ASSET MANAGEMENT PLAN

2016-2026

NETWORK TASMAN LIMITED

CONTENTS

1 EXECUTIVE SUMMARY

1.1 *OVERVIEW AND PLAN PURPOSE*

The Network Tasman Limited (NTL) electricity network distributes power to approx 38,500 end use consumers in an area of 10,800 sq km in the northwestern corner of the South Island of New Zealand. The coverage area is shown in the map of Appendix A.

The 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.

This plan incorporates regulatory reporting 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 2016 and extending to 31 March 2026. The date of this revision of the plan is 31 March 2016. This document was approved by the NTL board of directors on 21 March 2016.

The next review of this plan will be issued on 31 March 2017.

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 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 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 increase consumer value.

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

- Consumer service (provision for adequate capacity and reliability), based on both direct consultation with large customers and use of suitable proxies for estimating the requirements of the mass market.
- Safety (of workers, contractors and the general public)
- 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 new 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. In this environment, the company is looking to applying new technologies to defer large capital projects where it is practicable and economical to do so.

To adjust for the likelihood that only a proportion of projects will proceed, a downwards adjustment has been made to forecast capital expenditure in Appendix D.

1.4 ASSET MANAGEMENT SYSTEMS AND INFORMATION

A number of information sub-systems 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
- Use of suitable proxies for consultation with the mass market, such as security standards based on industry best practice and the level of customer dissatisfaction expressed to Network Tasman.

1.5 NETWORK CONFIGURATION AND ASSET DESCRIPTION

The plan covers the network assets of NTL which comprise:

- Subtransmission lines and cables
- Distribution lines and cables
- Substations including all plant and equipment within the substation such as transformers, switchgear, SCADA
- Protection relays and voltage regulators
- Control centre – SCADA and associated communications systems
- Load control facilities

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

On December 1 2014, Network Tasman acquired the 66kV subtransmission assets in the northwest of the south island. These assets include two 66kV overhead lines between Stoke and Golden Bay and three substations at Motueka, Upper Takaka and at Cobb Power Station. These were previously owned and operated as part of the national grid by Transpower NZ Ltd.

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	13
Ripple Injection Transmitters	5
66kV + 33kV Networks (km)	311
22kV + 11kV + 6.6kV Networks (km)	2,145
400V Networks (km)	1,114
Distribution Substations	4,471
Overall Peak Load (System Demand for supply to consumer ICPs)	114
Annual Energy Delivered (MWh for supply to consumer ICPs)	603,500
Annual System Load Factor	65.0%

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

The asset management plan does not cover non-network assets such as non-network related land and buildings, motor vehicles or furniture.

1.6 SERVICE LEVEL OBJECTIVES

Reliability targets have been reviewed 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.

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

Recent consumer consultation undertaken consisted of:

- Direct and detailed consultation with the approx 30 largest consumers.
- Assessment of mass market satisfaction via consultation with Trust and consumer groups.

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	1999/0	19	12	31	62	122	184	215
	2000/1	67	0	67	35	70	105	172
	2001/2	44	0	44	21	49	70	114
	2002/3	43	0	43	17	91	108	151
	2003/4	36	7	43	26	95	121	164
	2004/5	55	9	64	28	118	146	210
	2005/6	26	73	99	25	97	122	221
	2006/7	51	125	176	33	77	110	286
	2007/8	16	0	16	45	111	156	172
	2008/9	53	44	97	37	215	252	349
	2009/10	0	79	79	62	85	147	226
	2010/11	48	18	66	48	129	178	244
	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
Forecast	2015/16	15	0	15	99	84	183	198
Target	2015/16	35	5	40	40	75	115	155
	2016/17	10	5	15	75	75	150	165
	2017/18	10	5	15	75	75	150	165
	2018/19	10	5	15	75	75	150	165
	2019/20	10	5	15	75	75	150	165
	2020/21	10	5	15	75	75	150	165
	2021/22	10	5	15	75	75	150	165
	2022/23	10	5	15	75	75	150	165
	2023/24	10	5	15	75	75	150	165
	2024/25	10	5	15	75	75	150	165
	2024/26	10	5	15	75	75	150	165

SAIFI

		Transpower Planned	Transpower Unplanned	Total Transpower	NTL Planned	NTL Unplanned	NTL Total	Overall SAIFI
Actual	1999/0	0.05	0.23	0.28	0.65	2.01	2.65	3.77
	2000/1	0.23	0.06	0.29	0.29	1.34	1.63	1.92
	2001/2	0.14	0.00	0.14	0.13	0.87	1.00	1.14
	2002/3	0.17	0.20	0.37	0.19	1.30	1.49	1.86
	2003/4	0.14	0.37	0.51	0.15	1.07	1.22	1.73
	2004/5	0.23	0.53	0.76	0.23	1.48	1.71	2.47
	2005/6	0.14	1.40	1.54	0.13	0.92	1.05	2.59
	2006/7	0.14	1.63	1.77	0.29	1.23	1.52	3.29
	2007/8	0.09	0.02	0.11	0.20	1.32	1.52	1.63
	2008/9	0.17	0.49	0.66	0.15	1.53	1.68	2.34
	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
Forecast	2015/16	0.10	0.00	0.10	0.40	1.20	1.60	1.70
Target	2015/16	0.12	0.12	0.24	0.29	1.07	1.36	1.60
	2016/17	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2017/18	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2018/19	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2019/20	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2020/21	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2021/22	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2022/23	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2023/24	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2024/25	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2025/26	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	1999/0	380	52	111	95	61	69	57
	2000/1	291	0	231	121	52	64	90
	2001/2	314	0	314	165	57	70	100
	2002/3	258	1	116	86	70	60	81
	2003/4	247	19	84	169	89	99	95
	2004/5	239	17	84	122	80	85	85
	2005/6	186	52	64	192	105	116	85
	2006/7	364	77	99	113	63	73	87
	2007/8	177	21	147	225	84	103	106
	2008/9	315	90	147	244	140	150	149
	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
Forecast	2015/16	150	0	150	248	70	114	116
Target	2015/16	300	40	167	138	70	85	97
	2016/17	333	40	100	139	70	93	94
	2017/18	333	40	100	139	70	93	94
	2018/19	333	40	100	139	70	93	94
	2019/20	333	40	100	139	70	93	94
	2020/21	333	40	100	139	70	93	94
	2021/22	333	40	100	139	70	93	94
	2022/23	333	40	100	139	70	93	94
	2023/24	333	40	100	139	70	93	94
	2024/25	333	40	100	139	70	93	94

Asset effectiveness targets are as follows:

Service Criterion	**Key Performance Indicator**	**Annual Target 2015/16 to 2025/26**	**Actual 2014/15**	**Forecast 2015/16**
Supply Quality	Number of proven voltage complaints	10	4	3
Contractual Performance	Breaches of UOSA	0	1	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 incidents	0	1	1
Safety	Public Injury near misses	52	49	56
Safety	Public Property near misses	5	7	4

Asset efficiency targets are as follows:

Service Criterion	**Key Performance Indicator**	**Annual Target 2016/17 to 2025/26**	**Actual 2014/15**	**Forecast 2015/16**
Thermal Efficiency	Network Losses	6%	5.7%	5.6%
Transformer Utilisation	KVA peak demand/distribution transformers	30%	29%	27%
Operating Efficiency	Cash operating costs per consumer	$290	$264	$278

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 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 very good overall condition at present. This conclusion is supported by the low rates of faults per line km experienced over the network (long term average approx 6 per 100km pa).

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 75% overhead by circuit length. The overhead distribution is 95% based on concrete poles that are well manufactured to a conservative design. These poles have shown to have a life in excess of 70 years in the benign Nelson environment. Aside from a small number of poles in relatively short sections of coastal line and in estuaries, and approximately 1200 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. Studies are ongoing to attempt to identify the ageing mechanism that will bring about the end of life of the poles. Iron rail poles on the network however are reaching end of life and many will be replaced with concrete poles over the next decade. There are a small number of treated softwood poles dating back to the 1970's. The oldest of these may be reaching end of life. Condition testing of these will commence within the timeframe of this plan.

Crossarms on the network have varying life from 15 to 45 years. Condition of in-service crossarms is assessed individually as timber quality is highly variable even within individually supplied batches of crossarms. Local climatic 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 approximately 1200 replacements per year.

Line hardware is mainly of porcelain and galvanised steel that has a very long life in the Nelson environment. Some specific items have identified failure mechanisms (eg. two piece dropout fuses and "kidney" strain insulators) and replacement strategies for these are now being implemented.

Overhead line conductor in service is mainly copper, steel reinforced aluminium (ACSR), or all aluminium conductor. 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. A ten year programme to replace light copper conductors on high voltage lines is included in this plan. This is to commence in the 2016/17 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 been recently completed.

Galvanised steel conductor installed in the 1940's and 50's is still in place on some rural spur lines. This is reaching end of life due to corrosion and is targeted for replacement with ACSR.

The underground cables on the network are mainly paper 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 of lower capacity HV cables has been recently identified 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 situation is being monitored, since underground reticulation was commenced in the early 1970's the oldest cables are now 45 years old. Network Tasman has developed a replacement programme for these cables and this program is expected to commence within the time horizon of this plan.

The 66kV subtransmission system is based on a combination of hardwood poles, concrete poles and lattice towers.

The network contains eleven 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. All are in good condition and are well designed for normally expected electrical and seismological duty. There are twenty 33/11kV three phase power transformers, four 66/11kV three phase transformers and one 66/33kV transformer bank in service at these substations. The power transformers range in age from 1 to 57 years. All are monitored by annual dissolved gas analysis test and diagnosis.

A programme of insulation testing and winding reclamping of the oldest transformers is underway. To date all of the four transformers manufactured prior to 1968 have undergone a mid-life refurbishment are expected to see out a 70 year life. Due to the fact that the transformers have been conservatively loaded and have not experienced high numbers of through faults then no transformer end of life is expected within this AMP timeframe. Tapchangers on the two oldest units (cc1959) have been replaced with modern equivalents in conjunction with transformer refurbishment.

High voltage circuit breakers consist of nine 66kV outdoor ground mounted CB's, two indoor 33kV switchboards, twenty pole mounted 33kV CB's, seven indoor 11kV switchboards and sixty four 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 over 30 years old are obsolete and are being replaced under a switchgear replacement programme. This programme is nearing completion.

There are 268 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 are subject to a replacement programme due to a weakness in the design that creates intermittent operational problems.

The network contains 4,471 distribution substations ranging in size from 5kVA to 1MVA. A small number of in-service transformer failures occur each year as a result of lightning strikes mainly. A distribution transformer renewal programme targeting the replacement of in service transformers that are older than 60 years is in place.

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 bulk supply region and steady but slower growth in the Motueka and Golden Bay regions. The Kikiwa and Murchison regions have shown significant growth in the past few years due to land use change to dairy farming and forestry processing.

A steady increase in base domestic and small commercial load annually over the whole region is expected of approximately 6GWh and 2.0MW per annum for the period of this plan. This growth excludes large consumer specific load increases. This translates to a steadily decreasing growth rate in percentage terms.

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. Electric vehicle recharging is a new load that may develop within the time horizon of the plan. There is limited information on how this will affect network loading at present. Electric vehicles are small in number in the area at present but are expected increase over time. The effects of electric vehicle charging will be considered in future AMP reviews.

The load factor of the expected incremental growth is less than the current system load factor due to new loads such as domestic space heating appearing on peak and the effect of solar distributed generation which negates consumption but does not negate peak network load. This may lead to an overall declining system load factor over time.

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 NTL network is generally of low consumer density. This means that network constraints reached tend to be primarily end of line voltage related rather than component current capacity related. Upgrades to specific items of equipment due to projected overloading therefore tend to be the exception rather than the rule.

The development projects include some specific upgrades to the 33kV sub-transmission system, additional zone substations and some specific reinforcements of the 11kV distribution system. Non-specific developments 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. This is transmitted to the Nelson region over 220kV lines. Transmission capacity from Christchurch to Nelson was upgraded in 2006 by approximately 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 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.

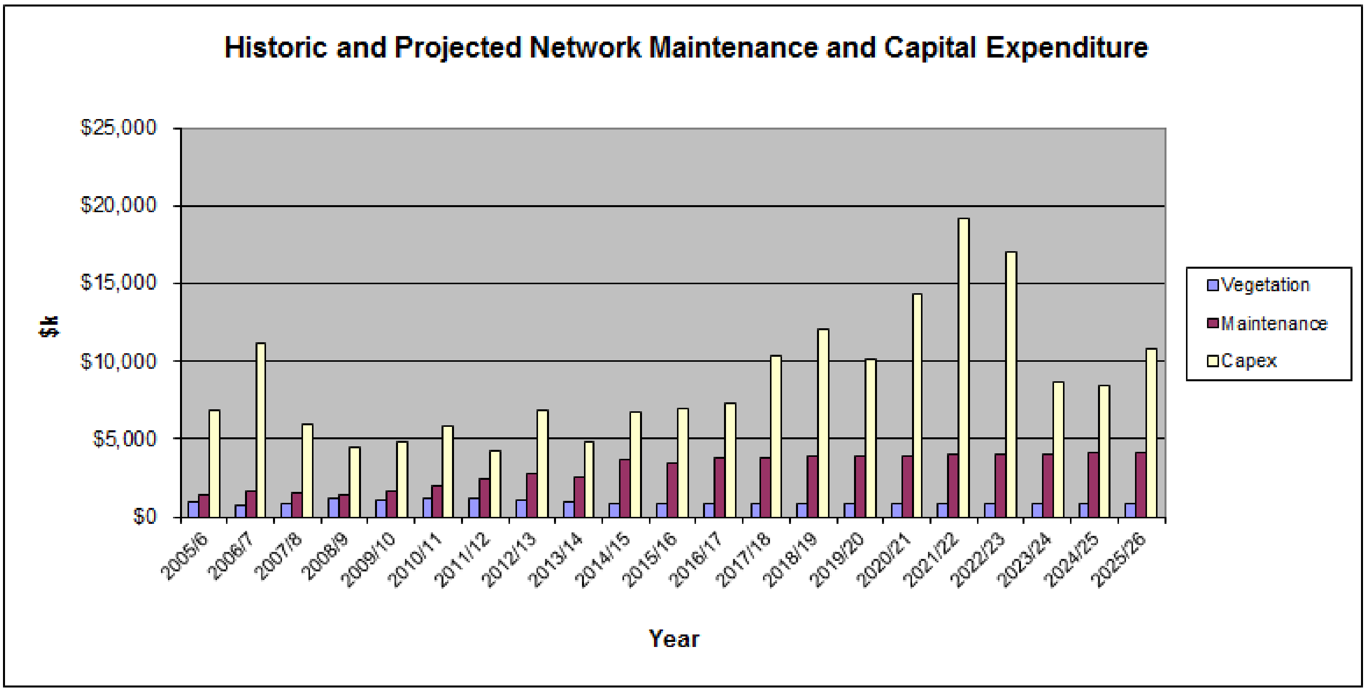
Apart from the specifically identified network development projects, allowance has been made for network line extensions to new consumers in both urban subdivisions and in rural areas. The capital contributions policy was revised during 2011, and capital development contributions from prospective new 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:

- Upgrade of Motueka Zone Substation.
- Extension of 33kV network to proposed new substations at Hira and Wakefield.
- Construction of new Grid exit point substation at Brightwater.
- Construction of new zone substation at Riwaka.
- End of life distribution transformer renewal programme.

The chart below shows the overall levels of expenditure on the distribution network since 2006 together with the projected expenditure to 2026.



This chart shows that capital expenditure has been steady and around $6m per year since 2006/7 when two zone substations were added to the network. Increased capital expenditure is

expected for the next eight years during which time a number of upgrades to existing substations are planned a new major GXP substation (2020-22) will be required.

Meanwhile, network maintenance and renewals continues at a steady rate of approx $4m per year, mainly consisting of crossarm and pole hardware replacements. Vegetation maintenance expenditure is also shown in the chart generally averaging approx $0.8m per year. Vegetation expenditure is treated as an operational overhead but NTL views it as an important and necessary component of operating a high performing network.

1.9 RISK MANAGEMENT

A risk assessment and risk management study of the distribution network was initially undertaken by the company during 1998. This study has been reviewed and updated in conjunction with the 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 this document under section 5.4.

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 Recovery Plan" (refer Appendix L) for those risk events that are treated through deployment of a specific contingency plan.

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. NTL is aware of this risk and will seek assurance from Transpower that prudent management of this risk is in place.

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 to the board.
- Regularly reviewing Public Safety Hazards and implementing risk mitigation strategies

1.10 PERFORMANCE GAP ANALYSIS AND IMPROVEMENT PLANS

The network reliability performance target (SAIDI), was exceeded in 2014/15 due to a cyclone that occurred over Easter 2014, and it is forecast to be over target for 2014/15.

SAIDI from unplanned outages is forecast to be slightly over target (84 against target 75). There have been three unplanned outages that created more than 3 SAIDI points, but aside from these 2015/16 has been a typical year with no extreme storm events.

SAIDI from planned outages however is forecast to be well over target (99 against target 40). This is partly due to a shutdown of the Golden Bay supply area which has an 'N' security of supply. Previously these shutdowns have been classed as Transpower shutdowns but with the transfer of the 66kV network to NTL in Dec 2014, these shutdowns are now attributable to NTL's network.

A higher number of maintenance shutdowns have also contributed to the overall result. Some of these shutdowns have been to allow conductor replacement work to take place. Unfortunately in these cases it is often not possible to provide alternative means of supply as the network is in effect non-existent while the wires are being replaced. Further conductor replacement works are programmed in the future.

In light of the above factors, the reliability targets for planned outages for the term of this plan have been revised upwards in this review of the AMP. Class C SAIDI target increases from 40 to 75 and SAIFI increases from 0.29 to 0.54.

The 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 five to ten 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.

Recent consultation with consumers indicates that there are no major concerns with respect to the supply reliability delivered or with the line price paid.

Network development activity continues in line with the development plan, so that network capacity and security is not compromised in the face of growth in load.

Distributed generation in the form of Solar PV has high uptake in Nelson when compared with other areas of NZ, however the current overall penetration level is not significant enough to effect network operations at present. Solar PV growth in the area is ongoing. The company is undertaking 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. The potential for consumer grid connected battery storage is also being investigated with the aim of developing operating systems that benefit both the consumer and the network.

Ongoing network maintenance and renewal activity includes pole, crossarm and line hardware replacements, trefoiling of 11kV circuits in some areas, and renewing overhead line corridors.

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 improving the overall accuracy of some datasets.

2 BACKGROUND AND OBJECTIVES

2.1 ASSET MANAGEMENT PLAN PURPOSE

The purpose of this asset management plan (AMP) 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:

1. **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. **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 employment legislation and electricity industry safety standards.
   - develop and operate appropriate risk management practices.

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.

4. **Environmental Responsibility**
   NTL is committed to managing its business in an environmentally responsible manner for the benefits of its consumers, community, shareholders and staff. NTL's commitment is set out in its environmental policy.
   Particular environmental objectives identified include:
   - A duty to avoid discharge of contaminants into the environment.
   - A duty to avoid noise.
   - A duty to avoid, remedy or mitigate any adverse effects on the environment.

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 NZ 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.
- NZ Electrical Codes of Practice
- Resource Management Act 1991
- Electricity Governance Rules.

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 REVIEW PERIODS

The planning period of this AMP is 1 April 2016 to 31 March 2026.

This document was approved by the board of NTL on 21 March 2016.

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 2017.

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 conflict 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 reliable, safe and sustainable network operation. Balancing this trade-off is the primary function of the asset management process.

Feedback from consumer/stakeholders is formally sought through direct consultation. The consultation process was last undertaken during 2012. 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 conflict 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.

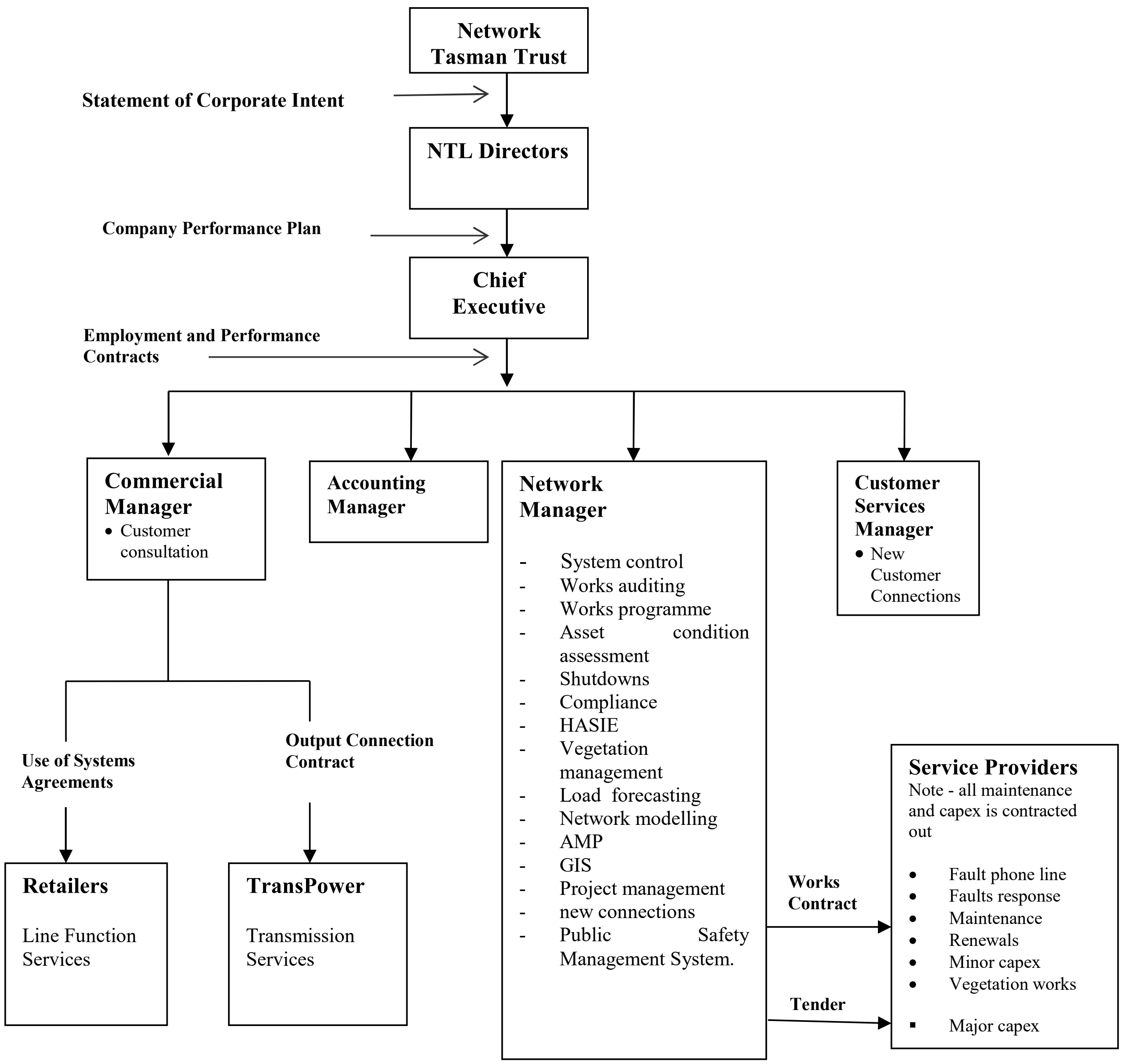
Key stakeholders and their interest in NTL are generally summarised below.

Stakeholder		Interest
Customers	Retailers Direct supplied consumers End use consumers Developers Electrical Contractors	Reliability of Supply Quality of Supply Price of services Company Operational Efficiency Capital Contributions Policy Safety
Suppliers	TPNZ Electrical Contractors Service Providers	Utilisation of provided services NTL Financial viability
Other	Local Authorities Community Groups Government	Underground conversion policy Environmental performance Regulatory Compliance Corporate Citizenship
Company	Trust Beneficiaries Network Tasman Trust Directors Management Staff	Financial Performance Operational Performance Quality of Employment

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 3 largest consumers. The Trust has the role of appointing the directors of the company, and approving the Statement of Corporate Intent (SCI), which is the guiding document of the company. The Trust, as representatives of the consumers, also have a role of feeding back 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 six 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 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 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.

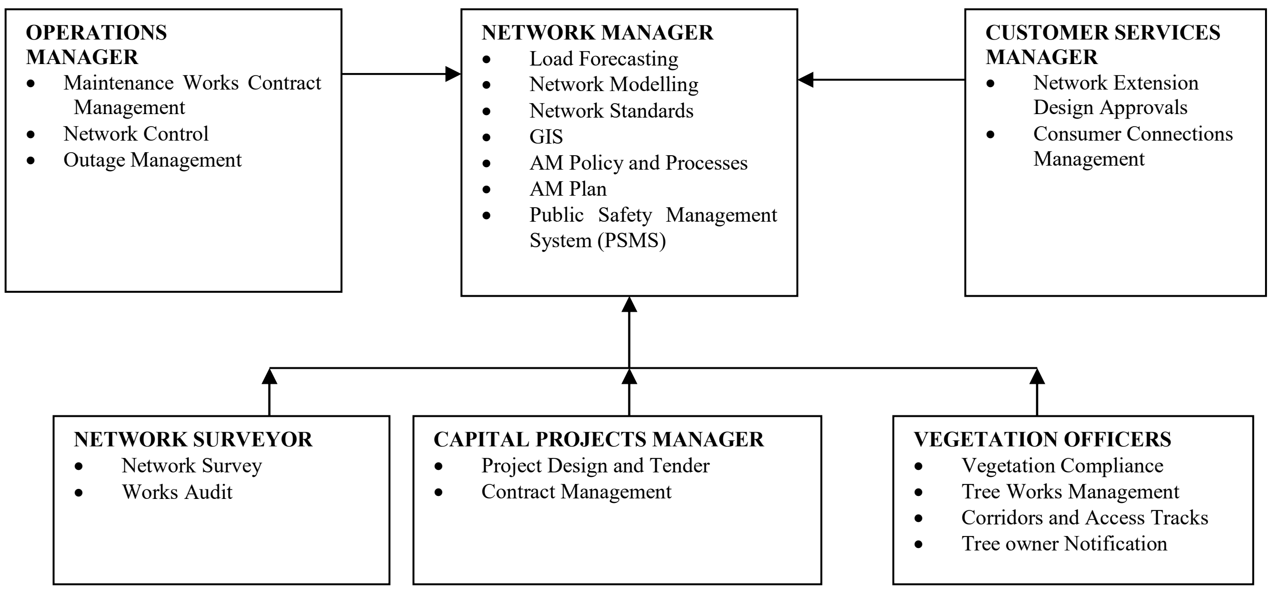
Also as part of the review process, any policy developments through the year affecting the AMP, or any recommendations from external reviews or audits are discussed and incorporated into the AMP as appropriate. Such plan developments are highlighted in the final presented draft.

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 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. 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 provision of a faults response service, all asset maintenance works and minor capital works has been entered into between NTL and Delta Utility Services Ltd. This five year term contract commenced on 1 April 2011. During 2015 the contract was renewed and extended for a further five year term commencing on 1 April 2016.

The Network Manager is responsible for the outcomes of this contract, and for the cost performance of the network operation against budget. Contractor performance is monitored through regular meetings with the contractor 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.

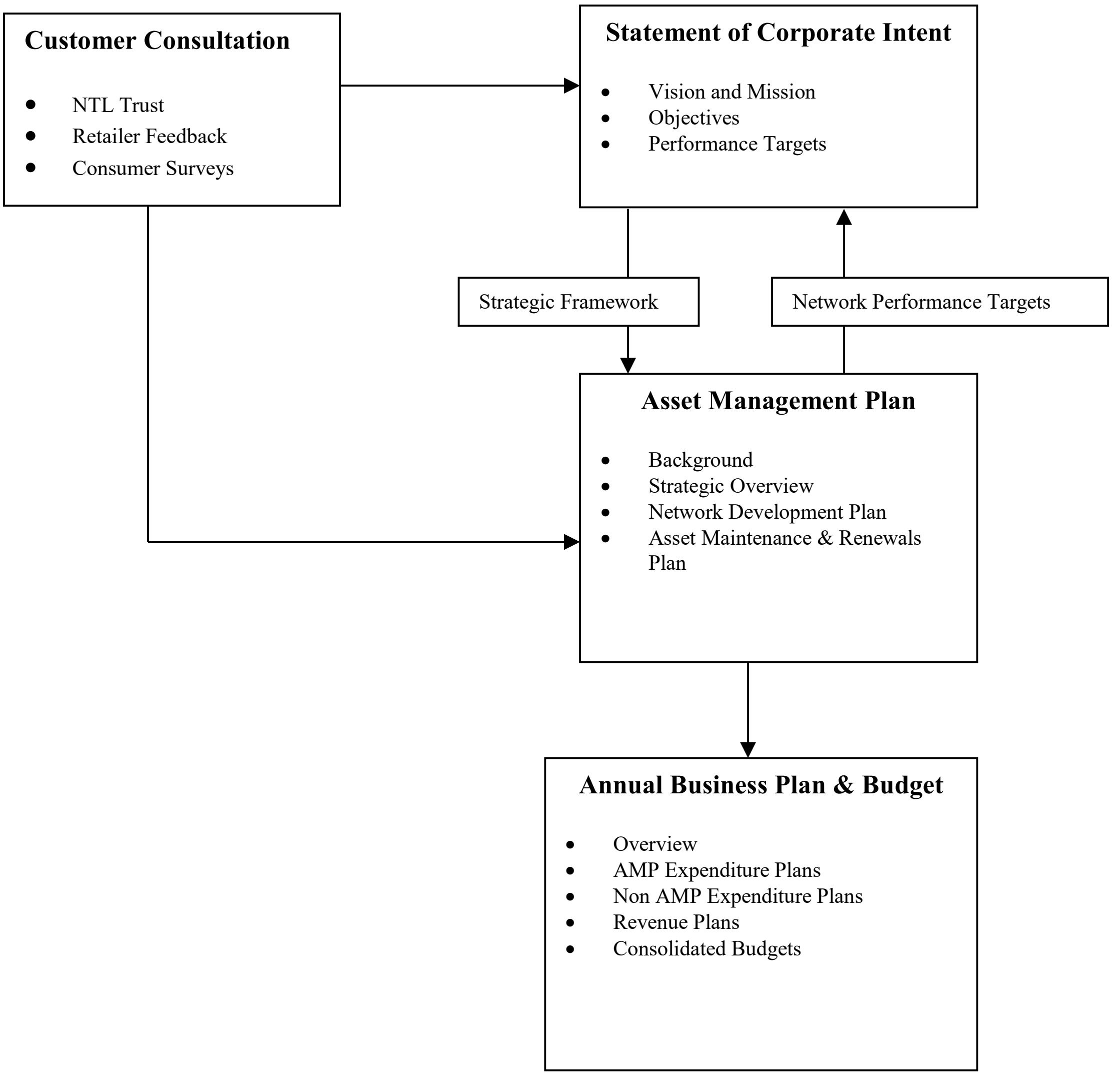
Document approvals and levels of expenditure delegation are given in the following table:

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 >$50,000 and <$100,000	Chairman
Expenditure >$10,000 and <$50,000	CEO
Expenditure <$10,000	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 (ref section 2.1), are translated into corporate goals that are network performance focussed. The goals specified in the company's Statement of Corporate Intent (SCI) 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 plans 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.

1. Geographic Information System (GIS)

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 sub-system databases that are maintained on an ongoing basis. These sub-systems are:

a. The Substation/Transformer database – this database records the parameters of all distribution substation sites (approx 4,300) and holds earth test and loading records for the sites. The database also tracks the location, specifications and test records of all transformers.
b. 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.
c. 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 proforma sheets 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.
d. 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. Outages and Faults Databases

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 under the regulation to be disclosed annually. Process and procedures are in place to ensure that records for this purpose are complete and accurate. Full details of these procedures and process 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.

3. **Network Load Flow Model**
A network loadflow model 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.

4. **SCADA System**
The SCADA system (Supervisory Control and Data Acquisition) has remote stations at the major zone substations, subtransmission substations, GXP substations and ripple injection plants. The system allows for the remote monitoring 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.

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

6. **Customer consultation database**
Two key means of customer consultation occurs:
- Direct, detailed consultation with the 30 or so largest customers
- Assessment of the mass markets satisfaction with supply reliability as assessed by several proxies.

Customer consultation outcomes are given in Appendix K.

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 assigned from other records such as the year of line construction, assuming that the poles used in the line construction were manufactured in the same year.

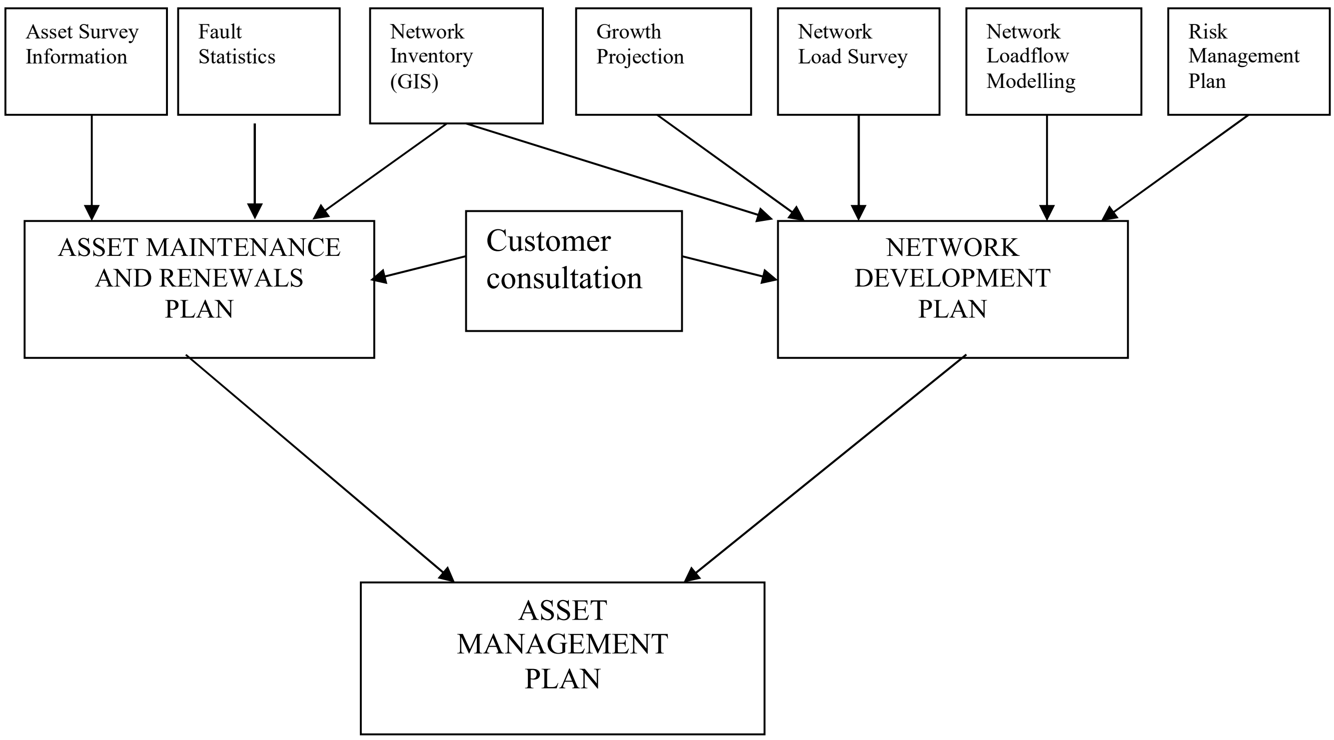
As the asset renewal and maintenance regime is condition based down to a high level of asset disaggregation, this limitation does not affect the effectiveness and performance of the maintenance systems. Also, the assumptions made do not significantly affect long term renewals expenditure projections 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

Figure 3 represents the information inputs and flows into the AMP formulation and review process.

FIGURE 3. ASSET MANAGEMENT PLANNING INFORMATION SYSTEM



AMP Formulation

Asset Condition Information
The company's Network Maintenance database which holds information from ongoing field asset surveys, supplies required and prioritised asset maintenance works activities to form the annual Asset Maintenance and Renewals Plan. This forms the basis of the works programme which is forwarded to Delta Utilities 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.

Network Development
The Network Development plan is built up using a loadflow 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.

Stakeholder Interests:
Specific stakeholder interests are considered during the AMP formulation and annual review. Such items include annual review of the undergrounding policy and project priorities in conjunction with the two territorial authorities, and review of vegetation management policy. Budgets for the ten 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 practises 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

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 NZ.

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 SCI.

Annual company performance against SCI targets are 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 (GXP's). Transpower GXP's exist at substations at Stoke (33kV and 66kV), Kikiwa (11kV) and Murchison (11kV). Maps showing the five bulk supply regions are also given in Appendix A.

The overall maximum demand on the Network Tasman distribution system for 2015/16 was 114MW. The total electricity delivered to consumer ICP's was 603.5GWh. The overall load factor was 65%.

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 26% 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 26,000 consumer connections. There are two direct supply 33kV consumers being Nelson Electricity Ltd (35MW) and Nelson Pine Industries Ltd (23MW). The main suburban townships in this region are Stoke and Richmond, with other rural centres at Atawhai, Brightwater, Wakefield and Mapua.

The Grid Exit Point (GXP) is at Transpower's Stoke substation from which a load of 130MW is supplied at 33kV. Transpower supplies Nelson Electricity's load from this substation as well as NTL. The firm capacity of this GXP is 143MVA. NTL demand from the substation is 99MW. 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 nine 33/11kV substations at 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 n-1 subtransmission security. Details of the subtransmission security for all zone substations is given in section 7.6. The total energy delivered to NTL from this GXP is 460,900MWh, giving an annual load factor of 54%.

The region contains a mainly overhead 33kV sub-transmission 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 7,500 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 19.8MW. The firm capacity of the Motueka zone substation is 20MW.

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 101,400MWh, 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 3,500 consumer connections including one large industrial load at the 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 autorecloser 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, this supply region has no firm capacity. The area has domestic 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 3.2MW. Firm capacity of 5MW 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. The peak period is typically February to April. The total annual energy delivered is 12,780MWh, giving an annual load factor of 46%.

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 approximately 2.9MW. The substation has a single bank of transformers, therefore there is no firm capacity available. In the event of a single phase transformer unit failure, an 8 hour outage would be required to switch in the spare on site transformer unit.

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. Irrigation is less than in Kikiwa however. The peak loading occurs in late summer and early autumn. The total annual energy delivered is 11,906MWh, giving an annual load factor of 47%.

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 1960's and 1970's. Underground conversion of the 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 suburban roads is ongoing under current policy.

Back-up 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 back-up 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 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) and Upper Takaka (100kW). 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.

Other small hydro generation projects are planned in the area. Solar Photovoltaic generation exists in the network with approx. 380 mostly domestic scale sites. Total installed PV is approx. 1200kW.

3.3 ASSET DESCRIPTION

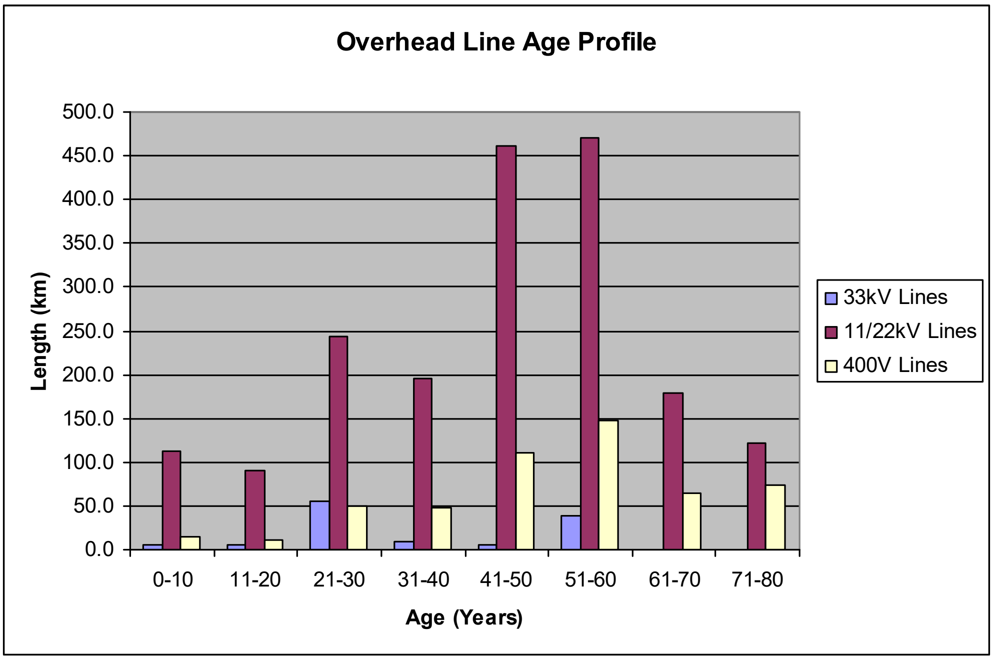
All distribution assets employed in the NTL network are listed by category in this section. The reader's attention is drawn to the map at Appendix A showing the main 11kV distribution network overlaid on a topological map.

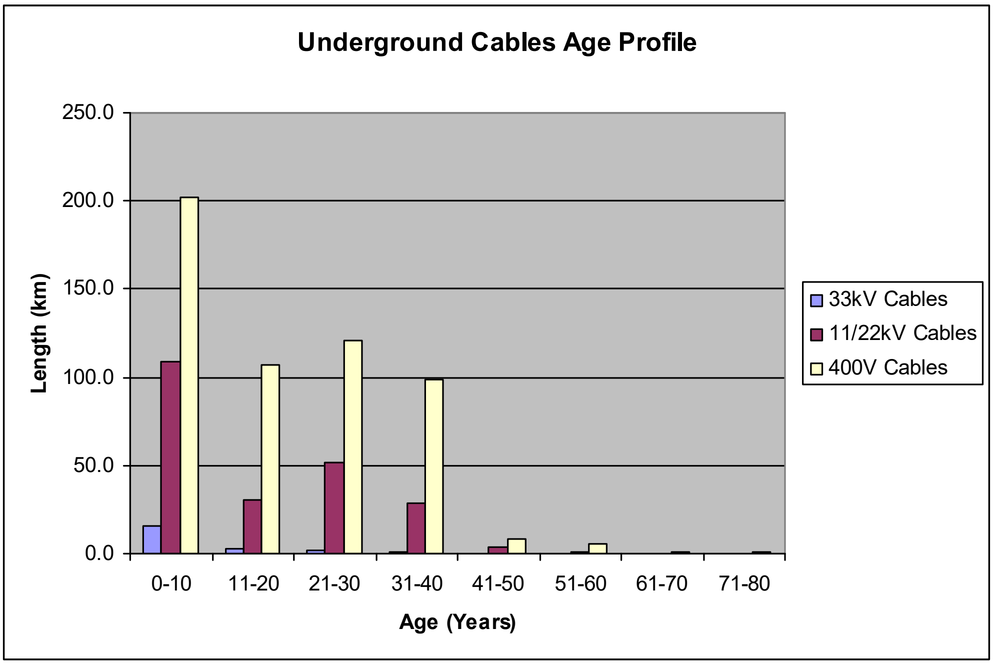
Distribution Lines (km)

	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	234.6	448.0	0.0	0.0	588.6	175.6	0.0	0.0	89.9	29.9	**1566.6**	42
Motueka	148.7	91.2	0.0	0.0	360.1	42.3	0.0	0.0	1.2	0.0	**643.6**	21
Golden Bay	61.2	46.5	14.1	0.0	385.9	9.3	0.0	0.0	32.1	0.4	**549.5**	10
Kikiwa	33.7	12.6	0.0	0.0	251.1	3.6	18.8	12.5	0.0	0.0	**332.3**	9
Murchison	30.1	6.9	0.0	0.0	186.4	3.1	93.3	0.0	0.0	0.0	**319.8**	3
	508.2	**605.2**	**14.1**	**0.0**	**1772.1**	**233.9**	**112.2**	**12.5**	**123.2**	**30.2**	**3411.8**	26

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)	Offtaks Max Demand (MW)	Outgoing 11kV Feeders	Meets Security Std
Annesbrook	2x11.5/23MVA	23	18.0	8	Yes
Hope	2x10MVA	10	7.9	5	Yes
Songer St	2x11.5/23MVA	23	17.2	8	Yes
Lower Queen St	2x15/30MVA*	30	23	8	N/A[1]
Eves Valley	2x5MVA	5	3.8	1	Yes
Takaka	2x 5/7.5MVA	7.5	5.7	2	Yes
Swamp Rd	2x 3MVA	3	2.3	2	Yes
Brightwater	2x 7.5/15MVA	15	7.3	3	Yes
Founders	2x7.5/15MVA	15	6.9	4	Yes
Mapua	2x10MVA	10	4.9	4	Yes
Richmond	2x11.5/23MVA	23	18.9	8	Yes
Motueka	2x 10/20MVA	20	19.8	8	Yes
Upper Takaka	2 x 6MVA	6	1.0	1	Yes

***Owned by Connected Large Industrial 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	2x40MVA*	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 2016

Substation	Unit	Serial No	Transform Voltage (kV)	MVA	Make	Year	Age	Year Refurbished
Hope	T1	58542	33/11	10	Brush	1959	57	2010
Hope	T2	58541	33/11	10	Brush	1959	57	2004
Annesbrook	T1	M0235A	33/11	11.5/23	Wilson	2003	13	NA
Annesbrook	T2	M0235B	33/11	11.5/23	Wilson	2003	13	NA
Songer St	T1	17761	33/11	11.5/23	Tyree	1976	40	NA
Songer St	T2	18716	33/11	11.5/23	Tyree	1987	29	NA
Eves Valley	T1	400131-1	33/11	5	ABB	2005	11	NA
Eves Valley	T2	400131-2	33/11	5	ABB	2005	11	NA
Brightwater	T1	18396	33/11	7.5/15	Tyree	1983	33	NA
Brightwater	T2	18715	33/11	7.5/15	Tyree	1987	29	NA
Founders	T1	18552	33/11	7.5/15	Tyree	1985	31	NA
Founders	T2	18827	33/11	7.5/15	Tyree	1988	28	NA
Takaka	T1	P0872A	33/11	5/7.5	Wilson	2009	7	NA
Takaka	T2	M9854A	33/11	5/7.5	Wilson	1999	17	NA
Swamp Rd	T1	644581	33/11	3	TJ	1977	39	1995
Swamp Rd	T2	691959	33/11	3	TJ	1970	46	1996
Motupipi	T1	25939-42	66/33	4 x 6.66	ASGEN	1966	50	NA
Mapua	T1	68352	33/11	10	Brush	1967	49	2005
Mapua	T2	68362	33/11	10	Brush	1967	49	2005
Richmond	T1	M0602B	33/11	11.5/23	Wilson	2007	9	NA
Richmond	T2	M0602A	33/11	11.5/23	Wilson	2007	9	NA
Motueka	T5	161731	66/11	10/20	Ferranti	1972	45	NA
Motueka	T6	161732	66/11	10/20	Ferranti	1972	45	NA
Upper Takaka	T1	P1423-01	66/11	6	Wilson	2015	1	NA
Upper Takaka	T2	P1423-02	66/11	6	Wilson	2015	1	NA
						Max Age (Yrs)	57	
						Avg Age (Yrs)	28.8	

Outdoor 66KV Switchgear
Current Year 2016

Unit	Type	Make	Year Manufactured	Age
Motupipi T1	Vacuum	AE Power	2012	4
Motueka 62	SF6	ABB	1990	26
Motueka 82	SF6	ABB	1990	26
Upper Takaka 172	SF6	ABB	1990	26
Upper Takaka 192	SF6	ABB	2007	9
Upper Takaka 202	SF6	ABB	1990	26
Upper Takaka 222	SF6	ABB	1992	24
Cobb 72	SF6	ABB	1992	24
Cobb 82	SF6	ABB	1992	24
			Max Age (Yrs)	26
			Average Age (Yrs)	21.0

Outdoor 33KV Switchgear
Current Year 2016

Unit	Type	Make	Year Manufactured	Age
Hope T1	Bulk Oil	Takaoka	1980	36
Hope T2	Bulk Oil	Takaoka	1980	36
Annesbrook T1	Bulk Oil	Takaoka	1980	36
Annesbrook T2	Bulk Oil	Takaoka	1980	36
Songer St T1	Bulk Oil	Takaoka	1976	40
Songer St T2	Bulk Oil	Takaoka	1976	40
Lower Queen St T2	Vacuum	McGraw Edison	1985	31
Lower Queen St T3	Vacuum	McGraw Edison	1997	19
Founders T1	Vacuum	Nulec N Series	1998	18
Founders T2	Vacuum	Nulec N Series	1998	18
Eves Valley	Vacuum	McGraw Edison	1985	31
Brightwater T1	Vacuum	McGraw Edison	1985	31
Brightwater T2	Vacuum	McGraw Edison	1985	31
Railway Reserve	Vacuum	McGraw Edison	1985	31
Takaka T1	Vacuum	Nulec N Series	2008	8
Takaka T2	Vacuum	Nulec N Series	2008	8
Takaka Feeder	Bulk Oil	Nissin	1969	47
Collingwood Feeder	Bulk Oil	Mitsubishi	1966	50
Three Bros Corner	Vacuum	Nulec N Series	2005	11
Hope Feeder	Vacuum	McGraw Edison	1985	31
			Max Age (Yrs)	50
			Average Age (Yrs)	29.5

Indoor 33kV Switchgear

Unit	Type	Make	Year Manufactured	Age
Mapua Incomer 1	SF6	Fluair 400	2005	11
Mapua BS	SF6	Fluair 400	2005	11
Mapua T1	SF6	Fluair 400	2005	11
Mapua T2	SF6	Fluair 400	2005	11
Richmond Incomer 1	Vacuum	Tamco	2006	10
Richmond Incomer 2	Vacuum	Tamco	2006	10
Richmond BS	Vacuum	Tamco	2006	10
Richmond T1	Vacuum	Tamco	2006	10
Richmond T2	Vacuum	Tamco	2006	10

Outdoor 11kV Pole Mounted Switchgear

	No.	Average Age Est
Recloser Reyrolle OYT	1	43
Recloser McGraw Edison KF	1	32
Recloser McGraw Edison KFE	4	29
Recloser Nulec U Series	54	7
Sectionaliser McGraw Edison GN3	4	31
Total	**64**	

Outdoor 11KV Ground Mounted Switchgear

	No.	Average Age Est
Magnefix 1T	1	40
Magnefix 2K1T	32	18
Magnefix 3K1T	55	18
Magnefix 4K1T	2	20
ABB SD3	124	12
ABB SD	47	12
ABB SDAF	1	33
Halo 3LBS	1	1
Halo 4LBS	2	1
Halo 2LBS+2CB	1	1
Xiria	2	5
Total Units	**268**	

Indoor 11kV Switchgear
Current Year 2016

Substation	Feeder	Type	Make	Year Manufactured	Age
Annesbrook	Tahuna	Vacuum	Reyrolle LMVP	2001	15
Annesbrook	Stoke	Vacuum	Reyrolle LMVP	2001	15
Annesbrook	Aerodrome	Vacuum	Reyrolle LMVP	2001	15
Annesbrook	Bishopdale	Vacuum	Reyrolle LMVP	2001	15
Annesbrook	Wakatu	Vacuum	Reyrolle LMVP	2001	15
Annesbrook	Pascoe St	Vacuum	Reyrolle LMVP	2001	15
Annesbrook	Bolt Rd	Vacuum	Reyrolle LMVP	2001	15
Annesbrook	Moana	Vacuum	Reyrolle LMVP	2001	15
Annesbrook	T1 Incomer	Vacuum	Reyrolle LMVP	2001	15
Annesbrook	T2 Incomer	Vacuum	Reyrolle LMVP	2001	15
Annesbrook	Bus Section	Vacuum	Reyrolle LMVP	2001	15
Founders	Akersten	Vacuum	Reyrolle LMVP	1998	18
Founders	Hira	Vacuum	Reyrolle LMVP	1998	18
Founders	Atawhai	Vacuum	Reyrolle LMVP	1998	18
Founders	Spare	Vacuum	Reyrolle LMVP	1998	18
Founders	T1 Incomer	Vacuum	Reyrolle LMVP	1998	18
Founders	T2 Incomer	Vacuum	Reyrolle LMVP	1998	18
Founders	Bus Section	Vacuum	Reyrolle LMVP	1998	18
Hope	Brightwater	Bulk Oil	Fergusson Pailin	1959	57
Hope	Wakefield	Bulk Oil	AEI	1970	46
Hope	Richmond	Bulk Oil	Fergusson Pailin	1959	57
Hope	Hill St	Bulk Oil	Fergusson Pailin	1959	57
Hope	Appleby	Bulk Oil	Fergusson Pailin	1959	57
Hope	T1 Incomer	Bulk Oil	Fergusson Pailin	1959	57
Hope	T2 Incomer	Bulk Oil	Fergusson Pailin	1959	57
Lower Queen St	Estuary	SF6	ABB Safesix	1985	31
Lower Queen St	Queen St	SF6	ABB Safesix	1985	31
Lower Queen St	Swamp Rd	SF6	ABB Safesix	1985	31
Lower Queen St	Furnaces	SF6	ABB Safesix	1985	31
Lower Queen St	Refiners	SF6	ABB Safesix	1985	31
Lower Queen St	Chip Mill	SF6	ABB Safesix	1985	31
Lower Queen St	MDF East	SF6	ABB Safesix	1997	19
Lower Queen St	Lumber Plant	SF6	ABB Safesix	2001	15
Lower Queen St	T1 Incomer	SF6	ABB Safesix	1985	31
Lower Queen St	T2 Incomer	SF6	ABB Safesix	1985	31
Lower Queen St	T3 Incomer	SF6	ABB Safesix	1985	31
Lower Queen St	Bus Section	SF6	ABB Safesix	1985	31
Mapua	Mahana	Vacuum	Reyrolle LMVP	2005	11
Mapua	Mapua	Vacuum	Reyrolle LMVP	2005	11
Mapua	Upper Moutere	Vacuum	Reyrolle LMVP	2005	11
Mapua	Spare	Vacuum	Reyrolle LMVP	2005	11
Mapua	T1 Incomer	Vacuum	Reyrolle LMVP	2005	11
Mapua	T2 Incomer	Vacuum	Reyrolle LMVP	2005	11
Mapua	Bus Section	Vacuum	Reyrolle LMVP	2005	11
Songer St	Main Road	Vacuum	Reyrolle LMVP	2003	13
Songer St	Aldinga	Vacuum	Reyrolle LMVP	2003	13
Songer St	Polstead	Vacuum	Reyrolle LMVP	2003	13
Songer St	Monaco	Vacuum	Reyrolle LMVP	2003	13
Songer St	Nayland	Vacuum	Reyrolle LMVP	2003	13
Songer St	Saxton E	Vacuum	Reyrolle LMVP	2003	13
Songer St	Saxton W	Vacuum	Reyrolle LMVP	2003	13
Songer St	Isel	Vacuum	Reyrolle LMVP	2003	13
Songer St	T1 Incomer	Vacuum	Reyrolle LMVP	2003	13
Songer St	T2 Incomer	Vacuum	Reyrolle LMVP	2003	13
Songer St	Bus Section	Vacuum	Reyrolle LMVP	2003	13
Richmond	King St	Vacuum	Reyrolle LMVP	2006	10
Richmond	Waverley St	Vacuum	Reyrolle LMVP	2006	10
Richmond	Talbot St	Vacuum	Reyrolle LMVP	2006	10
Richmond	McGlashen Ave	Vacuum	Reyrolle LMVP	2006	10
Richmond	Lower Queen St	Vacuum	Reyrolle LMVP	2006	10
Richmond	Beach Rd	Vacuum	Reyrolle LMVP	2006	10
Richmond	Champion Rd	Vacuum	Reyrolle LMVP	2006	10
Richmond	Darcy St	Vacuum	Reyrolle LMVP	2006	10
Richmond	T1 Incomer	Vacuum	Reyrolle LMVP	2006	10
Richmond	T2 Incomer	Vacuum	Reyrolle LMVP	2006	10
Richmond	Bus Section	Vacuum	Reyrolle LMVP	2006	10
Brightwater	Redwoods Valley	Vacuum	Reyrolle LMVP	2013	3
Brightwater	Higgins Road	Vacuum	Reyrolle LMVP	2013	3
Brightwater	Ellis St	Vacuum	Reyrolle LMVP	2013	3

Brightwater	Spring Grove	Vacuum	Reyrolle LMVP	2013	3
Brightwater	T1 Incomer	Vacuum	Reyrolle LMVP	2013	3
Brightwater	T2 Incomer	Vacuum	Reyrolle LMVP	2013	3
Brightwater	Bus Section	Vacuum	Reyrolle LMVP	2013	3
Motueka	Kaiteriteri	Vacuum	Reyrolle LMVP	2006	10
Motueka	Wildman Road	Vacuum	Reyrolle LMVP	1997	19
Motueka	Tasman	Vacuum	Reyrolle LMVP	1997	19
Motueka	Queen Victoria	Vacuum	Reyrolle LMVP	1999	17
Motueka	Dovedale	Vacuum	Reyrolle LMVP	1997	19
Motueka	Brooklyn	Vacuum	Reyrolle LMVP	1997	19
Motueka	Whakarewa	Vacuum	Reyrolle LMVP	1997	19
Motueka	Pah St	Vacuum	Reyrolle LMVP	2006	10
Motueka	T5 Incomer	Vacuum	Reyrolle LMVP	1999	17
Motueka	T6 Incomer	Vacuum	Reyrolle LMVP	1999	17
Motueka	Bus Section	Vacuum	Reyrolle LMVP	1999	17
				Max Age (Yrs)	57
				Avg Age (Yrs)	18.5

Regulators

	Type	Year
Wakapuaka No1	McGraw Edison VR32 100A 3 Cans	1991
Wakapuaka No 2	McGraw Edison VR32 100A 3 Cans	2010
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	Brentford 130A	
Kotinga 11/6.6kV Transformer	Crompton Parkinson 3 x 1ph 350kVA	
Kikiwa 22/11kV Transformer	Wilson 3 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
Uruwhenua Capacitor Bank	4 x 150kVA Steps	2010
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

Air Break Isolators

	No	Average Age Est
66kV	39	25
33kV	101	32
22kV	5	12
11kV	631	31
Total	**776**	

HV DDO Line Fuses

	No	Average Age Est
33kV	3	34
22kV	3	11
11kV	620	28
Total	**626**	

Mobile Generators

1 x1000kVA 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

Network kWh Metering Nil

Distribution Substations

	Fenced Enclosure	Padmount	Kiosk	Overhead Platform	Overhead Single Pole	Total
Stoke	26	460	24	256	1,209	**1,975**
Motueka	9	102	0	176	725	**1,012**
Golden Bay	3	25	1	58	730	**817**
Kikiwa	2	7	0	21	343	**373**
Murchison	0	3	0	17	274	**294**
TOTAL	**40**	**597**	**25**	**528**	**3,281**	**4,471**

There are 5 types of Distribution substation:

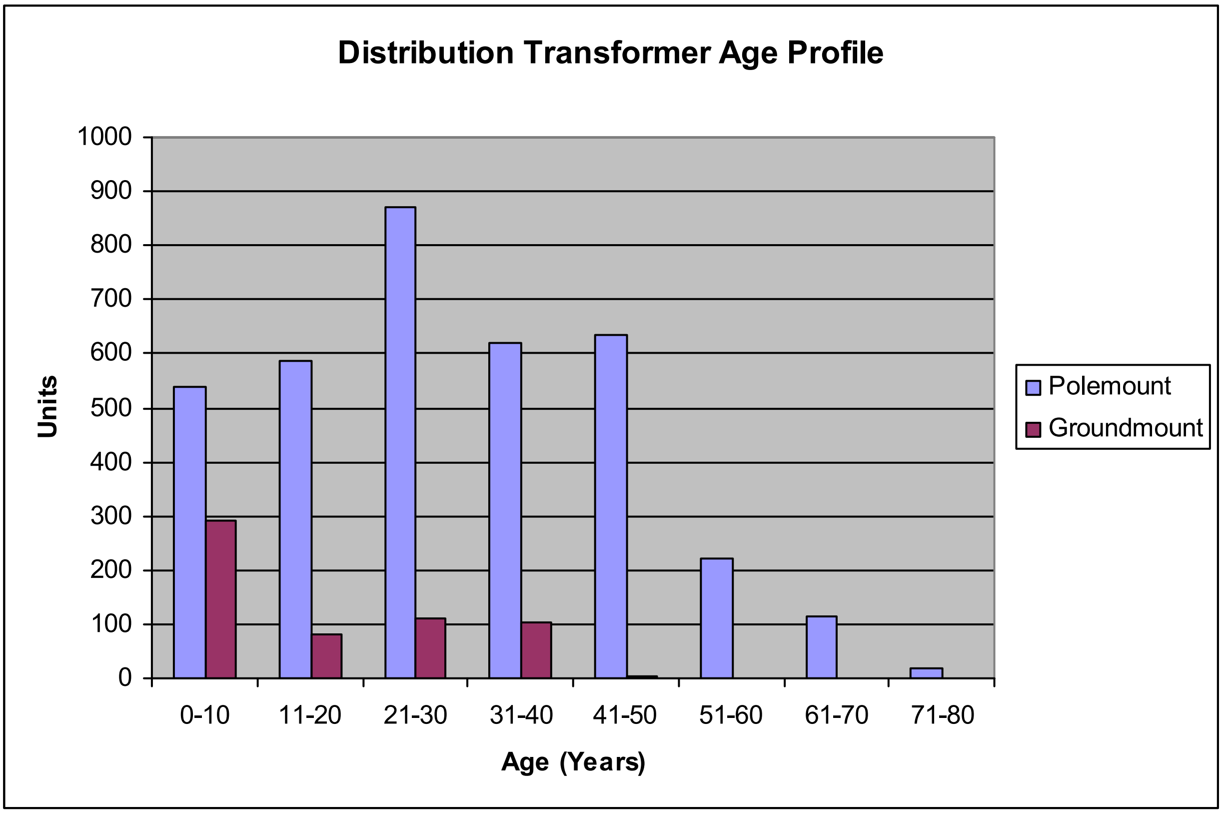
- Fenced Enclosure – Concrete foundation pad with open bushing ground mounted transformer. Underground cables incoming and outgoing with HV fuse protection typically DDO at remote end of HV cable. Outdoor 11kV termination, transformer, and LV fusing all enclosed by perimeter fence. Transformers 50kVA to 1000kVA.
- Padmount – Concrete pre-fabricated 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.
- Kiosk – Small concrete block building housing groundmount transformer, HV switchgear and HRC fuses, LV fuse board and streetlight controls etc.
- 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.
- 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	426	369	339	246	465	97	35	**1,977**
Motueka	256	218	204	162	141	22	8	**1,011**
Golden Bay	348	187	132	103	43	2	1	**816**
Kikiwa	184	86	54	28	20	0	1	**373**
Murchison	143	70	42	27	11	1	0	**294**
	1,357	**930**	**771**	**566**	**680**	**122**	**45**	**4,471**
Working Stock	13	13	2	1	0	0	0	**29**
Emergency Stock	23	14	7	7	4	0	0	**55**
Total Units	**1,393**	**957**	**780**	**574**	**684**	**122**	**45**	**4,555**

Distribution Transformers – Capacity (kVA)

	0-15kVA	16-30kVA	31-50kVA	51-100kVA	101-300kVA	301-500kVA	500kVA+	Total
Stoke	6,234	10,275	16,950	21,900	114,350	48,500	30,250	**248,459**
Motueka	3,697	5,960	10,200	14,675	31,550	10,650	7,250	**83,982**
Golden Bay	4,771	5,425	6,600	8,825	9,087	1,000	1,000	**36,708**
Kikiwa	2,558	2,280	2,700	2,350	4,175	0	750	**14,813**
Murchison	1,993	1,895	2,100	2,225	2,550	500	0	**11,263**
	19,253	**25,835**	**38,550**	**49,975**	**161,712**	**60,650**	**39,250**	**395,225**
Working Stock	180	370	100	100	0	0	0	**750**
Emergency Stock	345	420	350	600	1000	0	0	**2,715**
Total kVA	**19,778**	**26,625**	**39,000**	**50,675**	**162,712**	**60,650**	**39,250**	**398,690**



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.

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.

Service Boxes

	No	Average Age Est
All Concrete Pillar		
Concrete base		
All PVC		
Total	11,530	20

3.4 NETWORK VALUATION

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

Asset Class	**Actual 31-Mar-2015 ($000)**	**Forecast 31-Mar-2016 ($000)**
Distribution Cables	51,752	52,402
Distribution Lines	24,741	24,728
Distribution Subs and Transformers	22,850	22,676
Distribution Switchgear	6,998	7,873
Other Network Assets	14,123	14,294
Subtransmission Lines	8,386	8,814
Subtransmission Cables	9,649	9,697
Zone Substations	20,484	21,163
Non Network Assets	2,834	3,384
TOTAL	**161,817**	**165,031**

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

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 and in section 4.7.

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 mins on the NTL network is from equipment faults which has averaged 15 mins 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.

- 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 GXP 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 work being done live line on light copper conductors for safety reasons. Means of improving planned SAIDI from planned work will include deployment of temporary generators where practicable.

- Planned outages on the Transpower network are a major component of overall SAIDI performance (approx 30%). Due to the fact that two of the grid exit point substations are single transformer supply sites, shutdowns of the whole GXP supply are required to complete transformer maintenance activity.

- Investigations to identify means of averting the shutdowns at the NTL Motupipi substation have been completed. A capital upgrade solution is now planned for the substation in 2016-2018.

4.2 ASSET EFFECTIVENESS

1. <u>Supply Quality</u>

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 Regulations and in various industry codes of practice.

The parameters of supply quality are:
- Voltage magnitude
- 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 consumers 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 consumers switchboard 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 consumers 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.

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

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 6 hours for urban consumers and 10 hours for rural consumers.

3. Environmental Effectiveness

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. 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 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 KPI’s 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

1. <u>Thermal Efficiency</u>

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 4-6%.

2. <u>Distribution Transformer Capacity Utilisation</u>

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.

3. <u>Financial Efficiency</u>

NTL’s mission is to provide a reliable electricity network 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 NZ. 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 includes 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 NZ.

NTL has an objective to achieve 1st quartile industry performance in this measure.

4.4 PERFORMANCE OBJECTIVES

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	1995/6	65	26	90	101	127	228	318
	1996/7	0	1	1	78	152	230	231
	1997/8	0	44	44	100	148	248	292
	1998/9	56	15	71	81	189	270	341
	1999/0	19	12	31	62	122	184	215
	2000/1	67	0	67	35	70	105	172
	2001/2	44	0	44	21	49	70	114
	2002/3	43	0	43	17	91	108	151
	2003/4	36	7	43	26	95	121	164
	2004/5	55	9	64	28	118	146	210
	2005/6	26	73	99	25	97	122	221
	2006/7	51	125	176	33	77	110	286
	2007/8	16	0	16	45	111	156	172
	2008/9	53	44	97	37	215	252	349
	2009/10	0	79	79	62	85	147	226
	2010/11	48	18	66	48	129	178	244
	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
Forecast	2015/16	15	0	15	99	84	183	198
Target	2015/16	35	5	40	40	75	115	155
	2016/17	10	5	15	75	75	150	165
	2017/18	10	5	15	75	75	150	165
	2018/19	10	5	15	75	75	150	165
	2019/20	10	5	15	75	75	150	165
	2021/22	10	5	15	75	75	150	165
	2022/23	10	5	15	75	75	150	165
	2023/24	10	5	15	75	75	150	165
	2024/25	10	5	15	75	75	150	165
	2025/26	10	5	15	75	75	150	165

SAIFI

		Transpower Planned	Transpower Unplanned	Total Transpower	NTL Planned	NTL Unplanned	NTL Total	Overall SAIFI
Actual	1995/6	0.20	0.84	1.04	0.67	1.37	2.41	3.45
	1996/7	0.00	0.03	0.03	0.64	2.03	2.06	2.09
	1997/8	0.00	1.51	1.51	0.76	2.02	3.53	5.04
	1998/9	0.22	0.50	0.72	0.57	3.22	3.79	4.51
	1999/0	0.05	0.23	0.28	0.65	2.01	2.65	3.77
	2000/1	0.23	0.06	0.29	0.29	1.34	1.63	1.92
	2001/2	0.14	0.00	0.14	0.13	0.87	1.00	1.14
	2002/3	0.17	0.20	0.37	0.19	1.30	1.49	1.86
	2003/4	0.14	0.37	0.51	0.15	1.07	1.22	1.73
	2004/5	0.23	0.53	0.76	0.23	1.48	1.71	2.47
	2005/6	0.14	1.40	1.54	0.13	0.92	1.05	2.59

	2006/7	0.14	1.63	1.77	0.29	1.23	1.52	3.29
	2007/8	0.09	0.02	0.11	0.20	1.32	1.52	1.63
	2008/9	0.17	0.49	0.66	0.15	1.53	1.68	2.34
	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
Forecast	2015/16	0.10	0.00	0.10	0.40	1.20	1.60	1.70
Target	2015/16	0.12	0.12	0.24	0.29	1.07	1.36	1.60
	2016/17	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2017/18	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2018/19	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2019/20	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2021/22	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2022/23	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2023/24	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2024/25	0.03	0.12	0.15	0.54	1.07	1.61	1.76
	2025/26	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	1995/6	325	31	87	151	93	95	92
	1996/7	0	33	33	122	75	112	111
	1997/8	0	29	29	132	73	70	58
	1998/9	255	30	99	142	59	71	76
	1999/0	380	52	111	95	61	69	57
	2000/1	291	0	231	121	52	64	90
	2001/2	314	0	314	165	57	70	100
	2002/3	258	1	116	86	70	60	81
	2003/4	247	19	84	169	89	99	95
	2004/5	239	17	84	122	80	85	85
	2005/6	186	52	64	192	105	116	85
	2006/7	364	77	99	113	63	73	87
	2007/8	177	21	147	225	84	103	106
	2008/9	315	90	147	244	140	150	149
	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
Forecast	2015/16	150	0	150	248	70	114	116
Target	2015/16	300	40	167	138	70	85	97
	2016/17	333	40	100	139	70	93	94
	2017/18	333	40	100	139	70	93	94
	2018/19	333	40	100	139	70	93	94
	2019/20	333	40	100	139	70	93	94
	2021/22	333	40	100	139	70	93	94
	2022/23	333	40	100	139	70	93	94
	2023/24	333	40	100	139	70	93	94
	2024/25	333	40	100	139	70	93	94
	2025/26	333	40	100	139	70	93	94

Asset Effectiveness

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

Service Criterion	Key Performance Indicator	Annual Target 2015/16 to 2025/26	Actual 2014/15	Forecast 2015/16
Supply Quality	Number of proven voltage complaints	10	4	3
Contractual Performance	Breaches of UOSA	0	1	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 incidents	0	1	1
Safety	Public Injury near misses	52	49	56
Safety	Public Property near misses	5	7	4

Asset Efficiency

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

Service Criterion	Key Performance Indicator	Annual Target 2015/16 to 2025/26	Actual 2014/15	Forecast 2015/16
Thermal Efficiency	Network Losses	6%	5.7%	5.6%
Transformer Utilisation	KVA distribution transformers/peak demand	30%	29%	27%
Financial Efficiency	Cash operating costs per consumer	$290	$264	$278

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

Asset Performance

<u>Unplanned Outages - Reliability</u>

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. 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 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.

The results of this study show that medium term targets for unplanned events of SAIDI 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 approx seven feeders, most feeders contribute 0-3 SAIDI points per year to the total.

The worst performing feeders are generally 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.

Analysis of fault outage data over the past 5 years, reveals that our average unplanned SAIDI over the period is 88 points.

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**
Annesbrook Substation new feeder	2016-17	Pascoe St 11kV	Feeder shortened	0.25
Waimea West 33kV Interconnection	2017-18	Railway Reserve 33kV	Alternative circuit provided	2
Capacitor Banks Motueka/Motupipi	2016-17	N/A	Voltage support under emergency conditions	0
Motupipi Substation Upgrade	2017-19	N/A	Substation security improvement	20
Motueka Substation Upgrade	2018-20	Whakarewa, Queen Victoria	Additional Urban Feeders reduces extent of existing urban feeders	1
Wakapuaka/Hira Substation Development	2020-21	Hira	Feeder shortened/broken up	0.5
Brightwater GXP	2021-22	Hope 33kV, Railway Reserve 33kV	Feeders shortened/broken up	1
Riwaka GXP	2025-26	Brooklyn, Kaiteriteri, Pah St.	Feeders shortened/broken up	2
TOTAL				**27.75**

The worst performing feeders are subject to improvement through the implementation of AMP capital projects programmed in the next five years. 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.

<u>Planned Outages - Availability</u>

NTL’s target SAIDI from planned outages has been 40. During 2015, the 66kV network supplying the Motueka and Golden Bay regions became part became part of NTL’s network, when NTL purchased these network assets from Transpower NZ Ltd. Planned and unplanned events causing loss of supply to consumers that were previously attributable to transmission then became attributable to NTL’s distribution network.

Due to the irregular shutdowns of the Golden Bay area in particular (due to the Golden Bay supply being an n security level of supply), this means that an upward adjustment of NTL planned SAIDI and SAIFI targets is required.

Network Tasman is also commencing a 10 year copper conductor replacement program in its network. This 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 re-conductored lines is inevitable.

The combination of these two changes has resulted in a revision to increase in NTL’s planned SAIDI target to 75 and a corresponding increase of the NTL SAIFI target to 0.54.

The national average SAIDI figure for planned and unplanned is 157 points. Network Tasman’s corresponding target for the period of this plan is 150 points.

Given the topology of the NTL network, improvement beyond this point is unlikely without considerable additional capital expenditure. Performance gains would be low and investment in improvements in unplanned outage restoration operations will yield far greater results.

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 is varies at 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 Effectiveness

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 principle works contractor Delta Utility Services Ltd. This justifies the target level set.

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 or upgrading voltage 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 in line with the industry average for this measure which is 30%. NTL aims to hold or improve its current utilisation at the industry average. 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.

Consumer Consultation

Following from 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 indicates that NTL consumers are happy with both the reliability and quality of electricity supply and with the price paid. Further details of the

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 (SCI). The company SCI is available on our website www.networktasman.co.nz/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 2016-2026. 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.

<u>Formulation of Network Development Projects and Development Path</u>

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.

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 e.g. an unexpected large industrial load. Such developments will cause a revision of the capital works plan and may result in a change in the priority 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 re-prioritisation of capital projects.

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

1. Complete Demand Forecast review process (refer section 5.8)
2. Run Loadflow and System Analysis to identify network constraints and order of occurence.
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.

Capital Expenditure Approval Process

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 re-configuration, 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 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 is 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 does not seek to contract with other parties for the provision of means of removing network constraints. NTL is of the view that the distribution network asset operates to an extremely high level of reliability and availability which is 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 non-asset solutions such as home energy management systems, 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 remains cognisant of developments in the areas of 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. The benefits of reduced network losses, and the potential for reduced GXP demand based charges through cooperative operation are well recognised. 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 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 four mobile diesel generators ranging in size from 150kW to 1MW.

Network Tasman's current policy is to apply line charges only to load taking ICP's. Small scale distributed generation ICP's currently therefore do not attract line charges. Where generators are exporting to the network at peak load times, avoided transmission charges may be payable to the generator. 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 at www.networktasman.co.nz/consumers.

5.5 PLANNING CRITERIA

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. (ref section 4.1)
- System security to be consistent with Security Design Standard. (ref section 5.3)
- Urban subtransmission and zone substations planned using standard capacities – (subtransmission 23-34MVA, zone substations 23MVA, distribution feeders 6MVA).
- Rural networks planned around economic selection of conductors and components.
- Compliance with all applicable Acts and regulations.
- Mechanically and electrically safe.
- Minimised environmental impact.
- Economic Viability

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.
- Likelihood of incorporation into future network re-arrangement 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. (ref: Network Tasman Design and Construction Standards).

The Network Tasman Design and Construction Standards prescribe the design process to be followed in order to determine appropriate design 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.

5.6 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.

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.

5.7 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 approximately 18 hours.

Double coincident failure events are not incorporated into the NTL standard. Such events are dealt with by the company’s Risk Management and Disaster Recovery 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	**Load Classification**	**Customer Impact**	**Security Level**	**Time to restore first contingency**	**Time to restore second contingency**
Over 10MVA	Major Zone Substation	Over 5,000	N-1 (note 1)	Immediate Restore 100% GPD	100% GPD in repair/switching time
5-10MVA	Minor Zone Substation	2,500-5,000	N-1 (note 2)	100% restore within 3 hours	100% GPD in repair/switching time
Up to 5MVA	Urban Distribution Feeder	Up to 2,000	N-1 (note 2)	100% restore within 3 hours	100% GPD in repair/switching time
2-5MVA	Rural Zone Substation	1,000-2,500	N	50% restore within 3 hours 100% restore within 6 hours	100% GPD in repair/switching time
Up to 2MVA	Rural Distribution Feeder	Up to 1,000	N	100% restore within 6 hours	100% GPD in repair/switching time
Up to 2MVA	Remote Rural Distribution Feeder	Up to 300	N	50% within 6 hours. 100% GPD within 12 hours	100% GPD in repair/switching time
Up to 1MVA	Urban LV Network	Up to 300	N	100% GPD within 6 hours	100% GPD in repair/switching time
Up to 500kVA	Rural LV network	Up to 50	N	100% GPD 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 St substation (25MVA) 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 supply to Mapua substation (5MVA) incorporates a 4 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 18 hours would result.
3. The Motupipi GXP substation (7MVA) has a 4 x 1 single transformer bank configuration, requiring approx 5 hours to change out a unit following failure.

5.8 DEMAND FORECAST

The fundamental requirement for long term network planning is a sound demand forecast. The risks to NTL's asset management program 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.

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. TDC recognise the dangers with their asset management planning for water, sewer and storm-water assets based on inaccurate forecasts. To-date there has not been any coordinated growth model developed.

TDC and NCC are now working towards a 20 year footprint of development because of the unprecedented growth in the region. This "20 year footprint study" is designed to include a residential and industrial growth forecast model which incorporates more "science" in the development of the forecasts.

Currently, the best information available is forward population forecasts prepared by NZ statistics.

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 redeveloped.

Demand Forecast Methodology

<u>Step1. Identify Population Growth by District</u>

NTL's demand forecast is based on historic feeder loadings which are extrapolated using NZ Statistics population forecasts given for each area unit/district. The growth rates in each district are identified and checked with historical line connection growth rates. This information is also combined with any known development initiatives to refine the high medium and low population forecasts for each area unit/district.

<u>Step 2. Translate District Population Growth to Network Feeder Growth</u>

After diversity peak demands of 2.8kW per connection are assumed at 11kV feeder level.

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.

Step 3. Combine Upper Network Growth to develop GXP 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 connection decreases to approx. 2.0kW at GXP substation level

Embedded 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. 380 installed photovoltaic generation sites on the network at present representing 1.0% of total ICP’s. This is the highest percentage of ICP’s with solar generation in NZ. Total installed solar and wind generation across the network is still less than 0.7% of the total network load however.

Solar PV generation has a negative effect on consumption with no effect on peak network loading. This effect 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 likely have a detrimental effect on system load factor. This has been taken into account in the 2016 demand forecasts.

Modelling of the potential effects on the distribution network of various future PV generation scenario’s is being undertaken at present. Steps to avoid potential network voltage management problems due to high solar PV penetration levels in the future are being identified. 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 are also being identified and prescribed.

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 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 embedded generators to date has shown that generation can be unpredictable for some years even after commissioning has been completed.

Load Management

NTL operates peak load management as part of a joint initiative by other Upper South Island Lines companies to limit the peak loading on the transmission network supplying power to the Upper south island. Transpower transmission charges are based on NTL's contribution to the 100 highest peak loads each year. The dominant load in the Upper South island is Orion Group Ltd which includes the city of Christchurch. Due to the fact that the mix of domestic and industrial load in the Nelson area is similar to the Christchurch area, NTL shares similar characteristics to Orion Group and the networks in both areas tend to experience overall peaks at around 6pm on the coldest winter evenings. 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.

During the early summer period of 2015/16, high loads on the Upper South Island network were experienced when irrigation season start up load in south Canterbury coincided with cooler weather. These peaks exceeded some of the previously run chargeable winter peaks. It is unclear whether this will become a regular feature of Upper South Island system load management.

In practice, the action of load management causes peak loadings of parts the lower network (ie 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 is also accounted for in the formulation of the load forecast.

The demand forecast detailed in Appendix B, takes account for 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.

The connection of domestic storage water heaters to an approved ripple control receivers is now mandatory in the NTL distribution network area.

The 2016 Demand Forecast

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

Specific areas of load growth include:

- Domestic growth over the next decade in the area between Richmond and Stoke and from southern Richmond southward towards Hope and in Brightwater and Wakefield townships.

The Mapua area and coastal zone between Richmond and Mapua is also expected to show continued strong growth as a domestic housing area enjoying a semi rural coastal environment with reasonable proximity to Nelson city. 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.

- Industrial load growth in the region is expected to continue in the Tahuna 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 Atawhai area to the north of Nelson is a steadily growing residential area. Aquaculture and aquaculture research are industrial activities that are also expected in this area. Further north, subdivision of farmland into lifestyle blocks is occurring

- The central Motueka area is expected to show moderate growth. Rural blocks in the Waimea Plains and in the Moutere area are being subdivided into farmlets providing for many isolated rural line extensions. The Kaiteriteri/Marahau area is an increasingly popular holiday resort and retirement area, and subdivision of coastal land for permanent 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.

- Irrigation of dairy farms is being undertaken in the rural areas of Golden Bay, Tadmor, Korere, Murchison, Matakitaki and Maruia. Typically the irrigation systems require approx 100kVA of supply capacity. Most of these areas are currently serviced by long 11kV lines. Capacity upgrades are required to accommodate these on many of the feeders. Capacity upgrades are being provided by the installation of capacitor banks initially. A survey of the longer term plans of dairy farmers has been undertaken. The results of this has caused a review of the upgrade plans for some rural feeder systems. Capital investment into supply upgrades must show an economic return to NTL without increasing existing urban to rural cross subsidies.

- Further dairy farm development is possible in the Maruia Valley south of Murchison and in the Tapawera area. Both of these areas are remote from an electricity supply viewpoint and considerable capital expenditure is needed to make sufficient supply available. Such capital investment would need to be financially viable and allow NTL to achieve an acceptable return on the upgrade cost without increasing existing urban to rural cross subsidies.

<u>Large Industrial Loads</u>

Expansion of seafood processing is expected to generate a number of applications for increased load in the Tahuna industrial area. The demand forecast has been revised to include these new large industrial loads.

This new industrial load will generate the need for an additional 11kV feeder circuit supplying into the Merton Place/Beatty St area from Annesbrook substation. A project to provide this has been included in this year’s revision of the development plan.

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 load within the planning period. To date however, there has been no significant development of this load in the Nelson area. NTL is aware of the uptake drivers for electric vehicles and it operates two electric vehicles within its fleet. NTL is also installing two fast charging stations in its supply area.

We are keeping a watching brief on international electric vehicle technology developments and on the implications for electricity networks where they are appearing. To date these have tended to be in major cities rather than provincial towns.

High levels of uptake of electric vehicles may have network capacity implications with attendant high network upgrade costs. Load management initiatives such as controlled off peak charging may offer a more cost effective solution for consumer electric vehicle charging.

The demand forecast of this AMP at present takes no account of potential development of this load. Future demand forecasts and AMP reviews will consider the local developments of this load category.

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. 7400 units p.a to approx. 6800 units p.a over the last ten years. The effect on household peak demand is less pronounced however. Photo voltaic 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.

The revised growth forecast is given in Appendix B and the capital expenditure programme is Appendix E.

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

2016/17 to 2026/27	**Urban Connections**	**Rural Connections**
STOKE	365	26
MOTUEKA	34	23
GOLDEN BAY	16	17
KIKIWA	0	12
MURCHISON	0	7
TOTAL	415	85

5.9 DEVELOPMENT PLAN - DETAIL

5.9.1 Network Classifications

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

- Transpower GXP's
- Primary distribution network (33kV)
- Zone substations
- 11kV feeders
- Distribution transformers
- Urban low voltage lines
- Rural low voltage lines
- SCADA/load management system/communications
- Ripple injection system
- Distributed Generation

5.9.2 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. More recently the Stoke GXP substation firm capacity was increased with a major 220/33kv supply transformer and 33kV switchboard redevelopment.

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 loadflow studies of the network under projected loading scenario's, a list of development projects and approximate timings has been formulated.

In particular:

- 110/66kV transformer capacity at Stoke (2016)

The coincident loads of Motueka and Motupipi now exceed the rating of the 110/66 interconnecting bank at Stoke. This means that there is a reliance on the Cobb power station for generation to be on line during peak periods. This upgrade project is the subject of a new investment agreement.

- Capacitor banks Motueka and Motupipi (2017-2019)

Ongoing load growth will create the need for voltage support on the 66kV network under contingent conditions. This will take the form of capacitor banks to be installed at Motueka and Motupipi substations.

- New 220/33kV GXP at Brightwater (2022-2023)

At around 2022, the load on the Stoke 33kV bus is expected to exceed the firm capacity of the supply. Due to the limitations in bringing further load out from the Stoke GXP in its valley site, 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 substation site in 2009.

- Additional Transmission Capacity Southern Lakes Generation to Christchurch:

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.

5.9.3 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. Rural zone substations have no 33kV 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 in 33kV supply are Annesbrook, Songer St, Richmond, Hope Founders and Brightwater. The substations without full firm capacity in 33kV supply are Lower Queen St, Mapua, Eves Valley, Takaka and Swamp Rd.

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

A. The installation of a replacement 33kV underground cable at Songer St substation to boost the reserve capacity available in the backup 33kV feeder (2016/17). A short section of existing 33kV cable in the Railway Reserve feeder at Songer St substation will become capacity constrained due to load growth in the Richmond/Brightwater area. When the Brightwater GXP project is completed, this cable circuit will be reconfigured to form the Songer St A feeder circuit and become dedicated to the Songer St substation. This project has an estimated cost of $150,000.

B. Extension of the 33kV overhead network on an existing pole line from Eves Valley to Pea Viner Corner (2017/18). This extension is to provide an alternative route to the Appleby highway 33kV line feeding Mapua substation. This section of overhead line is prone to vehicle interference. This project has an estimated cost of $500,000.

C. Extension of 33kV network from Wakapuaka to Hira in preparation for new zone substation construction at Hira. (approx 2018/19). The estimated cost of this project is $1.80m.

D. Installation of four new 33kV feeder cable circuits linking new Brightwater GXP substation with existing 33kV network in the Brightwater area (2020/21). The estimated cost of this project is $3.2m.

E. Extension of 33kV network from Brightwater to Wakefield in preparation for zone substation construction at Wakefield. (approx 2020/22). The estimated cost of this extension is $1.5m

F. Reconductoring of the Motupipi to Collingwood 33kV circuit (26km). This circuit is expected to become capacity constrained by approx. 2024. The estimated cost of this project is $0.7m

G. 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 $500,000. The project is timed for when the Annesbrook substation bus load reaches 23MVA which is in 2026/27.

At the time that the Brightwater GXP is constructed, the 33kV network in the Stoke area will be re-configured so that a no break firm capacity 33kV supply is provided for the larger urban substations.

Also at this time, four new underground cable feeders to interconnect with existing overhead 33kV lines, will provide a switched firm supply for the Eves Valley, Hope, Brightwater and Mapua zone substations.

5.9.4 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.

This asset transfer was part of a programme of non-core transmission grid assets that are viewed as more appropriately owned and operated by lines companies rather than the national grid operator. Cost savings to the country as whole are likely to result from the lines companies being in a better position to operate and maintain the assets in a more cost effective manner that is optimised to the local environment.

One specific 66kV subtransmission circuit project has been identified. This is:

A. Installation of double circuit 66kV cables from the 66kV overhead lines at Riwaka to a new substation site. (approx 2025/2026). The estimated project cost is $700,000.

5.9.5 Zone Substation Upgrades

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

- **Brightwater/Wakefield Area**
  The Brightwater substation is the main supply for these areas. A project to upgrade the substation to full N-1 capacity has recently been completed.

  In the longer term (beyond the horizon of this plan), further load growth at Wakefield will generate the need for a zone substation at Wakefield.

- **Wakapuaka/Hira Area**
  The Wakapuaka/Hira area is supplied via a single overhead line that runs along the top of the Atawhai hills and drops down to the coast to a regulator site near the Glenn. Rearrangement of distribution transformer taps has been completed to further take advantage of the boosted capacity made available from the construction of Founders zone substation.

  The voltage at the end of the line at Kokoroa approaches statutory swing limits under current full load winter conditions. Growth in the Ludd and Teal Valleys is progressing with subdivision of farmland in these areas and this is expected to generate the need to

upgrade a section of line from the regulator site out to the Hira store within the next few years. A capacitor bank was installed at Hira during 2012.

Further growth in the area will generate the need to install a small zone substation at Hira near the entrance to Teal and Ludd valleys, or at Wakapuaka depending on industrial growth at the Glenn.

Preliminary modelling indicates that the most efficient method of achieving this would be a two stage development whereby a new 33kV cable would initially be installed and operated at 11kV to boost the supply until the substation was required. This development would be expected within 10 years at current growth rates.

A major aquaculture development could start up in the Glenn area within the next few years. Should this occur then it is likely that the zone substation would be needed at the existing regulator site at Wakapuaka. Such a development would supplant or significantly defer the development of the substation at Hira.

- **Motueka/Riwaka/Kaiteriteri Area**
  The Motueka substation was acquired from Transpower in December 2014. The substation has two 66/11kV transformers that have a 10/20MVA rating. The 20MVA rating is an emergency rating with forced air cooling in 10 degree C ambient. The transformers were manufactured in 1970.

  The substation peak load is limited to 19MW by operation of the load management system, however there are significant periods in summer at this loading.

  A renewal and capacity enhancement project to replace the transformers at the substation is planned for 2017/18. In this project, two new transformers will be installed each with nominal continuous rating of 23MVA.

  At around 2025, the load on the Motueka substation 11kV bus is expected to reach the firm capacity of the substation of 23MVA. Load growth is expected in the Motueka township and in Kaiteriteri and Marahau to the north. This load is difficult to serve at 11kV from the existing substation and it is proposed that a new zone substation at Riwaka is constructed. This will relieve loading on the Motueka substation, meet the incremental north Motueka load and provide an alternative source of supply for Motueka township. Land and cable easements for the substation have been procured and designated for this future substation.

  This project would require a cable extension of the 66kV network at Riwaka to the new substation site.

  Growth in the Kaiteriteri/Marahau area has been ongoing for a number of years. A capital works project to provide an additional feeder to this area from the Motueka substation was completed in 2006.

- **Motupipi Substation**
  The Motupipi substation is a single transformer bank 66/33kV substation. There are four single phase transformer units on site. Three of these are in service at any time, and a five hour shutdown of the substation is required to change out one of these with the spare unit. This configuration necessitates shutdowns of the Golden Bay load in order to maintain the transformer banks. The substation configuration also does not meet the security standard for the 7MVA load of 100% restoration of supply within 3 hours in the event of a transformer failure.

The existing transformers at Motupipi are now 49 years old.

A project to enhance the substation and bring it up to the appropriate security standard is now planned for 2019-2020. This project will involve replacing the existing transformer bank with two new three phase transformers and a second 66kV circuit breaker at the substation. Following this, each transformer bank will be capable of carrying the total load. This development will remove the need for regular shutdowns of Golden Bay for substation maintenance and it will significantly decrease the risk of extended unscheduled loss of supply.

- **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 original 33kV and 11kV switchboards are still in place. The substation is sited on land that has been designated by NZTA for future use as a highway.

  The substation 11kV switchboard is currently undergoing replacement. This project will replace the 11kV switchboard and relocate the switchroom building at the existing site but outside of the NZTA designation. This project gained board approval during 2014. The project has a value of $1.1m.

  In approximately 2020, it is expected that the Hope substation would be upgraded to 23MVA firm capacity by installing two new 11.5/23MVA units at the site.

- **Annesbrook Substation**
  At around 2026 a capacity upgrade of Annesbrook substation is expected. The substation firm capacity would be expanded to 34MVA by the installation of a third transformer and an additional 11kV switchboard.

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

2017/18	Install two new 23MVA three phase transformers at Motueka.
2018/19 and 2019/20	Install two new 66/33kV 10MVA three phase transformers at Motupipi Substation.
2020/21	Install new 11.5/23MVA transformers at Hope Substation.
2020/21	Construct new substation at Wakapuaka utilising two new 7.5/15MVA transformers.
2021/22 and 2022/23	Construct new GXP substation at Brightwater utilising two new 220/33kV 50MVA transformers.
2025/26	Construct new substation at Riwaka utilising refurbished 66/11kV 10/20MVA transformers.
2026/27	Upgrade Annesbrook substation with additional new 23MVA transformer.
2028/29	Construct new substation at Wakefield utilising two new 7.5/15MVA transformers.

5.9.6 11kV Feeder Upgrades

NTL operates a radial 11kV system generally without back-up 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 network down to 11kV 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.

- **Stoke Region 11kV feeders**
  As mentioned in the previous section a number of new 11kV feeders and existing feeder upgrades are planned in order to meet anticipated load growth, meet the design supply security standard and meet network supply quality and reliability performance targets. These are as follows:
  i) Installation of a new feeder circuit breaker at Annesbrook substation and a new 600A feeder cable from the substation to a new 11kV distribution switchboard in Merton Place. This is to boost supply to the Tahuna industrial area which is undergoing significant growth.
  ii) Installation of an interconnecting cable in Marsden Valley to link with the Panorama Drive 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.
  iii) Installation of an interconnecting cable to provide a backup supply to the Bells Island regional sewerage treatment plant.
  iv) 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.
  v) Installation of an interconnecting cable between Whitby and Lord Auckland Roads in Wakefield 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.

- **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.

  At around 2020, an upgrade to the 11kV feeder capacity into central Motueka is expected to be required. This will generate the need for two additional cable circuits run from the existing zone substation into the urban area. An expansion of the switchroom capacity at the substation to accommodate these circuits will also be required.

  Upper Moutere/Sunrise Valley
  This area is supplied from a line running from Mapua substation following the Moutere Highway from Lower Moutere. The end of line voltage conditions at Sunrise Valley are at the statutory limits during peak feeder loading at present. A regulator was installed at Old House Road during 2012 to improve end of line voltages. This will accommodate the present growth rate for the next ten years.

  Tasman/Ruby Bay
  The Tasman/Ruby Bay areas are supplied via a long light 11kV feeder line from Motueka substation. The section of feeder line from Motueka substation to Moana Road has been upgraded in conductor size in the past.

Subdivision of previous orchard land and upgrading of some packing sheds is creating a consistent growth in electrical peak load on this feeder.

The commissioning of the new substation at Mapua has boosted capacity in this area for the short term. Ongoing growth will generate the need for an 11kV conductor increase on the section of line between Moana Rd and Tasman Store and/or the section of line between Mapua School and Ruby Bay in the longer term.

Kaiteriteri/Marahau
The load at Kaiteriteri and Marahau is highly seasonal with a distinct peak during the Christmas and New Year holiday week. For the rest of the year, the load is relatively light. Recently, a new feeder circuit has been installed reducing the load on the original circuit and significantly improving the end of line voltage conditions during high load periods and also significantly improving the reliability of supply in the area.

For the longer term, the Kaiteriteri area is expected to continue to develop, particularly in the tourism area. A new zone substation in the Riwaka area is expected to be required later in the planning period. This development will relieve expected high loading on the existing Motueka substation, and improve expected voltage profiles at Marahau at the time.

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 study.

- **Golden Bay Region 11kV Feeders**

Upper Takaka
Ongoing installation of irrigation in the Upper Takaka Valley has generated the need for incremental voltage support and supply capacity enhancement. Capacitor banks were installed during 2010 and 2013 to provide this. Further irrigation load growth in the area is expected. The development of a new supply substation was approved by the NTL board during 2013. This is expected to be commissioned by the end of 2015/16.

Rockville
During 2011, three applications for irrigation system load were received in the Bainham area on the Rockville 11kV feeder. A capacitor bank was installed at Bainham during 2012 to support voltage in the area and 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.

- **Kikiwa Region 11kV Feeders**

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.

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.

Further dairying development in the future is possible. This may generate the need for partial line upgrade to 22kV.

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

- **Murchison Region 11kV Feeders**

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 are sited at strategic points along this line.

The voltage at Springs Junction is currently at regulatory swing limits under full load conditions. Further load growth will generate the need for further tactical capacity enhancement, likely to take the form of shunt capacitors.

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 the 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 Spring Junction end. The total cost of this upgrade project is estimated at $900,000.

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

Longford/Mangles
During 2011, three applications for irrigation system load were received in the Tutaki/Mangles area on the Longford 11kV feeder. A capacitor bank has been 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.

5.9.7 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 new 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.

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.

5.9.8 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 line 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.

5.9.9 SCADA/Load Management System Upgrades

An upgrade of the SCADA master station has been completed. This upgrade incorporated enhanced load management and improved remote access via laptops. It also allowed for the expansion of the system to incorporate down feeder line field devices such as autoreclosers. The master station hardware and software is 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 timeframe of this plan.

Expansion of the system to complete incorporation of all zone substations on the network is planned over the timeframe 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.

5.9.10 Remote Control of 11kV Field Autoreclosers

A programme to automate approx 60 distribution feeder field autoreclosers in stages commenced in the year 2000. Most autoreclosers (92%) have now been automated with control integrated into the company's SCADA system. Communication with these devices is by intermittent polling over a mesh radio network.

5.9.11 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 manifest themselves in Transpower transmission charges. The latest Transpower pricing indicates that the incremental cost of new demand on the system is $99/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 approximately $270m to supply a load of 140,000 kW. This translates to $1930/kW replacement capital, or $135/kW/year assuming a 7% p.a. cost of capital.

Adding these two component costs together gives a total avoided cost of $234/kW/year. At present the load control system reduces our overall peak loading by approximately 12,000kW. Therefore the ripple control system is saving NTL $2,808,000 in avoided capital charges per year.

During 2013, Network Tasman altered its policy for the supply of domestic storage water heaters, making mandatory the connection of the water heater through an NTL approved ripple control receiver.

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.

5.9.12 Fault Indicators

A capital investment identified during a study of reliability improvement measures is the installation of fault indicators at the ends of 11kV cable sections within the urban 11kV cable

network and at strategic points on the rural HV overhead line network. These indicators detect when fault currents have been passed and signal this by means of a flashing LED on site or via a communication to the control room SCADA system.

This aids cable fault location and greatly reduces the time taken to restore supply in unfaulted sections. A two year programme to install these at all switchgear and substation sites in the urban network and at strategic positions on the overhead rural distribution feeders is planned for 2016/17 and 2017/18.

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 taking place. 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.

5.9.13 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, then in order to meet urban supply restoration time limits of 6 hours, local generation is needed until the cable fault repairs can be effected.

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.

5.9.14 Power Factor Correction

As the load in the Motueka and Motupipi bulk supply regions increases, the firm capacity of the 66KV subtransmission network is encroached. Projects to install high voltage capacitors at Motueka and Motupipi substations to reinforce the upper network capacity have been identified. A budget capital allowance of $0.8m has been made for this project in the 2018/19 year.

5.9.15 Overhead to Underground Conversion

During 2001, the NTL board approved a new underground conversion policy. This policy provides for the conversion of overhead to underground and is based on “the overall benefit to the community as a whole”.

The overhead to underground conversion programme is based on NCC, TDC and NTL’s priorities with NTL determining the final programme. All underground conversion projects are subject to NTL’s underground conversion policy and only proceed if policy conditions are met.

The programme of works is as follows:

2016-17: High Street Motueka Stage 2, Batuep Rd Hope Stage1.
2017-18: High Street Motueka Stage 3, Batuep Road Hope Stage 2.
2018-19: Beach Road Tahuna, Champion Road, Richmond
2019-20: Songer Street (Nayland to Seaview), Nayland Road.
2020-21: Main Road Riwaka,
2021-22: Aranui Road, Mapua
2022-23: Bolt Road, Wakefield Northern entrance
2023-24: Ellis St, Brightwater
2024-25: Main Road Stoke Champion Road to Saxtons Road (11kV only).
2025-26: Waimea Road, (Annesbrook Drive to Beatson Road).

The average annual expenditure on underground conversion is approx $1,000,000.

5.10 NEW CONSUMER GENERATED NETWORK EXPENDITURE

5.10.1 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.

Activity has resulted in approximately 500 new connections per year.

5.10.2 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) is $624,600. 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 required.

Urban residential customers have an after diversity maximum (ADMD) of 3kW at low voltage distribution transformer level.

With approximately 415 new urban connections requiring 1245kVA of transformer capacity, NTL can expect to invest $160,000 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 10kVA of transformer capacity resulting in a low utilisation factor. Costs rise from $108/kVA for urban connections to $240/kVA for rural, leading to an overall $156,600 capital cost for rural transformer purchases to supply the 66 new rural consumers per year.

The Tasman District Council Rural 3 plan provides for cluster type development but this is unlikely to significantly alter the costs in rural areas.

Kikiwa and Murchison have respectively 12 and 7 new connections p.a. on average. Apart from the odd subdivision at Tophouse/St Arnaud, almost all connections require a dedicated 15kVA transformer. At approximately $5700 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 approximately 6 new transformers are purchased at a cost of

$180,000. For safety and convenience reasons, a recent trend has been a move away from fence enclosure type industrial substations to padmount substations.

5.10.3 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 $186,000 per year, for this equipment. As load and consumer numbers increase on rural feeders, sectionalisers and reclosers are added to aid fault location and supply restoration as a means of improving network performance.

5.10.4 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, switchgear except for some isolators and associated fixtures. On vesting and livening NTL will also pay a further contribution per electrically connected lot as consideration for vesting.

Estimated replacement costs for urban subdivision reticulation is on average $3,500 per lot. Total value with an average of 415 new lots per year amounts to $1,452,500.

5.10.5 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 p.a.

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

5.11 MAJOR NETWORK DEVELOPMENT PROJECTS 2016/17

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 2016/17 year. Alternative options for these major projects are discussed. Unless otherwise stated, these projects are subject to business case approval prior to commencement.

Specific details of the projects proposed are as follows:

1 <u>Hope Substation replacement 11kV Switchboard and Switchroom</u>

A project to relocate/replace the 1959 11kV switchroom and indoor switchboard commenced in 2015. This project replaces an aged bulk oil switchboard with a modern encapsulated vacuum type with up to date digital protection and SCADA. The project gained board approval in November 2014. The project commenced during 2015 and it is

due for completion in the second quarter of 2016. This renewals project has a total value of $1.1m.

2 New 11kV Feeder Annesbrook Substation

Step increases in load at a number of sites in the Tahuna industrial area have exceeded the firm capacity of 11kV supply. A new feeder into the area from the nearby Annesbrook substation is required to restore this firm capacity and provide for expected ongoing industrial load growth.

This project is a system growth project that has an estimated cost of $600,000.

5.12 MAJOR NETWORK DEVELOPMENT PROJECTS 2017/18-2020/21

Refer to Appendix D, detailing all capital expenditure identified as likely to occur in the four years 2017/18 to 2020/21.

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

1. Capacitor banks Motupipi (2018/19) and Motueka (2023/24):

The installation of capacitor banks at Motueka and Motupipi substations have been identified as a development step in a program of steps to boost subtransmission capacity over the next 20 years. The capacitor bank installations will provide voltage support under n-1 contingency conditions. The business case would consider the following alternative options:

- Contracting for local generation during contingencies
- New local generation
- 66kV line capacity upgrade by re-rating, reconductoring or voltage increase.

The capacitor banks have a budget cost of $1.3m. This project will have no incremental improvement effect on target service levels but it will serve to maintain existing supply security and quality at current levels despite the effects of load growth.

2 Motupipi Substation Upgrade (2017/18 to 2018/19):

This project is planned to bring the substation in to line with design security standards. The project will entail the addition of two new 66/33kV transformers at the substation together with associated 66kV and 33kV switchgear. The cost of this project is $3.0m.
Options to be considered in the business case will be

- Deferment based on extension of life of transformers.
- Further development of local embedded Generation.

This project will improve supply security but will not significantly improve any target service levels.

3 Motueka Substation 66/11kV Transformer Upgrade (2017/18):

This project is required to increase the capacity of the substation supplying the Motueka bulk supply area in line with the security design standard and expected load growth. The

project involves replacement of the existing 10MVA transformers with 23MVA rated units, matching the switchboard rating at the substation. The cost of the project is estimated at $1.5m.

Options to be considered in the business case will be

- Local Generation.
- Early development of Riwaka substation.

4 _ 33kV Cable extension Wakapuaka to Hira (2018/19) and Construction of new substation at Wakapuaka (2020/21)

This development is a two stage development to meet future load growth in the outer northern part of Nelson City. In the first stage a new 33kV cable extension from Wakapuaka to Hira would be installed and operated at 11kV to boost supply to the area. In the second stage, a substation at Wakapuaka would be developed. A full business case would include consideration of the following alternative options:

- Upgrade of existing 11kV feeder to 22kV.
- Local Generation

Due to the length of existing 11kV feeders supplying the area together with the existing voltage support devices, continued supply at 11kV from Founders substation is not expected to be a viable option.

The overall cost of this project is estimated at $3.75m.

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 Rockville Feeder 22kV Conversion Stage 1 (2018/19) and Stage 2 (2020/21)

Dairy irrigation expansion in the Aorere Valley may generate the need for conversion of the 11kV feeder from Swamp Road substation to 22kV. This project will become necessary when incremental capacity enhancements such as capacitor banks have been exhausted. A full business case for the project taking account of committed irrigation projects and load control options will be required.

This conversion project has an estimated value of $3.2m.

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

- 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.

6 11kV Switchboard Extension and Additional 11kV Feeders Motueka Substation (2019/20)

Residential growth and expansion of the Motueka township area is ongoing. By approx. 2019 the existing 11kV feeders will have increased such that the n-1 security level will have been reached. To remedy this, a project to install two additional 11kV feeder circuits into the township has been identified. This will require expansion of the 11kV switchboard at the substation as well.

Options considered in the planning for this development will include

- Major deployment of embedded generation in the Motueka township.

This project has an estimated value of $4.8m.

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.

7 33kV Feeder Cables (2020/21) and Brightwater GXP Substation (2022/23)

Forecast load growth in the area Richmond and South to Brightwater and Wakefield will cause the firm capacity of the Stoke GXP supply to be exceeded. A new 220/33kV GXP at Brightwater is proposed. This development will include the installation of four new outgoing feeder cables to interconnect with the existing 33kV network, along with the construction of a 50MVA firm substation.

Options considered in the planning for this development include

- Major new generation in the Brightwater area.
- Load transfer of major loads from the Stoke 33kV bus to the Stoke 110kV bus.
- Major deployment of embedded generation in the Stoke GXP area.

The overall estimated cost of this complete GXP project $27.2m.

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.

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, maintenance and renewal expenditure over the ten years of the plan by asset class is given in Appendix F. The projected expenditure for asset maintenance and renewal is summarised by category in the following table:

ASSET MAINT & RENEWAL EXP $k	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Faults and Emergency Maintenance	907	916	925	934	943	953	963	972	982	991
Routine and Preventive Maintenance	1,698	1,715	1,732	1,750	1,767	1,785	1,803	1,821	1,839	1,857
Refurbishment and Renewals Maintenance	2,100	2,121	2,142	2,164	2,185	2,207	2,229	2,251	2,274	2,297
Total	**4,705**	**4,752**	**4,799**	**4,848**	**4,895**	**4,945**	**4,995**	**5,044**	**5,095**	**5,145**

N.B. Figures are 2016 dollars and do not include inflation adjustment.

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 various types of components vary widely (e.g. timber crossarms 15 - 45 years, porcelain line hardware in excess of 50 years), then 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. Many technological items such as relays, switchgear and SCADA components are replaced for reasons of obsolescence rather than wear out. For those items that do reach end of life in service there can be significant variation of 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 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 mid life refurbishment.

In service failures of components on the network are infrequent and 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 CLASSES

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 MAINTENANCE 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 impacts 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 Maintenance

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 and/or crossarms and line hardware.

Refurbishment of equipment is generally only undertaken to the extend the life of major capital items such as power transformers or large distribution 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 renewal 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 engaged one staff member in the field to assess maintenance and renewal requirements. The entire network is subject to a survey round 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 with the bulk of the identified work being timber crossarm renewals with some pole replacements. The intention of network survey programmes is to inspect all components of the network system at least every five years on a condition driven maintenance basis.

Urban and rural inspections are generally made from the ground. Remote rural inspections are sometimes made from helicopter. 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 and Operational Test	Monthly
Power Transformers	Tapchanger Operational Test	Monthly
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 item 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 let to the principle maintenance contractor.

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.

6.6 LIFECYCLE ASSET MAINTENANCE AND RENEWAL BY ASSET CLASS

6.6.1 Pole Structures

The NTL overhead line network is based on purpose-designed concrete poles. There are approximately 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 1930's. They have proven to give excellent service and in the relatively benign conditions of Nelson 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 formed. Since that period some 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 and as yet undetermined 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 replaced for aesthetic and public safety reasons (risk of being struck by a falling piece of concrete) rather than for loss of strength.

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.

Approximately 1200 reinforced concrete poles have been scheduled for replacement over the period of this plan. This represents 4% of the total pole population.

The oldest concrete poles are being monitored to identify ageing mechanisms that might lead to loss of strength such that they require replacement. To date, apart from severe loss of concrete cover followed by corrosion of the reinforcing steel, no such mechanism has been isolated. Such severe pole degradation is rare even for the oldest poles.

Pole replacements due to spalling tend to be variable over the age distribution of poles and seem to be more related to the quality of initial manufacture rather than age. Until a distinct ageing mechanism for these poles can be isolated, we are assuming that the life of the poles is in excess of 80 years and that due to this no age-based renewal programme is needed in the time horizon of this plan.

Notwithstanding the above, the performance of 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 Bests Island. It has been ascertained that salt water ingress into these poles results in rapid rusting of the reinforcing steel within the pole leading (particularly in the case of pre-stressed concrete poles) to catastrophic failure of the pole. A programme has been put in place to replace all concrete estuary poles with class A marine treated pine poles is now in place.

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 pre-stressed construction. These are a stronger pole than the reinforced concrete pole, however they have the disadvantage of not having residual strength following breakage from vehicle impact for example.

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 1950’s and are now showing signs of reaching end of life in some areas. There are approx 650 of these still in service on the network.

A pro-active iron rail replacement programme is now operating. Iron rail poles that have maintenance scheduled on them (for example to change the crossarm) are now to be replaced with a concrete or treated pine pole. Also, as lines are being upgraded (e.g larger conductor installed) all iron rails in the line section will be replaced with a concrete pole as part of the job.

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 used now 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. 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 aged based spalling. Straightening poles and strengthening 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 programs are underway for spalling reinforced concrete poles and iron rail poles. These replacements are budgeted to continue at a steady rate for the time horizon of this plan.

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

6.6.2 Line Hardware

Line hardware consists of all pole structure sub-components other than the poles themselves. Items include crossarms, insulators, strain insulators, guy wires and anchors, bracestraps, dropout fuses and cutouts.

Crossarms: The timber crossarms in use in the NTL system are mainly Australian hard wood 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 50 years with an average of around 20 years. Factors influencing crossarm life are aspect and level of shading from the sun, and 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.

As many crossarms were changed prematurely in a previous maintenance regime, then the current average condition is good, and the present renewal requirement is low at around 900 crossarm changes per year. This is expected to increase to 1600 crossarm changes per year over the next ten years as the long term renewal rate is reached.

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 Maintenance:

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 p.a.) for the period of this plan.

No items of line hardware are refurbished.

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

These are listed as follows:

- Dominion dropout 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 re-inserted 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 northwest 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 pre-load spring systems are now used as replacements in these remote areas.

- Prior to 1995, the grease tube and line tap connector was 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 pin hole 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 required for some light copper and aluminium lines in the next ten years. Older light copper conductors in particular are reaching of 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.

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 re-binding 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) that has rusted to failure, and have reached the end of their economic life.

Conductor renewal has also taken place in spans of light conductor where conductor clashing has been known to have occurred over a long period of time. This leads to weak spots in the conductor.

This review of the AMP includes a program of replacement of 7/064 and lighter HV conductors over a ten year period, commencing in 2016/17. Conductor installation records and historical records of conductor breakages have been used to prioritise this replacement program. Under the program, approximately 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.

6.6.4 HV Underground Cables

In general the underground cable network is in good condition. It has been carefully installed in good 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. The preference has been to continue with paper lead as the standard, due to its proven performance and long life as a high voltage insulation. The MIND paper lead cable has

proven world wide to be a very long life cable construction. If operated carefully and not interfered with, the life of the cables is indeterminate.

In the past five years, a number of joints in the underground 11kV network have failed in service. The failures have tended to be instigated by water ingress into the joint. In particular the early Raychem type joint has been prone to this. It is proposed to partial discharge test critical cable sections with this type of joint in order to identify cases where there is a risk of failure.

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 or cables identified as having poor insulation are scheduled for replacement.

HV Underground Cables Refurbishment and Replacement

In service HV cable failures in the past two years have highlighted an issue with small c.s.a (35 sq mm and below) steel tape armoured cables installed during the 1980's and early 1990's. The steel tape has significantly corroded during the approx 20 years in service to the point that the mechanical protection that the steel tape provided has all but disappeared. 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.

Spur circuit sections of 35 sq mm HV cable have been now individually identified and a replacement program targeting these cables has been created. This program will commence in 2016 and continue for six years. The program consists of a number of individual cable replacement projects. The list of these projects, their cost and timing is given in Appendix E. The costs of these projects are included in the capital works budgets of Appendix D.

6.6.5 Zone Substations

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

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

Power Transformers

There is one bank of single phase 66/33kV transformers at Motupipi substation. These are circa 1966 units. They have seen light service only and condition monitoring such as partial discharge and dissolved gas analysis indicates good condition. The units do not have on load tapchangers fitted.

There are twenty 33/11kV three phase transformers ranging in capacity from 3MVA to 11.5/23MVA. The oldest of these are two 10MVA units at 57 years.

There are two three phase 66/11kV power transformers at Motueka substation. These have been recently transferred to Network Tasman from Transpower. These are 45 year old units. They are currently loaded to their firm capacity.

Power Transformer Routine and Preventative Maintenance:

The transformers, tapchangers and switchgear at all substations are maintained on a bi-annual basis. Oil samples are taken from the in-service transformers for Dissolved Gas Analysis every six months 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 practises, it is expected that the insulation of the power transformers is still in good condition.
The on load tapchangers on all units are opened up regularly and checked for wear, etc. Although original parts can no longer be purchased for the older ones, 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 tapchangers.

Power Transformer Refurbishment and Replacement:

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

Both of the two 54 year old transformer units had a new tapchanger fitted when they were refurbished.

Mid-life refurbishment of the Songer St substation T1 transformer is planned for 2016. This has been estimated to cost $200,000.

One of the transformers at Takaka substation failed in service in 2008, with a significant HV winding fault. This transformer was returned to the manufacturer for repair. This unit was fitted with a complete new 3 phase winding. The transformer was a nine year old unit. This transformer was returned to service in 2009.

Power Transformer replacements are major capital expenditure projects. There are no power transformer replacements envisaged within the planning 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 in good condition. The 66kV circuit breaker at Motupipi is a vacuum/dry air insulated type. The others are all SF6 type of varying ages. The Motupipi circuit breaker was new in 2012 having replaced the previous SF6 unit which had a slow gas leak.

66kV Switchboard Routine and Preventative 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 timeframe of this plan, however should any CB's develop significant gas leaks, then they may be removed from service and refurbished. Further analysis and determination of the life cycle situation with the 66kV SF6 circuit breakers is to take place during 2016.

33kV Switchboards

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 bi-annual basis.

The circuit breakers are either bulk oil or vacuum type, the oldest circuit breakers being circa 1966. These are inspected on a bi-annual basis. Very few fault clearing operations have occurred on these circuit breakers.

The Mapua and Richmond substations have indoor 33kV switchboards. The Mapua switchboard has SF6 CB's and the Richmond switchboard is an encapsulated vacuum 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.

33kV Switchboard Refurbishment and Renewals

High voltage switchboards are major capital items. Refurbishment and renewal are significant capital works. The 33kV switchboard at Hope substation is proposed to be replaced in conjunction with a zone substation relocation in 2014. Further information is provided in section 5.9.4.

11kV Indoor switchboards

There are six vacuum switchboards (circa 1998, 2001, 2003, 2005, 2006 and 2013), one SF6 indoor switchboard (circa 1985) and one bulk oil switchboard (circa 1959). These switchboards are all in good condition, have sufficient fault duty and are regularly serviced.

The one remaining bulk oil indoor switchboard is at Hope substation. Recent partial discharge monitoring has revealed little activity and the switchboard is in very good condition. This switchboard however is obsolete. Due to the relatively low rates of faults on the 11kV feeders, the circuit breakers now perform relatively few fault switch operations.

11kV Switchboards Routine and Preventative Maintenance

The maintenance requirements of the modern vacuum and SF6 switchboards are minimal. All switchboards are cleaned and inspected and tested on a bi-annual basis. Partial discharge testing is also undertaken on a bi-annual basis. Partial discharge testing of all switchboards has revealed no unusual discharge activity.

The Hope 11kV oil switchboard has greater maintenance requirements. This includes circuit breaker regular oil filtering and contacts dressing after major fault clearing operations.

11kV Switchboards Refurbishment and Renewal

All 11kV switchboard refurbishments or replacements are major capital works. There are no planned refurbishments or renewals of any of the vacuum or SF6 switchboards in the period of this plan.

The Hope substation 11kV switchboard, is currently undergoing replacement.

Protection Relays

The protection relays are a mixture of electro-mechanical and electronic devices. The more recent substations have all electronic protection relays:

- Lower Queen St (all digital electronic)
- Founders (all digital electronic)
- Annesbrook (digital electronic/electromechanical)
- Songer St (digital electronic/electromechanical)
- Mapua (all digital electronic)
- Richmond (all digital electronic)
- Hope substation (electromechanical)

Hope substation is the only substation with legacy electromechanical feeder relays still in-service on outgoing feeders. These are currently being replaced as part of the switchboard replacement project.

All remaining electromechanical protection relays are associated with transformer circuit breakers only. 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 relay technology now offers much greater functionality within one unit.

Oil Management

Oil handling procedures and facilities at all zone substations have been upgraded incorporating the provision of oil spill kits. Oil interceptor bund systems have been installed at Lower Queen St, Brightwater, Founders, Annesbrook, Mapua and Richmond substations as the transformer pads at these sites have been built or modified. Other bund systems are planned to be installed to the other zone substations as they are upgraded.

6.6.6 Air Break Switches

There are 776 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.

Bolted connections on overhead 11kV air break switches have previously been made using galvanised bolts and belville washers. These have severely corroded within five years of service, resulting in failure of these connections in service.

Air Break Switch Routine and Preventative Maintenance

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 usually initiated from reports from lines staff of operating problems.

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.

Problems have been experienced with the arc controlling flickers on modern air break switches. Investigations into this have revealed that the initial setup of these is critical to satisfactory operation over the life.

Air Break Switch Refurbishment and Replacement

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 changeouts 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.

6.6.7 Pole Mounted Switchgear (Autoreclosers and Sectionalisers)

There are 64 pole mounted autoreclosers and sectionalisers on the NTL network. These are either Reyrolle OYT oil type or McGraw Edison KF and KFE and Nulec vacuum type.

Pole Mounted Switchgear Routine and Preventative Maintenance

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 thermo graphic surveys.

Pole Mounted Switchgear Refurbishment and Replacement

Reyrolle OYT reclosers have reached the end of their useful lives due to fault rating and general obsolence.

The electronic control systems in the KF and KFE type vacuum reclosers and sectionalisers have shown signs of ageing and in many cases have become unreliable.

All of these recloser and sectionaliser units have been subject to a replacement program that will be completed during 2016. Under this program, all 64 reclosers and sectionalisers will be 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 replacement schedule for those units yet to be replaced is given in the table of Appendix E. Costs are included in the capital budget of Appendix D.

6.6.8 Ground Mounted HV Switchgear

There are two main types of ground mounted 11kV switchgear in service on the network. These are the Hazemeyer Magnefix type and the ABB SD oil switch type.

Ground Mounted Switchgear Routine and Preventative Maintenance

The Magnefix switchgear is a fully encapsulated compound insulation switchboard. 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. There are no units on the network that will reach this age within the time horizon of this plan.

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. 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.

A programme of oil testing in older units has recently been completed.

Ground Mounted Switchgear Refurbishment and Replacement:

The older series 1 Andelect oil switch units (35 units) have been scheduled for replacement under a renewal programme that has been running for the last ten years. This replacement program will be completed during 2016.

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. All HV oil fuse switches have now been removed from 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 a standard alternative for 11kV free standing ground mounted switch applications. These have the facility for future SCADA monitoring and control. There are now four Halo switch units in service on the NTL network.

6.6.9 Distribution Substations

There are currently 4,471 distribution substations on the network. These are in five standard types being single pole substations, multiple pole 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. 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.

The “Andelect J type fuse” low voltage fuseboards within older padmount substations have been identified as being prone to loosening and overheating, particularly in cases where they supply large commercial or industrial load. A design fault in these fuseboards has also been isolated where the busbars are fitted to the fuse pillars. The regular thermo cycling effect of the load causes the bolted connections and wedge type fuses to be loosened. A programme has been put in place to identify all sites that have the potential for this fault mechanism, and replacement modern equivalent fuseboards are being installed.

6.6.10 Distribution Transformers

A rising number of distribution transformers are coming up to a nominal 55 year life in the next few years (refer age profile chart 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 over voltage on the supply, surges and exposure to lightning. The latter exposure varies according to location.

Old transformers remaining in service typically fail finally during a lightning storm. The total failure rate of transformers has been very low over the past 10 years at approximately 150kVA per year. Lightning storms are intermittent in the Nelson area and five to ten transformers only are permanently damaged during major storms, however not all such failures are old transformers. The failure rate of transformers is not expected to rise at a dramatic rate over the next few years.

Many transformer changeouts 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 ICP applications or existing ICP upgrades also generate planned transformer changeouts.

<u>Distribution Transformer Routine and Preventative Maintenance</u>

Distribution transformers are maintained when they are released from service on the network for reasons of load increase/decrease or substation re-location due to underground conversion etc.

Distribution transformer maintenance consists of tank rust removal and re-painting, 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 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 changeout or in service failure will be scrapped and replaced if they are older than 50 years. Those that are less than 50 years old will be inspected and tested and if OK, repainted, oil treated and returned to service.

In service distribution transformers that are older than 60 years will be scheduled for replacement.

A renewals budget provision of $230,000 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 3 or 4 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 heatshrink. 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 11,530 service boxes in place on the network. There are three main types. These are all concrete pillar boxes 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.

Service Boxes Routine and Preventative Maintenance

The PVC type service box lids often require resecuring after they have been struck by vehicles. Sometimes damage in these cases extends to necessitating fuseboard 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

There are no plans for the refurbishment or replacement of service boxes in the time period of this plan.

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 rewireable 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 GXP region. All of these are solid state injection plants. All are in good condition and monitored annually. Ripple injection frequencies are 475Hz and 233Hz.

The convertor equipment at the Motueka ripple injection plant was upgraded during 2003.

The convertor equipment at the Stoke ripple injection plant was upgraded during 2004.

The convertor equipment at Motupipi is to be upgraded during 2016.

6.6.15 Network Communications Systems

The network system includes two main communications systems. These are the SCADA fibre and radio communications network and the VHF voice mobile communication network.

The SCADA communications network comprises fibre optic links from zone substations and ripple injection plants to the control centre at Hope.

Three point to point microwave radio links also connect the substations at Cobb and Upper Takaka in Golden Bay to the Hope control centre. These links were purchased in conjunction with the 66kV asset transfer in 2014.

A mesh radio communications network was installed in 2015/16 allowing improved communications to 60 field autoreclosers 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.

6.6.16 Other Specific Renewal Projects

Marsden Rd Stoke - Double Circuit 33kV

There is a section of double circuit 33kV line in Marsden Rd, Stoke. It is proposed to replace the double circuit configuration with standard single circuit flat configuration utilising a 450A aluminium conductor. This is to be completed in 2017. The project cost is estimated at $80,000.

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 powerlines. 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. Two vegetation notifying staff perform regular patrols of the overhead network to identify and notify tree owners of their obligations and options under the regulations. The aim is to reach a steady state where the network is fully patrolled every 18 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 2600km 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 involved, 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 free felling service to the tree owner.

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 de-stocked and left to revert to bush. Gorse and broom are the typical dominant species to 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 overtake the conductors, NTL takes a pro-active 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.

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 powerlines 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, 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.

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 4 wheel drive vehicles. Maintenance activities include water table and cutoff clearing, and track spraying. This work is put out to contract outside of the Network maintenance contract.

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.
- Regulatory Removals - All removals arising from the Electricity (Hazards from Trees) regulations.
- 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 the 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 then 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 practise has been completed. This review concluded that NTL vegetation expenditure levels are in line with similar networks in NZ and that its policy and practise are aligned with good industry practise.

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 described in the following table:

Type	Sub Type	Description
IT and Technology Systems	Network Modelling Software	CYME Dist Loadflow
	Geographic Information System (GIS)	ESRI ArcGIS
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 Cruiser 4WD – Line Survey
		2 x Daihatsu Terios – Vegetation Survey
		1 x Nissan Leaf – Office
		2 x Toyota Hi-Lux 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

Development

Network Tasman's asset management practises 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.

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.

7.3 NON NETWORK ASSET CAPITAL, MAINTENANCE AND RENEWAL PROJECTS 2016-2021

There are no large individual non network asset capital works projects or significant maintenance projects planned for the next five years.

The following replacements/renewals are budgeted:

Asset Replacement	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Computer Hardware and Software	330	330	330	330	330	330	330	330	330	330
Vehicles, Plant and Equipment	55	55	55	55	55	55	55	55	55	55

N.B. Figures are 2016 dollars and do not include inflation adjustment.

8 RISK MANAGEMENT

8.1 OVERVIEW

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.

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 (GXP's). In recent years, capacity constraints in the Transpower transmission network, particularly during times of peak load have become apparent. Transpower have addressed these by completing the stringing of the 3rd 220kv circuit from Islington to Kikiwa which has increased capacity by approximately 100MW and it is working over the next few years to complete various tactical upgrade projects. Beyond approximately 2030 however the transmission capacity into Christchurch may need to be further augmented. Transpower are now evaluating transmission and non transmission options.

NTL has a high degree of reliance on supply from Transpower GXP's in its network and there is very limited transfer capacity between GXP's. The Stoke GXP in particular carries the major load including Nelson City.

Total or partial loss of transmission capacity to the GXP's is dealt with in the Network Tasman Disaster Recovery Plan.

8.2 RISK MANAGEMENT STRATEGY

The primary risk strategy employed by NTL is to limit the load on single line feeder circuits that cannot normally be repaired under single contingency event scenario's 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.

Other risk events of a more catastrophic nature such as complete loss of substation switchboards are subject to specific contingency plans and these are detailed in the company's disaster recovery plan.

Risk events not directly resulting in loss of supply such as oil spills are also treated through documented contingency plans in the disaster recovery plan document.

In all commercial contracts with customers, Force Majeure applies as defined in the Use of Systems Agreement (UOSA).

8.3 RISK MANAGEMENT BACKGROUND

The core business of NTL is electricity distribution. The primary strategic goal of the company is to provide a reliable electricity supply service at minimum 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 NZ 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 NZS31000. 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 and reduction or to risk acceptance with reference to contingency plans.

Contingency plans are the subject of a separate document entitled 'Network Tasman Limited Disaster Recovery 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 and Wells Ltd

8.4 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 pad mount 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	4,400	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 when 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 1 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 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 effect 250 customers for 10 hours.

8.5 RISK BENCHMARKING

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 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 2000 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 timeframes of the Use of Systems Agreements (UOSA) that NTL has 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.

8.6 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. This allows supply restoration via connection through alternative supply routes in many cases.

Since the low voltage networks exist on a 300m maximum radius of distribution substations, the susceptibility of the networks to environmental effects since 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. The resulting risk level is significant however.

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, 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	0.03	2200	0.03	6000	72	12,960
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	0.03	1000	0.03	50	6	9
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 and 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 and 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 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	Feeders in	Probability of event on any	Customers Affected	Restore Time	Risk

	system	System	individual Feeder			
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	0.03	46	0.03	6500	168	32,2760
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 24hr 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	0.01	16	0.03	280	18	151
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 a 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 Substations and Subtransmission

Risk assessment matrices for each of NTL's 12 zone substations and 3 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 500 yrs	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 3,200 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 a simple outdoor switchgear design with 4 single phase transformers, three of which are required to be in service at any time. Events resulting in lengthy outage for the substation are low in probability. Loss of two or more transformer units from earthquake damage or lightning strike would be the most likely scenario for an extended outage event.

- **Hope Substation**

  This substation supplies 2,300 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 3 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 Recovery Plan (Ref. Appendix L).

The loss of major components of the substation such as part or all of the indoor switchboard or both of the transformers are the other major risks 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 Response and Recovery plan (refer Appendix L).

- **Songer St Substation**

  Songer St substation supplies the central Stoke area including 4,800 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 St 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 5,200 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 2,400 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 St. Therefore although similar probabilities of loss of supply are associated, the extent of outage is greatly reduced. Again contingency plans for

such events exist.

- **Brightwater Substation**

  This substation supplies the townships of Brightwater and Wakefield and the rural areas adjacent. There are 2,350 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 re-supplied 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 equivalence of 1000 customers is assigned to the station for the purposes of the 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 St Substation**

  Lower Queen St 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. This short line can be repaired quickly in the event of failure however. The combined effect of low probability of occurrence, short repair times and a relatively small number of affected customers (2,300), 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 approximately 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 recovery 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 1,850 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 35% percent of the route length. The substation therefore has only N level subtransmission security.

  The final 10km of the overhead line route is alongside a busy state highway. There are relatively frequent car vs pole events along this section of road. The 33kV supply to this substation is the greatest area of risk of loss of supply to consumers fed from this substation. There is a capital project in the asset management plan to provide an alternative overhead line as a backup for this section of line.

  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 5,000 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. 8,000 consumers in the 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 risk overall loss of supply risk rating.

- **Upper Takaka Substation**

  Upper Takaka substation is a 66kV subtransmission substation that serves acts as a connection node in the 66kV line network. There are three 66kV circuit breakers at the substation which form the major and critical components.There are currently no offtake consumers supplied from the substation, although failure of some critical items at the substation could affect the supply to Motupipi substation. Given that the repair time of these items is short, (circuit breakers can be bypassed and protection reconfigured in an emergency) then the substation has a low loss of supply risk rating.

- **Transpower GXP Substations**

  NTL relies for its supply on delivery of electricity to four Transpower GXP's in its region. These are at Stoke, Kikiwa and Murchison. Detailed risk assessment of these GXP's 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 GXP's (and the transmission lines supplying these GXP's) 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 faultline, as is the 220kV transmission line to it.

NTL contracts with TransPower for supply to its network via the four GXP's. Supply reliability is the subject of a commercial contract between NTL and TransPower. TransPowers's Risk Management Plan and the performance of Transpower is therefore of the upmost importance to NTL.

NTL has identified the risks associated with the supply from the Stoke substation and the other GXP's. Network Tasman's Disaster Recovery 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.

8.7 EARTHQUAKE PERFORMANCE 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-dependencies 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 northwesterly direction and runs along the Wairau Valley.

Other fault systems which are still active but having a high recurrence interval are the Waimea-Flaxmore systems.

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 Modified Mercalli (MM) scale 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 in 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, 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 into 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 from the GXP to the zone substations and the zone substations themselves. Each zone substation has a dedicated 33kV subtransmission line. The likely effects of a large earthquake on this supply line 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 pad mounted 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 north Nelson area including Atawhai and Hira. 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 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 fairly quickly repair damage 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 St 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 ten 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 to these 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 St. Two short underground 33kV cables from run into the substation from Songer St.

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 1980’s. 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 St 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.

Takaka Substation

Takaka substation supplies the Golden bay area aside from the northwestern 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 northwest Golden 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.

8.8 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 risks 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 24hr 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 24hr 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.

9 PERFORMANCE MEASUREMENT, EVALUATION AND IMPROVEMENT

9.1 FINANCIAL AND PHYSICAL PERFORMANCE

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 2014/15 financial year.

These are as follows:

CAPITAL EXPENDITURE ($k)	Actual 2014/15	Budget 2014/15	% Variance 2014/15
Customer Connection	1,031	926	+11%
System Growth	1,036	3,615	-71%
Reliability,Safety and Environment	9,785	8,500	+15%
Asset Replacement and Renewal	1,632	1,432	+14%
Asset Relocation	1,339	1,877	-29%
ASSET MANAGEMENT CAPITAL EXPENDITURE	**14,823**	**16,350**	**-9%**

OPERATIONAL EXPENDITURE ($k)	Actual 2014/15	Budget 2014/15	% Variance 2014/15
Routine and Preventative Maintenance	1,268	955	+33%
Refurbishment and Renewals Maintenance	2,433	1,646	+48%
Faults and Emergency Maintenance	851	720	+18%
Vegetation Management	861	949	-9%
ASSET MANAGEMENT OPERATIONAL EXPENDITURE	**5,413**	**4,270**	**+27%**

TOTAL DIRECT NETWORK EXPENDITURE ($k)	**20,236**	**20,620**	**-2%**

The above variances were discussed in the 2015 AMP review.

Progress against Plan for first year of 2015/16 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 close proxy, forecast figures based on the 11 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 2015/16	Budget 2015/16	%Variance 2015/16
Customer Connection	428	520	-18%
System Growth	2,501	3,546	-29%
Reliability,Safety and Environment	787	1,175	-33%
Asset Replacement and Renewal	1,903	1,941	-2%
Asset Relocation	1,350	2,690	-50%
ASSET MANAGEMENT CAPITAL EXPENDITURE	**6,969**	**9,872**	**-29%**

OPERATIONAL EXPENDITURE ($k)	Forecast 2015/16	Budget 2015/16	%Variance 2015/16
Routine and Preventative Maintenance	1,606	2,021	-20%
Refurbishment and Renewals Maintenance	1,886	1,850	+2%
Faults and Emergency Maintenance	651	756	-14%
ASSET MANAGEMENT OPERATIONAL EXPENDITURE	**4,143**	**4,627**	**-11%**

TOTAL DIRECT NETWORK EXPENDITURE ($k)	11,112	14,499	-24%

SYSTEM MANAGEMENT AND OVERHEADS ($k)	Forecast 2015/16	Budget 2015/16	%Variance 2015/16
System Operations	629	529	+19%
Vegetation Management	824	824	0%
TOTAL OVERHEADS	**1,453**	**1,353**	**+7%**

Network Development Projects

The completion status at near year end of the Network Development projects planned for 2015/16 is summarised as follows:

Specific Development Projects					
Network Enhancement Project	**Year**	**Estimated Cost**	**Region**	**Expenditure Class**	**Completion Status**
33kV cable circuit upgrade Songer St - 600A	2016	$150,000.00	Stoke	System Growth	Deferred
33kV Line Extension Eves Valley to Pea Viner Corner	2016	$500,000.00	Stoke	Reliability	Deferred
Andelect Replacement Beatty St 1516	2016	$22,000.00	Stoke	Renewal	Completed
Andelect Replacement Muritai St 1198	2016	$22,000.00	Stoke	Renewal	Completed
Andelect Replacement Rawhiti 1204	2016	$22,000.00	Stoke	Renewal	Completed
Andelect Replacement Toko Ngawa 1090	2016	$22,000.00	Motueka	Renewal	Completed
Andelect Replacement Waverley St 1210	2016	$30,000.00	Stoke	Renewal	Completed
Annesbrook Express Feeder CB and Cable	2016	$500,000.00	Stoke	System Growth	Deferred
Galv Conductor Replacement Whakarewa St	2016	$15,000.00	Motueka	Renewal	Deferred
Install 33kV CB's Swamp Road Substation	2016	$150,000.00	Golden Bay	Reliability	Deferred
Interconnection Cable Belfit Lane Wakefield	2016	$50,000.00	Stoke	Reliability	Deferred
Interconnection Cable Tasman Heights to Marsden Valley	2016	$100,000.00	Stoke	Reliability	Deferred
Narrow Band VHF Radio upgrades	2016	$25,000.00	Stoke	Reliability	Completed
New Patons Road 11kV Feeder	2016	$300,000.00	Stoke	System Growth	Deferred
New Recloser Pakawau Feeder	2016	$20,000.00	Golden Bay	Reliability	Completed
New Ripple Injection Plant Kikiwa	2016	$30,000.00	Kikiwa	Renewal	Completed
New Ripple Injection Plant Murchison	2016	$30,000.00	Murchison	Renewal	Completed
New Switchroom and Switchboard Hope Substation	2016	$1,250,000.00	Stoke	Relocation	50% Completed
Radio Link Takaka Hill to Takaka Substation	2016	$50,000.00	Golden Bay	Reliability	Completed
Reconductor Lower Queen St Swamp Rd to Lansdown Rd	2016	$90,000.00	Stoke	System Growth	Deferred
Refurbish T1 Transformer Songer St	2016	$200,000.00	Stoke	Renewal	Deferred
Replacement Recloser Collins Valley 655	2016	$15,000.00	Stoke	Renewal	Deferred
Replacement Recloser Kotinga 889	2016	$25,000.00	Golden Bay	Renewal	Completed
Replacement Recloser Maitai Camp 241	2016	$25,000.00	Stoke	Renewal	Completed
Replacement Recloser Sandy Bay 629	2016	$15,000.00	Motueka	Renewal	Deferred
Replacement Sectionaliser Dovedale 624	2016	$20,000.00	Motueka	Renewal	Deferred
Replacement Sectionaliser Maungarakau 623	2016	$25,000.00	Golden Bay	Renewal	Deferred
Replacement Sectionaliser Ngaio Bay 629	2016	$26,000.00	Motueka	Renewal	Deferred

Specific Development Projects					
Network Enhancement Project	**Year**	**Estimated Cost**	**Region**	**Expenditure Class**	**Completion Status**
Replacement Sectionaliser Woodstock 630	2016	$20,000.00	Motueka	Renewal	Deferred
Second Cable Bells Island	2016	$280,000.00	Stoke	System Growth	Deferred
Seismic Strengthening of Substation Buildings	2016	$200,000.00	Stoke	Renewal	25% Completed
Transformer Bunding Songer St Substation	2016	$50,000.00	Stoke	Reliability	Deferred
Underground Conversion Bateup Road	2016	$400,000.00	Stoke	Relocation	Deferred
Underground Conversion High St Motueka Stage 2	2016	$1,000,000.00	Motueka	Relocation	Completed
Underground Conversion Robert St - St Arnaud	2016	$40,000.00	Kikiwa	Relocation	Deferred
Upgrade Ripple Injection Plant Motupipi	2016	$60,000.00	Golden Bay	Renewal	Completed
Voltage Support Dovedale Feeder	2016	$200,000.00	Motueka	System Growth	Deferred
Zone Substation for Volatge Support Upper Takaka	2016	$1,600,000.00	Golden Bay	System Growth	Completed

During 2015/16, major network development projects completed included:

- SCADA incorporation of 66kV subtransmission network.
- Underground conversion High St Motueka Stage 1.
- Mesh Radio SCADA communications network.
- Zone Substation Upper Takaka

Contractor resource limitations influenced the commencement of some projects during 2015/16. A nationwide industry shortage of experienced and skilled staff is impacting resource availability in some work areas.

All projects not started during 2015/16 are now planned to be started during 2016/17 or 2017/18. The deferment of projects will not compromise the safety or security of the network,

Network Extensions

Customer driven network extensions continued steadily during 2015/16. 420 net new connections were added to the network compared with the long term average of 500.

Network Operations and Maintenance

Planned and emergency maintenance expenditure for the network is on budget for the year.

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 eg distribution substation earth testing and switchgear and regulator operational tests.

Maintenance and renewal projects commenced in previous years and still in progress are:

- Replacement and automation of pole mounted reclosers.
- Replacement of above ground HV switch units (Series 1 Andelect SD)
- Replacement of 60 year old plus distribution transformers

A new contract for the provision of network maintenance and faults response services commenced on 1 April 2011. This contract was awarded to Delta Utility Services in December 2010. This contract has a five year term. Agreement was reached during the

year with Delta Utilities to renew the existing contract for a further term of five years commencing on 1 April 2016.

Vegetation

Vegetation management expenditure for the 2015/16 year is on budget ($824,000).

Tree notifications during 2015/16 were mainly fourth and fifth round notifications under the Electricity (Hazards from Trees) Regulations. 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 were found to have branches reaching out that made them notifiable on the second or third round.

As a result of the free trim provisions of the regulations coming to an end, the vegetation budget for the 2014/15 year for tree cutting was reduced from the previous year. The budget for 2016/17 is unchanged from the 2015/16 budget. Vegetation budget projections going forward are now stable.

9.2 SERVICE LEVEL AND ASSET PERFORMANCE

Reliability Performance against target for the 2015/16 year are forecast near year end as follows:

	Target	Forecast
SAIDI Planned	40	99
SAIDI Unplanned	75	84
SAIFI Planned	0.29	0.40
SAIFI Unplanned	1.07	1.20
CAIDI Planned	138	248
CAIDI Unplanned	70	70

Planned outages for the 2015/16 year are forecast to be over budget at 99 minutes. This has been partly due to the planned outage on the 66kV system that occurred during the year that normally would not have attributed to NTL's total. It has also been partly due to a change in contractor policy which resulted in a ban on live line works where light copper conductors were involved, and due a higher than usual number of maintenance shutdowns that took place during the year.

Going forward, planned outages are expected to run at a higher level than previously experienced in order that a light copper HV conductor replacement program is undertaken.

Deployment of portable diesel generators that were purchased in 2013 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 is inevitable since it is the means of distributing even locally generated electricity power that is being replaced.

The reliability targets have been accordingly revised upwards in this revision of the AMP.

Unplanned outages are forecast to be slightly over target for the year (84 against target 75). This is a pleasing result, reflecting improvements in the inherent reliability of the network brought about by capital investments over the past five to ten years. Violent wind and lightning storms have impacted performance in previous years however and it is difficult to predict the frequency of these for the coming years. Network resilience to moderate storms is good.

Supply outages for the year were not unusual consisting of a mix of causes ie foreign interference (bird strikes, car vs pole etc), some adverse weather events, unknown causes and network defects. Network defects caused approx 10% of outage minutes for the year. The major unplanned outages (above 3.0 SAIDI points) for 2015/16 were:

Date	Event	SAIDI Points
28 Oct 2015	Bird Strike brings 11kV conductors down – Motueka	4.5
14 Nov 2015	Car vs Pole – Central Brightwater	3.4
8 Jan 2016	33kV Insulator Failure – Waimea Plains	4.9

The trend of reliability performance for the past five years is given in Appendix C.

Other service levels targeted for 2015/16 were as follows:

Service Criterion	Performance Indicator	Target 2015/16	Forecast 2015/16
Supply quality	Number of proven voltage complaints	10	3
Operating Efficiency	Breaches of UOSA	0	0
Operating Efficiency	Network losses	6%	5.6%
Operating Efficiency	Faults per 100km line	6	5.2
Operating Efficiency	Peak demand/KVA distribution transformers	30%	27%
Financial Efficiency	Cash operating costs per consumer	$291	$278
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	1

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 life rural style subdivision developments and dairy farming. Both of these types of load require relatively high and dedicated distribution transformer capacity. The dairy farming load in particular is 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.

9.3 GAP ANALYSIS AND IMPROVEMENT PLANS

There have been no significant changes in the AMP environment that are averse to the planning assumptions (refer section 9). Therefore there has been no required revision of forecast expenditures due to changes in the planning assumptions.

Developments in the disruptive technologies of Photovoltaic (PV) distributed generation, consumer based battery storage and electric vehicles although showing high growth rates are not yet significantly impacting network operations. At higher levels of penetration however, possibly occurring at the end of the ten year planning horizon, the potential for network voltage management issues exists. NTL is at the forefront of PV hosting at present and it is actively involved in research and modelling of future uptake scenario's and network conditions. It is identifying and taking steps to ensure that the network hosting capacity for disruptive technologies is maximised in a manner that is fair and equitable for all present and future users of the network.

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. 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, or 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 completed 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 completion 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.

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 been 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.

A recent independent review of vegetation policy and management concludes that NTL's practises, policies and expenditure levels align with good industry practise.

Areas of 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 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

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 (Continuance of supply) Amendment Bill 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. Ref. 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 be 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, fishing and forestry.

The AMP assumes land use development will happen at a steady gradual rate, and that this rate will not significantly deviate from 10-15 year past trends. Land subdivided for residential

development will occur in line with recent trends in terms of density etc. Dairy conversions are assumed to also to continue in line with modern trends ie large automated dairy sheds. Large scale load is not expected for irrigation due to the high water tables in the area.

The principal sources of information for developing these assumptions are:

Local territorial authorities
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 the 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 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 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 Supply from the National Grid

The plan assumes that the existing supply capacity continues to be available at all Transpower GXP's and that future projected demands are available to the Nelson area via the national grid

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.
- 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.
- 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 the various sections of this plan.

The potential effect of these sources of uncertainty on the prospective information in this plan is as follows:

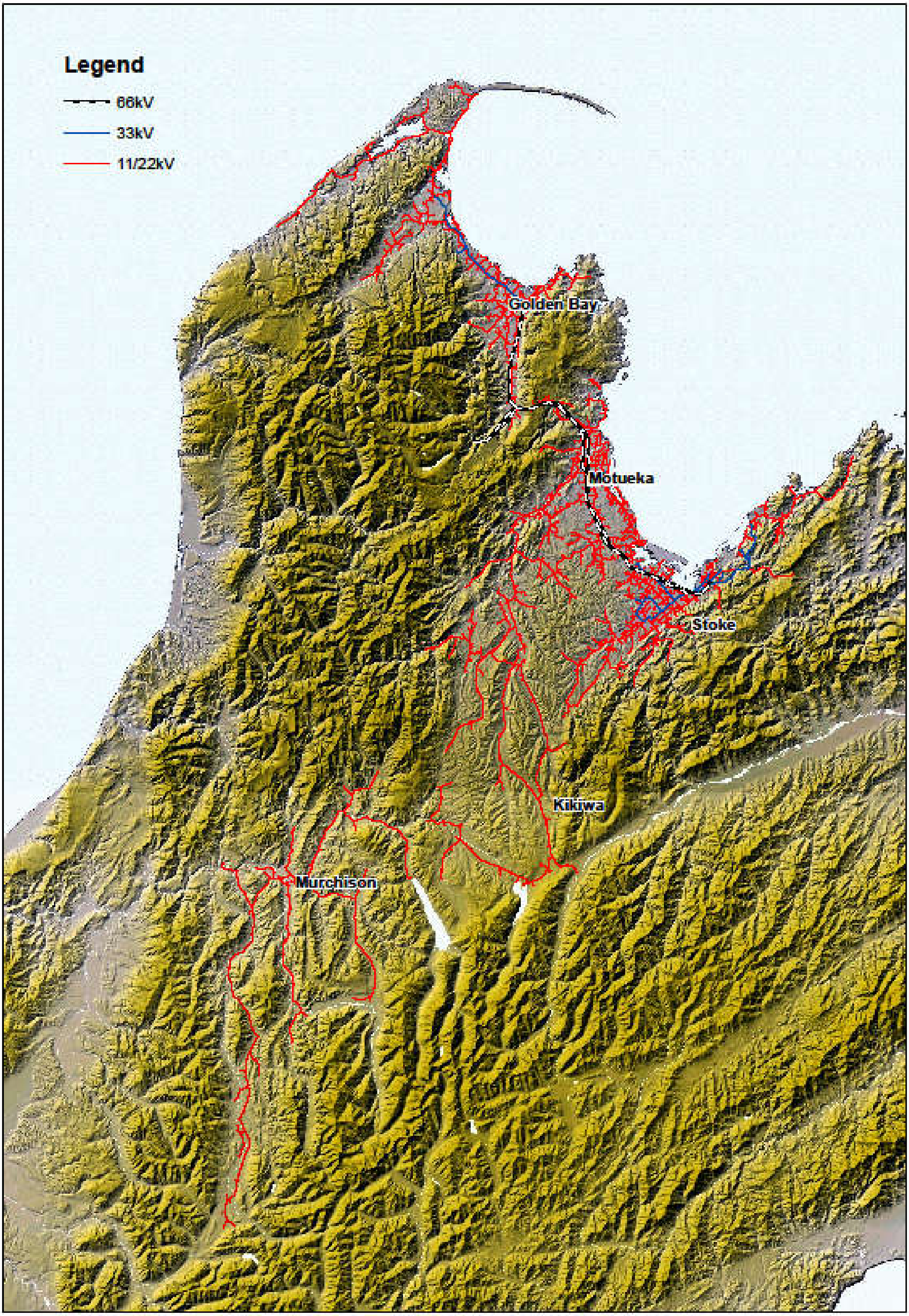
Source of Uncertainty	Potential Effect of Uncertainty	Potential Impact of Uncertainty
Regulatory Requirements	It is unlikely that any of the Requirements will reduce, thus the most likely impact is an increase in forecast expenditure to meet possible increased standards. It is not possible to quantify 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
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 5 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 5 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 APPENDICES

APPENDIX A

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
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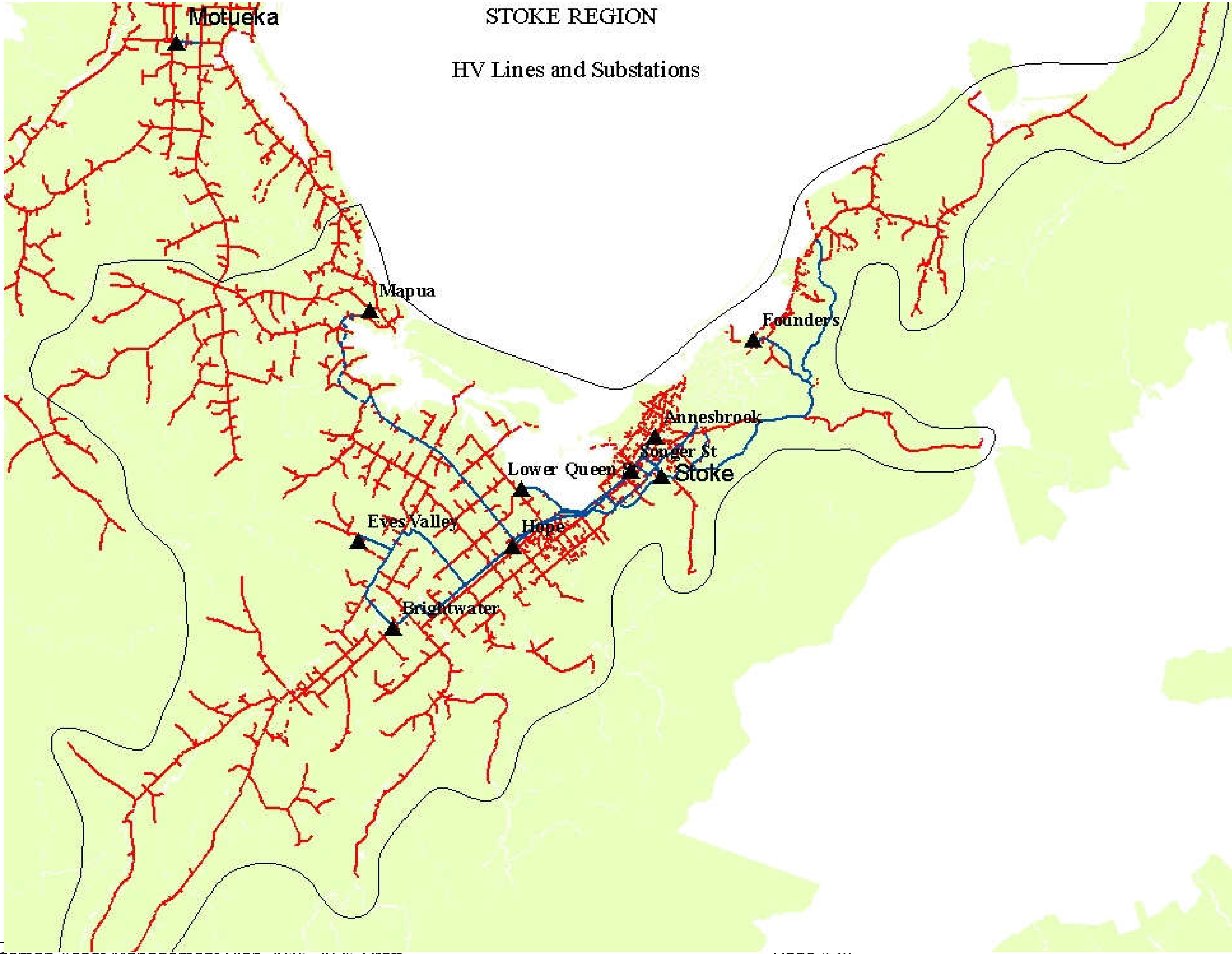
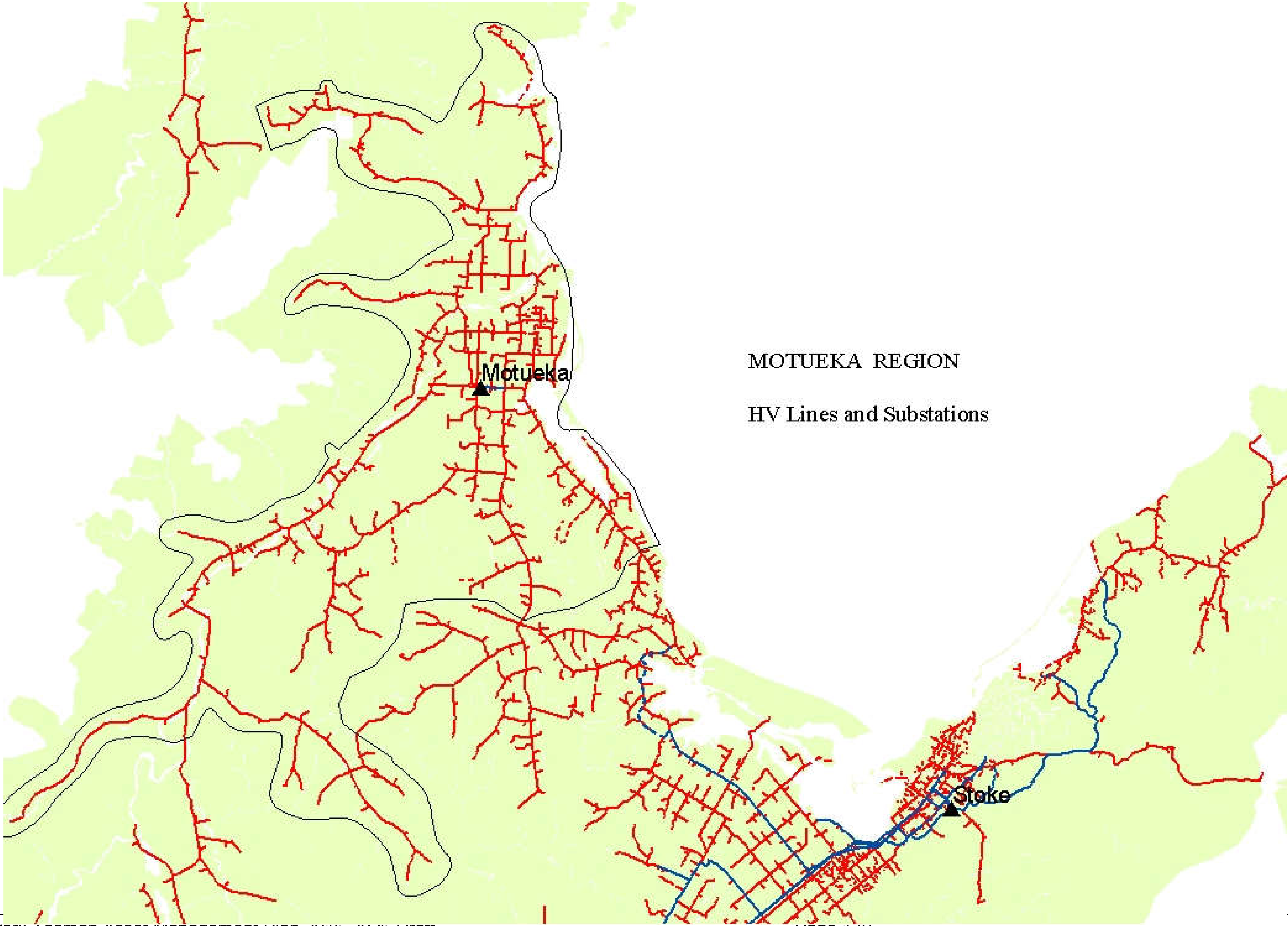
33kV
11/22kV
Golden Bay
Motueka
Stoke
Kikiwa
Murchison


STOKE REGION
HV Lines and Substations
Motueka
Mapua
Founders
Annesbrook
Songer St
Stoke
Lower Queen
Eves Valley
Hope
Brightwater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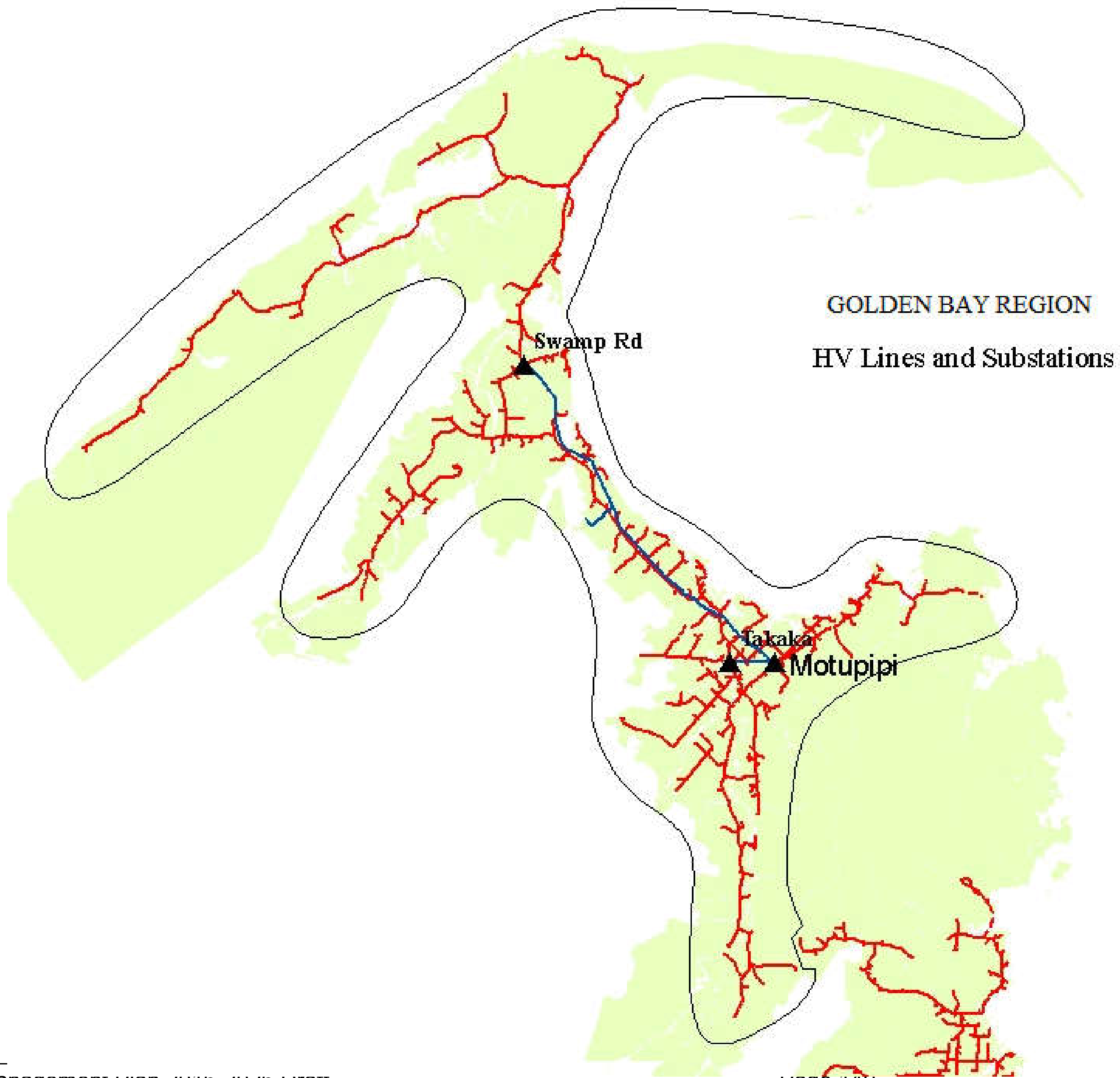
HV Lines and Substations
Motueka
Stoke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HV Lines and Substations
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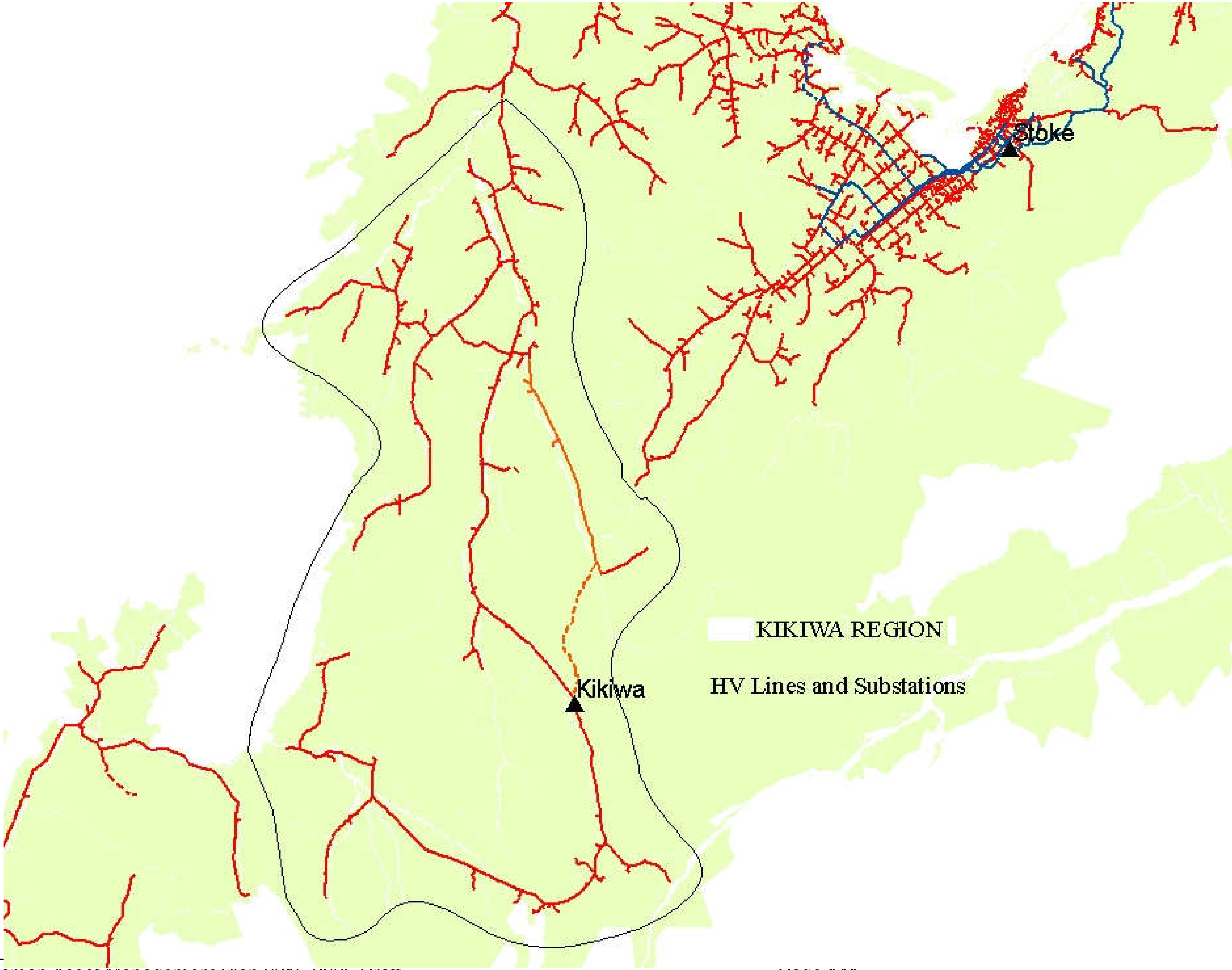
Takaka
Motupipi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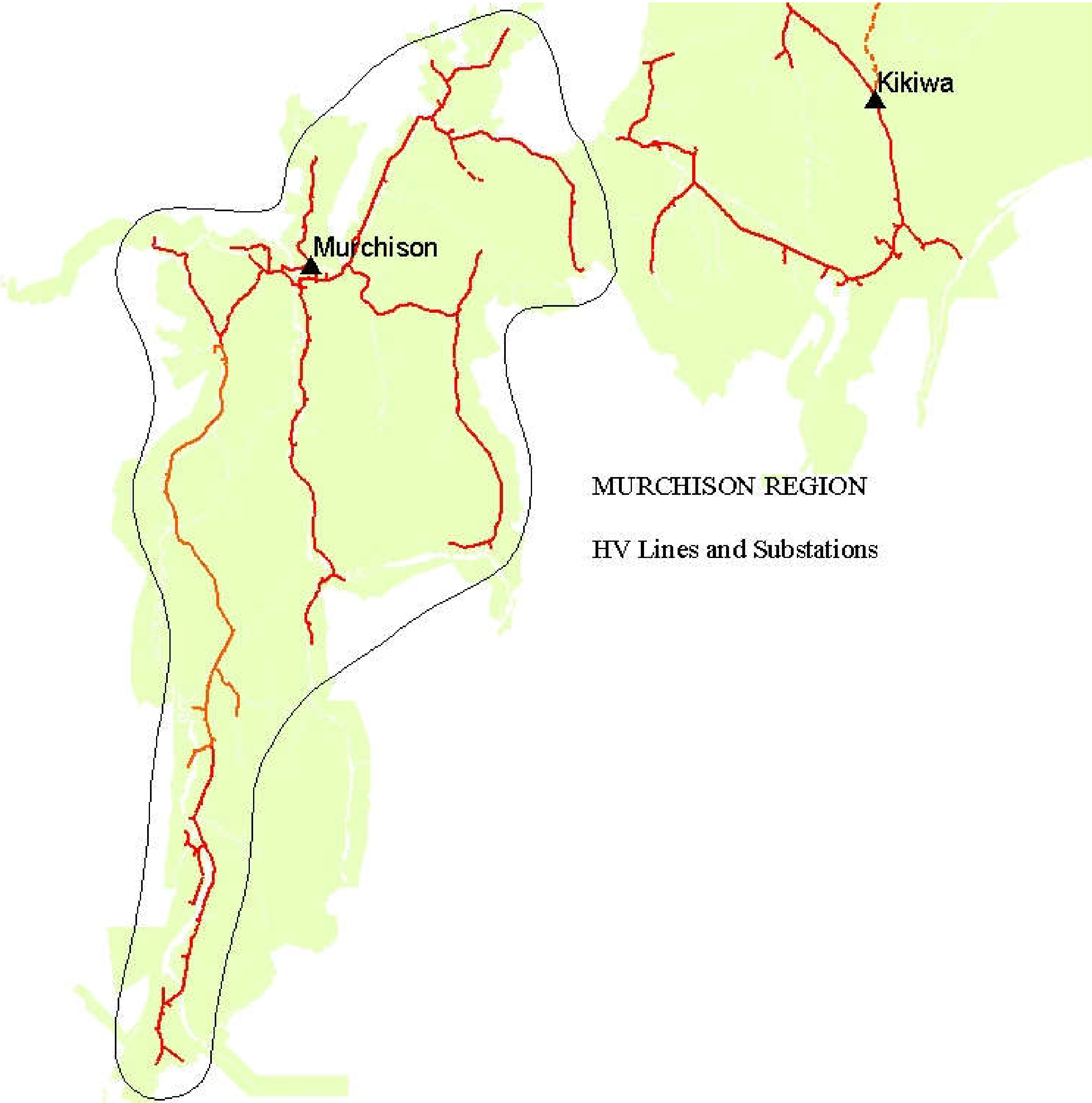
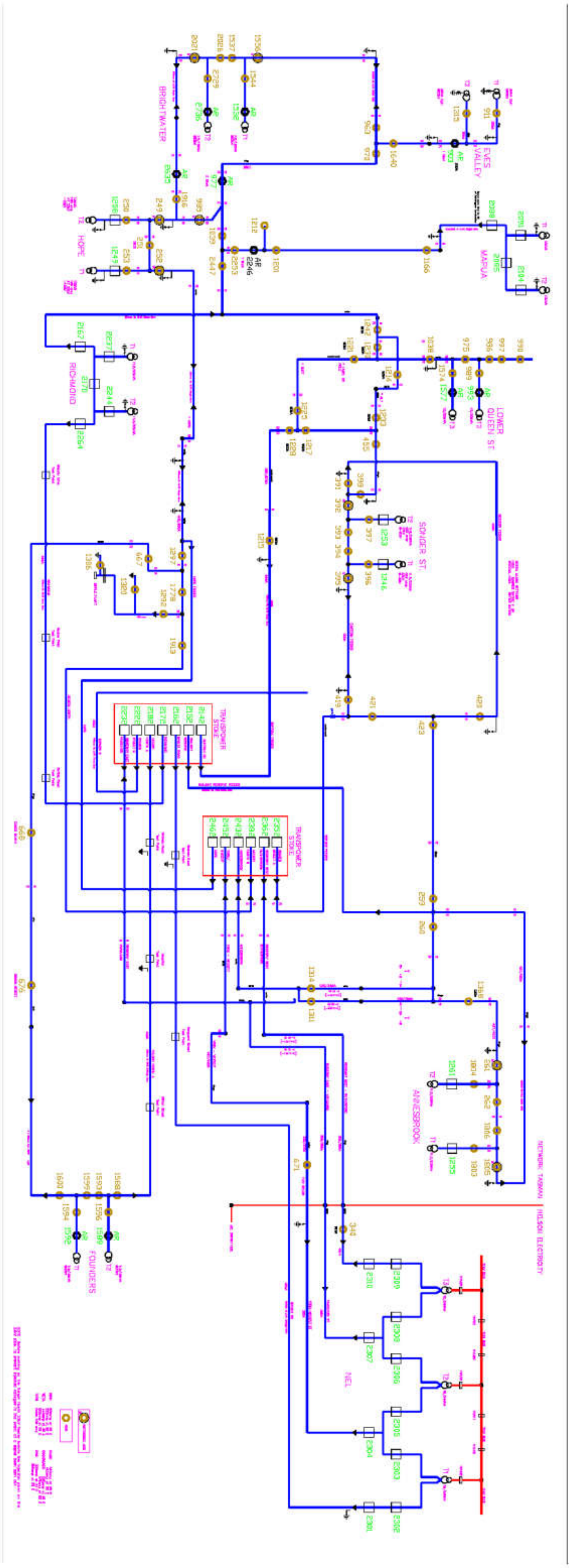
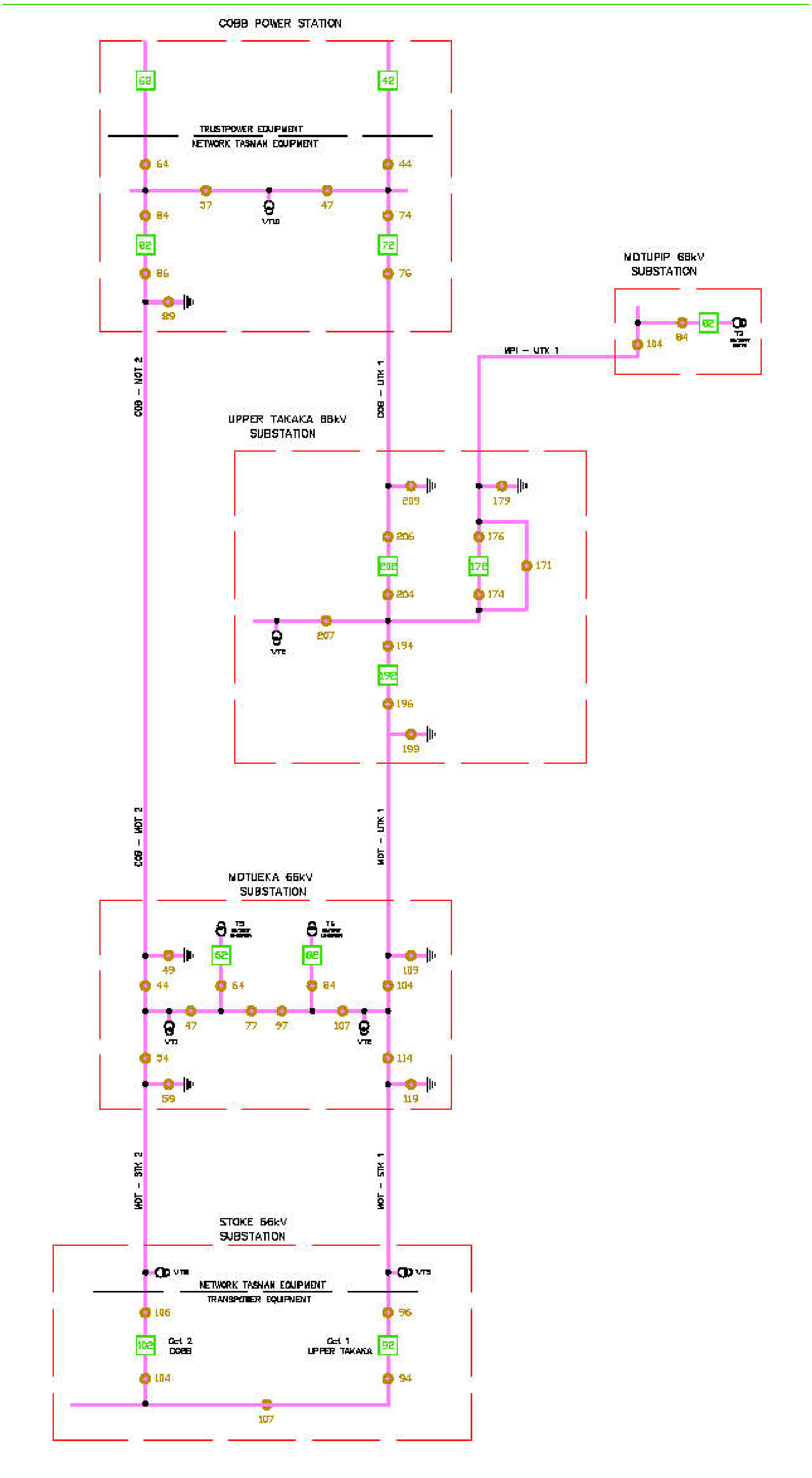
Kikiwa
KIKIWA REGION
HV Lines and Substations



MURCHISON REGION

HV Lines and Substations


BRIGHTWATER
HOPE
RICHMOND
MAPUA
EVES VALLEY
LOWER QUEEN ST
SONGER ST.
TRANSPOWER STOKE
ANNESBROOK
FOUNDERS
NETWORK TASMAN
NELSON ELECTRICITY
NEL



COBB POWER STATION
TRUSTPOWER EQUIPMENT
NETWORK TASMAN EQUIPMENT
MOTUPIPI 66kV SUBSTATION
UPPER TAKAKA 66kV SUBSTATION
MOTUEKA 66kV SUBSTATION
STOKE 66kV SUBSTATION
NETWORK TASMAN EQUIPMENT
TRANSPOWER EQUIPMENT
Cct 2 COBB
Cct 1 UPPER TAKAKA

APPENDIX B

B. GROWTH PROJECTION

Projections include effects of embedded Generation and Load Management. Projections exclude on supply to Nelson Electricity Ltd.

BULK SUPPLY REGION DEMAND PROJECTION (MW)

Year	**Stoke** (Stoke GXP)	**Stoke** (Brightwater GXP)	**Motueka** (Motueka Zone Sub)	**Motueka** (Riwaka Zone Sub)	Golden Bay	Kikiwa	Murchison	Total	Peak
2016	100.5	0.0	20.5	0.0	7.5	3.3	2.9	134.5	120.1
2017	101.9	0.0	20.8	0.0	7.6	3.4	2.9	136.4	121.7
2018	103.3	0.0	21.1	0.0	7.7	3.4	2.9	138.2	123.4
2019	104.7	0.0	21.4	0.0	7.8	3.5	3.0	140.1	125.1
2020	106.0	0.0	21.7	0.0	7.9	3.5	3.0	142.0	126.8
2021	107.4	0.0	22.0	0.0	8.0	3.6	3.0	143.8	128.4
2022	108.8	0.0	22.3	0.0	8.1	3.6	3.0	145.7	130.0
2023	81.3	28.9	22.5	0.0	8.2	3.7	3.1	147.5	131.7
2024	82.2	29.4	22.8	0.0	8.3	3.7	3.1	149.3	133.3
2025	83.0	29.9	23.1	0.0	8.4	3.8	3.1	151.1	134.9
2026	83.8	30.5	16.3	7.0	8.5	3.8	3.1	152.9	136.5

ZONE SUBSTATION DEMAND PROJECTIONS (MW)

NB Projections include effects of embedded Generation and Load Management

STOKE SUPPLY AREA ZONE SUBSTATIONS

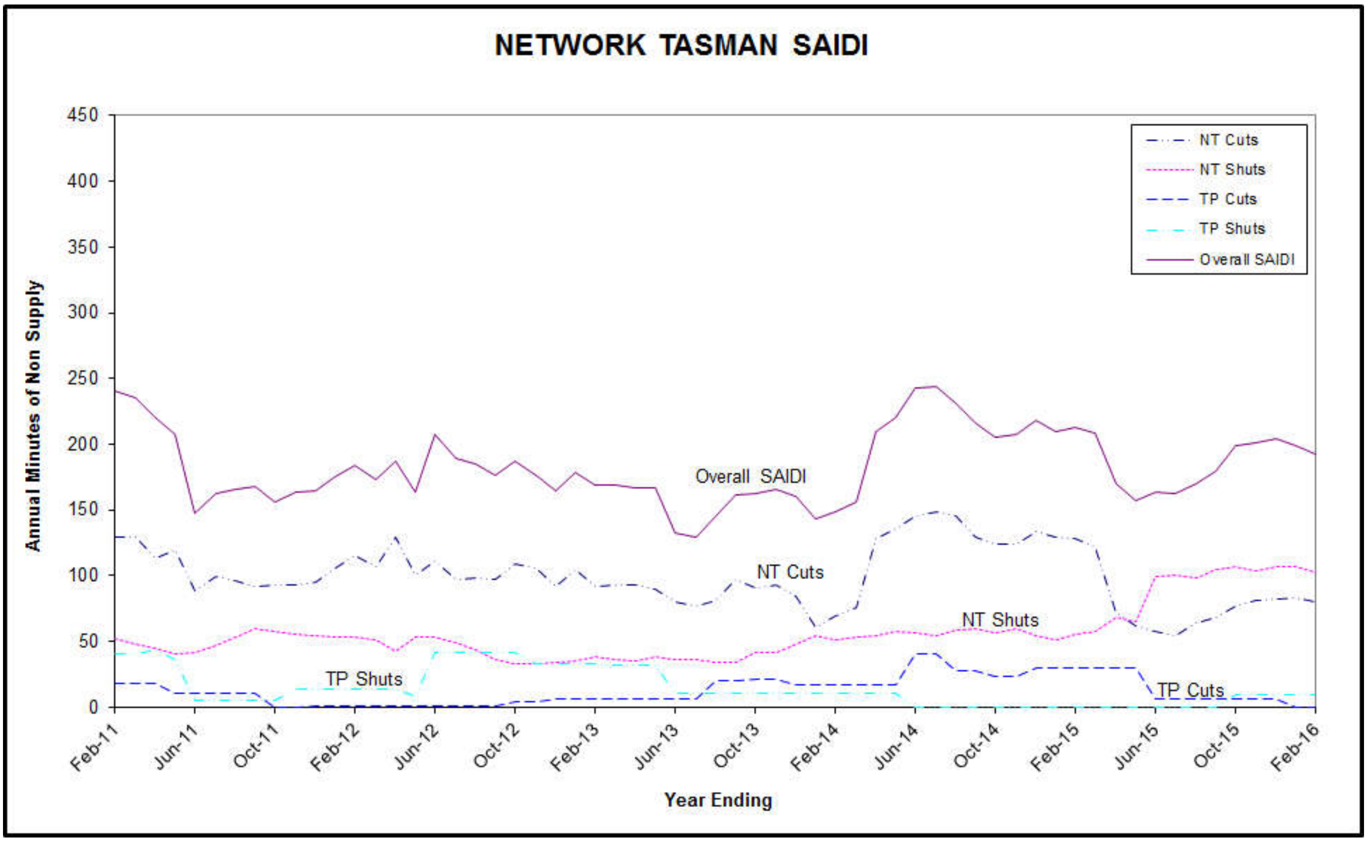
Year	Founders	Annesbrook	Songer St	Hope	Richmond	Mapua	LQS	Eves Valley	Brightwater	TOTAL	Peak
2016	7.0	17.9	19.0	8.4	17.8	5.1	22	3.8	7.6	108.8	100.5
2017	7.1	18.3	19.3	8.8	18.1	5.2	22	3.8	7.8	110.3	101.9
2018	7.2	18.6	19.6	9.1	18.3	5.3	22	3.8	7.9	111.8	103.3
2019	7.3	18.9	19.9	9.4	18.6	5.4	22	3.8	8.1	113.3	104.7
2020	7.4	19.2	20.2	9.7	18.8	5.5	22	3.8	8.2	114.8	106.0
2021	7.5	19.5	20.4	10.0	19.1	5.5	22	3.8	8.4	116.3	107.4
2022	7.6	19.9	20.7	10.3	19.3	5.6	22	3.8	8.5	117.8	108.8
2023	7.7	20.2	21.0	10.6	19.5	5.7	22	3.8	8.7	119.3	110.2
2024	7.8	20.5	21.3	10.9	19.8	5.8	22	3.8	8.8	120.8	111.6
2025	7.9	20.8	21.5	11.2	20.0	5.9	22	3.8	9.0	122.3	112.9
2026	8.0	21.2	21.8	11.5	20.3	6.0	22	3.8	9.1	123.8	114.3

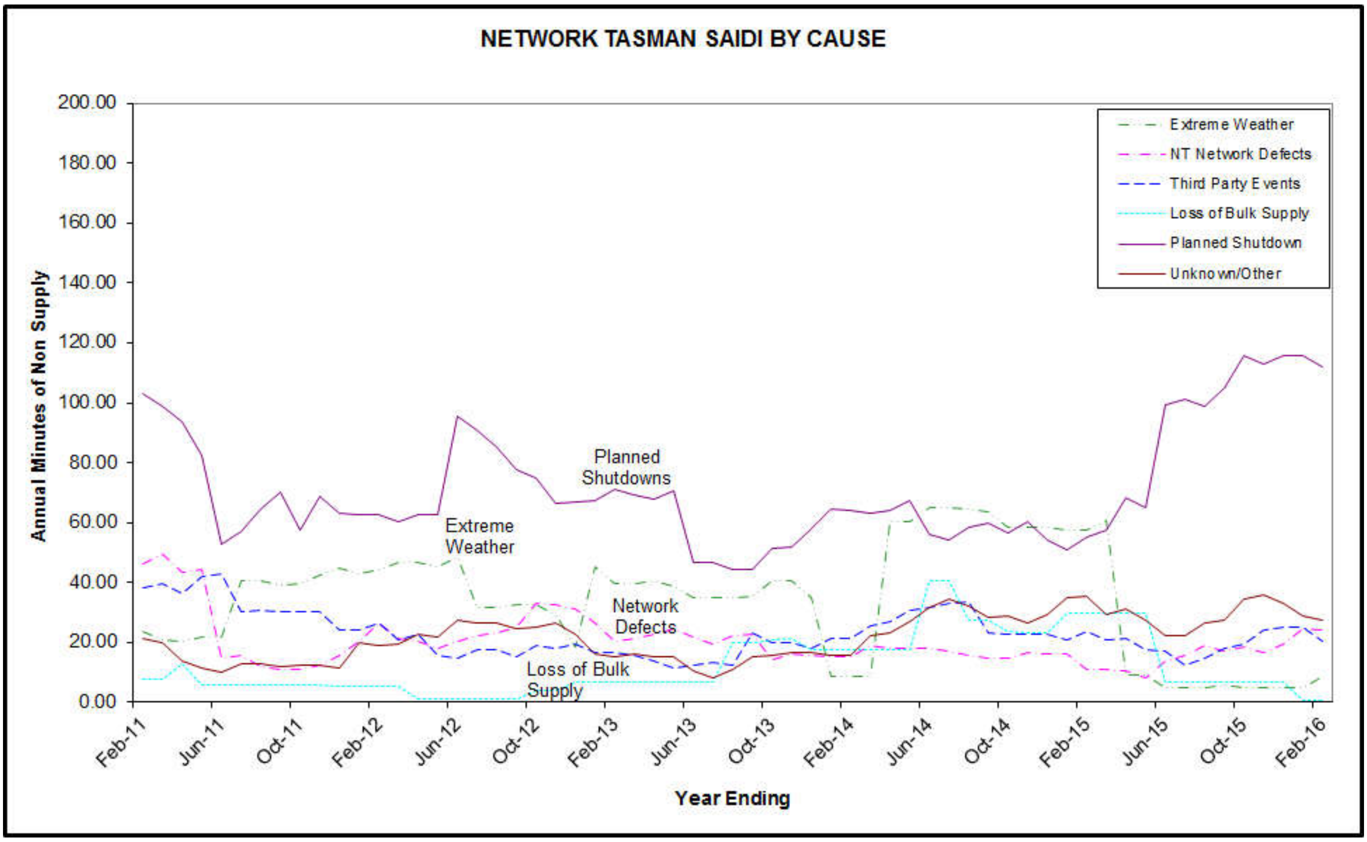
GOLDEN BAY SUPPLY AREA ZONE SUBSTATIONS

Year	Upper Takaka	Takaka	Swamp Rd	TOTAL	Peak
2016	0.9	4.6	2.5	8.0	7.8
2017	0.9	4.7	2.5	8.1	7.9
2018	0.9	4.7	2.6	8.2	8.0
2019	0.9	4.8	2.6	8.3	8.1
2020	0.9	4.8	2.7	8.4	8.2
2021	0.9	4.9	2.7	8.5	8.3
2022	0.9	4.9	2.8	8.6	8.4
2023	0.9	5.0	2.8	8.7	8.5
2024	0.9	5.0	2.9	8.8	8.6
2025	0.9	5.1	2.9	8.9	8.7
2026	0.9	5.1	3.0	9.0	8.8

APPENDIX C

C. NETWORK PERFORMANCE STATISTICS





APPENDIX D

D. CAPITAL EXPENDITURE PROJECTION NETWORK DEVELOPMENT & ASSET RENEWAL

CAPITAL EXPENDITURE PROJECTION

BY ASSET CATEGORY	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
11kV/22kV Networks	$3,142,750	$4,230,000	$4,990,000	$2,240,000	$3,900,000	$1,780,000	$1,780,000	$5,060,000	$5,380,000	$2,780,000
33/66kV Networks	$400,000	$750,000	$2,050,000	$330,000	$1,850,000	$3,350,000	$250,000	$950,000	$250,000	$1,550,000
400V Networks	$140,000	$180,000	$140,000	$140,000	$140,000	$140,000	$140,000	$140,000	$140,000	$140,000
Comms Networks	$0	$0	$50,000	$0	$0	$0	$0	$0	$0	$0
Dist Transformers	$1,073,260	$1,073,260	$1,073,260	$1,073,260	$993,260	$993,260	$993,260	$993,260	$993,260	$993,260
Generators	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PF Correction	$0	$0	$800,000	$0	$0	$0	$0	$500,000	$0	$0
Ripple Plants	$0	$0	$0	$0	$0	$0	$450,000	$0	$0	$300,000
SCADA	$30,000	$45,000	$0	$0	$0	$0	$0	$0	$0	$0
Substations	$930,000	$3,500,000	$1,500,000	$4,800,000	$6,000,000	$12,00,000	$12,200,000	$0	$200,000	$4,000,000
Switchgear	$334,500	$211,500	$186,500	$186,500	$186,500	$186,500	$186,500	$186,500	$186,500	$186,500
Underground Conversion	$1,200,000	$400,000	$1,300,000	$1,300,000	$1,300,000	$800,000	$1,050,000	$900,000	$1,300,000	$900,000
TOTAL	**$7,250,510**	**$10,389,760**	**$12,089,760**	**$10,069,760**	**$14,309,760**	**$19,189,760**	**$16,989,760**	**$8,669,760**	**$8,389,760**	**$10,789,760**

BY EXPENDITURE CLASS	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
System Growth	$1,796,500	$4,326,500	$7,406,500	$5,666,500	$10,186,500	$15,566,500	$12,916,500	$4,946,500	$4,066,500	$6,866,500
Reliability	$302,750	$1,360,000	$170,000	$60,000	$0	$0	$0	$0	$0	$0
Customer Connection	$520,260	$520,260	$520,260	$520,260	$520,260	$520,260	$520,260	$520,260	$520,260	$520,260
Safety and Environment	$140,000	$140,000	$140,000	$140,000	$0	$0	$0	$0	$0	$0
Relocation	$1,200,000	$440,000	$1,300,000	$1,300,000	$1,300,000	$800,000	$1,050,000	$900,000	$1,300,000	$900,000
Renewal	$3,291,000	$3,603,000	$2,553,000	$2,383,000	$2,303,000	$2,303,000	$2,503,000	$2,303,000	$2,503,000	$2,503,000
TOTAL	**$7,250,510**	**$10,389,760**	**$12,089,760**	**$10,069,760**	**$14,309,760**	**$19,189,760**	**$16,989,760**	**$8,669,760**	**$8,389,760**	**$10,789,760**
ADJUSTED TOTAL	**$7,250,510**	**$6,233,856**	**$7,253,856**	**$6,041,856**	**$8,585,856**	**$11,513,856**	**$10,193,856**	**$5,201,856**	**$5,033,856**	**$6,473,856**

All figures are 2016 dollars. Projected figures are not inflation adjusted.
The Adjusted Total takes into account that not all identified projects will necessarily proceed. The assumption has been made that in 2016/17, 100% of identified will proceed and that in all other years, approximately 60% of projects will eventuate.

APPENDIX E

E. SPECIFIC NETWORK DEVELOPMENT & ASSET RENEWAL PROJECTS

Specific Development Projects				
Network Enhancement Project	**Year**	**SumOfEstimated Cost**	**Region**	**Expenditure Class**
33kV cable circuit upgrade Songer St - 600A	2017	$150,000.00	Stoke	System Growth
Andelect Replacement Merton Pl 1048	2017	$22,000.00	Stoke	Renewal
Annesbrook Express Feeder CB and Cable	2017	$600,000.00	Stoke	System Growth
Fault Indicators Overhead Lines	2017	$12,750.00	Stoke	Reliability
Galv Conductor Replacement Central Road	2017	$25,000.00	Motueka	Renewal
Galv Conductor Replacement Whakarewa St	2017	$15,000.00	Motueka	Renewal
New Patons Road 11kV Feeder Stage 1	2017	$150,000.00	Stoke	System Growth
New Switchroom and Switchboard Hope Substation Stage 2	2017	$400,000.00	Stoke	Renewal
Reconductor ABS93 to Mangles Valley	2017	$60,000.00	Murchison	System Growth
Reconductor Lower Queen St Swamp Rd to Lansdown Rd	2017	$90,000.00	Stoke	System Growth
Refurbish T1 Transformer Songer St	2017	$200,000.00	Stoke	Renewal
Replacement Recloser Delaware Bay 655	2017	$15,000.00	Stoke	Renewal
Replacement Recloser Honeymoon Bay 629	2017	$26,000.00	Motueka	Renewal
Replacement Sectionaliser Maungarakau 623	2017	$25,000.00	Golden Bay	Renewal
Replacement Sectionaliser Rhappahanock 628	2017	$20,000.00	Murchison	Renewal
Replacement Sectionaliser Stanley Brook 630	2017	$20,000.00	Motueka	Renewal
Replacement Sectionaliser Woodstock 624	2017	$20,000.00	Motueka	Renewal
RTU Upper Takaka Substation	2017	$30,000.00	Golden Bay	Reliability
Second Cable Bells Island	2017	$280,000.00	Stoke	System Growth
Seismic Strengthening of Substation Buildings	2017	$200,000.00	Stoke	Renewal
Transformer Bunding Eves Valley Substation	2017	$40,000.00	Stoke	Reliability
Transformer Bunding Songer St Substation	2017	$50,000.00	Stoke	Reliability
Transformer Bunding Swamp Rd Substation	2017	$40,000.00	Golden Bay	Reliability
Underground Conversion Bateup Road Stage 1	2017	$200,000.00	Stoke	Relocation
Underground Conversion High St Motueka Stage 2	2017	$1,000,000.00	Motueka	Relocation
33kV Line Extension Eves Valley to Pea Viner Corner	2018	$500,000.00	Stoke	Reliability
Galv Conductor Replacement Top Takaka Hill 5.7km	2018	$240,000.00	Motueka	System Growth
Install 33kV CB's Swamp Road Substation	2018	$150,000.00	Golden Bay	Reliability
Interconnection Cable Belfit Lane Wakefield	2018	$50,000.00	Stoke	Reliability
Interconnection Cable Tasman Heights to Marsden Valley	2018	$100,000.00	Stoke	Reliability
Marahau Estuary Cable Replacement	2018	$800,000.00	Motueka	Renewal
Maruia Feeder 11/22kV conversion - Stage 1	2018	$150,000.00	Murchison	System Growth
Motupipi Substation Upgrade Stage 1	2018	$1,500,000.00	Golden Bay	System Growth
Mount Murchison Lower Cable Replacement 2.2km	2018	$500,000.00	Murchison	Renewal
New Patons Road 11kV Feeder Stage 2	2018	$150,000.00	Stoke	System Growth
New Recloser at Buller Gorge	2018	$25,000.00	Murchison	Reliability
Protection Relay Upgrades for Arc Flash Detection - Annesbrook	2018	$50,000.00	Stoke	Reliability
Protection Relay Upgrades for Arc Flash Detection - Brightwater	2018	$30,000.00	Stoke	Reliability
Protection Relay Upgrades for Arc Flash Detection - Founders	2018	$30,000.00	Stoke	Reliability
Protection Relay Upgrades for Arc Flash Detection - Lower Queen St	2018	$60,000.00	Stoke	Reliability
Protection Relay Upgrades for Arc Flash Detection - Mapua	2018	$30,000.00	Stoke	Reliability
Protection Relay Upgrades for Arc Flash Detection - Richmond	2018	$50,000.00	Stoke	Reliability
Protection Relay Upgrades for Arc Flash Detection - Songer St	2018	$50,000.00	Stoke	Reliability
Replacement 23MVA 66/11kV Transformers Motueka	2018	$1,500,000.00	Motueka	System Growth
RTU Motueka Substation	2018	$30,000.00	Motueka	Reliability
RTU Takaka Substation	2018	$15,000.00	Golden Bay	Reliability

Specific Development Projects				
Network Enhancement Project	**Year**	**SumOfEstimated Cost**	**Region**	**Expenditure Class**
Transformer Bunding Takaka Substation	2018	$50,000.00	Golden Bay	Reliability
Underground Conversion Batuep Road Stage 2	2018	$200,000.00	Stoke	Relocation
Underground Conversion High St Motueka Stage 3	2018	$200,000.00	Motueka	Relocation
Underground Conversion Robert St - St Arnaud	2018	$40,000.00	Kikiwa	Relocation
Upgrade to 66/110kV transformer at Stoke Substation	2018	$0.00	Stoke	System Growth
Voltage Support Dovedale Feeder	2018	$200,000.00	Motueka	System Growth
Wakapuaka to Hira Store Conductor Upgrades	2018	$120,000.00	Stoke	System Growth
33kV Cable Extension Wakapuaka to Hira Sub 7.2km	2019	$1,800,000.00	Stoke	System Growth
Capacitor Bank Motupipi 33kV 5 x 2MVAr	2019	$800,000.00	Golden Bay	System Growth
Feeder Interconnection Switch Croucher St	2019	$60,000.00	Stoke	Reliability
Longford Feeder reconductor to Ferret 15km	2019	$350,000.00	Murchison	System Growth
Maruia Feeder 11/22kV conversion - Stage 2	2019	$400,000.00	Murchison	System Growth
Matakitaki Valley Reconductor to Ferret 10km	2019	$250,000.00	Murchison	Renewal
Motupipi Substation Upgrade Stage 2	2019	$1,500,000.00	Golden Bay	System Growth
Radio Link Takaka Hill to Takaka Substation	2019	$50,000.00	Golden Bay	Reliability
Rockville Feeder 22kV Conversion Stage 1	2019	$1,560,000.00	Golden Bay	System Growth
Underground Conversion Beach Road Tahuna	2019	$400,000.00	Stoke	Relocation
Underground Conversion Champion Road	2019	$900,000.00	Stoke	Relocation
Upgrade Conductor Higgins Rd 7/080 to Mink	2019	$200,000.00	Stoke	System Growth
Upgrade Conductor Swamp Rd to ABS682	2019	$330,000.00	Golden Bay	System Growth
Maruia Feeder 11/22kV conversion - Stage 3	2020	$400,000.00	Murchison	System Growth
New Switchboard and New 11kV Feeders Motueka	2020	$4,800,000.00	Motueka	System Growth
Reconductor Marsden Rd 33kV Double Circuit Mink to Single Circuit Cockroach	2020	$80,000.00	Stoke	Renewal
Underground Conversion Nayland Road	2020	$700,000.00	Stoke	Relocation
Underground Conversion Songer St (Nayland to Seaview)	2020	$600,000.00	Stoke	Relocation
Brightwater GXP 33kV Feeder Cables Stage 1	2021	$1,600,000.00	Stoke	System Growth
Maruia Feeder 11/22kV conversion - Stage 4	2021	$400,000.00	Murchison	System Growth
New Zone Substation at Wakapuaka/Hira	2021	$3,500,000.00	Stoke	System Growth
Rockville Feeder 22kV Conversion Stage 2	2021	$1,650,000.00	Golden Bay	System Growth
Ruby Bay Feeder Cable 0.5km	2021	$70,000.00	Stoke	System Growth
Underground Conversion Main Road Riwaka ain Road Riwaka	2021	$1,300,000.00	Motueka	Relocation
Upgrade Hope Substation to 23MVA firm	2021	$2,500,000.00	Stoke	System Growth
33kV Cable Extension to Wakefield	2022	$1,500,000.00	Stoke	System Growth
Brightwater GXP 33kV Feeder Cables Stage 2	2022	$1,600,000.00	Stoke	System Growth
New 220/33kV GXP Substation Brightwater Stage 1	2022	$12,000,000.00	Stoke	System Growth
Underground Conversion Aranui Road Mapua	2022	$800,000.00	Stoke	Relocation
Brightwater GXP Ripple Injection Plant	2023	$450,000.00	Stoke	System Growth
New 220/33kV GXP Substation Brightwater Stage 2	2023	$12,000,000.00	Stoke	System Growth
Refurbish T1 Transformer Brightwater	2023	$200,000.00	Stoke	Renewal
Underground Conversion Bolt Road	2023	$750,000.00	Stoke	Relocation
Underground Conversion Wakefield Northern Entrance	2023	$300,000.00	Stoke	Relocation
Capacitor Bank Motueka	2024	$500,000.00	Motueka	System Growth
Collingwood 33kV Feeder Reconductor to Ferret	2024	$700,000.00	Golden Bay	System Growth
Korere Feeder 22kV Conversion Stage 1	2024	$1,650,000.00	Kikiwa	System Growth
Longford Feeder 22kV conversion Stage 1 - Mangles	2024	$1,630,000.00	Murchison	System Growth
Underground Conversion Ellis St Brightwater	2024	$900,000.00	Stoke	Relocation
Korere Feeder 22kV Conversion Stage 2	2025	$2,000,000.00	Kikiwa	System Growth
Longford Feeder 22kV conversion Stage 2	2025	$1,600,000.00	Murchison	System Growth
Refurbish T1 Transformer Founders	2025	$200,000.00	Stoke	Renewal
Underground Conversion Main Road Stoke (Champion to Saxtons)	2025	$1,300,000.00	Stoke	Relocation
33kV Cable Extension Neale Ave to Annesbrook Substation 600A 1.1km	2026	$400,000.00	Stoke	System Growth

Specific Development Projects				
Network Enhancement Project	**Year**	**SumOfEstimated Cost**	**Region**	**Expenditure Class**
66kV Cables Riwaka	2026	$800,000.00	Motueka	System Growth
66kV Zone Substation at Riwaka	2026	$3,800,000.00	Motueka	System Growth
New Ripple Injection Plant Riwaka	2026	$300,000.00	Motueka	System Growth
Pakawau Feeder 22kV conversion Stage 1	2026	$1,000,000.00	Golden Bay	System Growth
Refurbish T2 Transformer Songer St	2026	$200,000.00	Stoke	Renewal
Underground Conversion Waimea Road (Annesbrook Roundabout to Beatsons Roundabout)	2026	$900,000.00	Stoke	Relocation
Upgrade Conductor Railway Reserve 33kV Neale Ave to Annesbrook Cockroach	2026	$100,000.00	Stoke	System Growth
Pakawau Feeder 22kV conversion Stage 2	2027	$1,000,000.00	Golden Bay	System Growth
Refurbish T2 Transformer Brightwater	2027	$200,000.00	Stoke	Renewal
Upgrade Annesbrook Substation to 34MVA firm	2027	$3,500,000.00	Stoke	System Growth
Refurbish T2 Transformer Founders	2028	$200,000.00	Stoke	Renewal
New Zone Substation at Wakefield	2029	$4,000,000.00	Stoke	System Growth
Upgrade Conductor Railway Reserve 33kV Neale Ave to Hope 600A	2030	$0.00	Stoke	System Growth

APPENDIX F

F. NETWORK MAINTENANCE AND OPERATIONS EXPENDITURE PROJECTION

MAINTENANCE AND OPERATIONS EXPENDITURE	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
System Operations and Network Support										
Management Fee	528,191	533,473	538,808	544,196	549,638	555,134	560,685	566,292	571,955	577,675
Training	60,000	60,600	61,206	61,818	62,436	63,061	63,691	64,328	64,971	65,621
Emergency Stock Management	40,000	40,400	40,804	41,212	41,624	42,040	42,461	42,885	43,314	43,747
	628,191	634,473	640,818	647,226	653,698	660,235	666,837	673,506	680,241	687,043
Vegetation Management										
Tree Cutting	156,000	157,560	159,136	160,727	162,334	163,958	165,597	167,253	168,926	170,615
Line Corridors	273,000	275,730	278,487	281,272	284,085	286,926	289,795	292,693	295,620	298,576
Tree Regulations Removals	228,799	231,087	233,398	235,732	238,089	240,470	242,875	245,303	247,757	250,234
Fall Distance Tree Removal	166,399	168,063	169,744	171,441	173,155	174,887	176,636	178,402	180,186	181,988
	824,198	832,440	840,764	849,172	857,664	866,240	874,903	883,652	892,488	901,413
Service interruptions and emergencies										
Faults Services - Network	764,000	771,640	779,356	787,150	795,021	802,972	811,001	819,111	827,303	835,576
Faults Services - Vegetation	68,000	68,680	69,367	70,060	70,761	71,469	72,183	72,905	73,634	74,371
Fault Recoveries	(75,000)	(75,750)	(76,508)	(77,273)	(78,045)	(78,826)	(79,614)	(80,410)	(81,214)	(82,026)
Portable Generator Costs	30,000	30,300	30,603	30,909	31,218	31,530	31,846	32,164	32,486	32,811
Service Level Payments										
Emergency Maintenance	120,000	121,200	122,412	123,636	124,872	126,121	127,382	128,656	129,943	131,242
	907,000	916,070	925,231	934,483	943,828	953,266	962,799	972,427	982,151	991,973
OPERATIONS EXPENDITURE	**2,359,389**	**2,382,983**	**2,406,813**	**2,430,881**	**2,455,190**	**2,479,742**	**2,504,539**	**2,529,584**	**2,554,880**	**2,580,429**
Routine and corrective maintenance and inspection										
Substation Transformers	80,000	80,800	81,608	82,424	83,248	84,081	84,922	85,771	86,629	87,495
Substation switchgear and fuses	10,000	10,100	10,201	10,303	10,406	10,510	10,615	10,721	10,829	10,937
Substation Buildings & Switchyards	30,000	30,300	30,603	30,909	31,218	31,530	31,846	32,164	32,486	32,811
Substation SCADA	5,000	5,050	5,101	5,152	5,203	5,255	5,308	5,361	5,414	5,468
SCADA Master Station	1,000	1,010	1,020	1,030	1,041	1,051	1,062	1,072	1,083	1,094
Substation Batteries	5,000	5,050	5,101	5,152	5,203	5,255	5,308	5,361	5,414	5,468
Service Boxes	20,000	20,200	20,402	20,606	20,812	21,020	21,230	21,443	21,657	21,874
Connection Policy Alterations (Customer Services)	25,000	25,250	25,503	25,758	26,015	26,275	26,538	26,803	27,071	27,342
O/H Conductor 33kV & 66kV	20,000	20,200	20,402	20,606	20,812	21,020	21,230	21,443	21,657	21,874
U/G Cables 33kV	10,000	10,100	10,201	10,303	10,406	10,510	10,615	10,721	10,829	10,937

Distribution Transformers	120,000	121,200	122,412	123,636	124,872	126,121	127,382	128,656	129,943	131,242
O/H Conductor 11kV & 22kV	40,000	40,400	40,804	41,212	41,624	42,040	42,461	42,885	43,314	43,747
O/H Conductor 400v	25,000	25,250	25,503	25,758	26,015	26,275	26,538	26,803	27,071	27,342
U/G Cables 11kV & 22kV	45,000	45,450	45,905	46,364	46,827	47,295	47,768	48,246	48,729	49,216
U/G Cables 400v	4,000	4,040	4,080	4,121	4,162	4,204	4,246	4,289	4,331	4,375
Field Switchgear & fuses	80,000	80,800	81,608	82,424	83,248	84,081	84,922	85,771	86,629	87,495
Field regulators	40,000	40,400	40,804	41,212	41,624	42,040	42,461	42,885	43,314	43,747
Field ABS Isolators	30,000	30,300	30,603	30,909	31,218	31,530	31,846	32,164	32,486	32,811
LCP Transmitters	5,000	5,050	5,101	5,152	5,203	5,255	5,308	5,361	5,414	5,468
Communications Networks	1,600	1,616	1,632	1,648	1,665	1,682	1,698	1,715	1,733	1,750
SCADA & Ripple Plant Back Up	16,500	16,665	16,832	17,000	17,170	17,342	17,515	17,690	17,867	18,046
Operations General	80,000	80,800	81,608	82,424	83,248	84,081	84,922	85,771	86,629	87,495
Line Surveys	20,000	20,200	20,402	20,606	20,812	21,020	21,230	21,443	21,657	21,874
AR, Reg, Line MDI Reads	60,000	60,600	61,206	61,818	62,436	63,061	63,691	64,328	64,971	65,621
Sub VRR Settings	20,000	20,200	20,402	20,606	20,812	21,020	21,230	21,443	21,657	21,874
Dist Trans MDI Reads & Checks	35,000	35,350	35,704	36,061	36,421	36,785	37,153	37,525	37,900	38,279
Traffic Management Costs	200,000	202,000	204,020	206,060	208,121	210,202	212,304	214,427	216,571	218,737
Access Tracks	180,001	181,801	183,619	185,455	187,310	189,183	191,075	192,985	194,915	196,864
Audits (Customer Services)	40,000	40,400	40,804	41,212	41,624	42,040	42,461	42,885	43,314	43,747
Audit Recoveries (Customer Services)	(50,000)	(50,500)	(51,005)	(51,515)	(52,030)	(52,551)	(53,076)	(53,607)	(54,143)	(54,684)
66kV Network	500,000	505,000	510,050	515,151	520,302	525,505	530,760	536,068	541,428	546,843
	1,698,101	**1,715,082**	**1,732,233**	**1,749,555**	**1,767,051**	**1,784,721**	**1,802,568**	**1,820,594**	**1,838,800**	**1,857,188**
Refurbishment & Renewals Maintenance										
All Poles	1,800,000	1,818,000	1,836,180	1,854,542	1,873,087	1,891,818	1,910,736	1,929,844	1,949,142	1,968,633
Distribution Subs	180,000	181,800	183,618	185,454	187,309	189,182	191,074	192,984	194,914	196,863
Connection Assets	100,000	101,000	102,010	103,030	104,060	105,101	106,152	107,214	108,286	109,369
Transfomer Changeouts (Cust Services)	20,000	20,200	20,402	20,606	20,812	21,020	21,230	21,443	21,657	21,874
	2,100,000	**2,121,000**	**2,142,210**	**2,163,632**	**2,185,268**	**2,207,121**	**2,229,192**	**2,251,484**	**2,273,999**	**2,296,739**
ASSET MAINTENANCE & RENEWALS	**3,798,101**	**3,836,082**	**3,874,443**	**3,913,187**	**3,952,319**	**3,991,842**	**4,031,761**	**4,072,078**	**4,112,799**	**4,153,927**
TOTAL OPERATIONS AND MAINTENANCE	**6,157,490**	**6,219,065**	**6,281,256**	**6,344,068**	**6,407,509**	**6,471,584**	**6,536,300**	**6,601,663**	**6,667,679**	**6,734,356**

All figures are 2015 dollars. Projected figures are not inflation adjusted.

APPENDIX G

G. *TYPICAL ASSET MAINTENANCE AND RENEWALS ACTIVITIES*

REFURBISHMENT/RENEWALS:

Poles	Pole replacements and complete pole structure replacements
Line Hardware	Hardware Replacements (inc crossarms)
Conductor	Conductor Replacements
Service Boxes	Complete service box replacement
0Underground 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, fuseboard 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, pesting, 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

H. DESIGN NETWORK VOLTAGE REGULATION

DESIGN % VOLTAGE DROP ALLOCATIONS - LDC SUBSTATIONS
HOPE, FOUNDERS, LOWER QUEEN ST AND MOTUEKA SUSTATIONS

	Close to Zone Sub Normal Tap	Urban Normal Tap	Semi Rural 2.5% Tap	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

DESIGN % VOLTAGE DROP ALLOCATIONS - NON LDC SUBSTATIONS
EVES VALLEY, BRIGHTWATER, TAKAKA, SWAMP ROAD, KIKIWA, MURCHISON, ANNESBROOK, SONGER ST

	Close to Zone Sub Normal Tap	Urban Normal Tap	Semi Rural 2.5% Tap	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

I. ZONE SUBSTATION RISK ASSESSMENT MATRICES

Zone Substation Risk Assessment Matrices

- Motupipi Substation
- Takaka Substation
- Brightwater Substation
- Hope Substation
- Songer St Substation
- Annesbrook Substation
- Lower Queen St Substation
- Founders Substation
- Eves Valley Substation
- Swamp Road Substation
- Mapua Substation
- Richmond Substation

MOTUPIPI SUBSTATION

Customers affected by LOS 2500

Main 66kV Supply Upper Takaka **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 Disaster Recovery Plan
Landslip/movement	M	M	600	Accept Risk	Nil
Flood/tsunami	L	M	300	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	M	S	300	Accept Risk	Nil
Fire (outside source)	M	M	600	Accept Risk	Nil
Human incident	L	I	50	Accept Risk	Nil
Other Bird Strike	M	S	300	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	600	Accept Risk	Nil
Loss 2 –3 poles/spans	M	L	2400	Accept Risk	Nil
Loss 3 –5 poles/spans	L	L	1200	Accept Risk	Nil
Loss >5 poles/spans	L	E	4200	Contingency Plan	Ref Disaster Recovery Plan
Loss river xing span	L	M	300	Accept Risk	Nil
Loss major span	L	M	300	Accept Risk	Nil
Single point cable fault	N	N/A	0	Accept Risk	Nil
< 100 m cable damage	N	N/A	0	Accept Risk	Nil
0.1-1km cable damage	N	N/A	0	Accept Risk	Nil
> 1 km cable damage	N	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake 19570

Substation Risk Index per Customer 7.828

Substation Motupipi

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 Disaster Recovery Plan
Landslip/movement	N	L	240	Accept Risk	Nil
Flood/tsunami	N	L	240	Accept Risk	Nil
Extreme weather	L	M	300	Accept Risk	Nil
Aircraft crash	N	L	240	Accept Risk	Nil
Road/rail crash	N	N/A	0	Accept Risk	Nil
Fire (outside source)	L	S	150	Accept Risk	Nil
Security/vandal	L	S	150	Accept Risk	Nil
Human incident	L	I	50	Accept Risk	Nil
Other	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	M	300	Accept Risk	Nil
Loss 2 inc 66kV CBs	N	N/A	0	Accept Risk	Nil
Loss 1 transformer	L	L	1200	Capital Works	Ref Asset Management Plan
Loss 2 transformers	L	E	4200	Contingency Plan	Ref Disaster Recovery Plan
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	S	150	Accept Risk	Nil
Loss 2 inc 33kV CBs	L	M	300	Accept Risk	Nil
Loss 1 feeder CB	L	N/A	0	Accept Risk	Nil
Loss 2 feeder CBs	N	N/A	0	Accept Risk	Nil
Loss >2 feeder CBs	N	N/A	0	Accept Risk	Nil
Loss 1 half switchboard	N	N/A	0	Accept Risk	Nil
Loss complete swboard	N	N/A	0	Accept Risk	Nil
Control room fire	L	S	150	Accept Risk	Nil

TAKAKA SUBSTATION

Customers affected by LOS: 1870

Main 33kV Supply: Takaka **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	6283	Contingency Plan - Insurance	Refer Disaster Recovery Plan
Landslip/movement	L	M	224	Accept Risk	Nil
Flood/tsunami	L	M	224	Accept Risk	Nil
Extreme weather	L	S	112	Accept Risk	Nil
Aircraft crash	L	M	224	Accept Risk	Nil
Road/rail crash	L	S	112	Accept Risk	Nil
Trees	L	S	112	Accept Risk	Nil
Fire (outside source)	L	S	112	Accept Risk	Nil
Human incident	L	I	37	Accept Risk	Nil
Other Bird Strike	M	S	224	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	449	Accept Risk	Nil
Loss 2 –3 poles/spans	L	L	898	Accept Risk	Nil
Loss 3 –5 poles/spans	L	L	898	Accept Risk	Nil
Loss >5 poles/spans	L	E	3142	Contingency Plan	Ref Disaster Recovery Plan
Loss river xing span	N	N/A	0	Accept Risk	Nil
Loss major span	L	M	224	Accept Risk	Nil
Single point cable fault	L	I	37	Accept Risk	Nil
< 100 m cable damage	L	I	37	Accept Risk	Nil
0.1-1km cable damage	N	N/A	0	Accept Risk	Nil
> 1 km cable damage	N	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 13516

Substation Risk Index per Customer: 7.228

Substation: 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	6283	Contingency Plan	Ref Disaster Recovery Plan
Landslip/movement	N	L	180	Accept Risk	Nil
Flood/tsunami	M	L	1795	Accept Risk	Nil
Extreme weather	L	M	224	Accept Risk	Nil
Aircraft crash	N	L	180	Accept Risk	Nil
Road/rail crash	N	N/A	0	Accept Risk	Nil
Fire (outside source)	L	S	112	Accept Risk	Nil
Security/vandal	L	S	112	Accept Risk	Nil
Human incident	L	I	37	Accept Risk	Nil
Other	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	N	N/A	0	Accept Risk	Nil
Loss 2 inc 33kV CBs	N	N/A	0	Accept Risk	Nil
Loss 1 transformer	L	I	37	Accept Risk	Nil
Loss 2 transformers	N	E	628	Accept Risk	Nil
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	M	224	Accept Risk	Nil
Loss 2 inc 11kV CBs	L	L	898	Accept Risk	Nil
Loss 1 feeder CB	L	S	112	Accept Risk	Nil
Loss 2 feeder CBs	N	N/A	0	Accept Risk	Nil
Loss >2 feeder CBs	N	N/A	0	Accept Risk	Nil
Loss 1 half switchboard	L	L	898	Accept Risk	Nil
Loss complete swboard	L	L	898	Accept Risk	Nil
Control room fire	L	S	112	Accept Risk	Nil

BRIGHTWATER SUBSTATION

Customers affected by LOS: 2164

Main 33kV Supply Railway Reserve Feeder **Backup** Hope Feeder

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	2077	Contingency Plan	Ref Disaster Recovery Plan
Landslip/movement	L	I	43	Accept Risk	Nil
Flood/tsunami	M	I	87	Accept Risk	Nil
Extreme weather	L	I	43	Accept Risk	Nil
Aircraft crash	L	I	43	Accept Risk	Nil
Road/rail crash	N	I	9	Accept Risk	Nil
Trees	L	I	43	Accept Risk	Nil
Fire (outside source)	L	I	43	Accept Risk	Nil
Human incident	L	I	43	Accept Risk	Nil
Other	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	43	Accept Risk	Nil
Loss 2 –3 poles/spans	L	I	43	Accept Risk	Nil
Loss 3 –5 poles/spans	L	I	43	Accept Risk	Nil
Loss >5 poles/spans	L	I	43	Accept Risk	Nil
Loss river xing span	L	I	43	Accept Risk	Nil
Loss major span	L	I	43	Accept Risk	Nil
Single point cable fault	L	I	43	Accept Risk	Nil
< 100 m cable damage	L	I	43	Accept Risk	Nil
0.1-1km cable damage	N	I	9	Accept Risk	Nil
> 1 km cable damage	N	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 16412

Substation Risk Index per Customer: 7.584

Substation

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment
Earthquake	M	L	2077	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Landslip/movement	L	L	1039	Accept Risk	Nil
Flood/tsunami	N	M	52	Accept Risk	Nil
Extreme weather	L	I	43	Accept Risk	Nil
Aircraft crash	N	L	208	Accept Risk	Nil
Road/rail crash	N	M	52	Accept Risk	Nil
Fire (outside source)	N	L	208	Accept Risk	Nil
Security/vandal	L	M	260	Accept Risk	Nil
Human incident	L	S	130	Accept Risk	Nil
Other	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
Loss 1 inc 33kV CB	L	M	260	Accept Risk	Nil
Loss 2 inc 33kV CBs	N	N/A	0	Accept Risk	Nil
Loss 1 transformer	M	E	7271	Capital Works - 2nd Transformer	Ref Asset Management Plan
Loss 2 transformers	N	N/A	0	Accept Risk	Nil
Loss 1 33kV bus section	L	E	3636	Capital Works - 2nd Transformer	Ref Asset Management Plan
Loss 2 33kV bus sections	N	N/A	0	Accept Risk	Nil
Loss 1 inc 11kV CB	M	L	2077	Capital Works - 2nd Transformer	Ref Asset Management Plan
Loss 2 inc 11kV CBs	N	N/A	0	Accept Risk	Nil
Loss 1 feeder CB	L	I	43	Accept Risk	Nil
Loss 2 feeder CBs	N	S	26	Accept Risk	Nil
Loss >2 feeder CBs	N	I	9	Accept Risk	Nil
Loss 1 half switchboard	L	S	130	Accept Risk	Nil
Loss complete swboard	L	S	130	Accept Risk	Nil
Control room fire	L	S	130	Accept Risk	Nil

SWAMP ROAD SUBSTATION

Customers affected by LOS: 1000

Main 33kV Supply Collingwood **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	3360	Contingency Plan + Insurance	Ref Disaster Recovery Plan
Landslip/movement	M	M	240	Accept Risk	Nil
Flood/tsunami	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	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 Disaster Recovery Plan
Loss river xing span	L	M	120	Accept Risk	Nil
Loss major span	L	M	120	Accept Risk	Nil
Single point cable fault	N	N/A	0	Accept Risk	Nil
< 100 m cable damage	N	N/A	0	Accept Risk	Nil
0.1-1km cable damage	N	N/A	0	Accept Risk	Nil
> 1 km cable damage	N	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 9352

Substation Risk Index per Customer: 9.352

Substation Swamp Rd

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 Disaster Recovery Plan
Landslip/movement	N	L	96	Accept Risk	Nil
Flood/tsunami	L	L	480	Accept Risk	Nil
Extreme weather	L	M	120	Accept Risk	Nil
Aircraft crash	N	L	96	Accept Risk	Nil
Road/rail crash	N	N/A	0	Accept Risk	Nil
Fire (outside source)	L	S	60	Accept Risk	Nil
Security/vandal	L	S	60	Accept Risk	Nil
Human incident	L	I	20	Accept Risk	Nil
Other	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	N	N/A	0	Accept Risk	Nil
Loss 2 inc 33kV CBs	N	N/A	0	Accept Risk	Nil
Loss 1 transformer	M	L	960	Capital Works	Ref Asset Management Plan
Loss 2 transformers	L	E	1680	Contingency Plan	Ref Disaster Recovery Plan
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	L	480	Accept Risk	Nil
Loss 2 inc 11kV CBs	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 CBs	N	N/A	0	Accept Risk	Nil
Loss 1 half switchboard	N	N/A	0	Accept Risk	Nil
Loss complete swboard	N	N/A	0	Accept Risk	Nil
Control room fire	L	S	60	Accept Risk	Nil

MAPUA SUBSTATION

Customers affected by LOS 1750

Main 33kV Supply Railway Reserve 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	5880	Contingency Plan	Ref Disaster Recovery Plan
Landslip/movement	M	L	1680	Accept Risk	Nil
Flood/tsunami	M	M	420	Accept Risk	Nil
Extreme weather	L	M	210	Accept Risk	Nil
Aircraft crash	L	M	210	Accept Risk	Nil
Road/rail crash	H	M	2100	Capital Works	Ref Asset Management Plan
Trees	L	S	105	Accept Risk	Nil
Fire (outside source)	L	S	105	Accept Risk	Nil
Human incident	L	S	105	Accept Risk	Nil
Other	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	M	210	Accept Risk	Nil
Loss 2 –3 poles/spans	L	L	840	Accept Risk	Nil
Loss 3 –5 poles/spans	L	L	840	Accept Risk	Nil
Loss >5 poles/spans	L	E	2940	Capital Works	Ref Asset Management Plan
Loss river xing span	L	L	840	Accept Risk	Nil
Loss major span	L	L	840	Accept Risk	Nil
Single point cable fault	M	S	210	Accept Risk	Nil
< 100 m cable damage	N	E	588	Accept Risk	Nil
0.1-1km cable damage	N	E	588	Accept Risk	Nil
> 1 km cable damage	N	E	588	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake 19768

Substation Risk Index per Customer 11.296

Substation

Non Equipment Incidents

Incident	Probability H/M/L/N	Supply Restoration time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment
Earthquake	M	E	5880	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Landslip/movement	L	L	840	Accept Risk	Nil
Flood/tsunami	L	M	210	Accept Risk	Nil
Extreme weather	L	I	35	Accept Risk	Nil
Aircraft crash	N	E	588	Accept Risk	Nil
Road/rail crash	N	M	42	Accept Risk	Nil
Fire (outside source)	L	L	840	Accept Risk	Nil
Security/vandal	L	M	210	Accept Risk	Nil
Human incident	L	S	105	Accept Risk	Nil
Other	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
Loss 1 inc 33kV CB	L	M	210	Accept Risk	Nil
Loss 2 inc 33kV CBs	N	N/A	0	Accept Risk	Nil
Loss 1 transformer	M	I	70	Accept Risk	Nil
Loss 2 transformers	L	L	840	Accept Risk	Nil
Loss 1 33kV bus section	L	M	210	Accept Risk	Nil
Loss 2 33kV bus sections	N	N/A	0	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	35	Accept Risk	Nil
Loss 2 inc 11kV CBs	N	N/A	0	Accept Risk	Nil
Loss 1 feeder CB	L	I	35	Accept Risk	Nil
Loss 2 feeder CBs	N	S	21	Accept Risk	Nil
Loss >2 feeder CBs	N	L	168	Accept Risk	Nil
Loss 1 half switchboard	L	M	210	Accept Risk	Nil
Loss complete swboard	L	L	840	Accept Risk	Nil
Control room fire	L	L	840	Accept Risk	Nil

RICHMOND SUBSTATION

Customers affected by LOS 3870

Main 33kV Supply Richmond **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	L	3715	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Landslip/movement	L	I	77	Accept Risk	Nil
Flood/tsunami	N	I	15	Accept Risk	Nil
Extreme weather	N	I	15	Accept Risk	Nil
Aircraft crash	N	I	15	Accept Risk	Nil
Road/rail crash	N	I	15	Accept Risk	Nil
Trees	N	I	15	Accept Risk	Nil
Fire (outside source)	N	I	15	Accept Risk	Nil
Human incident	M	I	155	Accept Risk	Nil
Other	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	N/A	0	Accept Risk	Nil
Loss 2 –3 poles/spans	N	N/A	0	Accept Risk	Nil
Loss 3 –5 poles/spans	N	N/A	0	Accept Risk	Nil
Loss >5 poles/spans	N	N/A	0	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Loss river xing span	N	N/A	0	Accept Risk	Nil
Loss major span	N	N/A	0	Accept Risk	Nil
Single point cable fault	M	I	155	Accept Risk	Nil
< 100 m cable damage	L	I	77	Accept Risk	Nil
0.1-1km cable damage	N	I	15	Accept Risk	Nil
> 1 km cable damage	N	I	15	Accept Risk	Nil

Total Substation Risks Index excluding Earthc 18638

Substation Risk Index per Customer 4.816

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	13003	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Landslip/movement	N	L	372	Accept Risk	Nil
Flood/tsunami	L	L	1858	Contingency Plan - Insurance	Nil
Extreme weather	L	I	77	Accept Risk	Nil
Aircraft crash	N	E	1300	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Road/rail crash	L	M	464	Accept Risk	Nil
Fire (outside source)	M	M	929	Accept Risk	Nil
Security/vandal	L	M	464	Accept Risk	Nil
Human incident	L	S	232	Accept Risk	Nil
Other	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	77	Accept Risk	Nil
Loss 2 inc 33kV CBs	N	L	372	Accept Risk	Nil
Loss 1 transformer	L	I	77	Accept Risk	Nil
Loss 2 transformers	L	L	1858	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Loss 1 33kV bus section	L	I	77	Accept Risk	Nil
Loss 2 33kV bus sections	N	L	372	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	77	Accept Risk	Nil
Loss 2 inc 11kV CBs	L	L	1858	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Loss 1 feeder CB	L	I	77	Accept Risk	Nil
Loss 2 feeder CBs	L	I	77	Accept Risk	Nil
Loss >2 feeder CBs	L	L	1858	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Loss 1 half switchboard	L	L	1858	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Loss complete swboard	L	L	1858	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Control room fire	L	L	1858	Contingency Plan - Insurance	Ref Disaster Recovery Plan

EVES VALLEY SUBSTATION

Customers affected by LOS: 1000

Main 33kV Supply Railway Reserve **Backup** Hope 33kV

Non equipment incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment
Earthquake	M	L	960	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Landslip/movement	L	L	480	Accept Risk	Nil
Flood/tsunami	M	M	240	Accept Risk	Nil
Extreme weather	L	M	120	Accept Risk	Nil
Aircraft crash	L	M	120	Accept Risk	Nil
Road/rail crash	N	M	24	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	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
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 xing span	L	M	120	Accept Risk	Nil
Loss major span	L	M	120	Accept Risk	Nil
Single point cable fault	L	M	120	Accept Risk	Nil
< 100 m cable damage	L	L	480	Accept Risk	Nil
0.1-1km cable damage	N	L	96	Accept Risk	Nil
> 1 km cable damage	N	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 4804

Substation Risk Index per Customer: 4.804

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
Earthquake	M	E	3360	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Landslip/movement	L	L	480	Accept Risk	Nil
Flood/tsunami	N	M	24	Accept Risk	Nil
Extreme weather	L	I	20	Accept Risk	Nil
Aircraft crash	N	L	96	Accept Risk	Nil
Road/rail crash	N	M	24	Accept Risk	Nil
Fire (outside source)	L	L	480	Accept Risk	Nil
Security/vandal	L	M	120	Accept Risk	Nil
Human incident	L	S	60	Accept Risk	Nil
Other	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
Loss 1 inc 33kV CB	L	S	60	Accept Risk	Nil
Loss 2 inc 33kV CBs	N	N/A	0	Accept Risk	Nil
Loss 1 transformer	L	I	20	Accept Risk	Nil
Loss 2 transformers	N	L	96	Contingency Plan	Ref Disaster Recovery Plan
Loss 1 33kV bus sectio	N	N/A	0	Accept Risk	Nil
Loss 2 33kV bus sectio	N	N/A	0	Accept Risk	Nil
Loss 1 inc 11kV CB	N	N/A	0	Accept Risk	Nil
Loss 2 inc 11kV CBs	N	N/A	0	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 CBs	N	N/A	0	Accept Risk	Nil
Loss 1 half switchboard	N	I	4	Accept Risk	Nil
Loss complete swboard	L	S	60	Accept Risk	Nil
Control room fire	L	I	20	Accept Risk	Nil

FOUNDERS SUBSTATION

Customers affected by LOS 1920

Main 33kV Supply Founders **Backup** 11kV Supply via Nelson Electricity

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	6451	Contingency Plan	Ref Disaster Recovery Plan
Landslip/movement	M	S	230	Capital Works - Second Circuit	Ref Asset Management Plan
Flood/tsunami	N	S	23	Accept Risk	Nil
Extreme weather	M	S	230	Accept Risk	Nil
Aircraft crash	L	S	115	Accept Risk	Nil
Road/rail crash	M	I	77	Accept Risk	Nil
Trees	M	S	230	Accept Risk	Nil
Fire (outside source)	M	S	230	Capital Works - Second Circuit	Ref Asset Management Plan
Human incident	L	S	115	Accept Risk	Nil
Other Bird Strike	M	S	230	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	S	230	Accept Risk	Nil
Loss 2 –3 poles/spans	L	S	115	Accept Risk	Nil
Loss 3 –5 poles/spans	L	S	115	Accept Risk	Nil
Loss >5 poles/spans	L	S	115	Accept Risk	Ref Asset Management Plan
Loss river xing span	N	N/A	0	Accept Risk	Nil
Loss major span	L	S	115	Accept Risk	Nil
Single point cable fault	L	S	115	Accept Risk	Nil
< 100 m cable damage	N	S	23	Accept Risk	Nil
0.1-1km cable damage	N	S	23	Accept Risk	Nil
> 1 km cable damage	N	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake	9178
Substation Risk Index per Customer	4.78

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	6451	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Landslip/movement	L	L	922	Accept Risk	Nil
Flood/tsunami	L	L	922	Accept Risk	Nil
Extreme weather	L	M	230	Accept Risk	Nil
Aircraft crash	L	M	230	Accept Risk	Nil
Road/rail crash	L	S	115	Accept Risk	Nil
Fire (outside source)	N	N/A	0	Accept Risk	Nil
Security/vandal	L	S	115	Accept Risk	Nil
Human incident	L	I	38	Accept Risk	Nil
Other	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	38	Accept Risk	Nil
Loss 2 inc 33kV CBs	L	S	115	Accept Risk	Nil
Loss 1 transformer	L	I	38	Accept Risk	Nil
Loss 2 transformers	L	L	922	Accept Risk	Nil
Loss 1 33kV bus section	N	I	8	Accept Risk	Nil
Loss 2 33kV bus sections	N	N/A	0	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	38	Accept Risk	Nil
Loss 2 inc 11kV CBs	L	L	922	Accept Risk	Nil
Loss 1 feeder CB	L	I	38	Accept Risk	Nil
Loss 2 feeder CBs	L	I	38	Accept Risk	Nil
Loss >2 feeder CBs	L	M	230	Accept Risk	Nil
Loss 1 half switchboard	L	I	38	Accept Risk	Nil
Loss complete swboard	L	L	922	Accept Risk	Nil
Control room fire	L	L	922	Accept Risk	Nil

LOWER QUEEN ST SUBSTATION

Customers affected by LOS: 1620

Main 33kV Supply Suffolk Rd Feeder **Backup** 11kV supply via Hope

Non equipment incidents

Incident	Probability H/M/L/N	Supply Restoration Time I/S/M/L/E	Risk	Risk Management Strategy	Risk Treatment
Earthquake	M	I	65	Accept Risk	Nil
Landslip/movement	L	I	32	Accept Risk	Nil
Flood/tsunami	M	I	65	Accept Risk	Nil
Extreme weather	M	I	65	Accept Risk	Nil
Aircraft crash	L	I	32	Accept Risk	Nil
Road/rail crash	M	I	65	Accept Risk	Nil
Trees	M	I	65	Accept Risk	Nil
Fire (outside source)	L	I	32	Accept Risk	Nil
Human incident	L	I	32	Accept Risk	Nil
Other Bird Strike	M	I	65	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
Loss 1 pole/span	L	I	32	Accept Risk	Nil
Loss 2 –3 poles/spans	L	I	32	Accept Risk	Nil
Loss 3 –5 poles/spans	L	I	32	Accept Risk	Nil
Loss >5 poles/spans	L	I	32	Accept Risk	Nil
Loss river xing span	N	N/A	0	Accept Risk	Nil
Loss major span	L	I	32	Accept Risk	Nil
Single point cable fault	L	I	32	Accept Risk	Nil
< 100 m cable damage	L	I	32	Accept Risk	Nil
0.1-1km cable damage	L	I	32	Accept Risk	Nil
> 1 km cable damage	N	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 1257

Substation Risk Index per Customer: 0.776

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
Earthquake	M	I	65	Accept Risk	Nil
Landslip/movement	N	I	6	Accept Risk	Nil
Flood/tsunami	N	I	6	Accept Risk	Nil
Extreme weather	L	I	32	Accept Risk	Nil
Aircraft crash	N	I	6	Accept Risk	Nil
Road/rail crash	N	N/A	0	Accept Risk	Nil
Fire (outside source)	L	I	32	Accept Risk	Nil
Security/vandal	M	I	65	Accept Risk	Nil
Human incident	L	I	32	Accept Risk	Nil
Other	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
Loss 1 inc 33kV CB	L	I	32	Accept Risk	Nil
Loss 2 inc 33kV CBs	N	N/A	0	Accept Risk	Nil
Loss 1 transformer	M	I	65	Accept Risk	Nil
Loss 2 transformers	N	N/A	0	Accept Risk	Nil
Loss 1 33kV bus section	N	I	6	Accept Risk	Nil
Loss 2 33kV bus sections	N	N/A	0	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	32	Accept Risk	Nil
Loss 2 inc 11kV CBs	L	I	32	Accept Risk	Nil
Loss 1 feeder CB	L	I	32	Accept Risk	Nil
Loss 2 feeder CBs	L	I	32	Accept Risk	Nil
Loss >2 feeder CBs	L	I	32	Accept Risk	Nil
Loss 1 half switchboard	L	I	32	Accept Risk	Nil
Loss complete swboard	L	I	32	Accept Risk	Nil
Control room fire	L	I	32	Accept Risk	Nil

ANNESBROOK SUBSTATION

Customers affected by LOS: 3870

Main 33kV Supply Annesbrook **Backup** Railway Reserve

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	L	3715	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Landslip/movement	L	I	77	Accept Risk	Nil
Flood/tsunami	L	I	77	Accept Risk	Nil
Extreme weather	L	I	77	Accept Risk	Nil
Aircraft crash	N	I	15	Accept Risk	Nil
Road/rail crash	N	I	15	Accept Risk	Nil
Trees	L	I	77	Accept Risk	Nil
Fire (outside source)	L	I	77	Accept Risk	Nil
Human incident	L	I	77	Accept Risk	Nil
Other	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	77	Accept Risk	Nil
Loss 2 –3 poles/spans	L	I	77	Accept Risk	Nil
Loss 3 –5 poles/spans	L	I	77	Accept Risk	Nil
Loss >5 poles/spans	L	I	77	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Loss river xing span	N	N/A	0	Accept Risk	Nil
Loss major span	L	I	77	Accept Risk	Nil
Single point cable fault	N	N/A	0	Accept Risk	Nil
< 100 m cable damage	N	N/A	0	Accept Risk	Nil
0.1-1km cable damage	N	N/A	0	Accept Risk	Nil
> 1 km cable damage	N	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 16192

Substation Risk Index per Customer: 4.184

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	13003	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Landslip/movement	N	L	372	Accept Risk	Nil
Flood/tsunami	N	L	372	Accept Risk	Nil
Extreme weather	L	I	77	Accept Risk	Nil
Aircraft crash	N	E	1300	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Road/rail crash	N	M	93	Accept Risk	Nil
Fire (outside source)	L	M	464	Accept Risk	Nil
Security/vandal	L	M	464	Accept Risk	Nil
Human incident	L	S	232	Accept Risk	Nil
Other	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	77	Accept Risk	Nil
Loss 2 inc 33kV CBs	N	I	15	Accept Risk	Nil
Loss 1 transformer	L	I	77	Accept Risk	Nil
Loss 2 transformers	L	L	1858	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Loss 1 33kV bus section	N	I	15	Accept Risk	Nil
Loss 2 33kV bus sections	N	L	372	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	77	Accept Risk	Nil
Loss 2 inc 11kV CBs	L	L	1858	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Loss 1 feeder CB	L	I	77	Accept Risk	Nil
Loss 2 feeder CBs	L	I	77	Accept Risk	Nil
Loss >2 feeder CBs	L	L	1858	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Loss 1 half switchboard	L	L	1858	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Loss complete swboard	L	L	1858	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Control room fire	L	L	1858	Contingency Plan - Insurance	Ref Disaster Recovery Plan

HOPE SUBSTATION

Customers affected by LOS: 3950

Main 33kV Supply: Hope Feeder — **Backup**: Railway Reserve Feeder

Substation: Hope

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	L	3792	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Landslip/movement	L	I	79	Accept Risk	Nil
Flood/tsunami	L	I	79	Accept Risk	Nil
Extreme weather	L	I	79	Accept Risk	Nil
Aircraft crash	N	I	16	Accept Risk	Nil
Road/rail crash	N	I	16	Accept Risk	Nil
Trees	L	I	79	Accept Risk	Nil
Fire (outside source)	L	I	79	Accept Risk	Nil
Human incident	L	I	79	Accept Risk	Nil
Other	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	L	I	79	Accept Risk	Nil
Loss 2 –3 poles/spans	L	I	79	Accept Risk	Nil
Loss 3 –5 poles/spans	L	I	79	Accept Risk	Nil
Loss >5 poles/spans	L	L	1896	Accept Risk	Nil
Loss river xing span	N	N/A	0	Accept Risk	Nil
Loss major span	L	I	79	Accept Risk	Nil
Single point cable fault	N	N/A	0	Accept Risk	Nil
< 100 m cable damage	N	N/A	0	Accept Risk	Nil
0.1-1km cable damage	N	N/A	0	Accept Risk	Nil
> 1 km cable damage	N	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 17032

Substation Risk Index per Customer: 4.312

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	13272	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Landslip/movement	N	L	379	Accept Risk	Nil
Flood/tsunami	N	L	379	Accept Risk	Nil
Extreme weather	L	I	79	Accept Risk	Nil
Aircraft crash	N	E	1327	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Road/rail crash	N	N/A	0	Accept Risk	Nil
Fire (outside source)	L	M	474	Accept Risk	Nil
Security/vandal	M	M	948	Accept Risk	Nil
Human incident	L	S	237	Accept Risk	Nil
Other	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	79	Accept Risk	Nil
Loss 2 inc 33kV CBs	N	S	47	Accept Risk	Nil
Loss 1 transformer	M	I	158	Accept Risk	Nil
Loss 2 transformers	L	L	1896	Contingency Plan	Ref Disaster Recovery Plan
Loss 1 33kV bus section	N	I	16	Accept Risk	Nil
Loss 2 33kV bus sections	N	N/A	0	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	79	Accept Risk	Nil
Loss 2 inc 11kV CBs	L	L	1896	Contingency Plan	Ref Disaster Recovery Plan
Loss 1 feeder CB	L	I	79	Accept Risk	Nil
Loss 2 feeder CBs	L	I	79	Accept Risk	Nil
Loss >2 feeder CBs	L	L	1896	Contingency Plan	Ref Disaster Recovery Plan
Loss 1 half switchboard	L	M	474	Accept Risk	Nil
Loss complete swboard	L	L	1896	Contingency Plan	Ref Disaster Recovery Plan
Control room fire	L	L	1896	Contingency Plan	Ref Disaster Recovery Plan

SONGER ST SUBSTATION — Customers affected by LOS: 5160

Main 33kV Supply Songer St Feeder **Backup** Railway Reserve Feeder

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	4954	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Landslip/movement	L	I	103	Accept Risk	Nil
Flood/tsunami	L	I	103	Accept Risk	Nil
Extreme weather	L	I	103	Accept Risk	Nil
Aircraft crash	N	I	21	Accept Risk	Nil
Road/rail crash	N	I	21	Accept Risk	Nil
Trees	L	I	103	Accept Risk	Nil
Fire (outside source)	L	I	103	Accept Risk	Nil
Human incident	L	I	103	Accept Risk	Nil
Other	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	103	Accept Risk	Nil
Loss 2 –3 poles/spans	L	I	103	Accept Risk	Nil
Loss 3 –5 poles/spans	L	I	103	Accept Risk	Nil
Loss >5 poles/spans	L	I	103	Accept Risk	Nil
Loss river xing span	N	N/A	0	Accept Risk	Nil
Loss major span	L	I	103	Accept Risk	Nil
Single point cable fault	L	I	103	Accept Risk	Nil
< 100 m cable damage	L	L	2477	Accept Risk	Nil
0.1-1km cable damage	N	L	495	Accept Risk	Nil
> 1 km cable damage	N	N/A	0	Accept Risk	Nil

Total Substation Risks Index excluding Earthquake: 24273

Substation Risk Index per Customer: 4.704

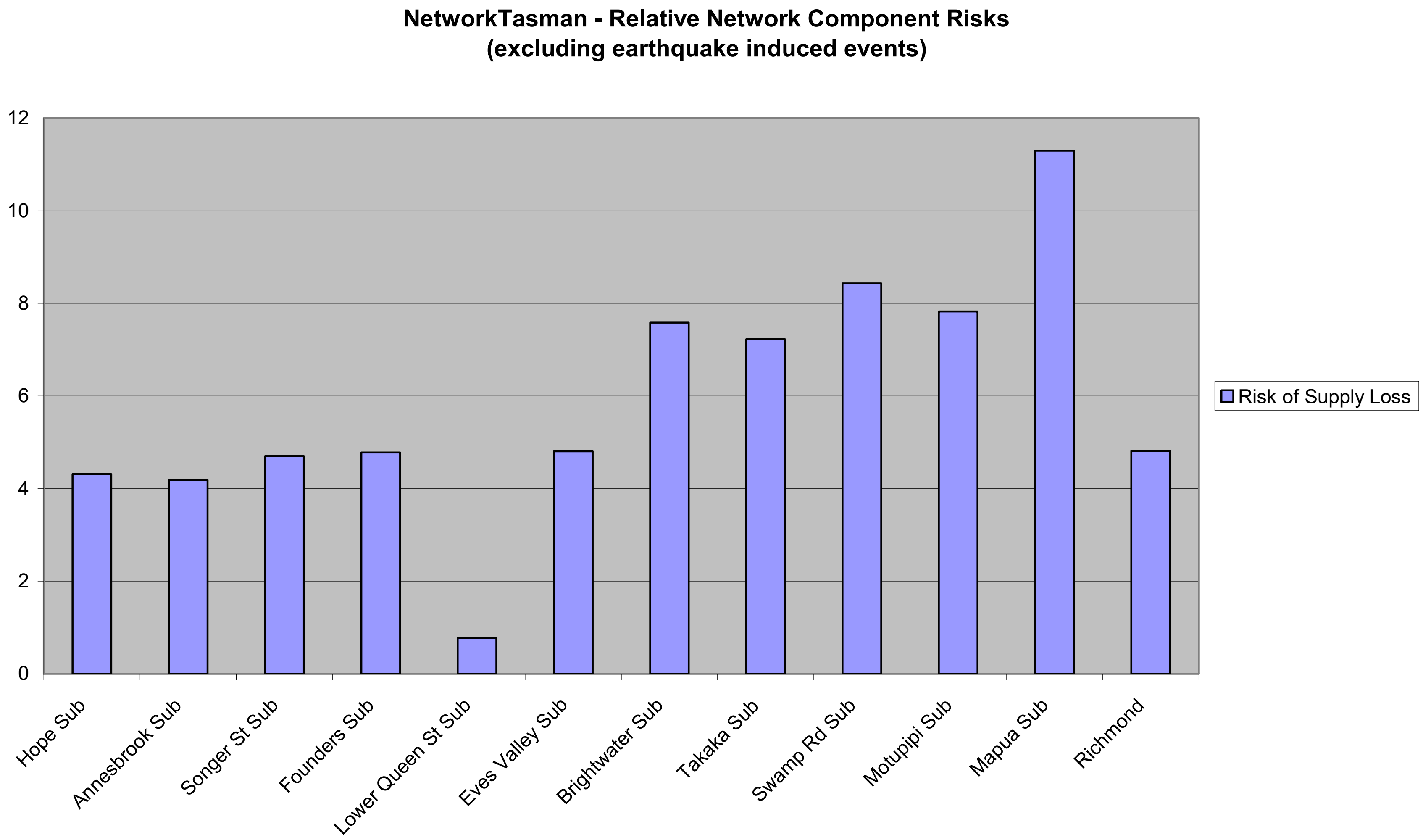
Substation Songer St

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	17338	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Landslip/movement	N	L	495	Accept Risk	Nil
Flood/tsunami	N	L	495	Accept Risk	Nil
Extreme weather	L	I	103	Accept Risk	Nil
Aircraft crash	N	E	1734	Contingency Plan - Insurance	Ref Disaster Recovery Plan
Road/rail crash	N	M	124	Accept Risk	Nil
Fire (outside source)	L	L	2477	Mitigate Risk	Cut nearby trees
Security/vandal	L	M	619	Accept Risk	Nil
Human incident	L	S	310	Accept Risk	Nil
Other	N	N/A	0	Accept Risk	Nil

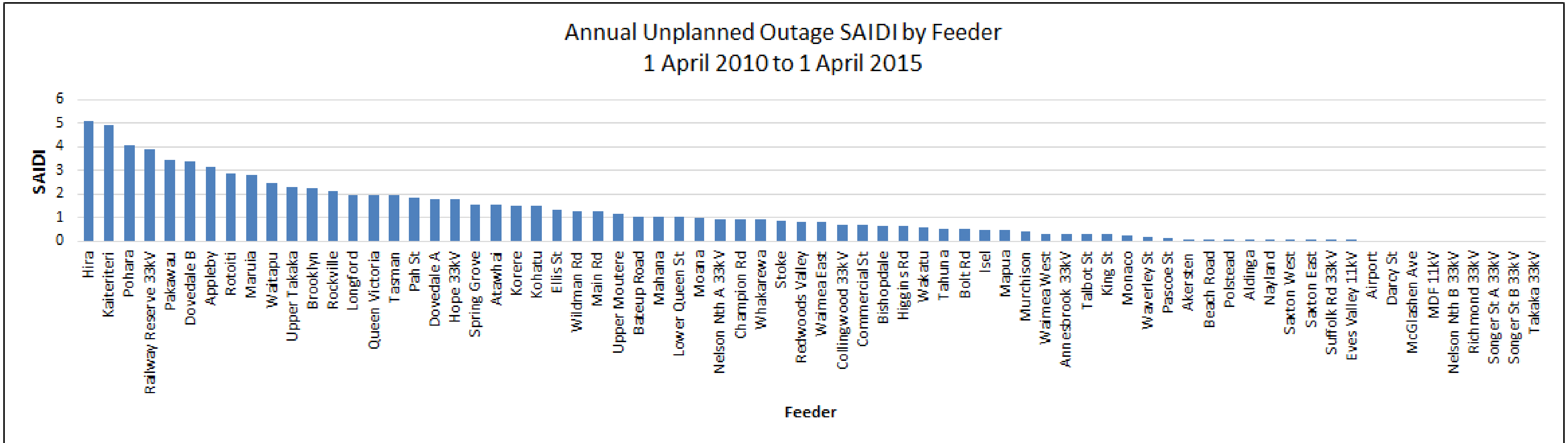
Equipment incidents

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	103	Accept Risk	Nil
Loss 2 inc 33kV CBs	N	I	21	Accept Risk	Nil
Loss 1 transformer	M	I	206	Accept Risk	Nil
Loss 2 transformers	L	L	2477	Contingency Plan	Ref Disaster Recovery Plan
Loss 1 33kV bus section	N	I	21	Accept Risk	Nil
Loss 2 33kV bus sections	N	N/A	0	Accept Risk	Nil
Loss 1 inc 11kV CB	L	I	103	Accept Risk	Nil
Loss 2 inc 11kV CBs	L	L	2477	Contingency Plan	Ref Disaster Recovery Plan
Loss 1 feeder CB	L	I	103	Accept Risk	Nil
Loss 2 feeder CBs	L	I	103	Accept Risk	Nil
Loss >2 feeder CBs	L	L	2477	Contingency Plan	Ref Disaster Recovery Plan
Loss 1 half switchboard	L	M	619	Accept Risk	Nil
Loss complete swboard	L	L	2477	Contingency Plan	Ref Disaster Recovery Plan
Control room fire	L	L	2477	Contingency Plan	Ref Disaster Recovery Plan


NetworkTasman - Relative Network Component Risks
(excluding earthquake induced events)
12
10
8
6
4
2
0
Hope Sub
Annesbrook Sub
Songer St Sub
Founders Sub
Lower Queen St Sub
Eves Valley Sub
Brightwater Sub
Takaka Sub
Swamp Rd Sub
Motupipi Sub
Mapua Sub
Richmond
Risk of Supply Loss

APPENDIX J

J. FEEDER RELIABILITY ANALYSIS



APPENDIX K

K. CONSUMER SURVEY 2012

Consumer survey 2012

Compiled for Network Tasman Ltd
by Utility Consultants Ltd
www.utilityconsultants.co.nz
www.facebook.com/utilityconsultants

August 2012

Summary

This report summarises the views and preferences obtained from the following sample space…

- The consumers ranked #2 to #40 by energy consumption, of which 28 surveys were completed.

The fraction of completed samples was 72%, from which some reasonably clear patterns have emerged, as follows…

- The most important aspect of electricity supply is continuity of supply.
- The second most important aspect of electricity supply is restoration of supply.
- The third most important aspect of electricity supply is predominantly no flicker & surges, with a few consumers replying sufficient notice of planned shutdowns as their third choice.
- Overall, consumers rate Network Tasman's performance in the most important aspects of continuity and restoration as Very Good with a slight skew towards Excellent.
- Flicker and surge seems to a problem almost as often as it is noticeable.
- Consumers have expressed a strong preference for continuing to pay about the same line charges to receive about the same reliability.
- Consumers have also expressed a strong preference for paying about the same to have about the same amount of flicker.

In terms of management activities, these conclusions give Network Tasman a strong community mandate to pursue the following tactics…

- Focus resources and attention on maintaining continuity and restoration.
- Keep line charges at about the same level as they currently are.
- Keep the level of continuity at about the same level as it currently.
- Keep the speed of restoration at about the same level as it currently.
- Keep the level of flicker about the same as it currently is.
- If creeping improvements in efficiency can be made, consumer responses imply that the freed up resources should be targeted to reducing flicker rather than improving reliability.

Contents

1. Introduction

1.1 Background

Network Tasman recently commissioned a consumer survey to inform its asset management processes of market preferences for service levels and tariffs. This survey was completed during August 2012.

1.2 Survey sample space

This survey surveyed Network Tasman's large industrial consumers ranked #2 to #40 and resulted in 28 completed surveys.

Survey date	Market segment surveyed	Sample size and structure
2004	Large industrial #2 to #31	All consumers
2006	Large industrial #2 to #35	All consumers
2008	Large commercial #30 to #100	Random sample of 43
2012	Large industrial #2 to #40	All consumers (28 successfully surveyed)

Note that Network Tasman regularly engages with its' largest consumer, Nelson Pine Industries, which is excluded from this survey.

1.3 Survey response rates

The survey response rate was reasonable at 72%. The results obtained are very similar to the results obtained from the 3 previous Network Tasman surveys (2004, 2006 and 2008).

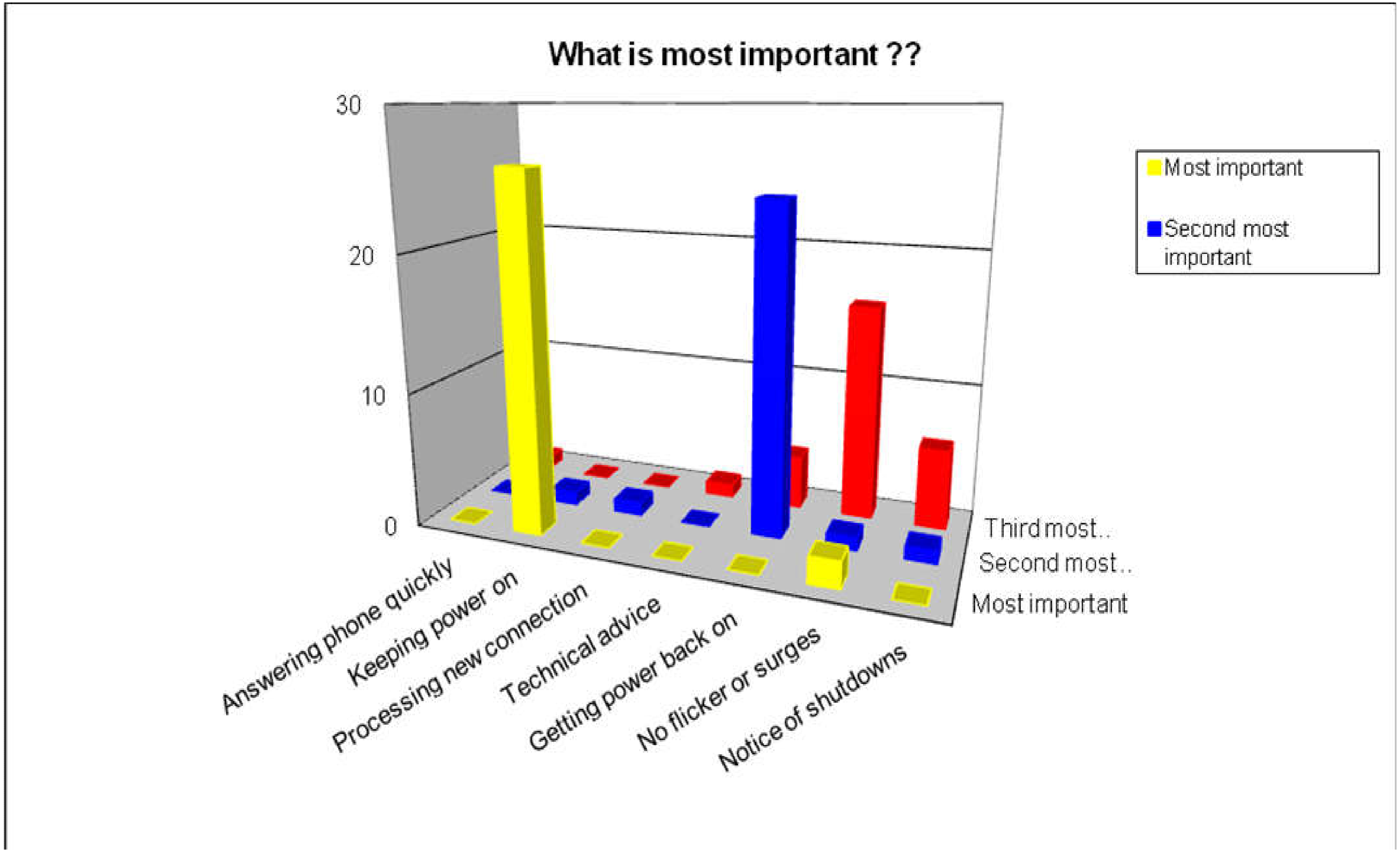
2. What is most important

The first question asked consumers which of the following 7 aspects of electricity distribution did they consider to be most important, 2nd most important and 3rd most important…

- Answering the phone quickly when they called Network Tasman.
- Keeping the power on all the time.
- Quick processing of applications for new connections.
- Advising on technical matters.
- Getting the power back on quickly if it goes off.
- No flicker or surge.
- Sufficient notice of planned shutdowns.

Chart description – shows which aspects of electricity supply that consumers consider to be most important, 2nd most important and 3rd most important.

Interpretation – a clear majority of consumers consider continuity of supply to be most important, and restoration of supply to be second most important. Third most important was split about 2/3 to 1/3 between no flicker or surges and sufficient notice of planned shutdowns.



What is most important ??
30
20
10
0
Most important
Second most important
Answering phone quickly
Keeping power on
Processing new connection
Technical advice
Getting power back on
No flicker or surges
Notice of shutdowns
Third most..
Second most..
Most important

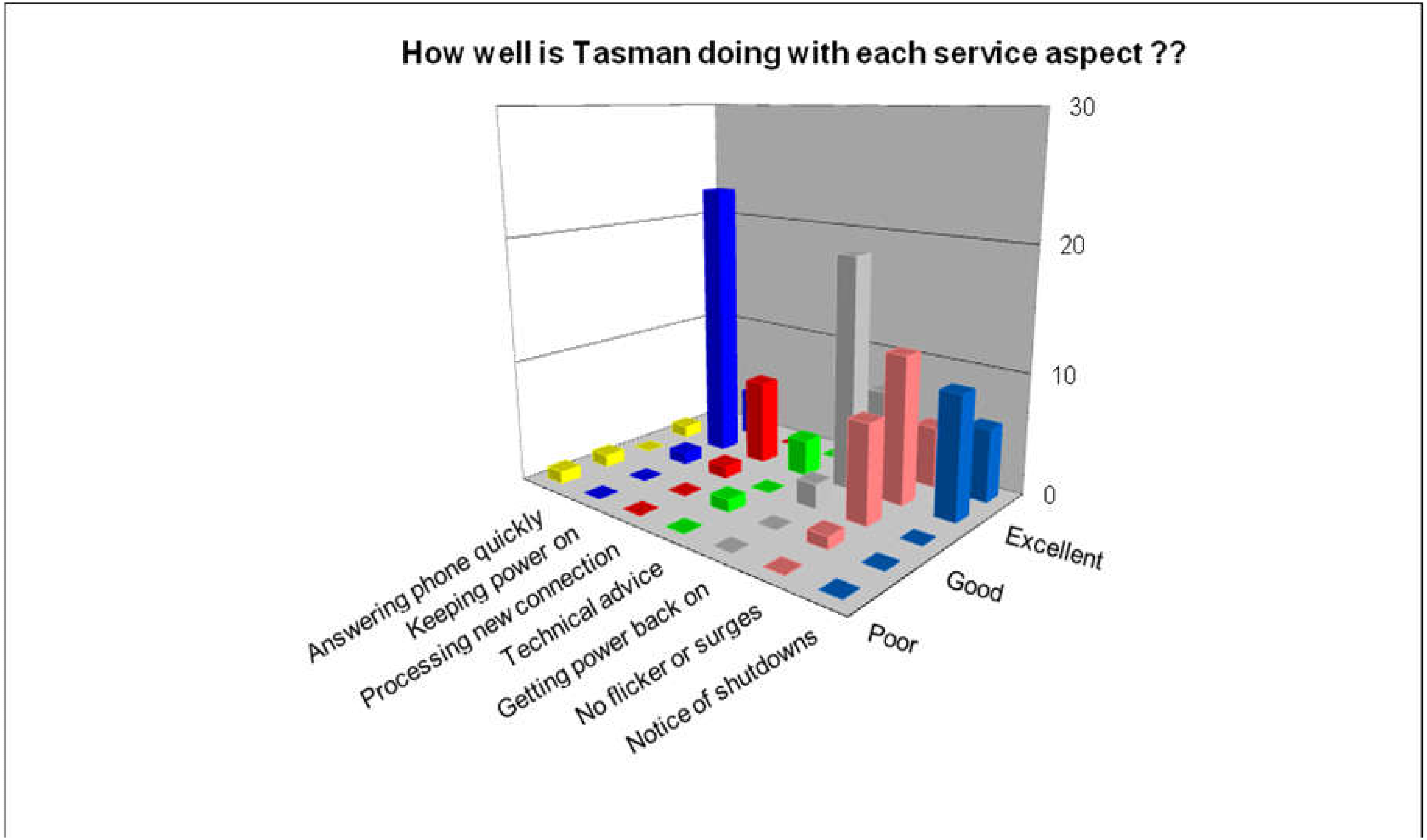
3. How well is Network Tasman doing

The second question asked consumers how well Network Tasman is performing in each of the following 7 aspects of electricity distribution…

- Answering the phone quickly when they called Network Tasman.
- Keeping the power on all the time.
- Quick processing of applications for new connections.
- Advising on technical matters.
- Getting the power back on quickly if it goes off.
- No flicker or surge.
- Sufficient notice of planned shutdowns.

Chart description – shows consumer perception of performance for each aspect.

Interpretation – in the most and second most important aspects of continuity and restoration, consumers rank Network Tasman's performance as Very Good with a slight skew towards Excellent. In the third most important aspects of no flicker and surge, most consumers rated Network Tasman's performance as Very Good, but a definite number rated performance as only Good. In the area of sufficient notice of planned shutdowns, consumers rated Network Tasman's performance as almost evenly split between Very Good and Excellent.


How well is Tasman doing with each service aspect ??
30
20
10
0
Answering phone quickly
Keeping power on
Processing new connection
Technical advice
Getting power back on
No flicker or surges
Notice of shutdowns
Excellent
Good
Poor

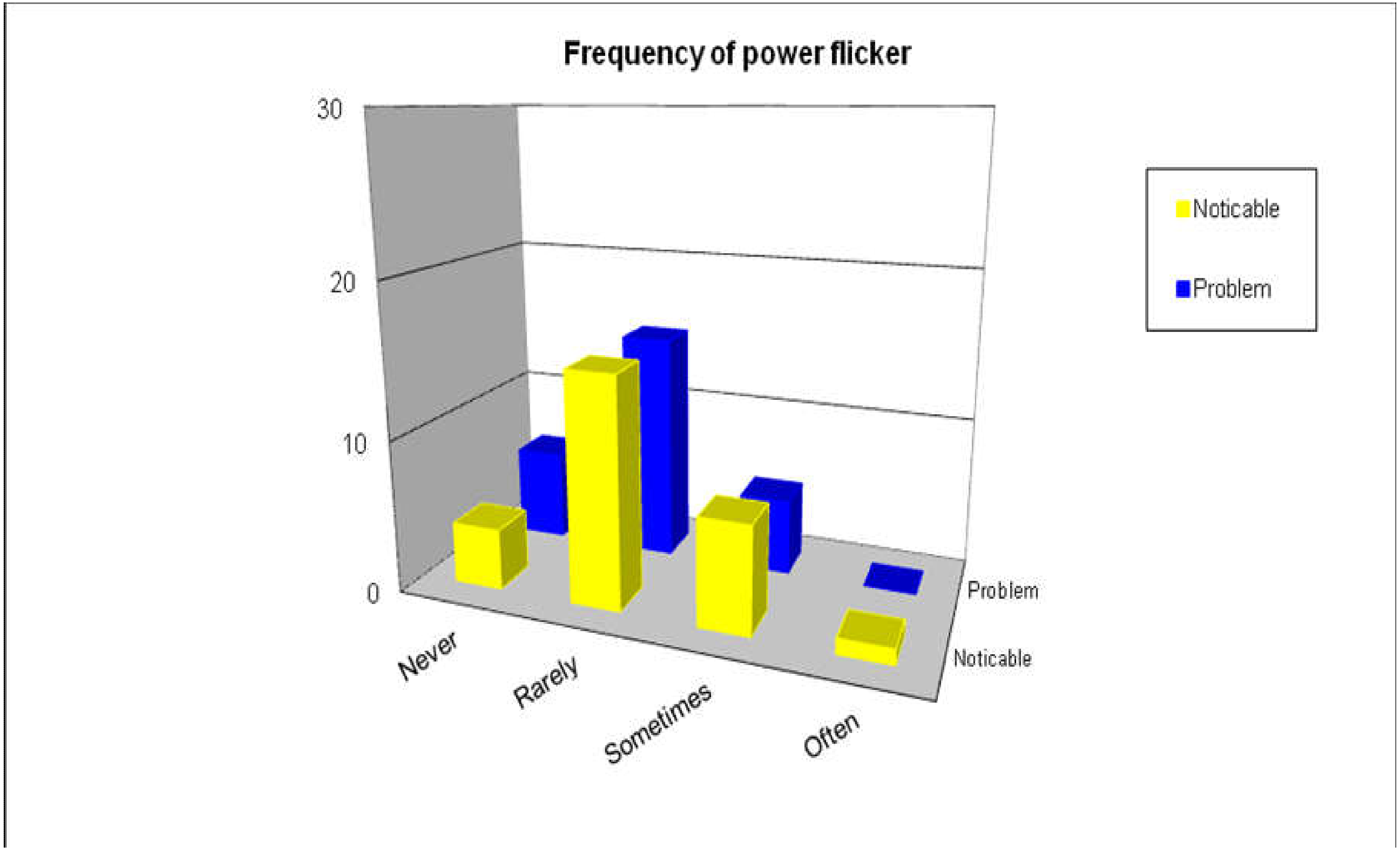
4. Is flicker an issue

This section asks consumers firstly how often flicker or surges are noticed at their premises, and then secondly how often is it actually a problem for their business.

Chart description – compares how often flicker or surge is noticed with how often it is actually a problem.

Interpretation – most consumers notice flicker Rarely with a definite skew to Sometimes. In terms of actually causing a problem, most consumers replied Rarely with a fairly even spread across never and sometimes. There was no obvious geographical clustering (inferred from phone numbers) of those consumers who replied that flicker was a problem Sometimes.

Notwithstanding the different sample space (the Top 30 to 100 consumers), it is noted from the 2008 consumer survey that the flicker seems to have become more of a problem with fewer consumers replying that flicker is Never a problem.


Frequency of power flicker
30
20
10
0
Noticable
Problem
Never
Rarely
Sometimes
Often
Problem
Noticable

5. Preferences for price, reliability and absence of flicker

This question fulfils the statutory requirement to consult with consumers on the issue of supply quality and price. For the purposes of this exercise, Network Tasman has interpreted supply quality as the combination of continuity and restoration which is referred to as reliability which is supported by the conclusions in chapter 2 of this report.

Comments from consumers in other surveys performed by Utility Consultants indicated that flicker and surge is of increasing concern, so it was decided to augment this question with a second question on preferences for price and absence of flicker or surge.

5.1 Price & reliability

Consumers were asked to select their preferred option from the following four options…

- Pay a bit less to receive a bit less reliability.
- Pay about the same to receive about the same reliability.
- Pay a bit more to receive a bit more reliability.
- Pay a lot more to receive a lot more reliability.

Chart description – records the preferences of consumers for each of the 4 price – reliability options above.

Interpretation – consumers have indicated a strong preference for paying about the same line charges to receive about the same reliability. The few consumers who did say additional reliability would be nice also said that it was simply unaffordable.

5.2 Price & absence of flicker

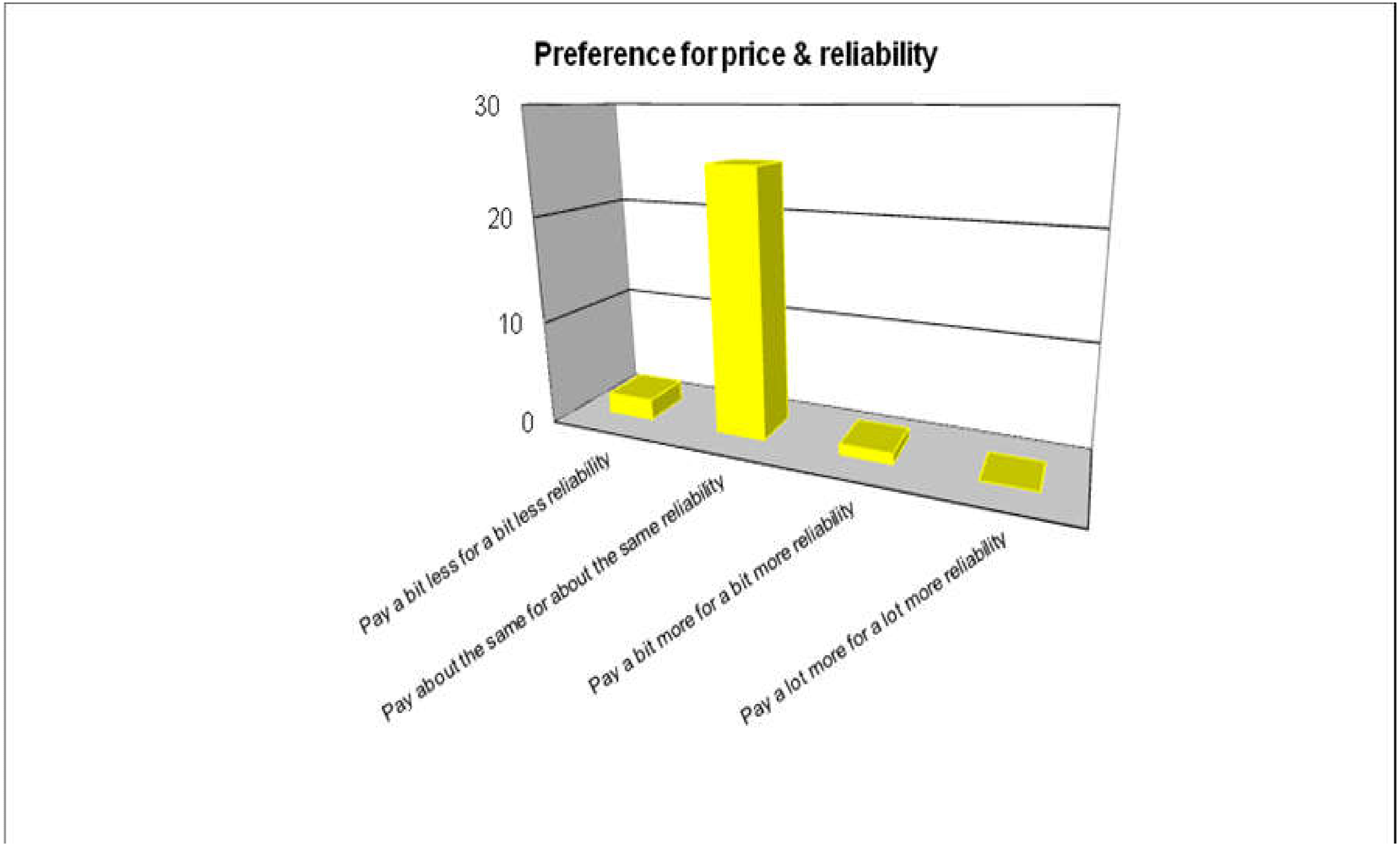
Consumers were asked to select their preferred option from the following four options…

- Pay a bit less to receive a bit more flicker or surge.
- Pay about the same to receive about the same level of flicker or surge.
- Pay a bit more to receive a bit less flicker or surge.
- Pay a lot more to receive a lot less flicker or surge.

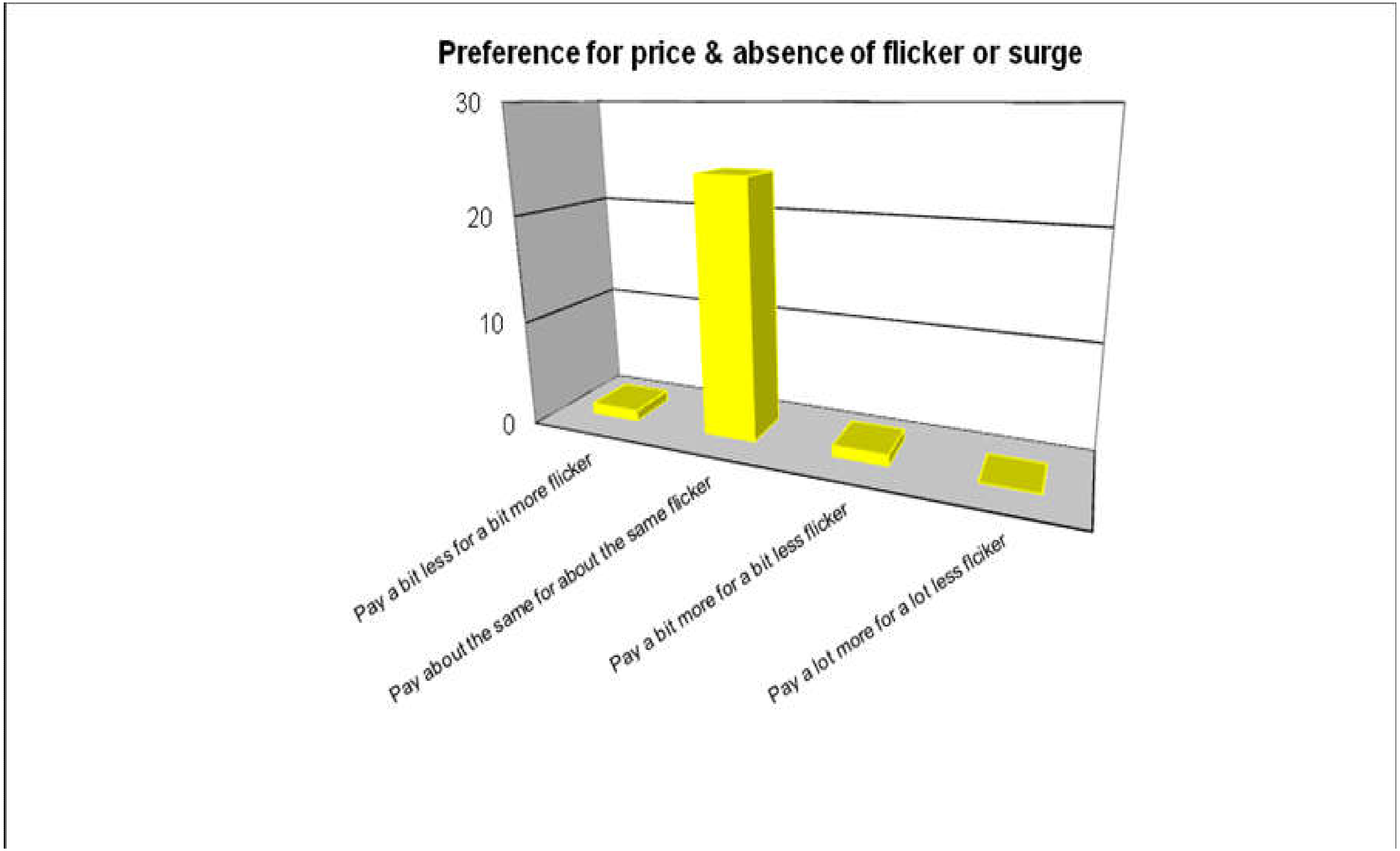
Chart description – records the preferences of consumers for each of the 4 price – flicker options above.

Interpretation – almost all consumers expressed a preference for paying about the same to receive about the same flicker and surge.

Notwithstanding the different sample space in the 2008 survey, it is noted that consumer preferences were split about 2/3 to 1/3 for paying about the same line charges to receive about the same level of flicker versus paying a bit more to receive a bit less flicker. Given that flicker seems to be more of a problem than it was in 2008, this suggests an unwillingness to pay more to have less flicker.



Preference for price & reliability
30
20
10
0
Pay a bit less for a bit less reliability
Pay about the same for about the same reliability
Pay a bit more for a bit more reliability
Pay a lot more for a lot more reliability


Preference for price & absence of flicker or surge
30
20
10
0
Pay a bit less for a bit more flicker
Pay about the same for about the same flicker
Pay a bit more for a bit less flicker
Pay a lot more for a lot less fliker

6. Comments, conclusions & recommendations

6.1 General comments from the survey

Some of the general comments that were expressed were as follows…

- Large consumers should be able to call a special phone number and get priority response. An even better approach could be for Network Tasman to text an estimate to each consumers' mobile phone.

- Large consumers need to know how long supply restoration will take … for example some fruit packing and storage companies have labor costs of $1,000 per hour at the height of the picking season, so they need to know if the power will be back on in 15 minutes or 4 hours.

- Consumers seem to accept that unplanned outages will occur – cars hitting poles was often quoted – but are less accepting of flicker and surge, in some cases because surges have caused expensive damage to computer equipment.

- Consumers appreciate Network Tasman proactively arranging planned shutdowns for off-seasons or weekends.

6.2 Conclusions

In the important areas of continuity and restoration, Network Tasman is performing Very Good with a slight skew towards Excellent. In the aspect of flicker and surge, there was a definite skew toward Good.

The aspect of flicker or surge continues to be of concern to consumers, possibly more so than in the 2008 survey (noting the different sample space) but with less willingness to pay more to have less flicker

6.3 Recommendations

It is recommended that Network Tasman consider the following initiatives…

- Having a dedicated phone line for say the Top 100 consumers that will be either manned during faults or provide a recorded message targeted to the in-bound phone number.

- Some sort of web-2-txt platform to advise the Top 100 consumers of likely restoration time.

- Some more work on how bad flicker actually is, and what can practically be done about it. This may include educating consumers about the causes of flicker and how large industrial consumers can cause flicker.

- Continue working with consumers to schedule planned outages during their off-peak periods.

A1. Details of consumers surveyed

Network Tasman requested that as many as possible of the following consumers be phoned...

Consumer	Response
Tasman District Council	Completed
Talley's Group	Completed
CHH – Eves Valley	Completed
Turners & Growers	Completed
Nelson City Council	Completed
South Pine (Nelson)	Completed
Waimea Sawmillers	Completed
Tahuna Beach Camp	Completed
Foodstuffs (SI)	Completed
Tinline Properties	Completed
Nelson Suburban Club	Completed
Alliance Group	Completed
Cold Storage Nelson	Completed
Sealord Group	Completed
Maclab NZ Ltd	Completed
Compass Fruit	Completed
Ranzau Horticulture	Completed
Tasman Coldstores	Completed
Fairfield Orchards	Completed
Fulton Hogan	Completed
Ryman Healthcare	Completed
Air Nelson	Completed
Waimea College	Completed
Moutere Timber	Completed
Mitre 10 Mega Nelson	Completed
Tasman Bay Food Group	Completed
Kevin McLean	Completed
Motueka Lumber	Completed
Community Leisure Management Group	Couldn't contact
Birdhirst	Incomplete phone number provided
Telecom	Not contacted – number doubtful
Countdown Stoke	No answer from operator
Goldpine Industries	Tried 3x to contact
Redwood Cellars	Tried 3x to contact
Metlife Oakwoods	Not contacted
Fonterra	Kept going to voice mail
NZ King Salmon Group	Kept going to voice mail
Restaurant Brands (KFC)	Declined to participate
Whareama Rest Home	Not contacted

This gives 28 completed surveys from a target list of 39, giving a success rate of 72% which compares well with other surveys perform

APPENDIX L

L. DISASTER RECOVERY AND RESPONSE PLAN

NETWORK TASMAN
DISASTER RESPONSE AND RECOVERY PLAN – JANUARY 2016
DMS Document No 432017

EXECUTIVE SUMMARY

This plan outlines Network Tasman's disaster response and recover 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. Recovery 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 3 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 would 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 recovery 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
Coordination of recovery activities.

2. INTRODUCTION

2.1 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.

2.2 Purpose of Plan

The purpose of this plan is to set out and document clearly established response and recovery 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.

3. EMERGENCY EVENTS

3.1 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 Atawhai 33kV feeder and other 11kV supplies
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.
Tsunamis	Unlikely	Medium	Highest recorded in Nelson area 1.5m and would affect low lying areas

3.2 Network Tasman Distribution Network

The following events are considered to be of a major and catastrophic nature:

Event	Likelihood	Impact	Comments
Multiple Zone Transformer Failure	Low	High	Refer to contingency plan
Zone 33 or 11kV Bus Failure	Low	High	Refer to contingency plan
Multiple underground 33 or 11kV cable failures	Low	High	Refer to contingency plan
Zone substation fire	Low	High	Refer to contingency plan
Sabotage	Low	High	Refer to contingency plan
Major oil spill	Low	Medium	Refer to contingency plan

3.3 Transpower Transmission Network

The following events are considered to be 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.
220Kv tower failures	Low	High	Emergency Generation Likely rolling blackouts Liaison with Transpower NZ Possible Civil Emergency
Substation bus failure- Stoke, Kikiwa, and Islington	Low	High	Emergency Generation Likely rolling blackouts Liaison with Transpower NZ Possible Civil Emergency

3.4 Generation

The following events are considered to be of a major and catastrophic nature:

Event	Likelihood	Impact	Comments
Low SI Generation	Medium	Medium	Possible prolonged hot water cutting and rolling blackouts
Maui Gas Failure	Low	High	Maximum HVDC transfer likely may limit available capacity in South Island
Total system collapse	Low	High	Civil Emergency

4. CIVIL DEFENCE

4.1 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.

4.2 National Plan

The National Civil Defence Emergency Management Plan 2006 details the principles, priorities, and responsibilities of regional, and local Emergency Management plans as well as generators, transmission, and distribution companies.

4.3 Network Tasman Obligations and Participation

Network Tasman is a Lifelines Utility with responsibilities under the Civil Defence Emergency Management Act (CDEM). These include:

Functioning to the fullest possible extent during and after an emergency.
Having plans for continuity.
Participating in CDEM Planning
Providing technical advice.

4.4 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 1 details essential services provided with line function services either directly or indirectly by Network Tasman. The extent of local or portable generation available for continuity of the service is detailed in DMS document 188459.

In addition to the essential services, there are consumers such as the port and airport, communication providers and radio stations that become critical to response and recovery efforts. Appendix 2 details critical customers provided with line function services either directly or indirectly by Network Tasman. The extent of local or portable generation available for continuity of the service is detailed in DMS document 188459.

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

4.5 Liaison

In the event of a declared Civil Defence Emergency or warning impacting on electricity supply, Network Tasman will provide a liaison officer at civil defence HQ. This person will act as the interface between Civil Defence and Network Tasman.

5. DISASTER MANAGEMENT AND CONTROL

5.1 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. Human resource required to carry out the action and communications plans may be drawn from available NTL staff members.

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.

The Emergency Management Team will comprise:

CEO (Team Leader)
Network Manager
Operations Manager
An appointed Communications Officer
Chairman
TransPower representative (as appropriate)
Retailer representatives (as appropriate)
Civil Defence or/and Local Body representatives (as appropriate)

Events for which the Emergency Management Team is to be formed include:

Civil Defence warnings or declared emergencies likely to result in a major loss of electricity supplies in the Nelson region for an extended period;
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;
Multiple generator failure likely to result in a loss of electricity supplies in the Nelson region for an extended period.

5.2 System Operator

The system operator controls fault restoration and electricity network disaster recovery operations in the field. System operators are fully trained in the operation of electricity networks and familiar with the layout and configuration of the Network Tasman system.

The system operator under all expected normal outage conditions controls supply restoration, and manages public safety under the direction of the Network Manager. Communication with the media is the responsibility of the CEO or Network Manager.

Network Tasman maintains 24 hour availability of system operator staff who remain within 20 minutes of the control centre at all times.

5.3 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 in section 5.4.

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 through the use of 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 system 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 markups. 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 100kW 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 weekly basis.

5.4 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. The minimum resources for the operation of the control room are:

1. One telephone operating on the telecom network or a cellphone.
2. One repeater based radio telephone channel and base set
3. One system mimic covering the bulk area to be managed, preferably mounted on a wall.
4. One PC running GIS viewer software with a copy of current Network Tasman GIS data files.

Using these items, an alternate control room can be setup within a relatively short timeframe in another building. Refer Appendix 15 for action plan.

Currently spares for item 3 above are held off site at the network manager's residence. These spares include a hardcopy and softcopy of the system mimic diagram complete with a list of the open switches and links on the HV network.

A spare radio repeater and base set is held by communications service provider Mt Campbell Communications Ltd.

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.

Possible alternate control centre locations are as follows:
Network Tasman Main Rd Hope building
TransPower Stoke
Nelson Electricity Haven Road
Suitable room(s) incorporating a large clear wall space at another public building or private residence.

6. COMMUNICATION

6.1 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 the event that the Control Centre is destroyed or inoperative, use would be made of handheld VHF radios (5 available) and/or arrangements made at an alternate Control Centre. Most Network Tasman and Delta vehicles are fitted with VHF radio telephones.

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.

6.2 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 timesCall 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.

6.3 Cellphone

A number of cellphones are available for use in the event that the telephone network is down and the cellphone system is still operational.

6.4 Satellite Telephone

A satellite telephone is available for use in the event that the telephone network is down and the cellphone system is heavily loaded. This is located in the Hope control room.

6.5 Key Communication Numbers

Key communication numbers are detailed in Appendix 3.

7. INFORMATION SYSTEMS

7.1 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.

7.2 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 affect 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 would carry out fault restoration procedures using the VHF radio telephone and the system mimic only. The SCADA system is not an essential pre-requisite of disaster recovery.

As covered in section 5.4, there are multiple copies of GIS and other critical files on laptops and the system is regularly backed up to CD's.

7.3 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.

Access to the settings of control and protection equipment is available through a spreadsheet file on the PC network - G:\ENGINEER\NETWORK PROTECTION\SETTINGS.XLS.

The HV faults database may also be used for historical reference and is available via the PC network - G:\ENGINEER\ACCESS\ACCESS DATABASES\OUTAGES.MDB

8. RESOURCES

8.1 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. In the event that 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.

8.2 Delta Utilities Ltd

Delta Utilities holds the contract for primary field response to all fault outages and can provide up to approximately 30 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 Netwok Tasman standards in the operation of all network equipment, and in the fault logging and reporting procedures. The faultmen are controlled by the Network Tasman System Operator.

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 will be 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.

8.3 Other Approved Contractors

There are a number of contractors in the greater Nelson area who have approvals to work on the distribution network. These contractors can be found in the AHC matrix in the company document management system (DMS) public folder "AHC Matrix Detail".

The largest alternative lines contractor is PowerTech Nelson. At the time of writing, Powertech has 12 approved staff that could be called upon in an emergency: 4 linesmen, 3 cable jointers, 3 electricians and 2 inspectors.

8.4 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 140826.

8.5 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. Appendix 8 details local electrical contractors.

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. Local civil contractors who may be able to respond are detailed in Appendix 9.

8.6 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.

The Network Emergency Stock list is included as Appendix 12.

Additional equipment and materials may be obtained from suppliers as detailed in Appendix 10.

8.7 Vehicles

Appendix 16 details the availability and location of vehicles.

9. PUBLIC AND MEDIA COMMUNICATION

9.1 Standard Procedure

Email communication to the local radio stations under standard operating procedures is available to the system operator via the control centre PC. In the event of failure of the PC network, a fax machine with separate telephone connection is also located in the control room, together with copies of proforma media facsimile forms for manual transmission of faxes to the radio stations and newspaper.

9.2 Civil Defence 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.

10. FINANCIAL

10.1 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.

10.2 Authority Limits

Under Civil Defence or major catastrophic events prompt decision making will be essential.

The following delegated authority limits will apply:

Chairman & CEO	$1,000,000

Deputy CEO	$500,000
Network Manager	$100,000
Operations Manager	$50,000

10.3 Declared Civil Defence Emergencies

It is unlikely that in the event of a declared civil defence emergency any funding will be available from central or local government directly for restoration of the distribution network. Refer to Section 26 of the National CDEM Plan.

10.4 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.

11. RECOVERY PLAN- NATURAL DISASTERS

11.1 Event, Expected Effects, and Recovery Plan

Event	Expected Effects	Recovery 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 substation failure	1. Network Field Survey of 33kV Lines Cables Zone Substations11kV 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.
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 Tahuna 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 Overhanging trees Susceptible Areas Murchison Kikiwa Takaka Hill Mt Campbell	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. 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 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.
Landslips	Loss of 33kV OH supply to Founders and Nelson Electricity Loss of Bulk Supply Loss of Hope 33kV Circuit Damage to Stoke Substation 33kV Bus Damage to Stoke Ripple Plant.	1. Restoration of 33kV via alternative routes where available. 2. Emergency reconstruction of OH line possibly on new route. 3. 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.

12. RECOVERY PLAN - MAJOR OR MULTIPLE NETWORK FAILURE

12.1 Standard Procedure

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 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 system operator is notified and he immediately makes his way to the control centre. Once in the control centre the system 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.

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
66kV and 33kV Subtransmission Feeders
Zone Substations
11kV Feeder Lines/Cables
Distribution Substations

12.2 Catastrophic Events

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, two ABB type SD3+SD oil 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 adjoing 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 this process of 3.1 above would be followed. Regular media reports would also be made.

Appendix 13 details the recovery plan procedure, equipment, material and resource requirements and procurement details.

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 of 3.1 above would be followed. Regular media reports would also be made.

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.

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.

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 cleanup operations.

Appendix 14 details the recovery plan procedure, equipment, material and resource requirements and procurement details.

13. RECOVERY 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

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:

Shutdown all controllable load (typically water heating via ripple control)
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"
Negotiate with large customers to shutdown or reduce load.
Run media campaign for conservation of electricity
System Operator to act in advisory capacity with Emergency Management Team

14. REFERENCES

14.1 Emergency Plans

Nelson Tasman Emergency Management Plan
The National Civil Defence Plan

14.2 Network Tasman

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

14.3 TransPower

14.4 Other

NZ Power Companies Directory

APPENDIX M

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, 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 (ie. who won't have supply restored until the necessary line repairs are completed)
2. Those outside the immediate fault area (ie. who can have power restored through co-ordinated 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 the 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 (6.6, 11, 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 (ICP's) in Total Area (recorded post event)
14. Customers (ICP's) 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

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**