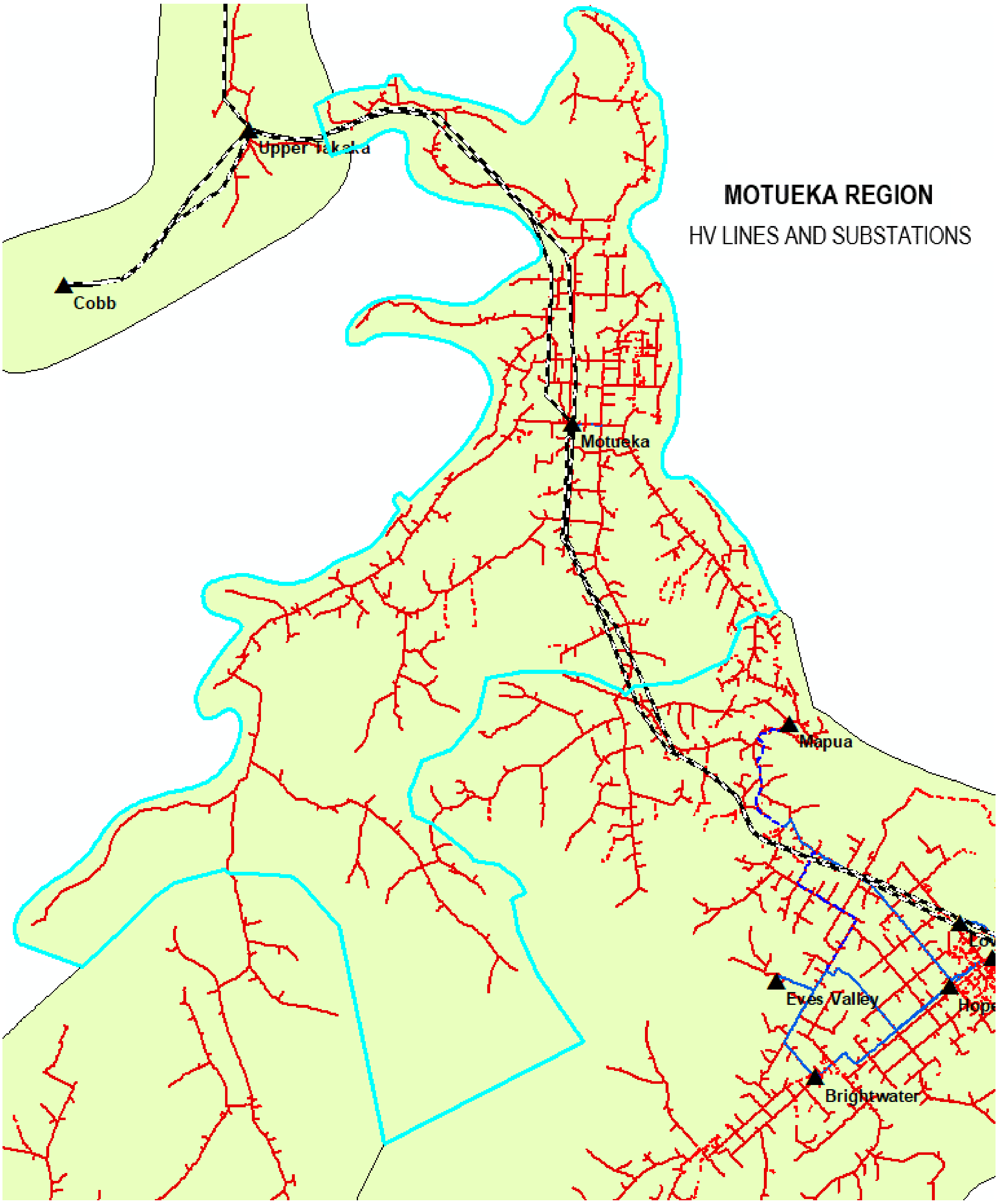
APPENDIX A

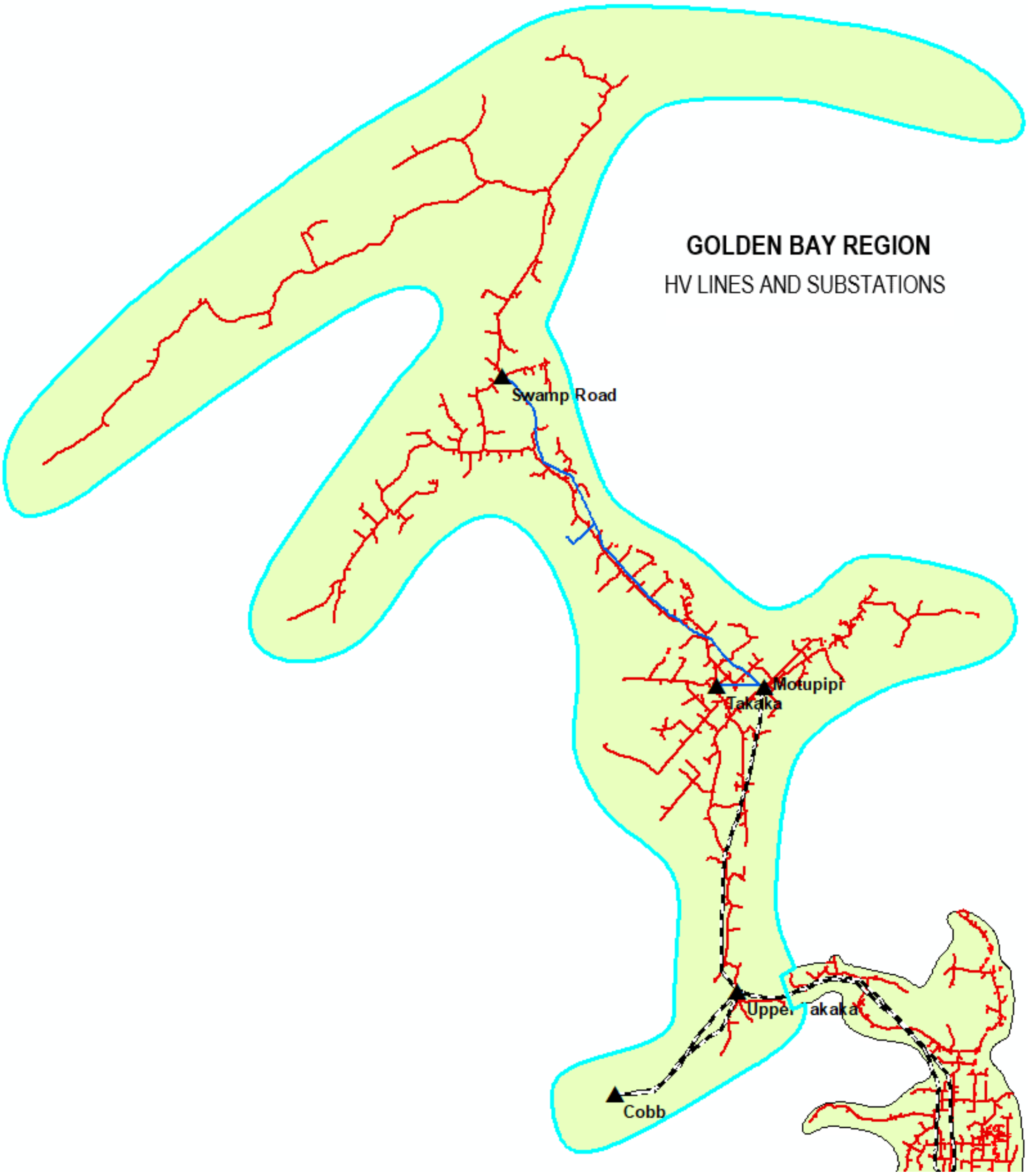
NETWORK LAYOUT

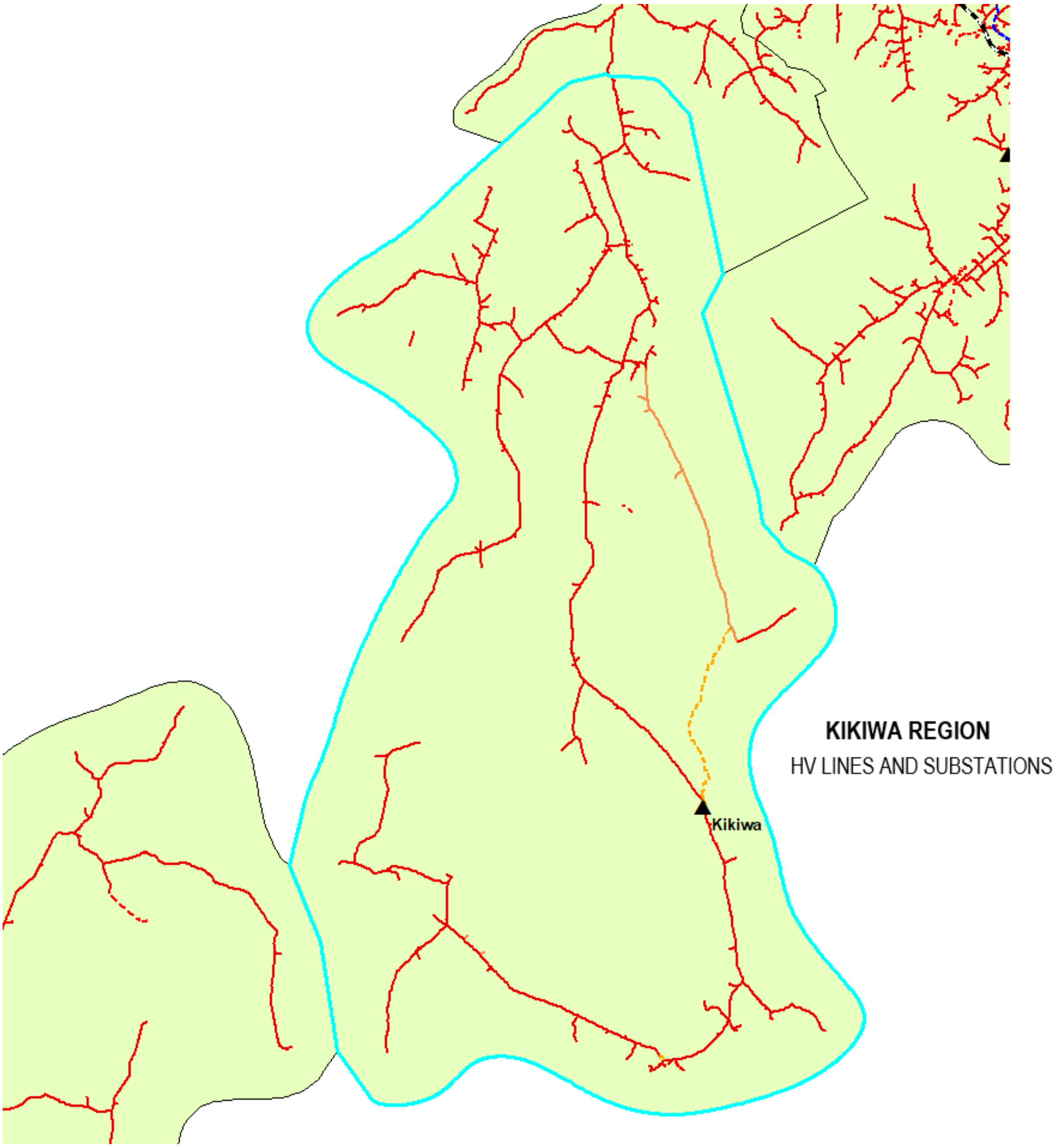
- Geographic layout - Network Tasman Network
- Geographic layout – Stoke Region
- Geographic layout – Motueka Region
- Geographic layout – Golden Bay Region
- Geographic layout – Kikiwa Region
- Geographic layout – Murchison Region
- 33kV Network Schematic – Stoke Region
- 66kV Network Schematic

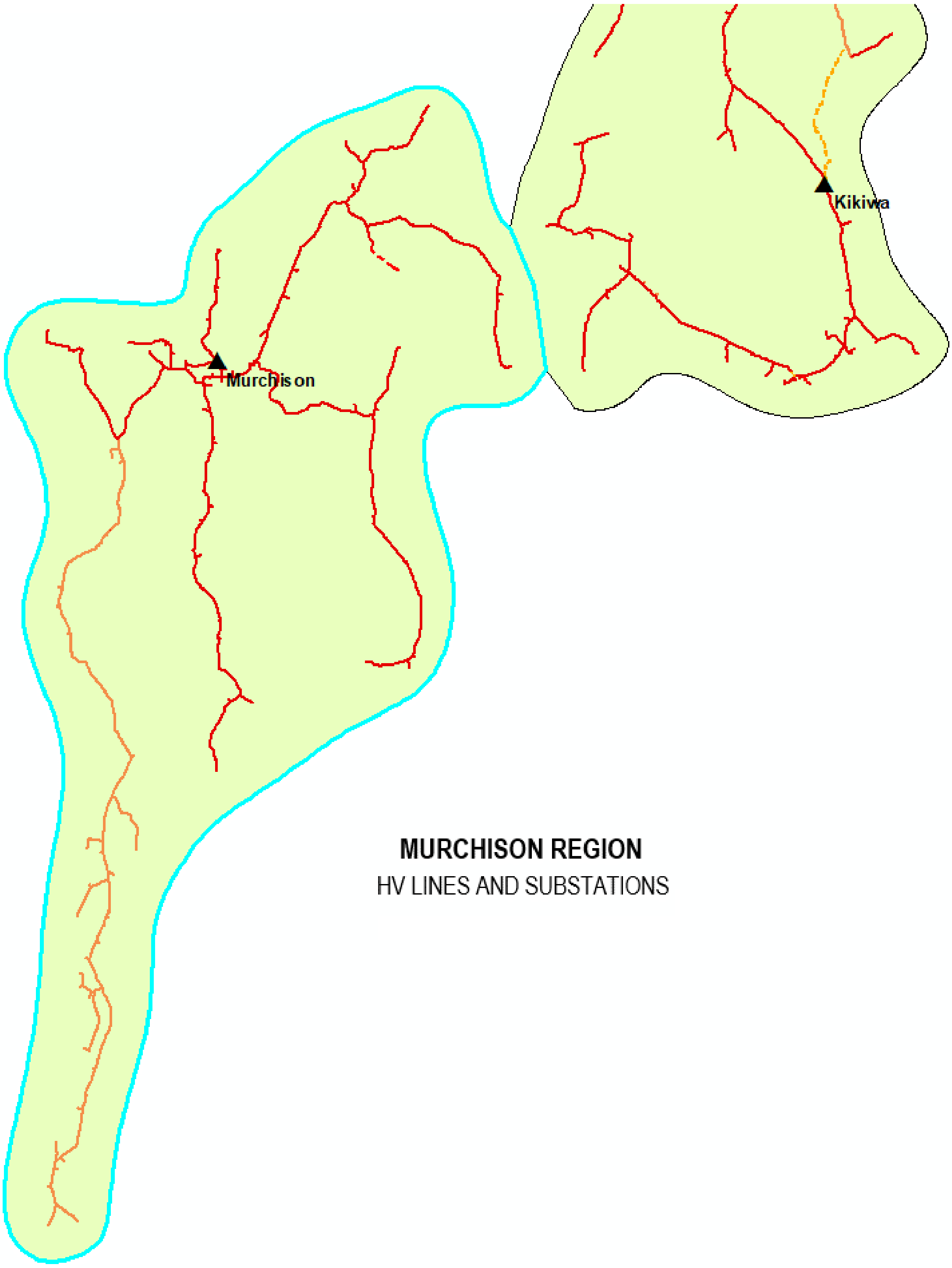

Legend
66kV
33kV
11/22kV
Golden Bay
Motueka
Stoke
Kikiwa
Murchison


STOKE REGION
HV LINES AND SUBSTATIONS
Motueka
Mapua
Wakapuaka
Founders
Nelson Elec Ltd
Annesbrook
Songer St
Lower Queen St
Richmond
Eves Valley
Hope
Brightwater

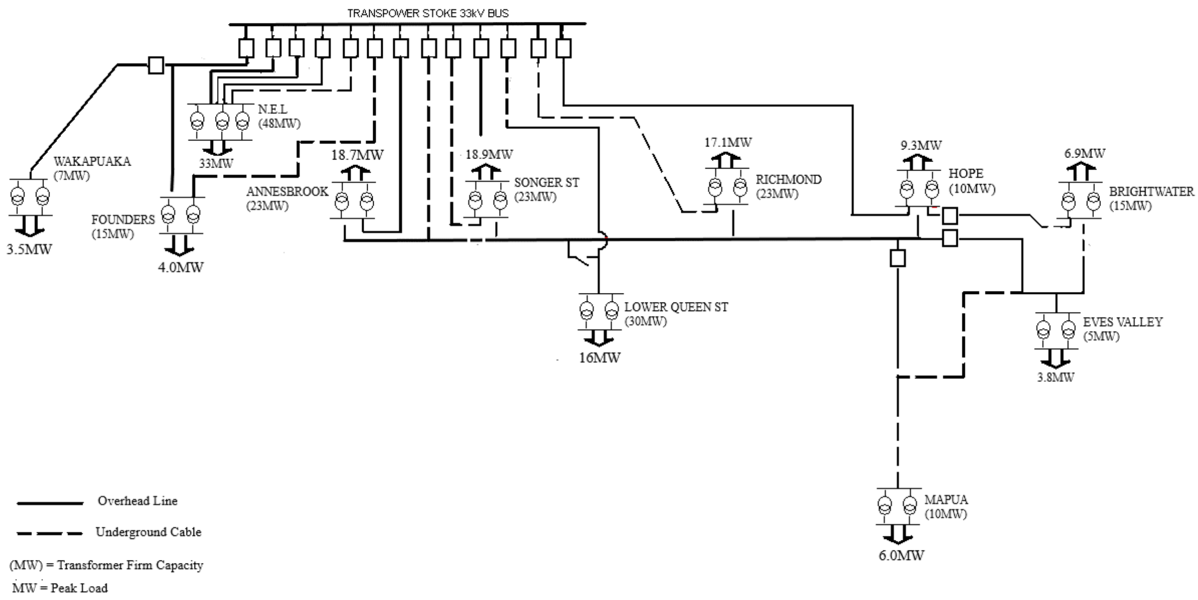

MOTUEKA REGION
HV LINES AND SUBSTATIONS
Upper Takaka
Cobb
Motueka
Mapua
Eves Valley
Brightwater


GOLDEN BAY REGION
HV LINES AND SUBSTATIONS
Swamp Road
Motupipi
Takaka
Upper Takaka
Cobb

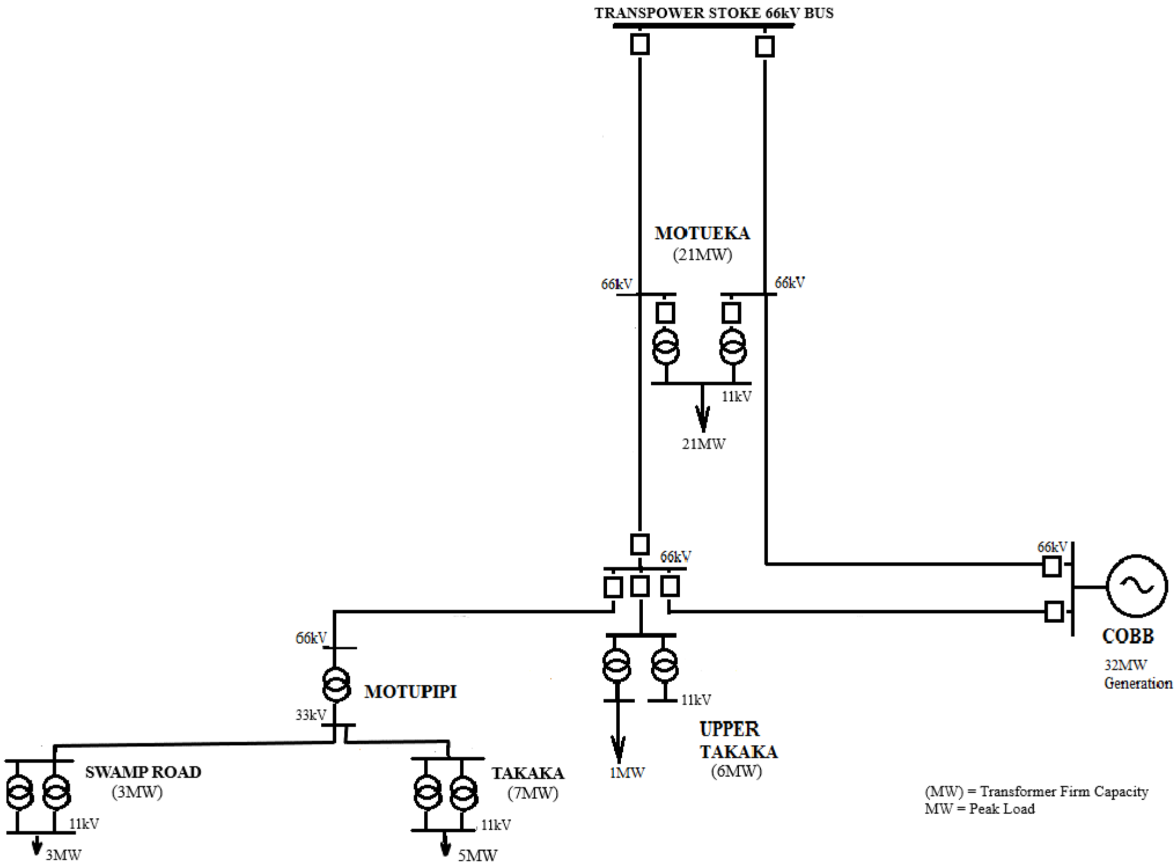

KIKIWA REGION
HV LINES AND SUBSTATIONS
Kikiwa


Murchison
Kikiwa
MURCHISON REGION
HV LINES AND SUBSTATIONS

Stoke Region 33kV Network Schematic



66kV Subtransmission System Schematic



APPENDIX B

GROWTH PROJECTION

Projections include effects of embedded generation and load management.

<u>Bulk Supply Region Demand Projection (MW)</u>

Projections include on supply to Nelson Electricity Ltd.

Calendar Year	Stoke (Stoke GXP)	Stoke (Brightwater GXP)	Motueka	Golden Bay	Kikiwa	Murchison	Peak
2023	130.1	0.0	21.1	7.2	3.5	2.9	152.6
2024	131.3	0.0	22.1	7.2	3.5	2.9	154.7
2025	132.6	0.0	22.4	7.3	3.6	2.9	156.3
2026	133.8	0.0	22.6	7.4	3.7	2.9	157.8
2027	104.9	30.0	22.9	7.5	3.8	2.9	159.2
2028	105.6	30.5	23.1	7.6	3.8	2.9	160.6
2029	106.2	31.1	23.3	7.7	3.9	2.9	162.1
2030	106.8	31.6	23.6	7.7	4.0	2.9	163.5
2031	107.4	32.2	23.8	7.8	4.0	2.9	165.0
2032	109.0	32.7	24.1	7.9	4.1	2.9	167.3
2033	109.7	33.3	24.3	7.9	4.2	2.9	168.8

Zone Substation Demand Projections (MW)

NB Projections include effects of embedded generation and load management

Stoke Supply Area Zone Substations

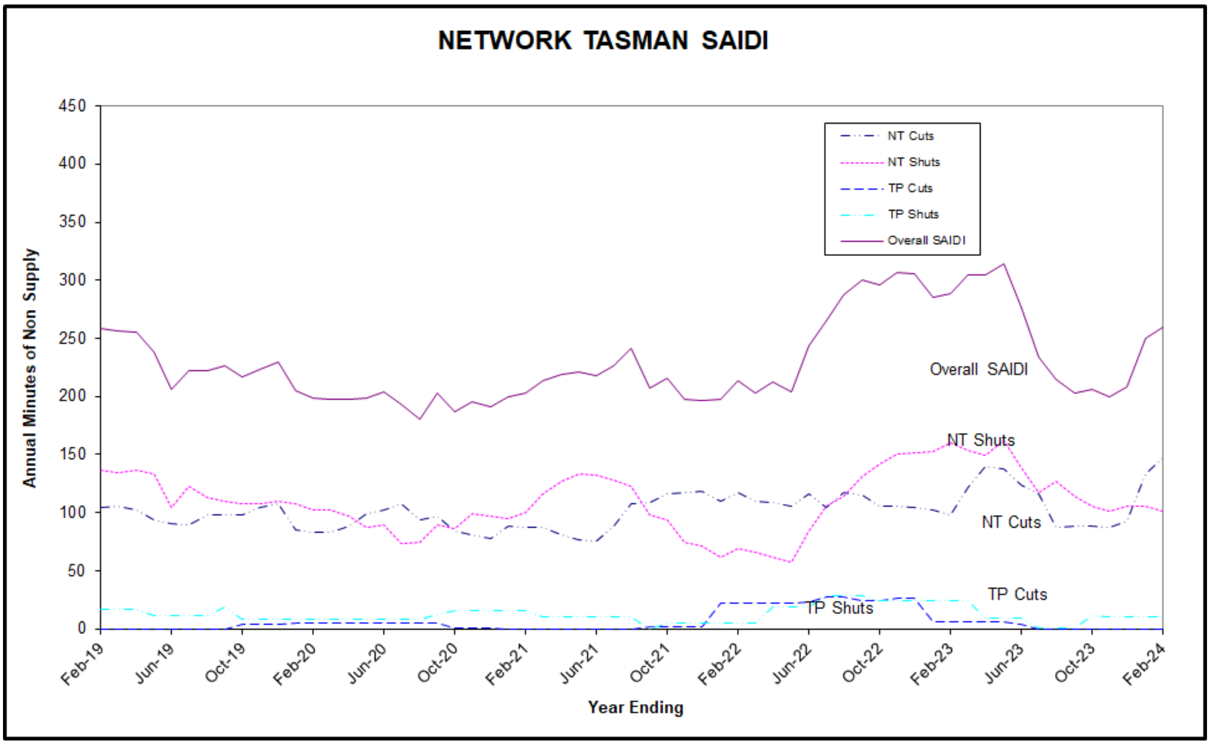
Calendar Year	Wakapuaka	Founders	Annesbrook	Songer St	Hope	Richmond	Mapua	LQS	Eves Valley	Brightwater	TOTAL	Peak
2023	3.4	3.6	19.2	18.7	10.6	16.9	6.1	16	3.8	7.2	105.5	97.6
2024	3.5	3.7	19.4	18.9	10.8	17.1	6.2	16	3.8	7.3	106.7	98.8
2025	3.5	3.7	19.7	19.1	11.3	17.2	6.4	16	3.8	7.5	108.1	100.1
2026	3.6	3.8	20.0	19.2	11.5	17.4	6.5	16	3.8	7.6	109.4	101.3
2027	3.6	3.8	20.2	19.4	11.8	17.6	6.6	16	3.8	7.7	110.6	102.4
2028	3.6	3.9	20.5	19.6	12.1	17.7	6.8	16	3.8	7.9	111.9	103.6
2029	3.7	3.9	20.8	19.8	12.3	17.9	6.9	16	3.8	8.0	113.1	104.7
2030	3.7	4.0	21.0	19.9	12.6	18.0	7.1	16	3.8	8.2	114.4	105.9
2031	3.8	4.0	21.3	20.1	12.8	18.2	7.2	16	3.8	8.3	115.6	107.1
2032	3.8	4.1	21.6	20.3	13.1	18.4	7.3	16	3.8	8.5	116.9	108.2
2033	3.8	4.1	21.8	20.4	13.4	18.5	7.5	16	3.8	8.6	117.9	109.2

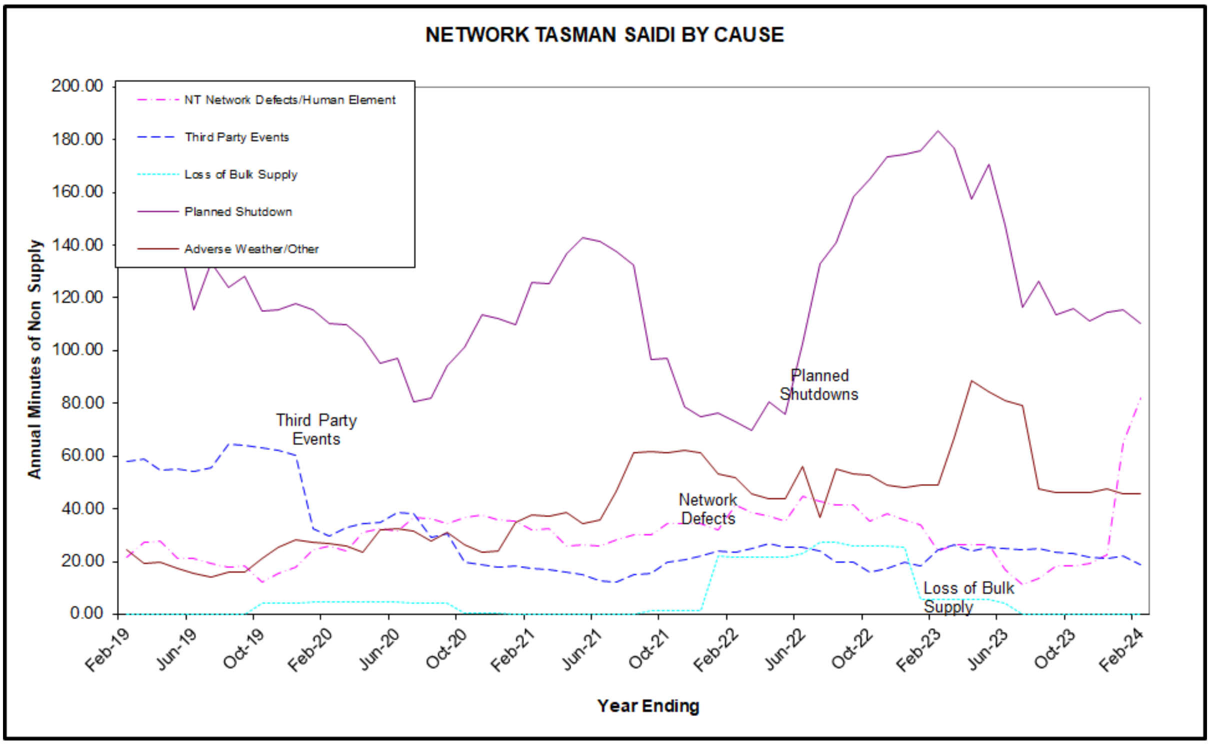
Golden Bay Supply Area Zone Substations

Calendar Year	Upper Takaka	Takaka	Swamp Rd	TOTAL	Peak
2023	0.3	4.8	2.8	7.9	7.2
2024	0.3	4.8	2.8	7.9	7.2
2025	0.3	4.9	2.9	8.0	7.3
2026	0.3	4.9	2.9	8.1	7.4
2027	0.3	4.9	3.0	8.2	7.5
2028	0.3	5.0	3.0	8.3	7.6
2029	0.3	5.0	3.1	8.4	7.7
2030	0.3	5.1	3.1	8.5	7.7
2031	0.3	5.1	3.2	8.6	7.8
2032	0.3	5.1	3.3	8.7	7.9
2033	0.3	5.2	3.3	8.8	8.0

APPENDIX C

NETWORK PERFORMANCE STATISTICS





APPENDIX D

CAPITAL EXPENDITURE PROJECTION NETWORK DEVELOPMENT AND ASSET RENEWAL

CAPITAL EXPENDITURE PROJECTION

BY ASSET CATEGORY	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
11kV/22kV Networks	$4,560,000	$6,100,000	$5,250,000	$8,500,000	$6,700,000	$6,400,000	$7,450,000	$5,250,000	$5,400,000	$5,450,000
33/66kV Networks	$1,860,000	$4,560,000	$7,760,000	$310,000	$2,560,000	$2,560,000	$2,560,000	$2,560,000	$1,020,000	$250,000
400V Networks	$370,000	$920,000	$920,000	$920,000	$920,000	$920,000	$920,000	$920,000	$920,000	$920,000
Comms Networks	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Dist Substations	$2,825,000	$2,825,000	$2,825,000	$2,825,000	$2,825,000	$2,825,000	$2,825,000	$2,825,000	$2,825,000	$2,825,000
Generators	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Land Purchases	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PF Correction	$0	$0	$0	$1,000,000	$0	$0	$0	$0	$0	$0
Ripple Plants	$0	$0	$600,000	$0	$0	$0	$0	$0	$0	$0
SCADA	$55,000	$0	$0	$0	$0	$0	$0	$0	$0	$0
Substations	$6,880,000	$7,300,000	$260,000	$1,960,000	$60,000	$60,000	$60,000	$10,660,000	$10,860,000	$4,060,000
Switchgear	$1,090,000	$1,000,000	$1,000,000	$400,000	$400,000	$400,000	$400,000	$400,000	$400,000	$400,000
TOTAL	$17,640,000	$22,705,000	$18,615,000	$15,915,000	$13,465,000	$13,165,000	$14,215,000	$22,615,000	$21,425,000	$13,905,000

BY EXPENDITURE CLASS	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
System Growth	$5,640,000	$13,240,000	$10,490,000	$8,140,000	$6,140,000	$5,840,000	$6,890,000	$15,290,000	$13,240,000	$6,640,000
Reliability	$3,765,000	$940,000	$860,000	$860,000	$860,000	$860,000	$860,000	$860,000	$860,000	$860,000
Customer Connection	$1,175,000	$1,175,000	$1,175,000	$1,175,000	$1,175,000	$1,175,000	$1,175,000	$1,175,000	$1,175,000	$1,175,000
Relocation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Renewal	$7,060,000	$7,350,000	$6,090,000	$5,740,000	$5,290,000	$5,290,000	$5,290,000	$5,290,000	$6,150,000	$5,230,000
	$17,640,000	$22,705,000	$18,615,000	$15,915,000	$13,465,000	$13,165,000	$14,215,000	$22,615,000	$21,425,000	$13,905,000

N.B. All figures are in 2024 dollars. Projected figures are not inflation adjusted.

APPENDIX E

SPECIFIC NETWORK DEVELOPMENT AND ASSET RENEWAL PROJECTS

Network Enhancement Project	Year	Estimated Cost	Region	Expenditure Class
New Recloser Pohara B Line and relocate Sunbelt recloser	2025	$40,000	Golden Bay	Reliability
Feeder Interconnection Switch Croucher St	2025	$60,000	Stoke	Reliability
Founders to Wakapuaka 33kV Cable 6km Stg 2	2025	$1,800,000	Stoke	Reliability
Install 33kV CB's Swamp Road Substation	2025	$650,000	Golden Bay	Reliability
Interconnection Cable Montebello to Marsden Valley	2025	$250,000	Stoke	Reliability
Motueka Substation Upgrade Stage 2	2025	$4,000,000	Motueka	System Growth
New Recloser Mahana Feeder Pole 3280	2025	$50,000	Stoke	Reliability
Refurbish T1 Transformer Brightwater	2025	$250,000	Stoke	Renewal
Replace 33kV Circuit Breakers and Relays (SEL787) Annesbrook Substation	2025	$350,000	Stoke	Renewal
Replace 33kV Circuit Breakers and Relays (SEL787) Songer St Substation	2025	$350,000	Stoke	Renewal
Replacement 11kV CB trucks Lower Queen St Substation 3x630A, 6x1250A	2025	$450,000	Stoke	Renewal
RTU Takaka Substation	2025	$25,000	Golden Bay	Reliability
RTU Upper Takaka Substation	2025	$30,000	Golden Bay	Reliability
SEL551 Protection Relay Replacements - Annesbrook Substation	2025	$80,000	Stoke	Renewal
SEL551 Protection Relay Replacements - Founders Substation	2025	$50,000	Stoke	Renewal
SEL551 Protection Relay Replacements - Richmond Substation	2025	$70,000	Stoke	Renewal
SEL551 Protection Relay Replacements - Songer St Substation	2025	$70,000	Stoke	Renewal
Upgrade Hope Substation to 23MVA firm - Stage 1	2025	$500,000	Stoke	System Growth
33kV Conductor Upgrade Hope to Railway Reserve/Clover Rd Mink to Cockroach 4.4km	2026	$500,000	Stoke	System Growth
Refurbish T1 Transformer Founders	2026	$250,000	Stoke	Renewal
Upgrade Hope Substation to 23MVA firm - Stage 2	2026	$4,500,000	Stoke	System Growth
Motueka Substation Upgrade Stage 3	2026	$2,000,000	Motueka	System Growth
Marahau Estuary Cable Replacement	2026	$800,000	Motueka	Renewal
Voltage Support Pakawau Feeder	2026	$250,000	Golden Bay	System Growth
Brightwater GXP 33kV Feeder Cables Stage 1	2026	$4,000,000	Stoke	System Growth
Refurbish T2 Transformer Songer St	2026	$250,000	Stoke	Renewal
Transformer Differential Protection Relays - Richmond Substation	2026	$80,000	Stoke	Reliability
Ruby Bay Feeder Cable Mapua Sub to Pole 16337	2026	$300,000	Stoke	System Growth
SEL551 Protection Relay Replacements - Brightwater Substation	2026	$50,000	Stoke	Renewal
SEL551 Protection Relay Replacements - Lower Queen St Substation	2026	$60,000	Stoke	Renewal
SEL551 Protection Relay Replacements - Mapua Substation	2026	$50,000	Stoke	Renewal
Collingwood 33kV Feeder Reconductor to Ferret	2027	$1,700,000	Golden Bay	System Growth
Refurbish T2 Transformer Brightwater	2027	$200,000	Stoke	Renewal
Brightwater GXP Ripple Injection Plant	2027	$600,000	Stoke	System Growth
Upgrade Conductor Higgins Rd 7/080 to Mink	2027	$500,000	Stoke	System Growth
Brightwater GXP 33kV Feeder Cables Stage 2	2027	$6,000,000	Stoke	System Growth
Horton Road Feeder Cable and Mapua Sub CB 6.0km	2028	$3,000,000	Stoke	System Growth
Voltage Support Dovedale Feeder	2028	$250,000	Motueka	System Growth

Upgrade Swamp Road Substation transformers to 2 x 5MVA	2028	$900,000	Golden Bay	System Growth
Capacitor Bank Motueka	2028	$1,000,000	Motueka	System Growth
New 11kV Feeder Cable and CB Brightwater Substation to Hotel Corner 1.4km	2028	$800,000	Stoke	System Growth
Refurbish T2 Transformer Founders	2028	$200,000	Stoke	Renewal
Upgrade Conductor Swamp Rd to ABS682	2028	$500,000	Golden Bay	System Growth
Reconductor Marsden Rd 33kV Double Circuit Mink to Single Circuit Cockroach	2028	$250,000	Stoke	Renewal
66kV to 110kV Line Upgrade Stoke to Motueka Stage 1	2029	$2,500,000	Stoke	System Growth
New 11kV Feeder Cable Hope Substation to Swamp Road	2029	$1,700,000	Stoke	System Growth
Voltage Support Longford Feeder	2029	$250,000	Murchison	System Growth
Korere Feeder 22kV Conversion Stage 1	2030	$1,650,000	Kikiwa	System Growth
66kV to 110kV Line Upgrade Stoke to Motueka Stage 2	2030	$2,500,000	Stoke	System Growth
66kV to 110kV Line Upgrade Stoke to Motueka Stage 3	2031	$2,500,000	Stoke	System Growth
Korere Feeder 22kV Conversion Stage 2	2031	$2,000,000	Kikiwa	System Growth
Maruia Feeder 11/22kV conversion - Stage 1	2031	$700,000	Murchison	System Growth
New 11kV CB and cables for Templemore Feeder -Richmond Substation	2032	$600,000	Stoke	System Growth
Motueka 110/66kV Substation Stg 1	2032	$10,000,000	Motueka	System Growth
Maruia Feeder 11/22kV conversion - Stage 2	2032	$500,000	Murchison	System Growth
V to 110kV Line Upgrade Stoke to Motueka Stage 4	2032	$2,500,000	Stoke	System Growth
Age based replacement transformers Mapua Substation	2033	$800,000	Stoke	Renewal
Bolt Road Feeder extension to Quarantine/Trent Drive	2033	$150,000	Stoke	System Growth
33kV Conductor Upgrade Hope to Railway Reserve/Eden Road Dog to Cockroach 2.9km	2033	$350,000	Stoke	System Growth
Maruia Feeder 11/22kV conversion - Stage 3	2033	$500,000	Murchison	System Growth
Motueka 110/66kV Substation Stg 2	2033	$10,000,000	Motueka	System Growth
33kV Cable Extension Neale Ave to Annesbrook Substation 600A 1.1km	2033	$550,000	Stoke	System Growth
Wakapuaka to Hira Store Conductor Upgrades	2034	$200,000	Stoke	System Growth
Upgrade Conductor Railway Reserve 33kV Neale Ave to Annesbrook Cockroach 1.1km	2034	$250,000	Stoke	System Growth
Upgrade Annesbrook Substation to 34MVA firm Stage 1	2034	$4,000,000	Stoke	System Growth
Maruia Feeder 11/22kV conversion - Stage 4	2034	$500,000	Murchison	System Growth
Upgrade Annesbrook Substation to 34MVA firm Stage 2	2035	$4,000,000	Stoke	System Growth
33kV Cable Extension to Wakefield	2035	$4,500,000	Stoke	System Growth
New Zone Substation at Wakefield	2036	$5,000,000	Stoke	System Growth

APPENDIX F

NETWORK MAINTENANCE AND OPERATIONS EXPENDITURE PROTECTION

10 year Budget 2025 to 2034	*FORECAST 2024*	*Mar 25*	*Mar 26*	*Mar 27*	*Mar 28*	*Mar 29*	*Mar 30*	*Mar 31*	*Mar 32*	*Mar 33*	*Mar 34*
System operations and network support											
Management Fee	631,720	656,433	682,887	703,511	724,757	746,644	769,193	792,423	816,354	841,008	866,406
Training	13,185	10,167	10,576	10,896	11,225	11,564	11,913	12,273	12,643	13,025	13,419
Contractor H&S Auditing	69,138	53,741	55,907	57,595	59,335	61,126	62,972	64,874	66,833	68,852	70,931
Emergency Stock Management	41,108	44,945	46,756	48,168	49,623	51,121	52,665	54,256	55,894	57,582	59,321
	755,152	**765,286**	**796,127**	**820,170**	**844,939**	**870,456**	**896,744**	**923,825**	**951,725**	**980,467**	**1,010,077**
Vegetation Management											
Tree Cutting	410,114	337,807	351,420	362,033	372,967	384,230	395,834	407,788	420,104	432,791	445,861
Line Corridors	367,318	361,263	375,822	387,172	398,864	410,910	423,319	436,104	449,274	462,842	476,820
Line Corridors - Rivers	18,103	36,200	37,659	38,796	39,968	41,175	42,418	43,699	45,019	46,379	47,779
Tree Regulations Removals	453,824	459,150	477,654	492,079	506,940	522,249	538,021	554,269	571,008	588,253	606,018
Fall Distance Tree Removal	264,264	270,690	281,599	290,103	298,864	307,890	317,188	326,767	336,636	346,802	357,276
	1,513,623	**1,465,110**	**1,524,154**	**1,570,183**	**1,617,603**	**1,666,455**	**1,716,781**	**1,768,628**	**1,822,041**	**1,877,066**	**1,933,754**
OPERATIONS EXPENDITURE	**2,268,775**	**2,230,396**	**2,320,281**	**2,390,353**	**2,462,542**	**2,536,911**	**2,613,525**	**2,692,454**	**2,773,766**	**2,857,534**	**2,943,831**
Service interruptions and emergencies											
Faults Services - Network	935,092	982,832	1,022,440	1,053,318	1,085,128	1,117,899	1,151,659	1,186,440	1,222,270	1,259,183	1,297,210
Faults Services - Vegetation	56,774	54,723	56,928	58,647	60,418	62,243	64,123	66,059	68,054	70,110	72,227
Fault Recoveries	(104,139)	(115,531)	(120,187)	(123,817)	(127,556)	(131,408)	(135,377)	(139,465)	(143,677)	(148,016)	(152,486)
Service Level Payments	674	-	-	-	-	-	-	-	-	-	-
Emergency Maintenance	340,586	305,000	317,292	326,874	336,745	346,915	357,392	368,185	379,304	390,759	402,560
	1,228,988	**1,227,023**	**1,276,472**	**1,315,022**	**1,354,736**	**1,395,649**	**1,437,797**	**1,481,219**	**1,525,951**	**1,572,035**	**1,619,511**
Routine and corrective maintenance and inspection											
Substation Transformers	145,196	170,624	177,501	182,861	188,383	194,073	199,934	205,972	212,192	218,600	225,202
Substation switchgear and fuses	40,207	46,689	48,571	50,038	51,549	53,105	54,709	56,361	58,064	59,817	61,624
Substation Buildings & Switchyards	132,433	136,430	141,928	146,214	150,630	155,179	159,865	164,693	169,667	174,791	180,069
Substation SCADA	3,190	8,188	8,518	8,775	9,040	9,313	9,595	9,884	10,183	10,491	10,807
SCADA Master Station	1,403	1,501	1,562	1,609	1,657	1,707	1,759	1,812	1,867	1,923	1,981
Substation Batteries	7,855	10,019	10,422	10,737	11,061	11,395	11,740	12,094	12,459	12,836	13,223
Service Boxes	139,280	207,518	215,881	222,401	229,117	236,037	243,165	250,508	258,074	265,868	273,897
Connection Policy Alterations	12,833	14,127	14,696	15,140	15,597	16,068	16,553	17,053	17,568	18,099	18,645
O/H Conductor 33kV & 66kV	-	-	-	-	-	-	-	-	-	-	-
U/G Cables 33kV	814	969	1,008	1,038	1,070	1,102	1,135	1,170	1,205	1,241	1,279
Distribution Transformers	199,022	212,161	220,711	227,377	234,244	241,318	248,606	256,114	263,848	271,816	280,025
O/H Conductor 11kV & 22kV	10,362	10,417	10,837	11,164	11,501	11,849	12,206	12,575	12,955	13,346	13,749
O/H Conductor 400v	23,058	25,343	26,364	27,160	27,981	28,826	29,696	30,593	31,517	32,469	33,449
U/G Cables 11kV & 22kV	14,941	16,570	17,238	17,758	18,295	18,847	19,416	20,003	20,607	21,229	21,870
U/G Cables 400v	22,778	29,710	30,907	31,841	32,802	33,793	34,814	35,865	36,948	38,064	39,213
Field Switchgear & fuses	44,533	53,099	55,239	56,907	58,626	60,396	62,220	64,099	66,035	68,029	70,084
Field regulators	36,625	84,459	87,862	90,516	93,249	96,066	98,967	101,956	105,035	108,207	111,474
Field ABS Isolators	163,894	143,058	148,823	153,317	157,948	162,718	167,632	172,694	177,910	183,282	188,818
LCP Transmitters	530	602	626	645	665	685	705	727	749	771	794
Communications Networks	3,632	2,731	2,841	2,926	3,015	3,106	3,200	3,296	3,396	3,498	3,604
SCADA & Ripple Plant Back Up	60,062	62,362	64,875	66,835	68,853	70,932	73,075	75,282	77,555	79,897	82,310
Operations General	94,859	105,666	109,925	113,244	116,664	120,188	123,817	127,557	131,409	135,377	139,466
Line Surveys	167,973	26,706	27,782	28,621	29,485	30,376	31,293	32,238	33,212	34,215	35,248
AR, Reg, Line MDI Reads	84,702	87,794	91,332	94,091	96,932	99,859	102,875	105,982	109,183	112,480	115,877
Sub VRR Settings	33,285	31,261	32,521	33,503	34,515	35,558	36,631	37,738	38,877	40,051	41,261
Dist Trans MDI Reads & Checks	23,582	27,175	28,270	29,124	30,004	30,910	31,843	32,805	33,796	34,816	35,868
Traffic Management Costs	228,530	269,883	280,759	289,238	297,973	306,972	316,242	325,793	335,632	345,768	356,210
Access Tracks	504,729	484,846	504,385	519,617	535,310	551,476	568,131	585,288	602,964	621,174	639,933
Portable Generator Costs	111,078	155,507	161,774	166,659	171,692	176,877	182,219	187,722	193,391	199,232	205,248
Voltage Support	234,182	243,151	252,949	260,589	268,458	276,566	284,918	293,523	302,387	311,519	320,927
Audits	67,129	73,482	76,443	78,752	81,130	83,580	86,105	88,705	91,384	94,144	96,987
Audit Recoveries	(86,292)	(94,243)	(98,041)	(101,002)	(104,053)	(107,195)	(110,432)	(113,767)	(117,203)	(120,743)	(124,389)
	2,526,399	**2,647,804**	**2,754,511**	**2,837,697**	**2,923,395**	**3,011,682**	**3,102,634**	**3,196,334**	**3,292,863**	**3,392,308**	**3,494,756**
Refurbishment & Renewals Maintenance											
All Poles	1,371,836	1,392,214	1,448,321	1,492,060	1,537,120	1,583,541	1,631,364	1,680,631	1,731,386	1,783,674	1,837,541
Distribution Substations	587,515	616,772	641,627	661,005	680,967	701,532	722,718	744,545	767,030	790,194	814,058
Connection Assets	145,232	153,686	159,880	164,708	169,682	174,807	180,086	185,524	191,127	196,899	202,846
Transformer Changeouts	17,066	45,337	47,164	48,588	50,056	51,567	53,125	54,729	56,382	58,085	59,839
	2,121,649	**2,208,009**	**2,296,992**	**2,366,361**	**2,437,825**	**2,511,447**	**2,587,293**	**2,665,429**	**2,745,925**	**2,828,852**	**2,914,284**
ASSET MAINTENANCE & RENEWALS	**5,877,036**	**6,082,837**	**6,327,975**	**6,519,080**	**6,715,956**	**6,918,778**	**7,127,725**	**7,342,982**	**7,564,740**	**7,793,195**	**8,028,550**
TOTAL NETWORK MAINTENANCE	**8,145,810**	**8,313,232**	**8,648,255**	**8,909,433**	**9,178,498**	**9,455,688**	**9,741,250**	**10,035,436**	**10,338,506**	**10,650,729**	**10,972,381**

APPENDIX G

TYPICAL ASSET MAINTENANCE AND RENEWALS ACTIVITIES

REFURBISHMENT/RENEWALS:

Poles	Pole replacements and complete pole structure replacements
Line Hardware	Hardware replacements (incl crossarms)
Conductor	Conductor replacements
Service Boxes	Complete service box replacement
Underground Cables	Complete cable replacement
Distribution Transformers	End of life transformer replacements, winding replacement
Pole Mounted Switchgear	Pole mounted CB replacements
Ground Mounted Switchgear	Ground mount switch unit replacements

ROUTINE/PREVENTATIVE MAINTENANCE:

Pole Structures	Pole patching, strengthening pole footings
Line Hardware	Tightening hardware
Conductor 33kV	Rebinding, restraining, conductor repairs
Cables 33kV	Cable testing, reterminating
Distribution Subs	Cleaning, testing, hardware tightening, replacing fuses, earthing maintenance
Distribution Transformers	Cleaning, tightening connections, oil maintenance, painting, testing
Conductor 11kV	Rebinding, restraining, conductor repairs
Cables 11kV	Cable testing, reterminating
Conductor 400V	Rebinding, restraining, conductor repairs
Cables 400V	Cable testing, reterminating
Service Boxes	Resecuring lids, digging out, cleaning, fuse board replacement, relabelling
Field ABS Isolators	ABS adjustment, connector tightening
Field Switchgear & Line Fuses	AR maintenance and testing, replacing fuse links
Field Regulators	Testing, cleaning, painting, oil treatment
Connection Assets	Fuse link replacement
Access Track Maintenance	Track clearing, stabilisation, water table maintenance
Tree Cutting	Surveys, tree clearing
Subs – Transformers	Cleaning, painting, testing, tightening connections, oil treatment
Subs - Switchgear + Fuses	Contact adjustment, connection tightening, testing, oil treatment
Subs – Buildings	Painting, cleaning, yard spraying
Subs – SCADA	Testing, cleaning
Subs – Batteries	Testing, cleaning
Load Control Plant – Transmitters	Cleaning, testing, greasing bearings, tuning
SCADA Master Station	Testing, cleaning, calibration
Communications Networks	Testing, line hardware tightening, tuning, RT repairs
Public Lighting	Cleaning and adjusting fitting, tightening hardware
Network Meters	Testing, cleaning, calibration

FAULTS/EMERGENCY REPAIRS:

Fuse replacements from overloads
Fuse replacements from lightning surges
Vehicle damage repairs
Conductor repairs from bird strikes
Storm damage repairs
All damage repairs required to restore normal network serviceability

APPENDIX H

DESIGN NETWORK VOLTAGE REGULATIONS

<u>Design % Voltage Drop Allocations</u>
Hope, Founders, Lower Queen Street and Motueka Substations

	Close to Zone Sub Normal Tap	Urban Normal Tap	Rural 2.5% Tap	Remote Rural 5% Tap
HV Min Load Volts	-1.5	-1.5	-2	-4
HV Full Load Volts	1.5	-2.5	-5.5	-8.5
Distribution T/F Nominal Boost	4.25	4.25	4.25	4.25
Distribution T/F Fixed Tapping Boost	0	0	2.5	5
Distribution T/F Full Load Drop	-1	-1	-1	-1
LV Distribution Line Min Load Drop	0	0	0	0
LV Distribution Line Full Load Drop	-4.5	-4	-3.5	-3
HV Swing	3	1	3.5	4.5
Total Swing (Max 9.5)	2.5	6	8	8.5
Full Load NCP Volts (Min -3.25)	0.25	-3.25	-3.25	-3.25
Min Load NCP Volts (Max 5.25)	2.75	2.75	4.75	5.25
Centre NCP Volts	1.5	-0.25	0.75	1

NOTES
1. Zone Sub LDC assumed set to give 4.0% boost at full load
   Zone Sub aiming no load voltage set at 98% volts
2. Design NCP receive voltage 230V +5%/-3% (allows 2% max voltage drop in-service cable thereby meeting +/- 5% at switchboard)
3. 0.5% additional swing allowed for diversity between volt drop maximums

<u>Design % Voltage Drop Allocations</u>
Eves Valley, Brightwater, Takaka, Swamp Road, Kikiwa, Murchison, Annesbrook, Songer Street

	Close to Zone Sub Normal Tap	Urban Normal Tap	Rural 2.5% Tap	Remote Rural 5% Tap
HV Min Load Volts	0	-0.5	-2	-4
HV Full Load Volts	0	-2.5	-5.5	-8.5
Distribution T/F Nominal Boost	4.25	4.25	4.25	4.25
Distribution T/F Fixed Tapping Boost	0	0	2.5	5
Distribution T/F Full Load Drop	-1	-1	-1	-1
LV Distribution Line Min Load Drop	0	0	0	0
LV Distribution Line Full Load Drop	-4.5	-4	-3.5	-3
HV Swing	0	2	3.5	4.5
Total Swing (Max 9.5)	5.5	7	8	8.5
Full Load NCP Volts (Min -3.25)	-1.25	-3.25	-3.25	-3.25
Min Load NCP Volts (Max 5.25)	4.25	3.75	4.75	5.25
Centre NCP Volts	1.5	0.25	0.75	1

NOTES
1. Zone Sub has no line drop compensation
   Zone Sub aiming no load voltage set at 100% volts
2. Design NCP receive voltage 230V +5%/-3% (allows 2% max voltage drop in-service cable thereby meeting +/- 5% at switchboard)
3. 0.5% additional swing allowed for diversity between volt drop maximums

APPENDIX I

NETWORK RISK AND RESILIENCE ANALYSIS

Network Risk Management Background

The core business of NTL is electricity distribution. In all of its operations the company aims to provide a reliable and safe electricity supply service at low cost whilst achieving a satisfactory return on its assets. The stakeholders of NTL are its shareholders, its customers who are electricity retailers or end use customers, its employees and its suppliers (Transpower New Zealand Ltd and contractors).

Risk is defined as 'the chance of something happening that will have an impact upon objectives'. In the context of NTL's core operations, risk will be any event that could potentially be of detriment to the strategic mission of the company as outlined above.

The electricity distribution business is characterised by its asset base: that is the poles, lines, cables and transformers making up the distribution system. This asset base is large in value in relation to the business turnover and the risks associated with not managing this asset well are significant not only to NTL as a company but also to the wider community who are its shareholders.

Risks relevant to NTL take many forms. These may be categorised as follows:

- Business Risk
- Commercial Risk
- Political Risk
- Economic Risk

This document analyses and records the risks of physical failure or damage to the assets that make up the distribution network and that results in loss of supply to customers for more than 24 hours.

Dealing with power supply interruptions of duration up to 24 hours are part of the normal business of network management operations.

The process of risk management undertaken follows ISO31000. The steps are:

- Establish Risk Context
- Identify the Risks
- Assess the Risks
- Treat the Risks
- Monitor and Review

The network is broken down into its major constituent parts and, through a process of risk identification and assessment, a risk grading is assigned to events affecting each part. The specific risks that are inherent to each component are identified and highlighted. Analysis of these risks then leads to plans for either risk mitigation or reduction, or to risk acceptance with reference to contingency plans.

Contingency plans are the subject of a separate document entitled *Network Tasman Disaster Readiness and Response Plan*. This document is appended as Appendix L.

Reference is made to three documents related to risk management of the NTL network. Although now dated, the subjects of these reports remain unchanged and the reports are still current.

'Natural Hazards Risk Analysis Report – Feb 1997'
Sedgwick Ltd

'Risk Profile for Tasman Energy Ltd – Sept 1998'
Sedgwick Risk Services Ltd

'Seismic Assessment of Network Tasman Structures – Dec 1998'
Worseldine & Wells Ltd

Network Risks Context

An electricity distribution network is made up of a series of component parts, the total set being arranged in a supply hierarchy. At the top of the hierarchy are the extra high voltage subtransmission lines and cables that transmit bulk electricity from the national grid bulk supply point to the power companies' zone substations. These lines and cables typically form a network that, for security of supply reasons, allows a number of alternative routes of supply to important zone substations. Because of the nature of subtransmission as opposed to distribution, the number of lines in this grid tend to be low in number, however each typically has high strategic importance.

Next in the supply hierarchy is the zone substations themselves. These break the voltage of supply down from the subtransmission voltage to the primary distribution voltage. Typically, a zone substation will have one or two subtransmission lines feeding in to it, and there will be four or more HV distribution lines feeding power out of it.

The HV distribution lines form the third tier in the supply hierarchy. Typically, these are 22,000V or 11,000V lines and underground cables that are configured in a grid in urban areas or more simply as a long distribution feeder in the rural areas. The HV distribution lines are run through streets and along roads or over private land to within 300m of the end use customers. The grid pattern in the urban areas provides for redundancy and backup circuits in the event that a particular section of line or cable should become faulted and unavailable for service. In the rural areas, such interconnections and multiple routes of feed are less common and if the line develops a fault, then the power remains off until repairs are completed.

The fourth level in the supply hierarchy is the distribution substations. These substations step the supply voltage down from the HV distribution voltage of 22kV or 11kV to 230/400V. This is the voltage of supply for most end use electricity customers. Distribution substations can be found in most streets and along roads and take the form of pole mounted transformers, kiosks or padmount transformers located on street berms.

The fifth and final level in the supply hierarchy is the low voltage network. These are lines and cables that distribute power from the distribution substations to the end use customers' connection points. Due to voltage drop constraints, these are generally fairly large conductors and generally limited in length to around 300m.

The following table is indicative of the numbers of customers that can be associated with any one component in the various supply hierarchy levels.

	No. of Feeders or Subs	Max Customers per Feeder or Substation
Subtransmission Feeders	11	6,000
Zone Substations	13	5,000
Urban HV Distribution Feeders	22	1,500
Rural HV Distribution Feeders	26	1,000
Distribution Substations	4,500	100
O/H LV Distribution Feeders	2,200 (est)	40
U/G LV Distribution Feeders	1,000 (est)	50

From the above table, it can be seen that the higher level components of the network tend to be few in number but each component supports a high number of customers. Lower level components are greater in number but support a much smaller number of customers.

From a risk management point of view, the subtransmission network supports a high number of customers using a small number of feeder circuits. This leads to the situation where the probability of a loss of supply event at this level is low but the consequence of failure is very high.

At the other end of the supply hierarchy, where there are a large number of LV distribution network lines, the probability of a loss of supply event occurring is high but the consequence is low.

An added factor of the consequence of a failure, where a loss of supply to customers is concerned, is the time needed to restore supply following the incidence of a fault that generates a loss of supply. Loss of supply can be measured in customer hours, whereby loss of supply to one customer for one hour generates one customer hour of unavailability.

Risk can be defined as:

Risk = Probability of Failure x Consequence of Failure

The risk analysis in this report is based on a numeric ranking of risks for the various components of the network.

Risk of non-supply for the purposes of the risk ranking of NTL's network is defined as:

Risk of Non-Supply = Annual Failure Probability x Customers Affected x Duration of Outage

An event with a risk level of 5000 therefore could be an event that typically occurs once per year, resulting in loss of supply to 5000 customers for one hour. Another event with the same risk level could have a twice per year probability of occurrence and affect 250 customers for 10 hours.

<u>Risk Benchmarking</u>

Events with a low risk level may be accepted as events that can be dealt with in the normal course of operating a distribution network. Events falling in to this category are outages caused by foreign interference with the network such as vehicle accidents, bird strikes and the like.

It is necessary to establish a benchmark risk level in order to identify those risk events that require consideration for mitigation treatment. Events with risk rankings below this benchmark are accepted as "run of the mill" hazards managed by everyday operations.

The following table gives an indication of the dimensions for an event risk level of 2000, for outages of duration of one day.

Event Return Period (Yrs)	Event Frequency	Outage Duration	Customers Affected
1	1	24	83
2	0.5	24	164
5	0.2	24	416
10	0.1	24	833

The risk ranking of 2,000 is an appropriate benchmark cut-off against which event risk rankings can be identified for further risk treatment. A decision prompt is generated for events falling above this as to whether or not some mitigation action should be taken to reduce the risk level.

This level of risk corresponds to events that are outside of the type of events that occur in the normal course of running the network. Events of risk rating above 2000 include wind storms etc. that generate environmental forces beyond the design strengths of the overhead network. Other less severe storms but longer lasting are also in this risk category.

Such events are beyond the capacity of the normal systems and processes of fault response, to resolve within the time frames of the *Use of Systems Agreement* that NTL has with its retailer customers.

Risk treatment may involve capital expenditure to reduce the probability of the event, or the number of customers affected, or contingency planning to reduce the duration of the resulting outage. Other options include insurance to cover any financial effect of the risk on the company.

Network Risk Analysis

Low Voltage Network

Events resulting in loss of supply on the low voltage network are fairly frequent (approx. 100 times per year). Repair and supply restoration times are short for most events on both overhead lines and underground systems due to the low grade of conductor insulation required and the high degree of development of repair kits and connector systems etc. In urban areas, there is a significant amount of redundancy in low voltage systems since circuits are often run to meet up with nearby supply substations. In many cases, this allows supply restoration via connection through alternative supply routes.

Since the low voltage networks exist on a 300m maximum radius of distribution substations, the susceptibility of the networks to environmental effects such as weather, seismic events and vehicle collisions is very much site specific. In general, overhead systems are more susceptible than underground systems, however the time taken to identify and repair a fault on overhead is usually much shorter than with underground cables.

Risks of prolonged non-supply due to simultaneous damage of multiple low voltage networks caused by environmental conditions, such as wind storms and earthquakes, are likely to carry higher consequence although with very low probability. However, the resulting risk level is significant.

The low voltage overhead networks are generally resilient to the wind storms of return frequency up to 1 in 20 years. The later overhead networks are generally designed around a peak wind speed of 130km/hr, however at such wind speeds the influence of windborne flying debris rather than mechanical line strength tends to dominate performance. Fortunately, wind storms of such strength are generally rare in the Nelson area. Four have been experienced in the last 40 years.

Similarly, the networks are resilient to earthquakes of strength up to MMV (Modified Mercalli scale), however earthquakes of strength up to MMVIII have a moderate probability in the Nelson region. Earthquakes of this strength may result in damage to both overhead and underground reticulation with simultaneous faults in many areas.

The risk assessment matrix for events affecting the LV networks is as follows;

Risk: Loss of Supply due to event on Low Voltage Overhead Network

Event	No. events per year over entire system	Feeders in system	Probability of event on any individual feeder	Customers affected	Restore time	Risk
Tree through line	10	2200	0.005	40	2	0.4
Pole knocked down by vehicle	5	2200	0.0025	40	4	0.2
All single point effect events	50	2200	0.022	40	2	1.76
Wind storm >130km/hr	0.1	2200	0.00004	6000	72	17
Major earthquake	0.02	2200	0.02	6000	168	20,160

Risk: Loss of Supply due to event on Low Voltage Underground Network

Event	No. events per year over entire system	Feeders in system	Probability of event on any individual feeder	Customers affected	Restore time	Risk
Insulation failure in LV Cable	5	1000	0.005	30	2	0.3
Connection or joint failure	10	1000	0.01	30	4	1.2
All single point effect events	25	1000	0.011	30	2	0.66
Wind storm >130km/hr	0.1	1000	0.00004	0	0	0
Major earthquake	0.02	1000	0.02	3000	168	23,040

There is little more that can be done to mitigate the effects of major earthquake or major wind storm on the low voltage network other than to possibly relocate lines underground in some areas, and to be cognisant of objects or vegetation close to overhead lines that could damage them in the event of high winds.

The risks of such events are best managed through effective contingency planning and insurance.

Distribution Substations

Distribution substations on the NTL system take a number of forms. These can be pole or platform mounted overhead substations, or pad or kiosk enclosed ground mounted substations. Faults in substations can range from simple protection fuse ruptures to internal faults within substations, resulting in total loss of the transformer and/or the substation support structure.

Lightning storms affecting a wide area pose a significant risk of overwhelming the faults response capability.

As transformers contain insulating oil there is also risk of oil spillage associated with all substations. Although not necessarily affecting supply restoration, oil spillage is an event that must be dealt with quickly to avoid infiltration into waterways etc. Oil spill management is the subject of a contingency plan included in the NTL disaster recovery plan.

The effect of major earthquakes on our overhead and underground distribution substations is the subject of a report by consulting civil engineers Worseldine & Wells dated December 1998. The management of earthquake risk through insurance is the subject of another document entitled *Risk Profile for Tasman Energy Ltd* by Sedgwick Risk Services dated September 1998.

As with most of our earthquake risk assessment, the risk associated with a major earthquake affecting the distribution transformers can be very high, however no amount of capital expenditure will bring this down to a level of complete comfort. Therefore, NTL must accept such risk but plan for an event through contingency plans and control financial risk through appropriate levels of insurance.

An assessment of events resulting in loss of supply with distribution transformers is given in the following:

Risk: Loss of Supply due to event on a Distribution Substation

Event	No. events per year over entire system	Stations in system	Probability of event on any individual substation	Customers affected	Restore time	Risk
Internal substation fault	10	4000	0.003	100	3	0.9
Connection or joint failure	10	4000	0.003	100	4	1.2
All single point effect events	25	4000	0.007	100	3	2.1
Lightning storm	4	4000	0.001	400	6	9600
Major earthquake	0.02	4000	0.02	3000	168	10,080

High Voltage Distribution Network

Events on the HV distribution network resulting in loss of supply are relatively frequent. Fault statistics show an average incidence of 100 events per year with an average outage time of 1.2 hours. The average number of customers affected by any one fault is 280.

Of this, the overhead network has an average incidence of 95 events per year, and the underground network an incidence of 5 per year. Most of these faults are the result of external interference with the network system. Examples of sources of such interference are bird strikes to overhead lines, vehicle collisions, contractor activity (cranes, excavators), animals and trees.

Overhead Lines

Risk: Loss of Supply due to event on High Voltage Overhead Network

Event	No. events per year over entire system	Feeders in system	Probability of event on any individual feeder	Customers affected	Restore time	Risk
Tree through Line	10	46	0.22	280	2	123
Pole knocked down by vehicle	5	46	0.11	280	4	123
All single point effect events	95	46	2.1	280	2	1,176
Wind storm >130km/hr	0.1	46	0.002	6500	168	2,373
Major earthquake	0.02	46	0.02	6500	336	43,680

A higher risk ranking for overhead HV lines comes from a high susceptibility to externally initiated fault events, resulting in a high probability of event occurrence. The consequences of each event are moderate, however, since the supply restoration times are short and the number of customers affected by an event moderate. It is the combination of high probability and moderate consequence that generates the high risk.

The probability of an event that would result in prolonged loss of supply is much lower, and is generally limited to extreme wind conditions such as cyclones and major earthquakes.

NTL currently manages the risk through the deployment of a comprehensive 24-hour fault repair operation. Clearly, however, any further efforts to mitigate overall risk of loss of supply to customers should be focussed in this area. Possible practical treatment actions could include:

- Installing additional switchgear and line sectionalising equipment (reduces number of customers affected by a fault)
- “Trefoil” reconstruction of overhead lines (reduces susceptibility of overhead lines to birds etc.)
- Additional automation of system by extension of SCADA system (reduces average time to restore power following a fault)

Underground HV Cables

Risk: Loss of Supply due to event on High Voltage Underground Network

Event	No. events per year over entire system	Feeders in system	Probability of event on any individual feeder	Customers affected	Restore time	Risk
Insulation failure in HV Cable	0.1	16	0.006	280	20	50
Connection or joint failure	3	16	0.19	280	12	958
All single point effect events	5	16	0.31	280	12	1,562
Wind storm >130km/hr	0.1	16	0.006	0	0	0
Major earthquake	0.02	16	0.02	6000	168	20,160

Given the low incidence of underground HV cable faults, the risk levels associated with this part of the network are more or less at an acceptable level at present. The benchmark of 2000 risk points can be used as an indicator, however, in the urban area, particularly where underground HV spur systems are present. On a spur system there is no backup cable route in the event of a fault, therefore restoration time for customers supplied on the spur are set by the time taken to repair the fault.

The longest repair time cable faults are those requiring section replacements and these have a typical repair time of 24-36 hours. In order to limit the number of customers that can be affected by a single underground cable fault, a network design standard limit on the load on a domestic underground HV spur system of 500kVA is in effect. This is the maximum load that can be supplied by a truck mounted temporary generator.

Zone Substation and Subtransmission

Risk assessment matrices for each of NTL's 12 zone substations and three subtransmission substations are included as Appendix J to this document. Risks associated with the 33kV supply network that feeds these substations are included in these matrices.

In this exercise, each of the major substations and other major components of the supply network were analysed by working through a specific set of criteria designed to identify the specific weaknesses and inherent risks associated with that component.

The following numeric values are assigned to the Probability and Outage Duration

Probability	Return Period	Value	Outage Duration	Action to Restore	Restore Time (hrs)
High (H)	1 in 10yrs	0.1	Extreme (E)	Extensive Repairs	168
Med (M)	1 in 50yrs	0.02	Long (L)	Many Long Jobs	48
Low (L)	1 in 100yrs	0.01	Medium (M)	Long Jobs/Many Small	12
Negligible (N)	1 in 500yrs	0.002	Short (S)	Minor Repairs	6
			Instantaneous (I)	Switching Only	2

The results of the risk assessments for each zone substation are discussed below:

Motupipi Substation

This substation is a subtransmission substation supplying two zone substations, in turn supplying 3,500 customers in Golden Bay.

The 66kV supply to Motupipi substation is a single circuit overhead line from Upper Takaka, therefore providing only N level subtransmission security. The risks of loss of supply include the risks of loss of service of this line for a long period. As single structure failures can be repaired within a number of hours, it is longer repair time events, such as loss of three or more spans that are critical. The line traverses rolling hill country with a few river crossings. Risks of loss of service to this extent are low probability.

The substation is an outdoor switchyard design with two three -phase transformers, each of which can carry the total load, therefore having N-1 security level. Events resulting in lengthy outage for the substation are low in probability. Loss of both transformer units from earthquake damage or lightning strike would be the most likely scenario for an extended outage event.

Hope Substation

This substation supplies 4,500 customers in the Waimea Plains area. The main 33kV supply line to this substation is backed up by an alternative 33kV circuit on a separate line route giving an N-1 level of subtransmission security. The major risks associated with Hope substation include the risk of loss of 33kV supply for a prolonged period due to an event causing the loss of more than three spans, such as a landslip on the hillside area that the line crosses to the south of Stoke substation at a time when the alternative supply circuit is not available.

There is a high earthquake risk in the region and this substation could be affected. The switchroom building is being replaced with a building of modern seismic strength. Beyond this, the major earthquake event is covered in the *Disaster Readiness and Response Plan* (refer Appendix L).

The loss of major components of the substation, such as part or all of the indoor switchboard or both of the transformers, is the other major risk associated. Such events have a low probability but could result in a lengthy outage for many customers. These events are dealt with through specific contingency plans documented in the *Disaster Readiness and Response Plan* (refer Appendix L).

Songer Street Substation

Songer Street substation supplies the central Stoke area including 5,500 customers.

The substation has a main and backup 33kV feeder supply providing N-1 level subtransmission security.

The greatest risk of loss of supply with this substation is the loss of 33kV supply to the substation through extensive damage to the two underground cables that run from Songer Street to the substation at the rear of the Omaio Village. Both the primary and backup 33kV supplies to the substation come close together at this point. Such an event could come about through external interference such as excavation contractor error.

As with the other major substations, the loss of the major components of the substation will result in loss of supply to many customers, however due to the very low probability of this occurrence, the risk is satisfactorily managed using a contingency plan.

Annesbrook Substation

The Annesbrook substation has a full backup supply circuit available within the 33kV network. The substation has N-1 subtransmission security. Therefore, the risk of loss of supply due to 33kV line fault is low. There are 5,500 customers supplied from the substation.

As with the other major substations, the loss of the major components of the substation will result in loss of supply to many customers, however due to the very low probability of this occurrence, the risk is satisfactorily managed using a contingency plan.

By far the greatest risk of loss of supply results from the medium probability of a major earthquake in the region. This risk is managed through contingency planning again.

Founders Substation

Founders substation supplies 2,500 customers in the Nelson north area.

The substation has two lines of supply at 33kV, the primary line being an underground cable and the backup line being a hill country overhead line. The substation has two transformers providing full N-1 security. The risk of prolonged loss of supply for consumers supplied from the substation is now low.

The substation feeds a much smaller number of customers than Hope, Annesbrook or Songer Street. Therefore, although similar probabilities of loss of supply are associated, the extent of outage is greatly reduced. Again, contingency plans exist for such events.

Brightwater Substation

This substation supplies the townships of Brightwater and Wakefield and the rural areas adjacent. There are 2,500 customers supplied from the substation.

The substation is supplied via an open ring 33kV supply providing N-1 security, therefore the risks of prolonged non-supply from loss of 33kV supply are low.

The substation has two transformers in service and it now feeds a fairly wide area. In the event of equipment failure at the substation, the supply can be partially resupplied via 11kV supply from the Hope substation. The risks of pro-longed non-supply to the area supplied by it are moderate.

The risk of loss of the substation through major earthquake is the greatest threat to the system.

Eves Valley Substation

This substation, under normal conditions, supplies only one customer who is the Carter Holt Harvey sawmill. A nominal loss of supply consequence equivalent to 1,000 customers is assigned to the station for the purposes of risk profiling. The subtransmission security level is only N. The substation load can be backed up to a certain extent, however, via 11kV supply from Hope or Brightwater substations.

There are two transformers at the substation, either of which can supply the full load. The 33kV and 11kV switchboards are both outdoor overhead structures. These can be repaired within 24 hours.

Lower Queen Street Substation

Lower Queen Street substation is dedicated to the supply of the Nelson Pine Industries medium density fibreboard plant.

The 33kV supply can only be partially backed up from the subtransmission network. The substation is therefore an N security substation only. This level of security is in agreement with the customer.

Takaka Substation

This substation is fed by a short overhead 33kV supply line that runs over flat land from the NTL substation at Motupipi. The subtransmission security level is N only. However, this short line can be repaired quickly in the event of failure. The combined effect of low probability of occurrence, short repair times and a relatively small number of affected customers (2,500) results in a low risk ranking.

The substation has a simple outdoor overhead busbar structure that can be almost entirely rebuilt in a short time following a major event. There are two transformers at the site, either of which can carry the total substation load.

The substation site is on an alluvial plain that has been previously identified as being an earthquake liquefaction risk. A capital project to install an in ground platform supporting the transformers was completed in 1995, thereby greatly improving this risk hazard. The earthquake hazard is now managed in a similar fashion to the other substations through deployment of a contingency plan.

Swamp Road Substation

Swamp Road substation is the smallest substation on the network supplying approx. 900 customers. The 33kV supply is via a single 26km 33kV overhead line traversing mainly undulating farmland. The subtransmission security level is N only. Single point faults or structure failures on the line can be repaired fairly quickly, however loss of more than five spans would result in an outage possibly lasting a number of days. A contingency plan for such an event, possibly involving deployment of a diesel generator, is included in the company's *Disaster Readiness and Response Plan*.

The substation has a double transformer configuration with all outdoor overhead busbars. Either transformer can carry the total load of the substation.

Contingency plans cover the major hazards of severe earthquake damage and coincident failure of both transformers.

Mapua Substation

Mapua substation supplies approx. 2,000 customers in the rural area. The 33kV supply to the substation is via a long overhead line circuit that has interconnections to backup circuits over 70% of the route length. The substation therefore has only N level subtransmission security.

The final 12km to the substation is via a four core underground cable giving a spare core in the event of damage to or failure of one of the three in-service cores.

The substation has a double transformer configuration with all switchgear and transformers inside a building. Each of the 33kV and 11kV switchboards is built in two halves with a single bus section circuit breaker.

Richmond Substation

Richmond substation supplies approx. 5,500 customers in the Richmond area, including the Richmond CBD and industrial area. The substation is supplied directly from the Stoke GXP, via a 6km underground 33kV cable. A full capacity alternative 33kV supply is available to the substation from the railway reserve 33kV feeder which is on an entirely separate route. The substation therefore has N-1 subtransmission security.

The substation has a double transformer configuration with all switchgear inside a building. Each of the 33kV and 11kV switchboards is built in two halves with a single bus section circuit breaker.

As a result of the backup 33kV supply and the N-1 level of equipment redundancy at the substation, the substation has a low overall loss of supply risk ranking.

Motueka Substation

Motueka substation supplies approx. 7,500 consumers in the Motueka area, including Motueka township and its rural environs. The substation is supplied by two 66kV feeder lines from the Stoke substation 66kV GXP. The substation, therefore, has a full no-break N-1 security of supply.

The substation has a double transformer configuration with all 11kV switchgear inside a building. The 11kV switchboard is built in two halves with a single bus section circuit breaker.

As a result of the parallel 66kV supply and the N-1 level of equipment redundancy at the substation, the substation has a low overall loss of supply risk ranking.

Cobb Substation

Cobb substation is a subtransmission substation that connects the Cobb power station into the network. There are no load consumers supplied from the substation, however the Cobb power station does have significance for NTL as NTL is contracted to provide line function services for the power station.

The substation has two circuits feeding it at 66kV. If one circuit is unavailable then Cobb generation is still possible, but at reduced levels.

There are two transformers at the substation, either of which can support the full output of the station. These are, however, owned by Trustpower who are the owners of the generation.

The substation has a low overall loss of supply risk rating.

Upper Takaka Substation

Upper Takaka substation is a 66kV zone substation that also serves as a connection node in the 66kV line network. There are four three 66kV circuit breakers at the substation and two 66/11kV tranformers which form the major and critical components. Failure of 66kV circuit breakers or the 66kV busbar at the substation could also affect supply to the Motupipi substation.

There are currently approx 200 offtake consumers supplied from the substation. Given that there are two transformers at the substation and that the repair time of the key circuit breakers is short (circuit breakers can be bypassed and protection reconfigured in an emergency), the substation has a low loss of supply risk rating.

Wakapuaka Substation

Wakapuaka substation supplies approx. 1,400 customers in the rural area. The 33kV supply to the substation is via a long hill country overhead line circuit that has interconnections to backup circuits over 40% of the route length. The substation therefore currently has only N level subtransmission security.

The substation is sited aside the Nelson Haven on a site that has been built up approx. 2m above the local high tide mark.

The substation has a double transformer configuration with all switchgear and transformers inside a building. Each of the 33kV and 11kV switchboards is built in two halves with a single bus section circuit breaker.

Transpower GXP Substations

NTL relies for its supply on delivery of electricity to four Transpower GXPs in its region. These are at Stoke 66kV, Stoke 33kV, Kikiwa 11kV and Murchison 11kV. Detailed risk assessment of these GXPs is beyond the scope of this document, however since NTL relies almost entirely on supply through these substations, then consideration of the risks to NTL and the region as a whole of partial or total loss of supply from these GXPs (and the transmission lines supplying these GXPs) is warranted.

In particular, NTL has a high reliance on the Stoke GXP. This GXP is the northern terminus of the South Island 220kV transmission backbone. It is also an interconnection point for the 66kV network that supplies the Motueka and Golden Bay bulk supply regions and connects the Cobb power station. The substation is also near a known fault line, as is the 220kV transmission line to it.

NTL contracts with Transpower for supply to its network via the four GXPs. Supply reliability is the subject of a commercial contract between NTL and Transpower. Transpower's risk management plan and the performance of Transpower is therefore of the utmost importance to NTL.

NTL has identified the risks associated with the supply from the Stoke substation and the other GXPs. Network Tasman's disaster readiness and response plan incorporates contingency planning for the event of partial or total loss of supply from one or more of the Transpower bulk supply points. This plan is appended as Appendix L.

Earthquake Resilience and Risk

A specific analysis of the associated risks and expected performance of the network under potential earthquake conditions has been undertaken. The results of this, including any possible mitigation or special preparedness activities to be undertaken, are discussed in this section.

Network Tasman is part of the Nelson Tasman Engineering Lifelines group which considers the potential impacts and co-dependency's of lifeline organisations in the Nelson/Tasman district. Information has been drawn from the work of this group in this analysis.

The major active fault near the Nelson region is the Alpine fault. This passes through the Murchison district (Upper Matakitaki) and the Nelson Lakes in a north-westerly direction and runs along the Wairau Valley.

Another fault system, which is still active but has a high recurrence interval, is the Waimea-Flaxmore system.

The most recent major earthquake centred in the region was the Murchison earthquake of June 1929. This was a Richter 7.8 event which resulted in ground shaking intensity of MMVII to MMIX throughout the Nelson area.

The Nelson/Tasman district has a moderate probability of experiencing MMVII or greater earthquakes. Return periods (years) for Earthquakes of varying intensities are given in the following table:

AREA	MMVI	MMVII	MMVIII	MMIX
Nelson/Richmond	7	25	88	350
St Arnaud/Kikiwa	8	28	85	370
Murchison	9	30	100	410

Ground shaking and peak ground accelerations in soft sediments up to 30m deep can be amplified with respect to bedrock accelerations. Liquefaction is also possible when ground shaking exceeding MMVII occurs in saturated silty or sandy layers within approx. 20m of the surface and where high water tables exist.

In Nelson city, there are conditions for amplified ground shaking and liquefaction, particularly in the reclaimed areas around the port and Maitai estuary, but also in parts of Tahunanui and Stoke.

When assessing the prospect of damage to the electricity network, it is necessary to consider the network in two parts. These are the subtransmission system and the distribution system. The subtransmission system consists of the point-to-point individual lines that carry supply at 33kV or 66kV from the GXP to the zone substations and the zone substations themselves. Each zone substation has 33kV or 66kV subtransmission supply lines. The likely effects of a large earthquake on the supply lines and the substation itself can thus assessed on an individual basis.

The distribution network consists of the distribution feeders, street substations and low voltage feeders that distribute the supply out to all end use consumers. The distribution network can only be considered in a general sense as it is unavoidable that it passes into all areas to reach consumers, including areas highly prone to liquefaction and amplified ground shaking etc. All structures are designed to withstand up to MMVII shaking and there is little scope or justification for further strengthening of distribution network structures.

In a MMVIII or greater earthquake, pole footing damage can be expected to occur at overhead platform substations due to the high top weight of the transformer. Damage to underground cables and padmounted substations will also likely result where surface rupture or slumps occur. The network has redundancy in 11kV distribution cables and therefore a low level of underground cable failures could be tolerated without major loss of capacity to supply. In a major earthquake, pole footing failure from ground shaking may result in poles leaning. Such damage can be repaired fairly quickly to allow restoration of supply.

The susceptibility and expected performance of the subtransmission network in a major earthquake is discussed by reference to individual zone substation sections in the following.

Founders Substation

This substation supplies the area to the immediate north of Nelson city including Atawhai and the upper Maitai Valley. The supply to the substation is via a 10km long underground cable from the grid exit point substation at Stoke. This is backed up with a back country overhead line that runs from Stoke GXP to the substation.

The substation is built on reclaimed land that would be subject to liquefaction in a major earthquake event. The substation building and transformer pads have been constructed on piles down to bedrock and should therefore be immune to liquefaction at the site. The outdoor 33kV switchboard is not piled, however, and some damage (bus distortion and fracture of insulators) to the structure could occur during a major event. Only half of this structure is required to be in service for the substation to take full load, however, and being outdoor overhead, repairs to damaged components can be effected fairly quickly. The structure has been designed to withstand some distortion and movement due to seismic events of up to MMVII. To go beyond this would require significant capital investment, likely to be in the form of an indoor 33kV switchboard. Given the ability to repair damage fairly quickly to the outdoor switchboard in the event of a major earthquake, it is unlikely that such investment is justified.

Annesbrook Substation

Annesbrook substation supplies the Tahunanui and Bishopdale areas. It also supplies the airport under normal conditions, however the airport can also be supplied from the Songer Street substation. The supply to the substation is via relatively short overhead lines. Ground shaking and ground movement in a major earthquake may cause some poles to be leaning, but damage resulting in loss of line serviceability would be unlikely.

The substation is on land that has low susceptibility to liquefaction but moderate susceptibility to amplified ground shaking. Like Founders, it has an outdoor 33kV switchboard and indoor 11kV switchboard. The 33kV switching structure is susceptible to distortion and insulator breakage from severe ground shaking and movement. The substation has been completely upgraded within the last 10 years. Heavy cables connect the 11kV switchboard to the transformer. The transformer bushing connections, however, lack flexible connections.

This poses a risk of transformer bushing failure under earthquake conditions. Fitting of flexible connections is a sensible risk mitigation strategy that should be undertaken.

Songer Street Substation

This substation supplies the Stoke area. It can be backed up by 11kV supply lines from Annesbrook and Richmond substations. The supply for the substation is via a short overhead line running down Songer Street. Two short underground 33kV cables run into the substation from Songer Street.

Like Annesbrook, the substation is sited on land that has low susceptibility to liquefaction but moderate susceptibility to amplified ground shaking. It has the same configuration as Annesbrook as well, in that it has an outdoor switchyard that will be susceptible to distortion and insulator breakage from severe ground shaking. The transformer 11kV bushings do not have the same type of cable box and are less susceptible to breakage. Earthquake strengthening at the substation was undertaken in the late 1980s. There are no further modifications required.

Richmond Substation

This substation supplies the Richmond area, but it can be backed up by 11kV supply from the Songer Street and Hope substations. The main 33kV supply from Stoke is an underground cable. Damage to this cable from ground movement in a major earthquake is possible but unlikely.

Richmond substation is sited on land that has low susceptibility to liquefaction but could suffer amplified ground shaking. The substation has indoor 33kV and 11kV switchboards and outdoor transformers. The substation is well constructed and presents no special seismic hazard.

Hope Substation

Hope substation supplies Hope and the Waimea Plains. It is supplied via overhead line from Stoke GXP. The overhead line traverses hill country that is susceptible to slumping. This may result in structure footing failures in a major earthquake. There is an alternative supply route available.

The substation is sited on land that is not subject to liquefaction or amplification of ground shaking. Seismic strengthening of the outdoor 33kV structure and transformer mounting has been undertaken in the past. There are no further seismic improvements identifiable.

Brightwater Substation

This substation supplies the Brightwater and Wakefield townships and surrounding district. The normal 33kV supply is the Hope substation overhead line, therefore the same risks of loss of supply as to Hope substation apply.

Brightwater substation is not sited on land subject to liquefaction or amplified ground shaking. The substation has the same configuration and earthquake resilience as the Hope substation.

Mapua Substation

Mapua substation supplies the Upper Moutere and side valleys, Westdale, Ruby Bay and central Mapua. The 33kV supply line is from Stoke in a mixture of overhead line and underground cable. The final 12km is a four core underground cable with three cores in service and a spare.

Mapua substation is sited on land that is subject to liquefaction. The substation is constructed entirely within a building of domestic appearance but specifically designed to a high seismic strength standard.

Takaka Substation

Takaka substation supplies the Golden Bay area aside from the north-western Collingwood district. The 33kV supply is via single overhead lines from Upper Takaka to Motupipi and on to Takaka.

The site of the substation is known to be subject to liquefaction, but the transformer pads have been constructed to be resilient to this by being constructed on piles down to bedrock. Damage to the outdoor overhead structure could result from heavy ground shaking from an earthquake. Additional works to mitigate the risk of damage may be considered in the future.

Swamp Road Substation (Collingwood)

Swamp Road substation supplies the north-west Golden Bay area. 33kV supply is via a long overhead line traversing undulating land that may be subject to high peak ground acceleration during a major earthquake. This could result in pole footing failures.

The substation site is not subject to liquefaction. Seismic strengthening of the overhead outdoor structure has been undertaken in the past.

Upper Takaka Substation

This substation supplies the Upper Takaka area only. The substation is supplied from the two 66kV lines that run from Stoke 66kV GXP to the site. The route for the lines traverses estuaries, flat plains and the Takaka Hill. The lines are close to a known fault line along the Stoke foothills.

The substation site is not subject to liquefaction. The substation has an outdoor overhead bus structure and a simple ground mounted low voltage outdoor switchboard.

Cobb Substation

The Cobb substation is situated at the Cobb power station and connects the power station to the 66kV network. Two 66kV circuits supply the substation. These traverse mountainous and remote country that is subject to earthquake shaking and slips.

The substation is sited below a steep hillside and is subject to rockfall and slips in an earthquake. In a major earthquake affecting the substation, it is likely that the power station would be significantly damaged as well.

Motueka Substation

Motueka substation supplies the Motueka township and environs, from Marahau in the north to the Motueka river valley in the south. It is Network Tasman’s largest zone substation supplying approx. 7,500 consumers. The 66kV supply to the substation is via two circuits from Stoke 66kV GXP. These lines are close to a known fault line along the Stoke foothills.

The substation has a large 66kV gantry structure and an in indoor 11kV switchboard. The substation site is not subject to liquefaction.

Wakapuaka Substation

Wakapuaka substation supplies the north Nelson area including Marybank, Wakapuaka and Hira. The 33kV supply line is from Stoke in an overhead line that traverses hill country and forested land.

The substation is sited on land that is subject to liquefaction. The substation is constructed entirely within a building of domestic appearance but specifically designed to a high seismic strength standard.

Climate Change and Resilience

An increased frequency of storms and accelerated sea level rise could result from climate change. Zone substations and distribution substations at low levels near the coast can be expected to be affected. Cyclone Fehi, which occurred in February 2019, coincided with a 180-year high tide and resulted in coastal inundation and storm surge. This flooded two padmount distribution substations at Monaco and Richmond. Pole lines were also affected at Glenduan.

The risk of extended loss of supply of zone substation supply areas due to climate change influences has been assessed and the results are given in the risk matrices appended in this section.

Four zone substations carry a higher risk of coastal inundation/storm surge due to their proximity to the coast. These are Mapua, Lower Queen Street, Founders and Wakapuaka substations. However, the overall risk of loss of supply from this cause remains low in relation to other loss of supply risk causes.

Network Tasman will continue to monitor sea level rise and storm incidence in the district.

Risk Management Conclusions

Risk analysis of the NTL distribution network reveals the following points:

1. There is a significant risk of loss of supply from an earthquake of MMVIII or greater strength.

2. After the risk of non-supply resulting from a major earthquake, events affecting the HV overhead network supply have the highest risk ranking. This is reflected in reliability statistics for the network.

3. Aside from the effects of a major earthquake, the risk of loss of supply due to failure of the LV network and distribution substations is small. Incidents in this part of the network are adequately managed with the current 24-hour availability fault service.

4. Due to the nature and extent of the HV overhead network, NTL carries significant risk of loss of supply to customers from events caused by third party interference. The high risk grading for this part of the network comes from a high probability of loss of supply rather than a high consequence, since the repair time for most fault incidences is fairly low and the number of customers affected is moderate. Although currently adequately managed through the 24-hour fault service and contingency planning, reducing the susceptibility of the overhead network to external influence, or reducing the consequence of an event, would serve to improve the ongoing reliability of the network and lower the risks of non-supply.

5. The HV underground cable network generally has a low loss of supply risk rating, however a limit to the number of customers supplied by HV spur cables is necessary. Prudent risk management will also include a contingency supply, in the form of a temporary generator, to meet the spur circuit load whilst cable repairs are made.

6. Loss of supply at zone substation level generally carries a lower risk grading than HV distribution lines. Timely implementation of the capital work upgrade planning as included in the AMP is required in order to maintain this risk ranking.

7. There is a high dependence for continuity of supply on Transpower, in particular on the 220kV transmission lines in the area and on the Stoke GXP substation.

Zone Substation Risk Assessment Matrices

- Motupipi Substation
- Takaka Substation
- Swamp Road Substation
- Upper Takaka
- Founders Substation
- Annesbrook Substation
- Songer Street Substation
- Richmond Substation
- Hope Substation
- Brightwater Substation
- Mapua Substation
- Lower Queen Street Substation
- Eves Valley Substation
- Motueka Substation
- Cobb Substation
- Wakapuaka Substation

MOTUPIPI SUBSTATION — Customers affected by LOS: 3500

Main 66kV Supply: Upper Takaka — **Backup**: Nil

Substation: Motupipi

Non Equipment Incidents (Main 66kV Supply)

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	11760	Contingency Plan+Insurance	Ref DRRP
Landslip/Movement	M	M	840	Accept Risk	Nil
Flood/Tsunami	L	M	420	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	M	S	420	Accept Risk	Nil
Aircraft crash	L	M	420	Accept Risk	Nil
Road/rail crash	L	S	210	Accept Risk	Nil
Trees	M	S	420	Accept Risk	Nil
Fire (outside source)	M	M	840	Accept Risk	Nil
Human Incident	L	I	70	Accept Risk	Nil
Other - Bird Strike	M	S	420	Accept Risk	Nil

Non Equipment Incidents (Substation)

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	11760	Contingency Plan+Insurance	Ref DRRP
Landslip/Movement	N	L	336	Accept Risk	Nil
Flood/Tsunami	N	L	336	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	L	S	210	Accept Risk	Nil
Aircraft crash	N	L	336	Accept Risk	Nil
Road/rail crash	N/A	N/A	0	Accept Risk	Nil
Trees	L	S	210	Accept Risk	Nil
Fire (outside source)	L	S	210	Accept Risk	Nil
Human Incident	L	M	420	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents (Main 66kV Supply)

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 pole/span	M	M	840	Accept Risk	Nil
Loss 2-3 poles/spans	M	L	3360	Accept Risk	Nil
Loss 3-5 poles/spans	L	L	1680	Accept Risk	Nil
Loss >5 poles/spans	L	E	5880	Contingency Plan	Ref DRRP
Loss river crossing span	L	M	420	Accept Risk	Nil
Loss major span	L	M	420	Accept Risk	Nil
Single point cable failure	N	N/A	0	Accept Risk	Nil
<100m cable damage	N	N/A	0	Accept Risk	Nil
0.1-1km cable damage	N	N/A	0	Accept Risk	Nil
>1km cable damage	N	N/A	0	Accept Risk	Nil

Equipment Incidents (Substation)

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 inc 66kV CB	L	I	70	Accept Risk	Nil
Loss 2 inc 66kV CB's	N	M	84	Accept Risk	Nil
Loss 1 transformer	L	I	70	Accept Risk	Nil
Loss 2 transformers	N	E	1176	Contingency Plan	Ref DRRP
Loss 1 66kV bus section	N	N/A	0	Accept Risk	Nil
Loss 2 66kV bus sections	N	N/A	0	Accept Risk	Nil
Loss 1 inc 33kV CB	L	I	70	Accept Risk	Nil
Loss 2 inc 33kV CB's	N	L	336	Accept Risk	Nil
Loss 1 feeder CB	L	S	210	Accept Risk	Nil
Loss 2 feeder CBs	N	L	336	Accept Risk	Nil
Loss >2 feeder CB's	N	N/A	0	Accept Risk	Nil
Loss 1 half switchboard	L	S	210	Accept Risk	Nil
Loss complete switchboard	N	L	336	Accept Risk	Nil
Control room fire	L	S	210	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 21826

Substation Risk Index per Customer: 6.236

TAKAKA SUBSTATION — Customers affected by LOS: 2500

Main 33kV Supply: Takaka Feeder — **Backup**: Nil

Substation: Takaka

Non Equipment Incidents (Main 33kV Supply)

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	8400	Contingency Plan+Insurance	Ref DRRP
Landslip/Movement	L	M	300	Accept Risk	Nil
Flood/Tsunami	L	M	300	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	M	S	300	Accept Risk	Nil
Aircraft crash	L	M	300	Accept Risk	Nil
Road/rail crash	L	S	150	Accept Risk	Nil
Trees	L	S	150	Accept Risk	Nil
Fire (outside source)	L	S	150	Accept Risk	Nil
Human Incident	L	I	50	Accept Risk	Nil
Other - Bird Strike	M	S	300	Accept Risk	Nil

Non Equipment Incidents (Substation)

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	8400	Contingency Plan	Ref DRRP
Landslip/Movement	N	L	240	Accept Risk	Nil
Flood/Tsunami	M	L	2400	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	L	S	150	Accept Risk	Nil
Aircraft crash	N	L	240	Accept Risk	Nil
Road/rail crash	N/A	N/A	0	Accept Risk	Nil
Trees	L	S	150	Accept Risk	Nil
Fire (outside source)	L	S	150	Accept Risk	Nil
Security/Vanadalism	L	M	300	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents (Main 33kV Supply)

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 pole/span	M	M	600	Accept Risk	Nil
Loss 2-3 poles/spans	L	L	1200	Accept Risk	Nil
Loss 3-5 poles/spans	L	L	1200	Accept Risk	Nil
Loss >5 poles/spans	L	E	4200	Accept Risk	Nil
Loss river crossing span	N	N/A	0	Accept Risk	Nil
Loss major span	L	M	300	Accept Risk	Nil
Single point cable failure	L	I	50	Accept Risk	Nil
<100m cable damage	L	I	50	Accept Risk	Nil
0.1-1km cable damage	N	N/A	0	Accept Risk	Nil
>1km cable damage	N	N/A	0	Accept Risk	Nil

Equipment Incidents (Substation)

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 inc 33kV CB	L	I	50	Accept Risk	Nil
Loss 2 inc 33kV CB's	N	M	60	Accept Risk	Nil
Loss 1 transformer	L	I	50	Accept Risk	Nil
Loss 2 transformers	N	E	840	Contingency Plan	Ref DRRP
Loss 1 33kV bus section	N/A	N/A	0	Accept Risk	Nil
Loss 2 33kV bus sections	N/A	N/A	0	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	50	Accept Risk	Nil
Loss 2 inc 11kV CB's	L	L	1200	Accept Risk	Nil
Loss 1 feeder CB	L	S	150	Accept Risk	Nil
Loss 2 feeder CBs	L	S	150	Accept Risk	Nil
Loss >2 feeder CB's	N	M	60	Accept Risk	Nil
Loss 1 half switchboard	L	M	300	Accept Risk	Nil
Loss complete switchboard	L	L	1200	Accept Risk	Nil
Control room fire	L	S	150	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 17490

Substation Risk Index per Customer: 6.996

SWAMP ROAD SUBSTATION

Customers affected by LOS: 1000

Main 33kV Supply: Collingwood | **Backup**: Nil

Substation: Swamp Road

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	3360	Contingency Plan+Insurance	Ref DRRP
Landslip/Movement	M	M	240	Accept Risk	Nil
Flood/Tsunami	L	M	120	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	M	S	120	Accept Risk	Nil
Aircraft crash	L	M	120	Accept Risk	Nil
Road/rail crash	L	S	60	Accept Risk	Nil
Trees	M	S	120	Accept Risk	Nil
Fire (outside source)	M	M	240	Accept Risk	Nil
Human Incident	L	I	20	Accept Risk	Nil
Other - Bird Strike	M	S	120	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 pole/span	M	M	240	Accept Risk	Nil
Loss 2-3 poles/spans	M	L	960	Accept Risk	Nil
Loss 3-5 poles/spans	L	L	480	Accept Risk	Nil
Loss >5 poles/spans	L	E	1680	Contingency Plan	Ref DRRP
Loss river crossing span	L	M	120	Accept Risk	Nil
Loss major span	L	M	120	Accept Risk	Nil
Single point cable failure	L	I	20	Accept Risk	Nil
<100m cable damage	L	N/A	0	Accept Risk	Nil
0.1-1km cable damage	N	N/A	0	Accept Risk	Nil
>1km cable damage	N	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 7932

Substation Risk Index per Customer: 7.932

Non Equipment Incidents (Substation: Swamp Road)

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	3360	Contingency Plan	Ref DRRP
Landslip/Movement	N	L	96	Accept Risk	Nil
Flood/Tsunami	L	L	480	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	L	S	60	Accept Risk	Nil
Aircraft crash	N	L	96	Accept Risk	Nil
Road/rail crash	N	N/A	0	Accept Risk	Nil
Trees	L	S	60	Accept Risk	Nil
Fire (outside source)	L	S	60	Accept Risk	Nil
Human Incident	L	I	20	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents (Substation: Swamp Road)

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 inc 33kV CB	N	N/A	0	Accept Risk	Nil
Loss 2 inc 33kV CB's	N	N/A	0	Accept Risk	Nil
Loss 1 transformer	M	I	40	Accept Risk	Nil
Loss 2 transformers	L	E	1680	Contingency Plan	Ref DRRP
Loss 1 33kV bus section	N	N/A	0	Accept Risk	Nil
Loss 2 33kV bus sections	N	N/A	0	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	20	Accept Risk	Nil
Loss 2 inc 11kV CB's	L	L	480	Accept Risk	Nil
Loss 1 feeder CB	N	N/A	0	Accept Risk	Nil
Loss 2 feeder CBs	N	N/A	0	Accept Risk	Nil
Loss >2 feeder CB's	N	N/A	0	Accept Risk	Nil
Loss 1 half switchboard	N	N/A	0	Accept Risk	Nil
Loss complete switchboard	N	N/A	0	Accept Risk	Nil
Control room fire	L	S	60	Accept Risk	Nil

UPPER TAKAKA SUBSTATION

Customers affected by LOS: 300

Main 66kV Supply: Stoke-Upper Takaka 66kV | **Backup**: Stoke-Cobb 66kV

Substation: Upper Takaka

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	1008	Contingency Plan+Insurance	Ref DRRP
Landslip/Movement	L	I	6	Accept Risk	Nil
Flood/Tsunami	L	I	6	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	M	I	12	Accept Risk	Nil
Aircraft crash	L	I	6	Accept Risk	Nil
Road/rail crash	L	I	6	Accept Risk	Nil
Trees	L	I	6	Accept Risk	Nil
Fire (outside source)	L	I	6	Accept Risk	Nil
Human Incident	L	I	6	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 pole/span	L	I	6	Accept Risk	Nil
Loss 2-3 poles/spans	L	I	6	Accept Risk	Nil
Loss 3-5 poles/spans	L	I	6	Accept Risk	Nil
Loss >5 poles/spans	L	I	6	Accept Risk	Nil
Loss river crossing span	L	I	6	Accept Risk	Nil
Loss major span	L	I	6	Accept Risk	Nil
Single point cable failure	N/A	N/A	0	Accept Risk	Nil
<100m cable damage	N/A	N/A	0	Accept Risk	Nil
0.1-1km cable damage	N/A	N/A	0	Accept Risk	Nil
>1km cable damage	N/A	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 324

Substation Risk Index per Customer: 1.08

Non Equipment Incidents (Substation: Upper Takaka)

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	S	36	Contingency Plan	Ref DRRP
Landslip/Movement	L	S	18	Accept Risk	Nil
Flood/Tsunami	M	S	36	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	L	S	18	Accept Risk	Nil
Aircraft crash	N	L	28.8	Accept Risk	Nil
Road/rail crash	N	M	7.2	Accept Risk	Nil
Trees	L	I	6	Accept Risk	Nil
Fire (outside source)	L	I	6	Accept Risk	Nil
Security Vandalism	L	I	6	Accept Risk	Nil
Other - Bird Strike	N	I	1.2	Accept Risk	Nil

Equipment Incidents (Substation: Upper Takaka)

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 inc 66kV CB	L	I	6	Accept Risk	Nil
Loss 2 inc 66kV CB's	N/A	N/A	0	Accept Risk	Nil
Loss 1 transformer	L	I	6	Accept Risk	Nil
Loss 2 transformers	N	S	3.6	Contingency Plan	Ref DRRP
Loss 1 66kV bus section	L	I	6	Accept Risk	Nil
Loss 2 66kV bus sections	N	I	1.2	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	6	Accept Risk	Nil
Loss 2 inc 11kV CB's	L	I	6	Accept Risk	Nil
Loss 1 feeder CB	L	I	6	Accept Risk	Nil
Loss 2 feeder CBs	L	I	6	Accept Risk	Nil
Loss >2 feeder CB's	N/A	N/A	0	Accept Risk	Nil
Loss 1 half switchboard	L	I	6	Accept Risk	Nil
Loss complete switchboard	L	S	18	Contingency Plan	Ref DRRP
Control room fire	L	M	36	Accept Risk	Nil

COBB SUBSTATION

Customers affected by LOS: 1000

Main 66kV Supply: Stoke-Cobb 66kV **Backup**: Stoke-Upper Takaka 66kV

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	3360	Contingency Plan+Insurance	Ref DRRP
Landslip/Movement	L	I	20	Accept Risk	Nil
Flood/Tsunami	L	I	20	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	M	I	40	Accept Risk	Nil
Aircraft crash	L	I	20	Accept Risk	Nil
Road/rail crash	L	I	20	Accept Risk	Nil
Trees	L	I	20	Accept Risk	Nil
Fire (outside source)	L	I	20	Accept Risk	Nil
Human Incident	L	I	20	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 pole/span	L	I	20	Accept Risk	Nil
Loss 2-3 poles/spans	L	I	20	Accept Risk	Nil
Loss 3-5 poles/spans	L	I	20	Accept Risk	Nil
Loss >5 poles/spans	L	I	20	Accept Risk	Nil
Loss river crossing span	L	I	20	Accept Risk	Nil
Loss major span	L	I	20	Accept Risk	Nil
Single point cable failure	N/A	N/A	0	Accept Risk	Nil
<100m cable damage	N/A	N/A	0	Accept Risk	Nil
0.1-1km cable damage	N/A	N/A	0	Accept Risk	Nil
>1km cable damage	N/A	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 8068

Substation Risk Index per Customer: 8.068

Substation: Cobb

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	3360	Contingency Plan	Ref DRRP
Landslip/Movement	M	E	3360	Accept Risk	Nil
Flood/Tsunami	M	L	960	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	L	L	480	Accept Risk	Nil
Aircraft crash	N	L	96	Accept Risk	Nil
Road/rail crash	N	L	96	Accept Risk	Nil
Trees	L	L	480	Accept Risk	Nil
Fire (outside source)	L	L	480	Accept Risk	Nil
Security Vandalism	L	L	480	Accept Risk	Nil
Other - Bird Strike	N	I	4	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 inc 66kV CB	L	I	20	Accept Risk	Nil
Loss 2 inc 66kV CB's	L	L	480	Accept Risk	Nil
Loss 1 transformer	L	I	20	Accept Risk	Nil
Loss 2 transformers	N	E	336	Contingency Plan	Ref DRRP
Loss 1 66kV bus section	L	I	20	Accept Risk	Nil
Loss 2 66kV bus sections	N	E	336	Accept Risk	Nil
Loss 1 inc 6.6kV CB	N/A	N/A	0	Customer Risk	Nil
Loss 2 inc 6.6kV CB's	N/A	N/A	0	Customer Risk	Nil
Loss 1 feeder CB	N/A	N/A	0	Customer Risk	Nil
Loss 2 feeder CBs	N/A	N/A	0	Customer Risk	Nil
Loss >2 feeder CB's	N/A	N/A	0	Customer Risk	Nil
Loss 1 half switchboard	N/A	N/A	0	Customer Risk	Nil
Loss complete switchboard	N/A	N/A	0	Customer Risk	Nil
Control room fire	L	M	120	Accept Risk	Nil

FOUNDERS SUBSTATION

Customers affected by LOS: 2500

Main 33kV Supply: Nelson North B **Backup**: Nelson North A

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	8400	Contingency Plan+Insurance	Ref DRRP
Landslip/Movement	L	I	50	Accept Risk	Nil
Flood/Tsunami	M	I	100	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	N	I	10	Accept Risk	Nil
Aircraft crash	L	I	50	Accept Risk	Nil
Road/rail crash	N	I	10	Accept Risk	Nil
Trees	L	I	50	Accept Risk	Nil
Fire (outside source)	L	I	50	Accept Risk	Nil
Human Incident	L	I	50	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 pole/span	N/A	N/A	0	Accept Risk	Nil
Loss 2-3 poles/spans	N/A	N/A	0	Accept Risk	Nil
Loss 3-5 poles/spans	N/A	N/A	0	Accept Risk	Nil
Loss >5 poles/spans	N/A	N/A	0	Accept Risk	Nil
Loss river crossing span	N/A	N/A	0	Accept Risk	Nil
Loss major span	N/A	N/A	0	Accept Risk	Nil
Single point cable failure	M	I	100	Accept Risk	Nil
<100m cable damage	L	I	50	Accept Risk	Nil
0.1-1km cable damage	N	I	10	Accept Risk	Nil
>1km cable damage	N	I	10	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 12250

Substation Risk Index per Customer: 4.9

Substation: Founders

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	8400	Contingency Plan	Ref DRRP
Landslip/Movement	L	L	1200	Accept Risk	Nil
Flood/Tsunami	L	L	1200	Accept Risk	Nil
Coastal Inundation/Storm Surge	L	L	1200	Accept Risk	Nil
Extreme Weather	L	S	150	Accept Risk	Nil
Aircraft crash	L	L	1200	Accept Risk	Nil
Road/rail crash	N	M	60	Accept Risk	Nil
Trees	N	S	30	Accept Risk	Nil
Fire (outside source)	L	M	300	Accept Risk	Nil
Security/Vandalism	L	S	150	Accept Risk	Nil
Other - Bird Strike	N	I	10	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 inc 33kV CB	L	I	50	Accept Risk	Nil
Loss 2 inc 33kV CB's	N	M	60	Accept Risk	Nil
Loss 1 transformer	L	I	50	Accept Risk	Nil
Loss 2 transformers	N	E	840	Contingency Plan	Ref DRRP
Loss 1 33kV bus section	N	I	10	Accept Risk	Nil
Loss 2 33kV bus sections	N	M	60	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	50	Accept Risk	Nil
Loss 2 inc 11kV CB's	L	M	300	Accept Risk	Nil
Loss 1 feeder CB	L	I	50	Accept Risk	Nil
Loss 2 feeder CBs	N	S	30	Accept Risk	Nil
Loss >2 feeder CB's	N	M	60	Accept Risk	Nil
Loss 1 half switchboard	L	S	150	Accept Risk	Nil
Loss complete switchboard	L	E	4200	Contingency Plan	Ref DRRP
Control room fire	L	M	300	Accept Risk	Nil

ANNESBROOK SUBSTATION

Customers affected by LOS: 5500

Main 33kV Supply: Annesbrook | **Backup**: Railway Reserve

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	18480	Contingency Plan+Insurance	Ref DRRP
Landslip/Movement	L	I	110	Accept Risk	Nil
Flood/Tsunami	M	I	220	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	M	I	220	Accept Risk	Nil
Aircraft crash	L	I	110	Accept Risk	Nil
Road/rail crash	N	I	22	Accept Risk	Nil
Trees	L	I	110	Accept Risk	Nil
Fire (outside source)	L	I	110	Accept Risk	Nil
Human Incident	L	I	110	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 pole/span	L	I	110	Accept Risk	Nil
Loss 2-3 poles/spans	L	I	110	Accept Risk	Nil
Loss 3-5 poles/spans	L	I	110	Accept Risk	Nil
Loss >5 poles/spans	L	I	110	Accept Risk	Nil
Loss river crossing span	L	I	110	Accept Risk	Nil
Loss major span	L	I	110	Accept Risk	Nil
Single point cable failure	L	I	110	Accept Risk	Nil
<100m cable damage	L	I	110	Accept Risk	Nil
0.1-1km cable damage	N	I	22	Accept Risk	Nil
>1km cable damage	N	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 15576

Substation Risk Index per Customer: 2.832

Substation: Annesbrook

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	18480	Contingency Plan	Ref DRRP
Landslip/Movement	L	L	2640	Accept Risk	Nil
Flood/Tsunami	M	S	660	Accept Risk	Nil
Coastal Inundation/Storm Surge	L	M	660	Accept Risk	Nil
Extreme Weather	L	S	330	Accept Risk	Nil
Aircraft crash	N	L	528	Accept Risk	Nil
Road/rail crash	N	M	132	Accept Risk	Nil
Trees	N	L	528	Accept Risk	Nil
Fire (outside source)	L	M	660	Accept Risk	Nil
Security Vandalism	L	M	660	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 inc 33kV CB	L	I	110	Accept Risk	Nil
Loss 2 inc 33kV CB's	N	M	132	Accept Risk	Nil
Loss 1 transformer	L	I	110	Accept Risk	Nil
Loss 2 transformers	N	E	1848	Contingency Plan	Ref DRRP
Loss 1 33kV bus section	N	I	22	Accept Risk	Nil
Loss 2 33kV bus sections	N	M	132	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	110	Accept Risk	Nil
Loss 2 inc 11kV CB's	L	M	660	Accept Risk	Nil
Loss 1 feeder CB	L	I	110	Accept Risk	Nil
Loss 2 feeder CBs	L	S	330	Accept Risk	Nil
Loss >2 feeder CB's	N	M	132	Accept Risk	Nil
Loss 1 half switchboard	L	M	660	Accept Risk	Nil
Loss complete switchboard	N	E	1848	Contingency Plan	Ref DRRP
Control room fire	L	M	660	Accept Risk	Nil

SONGER STREET SUBSTATION

Customers affected by LOS: 5500

Main 33kV Supply: Songer St B | **Backup**: Railway Reserve

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	18480	Contingency Plan+Insurance	Ref DRRP
Landslip/Movement	L	I	110	Accept Risk	Nil
Flood/Tsunami	L	I	110	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	M	I	220	Accept Risk	Nil
Aircraft crash	L	I	110	Accept Risk	Nil
Road/rail crash	N	I	22	Accept Risk	Nil
Trees	N	I	22	Accept Risk	Nil
Fire (outside source)	N	I	22	Accept Risk	Nil
Human Incident	L	I	110	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 pole/span	N/A	N/A	0	Accept Risk	Nil
Loss 2-3 poles/spans	N/A	N/A	0	Accept Risk	Nil
Loss 3-5 poles/spans	N/A	N/A	0	Accept Risk	Nil
Loss >5 poles/spans	N/A	N/A	0	Accept Risk	Nil
Loss river crossing span	N/A	N/A	0	Accept Risk	Nil
Loss major span	N/A	N/A	0	Accept Risk	Nil
Single point cable failure	M	I	220	Accept Risk	Nil
<100m cable damage	L	I	110	Accept Risk	Nil
0.1-1km cable damage	N	I	22	Accept Risk	Nil
>1km cable damage	N	I	22	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 24816

Substation Risk Index per Customer: 4.512

Substation: Songer St

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	18480	Contingency Plan	Ref DRRP
Landslip/Movement	L	L	2640	Accept Risk	Nil
Flood/Tsunami	L	L	2640	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	L	S	330	Accept Risk	Nil
Aircraft crash	L	L	2640	Accept Risk	Nil
Road/rail crash	N	M	132	Accept Risk	Nil
Trees	N	S	66	Accept Risk	Nil
Fire (outside source)	L	M	660	Accept Risk	Nil
Security/Vandalism	L	S	330	Accept Risk	Nil
Other - Bird Strike	N	I	22	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 inc 33kV CB	L	I	110	Accept Risk	Nil
Loss 2 inc 33kV CB's	N	M	132	Accept Risk	Nil
Loss 1 transformer	L	I	110	Accept Risk	Nil
Loss 2 transformers	N	E	1848	Contingency Plan	Ref DRRP
Loss 1 33kV bus section	N	I	22	Accept Risk	Nil
Loss 2 33kV bus sections	N	M	132	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	110	Accept Risk	Nil
Loss 2 inc 11kV CB's	L	M	660	Accept Risk	Nil
Loss 1 feeder CB	L	I	110	Accept Risk	Nil
Loss 2 feeder CBs	L	S	330	Accept Risk	Nil
Loss >2 feeder CB's	N	M	132	Accept Risk	Nil
Loss 1 half switchboard	L	M	660	Accept Risk	Nil
Loss complete switchboard	L	E	9240	Contingency Plan	Ref DRRP
Control room fire	L	M	660	Accept Risk	Nil

RICHMOND SUBSTATION

Customers affected by LOS 5500

Main 33kV Supply Richmond Feeder **Backup** Railway Reserve

Substation Richmond

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	18480	Contingency Plan+Insurance	Ref DRRP
Landslip/Movement	L	I	110	Accept Risk	Nil
Flood/Tsunami	N	I	22	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	I	22	Accept Risk	Nil
Extreme Weather	N	I	22	Accept Risk	Nil
Aircraft crash	N	I	22	Accept Risk	Nil
Road/rail crash	N	I	22	Accept Risk	Nil
Trees	N	I	22	Accept Risk	Nil
Fire (outside source)	N	I	22	Accept Risk	Nil
Human Incident	N	I	22	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 pole/span	N/A	N/A	0	Accept Risk	Nil
Loss 2-3 poles/spans	N/A	N/A	0	Accept Risk	Nil
Loss 3-5 poles/spans	N/A	N/A	0	Accept Risk	Nil
Loss >5 poles/spans	N/A	N/A	0	Accept Risk	Nil
Loss river crossing span	N/A	N/A	0	Accept Risk	Nil
Loss major span	N/A	N/A	0	Accept Risk	Nil
Single point cable failure	M	I	220	Accept Risk	Nil
<100m cable damage	L	I	110	Accept Risk	Nil
0.1-1km cable damage	N	I	22	Accept Risk	Nil
>1km cable damage	N	I	22	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake 31438

Substation Risk Index per Customer 5.716

Non Equipment Incidents (Substation Richmond)

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	18480	Contingency Plan	Ref DRRP
Landslip/Movement	L	L	2640	Accept Risk	Nil
Flood/Tsunami	L	M	660	Accept Risk	Nil
Coastal Inundation/Storm Surge	L	M	660	Accept Risk	Nil
Extreme Weather	L	S	330	Accept Risk	Nil
Aircraft crash	N	L	528	Accept Risk	Nil
Road/rail crash	L	M	660	Accept Risk	Nil
Trees	N	N/A	0	Accept Risk	Nil
Fire (outside source)	L	S	330	Accept Risk	Nil
Security/Vandalism	L	S	330	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents (Substation Richmond)

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 inc 33kV CB	L	I	110	Accept Risk	Nil
Loss 2 inc 33kV CB's	N	L	528	Accept Risk	Nil
Loss 1 transformer	L	I	110	Accept Risk	Nil
Loss 2 transformers	L	E	9240	Accept Risk	Nil
Loss 1 33kV bus section	L	I	110	Accept Risk	Nil
Loss 2 33kV bus sections	N	L	528	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	110	Accept Risk	Nil
Loss 2 inc 11kV CB's	L	L	2640	Accept Risk	Nil
Loss 1 feeder CB	L	I	110	Accept Risk	Nil
Loss 2 feeder CBs	N	S	66	Accept Risk	Nil
Loss >2 feeder CB's	N	L	528	Accept Risk	Nil
Loss 1 half switchboard	L	M	660	Accept Risk	Nil
Loss complete switchboard	L	E	9240	Contingency Plan	Ref DRRP
Control room fire	L	M	660	Accept Risk	Nil

HOPE SUBSTATION

Customers affected by LOS 4500

Main 33kV Supply Hope 33kV **Backup** Railway Reserve

Substation Hope

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	15120	Contingency Plan+Insurance	Ref DRRP
Landslip/Movement	L	I	90	Accept Risk	Nil
Flood/Tsunami	M	I	180	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	M	I	180	Accept Risk	Nil
Aircraft crash	L	I	90	Accept Risk	Nil
Road/rail crash	N	I	18	Accept Risk	Nil
Trees	M	I	180	Accept Risk	Nil
Fire (outside source)	M	I	180	Accept Risk	Nil
Human Incident	L	I	90	Accept Risk	Nil
Other - Bird Strike	M	I	180	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 pole/span	L	I	90	Accept Risk	Nil
Loss 2-3 poles/spans	L	I	90	Accept Risk	Nil
Loss 3-5 poles/spans	L	I	90	Accept Risk	Nil
Loss >5 poles/spans	L	I	90	Accept Risk	Nil
Loss river crossing span	L	I	90	Accept Risk	Nil
Loss major span	L	I	90	Accept Risk	Nil
Single point cable failure	L	I	90	Accept Risk	Nil
<100m cable damage	L	I	90	Accept Risk	Nil
0.1-1km cable damage	N	I	18	Accept Risk	Nil
>1km cable damage	N	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake 18342

Substation Risk Index per Customer 4.076

Non Equipment Incidents (Substation Hope)

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	15120	Contingency Plan	Ref DRRP
Landslip/Movement	L	L	2160	Accept Risk	Nil
Flood/Tsunami	M	S	540	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	L	S	270	Accept Risk	Nil
Aircraft crash	N	L	432	Accept Risk	Nil
Road/rail crash	N	M	108	Accept Risk	Nil
Trees	N	L	432	Accept Risk	Nil
Fire (outside source)	L	M	540	Accept Risk	Nil
Security Vandalism	L	M	540	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents (Substation Hope)

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 inc 33kV CB	L	I	90	Accept Risk	Nil
Loss 2 inc 33kV CB's	N	M	108	Accept Risk	Nil
Loss 1 transformer	L	I	90	Accept Risk	Nil
Loss 2 transformers	N	E	1512	Contingency Plan	Ref DRRP
Loss 1 33kV bus section	N	I	18	Accept Risk	Nil
Loss 2 33kV bus sections	N	M	108	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	90	Accept Risk	Nil
Loss 2 inc 11kV CB's	L	M	540	Accept Risk	Nil
Loss 1 feeder CB	L	I	90	Accept Risk	Nil
Loss 2 feeder CBs	L	S	270	Accept Risk	Nil
Loss >2 feeder CB's	N	M	108	Accept Risk	Nil
Loss 1 half switchboard	L	S	270	Accept Risk	Nil
Loss complete switchboard	L	E	7560	Contingency Plan	Ref DRRP
Control room fire	L	M	540	Accept Risk	Nil

BRIGHTWATER SUBSTATION

Customers affected by LOS 2500

Main 33kV Supply Hope Feeder **Backup** Nil

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	8400	Contingency Plan+Insurance	Ref DRRP
Landslip/Movement	L	I	50	Accept Risk	Nil
Flood/Tsunami	M	I	100	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	M	I	100	Accept Risk	Nil
Aircraft crash	L	I	50	Accept Risk	Nil
Road/rail crash	N	I	10	Accept Risk	Nil
Trees	L	I	50	Accept Risk	Nil
Fire (outside source)	L	I	50	Accept Risk	Nil
Human Incident	L	I	50	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 pole/span	L	I	50	Accept Risk	Nil
Loss 2-3 poles/spans	L	I	50	Accept Risk	Nil
Loss 3-5 poles/spans	L	I	50	Accept Risk	Nil
Loss >5 poles/spans	L	I	50	Accept Risk	Nil
Loss river crossing span	L	I	50	Accept Risk	Nil
Loss major span	L	I	50	Accept Risk	Nil
Single point cable failure	L	I	50	Accept Risk	Nil
<100m cable damage	L	I	50	Accept Risk	Nil
0.1-1km cable damage	N	I	10	Accept Risk	Nil
>1km cable damage	N	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake 9260

Substation Risk Index per Customer 3.704

Substation Brightwater

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	L	2400	Contingency Plan	Ref DRRP
Landslip/Movement	L	L	1200	Accept Risk	Nil
Flood/Tsunami	L	M	300	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	L	S	150	Accept Risk	Nil
Aircraft crash	N	L	240	Accept Risk	Nil
Road/rail crash	N	M	60	Accept Risk	Nil
Trees	N	L	240	Accept Risk	Nil
Fire (outside source)	L	M	300	Accept Risk	Nil
Human Incident	L	S	150	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 inc 33kV CB	L	I	50	Accept Risk	Nil
Loss 2 inc 33kV CB's	N	M	60	Accept Risk	Nil
Loss 1 transformer	L	I	50	Accept Risk	Nil
Loss 2 transformers	N	M	60	Accept Risk	Nil
Loss 1 33kV bus section	N	S	30	Accept Risk	Nil
Loss 2 33kV bus sections	N	N/A	0	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	50	Accept Risk	Nil
Loss 2 inc 11kV CB's	L	M	300	Accept Risk	Nil
Loss 1 feeder CB	L	I	50	Accept Risk	Nil
Loss 2 feeder CBs	L	S	150	Accept Risk	Nil
Loss >2 feeder CB's	L	M	300	Accept Risk	Nil
Loss 1 half switchboard	L	S	150	Accept Risk	Nil
Loss complete switchboard	L	E	4200	Contingency Plan	Ref DRRP
Control room fire	L	M	300	Accept Risk	Nil

MAPUA SUBSTATION

Customers affected by LOS 2000

Main 33kV Supply Railway Reserve **Backup** Nil

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	6720	Contingency Plan+Insurance	Ref DRRP
Landslip/Movement	M	L	1920	Accept Risk	Nil
Flood/Tsunami	M	M	480	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	M	S	240	Accept Risk	Nil
Aircraft crash	L	M	240	Accept Risk	Nil
Road/rail crash	L	S	120	Accept Risk	Nil
Trees	M	S	240	Accept Risk	Nil
Fire (outside source)	L	S	120	Accept Risk	Nil
Human Incident	L	S	120	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 pole/span	L	S	120	Accept Risk	Nil
Loss 2-3 poles/spans	M	L	1920	Accept Risk	Nil
Loss 3-5 poles/spans	L	L	960	Accept Risk	Nil
Loss >5 poles/spans	L	E	3360	Accept Risk	Nil
Loss river crossing span	L	M	240	Accept Risk	Nil
Loss major span	L	M	240	Accept Risk	Nil
Single point cable failure	M	M	480	Accept Risk	Nil
<100m cable damage	N	M	48	Contingency Plan	Ref DRRP
0.1-1km cable damage	N	M	48	Contingency Plan	Ref DRRP
>1km cable damage	N	M	48	Contingency Plan	Ref DRRP

Total Substation Risks Index excluding Earthquake 19896

Substation Risk Index per Customer 7.9584

Substation Mapua

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	6720	Contingency Plan	Ref DRRP
Landslip/Movement	L	L	960	Accept Risk	Nil
Flood/Tsunami	L	M	240	Accept Risk	Nil
Coastal Inundation/Storm Surge	L	M	240	Accept Risk	Nil
Extreme Weather	N	S	24	Accept Risk	Nil
Aircraft crash	N	E	672	Accept Risk	Nil
Road/rail crash	N	M	48	Accept Risk	Nil
Trees	N	N/A	0	Accept Risk	Nil
Fire (outside source)	L	L	960	Accept Risk	Nil
Human Incident	L	S	120	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 inc 33kV CB	L	L	960	Accept Risk	Nil
Loss 2 inc 33kV CB's	N	S	24	Accept Risk	Nil
Loss 1 transformer	M	I	80	Accept Risk	Nil
Loss 2 transformers	L	E	3360	Contingency Plan	Ref DRRP
Loss 1 33kV bus section	N	S	24	Accept Risk	Nil
Loss 2 33kV bus sections	N	S	24	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	40	Accept Risk	Nil
Loss 2 inc 11kV CB's	L	S	120	Accept Risk	Nil
Loss 1 feeder CB	L	S	120	Accept Risk	Nil
Loss 2 feeder CBs	N	M	48	Accept Risk	Nil
Loss >2 feeder CB's	N	M	48	Accept Risk	Nil
Loss 1 half switchboard	N	M	48	Accept Risk	Nil
Loss complete switchboard	N	E	672	Contingency Plan	Ref DRRP
Control room fire	L	S	120	Accept Risk	Nil

LOWER QUEEN ST SUBSTATION

Customers affected by LOS 1000

Main 33kV Supply Suffolk Road 33kV **Backup** Nil

Substation Lower Queen St

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	3360	Contingency Plan+Insurance	Ref DRRP
Landslip/Movement	L	I	480	Accept Risk	Nil
Flood/Tsunami	M	M	240	Accept Risk	Nil
Coastal Inundation/Storm Surge	L	M	120	Accept Risk	Nil
Extreme Weather	M	S	120	Accept Risk	Nil
Aircraft crash	L	M	120	Accept Risk	Nil
Road/rail crash	N	S	12	Accept Risk	Nil
Trees	M	S	120	Accept Risk	Nil
Fire (outside source)	L	S	60	Accept Risk	Nil
Human Incident	L	S	60	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 pole/span	L	S	60	Accept Risk	Nil
Loss 2-3 poles/spans	L	M	120	Accept Risk	Nil
Loss 3-5 poles/spans	L	L	480	Accept Risk	Nil
Loss >5 poles/spans	L	L	480	Accept Risk	Nil
Loss river crossing span	N/A	S	0	Accept Risk	Nil
Loss major span	N	S	12	Accept Risk	Nil
Single point cable failure	L	M	120	Accept Risk	Nil
<100m cable damage	N	L	96	Accept Risk	Nil
0.1-1km cable damage	N	L	96	Accept Risk	Nil
>1km cable damage	N	L	96	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake 5880

Substation Risk Index per Customer 5.88

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	3360	Contingency Plan	Ref DRRP
Landslip/Movement	L	L	480	Accept Risk	Nil
Flood/Tsunami	L	M	120	Accept Risk	Nil
Coastal Inundation/Storm Surge	L	M	120	Accept Risk	Nil
Extreme Weather	L	S	60	Accept Risk	Nil
Aircraft crash	L	L	480	Accept Risk	Nil
Road/rail crash	N	M	24	Accept Risk	Nil
Trees	N	N/A	0	Accept Risk	Nil
Fire (outside source)	L	L	480	Accept Risk	Nil
Security/Vandalism	L	S	60	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 inc 33kV CB	L	I	20	Accept Risk	Nil
Loss 2 inc 33kV CB's	N	L	96	Accept Risk	Nil
Loss 1 transformer	L	I	20	Accept Risk	Nil
Loss 2 transformers	N	E	336	Contingency Plan	Ref DRRP
Loss 1 33kV bus section	N	I	4	Accept Risk	Nil
Loss 2 33kV bus sections	N	M	24	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	20	Accept Risk	Nil
Loss 2 inc 11kV CB's	L	M	120	Accept Risk	Nil
Loss 1 feeder CB	L	I	20	Accept Risk	Nil
Loss 2 feeder CBs	N	M	24	Accept Risk	Nil
Loss >2 feeder CB's	N	M	24	Accept Risk	Nil
Loss 1 half switchboard	L	S	60	Accept Risk	Nil
Loss complete switchboard	N	E	336	Contingency Plan	Ref DRRP
Control room fire	L	S	60	Accept Risk	Nil

EVES VALLEY SUBSTATION

Customers affected by LOS 1000

Main 33kV Supply Railway Reserve **Backup** Hope

Substation Eves Valley

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	L	960	Contingency Plan+Insurance	Ref DRRP
Landslip/Movement	L	I	480	Accept Risk	Nil
Flood/Tsunami	M	M	240	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	M	S	120	Accept Risk	Nil
Aircraft crash	L	M	120	Accept Risk	Nil
Road/rail crash	N	S	12	Accept Risk	Nil
Trees	L	S	60	Accept Risk	Nil
Fire (outside source)	L	S	60	Accept Risk	Nil
Human Incident	L	S	60	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 pole/span	L	S	60	Accept Risk	Nil
Loss 2-3 poles/spans	L	M	120	Accept Risk	Nil
Loss 3-5 poles/spans	L	L	480	Accept Risk	Nil
Loss >5 poles/spans	L	L	480	Accept Risk	Nil
Loss river crossing span	L	M	120	Accept Risk	Nil
Loss major span	L	M	120	Accept Risk	Nil
Single point cable failure	L	I	20	Accept Risk	Nil
<100m cable damage	L	I	20	Accept Risk	Nil
0.1-1km cable damage	N	I	4	Accept Risk	Nil
>1km cable damage	N	I	4	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake 4636

Substation Risk Index per Customer 4.636

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	3360	Contingency Plan	Ref DRRP
Landslip/Movement	L	L	480	Accept Risk	Nil
Flood/Tsunami	L	M	120	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	L	S	60	Accept Risk	Nil
Aircraft crash	N	L	96	Accept Risk	Nil
Road/rail crash	N	M	24	Accept Risk	Nil
Trees	N	N/A	0	Accept Risk	Nil
Fire (outside source)	L	L	480	Accept Risk	Nil
Security/Vandalism	L	S	60	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 inc 33kV CB	L	S	60	Accept Risk	Nil
Loss 2 inc 33kV CB's	N	N/A	0	Accept Risk	Nil
Loss 1 transformer	L	I	20	Accept Risk	Nil
Loss 2 transformers	N	E	336	Contingency Plan	Ref DRRP
Loss 1 33kV bus section	L	S	60	Accept Risk	Nil
Loss 2 33kV bus sections	N	N/A	0	Accept Risk	Nil
Loss 1 inc 11kV CB	L	S	60	Accept Risk	Nil
Loss 2 inc 11kV CB's	N	N/A	0	Accept Risk	Nil
Loss 1 feeder CB	L	S	60	Accept Risk	Nil
Loss 2 feeder CBs	N	N/A	0	Accept Risk	Nil
Loss >2 feeder CB's	N	N/A	0	Accept Risk	Nil
Loss 1 half switchboard	L	I	20	Accept Risk	Nil
Loss complete switchboard	L	S	60	Accept Risk	Nil
Control room fire	L	S	60	Accept Risk	Nil

MOTUEKA SUBSTATION

Customers affected by LOS: 7500

Main 66kV Supply: Stoke-Upper Takaka 66kV | **Backup**: Stoke-Cobb 66kV

Substation: Motueka

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	25200	Contingency Plan+Insurance	Ref DRRP
Landslip/Movement	L	I	150	Accept Risk	Nil
Flood/Tsunami	L	I	150	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	M	I	300	Accept Risk	Nil
Aircraft crash	L	I	150	Accept Risk	Nil
Road/rail crash	L	I	150	Accept Risk	Nil
Trees	L	I	150	Accept Risk	Nil
Fire (outside source)	L	I	150	Accept Risk	Nil
Human Incident	L	I	150	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 pole/span	L	I	150	Accept Risk	Nil
Loss 2-3 poles/spans	L	I	150	Accept Risk	Nil
Loss 3-5 poles/spans	L	I	150	Accept Risk	Nil
Loss >5 poles/spans	L	I	150	Accept Risk	Nil
Loss river crossing span	L	I	150	Accept Risk	Nil
Loss major span	L	I	150	Accept Risk	Nil
Single point cable failure	N/A	N/A	0	Accept Risk	Nil
<100m cable damage	N/A	N/A	0	Accept Risk	Nil
0.1-1km cable damage	N/A	N/A	0	Accept Risk	Nil
>1km cable damage	N/A	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 30690

Substation Risk Index per Customer: 4.092

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	25200	Contingency Plan	Ref DRRP
Landslip/Movement	L	L	3600	Accept Risk	Nil
Flood/Tsunami	M	S	900	Accept Risk	Nil
Coastal Inundation/Storm Surge	N	N/A	0	Accept Risk	Nil
Extreme Weather	L	S	450	Accept Risk	Nil
Aircraft crash	N	L	720	Accept Risk	Nil
Road/rail crash	N	M	180	Accept Risk	Nil
Trees	N	L	720	Accept Risk	Nil
Fire (outside source)	L	M	900	Accept Risk	Nil
Security Vandalism	L	M	900	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 inc 66kV CB	L	I	150	Accept Risk	Nil
Loss 2 inc 66kV CB's	N	L	720	Accept Risk	Nil
Loss 1 transformer	L	I	150	Accept Risk	Nil
Loss 2 transformers	N	E	2520	Contingency Plan	Ref DRRP
Loss 1 66kV bus section	N	I	30	Accept Risk	Nil
Loss 2 66kV bus sections	N	L	720	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	150	Accept Risk	Nil
Loss 2 inc 11kV CB's	L	M	900	Accept Risk	Nil
Loss 1 feeder CB	L	I	150	Accept Risk	Nil
Loss 2 feeder CBs	L	S	450	Accept Risk	Nil
Loss >2 feeder CB's	N	M	180	Accept Risk	Nil
Loss 1 half switchboard	L	S	450	Accept Risk	Nil
Loss complete switchboard	L	E	12600	Contingency Plan	Ref DRRP
Control room fire	L	M	900	Accept Risk	Nil

WAKAPUAKA SUBSTATION

Customers affected by LOS: 1400

Main 33kV Supply: Nelson North B Feeder | **Backup**: Nil

Substation: Wakapuaka

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	4704	Contingency Plan+Insurance	Ref DRRP
Landslip/Movement	M	M	336	Accept Risk	Nil
Flood/Tsunami	L	M	168	Accept Risk	Nil
Coastal Inundation/Storm Surge	L	S	84	Accept Risk	Nil
Extreme Weather	M	S	168	Accept Risk	Nil
Aircraft crash	L	M	168	Accept Risk	Nil
Road/rail crash	L	S	84	Accept Risk	Nil
Trees	M	S	168	Accept Risk	Nil
Fire (outside source)	M	L	1344	Contingency Plan	Ref DRRP
Human Incident	L	I	28	Accept Risk	Nil
Other - Bird Strike	M	S	168	Accept Risk	Nil

Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 pole/span	M	M	336	Accept Risk	Nil
Loss 2-3 poles/spans	M	L	1344	Contingency Plan	Ref DRRP
Loss 3-5 poles/spans	L	L	672	Accept Risk	Nil
Loss >5 poles/spans	L	E	2352	Contingency Plan	Ref DRRP
Loss river crossing span	L	M	168	Accept Risk	Nil
Loss major span	L	M	168	Accept Risk	Nil
Single point cable failure	L	I	28	Accept Risk	Nil
<100m cable damage	L	N/A	0	Accept Risk	Nil
0.1-1km cable damage	N	N/A	0	Accept Risk	Nil
>1km cable damage	N	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 12975.2

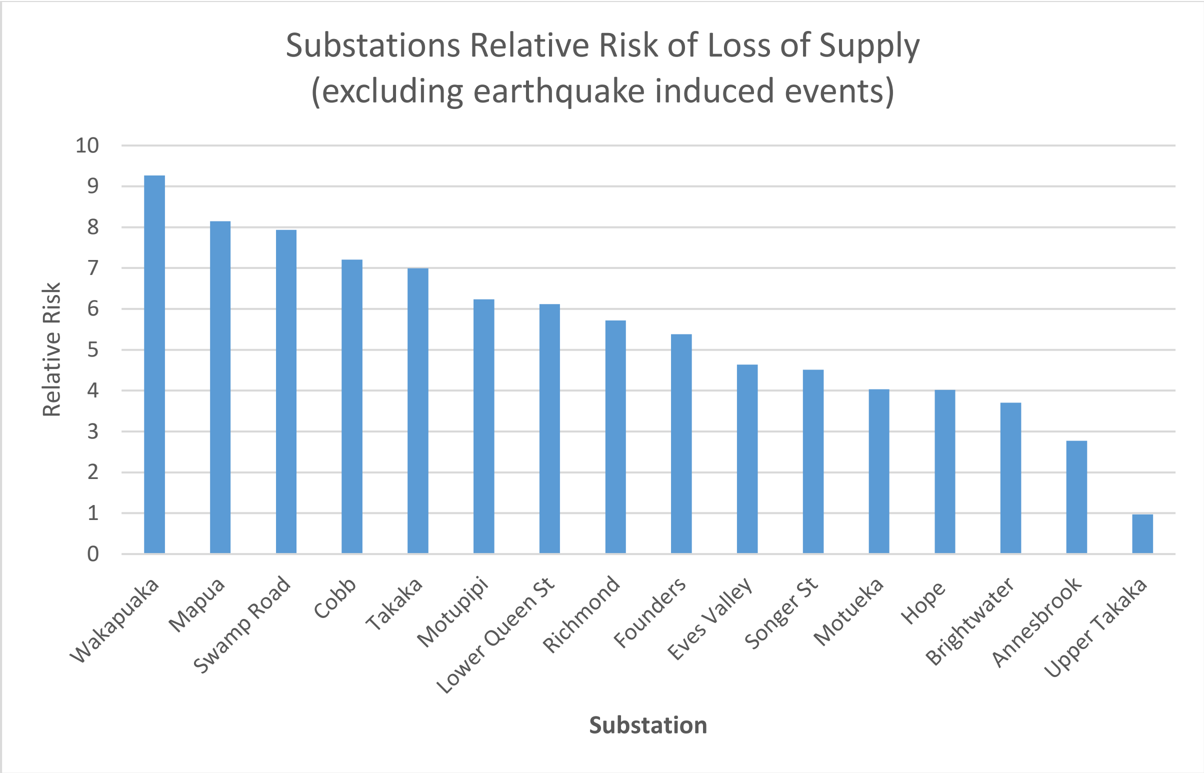
Substation Risk Index per Customer: 9.268

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Earthquake	M	E	4704	Contingency Plan	Ref DRRP
Landslip/Movement	N	L	134.4	Accept Risk	Nil
Flood/Tsunami	M	M	336	Accept Risk	Nil
Coastal Inundation/Storm Surge	M	S	168	Accept Risk	Nil
Extreme Weather	L	S	84	Accept Risk	Nil
Aircraft crash	N	L	134.4	Accept Risk	Nil
Road/rail crash	L	M	168	Accept Risk	Nil
Trees	N	S	16.8	Accept Risk	Nil
Fire (outside source)	L	S	84	Accept Risk	Nil
Security Vandalism	L	S	84	Accept Risk	Nil
Other - Bird Strike	N	N/A	0	Accept Risk	Nil

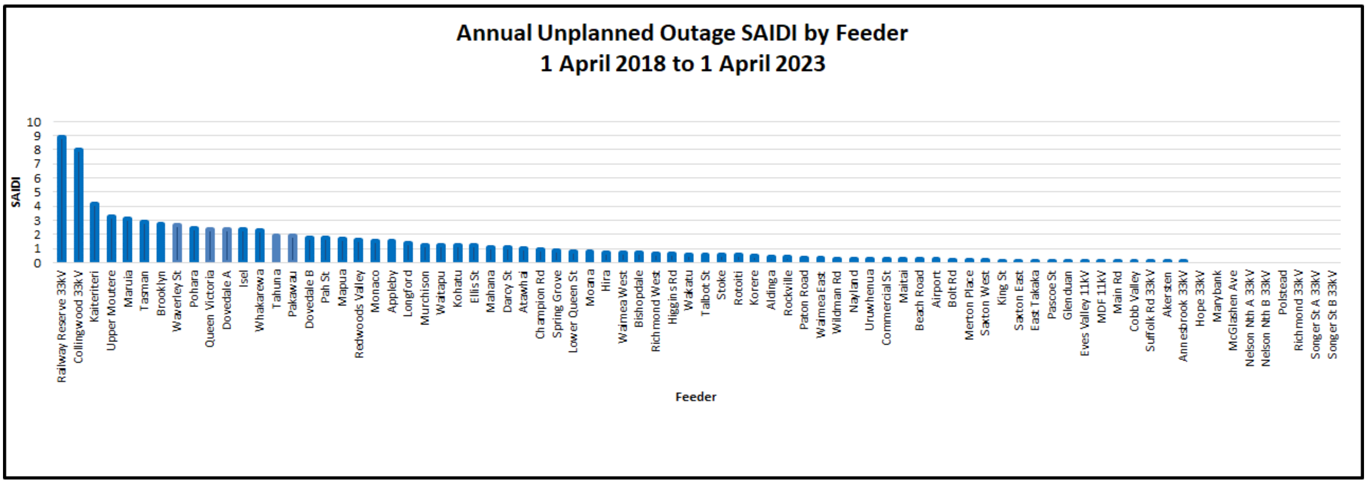
Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment Action
Loss 1 inc 33kV CB	L	L	672	Accept Risk	Nil
Loss 2 inc 33kV CB's	N	S	16.8	Accept Risk	Nil
Loss 1 transformer	M	I	56	Accept Risk	Nil
Loss 2 transformers	L	E	2352	Contingency Plan	Ref DRRP
Loss 1 33kV bus section	N	S	16.8	Accept Risk	Nil
Loss 2 33kV bus sections	N	S	16.8	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	28	Accept Risk	Nil
Loss 2 inc 11kV CB's	L	S	84	Accept Risk	Nil
Loss 1 feeder CB	L	S	84	Accept Risk	Nil
Loss 2 feeder CBs	N	M	33.6	Accept Risk	Nil
Loss >2 feeder CB's	N	M	33.6	Accept Risk	Nil
Loss 1 half switchboard	N	M	33.6	Accept Risk	Nil
Loss complete switchboard	N	E	470.4	Contingency Plan	Ref DRRP
Control room fire	L	S	84	Accept Risk	Nil


Substations Relative Risk of Loss of Supply
(excluding earthquake induced events)
Relative Risk
10
9
8
7
6
5
4
3
2
1
0
Wakapuaka
Mapua
Swamp Road
Cobb
Takaka
Motupipi
Lower Queen St
Richmond
Founders
Eves Valley
Songer St
Motueka
Hope
Brightwater
Annesbrook
Upper Takaka
Substation

APPENDIX J

FEEDER RELIABILITY ANALYSIS



APPENDIX K

CONSUMER SURVEY 2022

Network Tasman Ltd

SIL Research

| 2022 Consumer Survey

December 2022

SIL RESEARCH
Strategy | Insights | Leverage

networktasman
Your consumer-owned electricity distributor

Contact: Dr Virgil Troy 06 834 1996 or virgiltroy@silresearch.co.nz

CONTENTS

EXECUTIVE SUMMARY

The purpose of this research was to consultatively engage with Network Tasman's consumers to determine levels of satisfaction with, and perceptions of, Network Tasman's services and deliverables. Data was collected using posted survey forms and telephone interviews, with a small number of online community surveys, between October and November 2022. A total of n=400 surveys were used in the final analysis. The key findings were as follows:

1 Core findings: In 2022, awareness of Network Tasman increased; 44% of respondents recalled Network Tasman as the local faults organisation (30% in 2020), and 71% named Network Tasman as their lines company (58%).

- Satisfaction with Network Tasman's overall performance remained high in 2022, with 93% of respondents providing satisfaction ratings 7 out of 10 and above (8.55 out of 10).
- *Continuity* (9.11 out of 10) and *Quality* (8.99 out of 10) of power supply continued to be the top-rated deliverables. However, the two lowest rated deliverables showed material declines in 2022 compared to 2020: *Communication* (7.34) and *Price* (7.18).
- Despite some declines, Network Tasman's performance scores were significantly higher than the industry average for all performance-related measures.
- Overall, Network Tasman ownership awareness has shown good improvement since 2018 (41%), peaking at 61% in 2022.
- The proportion of respondents reporting 'no power cuts' (39%) in 2022 was slightly down compared to 2020 (45%). More respondents reported a power cut in 2022; with increases observed for reports of 1-2 power cuts (+10%).

2 Sustainability and energy use: Energy efficiency (7.49), energy prices (6.17) and cost of living (6.12) were the top-rated factors influencing respondents' energy use.

- A positive relationship was observed between concern about greater energy consumption and actual behaviour, including tracking energy use via app/website, purchasing energy efficient appliances, switching to energy efficient light bulbs, and reducing energy use for heating.
- 84% of respondents reported they had already installed energy efficient light bulbs, 70% reported reducing energy for heating/lighting, and half of respondents (55%) had already purchased energy efficient appliances.
- Energy tracking systems were least likely to be used already (34%); and just under half of respondents (46%) were unlikely to use these in the future.
- The potential uptake of solar panels was substantial in 2022. Over half of respondents had either invested, or were likely to invest, in solar power (56%).
- Fewer respondents (36%) reported owning or considering electric vehicles, or house batteries (37%).

3 **Communication and community engagement:** 29% of respondents could recall some recent advertising, media or publicity about Network Tasman (78% reported positive impressions of Network Tasman recalled communication); this communication recall has been stable over time.

- Awareness of safety messages declined since 2018; however, 6-in-10 respondents (61%) were still aware of these messages in 2022.
- Email (57%) was by far the most preferred method of Network Tasman communicating information to consumers.
- At the same time, there was a significant shift in how respondents preferred searching for fault information in 2022. Website (49%, up from 27% in 2020) and smartphone app (23%, up from 12% in 2020) became the two leading options – in preference to previously popular phone contact.

Brand awareness	Continuity	Quality
% recall name / fault organisation	average score	average score
2022: 71% / 44%	2022: 9.11	2022: 8.99
2020: 58% / 30%	2020: 9.32	2020: 9.14
2022 NZB: 53% / n/a	2022 NZB: 7.91	2022 NZB: 7.85
Restoration	**Accessibility**	**Communication**
average score	average score	average score
2022: 8.45	2022: 8.15	2022: 7.34
2020: 8.73	2020: 8.45	2020: 7.85
2022 NZB: 7.53	2022 NZB: 7.04	2022 NZB: 6.50
Price	**Zero power cuts**	**Overall performance**
average score	% recall	average score
2022: 7.18	2022: 39%	2022: 8.55
2020: 8.07	2020: 45%	2020: 8.74
2022 NZB: 5.37	Anecdotal benchmarking: 37%	2022 NZB: 7.32

METHODOLOGY

BACKGROUND AND OBJECTIVES

The purpose of this research was to consultatively engage with Network Tasman's consumers to determine levels of satisfaction with, and perceptions of, Network Tasman's services and deliverables. This project incorporated a unique opportunity to understand consumers' broader perceptions and sentiments on emerging technologies and sustainability.

Network Tasman Limited (NTL) operates the electricity distribution network in the wider Nelson and Tasman areas, distributing power to more than 42,200 consumer connections in an area of 10,800 km^2 in the north-western corner of the South Island.

SIL Research, together with NTL, developed a best practice questionnaire and included questions from 2014-2020 surveys for comparison.

A new set of questions was introduced in 2022; these questions related to sustainability and NTL's roles in this area, and general consumer sentiment toward electricity consumption.

PROJECT SPECIFICS

SIL used an updated multi-layered random sampling technique to ensure a proportional spread of consumers by area for commercial and residential connections.

DATA COLLECTION

Fieldwork was conducted between 3 October and 20 November 2022. The mixed-method approach included:

(1) Postal survey. 2,000 survey forms were delivered to randomly selected households in the Nelson-Tasman area. All postal survey forms included a freepost return address and a link (with QR code) for respondents who preferred completing the survey online.

(2) Telephone survey. Respondents were randomly selected from the publicly available telephone directories within the Nelson-Tasman area for a computer-assisted telephone interview.

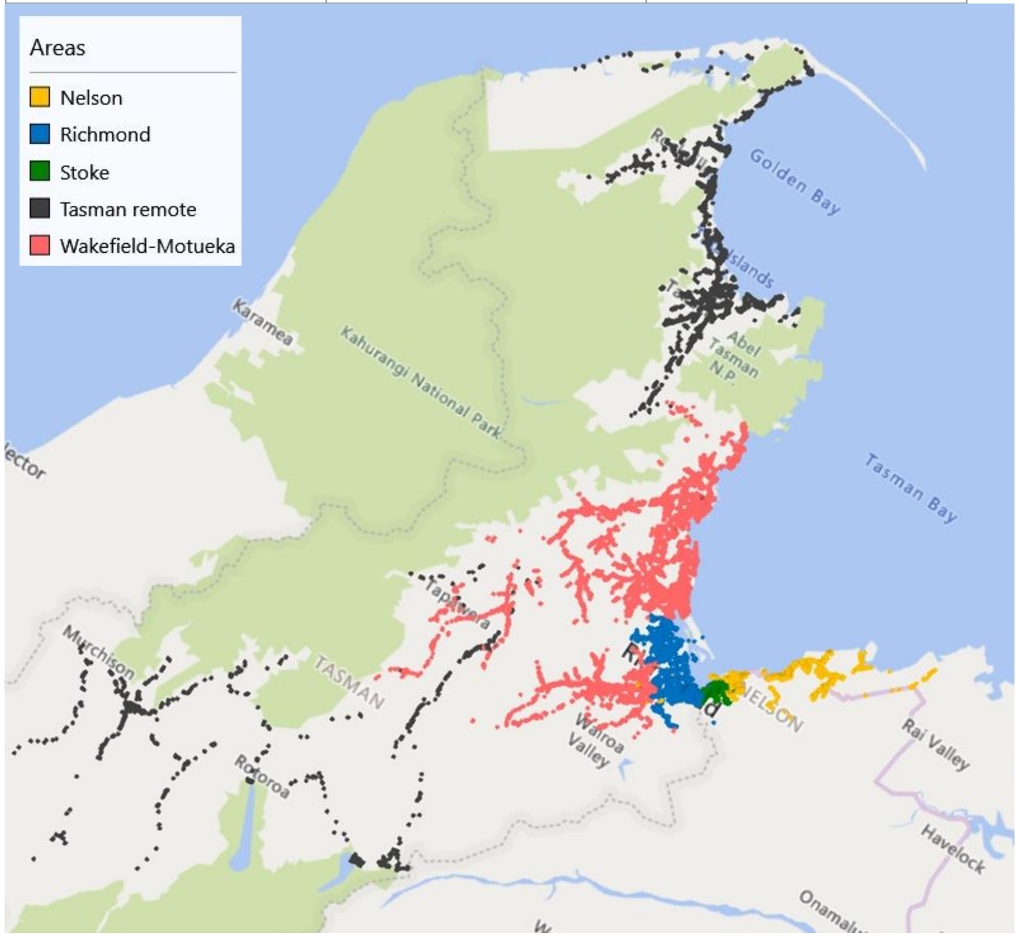
(3) Social media (available via SIL Research social media platforms such as Facebook/Instagram). The invitation advertisement was randomly promoted within the Nelson-Tasman area.

DATA ANALYSIS

A total of n=400 surveys were used in the final analysis (n=36 commercial and n=364 residential). Sample distribution by area can be found in the table below (and graphically presented in the provided regional map).

Table 1 Responses by aggregated area and approximate graphical area locations on the map

	Number of responses / %	Approximate % ICP
Nelson	109 / 27%	20%
Stoke	66 / 17%	17%
Richmond	66 / 17%	19%
Wakefield-Motueka	131 / 33%	34%
Tasman remote	28 / 7%	10%
Total	400	100%



Data was analysed using a variety of statistical tests. Additional statistical variance control tests were conducted between survey years, consumer segments, areas, age, and rural vs. urban locations. Where any statistically significant differences were identified, they have been mentioned in the findings.

Statistical weighting was initially applied to compensate for the age distribution. These results were then compared against non-weighted data. This analysis did not yield any significant differences for the brand and core questions. Few results varied by age, and the collected sample was sufficient to identify these differences. Therefore, the main brand and core results are reported unweighted (consistent with historical results). Questions related to residential consumers' perceptions about communications, sustainability and emerging technologies showed greater variation by age. These results were statistically weighted to reflect the age group proportions as determined by the Statistics New Zealand Census 2018 (also consistent with historical results). Weighting the results by age and gender ensures that the sample accurately represents the population being studied, and that the results are not skewed by an overrepresentation of one particular age or gender group (for example, consumers aged over 65 are generally less likely to adopt emerging technologies compared to younger consumers).

Overall, the total results (n=400) are reported at the 95% confidence level within a -/+5% maximum margin of error.

All open-ended responses were categorised and reported as key themes/topics; totals in these charts may exceed 100% owing to multiple responses for each respondent.

BENCHMARKING

SIL Research conducts a representative National survey among consumers of Electricity Lines Businesses to establish a series of benchmarks across a range of service measures. This allows NTL to compare their survey results against a national average (excludes Auckland, Wellington, Christchurch and Dunedin). The National survey data is collected throughout the year so that annual results can be presented without seasonal bias. The benchmarking results in this report are based on n=400 responses collected during 2022.

ENVIRONMENTAL FACTORS

When reading this report, it is important to note that factors such as the timing of unusual or one-off events can affect the ratings that consumers give, particularly if they occur close to the time when the survey data is being gathered. Factors that may have influenced consumer perceptions of Network Tasman performance include:

1. There have been more planned outages in recent years as part of a major project to replace aging assets on the NTL network. This may affect consumers' recall of outages and overall satisfaction with core performance deliverables, such as continuity, quality, and restoration. Consequently, an increase in the number of power outages may also raise brand awareness among consumers.

2. The August 2022 storm had a widespread impact, causing severe flooding and landslides. This weather event resulted in several major outages on the NTL network which occurred shortly before the survey was conducted, and may have influenced the sentiment of consumers.

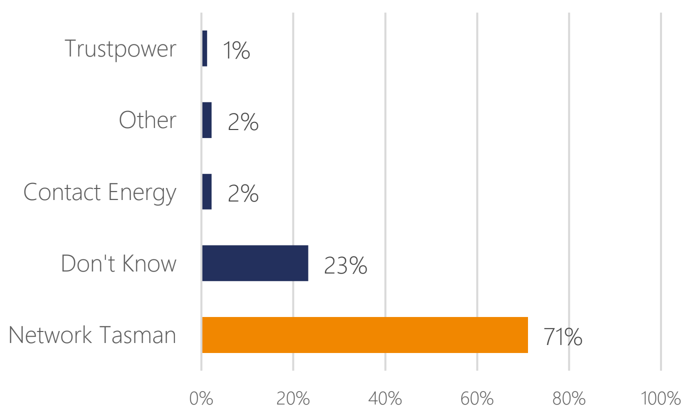
3. Inflationary pressure has continued to increase in the wake of the two-year Covid-19 pandemic, driven mainly by global oil prices and ongoing supply disruptions. This has led to a higher cost of living for consumers, making them more vulnerable to various household expenses, including their electricity bills.

BRAND SURVEY

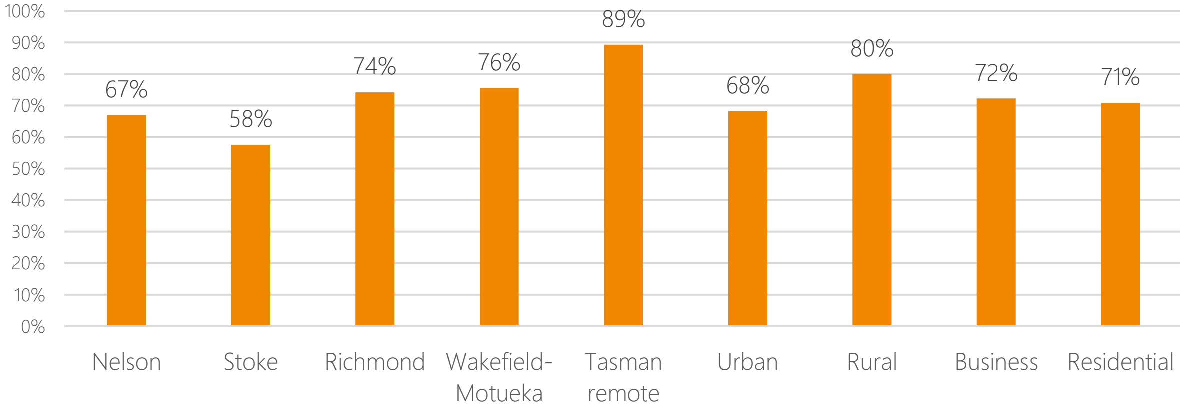
Name of lines company (unprompted name recall).

All respondents were asked "*What's the name of the company that owns and runs the region's electricity power lines*?"

Lines company recall in 2022 (aggregated)

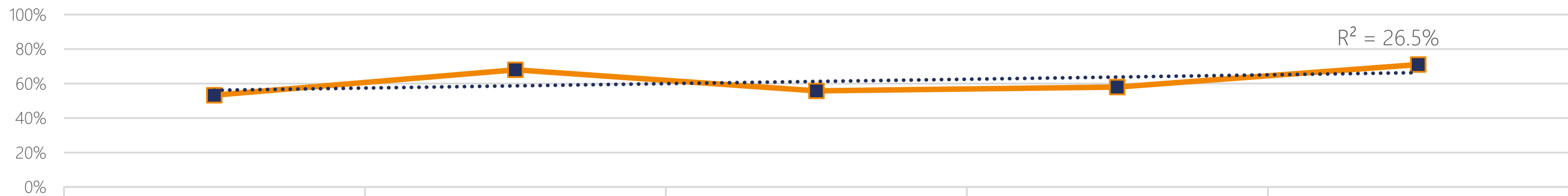


% NTL mentioned by area and segment in 2022



- In 2022, 7-in-10 respondents (71%) named Network Tasman as the company that owns and runs the region's electricity power lines – a new peak in awareness.
- The 2022 result was a significant improvement over 2020 (58%) and 2018 (56%), but similar to 2016 recall (68%).
- Compared to fault organisation recall, awareness of NTL as the lines company in 2022 was generally more consistent across different respondent segments and locations. However, rural (80%) and Tasman remote (89%) respondents were still more likely to correctly name Network Tasman compared to those from more urban locations.

% NTL mentioned by year

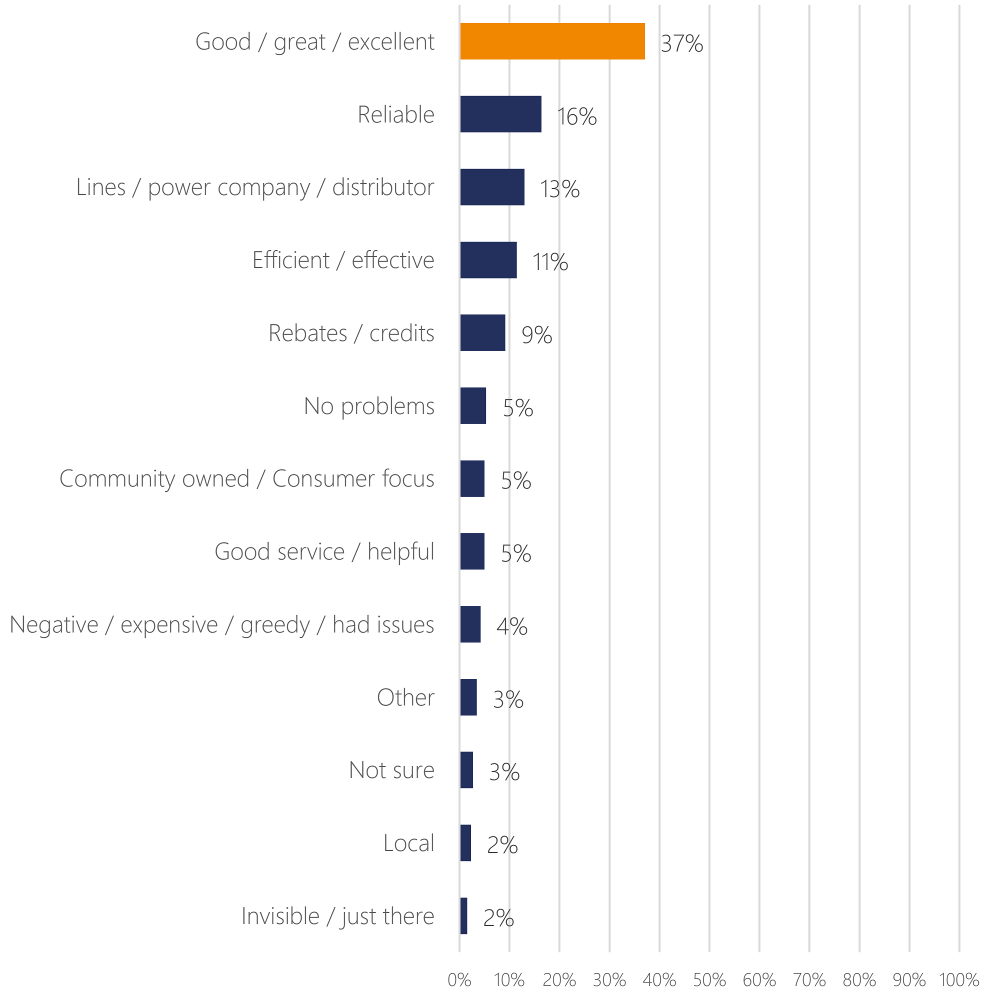


	2014	2016	2018	2020	2022
Network Tasman	53%	68%	56%	58%	71%

BRAND SURVEY

Brand perceptions.

All respondents were asked "*What words would you use to describe Network Tasman Limited?*" (open-ended comments aggregated into categories).

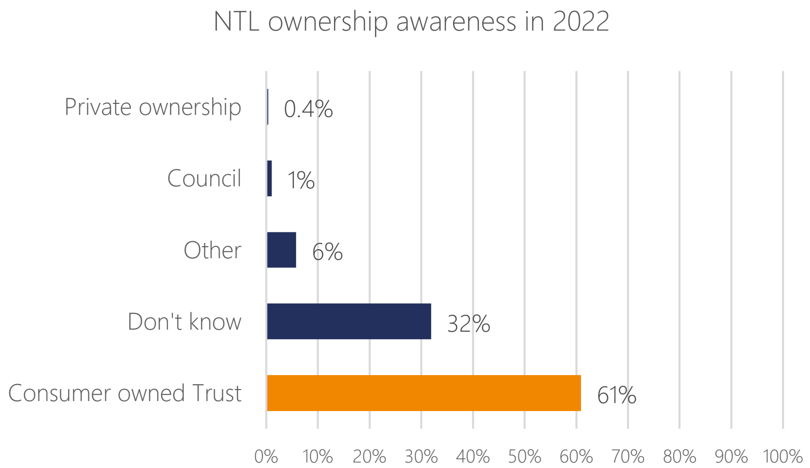


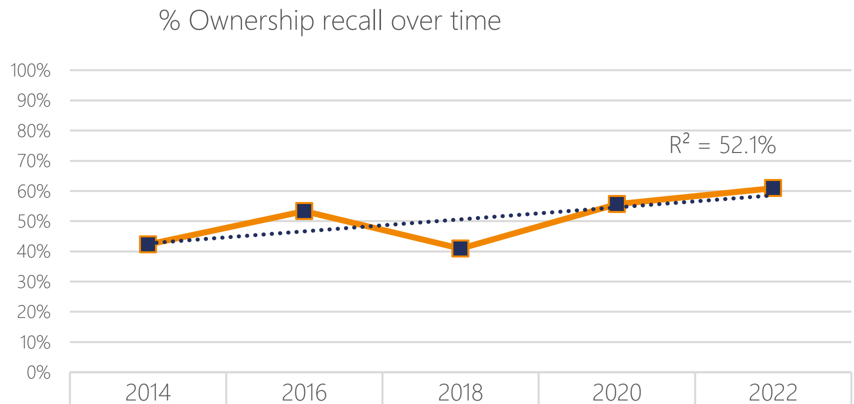
- Two-thirds of respondents (66%) provided a verbatim response describing Network Tasman.
- 96% of the comments received were positive or neutral, while only 4% reported a negative experience.
- Most typically, 37% of these respondents described Network Tasman as an '*Excellent/good company*', similar to 38% in 2020.
- 16% referred to Network Tasman as being '*Reliable*', and further 11% as '*Efficient / effective*'.
- Overall results showed a generally positive brand perception, consistent with 2018-2020 results.

BRAND SURVEY

Network Tasman ownership awareness.

Respondents indicating awareness of Network Tasman were asked "*Who owns Network Tasman Limited*?"





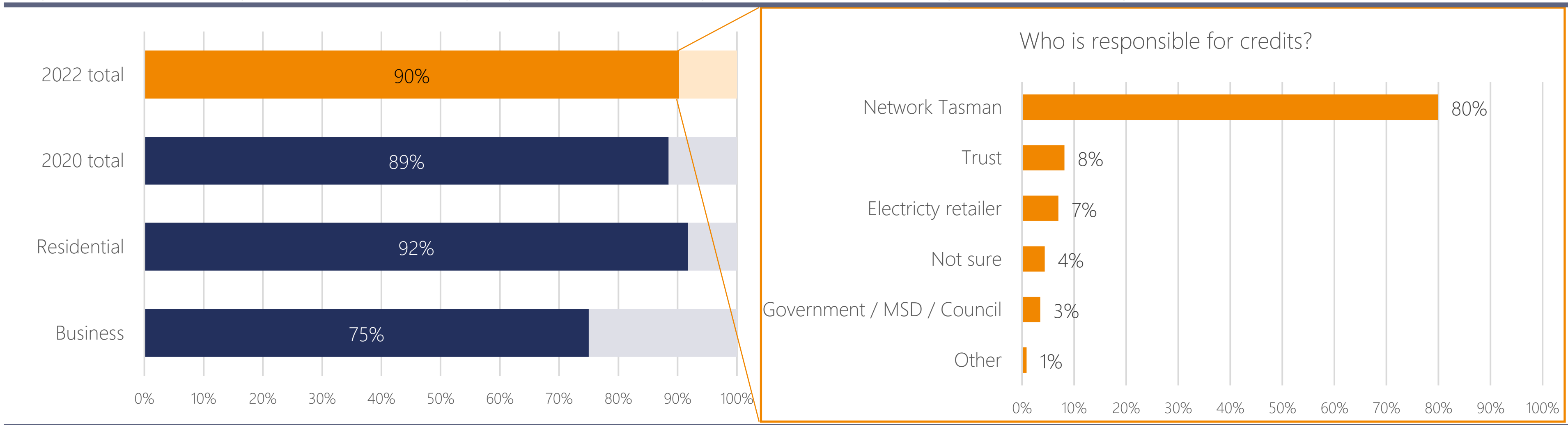
	2014	2016	2018	2020	2022
Consumer owned Trust	42%	53%	41%	56%	61%

- Overall NTL ownership awareness has shown good improvement since 2018, peaking at 61% in 2022.
- Residential respondents (63%) were more likely than businesses (43%) to identify Trust ownership. No significant differences were observed by respondents' location.
- Nevertheless, one-third of respondents (32%) remained unsure about NTL ownership (down from 38% in 2020).

BRAND SURVEY

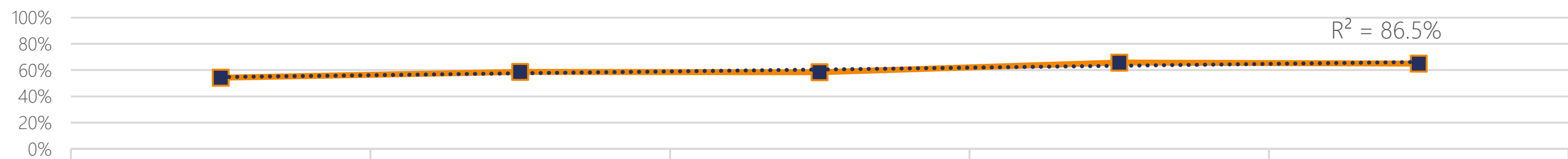
Rebates and discounts.

All respondents were asked "*Three times a year you receive a large credit that reduces your power bill (in Autumn, Winter and Spring). Are you aware that you receive these credits?*". If aware, they were asked '*Who is responsible for these credits to your power bill?*' and '*Would you still receive these credits if you switched electricity retailers?*'



- Most respondents (90%) could recall receiving a large credit three times a year (similar to 89% in 2020).
- 8-in-10 of these respondents (80%) named Network Tasman as responsible for the discount, and 8% named Network Tasman Trust specifically. Recall of both these sources improved in 2022 compared to 2020 (57% NTL and 4.5% Trust).
- Residential respondents were more likely to recall receiving credits (92%) compared to businesses (75%).
- Two-thirds of respondents (65%) correctly believed they would still receive their dividend and discount if they changed retailers. After an improvement in 2020, this result remained consistent in 2022.

Perceived impact of switching retailer on rebate and discount over time



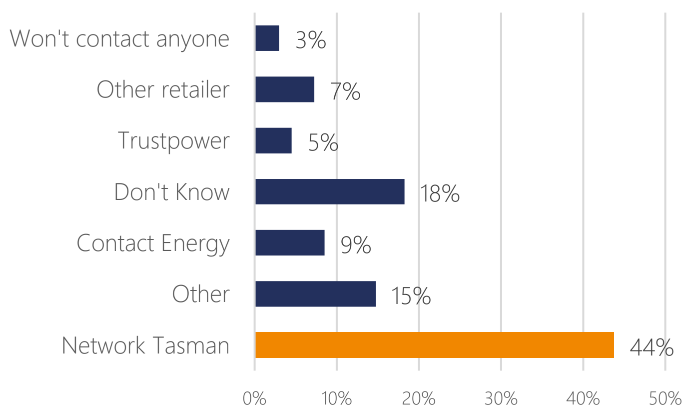
	2014	2016	2018	2020	2022
Will still receive after switching	54%	59%	59%	66%	65%

BRAND SURVEY

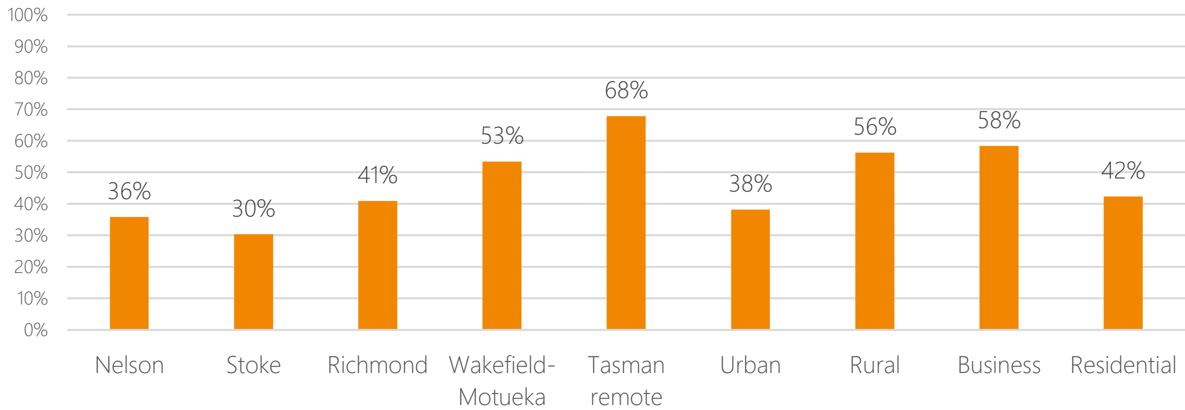
Name of fault organisation (unprompted name recall).

All respondents were asked *"In the event of a power cut, what organisation would you get in touch with for fault information?"*

Fault organisation recall in 2022 (aggregated)

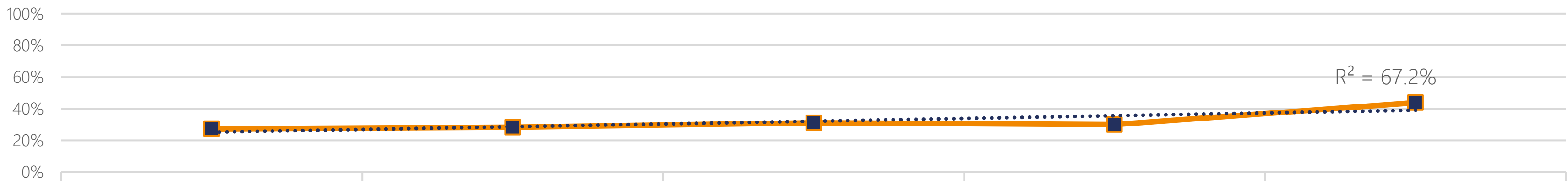


% NTL mentioned by area and segment in 2022



- Unprompted recall of Network Tasman as the local faults organisation in Nelson-Tasman area improved significantly in 2022 (44%), showing an overall positive trend over time.
- This recall remained greater among commercial (58%) vs. residential (42%) respondents.
- Current association of NTL as the faults organisation was similar between respondents of different age groups, but varied by general location. Respondents living in more remote and rural locations tended to name NTL as their fault organisation more so than urban residents.
- It is expected that rural areas have a higher level of awareness of power outages, as they tend to experience a higher frequency of outages compared to urban areas.

% NTL mentioned by year

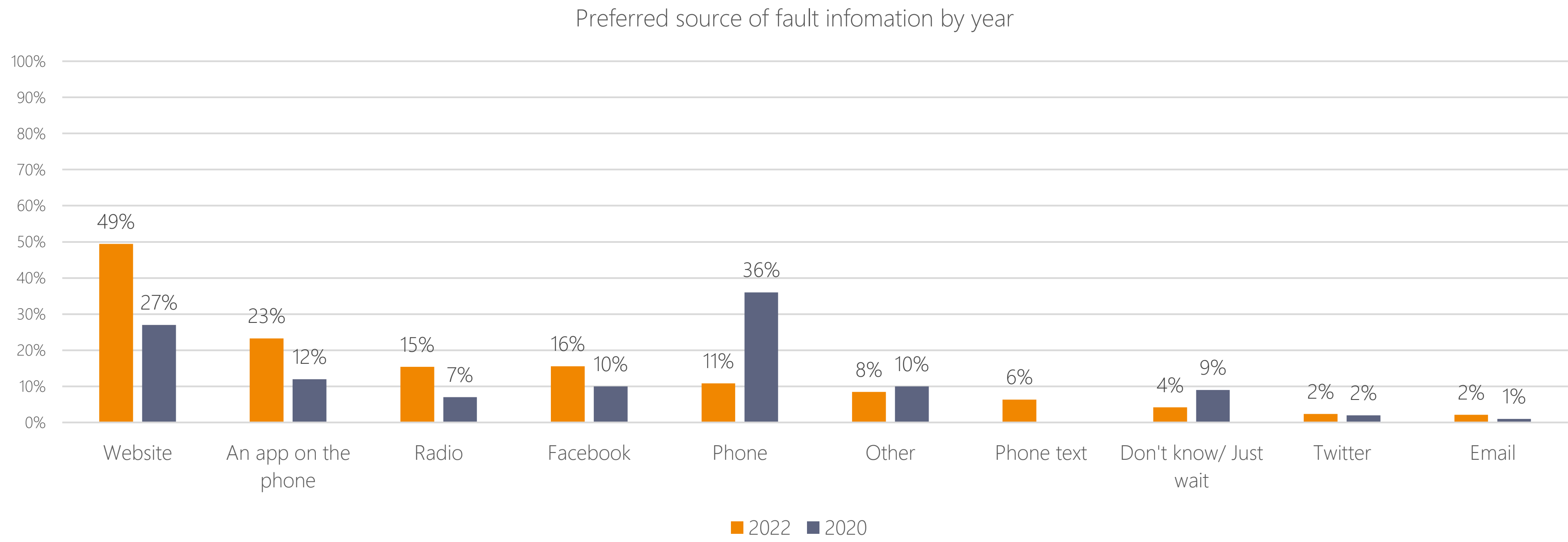


	2014	2016	2018	2020	2022
Network Tasman	27%	28%	31%	30%	44%

BRAND SURVEY

Preferred source of fault information.

All respondents were asked *"How would you prefer to source fault information?"* Note: results were weighted.

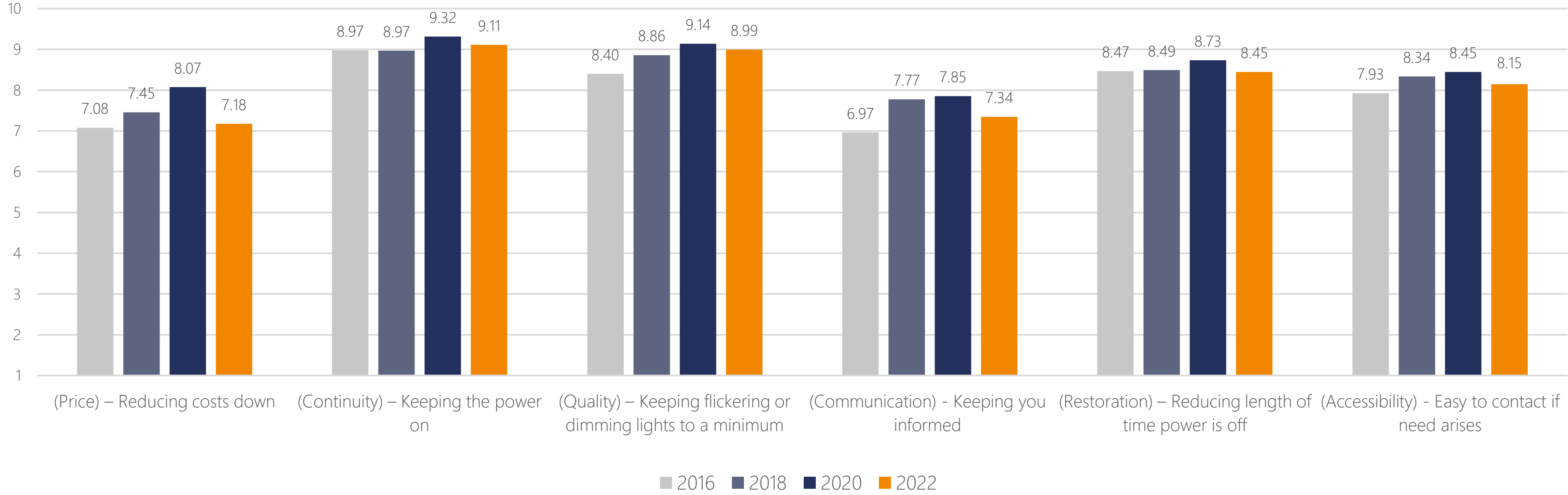


- In 2022, there was a significant shift in how respondents preferred searching for fault information.
- Website (49%, up from 27% in 2020) and smartphone app (23%, up from 12% in 2020) became the two leading options – in preference to previously popular phone contact.
- However, age differences in channel preferences were still apparent.
- Over half of respondents aged under 64 preferred website (57%), especially compared to older respondents (29%).
- Younger respondents aged under 39 were more likely to name Facebook (40%) as their preferred source of fault information.
- Radio (23%) and phone (19%) continued to be important sources of information for older respondents.

CORE SURVEY RESULTS

Service performance.

All respondents were asked *"On a scale of 1 to 10 (where 1 is poorest and 10 is highest) how would you rate your electricity lines company's performance in the following areas?"*

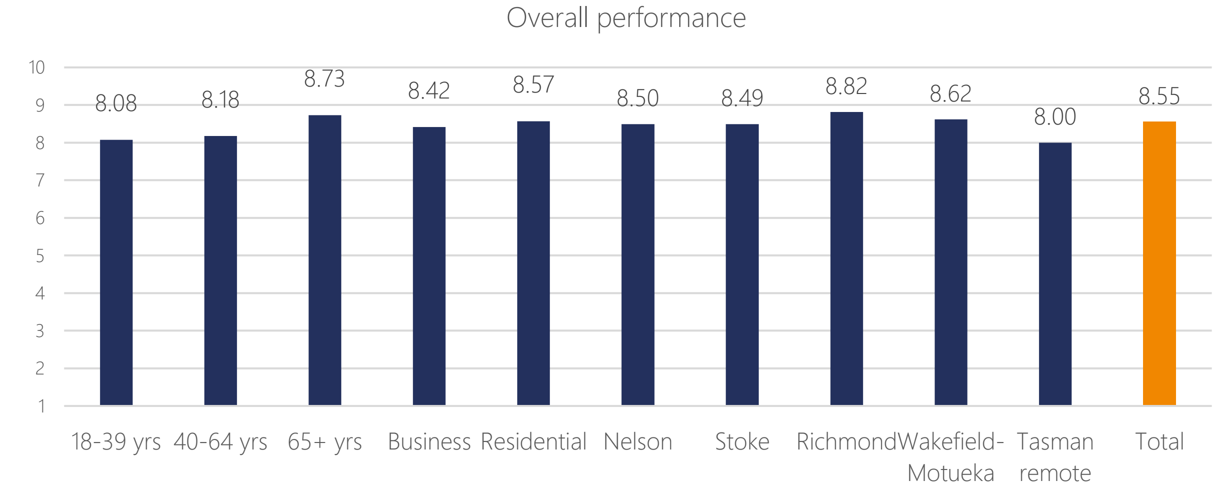


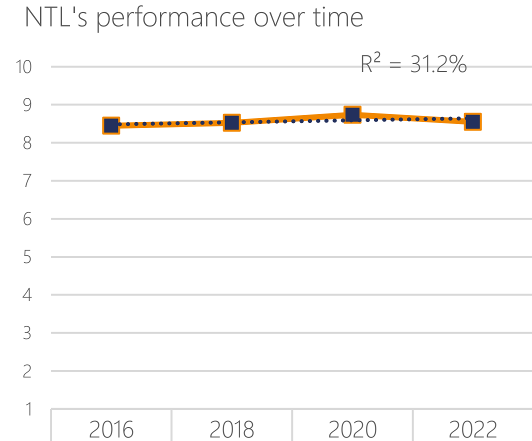
- Perceptions of NTL's service performance remained positive in 2022, with average scores above 7 (out of 10).
- *Continuity* (9.11 out of 10) and *Quality* (8.99 out of 10) of power supply continued to be the top-rated deliverables.
- Despite some variations, most results were on par with tracking averages, with *Quality* of power supply showing a positive trend over time.
- However, the two lowest rated deliverables showed material declines in 2022 compared to 2020: *Communication* and *Price.*
- Tasman remote respondents tended to provide lower ratings for *Continuity* (8.57) and *Quality* (8.25).
- Residential respondents aged under 64 were slightly less satisfied with *Accessibility* (7.39), and those aged 18-39 were less satisfied with *Restoration* (7.75).

CORE SURVEY RESULTS

Overall services performance.

All respondents were asked *"Taking into account all of the areas of performance (price, continuity, quality, communication, restoration and accessibility) how would you rate Network Tasman's overall performance?"*





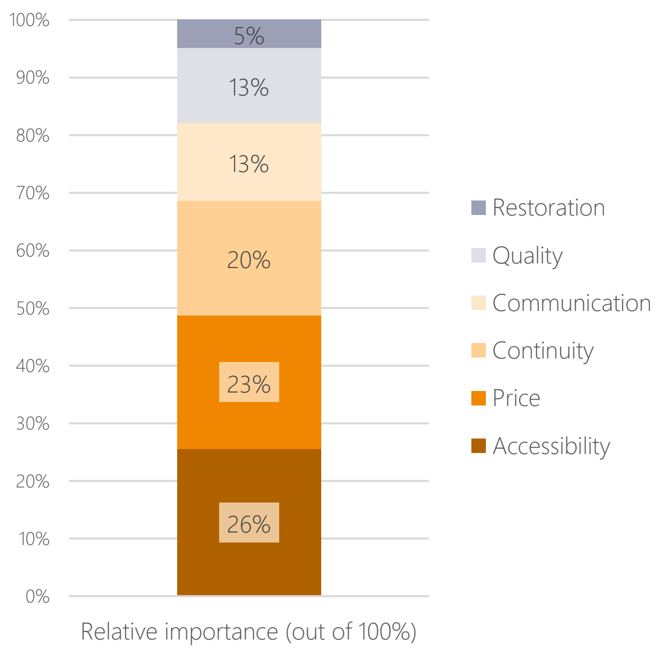
	2016	2018	2020	2022
Network Tasman	8.45	8.52	8.74	8.55

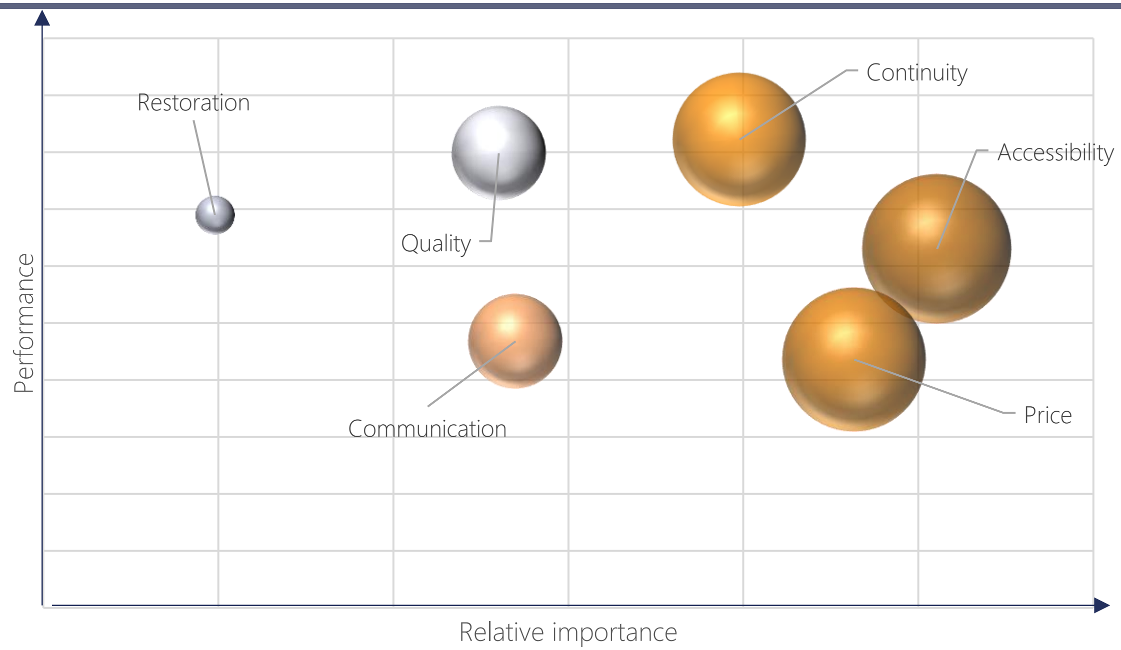
- Satisfaction with NTL's overall performance remained high in 2022 (8.55 out of 10), with 93% of respondents providing satisfaction ratings 7 and above.
- Despite a slight decline, the 2022 results were on par with the tracking average, with trends observed over time.
- Satisfaction was similar between commercial and residential respondents.
- At the same time, respondents aged under 64 tended to be less satisfied (8.13 on average). Also, Tasman remote respondents, on average, recorded a lower satisfaction score (8.00).

CORE SURVEY RESULTS

Priority assessment.

Regression analysis provides a statistical test to predict which of Network Tasman's service deliverables exert the greatest influence on overall performance and relative importance of each deliverable. The results are then compared with the perceived performance in these areas.





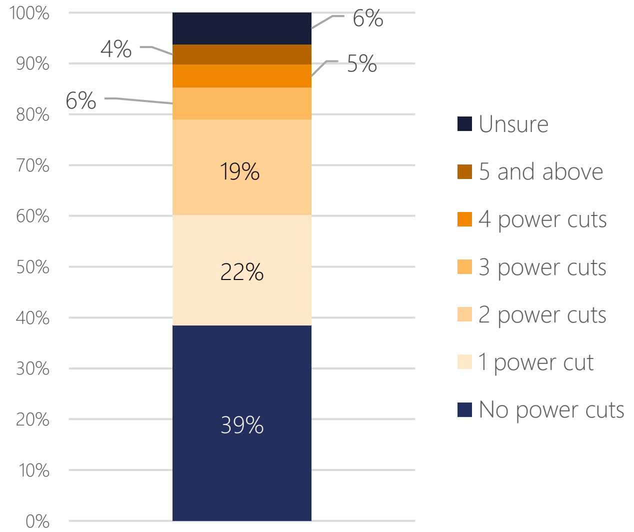
- 5-out-of-6 service deliverables had a significant influence on overall satisfaction with NTL's performance; *Restoration* had less influence.
- At the same time, *Accessibility* and *Price* exhibited the greatest relative importance, followed by *Continuity* (also the top-three most important attributes in 2020).
- When comparing relative importance against performance scores, *Accessibility* and *Communication* represented the greatest improvement potential across the board (excluding *Price*, since price cannot be wholly influenced or controlled by Network Tasman).
- *Accessibility* exhibited greater relative importance among rural respondents (41%).

POWER QUALITY AND RELIABILITY

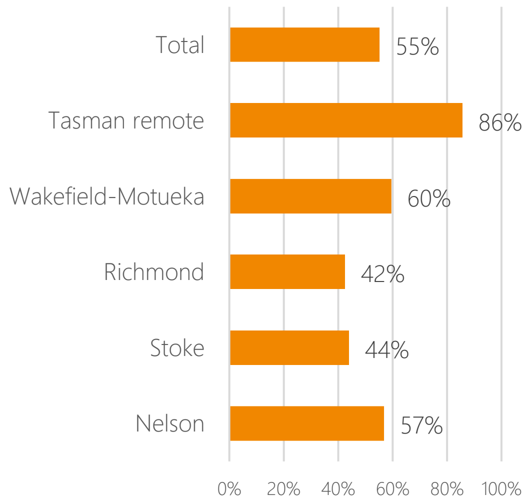
Power cuts recall in the past 12 months.

All respondents were asked "*Thinking now about the last 12 months, how many power cuts can you recall?*".

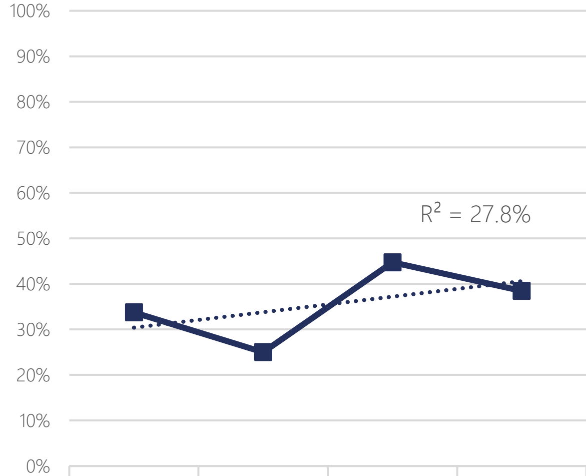
Total recalled power cuts in 2022



Reported occurrence of power cuts by area



Zero power cuts over time



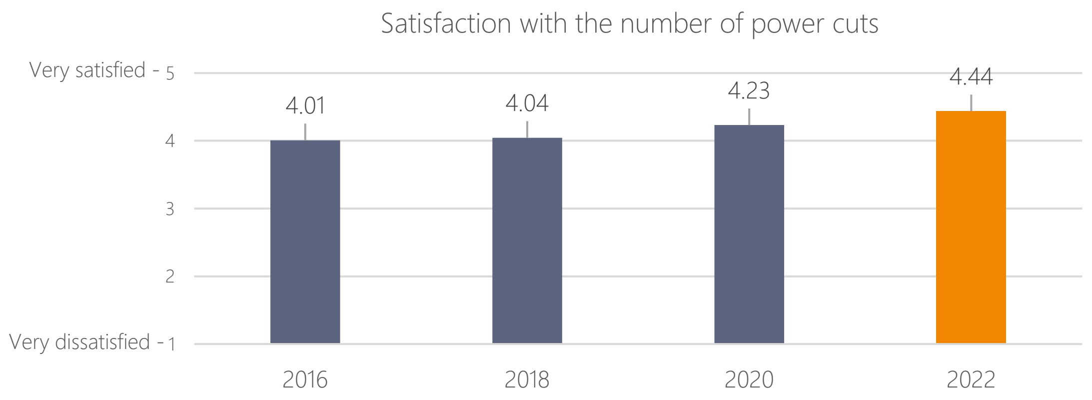
	2016	2018	2020	2022
No power cuts	34%	25%	45%	39%

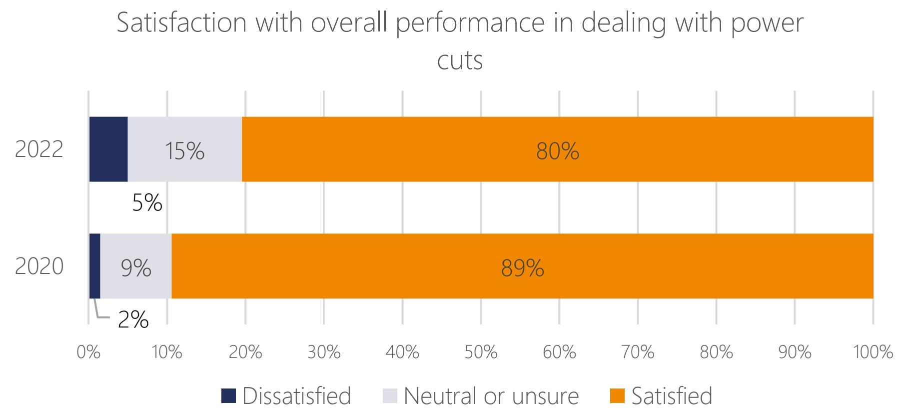
- In 2022, 2-in-5 respondents (39%) stated they had not experienced power cuts in the past year (slightly down compared to 45% in 2020); 55% reported experiencing at least 1 power cut.
- Slightly more consumers reported a power cut in 2022; compared to 2020, increases were observed in those reporting 1 and 2 power cuts (+10%).
- Power cut recall varied by area, with reported outages more likely in Tasman remote (86%). This same area recorded lower satisfaction scores with overall NTL performance, and specifically *Continuity* and *Quality*.

POWER QUALITY AND RELIABILITY

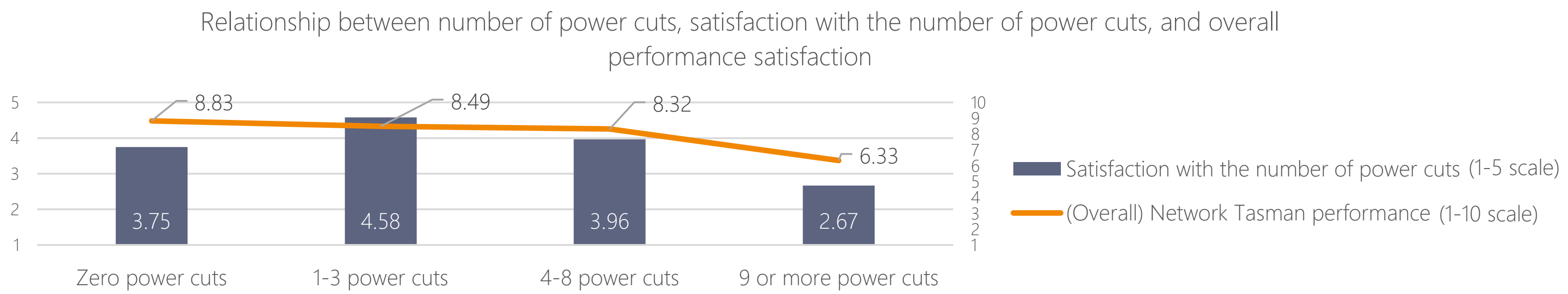
Satisfaction with performance in dealing with power cuts.

Respondents who experienced a power cut were asked *"How acceptable was the number of outages you experienced in the last 12 months?"* and '*How satisfied were you with Network Tasman's overall performance in dealing with your most recent power cut?*'.





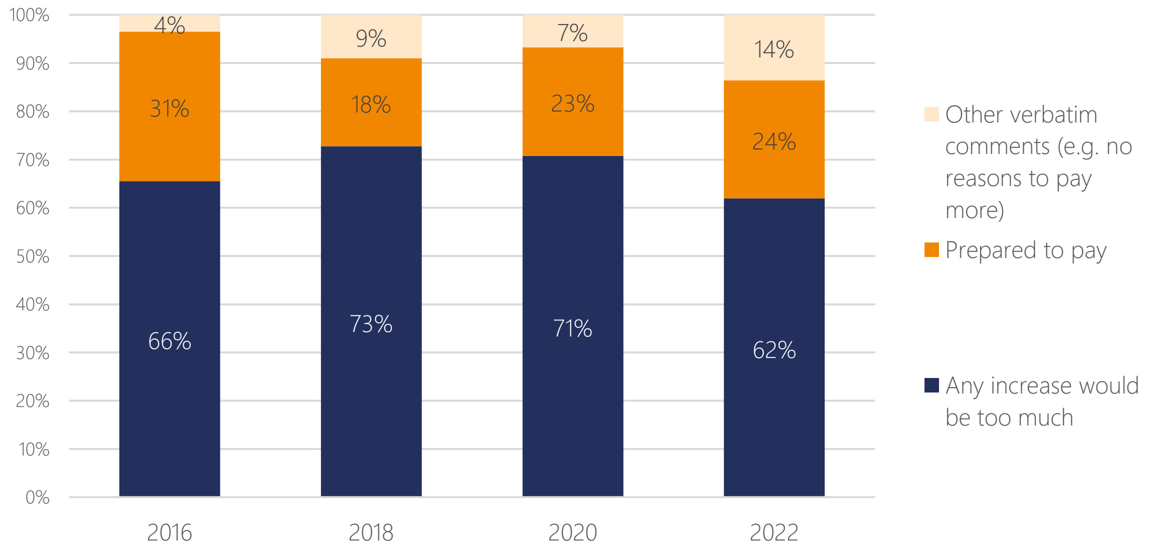
- Despite an increased number of reported power cuts, general satisfaction with this number remained high (4.44 out of 5), and slightly above the tracking average.
- Among respondents who experienced a power cut, the number of power cuts influenced their satisfaction (both with number of power cuts and overall NTL performance). Tolerance of power reliability decreased significantly only after experiencing 9 or more power cuts.
- Satisfaction with NTL's handling of power cuts was high in 2022 (80%); although down compared to 2020 (89%). However, this decrease was mainly attributed to a higher percentage of respondents who remained unsure about their sentiments.
- Younger respondents aged under 39 were more likely to remain neutral in relation to NTL's performance.

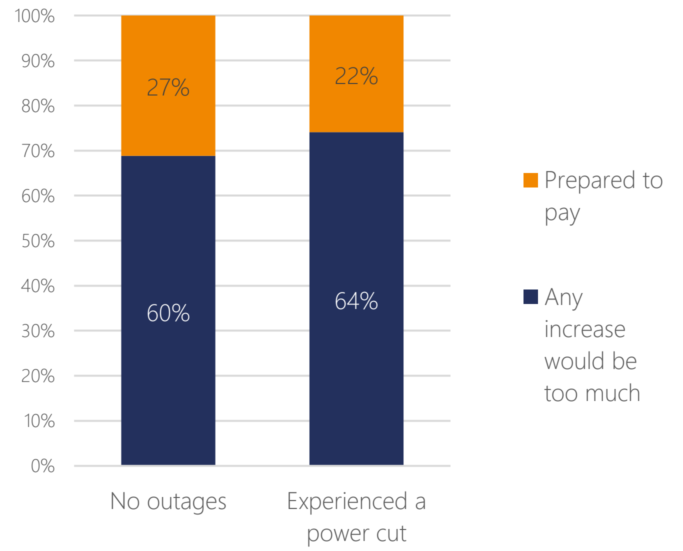


POWER QUALITY AND RELIABILITY

Willingness to pay for improved power quality.

All respondents were asked "*Your current line charges ensure the lights stay on most of the time with limited interruptions or power fluctuations. To improve your power quality even further what price would you be prepared to pay on top of your current charges?*"



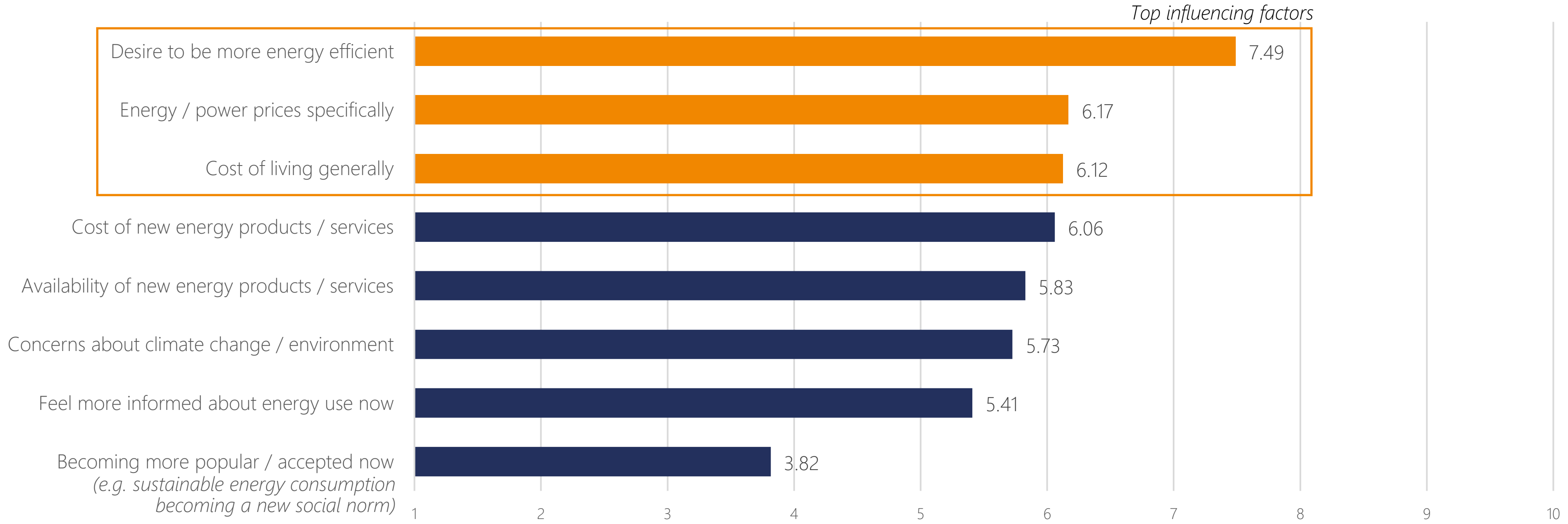


- Overall, 62% of respondents stated any increase in price would be too much to pay for improved power quality; 14% stated another reason – mainly '*Happy with quality so no need to pay more*'.
- Effectively, the percentage of respondents prepared to pay more for improved power quality in 2022 (24%) was similar to 2020 (23%).
- Experiencing a power cut was not a significant factor in willingness to pay more.

ENERGY USE

Key factors influencing energy consumption.

All respondents were asked "*To what extent, if at all, have each of these influenced your household's energy use*?" New in 2022. Results are reported weighted.

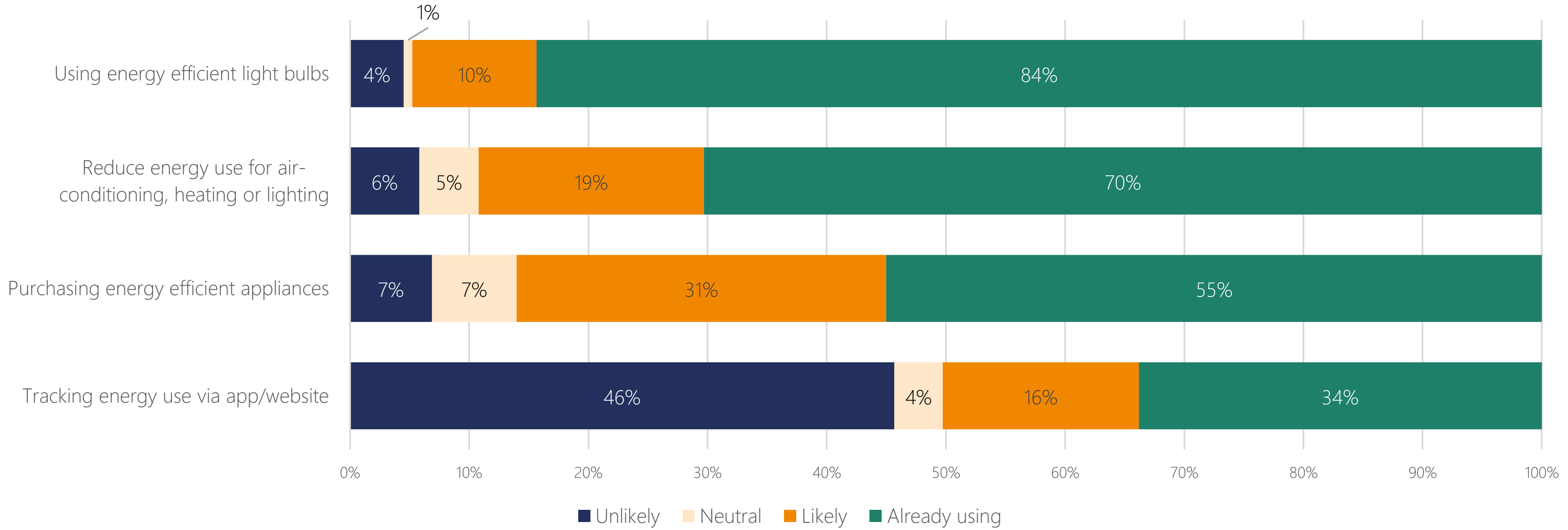


- Energy efficiency (7.49), energy prices (6.17) and cost of living (6.12) were the top-rated factors influencing respondents' energy use.
- The influence of cost of living, energy prices, desire for energy efficiency, and cost of new energy products declined with age; these four factors were of greater concern among younger respondents aged under 39.
- On average, residential respondents provided higher ratings than businesses.
- A positive relationship was observed between concern about greater energy consumption and actual behaviour, including tracking energy use via app/website, purchasing energy efficient appliances, switching to energy efficient light bulbs, and reducing energy use for heating.

EMERGING TECHNOLOGIES

Likelihood of future investment in new or alternative energy related products or services

All respondents were asked "*Which, if any, of these new or alternative energy related products/services are you now using or likely to use to manage your household's energy needs*?" New in 2022. Results are reported weighted.

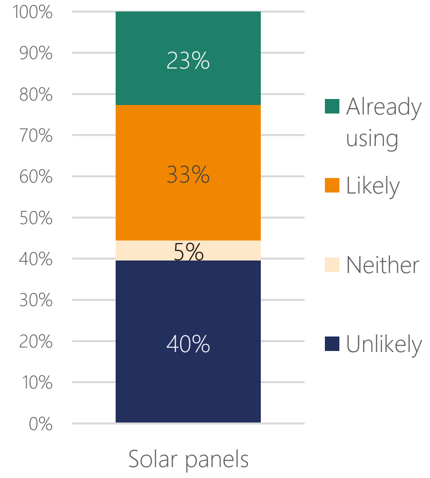


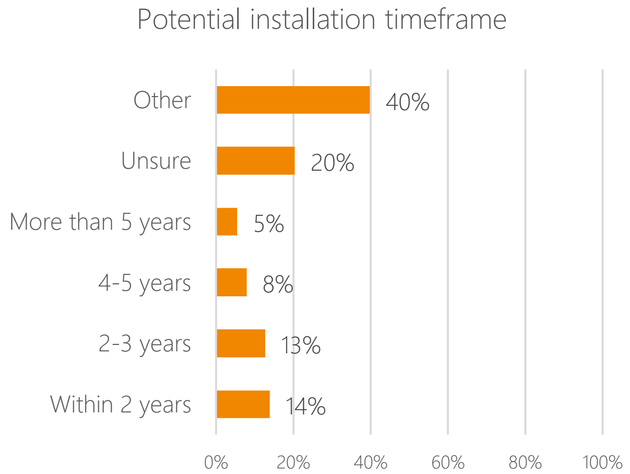
- The actual and potential uptake of energy efficient approaches varied considerably across specific activities.
- 84% of respondents reported they had already installed energy efficient light bulbs, 70% reported reducing energy for heating/lighting, and half of respondents (55%) had already purchased energy efficient appliances.
- Energy tracking systems were least likely to be used already (34%); and just under half of respondents (46%) were unlikely to use these in the future.
- However, younger respondents aged under 39 were significantly more likely to use energy tracking apps (64%), whereas 73% of aged 65+ respondents were unlikely to adapt this approach.

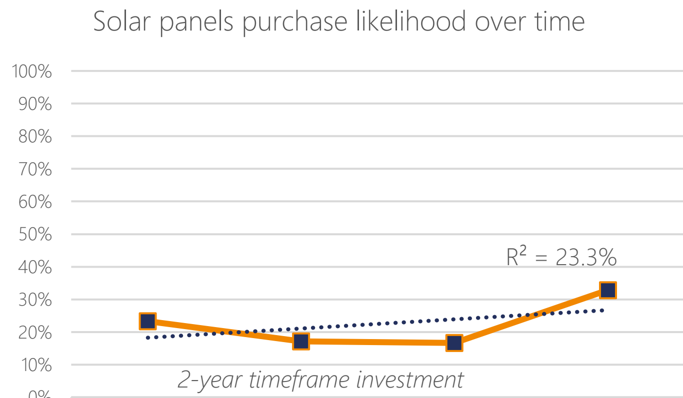
EMERGING TECHNOLOGIES

Likelihood of future investment in solar panels.

All respondents were asked *"Which, if any, of these emerging energy related products/services are you now using or likely to use?"* Results are reported weighted. Question wording updated in 2022

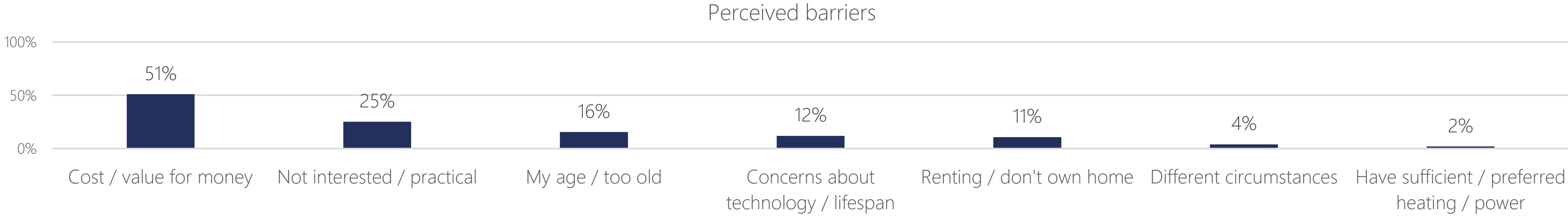






	2016	2018	2020	2022
Solar	23%	17%	17%	33%

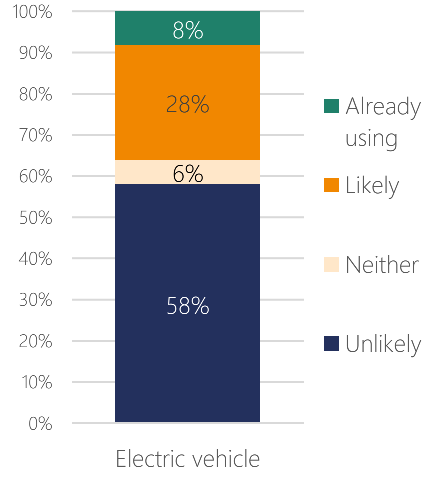
- The potential uptake for solar panels was substantial in 2022. Over half of respondents had either invested, or were likely to invest, in solar power (56%).
- However, among the 33% of respondents considering solar panel investment, only 14% were planning on doing so in the next 2 years (17% in 2020); 40% could not provide a specific timeframe, referring to either affordability or access to better technology.
- Cost (51%) was the most evident barrier for respondents to consider solar panel investment, followed by general lack of interest or perceived practicality (25%); 12% were concerned about technology.
- Older respondents aged 65+ were least likely to consider this investment.
- Respondents from Tasman remote were more likely to either already have (35%) or consider (51%) solar panels.

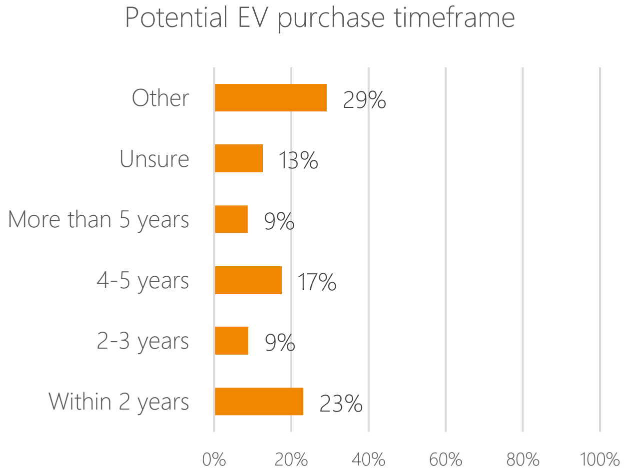


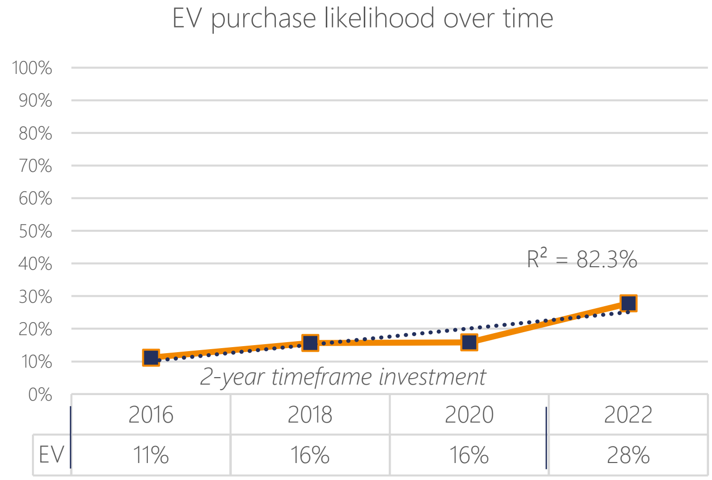
EMERGING TECHNOLOGIES

Likelihood of future investment in electric vehicles.

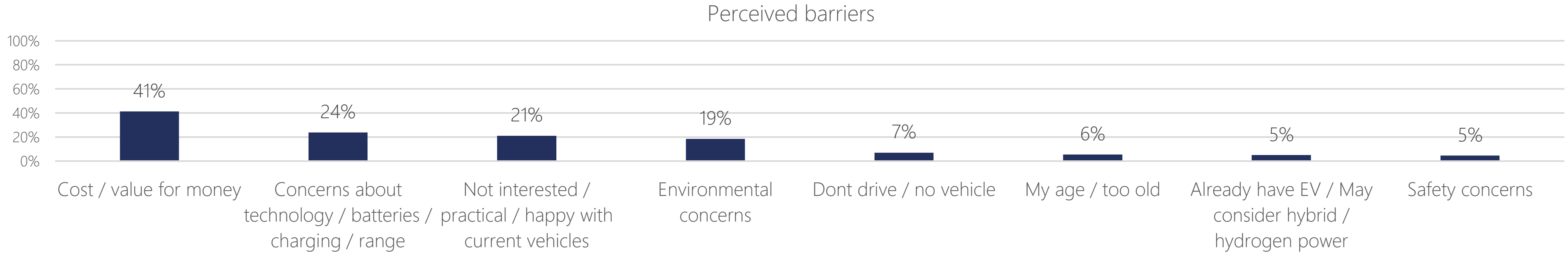
All respondents were asked "*Which, if any, of these emerging energy related products/services are you now using or likely to use?*" Results are reported weighted. Question wording updated in 2022







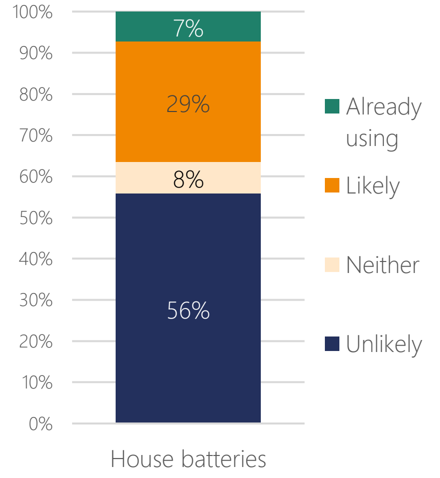
- Fewer respondents (36%) reported owning (8%) or considering (28%) electric vehicles, compared to solar panels.
- At the same time, among the 28% of respondents thinking about electric vehicles, 23% considered making this investment in the next 2 years (16% in 2020); half of respondents considered buying an electric vehicle within the next 5-year period (49%).
- Cost/value for money (41%) was named as the main barrier for electric vehicle investment.
- Concerns about reliability and efficiency (e.g. batteries, range), or personal preference for current or petrol cars, were also recurring issues.

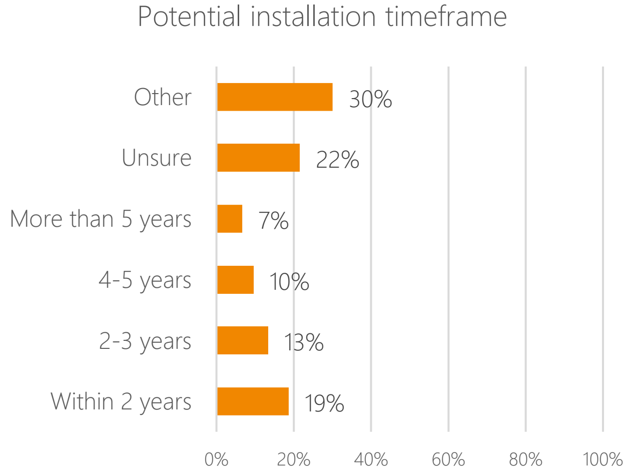


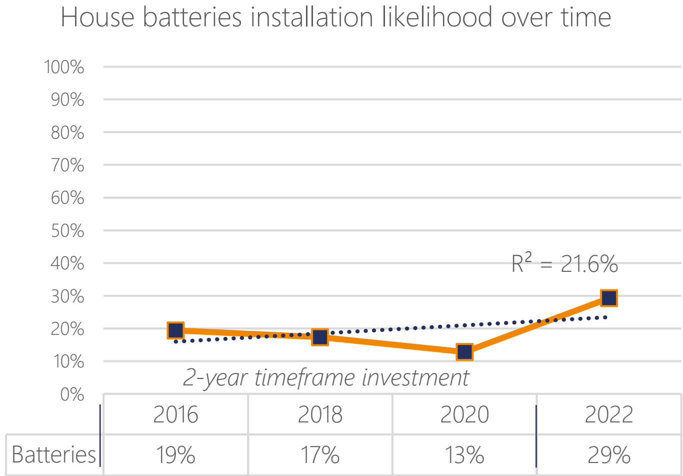
EMERGING TECHNOLOGIES

Likelihood of future investment in house batteries.

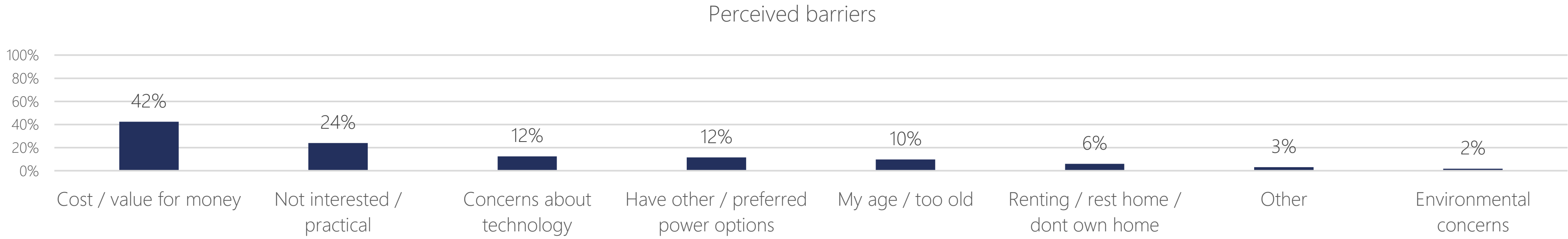
All respondents were asked *"Which, if any, of these emerging energy related products/services are you now using or likely to use?"* Results are reported weighted. Question wording updated in 2022







- 7% of respondents reported using house batteries and 29% of respondents reported considering this investment.
- As with other technologies, older respondents were least likely to consider this investment.
- Again, cost (42%) was the main barrier to invest in house batteries – and the leading barrier for consumers of all age groups.
- Overall perceptions of house batteries were more similar to consideration of electric vehicles. Just under half (48%) of respondents who considered investing in house batteries were likely to do so in the next 5 years.

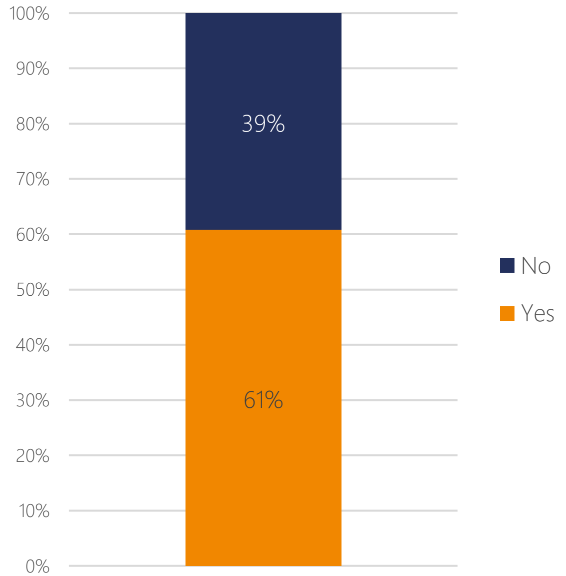


COMMUNICATION

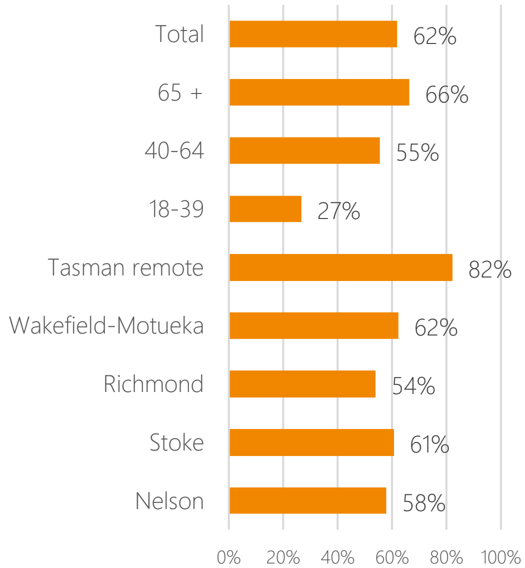
Safety messages awareness

All respondents were asked *"Are you aware of any communications or messages on behalf of your electricity lines company in relation to safety such as taking care around power lines, buried electricity cables and keeping trees away from powerlines?"*

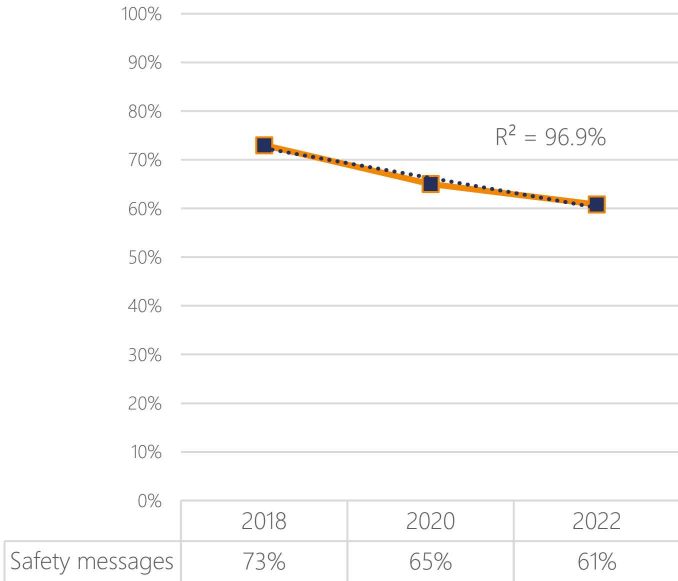
Overall safety message recall



Recall by area and age



Safety message recall over time

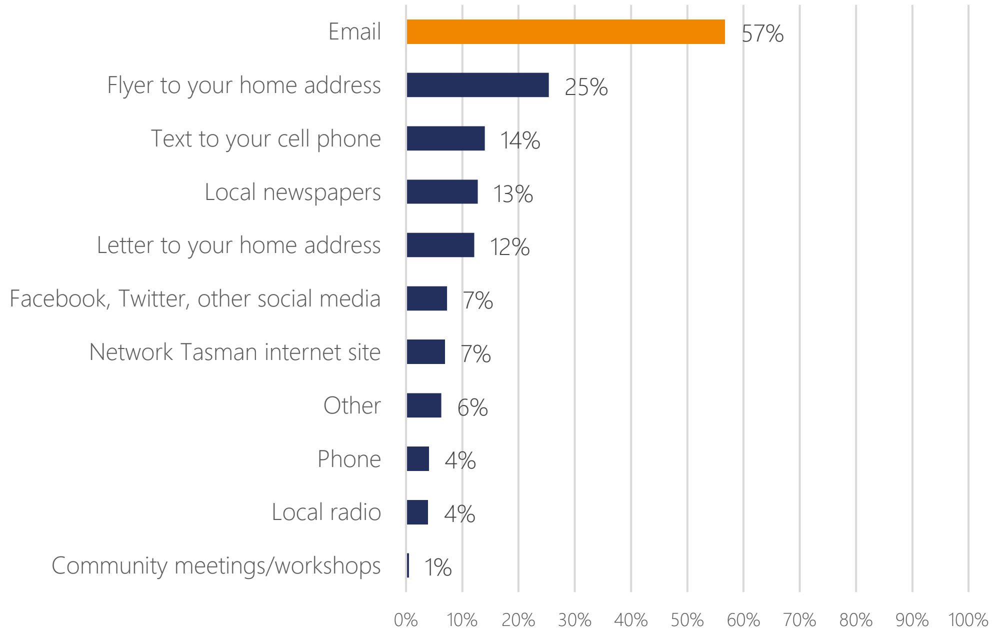


- Awareness of NTL's safety messages declined since 2018; however, 6-in-10 respondents (61%) were still aware of these messages in 2022.
- Recall of safety messages increased with age; 66% of respondents aged 65+ were aware of these messages, compared to only 27% of younger respondents (aged under 39).
- When weighted by age to take these differences into account, the overall recall of safety messages dropped further to 51% (56% in 2020).

COMMUNICATION

Communication methods

All respondents were asked "*What do you believe is the most effective way of Network Tasman communicating information to you?*" Note: results were weighted



Top three communication methods by age:

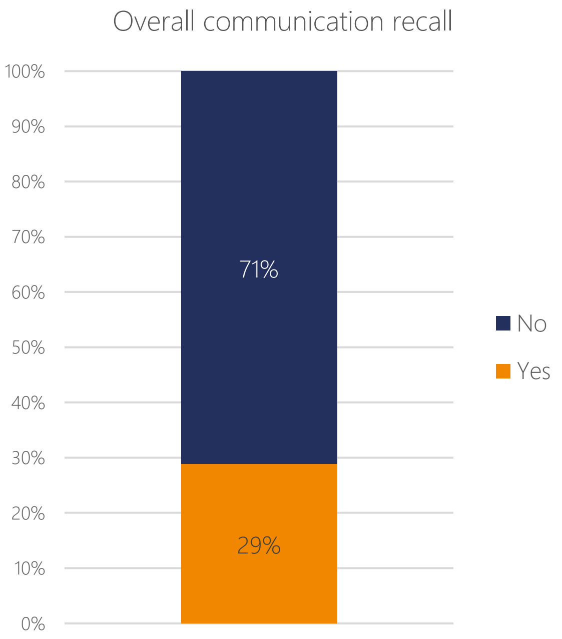
18-39	40-64	65+
Email (67%)	Email (59%)	Email (43%)
Text (20%)	Flyer (27%)	Flyer (34%)
Flyer (13%)	Newspapers (14%)	Newspaper (23%)

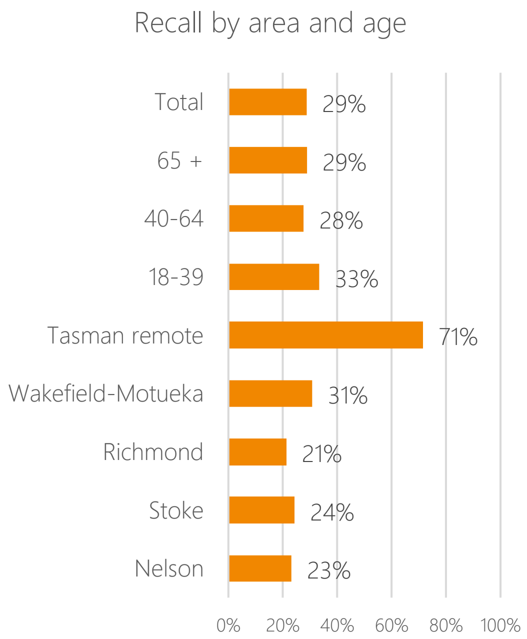
- Email (57%) was by far the most preferred method of Network Tasman communicating information to consumers.
- Despite some variations in degree of preference by age, email was the most preferred communication method among all age groups – and similar to 51% in 2020.
- Commercial respondents (78%) had an even stronger preference for email.

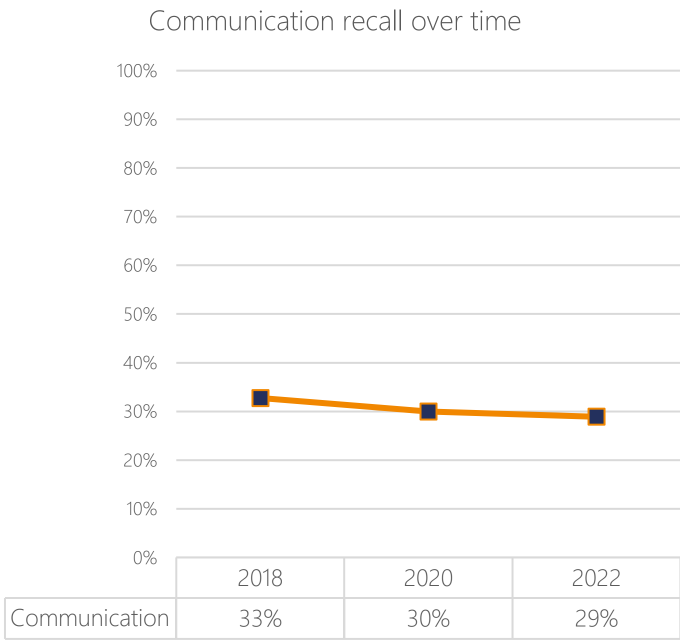
COMMUNICATION

Most recent communication

All respondents were asked *"Have you seen or heard any recent communications or messages from Network Tasman?"*





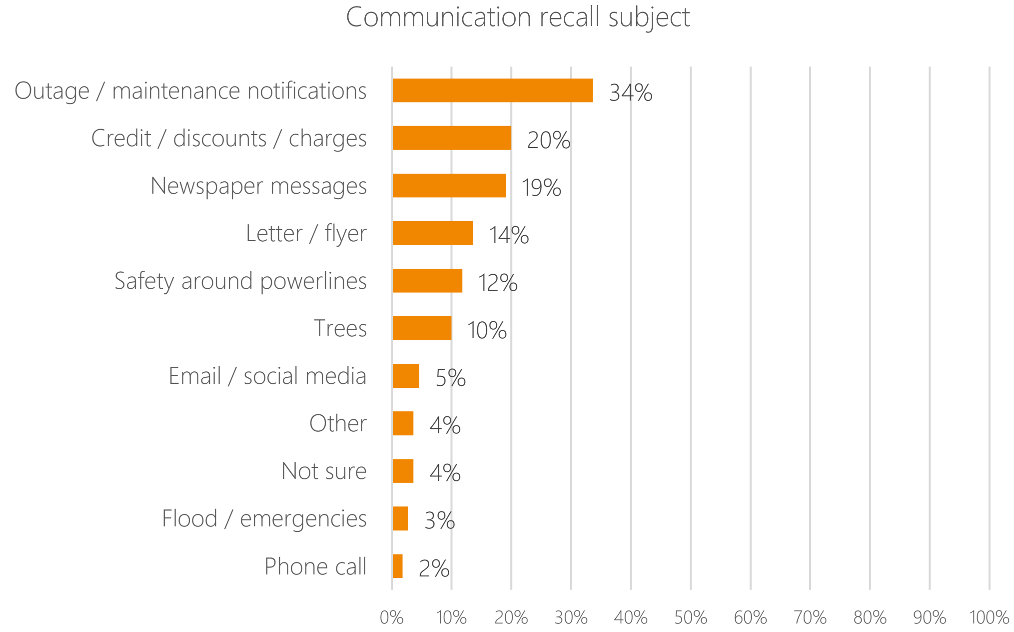


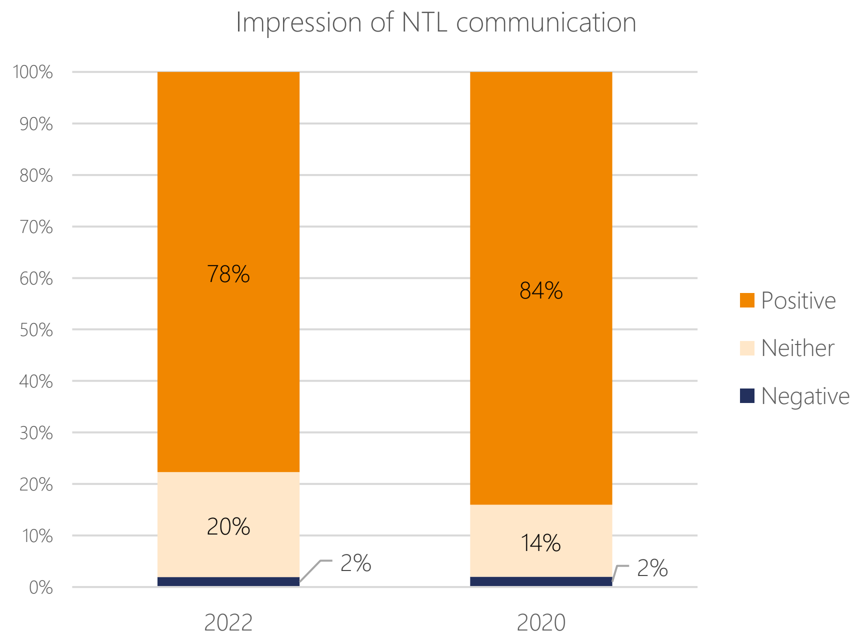
- 29% of respondents could recall some recent advertising, media or publicity about NTL; this communication recall has been stable over time.
- Communication recall was similar between different age groups.
- At the same time, more respondents from Tasman remote (71%) could recall NTL's recent communication.
- Respondents from rural locations (39%) were also more likely than urban residents to report seeing or hearing communications from Network Tasman.

COMMUNICATION

Impression of Network Tasman

Respondents who mentioned seeing or hearing any recent communications or messages from Network Tasman were asked "*What impression of Network Tasman did it give you*?" Note: results were weighted



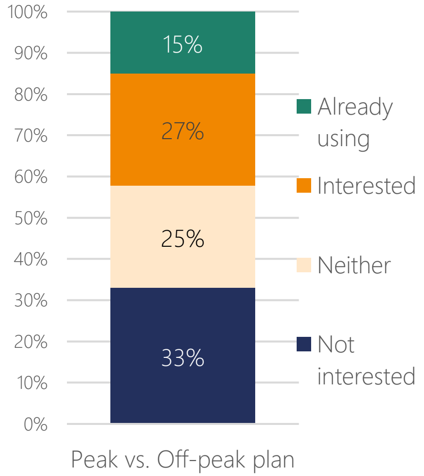


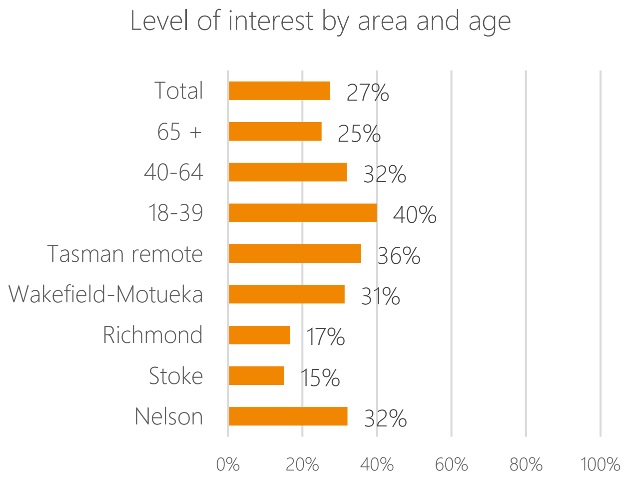
- Recalled communication was mainly associated with outage and maintenance notifications (34%), followed by received credits/discounts (20%).
- Newspapers were the most identified channel for NTL messages.
- Overall, 78% of respondents who recalled seeing or hearing from Network Tasman stated the message or communication had given them a positive impression of their lines company.
- Although this result was slightly down compared to 84% in 2020, negative impressions remained at a low (2%) level, with more respondents stating neither negative nor positive sentiment in 2022.
- Safety around power lines (92%) and credits/discounts (86%) messages were associated with greater positive impressions. Recalled direct communication from email or letter/flyer also elicited greater positive impressions.

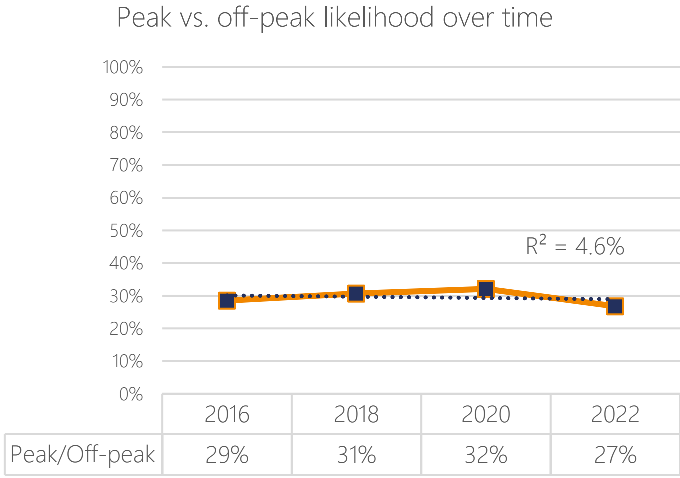
PEAK VS. OFF-PEAK

Peak vs. off-peak plan

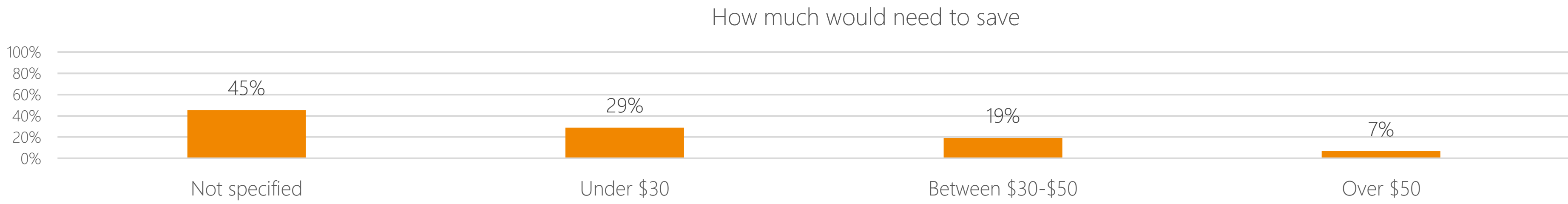
All respondents were asked *"How interested would you be in going to a peak vs. off-peak plan where you pay more for usage during network peak periods such as morning and evening and less during off-peak periods?"* and *"How much would you need to save each month for this to be worth doing?"*







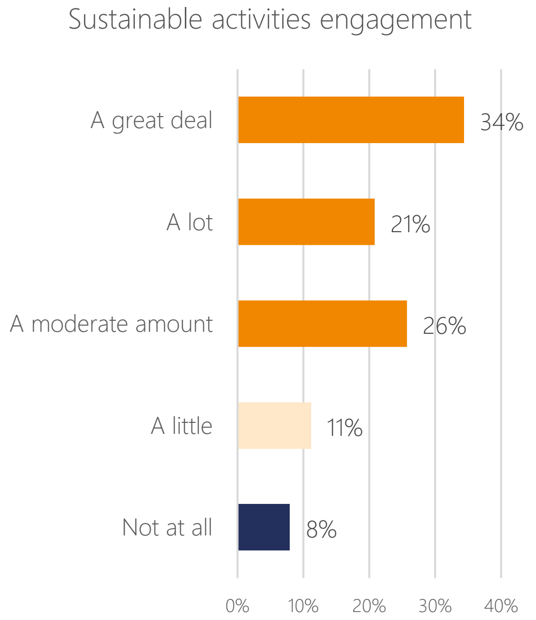
- 27% of respondents stated they were interested to some extent in the proposed peak vs. off-peak plan; 15% believed they were already on this plan.
- This interest was generally consistent over time.
- 45% of respondents indicated they were unsure as to how much they would need to save to make this plan worthwhile, or were not prepared to make that decision at this point.
- 29% of respondents suggested a savings amount under $30 per month, with an average $34.9 per month. Younger respondents aged under 39 were more likely to expect larger savings (on average, $41.1).

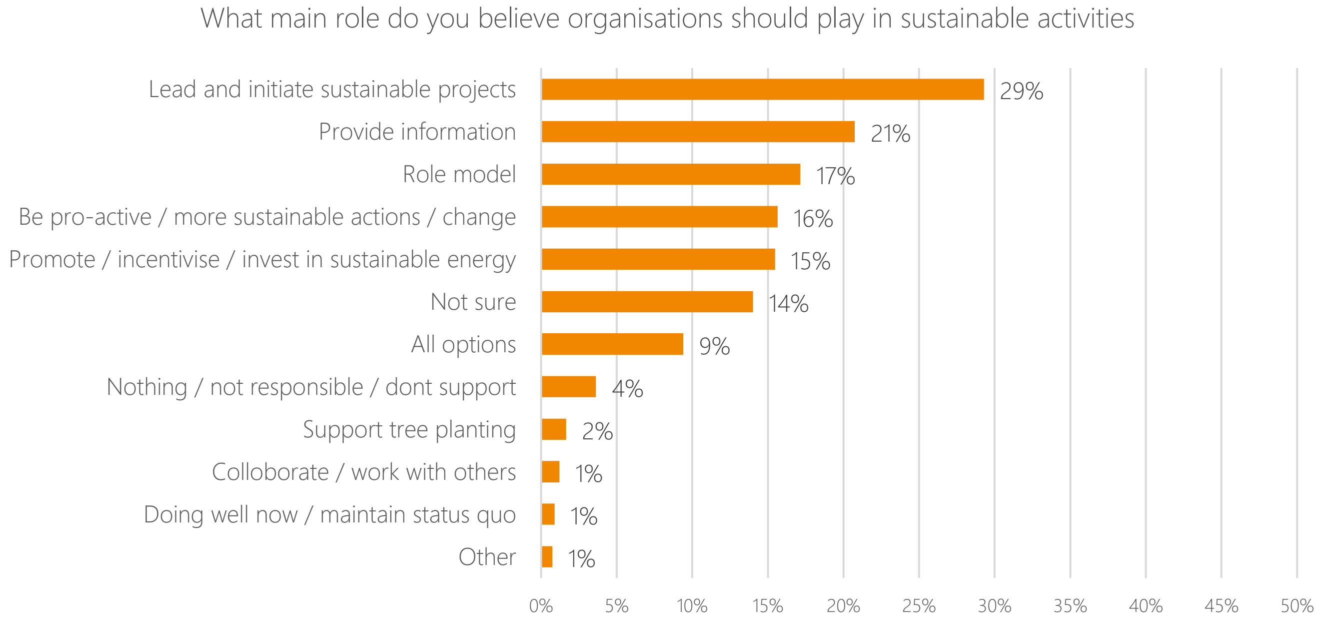


SUSTAINABILITY

Perceived Network Tasman contribution to communities

All respondents were asked "*To what extent do you believe Network Tasman should be engaged in sustainable activities and investment*?" and "*What roles Network Tasman should play in sustainability and decarbonisation*?" (open-ended comments sorted into categories). Results are reported weighted.

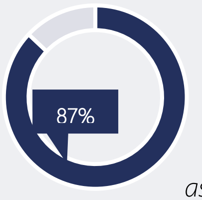




- Sustainability engagement expectations for Network Tasman were high; most respondents (81%) believed Network Tasman should be engaged in sustainable activities and investment from a moderate to a great deal.
- However, expectations varied by age. Younger respondents aged under 39 were more likely to expect Network Tasman engagement in such activities; in contrast, one-quarter of residents aged 65+ believed NTL should have no or little involvement.
- No single role was perceived by the community for Network Tasman to focus on; rather a combination of different roles and responsibilities was suggested. Leading and initiating sustainable projects, providing advice and information, while role modelling sustainable actions, were among the most notable responsibilities in this mix.

SUSTAINABILITY

Additional information and insights based on secondary research and anecdotal comparison to other regions.



- Overall, the majority of energy consumers across different regions agree that sustainability should be a key consideration for many organisations. This corresponds with **sustainability being a mainstream concern** for **87%** of New Zealanders nationwide (*Perceptive, 'How New Zealanders assess the sustainability of brands', 2019*). Two-fifths (43%) feel a personal commitment to living sustainably, with this steadily increasing over time; while two-in-three (66%) believe it is important for brands in particular to be committed to making society better (*Sustainable Business Council, 'Better Futures', 2022*).

LEADING THE CHANGE

- Despite the noted importance of business and agency involvement in sustainable action, there is currently **no clear leader** driving this change; in fact, 1-in-5 (18%) Kiwis are unable to identify any brand as being a leader through sustainability practices. Nevertheless, electricity retailers are among the brands perceived to be doing the most to become more sustainable (35%) (*Perceptive, 2019*). A clear opportunity exists for specific organisations to take a leading role in this space.
- However, this role should not be seen as a solitary or exclusive effort - collaboration is critical. About **1-in-3 energy consumers** across regions **believe responsibility for sustainable behaviour is a combined effort** – including **government, organisations and individuals** (*SIL Research, 2022*). Collaborating with government is considered crucial, though there is currently room for improvement: 1-in-4 (27%) believe collaboration between government and business to encourage sustainable behaviour "*is better in New Zealand than other countries*"; but a similar proportion (22%) think NZ does worse than other countries in this regard (*Sustainable Business Council, 2022*).
- Working with local government may be key to improving these perceptions; in at least one region, residents believed the regional council should be taking the lead with climate-related actions (*SIL Research, 'Hawke's Bay Regional Council Climate Crisis Survey', 2020*). Coordinating efforts with government and other agencies at both national and local levels may yield the greatest benefits, particularly to increase perceptions of credibility and relevance among residents and encourage buy-in from consumers.

A DIVERSE ROLE

- Energy consumers believe network companies could and should play **a wide-ranging role in sustainable action**, incorporating a mix of responsibilities. Providing an **advisory and information provision** role to households, while **role modelling sustainable actions**, were among the noted responsibilities in this mix (for about 1-in-10 consumers) (*SIL Research, 2022*).
- Focusing on and working towards more **alternative / renewable energy** production and supporting **sustainable power** (e.g., wind, solar farms) were commonly the top unprompted suggestions to **help mitigate climate change effects**. Improving **power supply infrastructure** to increase **resilience** in case of more frequent weather events was also important to consumers.
- Regardless of the roles and actions taken, **clear communication** about businesses' **social and environmental commitments** is vitally important. **87%** of New Zealanders **would like to be informed of companies' efforts to address environmental issues**; however, many (63%) feel this communication can be confusing (*Sustainable Business Council, 2022*). To help residents better assess their own sustainability, 1-in-4 (26%) want brands to be more transparent and honest, and believe more advertising or promotion are effective avenues to communicate sustainability (*Perceptive, 2019*).

DRIVING SUSTAINABLE ENERGY USE

- Many energy consumers are already keenly aware of the **need to reduce their energy usage** and use energy more sustainably, with this concern top-of-mind for some consumers. Asked about sustainability generally, **responsible and renewable energy** use were among the issues spontaneously highlighted by consumers without direct prompting (16%) (*SIL Research, 2022*). **Cost** is clearly one of the factors **driving concerns about energy usage**, with environmental considerations also playing a role on perceptions of price: **8-in-10 respondents believed climate change would have an impact on electricity prices**, **power supply** and **lifestyle** or business operation.
- Consumers are already responding to these usage and cost concerns. Typical power-saving strategies include using **energy-saving light bulbs** (**74%**), switching to **energy-efficient appliances** (**48%**), and changing **personal behaviour** by using more blankets to keep warm (**47%**) or limiting shower time (**46%**) (*Pulse Energy, 'The Great New Zealand Energy Survey', 2021*). In addition, there is high engagement across a number of energy-related sustainable activities: installing energy saving products, reducing energy use, and considering energy use for major purchases; with high consideration among those not yet engaged (*SIL Research, 2022*).
- Beyond these current reactive and proactive actions, consumers are expecting and predicting **more control over their future household electricity needs**; almost half (44%) believe it will be possible to generate their own electricity in the future. This desire for greater freedom is also reflected in consumer attitudes toward energy plans, with a similar proportion (47%) wishing to avoid locked-in contracts (*Pulse Energy, 2021*).
- Energy-related agencies clearly have a role to play in **promoting these sustainable actions**. Providing advice for practical energy-saving tips, while introducing and encouraging new and emerging smart technology, can help consumers reduce their power costs while adopting more sustainable behaviour.

EMERGING TECHNOLOGY

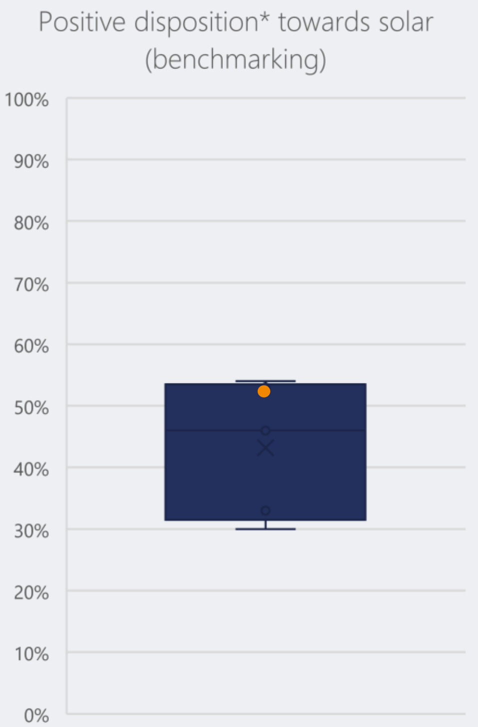
- Many consumers are positively disposed towards emerging and sustainable energy options – though this positivity is yet to be translated into significant uptake. While solar and EV adoption are supported in principle, substantial barriers (both actual and perceived) continue to limit firm commitment via purchase.
- Adoption of new or emerging technologies (non-fuel heating appliances, alternative energy/solar panels, house batteries, EVs) is notably low (under 15%), despite some positivity and varying consideration (highest for solar panels). While **cost remains the primary barrier**, practicality, concerns about efficacy of technology, environmental concerns about materials and disposal/replacement, and lack of information also contribute to consumer hesitation in uptake (*SIL Research, 2022*).

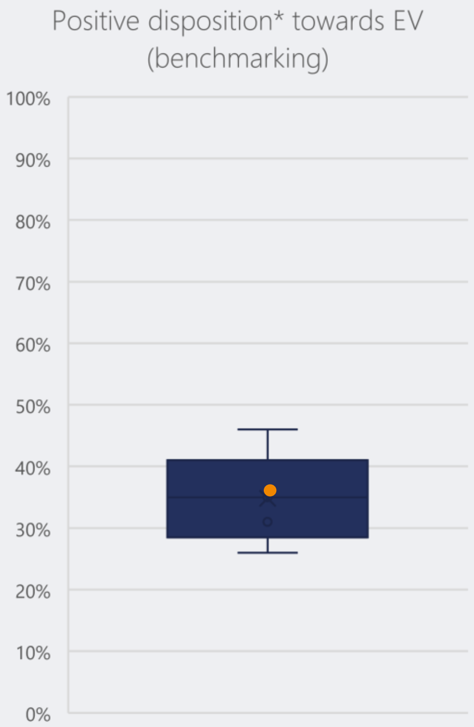
SOLAR ENERGY

- Solar power generation (particularly for hot water) continues to gain popularity in New Zealand, with substantial room for further growth in uptake as a step towards more sustainable energy use among consumers. According to the Electricity Authority, as of July 2022 over **41,300 ICPs had solar energy tech installed** (representing approx. 2% of all ICPs), with this continuing to **rise steadily** over time (up from 34,000 in 2021, and 28,500 in 2020).
- Around **2-in-5 energy consumers** indicate they would **consider investment** in solar panels, although significantly fewer (5%) are committed enough to plan doing so in the next year. Longer timeframes (2 or more years) are more likely, with many consumers unable or unwilling to commit to a specific timeframe due to the barriers highlighted above. However, younger consumers express greater willingness to invest in this technology, a trend that may lead to greater adoption over coming years (*SIL Research, 2022*).

ELECTRIC VEHICLES

- Adoption of electric vehicles continues to grow. According to the Ministry of Transport, in March 2022 there were **38,117 EVs in New Zealand** (representing 1.2% of all light vehicles in total); with EV **registrations increasing** in recent years. Consideration of EV purchase in 2021 was around 40%, with consumer confidence in meeting needs at around 15% *(Energy Efficiency and Conservation Authority, 2022*).
- However, there may be signs that enthusiasm for EVs is currently dropping; while 46% of New Zealanders in 2021 indicated they would consider buying an electric car "*if it was the same price as its petrol-powered counterpart*", this was down from 86% in 2017 (*Pulse Energy, 2021*). In the current year, SIL Research found that around **1-in-3 energy consumers** would consider **investing in an EV**, although less than half would consider doing so in the next two years. Again, more uncertain or non-committal timeframes were suggested, with cost, practicality, preference for existing vehicles or concerns about battery technology and charging infrastructure the greatest barriers to commitment *(SIL Research, 2022*)





** Positive disposition includes respondents who are likely to purchase (or have already purchased) solar panels and/or EV.*

APPENDIX L

DISASTER READINESS AND RESPONSE PLAN

NETWORK TASMAN LIMITED

DISASTER READINESS AND RESPONSE PLAN

DMS 719716

1. Executive summary

This plan outlines Network Tasman's disaster readiness and response strategy both for natural disasters and catastrophic events on either the NTL distribution network or the Transpower transmission network.

A major earthquake with an epicentre near Nelson City is potentially the worst case natural disaster to plan for. A high probability exists that a major event will occur in the Nelson region within the next 50 years. Response plans provide for alternate control centre, communication, media, resources, and priorities.

The worst case catastrophic event on the Network Tasman distribution network would be for the total loss of a zone substation from multiple transformer failures.

The worst case catastrophic events on the Transpower transmission network are considered to be multiple transformer failures, and 220kV transmission tower failures. Either of these will have a major impact on supply availability to the Nelson region. Significant restrictions or total loss of supply for up to three days could result. Effective media communication and coordination with Transpower will be required.

Network Tasman is required to have a Rolling Feeder Outage Plan for significant events on the grid or loss of national generation. This plan is posted on Network Tasman's website.

Under a declared civil defence emergency significantly impacting on electricity supplies, or major catastrophic events to the distribution or transmission networks an emergency management team will be formed to coordinate Network Tasman's response and recovery. The appendices detail essential services, communication details, contractor resources, emergency stock, alternative equipment and material suppliers.

Key elements in any disaster response plan will be to establish:

- Resource and manpower requirements if an extended loss of supply over several days is likely
- Effective media liaison
- Retailer communication and coordination of recovery activities.

1 Introduction

1.1 Network Tasman

Network Tasman is an electricity distribution company that owns, manages, and operates the distribution network in the Nelson Region excluding that of Nelson Electricity. The network is made up of overhead lines and underground cables, substations, switches, and connection assets that distribute electricity from four Transpower bulk supply points located at Stoke, Kikiwa and Murchison.

The operational headquarters of Network Tasman is based in Richmond and includes the management of all activities making up the operation and management of an electricity distribution network including maintenance, development and extensions for load growth and supply restoration after faults.

1.2 Purpose of this plan

The purpose of this plan is to set out and document clearly established readiness and response plans relating to Network Tasman's distribution network to be implemented in the event of either natural disasters or catastrophic events related to the failure of the distribution network or the Transpower transmission network.

1.3 References

1.3.1 Emergency plans

- Civil Defence Emergency Management Act (CDEM) 2002
- National Civil Defence Emergency Management Plan Order 2015
- Nelson Tasman Emergency Management Plan

1.3.2 Network Tasman

- Health and Safety Management Plan
- Public Safety Management Plan
- Security of supply participant outage plan – Appendix B
- Asset Management Plan
- Reliability and Risk management Plan
- Use of System Agreements
- Distribution Code
- Network Tasman Policies
- Network Tasman Procedures
- Network Tasman Design and Construction Standards

1.3.3 Other

- Electricity industry emergency contact list (EIECL)

2 Emergency events

2.1 Natural disasters

Expected natural disasters are outlined below.

Event	Likelihood	Impact	Comments
Earthquake	87% probability of mm force 7 in next 50yrs, and 67% mm 8 in next 100yrs	High	Most serious natural disaster for Network Tasman to prepare and respond to. Liquefaction in Nelson Port and Airport likely
Cyclone	Medium	Medium	Would result in a large number of lines down
Lightning Storm	Medium	Medium	Would most likely affect a large number of rural transformers. Possible damage to zone substations
Landslide	Medium	Low	Likely to be localised
Forest Fire	Medium	Low	Could affect Nelson Nth 33kV feeder and other 11kV supplies. Could affect both 66kV lines e.g. over Takaka Hill.
Flooding	High	Low	Relatively low impact on the electricity network- flooding may restrict restoration

Other Less Likely Events			
Tornadoes	Unlikely	Medium	Only relatively small tornadoes known to have occurred historically. A large tornado would cause major localised damage
Eruptions	Unlikely	Low	No active volcanoes but ash from eruption could impact on overhead lines and transmission lines to the Nelson region
Meteorites	Unlikely	High	To date none known to have fallen in the Nelson region.
Tsunami	Unlikely	Medium	Highest recorded in Nelson area 1.5m and would affect low lying areas

2.2 Network Tasman distribution network

The following events are of a major and catastrophic nature:

Event	Likelihood	Impact	Comments
Multiple Zone Transformer Failure	Low	High	Refer to section 11
Zone 66kV, 33kV or 11kV Bus Failure	Low	High	Refer to section 11
Loss of both 66kV transmission lines	Low	High	Refer to section 11
Multiple underground 33kV or 11kV cable failures	Low	High	Refer to section 11
Zone substation fire	Low	High	Refer to section 11
Sabotage	Low	High	Refer to section 11
Major oil spill	Low	Medium	Refer to section 11

2.3 Transpower transmission network

The following events are of a major and catastrophic nature:

Event	Likelihood	Impact	Comments
Multiple transformer failures at GXP's	Low	High	Emergency Generation Likely rolling blackouts Liaison with Transpower NZ Possible Civil Emergency. Refer to section 12.
220kV tower failures	Low	High	Emergency Generation Likely rolling blackouts Liaison with Transpower NZ Possible Civil Emergency Refer to section 12.
Substation bus failure- Stoke, Kikiwa, and Islington	Low	High	Emergency Generation Likely rolling blackouts Liaison with Transpower NZ Possible Civil Emergency Refer to section 12.

2.4 Generation

The following events are of a major and catastrophic nature:

Event	Likelihood	Impact	Comments
Low SI Generation	Medium	Medium	Possible prolonged hot water cutting and rolling blackouts
Low NI Generation	Medium	Medium	Maximum HVDC transfer likely may limit available capacity in South Island
Total system collapse	Low	High	Civil Emergency

3 Civil defence

3.1 Regional plan

The Nelson Tasman Emergency Plan details the priorities and responsibilities for emergency, welfare, and utility services in the event of a Civil Defence Emergencies.

During a civil defence emergency, Network Tasman will carry out its restoration procedures in accordance with this plan and normal operating practices, with priority to essential services, unless instructed otherwise by Nelson Tasman Civil Defence. Regular updates on the status of electricity supplies in the emergency area and restoration planning are provided to civil defence through the civil defence liaison person.

Where access to disaster areas is controlled by civil defence and is required by Network Tasman for the purposes of supply restoration then access permission will be requested from civil defence.

Civil Defence may at any time take control of Network Tasman's resources or order alteration to its restoration priorities.

3.2 National plan

The National Civil Defence Emergency Management Plan 2015 details the principles, priorities, and responsibilities of regional, and local Emergency Management plans as well as generators, transmission, and distribution companies.

3.3 Network Tasman obligations and participation

Network Tasman is a Lifelines Utility with responsibilities under the Civil Defence Emergency Management Act (CDEM) 2002. These include:

- Functioning to the fullest possible extent during and after an emergency.
- Having plans for continuity.
- Participating in CDEM Planning
- Providing technical advice.

3.4 Essential services

Some services such as water, sewer and health care facilities are essential for public health and well-being. Services such as petrol stations and super markets also become essential in the days immediately following an event. Appendix C details essential services and customers provided with line function services either directly or indirectly by Network Tasman.

Essential services will receive priority in restoration of service or alternatively the provision of standby generators (authorised by Civil Defence) in the event of either:

- Civil defence warning
- Declared civil defence emergency
- Major or catastrophic events related to either the Network Tasman or Transpower networks

NTL's 'Security of supply outage plan' (Appendix B) will also be referred to when allocating resources and prioritising restoration of the network following a major event involving multiple outages e.g. major earthquake.

3.5 Liaison

In the event of a declared Civil Defence Emergency or warning impacting on electricity supply, Network Tasman will make available a liaison officer to work out of civil defence HQ if requested. This person will act as the interface between Civil Defence and Network Tasman.

3.6 Generator sockets ("Project plug")

Network Tasman has installed power sockets and changeover switches at the following local area primary schools for the purpose of allowing portable generators to plugged in to provide power to the school complex in the event of a long term power outage:

- Hira
- Tapawera
- Murchison
- Lake Rotoiti (St Arnaud)
- Maruia
- Collingwood
- Dovedale
- Ngatimoti

The sockets are 5 pin male, three phase 400V, 63A, IP67, type 669, 6h, red coloured sockets and are mounted outside, close to the main switchboard. The main switchboard at each school has a manually operated off-load changeover switch fitted to it to allow easy changeover from mains supply to generator supply.

Installation and connection of an emergency generator must be done by a qualified electrician.

4 Disaster management and control

4.1 Emergency management team

For major events an emergency management team will be formed with the prime objective of determining and establishing appropriate strategies, action plans and communication plans for response and recovery. This includes human resource and team welfare planning. Human resource required to carry out the action and communications plans may be drawn from available NTL staff members.

Immediately following a major natural disaster such as a major earthquake, NTL staff will be released from normal duties to attend to family and homes. They will be contacted by the emergency management team within 24 hours.

The Emergency Management Team will comprise:

- CEO (Team Leader)
- Network Manager
- Operations Manager
- A Communications Officer (may be a dual role of one of the other members)

Additional team members as appropriate including:

- Transpower representative
- Retailer representatives
- Civil Defence or/and Local Body representatives

Meetings are to be held as required and directed by the team leader with minutes of meetings distributed to team members on a timely basis.

Events for which the Emergency Management Team may be formed include:

a) Civil Defence warnings or declared emergencies likely to result in a major loss of electricity supplies in the Nelson region for an extended period
b) Major or catastrophic events on either the Network Tasman or Transpower network likely to result in loss of electricity supplies in the Nelson region for an extended period.
c) Multiple generator failure likely to result in a loss of electricity supplies in the Nelson region for an extended period;
d) Natural disaster events such as major earthquakes.

4.2 Network controller

The network controller manages fault restoration and electricity network disaster recovery operations in the field. Controllers are fully trained in the control of electricity networks and familiar with the layout and configuration of the Network Tasman system.

The controller manages supply restoration under all expected normal outage conditions, and manages public safety under the direction of the Operations Manager or Network Manager. Communication with the media is the responsibility of the CEO or Operations Manager.

Network Tasman maintains 24 hour availability of control operator staff who remain within 20 minutes of the control centre at all times.

4.3 Control centre

Electricity supply network operations are controlled from the control centre based at 52 Main Road Hope. This control centre is set up with sufficient communication and information resources to allow one or more system operators to diagnose and direct restoration procedures to field staff throughout the entire Network Tasman supply area. Alternate Control Centre options and issues are discussed below.

At the control centre the schematic representation of the high voltage distribution network in the area is represented by a system mimic diagram. This mimic is a paper based plan that is laid out on a cork tiled wall in the control room. All lines switches and major substations are represented on this mimic diagram and the status of all field switches and connections are recorded on the mimic using indicator pins. All switch operations in the field are matched by corresponding indicator pin movements on the system mimic board. In this way the up to date status of the power system is continuously maintained by the control operator. All field switch operations are also logged with timestamps in the control room operations log book.

As the power system in the area is effectively made up of five separate networks, then the mimic is in five separate parts, one mimic for each network.

The master for the system mimic is a CAD drawing file that is stored on the company's computer fileserver. As new lines are added to the system, the mimic is updated by ink mark-ups. On an approximately six monthly basis these ink alterations are copied back into the CAD master file. Other copies of the mimic may be printed out as required as hardcopy backups to the control room mimic or as portable schematics.

The control room 230V power is backed up by a dedicated, permanently installed 80kW diesel generator so that the control room may continue to operate on an indefinite basis in the event of major and protracted loss of electricity supply.

The generator and UPS system are tested on a bi-monthly basis.

4.4 Alternate control centre

Control centre operations are set up so that they may continue to function following partial or even total loss of the existing control centre facilities.

SCADA and PC network based systems operate as parallel information systems rather than essential series elements in the fault restoration operation. They are therefore not essential for ongoing fault restoration operations. They are important tools however and significantly aid efficient network control operations, particularly under widespread outage conditions. Wherever possible, SCADA services should be made available to the control room.

The absolute minimum resources required for the operation of the control room are:

- One telephone or cell phone operating on the public switched telephone network.
- One repeater based radio telephone base set.
- One system mimic covering the bulk area to be managed, mounted on a wall.
- One laptop or PC running GIS viewer software with a copy of current Network Tasman GIS data files.

An alternate control centre containing the above items as a minimum, has been set up in a relocatable air-conditioned portacom building. This building is kept at Network Tasman's yard at 24 Main Rd Hope. The mimic within this building is regularly updated.

GIS software and data is held on at least two laptop PC's within the company that are generally held physically separate from the existing control centre.

Access to the SCADA system in the alternate control centre is preferred and can be set up by using a laptop based SCADA client connected in to the SCADA system fibre communications loop switch at various sites.

Possible alternate control centre locations with access to the SCADA fibre loop are as follows:

- Network Tasman Main Rd Hope yard.
- Nelson Electricity Haven Road
- Network Tasman Substations Annesbrook, Richmond or Songer St
- Transpower Stoke

Refer Appendix K for the alternate control centre response plan.

Practise/Test run operation of the alternate control centre is undertaken annually. During the test the company's network control centre operations are undertaken from the alternate control centre for one full day.

Test runs of the alternate control centre are recorded as events in INX.

5 Communication

5.1 Radio telephone network

Network Tasman operates an extensive network of VHF voice radio telephone channels that give two way half duplex voice coverage between the Richmond Control centre and mobile units moving around almost all points on the power supply network. There are four repeater sites in the region as listed below:

Fringed Hill Nelson	Channel 1 - Half Duplex FM
Mt Murchison	Channel 2 - Half Duplex FM
Mt Campbell	Channel 3 - Half Duplex FM
Mt Burnett	Channel 4 - Half Duplex FM

In addition to the above the company operates a "simplex" radio telephone channel allowing communication between mobiles within close proximity.

The repeater sites are operated and maintained under contract by Mt Campbell Communications Ltd. Contracted services include emergency repairs to the radio systems and regular performance monitoring. All repeaters have a minimum of 12 hours reserve battery capacity in the event of power supply failure to the sites.

At the Richmond Control Centre a radio base station gives the operators simultaneous access to all radio telephone channels. By assigning the use of the radio channels to specific geographic areas and assigning control room operators the update rights of individual mimics, control room operations can be split to handle simultaneous faults in different supply areas if required.

In addition to the fixed radio repeaters at the sites detailed above, there is a spare repeater unit and antennas that can be programmed with appropriate frequencies for the temporary erection of an alternative radio repeater on another hilltop should one of the fixed repeaters become out of service and inaccessible. Other equipment needed to erect an emergency repeater is a 12V car battery, a portable generator, battery charger and poles on which to mount antennas. This spare equipment is held by Mt Campbell Communications Ltd.

5.2 Telephone

Fault calls are normally received by contract fault call centres, operated under contract to Network Tasman, and are switched in and out on a timetable basis to give a continuous availability. The call centre operations timetable is as follows:

Business Weekdays 08:00 – 17:00	Delta Utility Services – Richmond
All other times	Call Care - Blenheim

Both call centres are equipped to handle many simultaneous incoming calls and although under normal conditions they operate with a minimum number of two operators, they have the capability to expand to eight operators as demand requires. The Call Centre operators are trained to receive fault calls recording sufficient details for the caller to be individually identified and located and carry out a small amount of fault symptom diagnosis in order to pass on the fault details to the correct field personnel. The Call Centres have direct line telephone contact with the Richmond Control Room via an unlisted telephone line into the control room.

All calls from the entire Network Tasman supply area are received by the call centres. A free phone number 0800 508100 is advertised for all electricity related faults.

The Chorus public switched telephone network is the sole carrier of all fault calls from customers to Network Tasman. The Call centres are both remote from the supply area and therefore the telephone network is heavily relied upon not only within the Nelson region but also for its links to these remote centres as well.

In the event of a major telephone network failure radio advertising would be used to notify customers of alternative arrangements for reporting faults depending on circumstances and communication systems available.

5.3 Cell phone

A number of cell phones are available for use in the event that the telephone network is down, and the cell phone system is still operational.

5.4 Satellite telephone

A satellite telephone is available for use in the event that the telephone network is down, and the cell phone system is heavily loaded. This is in the Hope control room.

5.5 Key communication numbers

Key communication numbers are detailed in Appendix D.

6 Information systems

6.1 *Graphical Information System (GIS)*

Geographic Information on the electricity distribution system is at the main office IT centre with access to this from within the control room.

The GIS system contains comprehensive and accurate information on the location and electrical parameters of all components of the network including all poles and points of connection to all customers. Being in computerised form, the information can be queried and searched on any basis including geographic area. The location and contact details of all individual customers are stored in the system also. This system runs on PC screen's throughout the company's main office and in the control room. The system is therefore a valuable information store and information processing resource for the system operator. The GIS system is updated on a daily basis and therefore represents the most current record held by the company.

View only copies of the GIS system are maintained on the control operator's laptop and on other company laptops.

6.2 *SCADA*

Network Tasman has a computer based SCADA system (supervisory control and data acquisition system). This system has a master station located at the Richmond Control centre and remote terminal units located at the company's major zone substations and ripple injection plants. Communication to the outstations is by fibre optic landline and VHF radio.

The SCADA system provides remote monitoring of substation loads and remote control of substation switchgear and voltage regulators. Instantaneous access to conditions at various substations facilitates the safe and controlled transfer of load around the network without loss of supply or adverse effect on customers.

The SCADA system records and time tags all automatic switch operations at substations and also outputs alarms to the system operator whenever abnormal conditions exist at a substation. Unauthorised entry to a substation can also be reported via the SCADA system.

If the SCADA system were unavailable for any reason then the operator may carry out fault restoration procedures using the VHF radio telephone and the system mimic only.

6.3 *Operating manuals, procedures, and reference manuals*

Copies of the instruction manuals for all types of automatic high voltage switchgear and voltage regulators that are used on the network are kept on file in the control room. Also sets of recent photographs of field plant and equipment are available in the control room for reference.

7 Resources

7.1 Network Tasman

After ensuring for the security and safety of family, Network Tasman operations staff will be requested to report to the Control Centre following a declared natural disaster such as an earthquake. If they cannot reach the Control Centre they are to report to the nearest civil defence sector and await transport to Network Tasman. Clear identification and authorisation will be required by all staff under a declared Civil Defence Emergency. Staff will be assigned tasks as required.

7.2 Delta Utilities Ltd

Delta Utilities holds the contract for primary field response to all fault outages and can provide up to approximately 40 field staff. Contract services include:

- Provision of first and second level fault response staff on continuous basis
- Provision of fault vehicles to minimum Network Tasman specification

All personnel performing fault response activities on the network are class approved for these functions by Network Tasman and are required to keep current safety training as per industry standards. All front line fault staff are trained to Network Tasman standards in the operation of all network equipment, and in the fault logging and reporting procedures. The fault responders are controlled by the Network Tasman Controller.

Generally, the contracted resources of Delta Utility Services Ltd could maintain a continuous emergency repair operation for up to 48 hours. Further repair work beyond this time could be carried on a 9-10 hour day basis only. If 24 hour operation was still required then labour resource and possibly materials resource would need to be brought in to the job from outside NTL and Delta Utility Services.

Early assessment and appraisal of resource requirements is essential to prevent overload and to manage response 24 to 48 hours following an event. In the event of a major earthquake it is likely that only about 50% of available resources will be available.

7.3 Treescape

Treescape hold the contract for NTL's vegetation control services. They have the equipment and expertise to deal with vegetation that is interfering with the network, including felling dangerous trees and removing fallen trees from lines. Treescape has the capability to provide a 24/7 response to NTL if called upon.

7.4 Other approved contractors

There are several contractors in the greater Nelson area who have approvals to work on the distribution network. These contractors can be found on the NTL Health and Safety INX system under register 'NTL 08 – Approved contractors register", refer to appendix E.

The largest alternative lines contractors in the Tasman area are:

- PowerTech Nelson – distribution services providers
- Ventia – transmission line services providers (Ventia hold the Transpower contract for field services in the top half of the South Island)

- ElectroNet Limited - ElectroNet has a depot in the Tasman region providing vegetation services to NTL for the 66kV lines. They are part of Westpower and hence have access to distribution services.

Work type competencies (WTC's) for NTL staff and approved contractors are saved in INX also. These can be viewed by selecting 'People' and then searching on their name and then selecting 'Competencies', or by running a report under 'Reports & Graphs' / 'Statistics' / 'Compliance'.

7.5 Lines companies mutual aid agreement

Network Tasman has an operating agreement with other South Island lines companies to share resources during emergencies as and when available. Refer to DMS file 851823, appendix A.

7.6 Other resources

Use of local non-power system electrical contractors may also be required for customer installation requirements (cost allocation issues) or for assistance with other recovery teams. In some instances the resources of civil contractors may be required to assist in the repair of pole foundations, cable trenching and in pole erection.

Appendix E details pre-approved contractors.

7.7 Emergency stock

A list of emergency material stocks such as poles, transformers, line hardware etc. is specified by Network Tasman. This list not only specifies the items and stock levels of each required but it also specifies at which location these stocks are to be situated. This regional list takes into account the type of construction in each supply area, and also the possibility that road access to some areas could be blocked under certain crisis conditions. Stock levels are set around that level needed for a typical continuous restoration exercise lasting up to three days. This period being the expected maximum delay before stocks could be brought in to the area from sources outside the region. Given such a crisis it would be expected that external overload contracting resource would also be required.

Spares for one off critical items in the network such as large distribution transformers, voltage regulators and ripple injection plant equipment are included in the list.

Additional equipment and materials may be obtained from suppliers as detailed in Appendix F.

7.8 Vehicles

Information on NTL vehicles details and their locations is available via the Smartrak fleet management system.

7.9 Portable generators

NTL owns the following portable generators:

Asset no.	Description	Rego.
GEN 1	Original 1 MW diesel (trailer mounted)	A947L
GEN T1	Original 1 MW transformer to match GEN 1 (trailer mounted)	B632M
GEN 2	Gough 550 kVA diesel (skid mounted)	
GEN 3	Gough 400 kVA diesel (skid mounted)	
GEN 4	Gough 200 kVA diesel (skid mounted)	
GEN 5	Yamaha 2.4 kW petrol (hand carry)	
GEN 6	Honda 2.0kW petrol (hand carry)	
GEN 7	GT 5.5kW petrol (hand carry)	
GEN 8	New 1 MW diesel (trailer mounted c/w transformer)	M494U
GEN 9	80kW office generator (permanently mounted)	

The generators (apart from GEN 9) are stored in the NTL Hope depot yard, or in the emergency store (for the hand carry generators).

8 External communication

8.1 Major events

Most faults are managed solely by the network controller and information regarding the fault is posted by them on to the NTL website.

Should a major event occur in which there are widespread and or prolonged outages following a fault, then the NTL Operations Manager or Network Manager will attend in the control room to assist the controller with communications and to provide technical support if necessary. Should this occur, the NTL Manager will advise the Nelson Tasman Emergency Management Group (NTEMG) duty officer of the event via email at the following address: emergencymanagement@ncc.govt.nz

If the NTEMG duty officer requires further information about the event, they will call either the Operations Manager or the Network Manager directly. Should the NTL Manager want to speak with the **NTEMG duty officer**, their number is **0800 683 636**

NTL has a Facebook account which can be used to provide public communication in the event of a major event. The following NTL staff have access to the NTL Facebook account:

- Operations Manager (Robert Derks)
- Easement Officer (Kerryn Delany)
- Office Administrator (Brooke Gill)

The NTEMG will share NTL Facebook posts regarding major events. NTL also has a smartphone outage app and website that can be used to provide information about outages. These communications channels all rely on internet services being available. Mainstream media providers including newspaper, radio and television will contact NTL in the event of a major disruption and the nominated communications officer will field these queries as they arise.

8.2 Civil Defence emergencies and catastrophic network events

In the event of a declared civil defence emergency or a major catastrophic event on either the Network Tasman or Transpower network, media and public relations communication will be handled by the appointed Communications Officer under the Emergency Management Team.

In the event of a failure of normal communication systems, media communication will be via radio telephone from the control centre to Civil Defence HQ either to the Network Tasman liaison officer or direct to the media at Civil Defence HQ. All media inquiries are to be routed to the Network Tasman Communications Officer under declared civil defence emergencies or major catastrophic events.

9 Financial

9.1 Implications

Civil defence or major catastrophic events affecting the Network Tasman network are likely to have major financial implications. The Emergency Management Team is to document and assess the likely impact and notify the Chairman and directors as soon as possible of the implications.

9.2 Financial records

The Operations Manager is to ensure records of all contractual services or material requested from external organisations that have a financial implication are documented and recorded along with the estimated commitment.

9.3 Declared Civil Defence emergencies

It is unlikely that funding will be available from central or local government for restoration of the distribution network following a declared civil defence emergency.

9.4 Authority limits

Under a Civil Defence emergency or major catastrophic events prompt decision making will be essential. The following delegated authority limits will apply:

Chairman & CEO	$1,000,000
Network Manager	$100,000
Operations Manager	$50,000

10 Response plan - natural disasters

10.1 Event, expected effects and response plan

Event	Expected Effects	Response Plan

Earthquake	• O/H lines down due to land movement/subsidence.
	• Pole mounted transformers down
	• UG cable fracture due to land movement/subsidence.
	• Damaged pole mounted substations.
	• Zone Substation damage:
	  ○ 11kV Switchboards,
	  ○ Transformer Bushings
	  ○ Feeder Cable fractures at building entry points,
	• Control Centre destroyed or damaged.
	• Computer network unavailable.
	• Transpower transmission line failure
	• Transpower substation failure
		1. Network Field Survey of 66kV and 33kV Lines Cables Zone Substations 11kV Feeders Distribution Transformers
		2. Forward planning of field manpower and materials resources
		3. Forward planning of control room operator roster.
		4. Liaison with Transpower to ascertain Supply availability
		5. Liaison with Civil Defence
		6. Restoration to take into account critical customer priority
		7. Possible relocation of Control Centre or setup second remote control room at alternate location
		8. Repair priorities by Network Hierarchy.

Event	Expected Effects	Response Plan
Cyclone	• Trees over lines • Lines blown over • Pole mounted transformers down • Drop Leads off OH Transformers • Lateral movement of poles near parallel ditches/cuttings • Zone Substation outdoor bus damage from flying debris • Pole Flooding (see Flooding)	1. Consider holding off field work until storm abates. 2. Network Survey of affected OH lines by Helicopter 3. Forward planning of field manpower and materials resources 4. Forward planning of control room operator roster. 5. Liaison with Transpower to ascertain supply availability 6. Liaison with Civil Defence 7. Restoration to take into account Critical Customers 8. Restoration to take into account critical customer priority 9. Repair priorities by Network hierarchy

Major Flood	• Pole washouts particularly near rivers
	• Padmounts and service box failure
	• Particularly susceptible areas:
	  ○ Central Takaka
	  ○ Annesbrook
	  ○ Tahunanui
	  ○ Transpower Stoke Sub
	  ○ Stoke Ripple Plant
		1. Network Survey by Helicopter - assess access as well as network damage.
		2. Possible forward resource and manpower planning if damage widespread.
		3. Possible switch off HV Feeders if padmounts flooded.
		4. Liaison with Civil Defence
		5. Repair priorities by Network Hierarchy.

Snow Storm	• Possible limitation of Bulk Supply (Transpower 220kV lines affected)
	• Damage to 11kV OH Feeders:
	  ○ Broken Poles
	  ○ Broken crossarms
	  ○ Broken Conductors
	  ○ Feeder tripping due to snow unloading
		1. Consider holding off field work until storm abates.
		2. Network Survey of affected OH lines by Helicopter
		3. Forward planning of field manpower and materials resources.
		4. Forward planning of control room operator manning.

	○ Overhanging trees • Susceptible Areas include: ○ Murchison ○ Kikiwa ○ Takaka Hill ○ Mt Campbell	5. Liaison with Transpower to ascertain supply availability 6. All Field Vehicles to be 4WD. 7. Special requirements for food and clothing of Field Staff. 8. Possible delayed restoration if storm ongoing.
Lightning Storm	• Zone Substation Damage • 66kV lines (e.g. Takaka Hill, Barrons Flat) • 33kV Bus Insulators and Arresters • Possible Zone Substation Transformer breakdown • Large number of distribution sub fuses blown • Some damaged distribution transformers • 11kV cable terminations at overhead line connection points.	1. Consider holding off field work until storm abates. 2. Centralise control in control room. 3. Possible split operation geographically. 3. Consider transfer of call reception to control room. 4. Forward planning of field manpower and materials resources. 5. Forward planning of control room operator manning. 6. Monitor stocks of Fuse links and distribution transformers.

Event	**Expected Effects**	**Response Plan**
Landslips	• Loss of 66kV lines due to slips on land behind Stoke • Loss of 33kV OH supply to Founders, Wakapuaka and Nelson Electricity • Loss of Bulk Supply • Loss of Hope 33kV Circuit • Damage to Stoke Substation 33kV Bus • Damage to Stoke Ripple Plant.	1. Emergency reconstruction of OH line possibly on new route. 2. Consider black-start of Cobb and running it in island mode. 3. Restoration of 33kV via alternative routes where available. 4. Use helicopter for line survey on back hill country feeder routes.
Large Forest Fire	• Loss of HV feeder lines through crossarm fire, pole damage, melted conductors, carbon contamination • Loss of Distribution transformers • Loss of Bulk supply through EHV transmission circuit damage • Susceptible Areas: ○ Brook St Maitai - 33kV to Founders ○ Atawhai 11kV Feeders ○ Dovedale Motueka Valley 11kV Feeders ○ Richmond Hills 11kV Spur lines ○ Mahana - 11kV Feeders ○ Golden Downs - 11kV Feeders	1. Liaise with Civil Defence if necessary 2. Liaise with rural fire network during fire control operations. May require feeder shutdowns 3. Reinforce control of information releases and field staff comment. 4. Restoration may be delayed due to access constraints. 5. Possible restoration by constructing bypass line route.

11 Contingency plan - major or multiple network failure

11.1 Standard procedure

11.1.1 Standard operating fault management

The fault restoration management procedures and systems are designed to handle all expected faults from simple single contingency incidents to multiple simultaneous faults spread out over the entire network area. Basic procedures are followed in all incidents, but operations are split and resources added as demand requires. The control centre has the capability to operate to restore faults in three supply areas simultaneously. If further geographic splits are necessary or faults occur in all supply areas simultaneously then additional temporary control rooms (including the alternate control centre) can be setup.

Under typical network fault procedures, if a fault affecting the HV network or a major section of LV network is encountered, then the rostered control operator is notified and he immediately makes his way to the control centre. Once in the control centre the control operator takes full charge of the fault identification, isolation and restoration process, informing call centres and media of outage area and restoration progress, and calling in and dispatching field resources as required.

11.1.2 Restoration priorities

Where a large number of network faults have occurred or in situations where the supply capacity has been limited and is likely to remain limited for more than 12 hours, then restoration activities are prioritised to restoring power supply to essential services and critical customers as determined in cooperation with Nelson Tasman Civil Defence. Following restoration of supply to essential services priority will be given to critical customers and then network hierarchy detailed below.

Methods of restoration of supply to such customers may be via the distribution network if an 11kV feeder supply is available or by dedicated 11kV supply under conditions of limited power supply availability. Alternatively temporary on site generation may be utilised. Generators may be supplied by either the customer themselves or by Network Tasman. A list of known portable generation for hire is included as Appendix 11 of this document.

Under normal conditions restoration procedures are based on the following network hierarchy

A. 66kV lines
B. 33kV Feeders
C. Zone Substations
D. 11kV Feeder Lines/Cables
E. Distribution Substations

11.2 Catastrophic events

11.2.1 Loss of two 66kV circuits between Stoke – Motueka – Upper Takaka

The 66kV network comprises double circuits between the Transpower Stoke GXP, Motueka zone substation and Upper Takaka substation. The system can withstand the loss of one circuit at a time, but if two simultaneous outages occur between any two adjacent substation then there will be a total loss of supply to some or all of the 66kV zone substations.

If the loss of the circuits is due to major damage to structures, then an emergency structure would be erected to support the lines. NTL has three 26m tall stackable steel structures in the Hope depot suitable for easy transport and erection. Sufficient hardware is available to provide dual circuits to be supported from each structure.

Certain outage scenarios may present the option of Cobb power station being able to provide power to affected zone substations. This is dependent on the power station being 'black started' which is presently being worked on as a project by Manawa Energy. NTL would liaise with Manawa about using this capability if circumstances permit.

11.2.2 Loss of the Upper Takaka – Motupipi 66kV line

A single 66kV line supplies Motupipi out of Upper Takaka substation. A failure of this line results in a total loss of supply to most of the Golden Bay area. NTL has spare poles and hardware stored in Golden Bay for a complete structure rebuild. Supply would remain off until this could be completed. If a prolonged restoration of the damaged line was expected then NTL may consider using diesel generators to provide some supply on a rolling outage basis, but this would be subject to the Takaka Hill road being open and generators being available.

11.2.3 Major zone substation failures

The Network Tasman network generally has n-1 security in the transformers at each of its zone substations. This means that no interruption of supply other than that required for switching would be required for the following:

- Loss of single transformer
- Loss of one side of 33kV busbar
- Loss of one side of 11kV indoor switchboard.

The network is not designed to provide full supply availability immediately after the following events:

- Loss of two transformers at a zone substation
- Total loss of 11kV switchboard
- Total loss of 33kV Busbar
- Total loss of entire substation.

The fault events above have a very low probability of occurrence, however they could result from a deliberate act such as sabotage or arson, from a major circuit breaker malfunction, or from an act of God such as a massive earthquake or direct lightning strike.

In general, the network is not designed to be able to provide backup for either the loss of an entire 11kV indoor switchboard or the total loss of a zone substation, and as a result loss of supply to some customers would be inevitable in these cases until repairs were effected. Where possible, supply would be made to the area via neighbouring substations. Load control and or rolling shutdowns to ration available capacity would then be effected in the remaining area.

In the event of total loss of a zone substation restoration efforts would focus on rebuilding a make shift substation utilising a transformer from a substation that was not carrying abnormal load. The make shift substation would have a single transformer with single 33kV circuit breaker on overhead 33kV bus. The 11kV feeder cables would be re-terminated onto two new temporary ground mounted oil switchgear units – Extensible ABB SD3. These 11kV switch units are held in emergency stock at the Hope depot. Each of these switch units would be directly connected to the transformer. Earth fault protection would be effected via the transformer NCT and a relay tripping the 33kV circuit breaker. Overload protection would be set at 400A (8MVA) for each transformer.

Substation load beyond 16MVA would be temporarily switched away to adjoining substations. The estimated time to complete this work is 72 hours.

In the event of the loss of an indoor 11kV switchboard at a major zone substation, spare ground mount switch units would be installed in the substation switchyard with each of the available transformers connected to them, and operating under split bus solo transformer operation. The earth fault protection would be by means of the transformer NCT directly tripping the 33kV CB. Overload protection would be set at 400A (8MVA) for each transformer. Substation load beyond 16MVA would be temporarily switched away to adjoining substations. The estimated time to complete this work is 48 hours.

During the emergency repair operations, localised load limiting would be necessary. The steps in the 'Participant outage plan' would be followed.

Appendix I details the response plan procedure, equipment and resource requirements and procurement details.

11.2.4 Multiple underground feeder failure
In the event of multiple underground feeder failure, supply would be restored via available alternative circuits where possible. Repair efforts would then focus on locating and repairing the faulted cables. Typically a fault location and cable repair exercise will take 12 hrs. One crew would be assigned to each faulted cable section. Simultaneous cable failures may require resource external to Delta Utilities to be deployed.

During the period of the repair operations, localised load limiting may be necessary. The steps in this process above would be followed. Regular media reports would also be made.

11.2.5 Ripple injection plant failure
Network Tasman operates one ripple injection transmitter in each bulk supply region. These are used to switch storage type loads such as domestic and commercial water heaters and space heaters. They are also used in some areas for meter tariff register switching. The worst case scenario is failure of a plant after it has operated to switch off all controllable loads.

In the event of a failure at a plant immediate activity would be focussed on finding and rectifying the fault in the existing equipment. Limited spares are held for all plants. A spare transmitter is held by supplier, Landis and Gyr, in Auckland. Limited spares are available for the coupling cells.

Ripple control receivers are generally programmed to switch to the on state if they have not received a valid ripple control signal for 24 hours. A media message however would inform customers that they may run out of hot water or that their night storage heaters may go cold within the next 12 – 36 hours, and that they should telephone in if that occurred. Energy retailers would also be informed that meters might not have been switched.

Recovery efforts would be focussed on re-establishing the ripple control plant with the supplier Landis and Gyr.

11.2.6 Fire - Special procedures

In the event of fire, special procedures are needed supplementing normal outage restoration activities.

These may include the following:

- Isolation of the affected area.
- Liaison with fire control officers to allow fire control.
- Restoration of affected supplies not in the fire area via alternative routes where possible.
- Field assessment of damage to network equipment.
- Formulate repair plans, considering new line routes if fire area likely to be inaccessible for extended period.

11.2.7 Oil spill - Special procedures

In the event of oil spill, field resources will be deployed. Activities will focus on the following priorities:

1. Shutting off the source of spilt oil.
2. Containment of spilled oil.
3. Removal of contaminated soils.
4. Reporting to local authorities.

Where oil has been spilled into waterways, professional help may be employed to control oil movement and effect clean-up operations. Appendix J details the response plan procedure, equipment, material and resource requirements and procurement details.

12 Response plan - Transpower bulk supply failure

Situations may arise where the supply capacity into the distribution network is constrained. These may be due to one or more of the following:

1. Component failure on the Transpower transmission network
2. Unavailability of generation
3. Reduced capacity at a Transpower bulk supply substation.

Specific credible incidences that may cause this are as follows:

Event	Bulk Supply Areas Affected	Repair Time	% Capacity Available
Loss of 220kV Transmission Tower Kikiwa - Stoke	Stoke	48 hrs	20
Loss of double circuit Transmission Tower Islington – Kikiwa	Stoke, Motueka, Motupipi	48 hrs	70
Loss of 11kV supply from Murchison GXP	Murchison	Up to 6 weeks	0
Loss of 11kV supply from Kikiwa GXP.	Kikiwa	Up to 6 weeks	0

In these situations NTL is in the position of managing the total electrical load on the local electricity network to within the supply capacity available. The task reverts to a supply allocation and consumer communications exercise.

Generic tasks would include the following:

1) Shutdown all controllable load (typically water heating via ripple control)
2) Activate Rolling Outage Plan to prioritise available supply to feeders with essential services and critical customers. Refer “Network Tasman Participant Outage Plan” – Network Tasman website under “Disclosures”. (DMS189385)
3) Negotiate with large customers to shut down or reduce load.
4) Run media campaign for conservation of electricity
5) System Operator to act in advisory capacity with Emergency Management Team.

In the case of loss of grid supply from Murchison or Kikiwa GXP’s, temporary supply could be made available by connecting portable standalone diesel generators (either NTL owned or hired) to each of the 11kV feeders from the affected substation.

13 Distribution and document information

This plan is saved in DMS as document number **791716**.

A hard copy complete with appendices is kept by the Operation Manager on their desk or in the control room. Soft copies should be used if available to ensure the most up to date references and appendices are being used.

Revision information:

Version	Date	Author	Notes
1	2012	Murray Hendrickson	First version
2	Nov 2022	Robert Derks	Refresh and general update
3	Dec 2022	Robert Derks	S3.6 added
4	Jan 2023	Robert Derks	Em. control room test table updated
5	Jun 2023	Robert Derks	S 8 amended
6	Oct 2023	Robert Derks	S8 and S9 - updated contact details
7	March 2024	Robert Derks	4.4 schedule removed and refer to INX Hard copy distribution list added

Hard copy distribution list:

Hard copy reference number	Document Version	Date	Location
1	7	March 2024	Ops Manager desk

APPENDIX A Mutual aid agreement

Refer DMS Document **851823**.

Network Tasman is party to a mutual aid agreement with other NZ lines companies. Materials, machinery and manpower resources may be requested under emergency conditions from the following lines companies:

- Marlborough Lines
- Mainpower
- Westpower (Electronet)
- Orion
- EA Networks (Electricity Ashburton)
- Alpine Energy
- PowerNet
- Aurora Energy
- Network Waitaki
- Nelson Electricity
- Buller Electricity

APPENDIX B Security of supply participant outage plan

Refer to DMS document number **189385**

The procedures outlined in this plan are for responding to major generation shortages and/or significant transmission constraints. Typical scenarios include unusually low inflows into hydro-generation facilities, loss of multiple thermal generating stations or multiple transmission failures.

APPENDIX C Essential services and critical customers

Essential Services

- Nelson Regional Sewerage Business Unit
- Nelson City Council Water Pumping Stations (potable, waste and storm water)
- Tasman District Council Water Pumping Stations (potable, waste and storm water)
- Nelson Marlborough Heath facilities
- Independent Health Care facilities
- Supermarkets
- Petrol Stations

Critical Customers

- Nelson Electricity (NTL own parts of three of the four 33kV feeders that supply into NEL's Haven Road substation)
- NZ Fire Service
- NZ Police
- Port Nelson Ltd
- Nelson Airport Ltd
- Mt Campbell Communications Ltd

APPENDIX D Network Tasman phone number list

Refer to DMS document number **902431**

APPENDIX E Pre-approved contractors

Refer INX, Register 08 “Approved contractors register”

APPENDIX F Equipment and material providers

Ideal Networks Main Road Hope	03 544 8491 fax 03 544 9304
Marlborough Lines PO Box 144 Blenheim	03 578 4039 fax 03 578 0771
Buller Electricity Limited PO Box 243 Westport	03 789 7219 03 789 7530 a/h fax 03 799 6624
MainPower Limited Private Bag 1004 Rangiora	03 313 6069 fax 03 313 4353
Gough Technology PO Box 22 – 073 Christchurch	0800 802 020 03 379 8740 fax 03 379 6776
Electronic & Transformer Engineering Ltd PO Box 15121 New Lynn Auckland	09 828 0330 fax 09 820 0190
New Zealand Insulators PO Box 5 Temuka	03 615 9551
Electropar PO Box 58623 Auckland	09 274 2020 – customer service 09 274 2000 fax 09 274 2001 A/H 09 575 3982 A/H 09 266 9403 A/H 09 488 0965 A/H 09 624 1608

APPENDIX G Electricity Industry Emergency Contact List (EIECL)

Refer to ‘Electricity industry emergency contacts’ list (EIECL) DMS : **933833**

APPENDIX H Emergency stock list

Refer to DMS document number: **934785**

APPENDIX I   Emergency zone substation contingency plan

Response Plan

The tasks involved in constructing an emergency substation are as follows:

1. Clear area of 6m x 10m within switchyard for construction of emergency substation at site.
2. Arrange decommissioning and transport to site of emergency transformer, tapchange control panel and transformer HV CB. Refer source in table below.
3. Arrange transport to site of 2 x 11kV ground mount 4 way switch units and bases from Network Emergency stock.
4. Install and brace 33kV switch unit and transformer in position directly on the ground.
5. Erect leads from existing 33kV line or cable to new CB. Support using temporary poles and insulators as required.
6. Install and mount 2 x ground mount switch units.
7. Install and terminate transformer incomer cables to 2 x SD switch units.
8. Install and terminate temporary 11kV Feeder cables to ABB SD3 switch outlet terminals and joint into existing feeder cables.
9. Connect and test 11kV Earth fault protection via Transformer NCT and relay.
10. Connect and test Tapchanger control panel.
11. Erect temporary fencing.
12. Commission and liven temporary substation.

The sources of emergency transformers and transformer HV circuit breakers and the times to complete construction of the full emergency substation are given below:

Affected Zone Substation	Transformer and CB Source	Estimated Time to complete
Founders	Brightwater T2	72 hours
Annesbrook	Songer St T2	96 hours
Songer St	Annesbrook T2	96 hours
Hope	Brightwater T2	72 hours
Richmond	Annesbrook T2	96 hours
Eves Valley	Brightwater T2	72 hours
Motueka	Transpower Mobile Substation	170 hours
Brightwater	Founders T2	72 hours
Takaka	Brightwater T2	120 hours
Swamp Rd	Brightwater T2	120 hours

Recovery

Following the above steps, normal supply will be restored to all customers, however with less than normal security of supply. No individual items of plant however will be operating outside their design ratings.

Recovery exercises will be centred on the reinstatement and return to service of the damaged substation. This will generally require extensive planning and may take up to 18 months to completely effect.

APPENDIX J Major oil spill contingency plan

Response Plan

The specific procedure to be followed in the event of an oil spill will vary depending on the extent and local conditions at the spill site. The general procedure to be followed is as follows:

1) De-energise and isolate all equipment that is spilling oil.
2) Stem oil flow using available oil spill kits.
3) Contact local authority and inform them that a spill has occurred
4) Arrange for pumps and tankers to remove excess oil from the site.
5) Discuss containment strategy of spilt oil with local authority and enlist expert assistance as required or directed.
6) Assist or effect containment and removal of contaminated soils as required.

Where oil has been spilled into waterways, professional help may be employed to control oil movement and effect cleanup operations.

“Wheelie bin” type oil spill kits are held at each zone substation. Where the extent of a spill at any one substation is in excess of the capability of the on-site kit then other kits may be sourced from other substations.

Oil drums and pumps may be necessary. These are available from Delta Utilities Ltd.

Network Tasman also has a 5000 litre oil tank in its yard.

APPENDIX K Alternative control centre contingency plan

Response Plan

1. Decide on alternative location:
   a) First choice NTL yard Main Road Hope close to Hope Substation.
   b) Second choice Nelson Electricity yard Haven Road.
   c) Third choice Annesbrook Substation yard
   d) Fourth choice Transpower Stoke Substation yard.
2. Relocate Portacom Control Room to decided location and establish 230V power supply.
3. Setup laptop or PC running GIS viewer software in Control room with copies of current GIS. If data files are unavailable from NTL office, a copy can be procured from:
   a) Network Tasman mobile PC from Lines Surveyors vehicle.
   b) Delta Utilities
4. Establish VHF radio(s) and telephone/cellphone communications.
5. Establish Control desk with switching log books.
6. Establish SCADA laptop client operation by connecting in to SCADA fibre network connection.
7. Notify new control room site location and contact details to:
   a) Emergency Management Team
   b) Network Tasman staff
   c) Nelson Tasman Civil Defence
   d) Delta Utilities
   e) Other Contractors

Recovery

Recovery would focus on re-establishing a permanent control centre/head office. This could take up to 18 months.

APPENDIX L Faults telephone line switching instructions

THIS DOCUMENT IS SWITCHING INSTRUCTIONS FOR CHANGING THE DEFAULT ANSWERING OF THE 0800 FAULT LINE TO NTL OFFICE, TO CALLCARE OR TO A ONE OFF REMOTE DESTINATION.

FOR GUIDANCE ON WHEN TO ACTIVATE TELEPHONE SWITCHING, AND FOR INSTRUCTIONS ON ACTIVATING INFO MESSAGING, PLEASE REFER TO NTL POLICY "LARGE OUTAGE NOTIFICATION PROCEDURE" - DOCUMENT NTL_E_OP_A011_01.

Destinations

Terminating number (contractor)	**543 8073** (destination 1 / default)
Callcare answer service	**546 2303** (destination 2)
NTL Office	**989 3638** (destination 3)

Info message – refer to **NTL_E_OP_A011_01** (destination 4)

One off remote site	area code + site phone number (destination 5)

Please note:

- **If dialling from within Network Tasman first dial 1 for an outside line.**
- **You will hear recorded instructions as you go along.**

To Bring Fault Calls To NTL Office

1. Call fault contractor (or Callcare A/H) and notify them of the change.
2. Ring **0800 365569**
3. Enter Access Number **0800508100**
4. Enter terminating number **03 543 8073**
5. Enter pin number **0310**
6. Press **1** to change destination
7. Enter **3** for NTL Office
8. Enter **1** to confirm (2 to cancel) Hang up now.

Logging on

Up to 20 of Network Tasman's office phones can be set up as a call centre to answer fault calls. Each phone needs to be logged on to the faults call group before it can receive calls from the Fault call queue.

The following extensions are pre-set and can be logged on by pressing the "Log on Faults" key on the phone display once the destination number has been switched to NTL Office.

Extn 612	Jodi	Extn 610	Murray
Extn 613	Robert	Extn 611	Darren
Extn 614	James	Extn 602	Andrew

To "Log on" additional phones refer to the instructions at the end of this document.

While logged on to the fault queue the phone extension will not be available for other calls.

To Divert Fault Calls Directly To Call Care

1. Call fault contractor and Callcare and notify them of change.
2. Ring **0800 365569**
3. Enter Access Number **0800508100**
4. Enter terminating number **03 543 8073**
5. Enter pin number **0310**
6. Press **1** to change destination
7. Enter **2** for Call Care.
8. Enter **1** to confirm (2 to cancel) Hang up now.

To Divert Fault Calls To A One Off Destination

1. Call fault contractor (or Callcare A/H) and and notify them of change.
2. Ring **0800 365569**
3. Enter Access Number **0800508100**
4. Enter terminating number **03 543 8073**
5. Enter pin number **0310**
6. Press **1** to change destination
7. Press **5** for one off destination
8. Enter **the number including the area code** (the number will be repeated to you).
9. Press **1** to confirm the destination (2 to cancel).

To Move Calls Back To Faults Contractor

1. Call fault contractor (or Callcare A/H) and notify them of change.
2. Ring **0800 365569**
3. Enter Access Number **0800508100**
4. Enter terminating number **03 543 8073**
5. Enter pin number **0310**
6. Press **1** to change destination
7. Enter **6** to reset (you will hear the default phone number).
8. Press **1** to confirm (2 to cancel).

To program a one-touch button for logging in/out of the fault queue
press *91,
then press the key you want to program,
press tick to change feature,
press left arrow 6 times to select UCD, press tick
press tick again to Log On,
enter agent Number (100 to 119)
press tick to Save Entry
press tick again to end

APPENDIX M

PROCEDURES FOR RECORDING OUTAGE INFORMATION FOR REGULATORY DISCLOSURE

Reliability Recording Policies and Procedures

For the purposes of compiling annual SAIDI and SAIFI data:

- A high voltage outage on the distribution network is defined as an event resulting in loss of supply to any number of consumers for a duration of more than one minute.
- Only high voltage outages (6.6kV and above) resulting from de-energisation of any high voltage feeder or conductor are included in SAIDI & SAIFI statistics.
- Both planned and unplanned events are included within high voltage outage statistics.
- All high voltage outages are managed through NTL's control room by a qualified NTL system operator.
- The faults and maintenance contract between the company and its faults contractor, Delta Utility Services, obligates both parties to manage all outage events centrally through the control room.
- All HV fault switching operations are recorded by the system operator in the control room log at the time the activity takes place. This provides a detailed record of the switching events for future reference.

Customers affected by operation of a distribution system high voltage protection device can be divided into:

1. Those within the core fault area (i.e. who won't have supply restored until the necessary line repairs are completed).
2. Those outside the immediate fault area (i.e. who can have power restored through coordinated switching activity).

To calculate the customer minutes lost under each fault event, each event is approximated as a maximum two step restoration process. This is in keeping with the philosophy of fault restoration which relies on following a sequential process for supply restoration:

1. Identification, isolation and minimisation of the core fault area.
2. Restoration, through switching, of supply to areas not immediately within the core fault area.
3. Making repairs and restoration of the core fault area.

The switching and recording process is managed by a NTL system operator using NTL's Geographical Information System (GIS). To record outage data, the operator draws geographical selection polygons around all sections of the high voltage line affected by the fault event. The software is then used to select and identify all the distribution transformers within the fault area. A query is then made into NTL's customer connection database to find and list all customers connected to those transformers affected by the fault event.

This data is then used in the following formula to calculate the total customer minutes for a fault event:

Total No. of customers initially affected x (Time Unfaulted Area restored – Time of Initial Interruption)
+ No. of Fault area customers x (Time Fault Area restored – Time Unfaulted Area restored)

Planned and unplanned events use essentially the same recording process, however, by nature, planned interruptions can be identified to a set of consumers and a known area in advance.

The total customer minutes for a planned interruption are thus calculated using the following formula:

Total No. of customers interrupted x (Time Interrupted Area restored – Time of Initial Interruption)

The system operator records details of all outage events in the NTL Outage Database. This is an access database that remains on line in the control room. Each planned or unplanned event forms a one record entry into the database. The Outages Database is subject to NTL's normal electronic file backup and security protocols.

The Outage Database records the following data fields for each event:

1. Date
2. ID number of the protective device that has operated (allows identification of the HV feeder and area affected)
3. Area (text description of area affected)
4. Description (text description of fault cause and type – recorded once known)
5. Outage type (Shutdown or Fault)
6. Area Class (Urban or Rural)
7. Fault Class (Overhead or Underground)
8. Fault Voltage (6.6kV, 11kV, 33kV)
9. Outage Region (Stoke, Motueka, Golden Bay, Kikiwa, Murchison)
10. Time of Initial Interruption
11. Time unfaulted area restored
12. Time fault area restored
13. Customers (ICPs) in Total area (recorded post event)
14. Customers (ICPs) in Fault area (recorded post event)

Unless otherwise stated all data is recorded on line by the system operator at the time of the event.

The outage database is queried on an "as needed" basis by NTL's network and operations managers and summary outage statistics are prepared and provided to NTL's CEO and board of directors on a monthly basis. Annual outage statistics are prepared and independently audited for regulatory reporting purposes. The summary statistics are recorded on a cumulative basis and are used for comparative analysis and form a key input into NTL annual asset management planning process. Annual data is also reported against NTL's SCI reliability targets. These targets are negotiated annually with the Network Tasman Trust.

APPENDIX N

INFORMATION DISCLOSURE SCHEDULES

Schedule 11a	Report on Forecast Capital Expenditure
Schedule 11b	Report on Forecast Operational Expenditure
Schedule 12a	Report on Asset Condition
Schedule 12b	Report on Forecast Capacity
Schedule 12c	Report on Forecast Network Demand
Schedule 12d	Report on Forecast Interruptions and Duration
Schedule 13	Report on Asset Management Maturity

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

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

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

This information is not part of audited disclosure information.

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8			**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**
9		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	1,336	1,175	1,210	1,234	1,259	1,284	1,310	1,336	1,363	1,390	1,418
11		System growth	2,183	5,640	13,637	11,021	8,723	6,711	6,511	7,835	17,736	15,665	8,013
12		Asset replacement and renewal	6,247	7,060	7,571	6,398	6,151	5,782	5,898	6,016	6,136	7,276	6,312
13		Asset relocations	3	-	-	-	-	-	-	-	-	-	-
14		Reliability, safety and environment:											
15		Quality of supply	3,635	3,205	309	315	321	328	334	341	348	355	362
16		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	683	560	659	588	600	612	624	637	650	663	676
18		**Total reliability, safety and environment**	4,318	3,765	968	903	921	940	958	978	998	1,018	1,038
19		**Expenditure on network assets**	14,087	17,640	23,386	19,556	17,054	14,717	14,677	16,165	26,233	25,349	16,781
20		**Expenditure on non-network assets**	528	2,298	879	907	920	941	958	978	997	1,017	1,038
21		**Expenditure on assets**	14,615	19,938	24,265	20,463	17,974	15,658	15,635	17,143	27,230	26,366	17,819
22													
23	*plus*	Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less*	Value of capital contributions	51	107	232	188	152	120	117	138	292	263	141
25	*plus*	Value of vested assets	458	458	472	481	491	501	511	521	531	542	553
26													
27		**Capital expenditure forecast**	15,022	20,289	24,505	20,756	18,313	16,039	16,029	17,526	27,469	26,645	18,231
28													
29		Assets commissioned	17,773	18,973	23,451	21,693	18,924	16,608	16,032	17,152	24,983	26,851	20,333
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			**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**
32			**$000 (in constant prices)**										
33		Consumer connection	1,336	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175
34		System growth	2,182	5,640	13,240	10,490	8,140	6,140	5,840	6,890	15,290	13,240	6,640
35		Asset replacement and renewal	6,248	7,060	7,350	6,090	5,740	5,290	5,290	5,290	5,290	6,150	5,230
36		Asset relocations	3	-	-	-	-	-	-	-	-	-	-
37		Reliability, safety and environment:											
38		Quality of supply	3,634	3,205	300	300	300	300	300	300	300	300	300
39		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	683	560	640	560	560	560	560	560	560	560	560
41		**Total reliability, safety and environment**	4,317	3,765	940	860	860	860	860	860	860	860	860
42		**Expenditure on network assets**	14,086	17,640	22,705	18,615	15,915	13,465	13,165	14,215	22,615	21,425	13,905
43		Expenditure on non-network assets	528	2,298	854	863	858	860	859	860	860	860	860
44		**Expenditure on assets**	14,614	19,938	23,559	19,478	16,773	14,325	14,024	15,075	23,475	22,285	14,765
45													
46		**Subcomponents of expenditure on assets (where known)**											
48		Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
49		Overhead to underground conversion	-	-	-	-	-	-	-	-	-	-	-
50		Research and development	-	-	-	-	-	-	-	-	-	-	-
52													

Company Name	Network Tasman Limited
AMP Planning Period	1 April 2024 – 31 March 2034

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

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

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

This information is not part of audited disclosure information.

sch ref

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
54		**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**
55	**Difference between nominal and constant price forecasts**	**$000**										
56	Consumer connection	-	-	35	59	84	109	135	161	188	215	243
57	System growth	1	-	397	531	583	571	671	945	2,446	2,425	1,373
58	Asset replacement and renewal	(1)	-	221	308	411	492	608	726	846	1,126	1,082
59	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
60	Reliability, safety and environment:											
61	Quality of supply	1	-	9	15	21	28	34	41	48	55	62
62	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
63	Other reliability, safety and environment	-	-	19	28	40	52	64	77	90	103	116
64	**Total reliability, safety and environment**	1	-	28	43	61	80	98	118	138	158	178
65	**Expenditure on network assets**	1	-	681	941	1,139	1,252	1,512	1,950	3,618	3,924	2,876
66	Expenditure on non-network assets	-	-	25	44	62	81	99	118	137	157	178
67	**Expenditure on assets**	1	-	706	985	1,201	1,333	1,611	2,068	3,755	4,081	3,054
68												

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

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

71

72

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
74	**11a(ii): Consumer Connection**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
75	*Consumer types defined by EDB**	**$000 (in constant prices)**					
76	Consumers 20kVA and less	662	455	455	455	455	455
77	Consumers greater than 20kVA	674	720	720	720	720	720
78	-						
79	-						
80	-						
81	**include additional rows if needed*						
82	**Consumer connection expenditure**	1,336	1,175	1,175	1,175	1,175	1,175
83	*less* Capital contributions funding consumer connection	-	-	-	-	-	-
84	**Consumer connection less capital contributions**	1,336	1,175	1,175	1,175	1,175	1,175
85	**11a(iii): System Growth**						
86	Subtransmission	-	-	4,500	7,700	-	2,500
87	Zone substations	17	4,500	6,500	-	900	-
88	Distribution and LV lines	-	290	1,090	1,340	1,590	1,090
89	Distribution and LV cables	420	-	300	-	3,800	1,700
90	Distribution substations and transformers	689	450	450	450	450	450
91	Distribution switchgear	505	400	400	400	400	400
92	Other network assets	551	-	-	600	1,000	-
93	**System growth expenditure**	2,182	5,640	13,240	10,490	8,140	6,140
94	*less* Capital contributions funding system growth	34	87	205	163	126	95
95	**System growth less capital contributions**	2,148	5,553	13,035	10,327	8,014	6,045
96							

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

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

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

This information is not part of audited disclosure information.

sch ref

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
98		**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
99	**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**					
100	Subtransmission	60	60	60	60	310	60
101	Zone substations	1,533	1,670	660	200	200	-
102	Distribution and LV lines	3,247	3,130	3,130	3,130	3,130	3,130
103	Distribution and LV cables	400	900	2,200	1,400	1,400	1,400
104	Distribution substations and transformers	702	700	700	700	700	700
105	Distribution switchgear	147	600	600	600	-	-
106	Other network assets	159	-	-	-	-	-
107	**Asset replacement and renewal expenditure**	6,248	7,060	7,350	6,090	5,740	5,290
108	*less* Capital contributions funding asset replacement and renewal	17	19	20	17	16	14
109	**Asset replacement and renewal less capital contributions**	6,231	7,041	7,330	6,073	5,724	5,276
110							

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
112							
113	**11a(v): Asset Relocations**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
114	*Project or programme**	**$000 (in constant prices)**					
115	-	-	-	-	-	-	-
116	-	-	-	-	-	-	-
117	-	-	-	-	-	-	-
118	-	-	-	-	-	-	-
119	-	-	-	-	-	-	-
120	**include additional rows if needed*						
121	All other project or programmes - asset relocations	3	-	-	-	-	-
122	**Asset relocations expenditure**	3	-	-	-	-	-
123	*less* Capital contributions funding asset relocations	-	-	-	-	-	-
124	**Asset relocations less capital contributions**	3	-	-	-	-	-
125							

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
127		**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
128	**11a(vi): Quality of Supply**						
129	*Project or programme**	**$000 (in constant prices)**					
130	Switchgear	173	800	-	-	-	-
131	11kV interconnections	3,264	2,350	300	300	300	300
132	-	-	-	-	-	-	-
133	-	-	-	-	-	-	-
134	-	-	-	-	-	-	-
135	**include additional rows if needed*						
136	All other projects or programmes - quality of supply	197	55	-	-	-	-
137	**Quality of supply expenditure**	3,634	3,205	300	300	300	300
138	*less* Capital contributions funding quality of supply	-	-	-	-	-	-
139	**Quality of supply less capital contributions**	3,634	3,205	300	300	300	300
140							

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).
This information is not part of audited disclosure information.

sch ref

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
142		**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
143	**11a(vii): Legislative and Regulatory**						
144	*Project or programme**	**$000 (in constant prices)**					
145		-	-	-	-	-	-
146		-	-	-	-	-	-
147		-	-	-	-	-	-
148		-	-	-	-	-	-
149		-	-	-	-	-	-
150	**include additional rows if needed*						
151	All other projects or programmes - legislative and regulatory	-	-	-	-	-	-
152	**Legislative and regulatory expenditure**	-	-	-	-	-	-
153	*less* Capital contributions funding legislative and regulatory	-	-	-	-	-	-
154	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
155							
156		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
157	**11a(viii): Other Reliability, Safety and Environment**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
158	*Project or programme**	**$000 (in constant prices)**					
159	Platform Transformer to Padmount Conversions	484	500	500	500	500	500
160		-	-	-	-	-	-
161		-	-	-	-	-	-
162		-	-	-	-	-	-
163		-	-	-	-	-	-
164	**include additional rows if needed*						
165	All other projects or programmes - other reliability, safety and environment	199	60	140	60	60	60
166	**Other reliability, safety and environment expenditure**	683	560	640	560	560	560
167	*less* Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
168	**Other reliability, safety and environment less capital contributions**	683	560	640	560	560	560
169							
170		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
171		**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
172	**11a(ix): Non-Network Assets**						
173	**Routine expenditure**						
174	*Project or programme**	**$000 (in constant prices)**					
175	IT Expenditure	371	959	665	665	665	665
176		-	-	-	-	-	-
177		-	-	-	-	-	-
178		-	-	-	-	-	-
179		-	-	-	-	-	-
180	**include additional rows if needed*						
181	All other projects or programmes - routine expenditure	157	139	189	198	193	195
182	**Routine expenditure**	528	1,098	854	863	858	860
183	**Atypical expenditure**						
184	*Project or programme**						
185	Property	-	1,200	-	-	-	-
186		-	-	-	-	-	-
187		-	-	-	-	-	-
188		-	-	-	-	-	-
189		-	-	-	-	-	-
190	**include additional rows if needed*						
191	All other projects or programmes - atypical expenditure	-	-	-	-	-	-
192	**Atypical expenditure**	-	1,200	-	-	-	-
193							
194	**Expenditure on non-network assets**	528	2,298	854	863	858	860

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

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

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8			**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**
9	**Operational Expenditure Forecast**		**$000 (in nominal dollars)**										
10	Service interruptions and emergencies		1,346	1,345	1,399	1,441	1,485	1,529	1,576	1,623	1,672	1,723	1,775
11	Vegetation management		1,514	1,465	1,524	1,570	1,618	1,666	1,717	1,769	1,822	1,877	1,934
12	Routine and corrective maintenance and inspection		2,767	2,902	3,019	3,110	3,204	3,300	3,400	3,503	3,609	3,717	3,830
13	Asset replacement and renewal		2,324	2,420	2,517	2,593	2,672	2,752	2,835	2,921	3,009	3,100	3,194
14	**Network Opex**		7,951	8,132	8,459	8,714	8,979	9,247	9,528	9,816	10,112	10,417	10,733
15	System operations and network support		3,964	4,276	4,448	4,583	4,721	4,864	5,011	5,162	5,318	5,479	5,644
16	Business support		2,950	3,059	3,278	3,377	3,479	3,584	3,693	3,804	3,919	4,037	4,159
17	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
18	**Non-network opex**		6,914	7,335	7,726	7,960	8,200	8,448	8,704	8,966	9,237	9,516	9,803
19	**Operational expenditure**		14,865	15,467	16,185	16,674	17,179	17,695	18,232	18,782	19,349	19,933	20,536
20			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
21			**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**
22			**$000 (in constant prices)**										
23	Service interruptions and emergencies		1,346	1,345	1,358	1,372	1,385	1,399	1,413	1,427	1,442	1,456	1,471
24	Vegetation management		1,514	1,465	1,480	1,495	1,510	1,525	1,540	1,555	1,571	1,587	1,602
25	Routine and corrective maintenance and inspection		2,767	2,902	2,931	2,960	2,990	3,019	3,050	3,080	3,111	3,142	3,173
26	Asset replacement and renewal		2,324	2,420	2,444	2,468	2,493	2,518	2,543	2,569	2,594	2,620	2,646
27	**Network Opex**		7,951	8,132	8,213	8,295	8,378	8,461	8,546	8,631	8,718	8,805	8,892
28	System operations and network support		3,964	4,276	4,319	4,362	4,406	4,450	4,494	4,539	4,585	4,630	4,677
29	Business support		2,950	3,059	3,183	3,215	3,247	3,279	3,312	3,345	3,379	3,413	3,447
30	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
31	**Non-network opex**		6,914	7,335	7,502	7,577	7,653	7,729	7,806	7,884	7,964	8,043	8,124
32	**Operational expenditure**		14,865	15,467	15,715	15,872	16,031	16,190	16,352	16,515	16,682	16,848	17,016
33	**Subcomponents of operational expenditure (where known)**												
35													
36	Energy efficiency and demand side management, reduction of energy losses		108	119	120	122	123	124	125	127	128	129	130
37	Direct billing*		-	-	-	-	-	-	-	-	-	-	-
38	Research and Development		-	-	-	-	-	-	-	-	-	-	-
39	Insurance		479	509	514	519	524	529	535	540	545	551	556
41	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*												
42													
43			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
44			**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**
45	**Difference between nominal and real forecasts**		**$000**										
46	Service interruptions and emergencies		-	-	41	69	100	130	163	196	230	267	304
47	Vegetation management		-	-	44	75	108	141	177	214	251	290	332
48	Routine and corrective maintenance and inspection		-	-	88	150	214	281	350	423	498	575	657
49	Asset replacement and renewal		-	-	73	125	179	234	292	352	415	480	548
50	**Network Opex**		-	-	246	419	601	786	982	1,185	1,394	1,612	1,841
51	System operations and network support		-	-	129	221	315	414	517	623	733	849	967
52	Business support		-	-	95	162	232	305	381	459	540	624	712
53	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
54	**Non-network opex**		-	-	224	383	547	719	898	1,082	1,273	1,473	1,679
55	**Operational expenditure**		-	-	470	802	1,148	1,505	1,880	2,267	2,667	3,085	3,520
56													
57	**Commentary on options and considerations made in the assessment of forecast expenditure**												
58	*EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.*												

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref												
7					**Asset condition at start of planning period (percentage of units by grade)**							
8												
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	No.	-	1.00%	19.00%	70.00%	10.00%	-	3	1.00%
11	All	Overhead Line	Wood poles	No.	-	-	50.00%	50.00%	-	-	4	-
12	All	Overhead Line	Other pole types	No.	-	60.00%	40.00%	-	-		2	100.00%
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	10.00%	90.00%	-	-	4	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	80.00%	20.00%		4	
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	-	-	-	100.00%	-	-	4	-
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.	-	-	7.00%	72.00%	21.00%	-	4	7.00%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	100.00%	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	10.00%	90.00%	-	-	4	10.00%
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.	-	-	-	100.00%	-	-	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.	-	-	-	89.00%	11.00%	-	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	13.00%	87.00%	-	4	
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.				50.00%	50.00%	-	4	
35												

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
36					**Asset condition at start of planning period (percentage of units by grade)**							
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	-	84.00%	16.00%	-	4	4.00%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km		4.00%	12.00%	84.00%	-	-	2	4.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
42	HV	Distribution Line	SWER conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	-	100.00%	-	-	2	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	3.00%	12.00%	85.00%	-	-	2	6.00%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	40.00%	60.00%	-	-	2	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	-	91.00%	9.00%	-	4	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	10.00%	25.00%	60.00%	5.00%	-	3	10.00%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	100.00%	-	-	3	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	-	95.00%	5.00%	-	3	-
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	3.00%	34.00%	60.00%	3.00%	-	2	3.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	16.00%	82.00%	2.00%	-	4	-
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	100.00%	-	-	3	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	100.00%	-	-	4	-
55	LV	LV Line	LV OH Conductor	km		5.00%	35.00%	60.00%	-	-	2	5.00%
56	LV	LV Cable	LV UG Cable	km	-	-	10.00%	90.00%	-	-	2	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
58	LV	Connections	OH/UG consumer service connections	No.		5.00%	25.00%	65.00%	5.00%	-	2	5.00%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	10.00%	80.00%	10.00%	-	4	10.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	-	100.00%	-	4	-
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	100.00%	-	-	4	-
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: **Network Tasman Limited**
AMP Planning Period: **1 April 2024 – 31 March 2034**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

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

sch ref

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

8	*Existing Zone Substations*	Current peak load (MVA)	*Not Required after DY2024* Installed firm Capacity (MVA)	*Not Required after DY2024* Security of Supply Classification (type)	*Not Required after DY2024* Transfer Capacity (MVA)	*Not Required after DY2024* Utilisation of Installed Firm Capacity %	*Not Required after DY2024* Installed Firm Capacity +5 years (MVA)	*Not Required after DY2024* Utilisation of Installed Firm Capacity + 5yrs %	*Not Required after DY2024* Installed Firm Capacity Constraint +5 years (cause)	*Not Required before DY2025* Current peak load period	*Not Required before DY2025* Installed operating capacity (MVA)	*Not Required before DY2025* Current security of supply classification (type)	*before DY2025* Current constraint type	*Not Required before DY2025* Current available capacity (MVA)	*Not Required before DY2025* Peak load period +5 yrs	*Not Required before DY2025* Available capacity +5 yrs (MVA)	*Not Required before DY2025* Security of supply classification +5 yrs (type)	*Not Required before DY2025* Peak load period +10 yrs	*Not Required before DY2025* Min. available capacity +10 yrs (MVA)	*Not Required before DY2025* Max. available capacity +10 yrs (MVA)	*Not Required before DY2025* Security of supply classification +10 yrs (type)	*Not Required before DY2025* Forecast constraint type	*Not Required before DY2025* Year of any forecast constraint	*Not Required before DY2025* Constraint primary cause	*Not Required before DY2025* Constraint solution type	*Not Required before DY2025* Constraint solution progress	*Not Required before DY2025* Temporary constraint solution remaining lifespan	Explanation
9	Founders	4	15	N-1	2	24%	15	26	No constraint within	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	
10	Annesbrook	19	23	N-1	8	83%	23	89	No constraint within	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	
11	Songer St	19	23	N-1	8	81%	23	85	No constraint within	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	
12	Richmond	17	23	N-1	10	73%	23	77	No constraint within	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	
13	Hope	11	10	N-1	6	106%	23	53	Transformer	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	Transformer Upgrade to 23MVA firm in 2025
14	Mapua	6	10	N	3	61%	10	68	No constraint within	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	Subtransmssion circuit has N security only
15	Brightwater	7	15	N-1	6	48%	15	53	No constraint within	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	
16	Eves Valley	4	5	N-1	4	76%	5	76	No constraint within	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	
17	Takaka	5	8	N	-	64%	8	67	No constraint within	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	Subtransmssion circuit has N security only
18	Swamp Road	3	3	N	1	93%	3	100	Transformer	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	Subtransmssion circuit has N security only
19	Lower Queen St	17	30	N	-	57%	30	57	No constraint within	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	Industrial customer only requires N security in Subtransmission
20	Motueka	22	23	N-1	1	96%	25	92	Subtransmission circu	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	Transformer Upgrade to 46MVA firm in 2024. Constraint in subtransmission of 25MVA however
21	Upper Takaka	1	6	N-1	1	15%	6	15	No constraint within	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	
22	Wakapuaka	3	8	N	1	45%	8	48	No constraint within	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	Backup 33kV cable circuit being installed in 2024
23						-			[Select one]	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	
24						-			[Select one]	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	
25						-			[Select one]	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	
26						-			[Select one]	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	
27						-			[Select one]	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	
28						-			[Select one]	[Select one]		[Select one]	[Select one]		[Select one]		[Select one]	[Select one]			[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	

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

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**

SCHEDULE 12c: REPORT ON FORECAST NETWORK DEMAND

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

sch ref

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected during year by consumer type*			**Number of connections**			
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 28**
11	*Consumer types defined by EDB**						
12	Group 0	0	0	0	0	0	0
13	Group 1	590	599	608	617	626	635
14	Group 2	46	46	46	46	46	46
15	Group 3	5					
	Group 6	0	0	0	0	0	0
	Group CB	0	0	0	0	0	0
16	Group MAT	0	0	0	0	0	0
17	**Connections total**	641	645	654	663	672	681
18	**include additional rows if needed*						
19							
20							
21							
22	**Distributed generation**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
23	Number of connections made in year	495	505	515	525	536	547
24	Capacity of distributed generation installed in year (MVA)	5	5	5	5	6	6
25	**12c(ii) System Demand**						
26		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
27	**Maximum coincident system demand (MW)**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 28**
28	GXP demand	126	127	128	129	130	131
29	*plus* Distributed generation output at HV and above	4	4	4	4	4	4
30	**Maximum coincident system demand**	130	131	132	133	134	135
31	*less* Net transfers to (from) other EDBs at HV and above	17	18	18	18	18	18
32	**Demand on system for supply to consumers' connection points**	113	113	114	115	116	117
33	**Electricity volumes carried (GWh)**						
34	Electricity supplied from GXPs	656	663	669	676	683	689
35	*less* Electricity exports to GXPs	78	79	79	79	80	80
36	*plus* Electricity supplied from distributed generation	196	197	198	199	200	201
37	*less* Net electricity supplied to (from) other EDBs	90	90	91	91	92	92
38	**Electricity entering system for supply to ICPs**	684	691	697	704	711	718
39	*less* Total energy delivered to ICPs	650	656	662	669	675	682
40	**Losses**	34	35	35	36	36	37
41							
42	**Load factor**	69%	70%	70%	70%	70%	70%
43	**Loss ratio**	5.0%	5.0%	5.0%	5.1%	5.1%	5.1%

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
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		**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 28**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	107.0	100.0	100.0	100.0	100.0	100.0
12	Class C (unplanned interruptions on the network)	128.0	75.0	75.0	75.0	75.0	75.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.35	0.70	0.70	0.70	0.70	0.70
15	Class C (unplanned interruptions on the network)	1.21	1.07	1.07	1.07	1.07	1.07

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	Although there is no specific AM Policy, chapter 2.2 of the AMP embodies the key elements of an AM Policy (systematic asset investment driven by customer preferences for supply reliability and price). Board sign-off of the AMP can be considered authorisation of these policy elements.	Network manager noted that chapter 6.2 of the AMP includes replacement policies for individual asset categories.	Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	Chapter 2.2 of the AMP sets out a range of stakeholder goals (eg. delivering supply reliability and prices aligned to customer consultation results etc) that drive the AM Strategy.	Network manager noted that the latest (Nov 2018) customer consultation recorded a 90% satisfaction including a strong preference for paying about the same to have about the same reliability.	In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	Chapters 6.1 and 6.2 of the AMP clearly recognise asset classes, and recognise the deterioration of assets over time. Chapter 6.6 of the AMP sets out the lifecycle tactics for each asset class.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3	Chapter 6.6 of the AMP sets out the lifecycle management policies and tactics for major asset classes. It is noted that the Design Standards, the Construction Standards and the Material Specifications are a key driver of lifecycle performance.	Network manager noted that the Design Standards can be amended as a result of performance and faults.	The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	In addition to the AMP being publically disclosed on the web, chapter 2.5 of the AMP describes the key stakeholder engagements that includes individual major customers, retailers and representative community groups such as Federated Farmers. The process of setting the SCI targets requires the Trust to engage with the Board on those targets. The Delta contract sets out NTL's expectations of continuity, restroation and costs.	Contractor GM said the AMP signals the long-term view, and on an annual basis year-ahead work is signalled about December from which work packs are compiled.	Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	Chapter 2.6 of the AMP sets out the responsibilities of all NTL staff, and in particular delinates the responsibilities of the Operations Manager and the Network Manager. The Network Manager is responsible for the cost and performance outcomes of the Delta contract.	Corporate Services manager clarified that the Operations Manager is responsible for the maintenance and tree trimming component of the Delta contract.	The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2	From a financial perspective, the AMP sets out 10 year forecasts which are approved by the Board. The Chief Executive has confirmed that the AMP spend forecasts are the primary driver of revenue, cashflow and pricing.	Contractor GM commented that the market for good people is tight, but Nelson is an attractive location. About 10% of the workforce are trainees.	It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Chapter 2.6 of the AMP notes that the Delta contract includes a fault response service. A comprehensive Disaster Readiness and Response plan is set out in Appendix L of the AMP which considers an appropriate range of natural disaster and asset failure scenarios.	Network manager noted that the Disaster Readiness and Response plan was externally reviewed by Mitton ElectroNet, for which some recommendations for improvement were made and which have been adopted.	Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Chapter 2.6 of the AMP sets out clear responsibilities for the Operations Manager and the Network Manager. The delegated authorities set out in the AMP requires CEO approval for spend over $50,000.	Network Manager commented that NTL's structure and contracting out arrangement emphasises the separation of Own, Think and Do.	In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3		CEO confirmed that the 10 year AMP spend forecasts are the primary driver of NTL's cashflow requirements, which in turn drives pricing (within the constraints of the DPP) - it is noted operating cashflows are strong enough to fund all forecast works, eliminating the need for capital funding. Suitable land for zone substations is designated well in advance to allow systematic network growth. Oliver did note that experienced engineers and trades staff are becoming hard to get, especially as other EDB's increase their spending.	Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	The importance of meeting asset management outcomes of safety, supply reliability and cost (price) are communicated in increasing detail from the Trust to the Board (via the SCI), from the Board to the CEO (via his KPI's, and through the AMP sign-off), from the CEO to the Operations Maanger and the Network Manager	Telecommunications and Metering manager commented as one outside of the electricity line services activity that asset management outcomes and performance are regularly talked about.	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	NTL has Design Standards and Construction Standards in place to minimise the likely non-conformity of work. Delta understand these requirements and regularly engage with NTL to ensure conformity.	Contractor GM confirmed that Delta observe trends and recommend changes back to NTL.	Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

		Company Name	**Network Tasman Limited**
		AMP Planning Period	**1 April 2024 – 31 March 2034**
		Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2	Discussion with key contractor on forthcoming AMP works and resource requirements.	Network manager confirmed that recruitment and development is driven by the AMP forecast work volumes and competencies eg. an aging cable fleet will require more cable jointers, NTL's planned replacement of copper conductor requires additional staff. Delta are recruiting based on NTL's forecasts.	There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3	Competency management through NTL Health and Safety system and AHC processes.	Contractor GM confirmed that competencies tend to be driven by EDB's choice of assets, and contractors need to demonstrate those competencies. It was confirmed that almost all NTL work fits within Delta's competencies.	Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3	Competency management through NTL Health and Safety system and AHC processes.	Contractor GM confirmed that Delta's HR strategy follows EDB's requirements, including 10% as trainees. In particular safety is systematically managed to a very high level.	A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

			Company Name	**Network Tasman Limited**
			AMP Planning Period	**1 April 2024 – 31 March 2034**
			Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	In addition to the AMP formally communicating conceptual asset management requirements, AM information is also informally commuicated by various means that range from asset condition inspections through to meetings with Delta. The Network Manager also meets with Delta to ensure that the Contract is meeting agreed performance and cost targets.	Contractor GM confirmed that the AMP and annual work plans are used to communicate long-term trends and annual work volumes to Delta. Murray added that larger projects are signalled to both Delta and to other contractors thru the AMP being available.	Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	Chapter 1.4 of the AMP summarises NTL's main information repositories, whilst Figure 3 at chapter 2.10 shows how these repositories feed into the maintenance and renewals plan, the development plan and ultimately the AMP.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3	Lifecyle information for each asset class including end of life failure modes and their identification has been collected.	Network manager confirmed that failure modes of individual asset categories (eg. copper conductor vibration and annealling) are a key driver of the classes of asset information captured and stored.	Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	A small number of inspectors who are specifically experienced in electricity distribution and specifically trained in asset condition assessment are deployed. Regular communication between asset inspectors to ensure consistency.	Network manager indicated that the core is asset condition databased derived from network inspections. The key measure of the quality of asset condition inspection data is the reconciling of internal condition of removed assets with the decision to renew. Feedback mechanisms exist to inspect removed components to calibrate renewal timing eg. wooden cross arms are sawn through to verify the extent of decay. Copper conductor removed from the network is also tensile strength tested.	The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	The primary evidence that the AM system set out in chapter 2.10 of the AMP is adequate and relevant to NTL's needs is the safe and reliable operation of the network as evidenced by a range of recurring and one-off inspection activities.	Network manager also confirmed that the asset condition information requirements are linked to condition drivers and failure modes, citing the recent concrete pole report compiled by the University of Canterbury.	Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	NTL addresses risk through the asset lifecycle primarily by using Design Standards and Construction Standards to minimse non-conformance at the start of the assets life, and then uses various inspection methods to assess asset condition through its life. These inspections inform the maintenance and renewals plan (chapter 2.10 of the AMP). There are also several external overlays to NTL's own lifecylce risk management which include the PSMS audit, inspection of works by Network Compliance, post-construction inspection of works as part of the Delta contract, and one-off inspections such as the Mitton ElectroNet review.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	3		Network manager confirmed that various feedback loops are in place to optimise the risk of in-service failure.	Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3	NTL uses a wide range of activities to ensure compliance and best practice, including subscribing to bulletins and journals, attending conferences, seeking external advice and assurance etc. These are incorporated into the AM system as process changes, including additional inspections or audits, amending thresholds or targets, over-writing previous data etc.	Corporate Services manager confirmed that he does a legislative compliance confirmation every 6 months that is reported to the Audit & Risk Committee.	In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	Quality control along the asset lifecycle is firstly established through the Design Standards, the Construction Standards, and the Material Specifications. This may include NTL reviewing design work performed by external parties. The next step include post-construction inspection of completed works as part of the Delta sign-off and payment process. Chapter 6.6 of the AMP sets out the range of asset inspection methods that are used to detect deteriorating condition.	Contractor GM commented that Delta has a QSE person in Nelson for the NTL contract.	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3	The on-going safety and reliability of the network is the primary criteria that NTL uses to asses the robustnenss of its AM practices (ie. calibrating the required inputs to the rerquired output). Various assessments of safety and reliability including the external audit of the PSMS, post-construction inspection of works, routine condition inspections, external inspection by Network Compliance, and the one-off Mitton ElectroNet inspection all point to an appropriate feedback and control mechanism.		Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3	NTL starts measuring the performance of its assets on an ex-ante basis by requiring adherence to Design Standards, Construction Standards and Material Specifications followed by post-contruction inpsection (as part of the Delta sign-off and payment process). Once commissioned, assets are subject to on-going inspections by prescribed methods to detect deteriorating condition, which feeds into the maintenance and renewal planning process. Assessment of asset condition over many decades indicates that the condition and performance targets are appropriate.		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3		Network manager said that failures tend to come through Ops manager, and him and Network manager investigate the failure and its wider implications and trends eg. ABS's being refurbished with different insulators.	Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	Network Tasman Limited
AMP Planning Period	1 April 2024 – 31 March 2034
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	Formal audits of wider AM activities include external assessment of the AMMAT, external assessment of the PSMS, and one-off reviews such as the Mitton ElectroNet asset condition assessment. Scrutiny of narrower aspects of the AM system include review of individual network designs and post-construction inspection of assets.	Contractor GM said that Delta has a comprehensive safety management framework in place that parallels its management struture. Delta has also engaged Network Compliance to examine their own field practices. This has since migrated to NTL so it oversess all of NTL's contractors, not just Delta.	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3		Contractor GM said that Delta have put a known defects register in place that signals failure trends to NTL. Network manager described how him and Ops manager discuss recurring faults to identify trends and define remedial actions.	Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	3		Corporate Services manager described the improvements being made to the Business Case template to ensure that a prescribed range of benefits are systematically considered, options for low investmnet are adequately considered, and that investment is aligned to strategic goals.	Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	NTL staff receive journals and bulletins, attend conferences and seek external advice on AM technologies and practices.	Telecommunications and Metering manager confirmed that larger investment opportunities are subject to rigorous analysis that includes specific variation scenarios.	One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Company Name	**Network Tasman Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

APPENDIX O

SUPPLEMENTARY NARRATIVE INFORMATION DISCLOSURES

Notification of Planned supply interruptions and Communication during Unplanned supply interruptions

Planned supply interruptions are notified to retailers at least 10 working days prior to proposed date of the interruption together with an alternative date should the interruption not occur on the proposed date. Reasons for the postponement of an interruption to the alternative date may include unexpected weather events, contracting staff illness (e.g Covid) etc.

The ICP numbers affected by the planned interruptions are sent to the appropriate retailer in a standard file format.

On receipt of notification from Network Tasman, each trader must promptly notify those affected customers for which it is responsible of the planned supply interruption and must ensure that notice is received by affected customers at least 4 working days' prior to the planned supply interruption.

Unplanned supply interruptions are posted on the Network Tasman website. A map showing the affected area together with an expected time of restoration when known are displayed. This map is posted automatically upon the tripping of a field circuit breaker or manually by the control room operator.

Major and longer term interruptions such as during Civil emergencies are also communicated through other media in conjunction with CDEM.

The formal notification/communication obligations with respect to supply interruptions are set out in Schedule 5 of Network Tasman's Default Distributor Agreement (DDA). The current version of Network Tasman's DDA is available on our website (https://networktasman.co.nz/information-retailers/).

Low voltage network power quality monitoring:

Network Tasman has completed a roll out of advanced electronic meters across its network. It communicates with these meters via a mesh radio network. The meters are on consumer switchboards and the coverage rate is currently 76%. Communicating meters are 95%.

Having these meters rolled out provides for a high degree of voltage quality monitoring, reporting and alarming across the network. Meters automatically send alarms if the voltage at the meter goes out of regulatory tolerance. Tools provided by Smartco Ltd and used by Network Tasman allow for the early detection of abnormal network conditions such as hot or broken connections, providing enhanced system performance and safety.

Any non-compliances with voltage quality requirements of the Electricity Safety Regulations are promptly followed up and rectified. This may include investigations into and upgrading of network capacity in LV networks in some cases.

Consumers affected by voltage quality issues are communicated with individually and kept informed of all responses whether these are repairs (e.g poor connections) or LV reticulation upgrades to reduce supply impedance.

More detail on the Smartco voltage monitoring tools is provided in the section discussing innovation below.

Practises and Processes for Connecting New Customers and altering existing Customer Connections.

Network Tasman has a consumer connections section that manages all new and existing network extensions and individual connections on the network.

The design and construction of all network extensions and any upline works required to reticulate and connect a new subdivision or large industrial development are outsourced to Network Tasman authorised electrical reticulation service providers.

Network Tasman has a published reticulation design and construction standard, which it requires authorised service providers to work to. This standard specifies the capacity design and voltage drop allocations in the new works and also the equipment, materials and installation methods to be used in construction.

Developers planning to create new industrial installations or residential subdivisions are directed to these service providers following initial consultation with Network Tasman. The selected service provider will talk with the developer and create a reticulation design and bring this to Network Tasman for approval. At the approval stage Network Tasman will consider the proposed reticulation design and may specify additional works related to providing added security or provision for future extension etc. Necessary easements or access requirements will also be discussed at the design approval meeting.

Project funding as to what the developer pays for and what Network Tasman pays for are specified under the Network Tasman Connection of New Loads Policy. This policy covers both urban and rural developments with differing levels of contribution from Network Tasman to projects depending on load and distance from major zone substations. In rural situations load and distance based Network Development Levies also apply. The Connection of New Loads policy is posted on the Network Tasman Website on the “New Connections, Reconnections and Alterations to Existing Connections” page.

Vesting of new works in Network Tasman is also agreed at the development approval stage. Network Tasman has a standard agreement document that covers the legal transfer of assets to be vested by the developer to Network Tasman at the time of livening of the new works.

Once all of the above has been considered and agreed, the reticulation service provider can provide a quotation to construct and connect the new reticulation to the network and undertake any additional works specified by Network Tasman. A contract for the works construction can then be formed between the service provider and the developer.

Prior to livening, a Network Tasman works auditor will inspect the new works for compliance with Network Tasman’s standard. Any non-compliances are required to be rectified prior to the livening of the new works.

Individual customer connections are managed under a Network Connections Application (NCA) process. Connection applications must specify the standard connection capacity required (number of phases and fuse sizing). Each NCA is considered for available network capacity – whether or not it is in a pre-reticulated subdivision or a new connection to the existing network etc. ICP capacity upgrades/downgrades are handled through the NCA process as well.

Injection connections are handled separately and if they require an upgrade to the capacity of an existing ICP, then this is managed using the NCA process. Injection is handled in line with the requirements and processes prescribed by Part 6 of the Electricity Industry Participation Code. Each application is individually considered in terms of available hosting capacity. If network upgrades are required to provide requested hosting capacity, applicants are provided with options of undertaking the network upgrade at their cost, or alternatively restricting the amount of power injected into the grid.

Network Tasman has consciously looked to minimise the costs to consumers of making connections with the network, by setting up and fostering a competitive market of reticulation development service providers. In order to facilitate this, NTL created design and construction standards for all service providers to operate to. It also created its Connection of New Loads Policy, its standard easement document and its vesting agreement document.

Planning and managing communications with consumers about new or altered connections is initially facilitated by having a “New Connections, Reconnections and Alterations to Existing Connections” page on its website where the NCA process is explained and on-line forms are available. The process for developers is also explained on the page. The list and contact details of the authorised reticulation service providers is also on this page. Following that, consumers and developers are keep abreast of the progress of their new connection or alteration through contact with our new connections staff.

Delays in completing processes can arise from equipment availability delays, contractor workload delays and in small numbers of cases, delays in completing major upper network upgrade projects where these are required.

Customer Services Practises

Our customer service standards are included in our Default Distributor Agreement with traders. These standards include response times to outages, communication errors in planned outage notifications, water heating service standards etc. Penalties for breaches are based on penalty payments to consumers impacted by the service standard breach.

Network Tasman aims to manage and resolve all customer complaints, and advises consumers of the independent complaints review services provided by Utilities Disputes Limited.

When a consumer makes a complaint, Network Tasman will:

- Acknowledge the complaint within two working days;
- Treat all complainants courteously and with respect showing sensitivity to any health, disability or language issues relating to the complainant;
- Investigate the issues that led to the complaint and respond within seven working days;
- Strive to settle complaints within 20 working days. If we cannot, we will advise the complainant of the reason and agree an extension.
- If we cannot reach a settlement within 40 working days, we will advise the complainant of their options, including referring the complaint to Utilities Disputes Limited.

Network Tasman undertakes mass market and industrial consumer satisfaction surveys bi-annually. The reports from these are appended to our publicly disclosed asset management plan (AMP) and they inform our AMP.

The latest survey was undertaken in 2022.

Assessing the impact of new connections likely to have a significant effect on network operations or asset management

High capacity (MW scale) new industrial connections or large residential subdivision developments can impact long term AMP planning and/or network operations.

All applications for new connections are assessed by Network Tasman’s consumer connections section under guidelines provided to them by the Network Manager who is responsible for network planning. If a proposed connection is expected to come under this category, then it is brought to the attention of the Network Manager for modelling in the Company’s network loadflow model in conjunction with all other existing and proposed load applications. This modelling takes into account the geographic and electrical locations of the proposed new load.

If there is an immediate change to the upper network required to accommodate the new load then the necessary incremental development projects are identified and the costs of these are estimated.

Funding contributions for such developments are determined through the application of the Connection of New Loads policy. Any developments that perturb the long term AMP capital development program are brought into the next AMP update.

The timing of supply availability is negotiated with applicants particularly where large loads are involved. It is made known with developers and consultants in the district that Network Tasman needs to know at as early a stage as possible about applications coming for large loads. Generally this advice is well heeded. Uncertainty is managed through continuous and open communication between the parties.

Financial risks to Network Tasman posed by the uncertainty around new connections are managed through the contribution commitments required by the Connection of New Loads Policy and those required of the reticulation contractors. Also the prescribed administrative processes are designed to provide a degree of risk mitigation for Network Tasman.

<u>Innovation practises</u>

Network Tasman established SmartCo in 2013 along with a number of other NZ EDBs with a view to increasing visibility of our LV network. "Hiko Energy Insights" is a technology initiative developed by SmartCo to improve electrical safety and network management.

The strategic objectives of the initiative were identified as:

1. Reducing the need for large capital expenditures over the next 20 years.
2. Enable monitoring and management of individual connection points from the bottom up, and a platform to identify and resolve issues more quickly and efficiently.
3. Provide end consumers with the potential for greater control over their energy usage.

The initiative will improve the technical performance of the network by providing better asset management and network planning through the software. The initiative will also reduce costs by addressing technical risks and improving network efficiency. Customer service has been improved as has field workforce management with a number of historically reactionary tasks now being addressed in a planned manner.

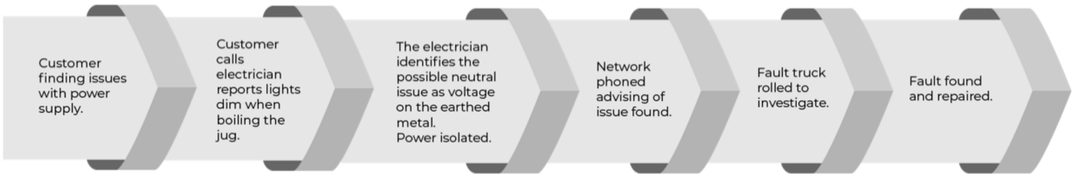
Network Tasman is adopting Hiko Energy Insights across our business in the following areas:

Business Area: Maintenance Engineering

SCENARIO: Customer Brown Out or Receiving Electrical Shock

Process

Common Current Process | MONTHS



Hiko Current Process | WEEKS

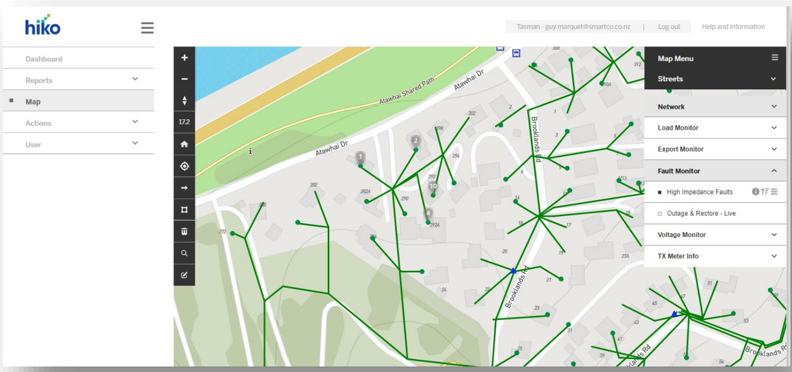
Value to Role

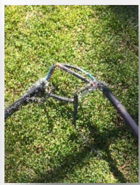
- Providing a customer with better service
- Reduced inbound calls from Customers.
- More planned work/reaction to emergencies less
- Save a Life or Serious Harm
- Proactive Network Safety management

Added Value

- Reducing High Consequence Risk (low incident rates)
- Response Time Reduced
- Save time and money by reducing Fault Truck jobs.
- Reduced 3rd Party Claims of Damage (time to process)

Hiko Images

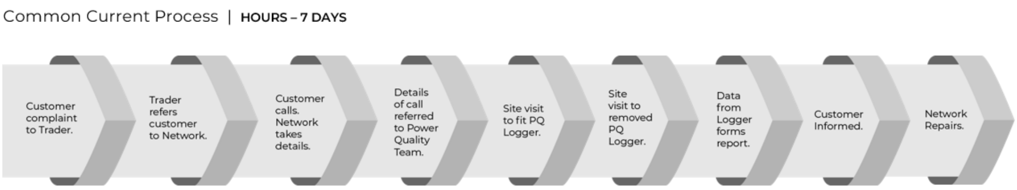


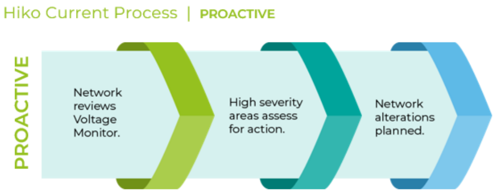


Business Area: Power Quality Engineering

SCENARIO: Voltage Complaint

Process





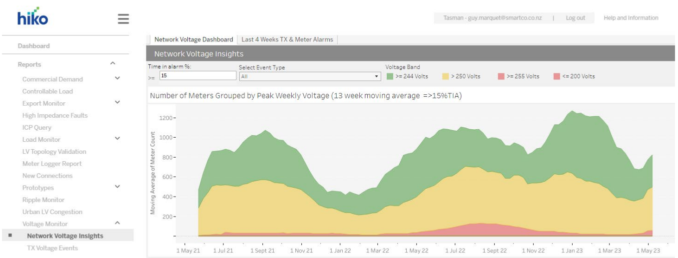
Value to Role

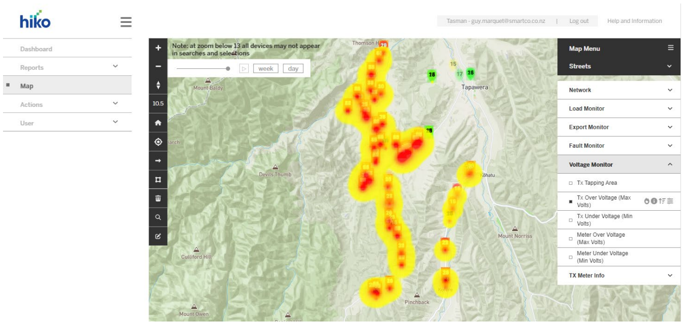
- Delivering improved customer service
- Reduced inbound calls from Customers.
- More planned work/reaction to emergencies, less
- More proactive network quality management

Added Value

- Substantiates asset management planning and budgeting.
- Utility Disputes Complaints reduced.
- Reduces damage to Customer Equipment
- Work completed is monitored

Hiko Images



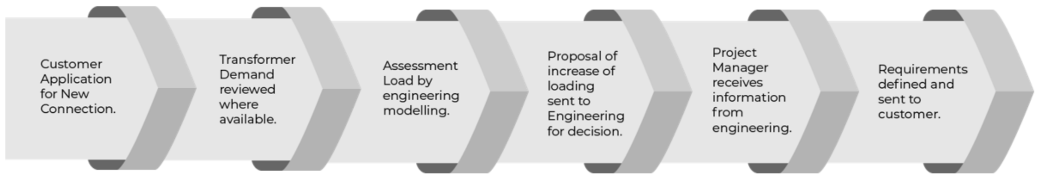


Business Area: New Connections Project Management

SCENARIO: Request for Increase Load or New Connection

Process

Common Current Process | **WEEKS**



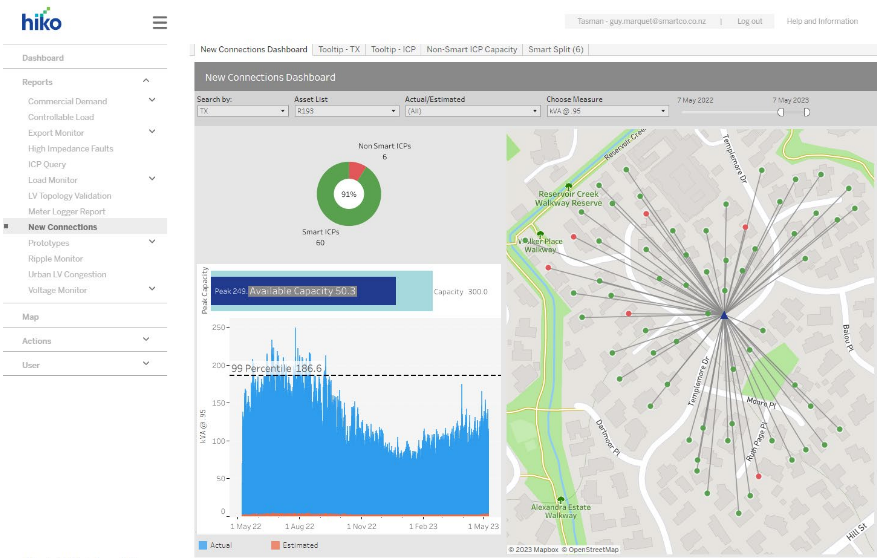
Hiko Current Process | **HOURS**

Value to Role

- Empowered to make good decisions.
- Less complication / back-log of requests pending 'engineering decisions'
- Customer satisfaction improved

Added Value

- Customer response time reduced = better service

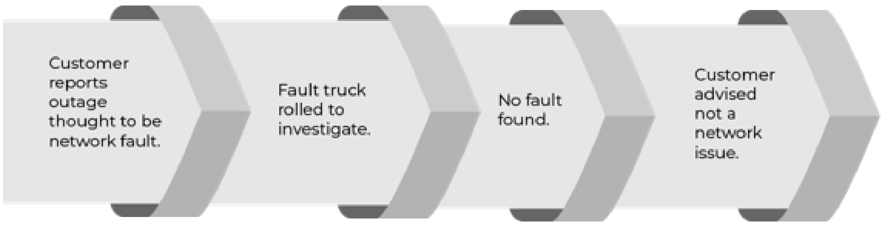


Business Area: Network Faults Supervision

SCENARIO: Rural Outage (25% to 40% Homeowner Issues)

Process

Common Current Process | X HOURS



Hiko Current Process | MINUTES

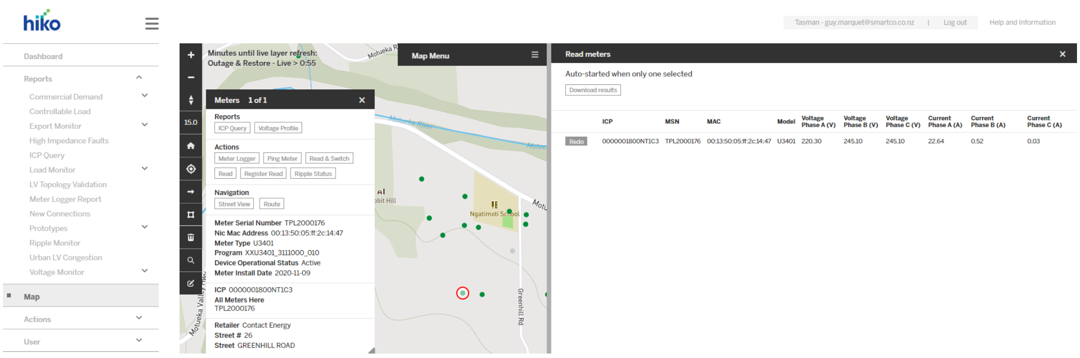
Value to Role

- No travel to the site able to assess remotely.
- No need to arrange faults person to attend

Added Value

- Decrease the cost and volume of unplanned work.
  (Unplanned work 3x more costly than planned work!)
- Protect planned work schedules
- Customer response time reduced = better service

Hiko Images



Business Area: Maintenance Engineering

SCENARIO: Distributed Generation Compliance

Process

No current Process

Hiko Control Export Monitor Process

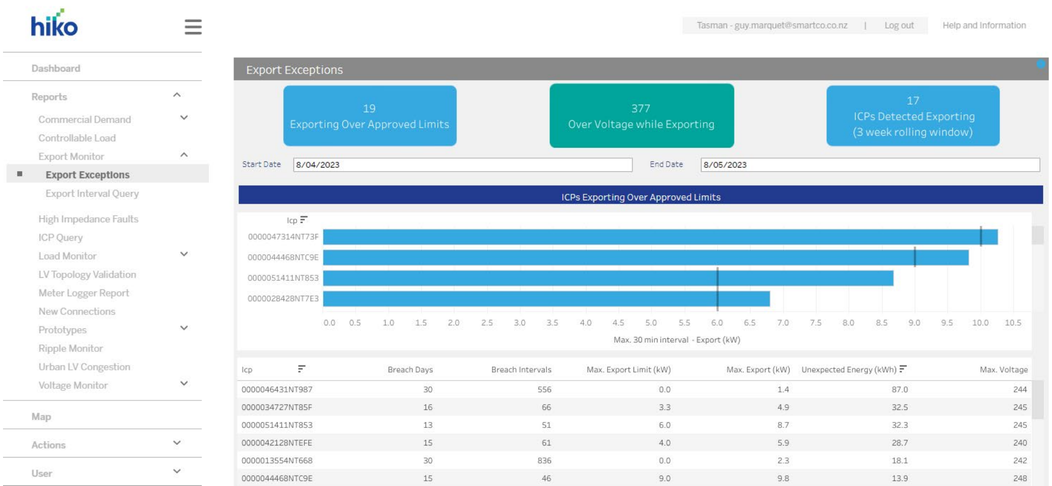
Value to Role

- Keeping the Network Team Safe
- Reduce the number of calls

Added Value

- Reduced H&S Risk of Electrical Shock
- Accommodate other/future customers to install solar/generating.
- Reduces Voltage issue incidents for Customers

Hiko Images



Network Tasman has also established mechanisms for the direct control of residential batteries through ripple control. This innovation expands on the load already under its control through its automatic load management system. It has not implemented this control to date however as it was discovered that the main owner of distributed battery storage was already using the batteries to suit Network Tasman's peak load profiles, by responding to price signals in its line tariffs.

The control mechanism remains an innovation for the future.

To be adopted by Network Tasman, any innovation must deliver benefits that provide value for money for end-use consumers i.e benefits in the provision of line function services that consumers are prepared to pay for and that are cost effective when compared with other means of providing the same benefit. The innovation must also demonstrate performance in terms of reliability, safety and availability that is line with traditional network solutions.

Network Tasman is not averse to contracting with other companies for innovation services but any contracts must guarantee performance and companies contracted with must be "robust" from a technical support point of view and from a financial point of view.

networktasman
Your consumer-owned electricity distributor

Network Tasman Limited
52 Main Road, Hope 7020
PO Box 3005
Richmond 7050
Nelson, New Zealand

Phone: +64 3 989 3600
Freephone: 0800 508 098
Email: info@networktasman.co.nz
Website: www.networktasman.co.nz

IN ACCORDANCE WITH THE COMMERCE ACT

Electricity Distribution Information Disclosure Determination 2012

Clause 2.9.1

Certification for Year-beginning Disclosures 2024

We, SARAH LOUSIE SMITH and ANTHONY PAGE REILLY, being directors of Network Tasman Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

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

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

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

S Smith

Sarah Louise SMITH

A Reilly

Anthony Page REILLY

25 March 2024