



Asset Management Plan

A 10-year management plan for
Orion's electricity network from
1 April 2015 - 31 March 2025

Orion
yourNETWORK

Front cover: A team from Independent Line Services removing conductors prior to dismantling transmission towers in the Westmorland Heights subdivision. The four towers were removed and replaced with slimline steel mono poles and 66kV underground cables. This was at the request of the subdivision's developer.



Welcome to Orion's 10-year network asset management plan (AMP). Our AMP details how we plan to extend, maintain and reinforce our electricity distribution network over the next decade.

Our AMP is central to our day-to-day operations. It's a practical resource that captures the valuable insights and experience of our highly-skilled employees.

Our risk management strategies have proven themselves during and following the recent earthquakes and we will continue to invest prudently for the future of our community.

Key issues discussed in this AMP include:

- our approach to restore the resilience of our eastern Christchurch network
- our measures to mitigate and prevent major electricity outages
- our approach to ensuring public, contractor and employee safety
- our investment in new technology to better understand, control and monitor the condition and capability of our network.

We hope you find this AMP informative and we welcome your comments on it or any other aspect of our performance. Comments can be emailed to john.langham@oriongroup.co.nz.

Rob Jamieson

CHIEF EXECUTIVE OFFICER

Liability disclaimer

This Asset Management Plan (AMP) has been prepared and publicly disclosed in accordance with the Electricity Distribution Information Disclosure Determination 2012.

Some of the information and statements contained in this AMP are comprised of, or are based on, assumptions, estimates, forecasts, predictions and projections made by Orion New Zealand Limited (Orion). In addition, some of the information and statements are based on actions that Orion currently intends to take in the future. Circumstances will change, assumptions and estimates may prove to be wrong, events may not occur as forecasted, predicted or projected, and Orion may at a later date decide to take different actions to those it currently intends to take.

Except for any statutory liability which cannot be excluded, Orion will not be liable, whether in contract, tort (including negligence), equity or otherwise, to compensate or indemnify any person for any loss, injury or damage arising directly or indirectly from any person using, or relying on any content of, this AMP.

When considering the content of this AMP, persons should take appropriate expert advice in relation to their own circumstances and must rely solely on their own judgement and expert advice obtained.

Contents



1	Summary	9
2	Background and objectives	35
	2.1 Purpose of our AMP	37
	2.2 Business plans and goals	37
	2.3 Stakeholders	40
	2.4 Management responsibilities	42
	2.5 Assumptions	45
	2.6 Asset management drivers	48
	2.7 Asset management process	50
	2.8 Systems and information	54
	2.9 Development of systems and processes	60
3	Service levels	61
	3.1 Introduction to service levels	63
	3.2 Consumer consultation	64
	3.3 Service level measures	66
	3.4 Service level forecasts	71
4	Lifecycle asset management	75
	4.1 Network overview	77
	4.2 Network justification	82
	4.3 Asset management approach	84
	4.4 Substations	86
	4.5 - 4.8 Overhead lines 66,33,11,0.4kV	91
	4.9 - 4.12 Underground cables 66,33,11,0.4kV	105
	4.13 Communication cables	120
	4.14 Circuit breakers	122
	4.15 Switchgear - high and low voltage	129
	4.16 Power transformers and regulators	135
	4.17 Distribution transformers	139
	4.18 Generators	142
	4.19 Protection systems	144
	4.20 Communications	147
	4.21 Load management systems	150
	4.22 Distribution management systems	154
	4.23 Information systems - Corporate	157
	4.24 Information systems - Asset management	160
	4.25 Metering	163
	4.26 Network property	165
	4.27 Corporate property	169
	4.28 Vehicles	171

Contents (continued)



5	Network development	173
	5.1 Introduction	175
	5.2 Network architecture	176
	5.3 Planning criteria	178
	5.4 Energy, demand and growth	186
	5.5 Network gap analysis	205
	5.6 Network development proposals	208
6	Risk management	243
	6.1 Introduction	245
	6.2 Governance and operational business risks	248
	6.3 Safety	251
	6.4 Environmental management	252
	6.5 Network risk analysis	253
	6.6 Interdependence	254
	6.7 Natural disaster	255
	6.8 Asset failure	258
	6.9 Mitigation measures	259
7	Financial	265
	7.1 Financial forecasts	267
	7.2 Changes from our previous forecasts	275
8	Evaluation of performance	277
	8.1 Introduction	279
	8.2 Review of consumer service	279
	8.3 Efficiency	283
	8.4 Works	287
	8.5 Safety	289
	8.6 Environment	289
	8.7 Legislation	289
	8.8 Improvement initiatives	290
	8.9 Gap analysis	295
	Appendices	297
	A Disclosure schedules 11 - 13	299
	B Cross reference table	328
	C Glossary of terms	329
	D Certificate of compliance	332

List of figures



Figure	Title	Page	Figure	Title	Page
Summary			4-16b	Power transformers - age profile	136
2-2a	Interaction of plans and processes	12	4-17a	Distribution transformers - age profile	140
1-1b	Asset management structure	13	4-19a	Protection systems - health index profile	145
1-3a	Orion's network area	18	4-19b	Protection systems - age profile	145
5-4b	Overall maximum demand trends on our network	22	4-20a	Radio communication network repeater sites	147
5-4e	Rural summer maximum demand (MW)	23	4-21a	Ripple injection system control diagram	150
8-2a	Orion network SAIDI FY92 - Current Year	30	4-22a	SCADA remote terminal units (RTU) - age profile	155
Background and objectives			4-26a	Substation buildings (owned by Orion) - age profile	166
2-2a	Interaction of plans and processes	39	4-26b	Kiosks - age profile	167
2-4a	Asset management structure	42	Network development		
2-6a	Optimal cost versus quality principle	48	5-2	Transpower system in Orion's network area	176
2-7a	Asset management system	50	5-3	Peak demand capping	183
2-7b	Process to introduce new equipment	52	5-4a	Orion network annual energy trends	187
2-7c	Process for routine asset inspection and maintenance	52	5-4b	Overall maximum demand trends on the Orion network	188
2-7d	Process for performance measurement	53	5-4c	System load factor	189
2-7e	Process for network development	53	5-4d	Christchurch urban area network – load duration curves	190
2-8a	Management systems and information flows	55	5-4e	Central Plains Water scheme stages	191
Service levels			5-4f	Rural summer maximum demand (MW)	191
3-3a	Orion SAIDI – ten year history and 10 year forecast	66	5-4g	Rural winter maximum demand (MW) graph	192
3-3b	Orion SAIFI – ten year history and 10 year forecast	67	5-4h	Take-up of industrial land	193
3-3c	Unplanned interruptions - % restored in under 3hrs	67	5-4i	GXP's – Maximum demand versus firm capacity	196
Lifecycle asset management			5-4j	Urban 66/33 zone substations – max demand v capacity	197
4-1a	66,33kV and 11kV subtransmission – Urban area	78	5-4k	Urban 11kV zone substations – max demand v capacity	197
4-1b	66kV and 33kV subtransmission network – Rural area	79	5-4l	Zone subs – urban (CY-1 max demand as % of capacity)	199
4-1c	Network voltage level/asset relationships	80	5-4m	Rural zone substations – max demand v firm capacity	200
4-3a	Condition score conversion - CBRM to ComCom 12a	85	5-4n	Zone subs – rural (max demand as a % of firm capacity)	202
4-5a	66kV Subtransmission – 66kV overhead lines	92	5-4o	66kV, 33kV and 11kV zone substation utilisation	203
4-5b	66kV Overhead lines – asset failures/100km	93	5-4p	Zone substation 11kV feeder cable utilisation graph	204
4-5c	66kV Overhead poles and towers – age profile	93	5-4q	Distribution transformer utilisation graph	204
4-6a	33kV Subtransmission network	96	5-6a	Transpower core grid and spur assets in Orion's area	210
4-6b	33kV Overhead lines – asset failures/100km	97	5-6b	Urban subtrans 66kV – existing and proposed (Diagram)	214
4-6c	33kV Overhead line poles - age profile	97	5-6c	Urban subtrans 33kV – existing and proposed (Diagram)	214
4-7a	11kV Overhead lines – asset failures/100km	99	5-6d	Urban subtrans 66,33kV – existing and proposed (Map)	215
4-7b	11kV Overhead line poles – age profile	101	5-6e	Rural subtrans 66kV – existing and proposed (Diagram)	221
4-8a	400V Overhead line poles – age profile	103	5-6f	Rural subtrans 33kV – existing and proposed (Diagram)	221
4-9a	66kV Subtransmission – UG cables - Christchurch urban area	105	5-6g	Rural subtrans 66,33kV – existing and future (Map)	222
4-9b	66kV Underground cables – asset failures/100km	107	Risk management		
4-9c	66kV Underground cables – age profile	107	6-1a	The three components of risk	245
4-10a	33kV Subtransmission – Christchurch urban area	109	6-1b	Key risk responsibilities	245
4-10b	33kV Underground cables – asset failures/100km	110	6-1c	Orion risk acceptability matrix	246
4-10c	33kV Subtransmission – Lincoln and Springston area	110	6-1d	Orion risk acceptability chart	246
4-10d	33kV Underground cables – age profile	111	6-4a	Environmental management documentation	252
4-11a	11kV Underground cables – asset failures/100km	113	6-4b	Environmental management process	252
4-11b	11kV Underground cables – age profile	115	Evaluation of performance		
4-12a	400V Underground cables – age profile	118	8-2a	SAIDI - Orion network FY92-Current year	280
4-13a	Communication cables – age profile	120	8-2b	SAIFI - Orion network FY92-Current year	281
4-14a	Circuit breakers - health index profile	125	8-2c	Least reliable rural feeders CY-5 to CY (SAIDI)	281
4-14b	Circuit breakers 33 and 66kV - age profile	125	8-2d	Cause of interruptions CY-15 to CY	282
4-14c	Circuit breakers 11kV - age profile	125	8-3a	Capex per annum per MWh supplied to consumers	283
4-15a	Switchgear 11kV - health index profile	132	8-3b	Opex per annum per MWh supplied to consumers	283
4-15b	Ringmain units 11kV - age profile	132	8-3c	Opex per annum per ICP	283
4-15c	Line ABI 11kV and 33kV - age profile	132	8-9a	Orion's maturity level scores (AMMAT)	296
4-16a	Power transformers - health index profile	136			

List of tables



Table	Title	Page	Table	Title	Page
Summary			5-5b	Orion security gaps	207
3-4a	Service descriptions, forecasts and measures for CY+1	17	5-6a	Spur assets, indicative cost to purchase	211
1-3a	Orion's electricity network asset quantities	18	5-6b	Affected Transpower new investment agreements	211
1-6a	Summary of forecast network expenditure	27	5-6c	Major GXP projects	211
8-2a	Orion network actual reliability results	29	5-6d	Major urban projects	213
8-2b	Forecasts and results for CY – Network power quality	31	5-6e	Major rural projects	220
8-3a,b,c	Efficiency results for CY and 5 year average	31	5-6f	11kV urban reinforcement projects	232
8-5a	Personal safety – performance results	32	5-6g	11kV rural reinforcement projects	237
Service levels			5-6h	DSM value for network development alternatives	241
3-4a	Service descriptions, forecasts and measures for CY	71	Risk management		
3-4b	Service descriptions, forecasts and measures for future	72	6-5a	Primary risk for major assets	253
Lifecycle asset management			6-5b	Possible cause of contaminant discharge and risks	253
4-1a	Orion's electricity network asset quantities	77	6-6a	Interdependence of lifelines (1 week after earthquake)	254
4-4a	Zone substation equipment schedule	88	6-6b	GXP – Liquefaction potential and related damage	255
4-4b	Distribution substation types	90	6-7a	Orion – Liquefaction potential and related damage	256
4-5a	66kV tower line circuits	91	Financial		
4-6a	Standard 33kV conductors	96	7-1.1	Opex - network	267
4-7a	Standard 11kV conductors	99	7-1.2	Opex - non network	268
4-8a	Standard 400V conductors	102	7-1.3	Capital contributions revenue	268
4-9a	66kV cable circuits	106	7-1.4	Capex - summary	268
4-10a	33kV cable circuit listing	111	7-1.5	Capex - non network	268
4-11a	11kV feeder cable circuit listing	114	7-1.6	Capex - major GXP projects	269
4-14a	Circuit breaker quantities	123	7-1.7	Capex - urban reinforcement	269
4-14b	Circuit breaker ratings	124	7-1.8	Capex - rural and total reinforcement	270
4-14c	Line circuit breaker ratings	124	7-1.9	Capex - replacement	271
4-14d	Circuit breaker average age (years)	124	7-1.10	Capex—urban major projects	272
4-14e	Switchgear inspection and maintenance schedule	126	7-1.11	Capex—rural major projects	273
4-15a	Switchgear quantities	130	7-1.12	Capex - Transpower spur asset purchase values	274
4-16a	Power transformer quantities	135	7-1.13	Transpower new investment agreement buyouts	274
4-16b	Regulator quantities	135	7-1.14	Transpower new investment agreement charges	275
4-17a	Distribution transformer quantities	139	7-1.15	Transpower connection and interconnection charges	275
4-18a	Generator listing	142	Evaluation of performance		
4-19a	Relay types in Orion's network	144	8-2a	Orion network reliability for CY and 5 year average	279
4-26a	Distribution kiosk quantities	165	8-2b	Service forecasts and results for network power quality	282
4-28a	Vehicle quantities	171	8-3a	Capacity utilisation results for CY and 5 year average	284
Network development			8-3b	Load factor results for CY and 5 year average	284
5-3a	Distribution network supply security standard	179	8-3c	Loss results for Current Year and 5 year average	284
5-3b	Standard network capacities	181	8-3d	Network loss contributors	284
5-4a	Fletcher EQC response to restoring heating	194	8-3e	Transformer loss values	285
5-4b	GXP substations – load forecasts (MVA)	196	8-3f	Underground cable versus overhead line comparison	285
5-4c	Urban 66 and 33kV zone sub – load forecasts (MVA)	198	8-4a	Project completion status	288
5-4d	Urban 11kV zone substations – load forecasts (MVA)	198	8-5a	Personal safety – performance results	289
5-4e	Rural 66 and 33kV zone sub – load forecasts (MVA)	201	8-6a	Environmental responsibility – performance results	289
5-5a	Transpower GXP security gaps	206	8-8b	Installation of GFN – reliability savings	292

Summary



1

1.1	Background and objectives	11
1.1.1	Purpose of our AMP	11
1.1.2	Network resilience	11
1.1.3	Key themes of this year's AMP	11
1.1.4	Business plans and goals	12
1.1.5	Stakeholders	12
1.1.6	Management responsibilities	13
1.1.7	Assumptions	13
1.1.8	Asset management drivers	14
1.1.9	Asset management process	14
1.1.10	Systems and information	15
1.1.11	Development of systems and processes	15
1.2	Service levels	16
1.2.1	Introduction	16
1.2.2	Consumer consultation	16
1.2.3	Service level measures	16
1.2.4	Service level forecasts	17
1.3	Lifecycle asset management	18
1.3.1	Network overview	18
1.3.2	Network justification	19
1.3.3	Asset management approach	19
1.3.4	Substations	19
1.4	Network development	20
1.4.1	Introduction	20
1.4.2	Network architecture	20
1.4.3	Planning criteria	20
1.4.4	Energy, demand and growth	21
1.4.5	Network gap analysis	23
1.4.6	Network development proposals	23
1.5	Risk management	25
1.5.1	Introduction	25
1.5.2	Governance and operational business risks	25
1.5.3	Safety	25
1.5.4	Environmental management	25
1.5.5	Impact of natural events	25
1.5.6	Asset failure	26
1.5.7	Insurance	26
	Continued overleaf	



1

1.6	Financial forecasts	27
1.6.1	Network Opex and Capex	27
1.6.2	Changes from previous forecasts	27
1.7	Evaluation of performance	29
1.7.1	Introduction	29
1.7.2	Consumer service	29
1.7.3	Efficiency	31
1.7.4	Works expenditure in FY14	31
1.7.5	Safety	32
1.7.6	Environment	32
1.7.7	Improvement initiatives	32
1.7.8	Gap analysis	33

List of figures and tables in this section

Figure	Title	Page	Table	Title	Page
2-2a	Interaction of plans and processes	12	3-4a	Service descriptions, forecasts/measures for CY+1	17
1-1b	Asset management structure	13	1-3a	Orion's electricity network asset quantities	18
1-3a	Orion's network area	18	1-6a	Summary of forecast network expenditure	27
5-4b	Overall maximum demand trends	22	8-2a	Orion network reliability results	29
5-4e	Rural summer maximum demand (MW)	23	8-2b	Service level results for FY14 – Network power quality	31
8-2a	Orion network SAIDI FY92 - CY	30	8-3abc	Efficiency results for CY and 5 year average	31
			8-5a	Personal safety – performance results	32

1.1 Background and objectives

1.1.1 Purpose of our AMP

Our AMP documents the asset management practices we use as part of an optimised lifecycle management strategy for our electricity assets.

The overall objective of our AMP is:

To consistently deliver a safe, secure and cost-effective supply of electricity to our customers.

This AMP looks ahead for the 10 years from 1 April 2015. The main focus is on the first three to five years – for this period, most of our significant planned projects have been identified. Beyond this period, analysis is more indicative. Based on long term trends and, depending on consumer demand growth, it is likely that new projects will arise and some planned projects could be eliminated in the latter half of the 10 year period. We update and publish our AMP just prior to the start of each financial year (April).

We created our first AMP in 1994 and we have since developed our plan to comprehensively meet the requirements of the Electricity Distribution Information Disclosure Determination 2012. These requirements include:

- a summary of the plan
- background and objectives
- forecast service levels
- details of assets covered, lifecycle management plans
- load forecasts, development and maintenance plans
- risk management, including policies, assessment and mitigation
- performance measurement, evaluation and improvement initiatives.

As the format of our AMP does not completely follow the order as suggested in the regulatory disclosure determination, a cross reference table to the relevant sections of our AMP is shown in Appendix B.

Our AMP goes beyond regulatory requirements. We use it on a day-to-day basis and we aim to demonstrate responsible stewardship of our network assets — in the long term interests of our consumers, shareholders, electricity retailers, government agencies, contractors, electricity end users, financial institutions and the general public.

In this AMP, we aim to optimise the lifecycle costs for each network asset group (including creation, operation, maintenance, renewal and disposal) to meet agreed service levels and future demand. Each year we aim to improve our AMP to take advantage of new information and changing technology. These innovations help us to maintain our ranking as one of the most resilient, reliable and efficient electricity networks in the country.

Our AMP does not cover how we derive and apply our network pricing. This information is available on our website; oriongroup.co.nz.

1.1.2 Network resilience

There is a public expectation that electrical utility networks will be reliable and cost effective. There is a high dependency on electricity for information systems, communications and signal control systems (traffic, rail etc.).

In Canterbury, and in particular Christchurch, there is also a high dependency upon the electrical network for home heating. Traditionally Christchurch residents could rely on open fires to heat their homes but open fires are now banned and restrictions imposed on the use of log burners as part of ECAN's clean air initiative. Unlike some centres, Christchurch doesn't have reticulated natural gas for home heating.

Canterbury can experience cold winters. Our winter load demand is larger than our summer demand and is primarily due to electric home heating.

Cold snaps coupled with earthquake damaged homes and the loss of fires means there is a higher dependency upon the electrical network for people's health. Therefore it is important that our network is resilient.

1.1.3 Key themes of this year's AMP

Our business as usual themes are:

- further refinement of the lifecycle management of our assets
- refinement and timing of works to develop our network in response to load growth and redistribution of population.

The key themes of this year's plan in addition to our business as usual practices are:

- continue to restore network resilience
- integration of spur assets and subdivision purchases
- meet expectations of the rebuild.

1.1.4 Business plans and goals

Our activities are guided by what we call our ‘mission’, that consists of a purpose statement, a vision statement for the future state of the company and a set of company values as detailed below. Necessary competencies to achieve this mission include; asset management, stakeholder communication, risk management and network pricing. This AMP is consistent with, and is an important part of, our mission.

Our AMP is a key component of our planning process that combines management, financial and technical practices to ensure that the level of service required by consumers is provided by us at the lowest long term cost.

The major outcome we seek to achieve from our AMP is a 10 year capital investment and maintenance forecast characterised by:

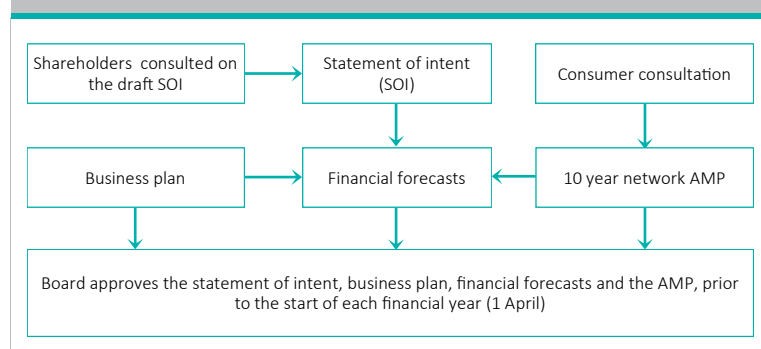
- steady investment in the urban network to meet regional growth and recovery from the 2010/2011 Canterbury earthquakes
- continued investment in rural areas to meet strong residential growth in the rural towns and dairy farming loads between the Selwyn and Rakaia rivers
- a steady overall increase in capital expenditure in the longer term to replace assets installed in the high electricity growth years of the 1960s. The forecast cost of this replacement may change if we adopt future monitoring and risk assessment strategies across all asset classes
- relatively constant investment in new connections and extensions to the network. This forecast is based on overall modest growth with pockets of higher growth in specific areas
- the additional cost of complying with regulations
- material and contractor cost increases that affect our construction costs.

Other plans that make up our annual business planning process are:

- statement of intent
- business plan
- financial forecasts.

The following figure shows how our business plans and processes interact with each other.

Figure 2-2a Interaction of plans and processes



1.1.5 Stakeholders

Our key stakeholders are:

- shareholders – Christchurch City Council Holdings Limited and Selwyn District Council
- retailers, contracted customers and consumers
- employees
- Transpower
- government agencies
- contractors and suppliers
- financial institutions.

We have identified our key stakeholder interests through various forums and have instigated practices to accommodate these interests. If a conflict between stakeholder interests is identified then we will adopt an appropriate conflict resolution process to suit the issue and stakeholder concerns.

Stakeholder/consumer research is covered further in section 3 – Service levels.

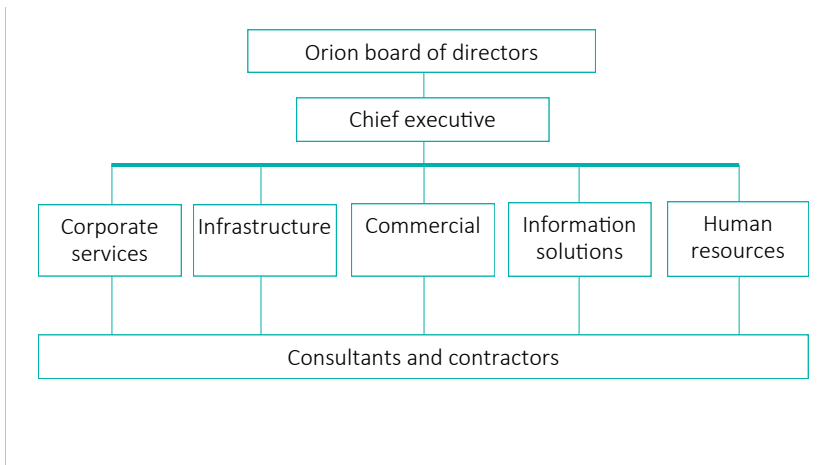
1.1.6 Management responsibilities

We utilise a competitive contracting model – contractors design, construct, connect and maintain our distribution network. Consultants and independent experts assist in areas where we do not maintain specific expertise. Our network is managed and operated from our Christchurch office at 565 Wairakei Rd.

Orion's directors are appointed by the shareholders to govern our activities. The board of directors is the overall and final body responsible for all decision-making within the company.

Our governance/management structure is as follows:

Figure 1-1b Asset management structure



1.1.7 Assumptions

Significant assumptions

This AMP assumes that we will continue to restore the resilience and reliability of our network following the Canterbury earthquakes. We also assume no major changes in the regulatory framework, asset base through merger, changes of ownership and/or requirements of stakeholders. We forecast increased levels of expenditure due to the region's post-earthquake rebuild over the next few years and the acquisition of local Transpower spur assets.

Sources of uncertainty

Potential sources of uncertainty in our key assumptions include changes in:

- regulations
- our ownership
- wider region's post-earthquake rebuild
- consumer demand and growth.

Cost inflation

The key assumptions for our cost forecasts are largely discussed in section 7.1 where all dollars are in FY16 terms with no allowance for CPI adjustments, changes in foreign exchanges rates, or local rates. Refer to the appendices for the expenditure schedules in nominal (inflation-adjusted) terms.

Factors that may lead to material differences include:

- regulatory requirements may change
- our ownership may change
- changes in demand or generation and the level of network resilience/reliability
- major equipment failure and/or a major natural disaster
- input costs and rates influencing project economics
- changes to industry standards
- requirements for us to facilitate the rollout of a third party communications overhead network.

1.1.8 Asset management drivers

Investment principles

When we extend, replace, maintain and operate our network, we consider the balance between cost and the quality of supply. The optimum point of investment is achieved when the marginal cost of further expenditure would exceed the marginal additional value of benefits to our consumers. We seek to achieve this optimal point by applying economic analysis during the development and review of our asset management standards, specifications and procedures. We also encourage optimal outcomes by submitting our views during the consultation phase of national rules and regulations.

Business drivers

Our top priority is the efficient and effective management of our electricity network. We aim to provide customers with a high level of service, a reliable and secure supply and efficient prices. We also aim to provide our shareholders with an attractive risk adjusted return on their investment.

The business drivers which define the need, priority and scope for improved asset management practices at Orion can be summarised as safety, customer service, environmental responsibility, economic efficiency and legislation.

1.1.9 Asset management process

We undertake lifecycle management and asset maintenance planning using whole of life cost analysis, reliability centered maintenance (RCM), condition-based maintenance (CBM) and risk management techniques. The techniques support our performance and reliability forecasts. Our high level forecasts are discussed in section 3.

In FY11 we engaged EA Technology Limited (see Glossary) to develop condition based risk management (CBRM) models for the majority of our network assets. These models use the results from our asset condition monitoring programmes and will underpin the economic justification for our expenditure forecasts. We are currently integrating this practice into our business processes and have used the CBRM models to develop a number of our network asset lifecycle programmes.

Planning priorities

Recent changes in regulations and industry codes of practice have highlighted the need to mitigate safety risks for the public, employees and contractors. Therefore we continue to:

- remove at-risk equipment
- increase security around substations and equipment
- tighten controls on equipment access.

In recent years, we have focused on meeting the growth needs of the community while ensuring appropriate reliability and security. Network security is always compromised during times when capital or maintenance works are carried out.

To mitigate risk associated with reduced security during these periods of change we:

- endeavour to plan work methods and contingencies to minimise any impact on the network
- use programmes that allow for contingency events
- programme works in a manner that provides consistent work for the skilled resources available
- are proactive in the development and retention of skilled resources for the future.

Construction standards and working practices

In order to manage the safety, cost, efficiency and quality aspects of our network we seek to standardise design and work practices. We have a set of design standards and drawings that are available to approved designers/contractors. We normally only accept designs that conform to these standards.

A comprehensive set of specifications and procedures for performing different activities on our network has also been developed. These specifications are intended for authorised contractors who construct and maintain our network.

We also seek to standardise the components of our network. To this end, a set of specifications detailing accepted performance criteria for significant equipment has been developed.

To ensure the wide variety of equipment on our network is operated safely with minimum impact on our consumers, we have developed an operating instruction for each different type of equipment on our network. We add to these when any new equipment is introduced. See figure 2-7b – Process to introduce new equipment.

We process these 'controlled documents' using our in-house document control process. A restricted-access area on our website is used to make documents and drawings accessible to approved contractors and designers.

Introduction of new equipment types

New equipment is reviewed to carefully establish any benefits that it may provide. Introduction is carried out to a plan to ensure that the equipment meets our technical requirements and provides cost benefits. It must be able to be maintained and operated to provide safe, cost effective utilisation to support our supply security requirements.

1.1.10 Systems and information

Our management systems are used to document the existing asset components of our network and provide access to the data for all aspects of developing, maintaining and operating our business. The various systems and information flows between them are shown in figure 2-8a. Our main applications are:

- | | |
|---|-----------------------------------|
| 1. Microsoft office network | 13. Interruption statistics |
| 2. Geographic information (GIS) | 14. Load management |
| 3. Asset register (EMS WASP) | 15. Incident management |
| 4. Works management system | 16. Valuation model |
| 5. Connections-related service requests | 17. Pricing model |
| 6. Connections register | 18. Orion's Mco billing system |
| 7. Financial management information system (FMIS) | 19. Network asset loading history |
| 8. Network monitoring system (SCADA) | 20. Power system modelling |
| 9. Network management system (NMS) | 21. Cable databases |
| 10. Outage management system (OMS) | 22. Transformer oil analysis |
| 11. Outage reporting | 23. Document control |
| 12. Livening and demolition management | 24. Orion website |

Asset data

The majority of our primary asset information is held in our asset register, GIS system and cable databases. We hold information about our network equipment - from GXP connections down to individual low voltage poles - with a high level of accuracy. The data has improved over time due to various inspections and projects since we introduced our GIS system and asset register in the early 1990s.

Details of current data, compliance inspections and maintenance regimes for each asset group are shown in section 4 – Lifecycle asset management – (relevant asset) – Standards and asset data.

1.1.11 Development of systems and processes

Network management system

We completed a major upgrade of our network management system (SCADA, NMS and OMS) in FY14. We have also implemented a companion Historian and migrated much of our historic network asset loading information into it. Once fully implemented, Historian will provide a continuous historic record of trends for a wide variety of monitored network items.

Document management system

Microsoft Sharepoint has been implemented and is being used across the business. The initial focus is to improve the management of "Office" documents and scanned images, but over time it will become used for a wide variety of information sharing features as well as providing framework for a replacement Intranet.

Condition based risk management model

In FY11 we engaged EA Technology Ltd to develop condition based risk management (CBRM) models for the majority of our network assets. We are currently integrating the use of these models into our business processes to develop our asset lifecycle programmes. The models have been used this year in the development of the replacement plans for our high voltage circuit breakers, high voltage and low voltage switchgear and protection systems. Over the next few years we intend to streamline the processes for updating our condition information and to underpin the replacement expenditure for our other network assets by using the CBRM models.

1.2 Service levels

1.2.1 Introduction

This section of our plan outlines our performance forecasts. It deals with consumer-related service requirements and other requirements relating to our asset management drivers as defined in section 2.6. Those drivers are:

- customer service
- safety
- environmental responsibility
- investment principles
- economic efficiency
- legislation.

We aim to meet the expectations of our consumers and other stakeholders. This is consistent with our 'mission' and statement of intent (SOI). Our SOI contains specific service level forecasts for reliability (SAIDI, SAIFI) and other aspects of our business, some of which are outside the scope of this AMP.

Our service level forecasts are based on a balance of:

- consumer and stakeholder consultation
- safety considerations
- regulatory requirements
- international best practice
- past practice.

1.2.2 Consumer consultation

Consumers are our key stakeholders. We recognise that their individual expectations will differ and we endeavour to ensure that, as far as practicable, all are satisfied with the level of service we provide in the long term and that no one party is unfairly advantaged or disadvantaged.

Consultation with our consumers has shown that they expect a reliable and secure supply of electricity. Since the earthquakes, our consultation has shown that customers want a return to near pre-earthquake levels of resilience and reliability.

We have undertaken the following methods of consultation:

- involve consumers in setting our security of supply standard
- undertake consumer surveys
- engage with consumers via retailers
- obtain direct consumer feedback
- consult consumers on selected major projects.

In setting our service level forecasts we believe we have achieved an appropriate balance between legislative, regulatory and stakeholder requirements and consumer expectations.

1.2.3 Service level measures

All of our consultation methods show that, almost without exception, a reliable supply of electricity at a reasonable price is our consumers' greatest requirement of us. We measure our performance against this primary consumer requirement in a number of ways as shown in table 3-4a on the following page.

Our primary network reliability measures are applied as required by the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012. These measures are:

- **SAIDI**, system average interruption duration index, measures the average number of minutes per annum that a consumer is without electricity.
- **SAIFI** system average interruption frequency index, measures the average number of times per annum that a consumer is without electricity.

Extreme environmental events can have a major impact on the reliability of an electricity network. To moderate this impact, the current regulatory regime calculates a daily boundary value to cap the number of consumer-minutes lost in the case of extreme events. Our annual network reliability limits and daily boundary values are currently set by the Commerce Commission under the Customised Price-quality Path (CPP) regime determined for Orion after the earthquakes of FY11. These limits will run from FY15 through to FY19 when they will be evaluated. Orion's SAIDI and SAIFI forecasts are set in relation to the same calculation methodology and daily boundary values.

Other service measures such as efficiency, safety, environmental and legislative compliance reflect a range of performance measures that we monitor. Our performance in these areas often provides advance notice about where Orion's performance is heading prior to any change being noticed in our primary reliability results.

For some of these other service measures we have not set a specific value. In those cases we explain our position as to why we believe doing so would be counter productive.

1.2.4 Service level forecasts

There is still much work ahead of us to restore network resilience and reliability to near pre-earthquake levels. Significant infrastructure rebuilding activity in the city will also likely see an increase in damage and disturbance of our network assets.

We expect to restore our network reliability to near pre-earthquake levels by FY19.

All our forecasts for FY16 are shown in the following table.

Table 3-4a Service descriptions, forecasts and measures for (FY16)				
Service class	Service measure	FY16 forecast	Performance measure	Measurement procedure
Network reliability	SAIDI - system average interruption duration index	< 94	Orion network- average minutes lost per consumer per annum for all interruptions (planned and unplanned). Orion network only.	Tracking of all interruptions to our network (process audited annually).
	SAIFI - system average interruption frequency index	< 1.2	Orion network- average number of times a consumer's supply is interrupted per annum for all interruptions (planned and unplanned). Orion network only,	All 400V faults and HV faults <1min in duration are excluded. Capped to daily boundary values for any extreme event days as per CPP requirements (see section 3.3.1).
Network restoration	Unplanned interruptions restored within 3 hours	> 60%	% of total number of unplanned interruptions where the last consumer is restored in three hours or less. Orion network only, See section 3.3.2.	
Network capacity	Delivering reasonable levels of network security	To meet our security standard	Any gaps identified against our security standard. See section 5.5	
Power quality	Steady state level of voltage	< 70	Voltage complaints (proven). See section 3.3.4	Tracking of all enquiries
	Level of harmonics or distortion	< 4	Harmonics (wave form) complaints (proven). See section 3.3.4	Checks performed using an harmonic analyser
Safety	Safety of employees and contractors	Zero	Number of lost time accidents. See section 3.3.5.	Accident/incident reports
	Safety of public	Zero	Number of accidents involving members of the public (excluding car v pole accidents) See section 3.3.5.	Accident/incident reports
Environment	SF ₆ gas lost	< 1% loss	Gas lost expressed as a % of the total contained in our network equipment. See section 3.3.7.	Set out in Orion Procedure NW70.10.01
	Oil spilt	Zero spills	Oil spills not contained. See section 3.3.7.	Set out in Orion Procedure NW70.10.02
Economic efficiency	Capacity utilisation ratio	No forecast	Maximum demand on network divided by distribution transformer capacity.	See section 3.3.8.
	Load factor	No forecast	Average load on network divided by the maximum load experienced in a given year.	
	Losses	No forecast	The % of energy lost between the points of injection (mainly Transpower GXPs) and the point of off-take (consumer connections).	

1.3 Lifecycle asset management

1.3.1 Network overview

Asset description

We own and operate the electricity distribution network in central Canterbury. Our network is both rural and urban and covers 8,000 square kilometres across central Canterbury between the Waimakariri and Rakaia rivers and from the Canterbury coast to Arthur's Pass. Consumer densities range from five consumers per km to 26.

Figure 1-3a Orion's network area

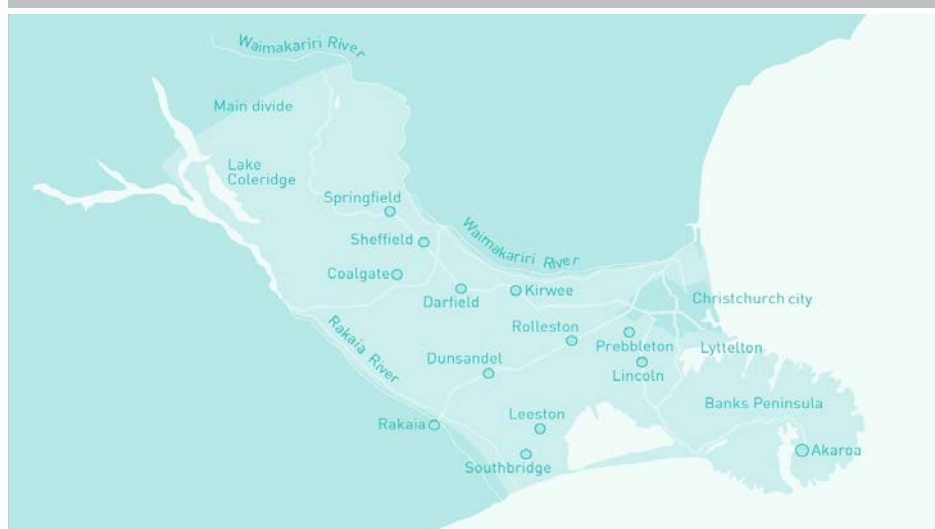


Table 1-3a Orion's electricity network asset quantities

Category	Description	31 March 2014
Subtransmission lines/cables (km)	66kV and 33kV	610
Distribution lines/cables (km)	11kV	5,627
	400V	4,618
Zone substations	66kV	24
	33kV	20
	11kV	9
Distribution substations	Buildings	471
	Ground mounted	4,339
	Pole mounted	6,300
Consumer connections		188,977

Urban network description

Our urban network consists of both a 66kV and a 33kV subtransmission system. Our urban 66kV system supplies zone substations in and around Christchurch city and is supplied from Transpower's 66kV GXP's at Bromley and Islington. Our urban 33kV system supplies another six zone substations in the western part of Christchurch and is supplied from Transpower's Islington 33kV GXP. A further nine zone substations in the urban area take supply at 11kV from our 66kV zone substations.

The urban zone substations supply a network of 11kV cables connected to 219 network substations. These network substations in turn supply over 4,000 distribution substations on a secondary 11kV cable network. The low voltage (400V) system to which most of our consumers are connected is supplied from these distribution substations. The reasons for the structure of our network are further discussed in section 4.2.

Rural network description

Our rural network also consists of both a 66kV and a 33kV subtransmission system (see figure 4-1b) that supplies zone substations from Transpower's Hororata, Islington and Kimberley GXP's.

The rural 11kV distribution system primarily consists of 11kV overhead radial feeders from our rural zone substations and three small Transpower GXP's (see figure 5-2) at Coleridge, Castle Hill and Arthur's Pass.

Canterbury earthquakes

While the earthquakes and large aftershocks of 2011/12 caused extensive damage throughout the region, our investment in a programme to increase the resiliency of our infrastructure was a major factor in limiting the amount of damage to our network. As the rebuild of the region gets underway we will continue to use these principles and lessons learnt to bring the network back to pre-earthquake levels of resilience and reliability. Our key priorities are:

- work with the community to meet their needs as they rebuild
- integrate and react to the changing requirements of the network
- restore the resilience and reliability of our network by around 2019.

Large consumers

The Canterbury area and business sectors are largely service and/or agricultural based. This is reflected in the mix of approximately 325 major business customers connected to our network with loads ranging from 0.3MW to 11MW. The largest single load in this category is less than 2% of our total maximum demand.

Currently we have 17 consumers that have an anytime maximum demand of greater than 2MVA. Each of these major consumers is charged on a 'major customer connection' delivery charge basis.

Generally our operating regimes and asset management practices do not specifically provide enhanced levels of service for these consumers.

1.3.2 Network justification

The first electricity distribution systems in Christchurch were a mix of underground cable and overhead lines originating from the Government's Addington substation. Additional 11kV grid connection points evolved at Bromley and Papanui, providing quite large capacity at high fault levels. A comprehensive underground cable network based on electrical districts then grew from these three main grid connection points. This network served the city until the rapid development period of the 1960s, when demand grew by 7% per year. Zone substations (66/11kV) were then built to meet the increased demand. Those substations are the backbone of the present urban system.

The earliest rural electricity distribution networks in Orion's area were based on 3.3kV and 6.6kV systems supplied from connection points off the Coleridge transmission lines, mainly at Hororata and Addington. These systems were simple radial lines, subsequently up-rated to 11kV to meet increasing demand. Load growth required the introduction of 33kV subtransmission in the mid 1960s. The 33kV was used to supply an increasing number of 'zone' substations, usually consisting of a 7.5MVA transformer with 11kV radial feeders interconnected to adjacent substations.

1.3.3 Asset management approach

Generally assets are not replaced on age alone, but are kept in service until their continued maintenance is uneconomic or until they pose a safety, environmental or reliability risk. Reliability performance is measured and used to identify areas where further maintenance is needed to improve our delivery service or where maintenance may be reduced without affecting service levels.

We develop our maintenance and replacement programmes and use a competitive tender process to contract out all works.

1.3.4 Substations

A 'substation' encompasses buildings, switchgear, transformers, protection and control equipment used for the transformation and distribution of electricity. Our network structure has three identified levels of substations – zone, network and distribution (see figure 4-1c).

A zone substation is a high voltage substation that has been identified as a zone substation because of its importance in our network. We have 53 zone substations and, in general, they include a site where one of the following takes place: voltage transformation of 66 or 33kV to 11kV, two or more incoming 11kV feeders are redistributed or a ripple injection plant is installed.

Network substations are in our primary 11kV network, all within the Christchurch urban area (see section 4.2.2 for a description of the primary/secondary network). They contain at least one 11kV circuit breaker per connected primary cable and one or more circuit breakers for radial distribution feeders.

Distribution substations can take the form of any of the types shown in table 4-4b. They take supply at 11kV from either a zone substation, a network substation or from another distribution substation. In many situations a consumer will own the building that houses these substations.

1.4 Network development

1.4.1 Introduction

Developing our network to meet future demand growth requires significant capital expenditure. Before spending capital on our network, we consider a number of options including those available in demand side management and distributed generation.

The amount we spend on our network is influenced by existing and forecast consumer demand for electricity and the number of new consumer connections to our network. Other significant demands on capital include:

- earthquake recovery costs
- meeting safety and environmental compliance requirements with existing ageing equipment
- meeting and maintaining our security of supply standard
- meeting our reliability of supply forecasts.

The growth rate in overall maximum network system demand (measured in megawatts) traditionally drives our capital investment. Maximum demand is strongly influenced in the short term by climatic variations (specifically the severity of our winter conditions). In the medium term our maximum system demand is influenced by growth factors such as underlying population trends, growth in commercial/industrial output, and changes in land use in the rural sector. Our maximum demand forecast has been updated to include the population forecast for Christchurch using the Land Use Recovery Plan (LURP) prepared for CERA by Environment Canterbury. However it is still too soon to establish population forecasts with confidence. It is also difficult to forecast the return of commercial load in central Christchurch.

We have developed a long term strategic plan for our 66kV urban subtransmission system based on developing increased resilience following the Canterbury earthquakes. This is based on closed-ring network topology so as failure of any single route will not interrupt supply to a zone substation. Cables will be sized to give sufficient inter-GXP capacity to provide full support in the loss of either Islington or Bromley 66kV supply. This design is being applied to the replacement and upgrade of the 66kV subtransmission network in the north east of Christchurch.

1.4.2 Network architecture

Our network is supplied from seven GXP substations – two in the Christchurch urban area, two on the rural plains and three remote GXPs at Arthur's Pass, Coleridge and Castle Hill. The three remote GXPs have a single transformer and a much lower throughput of energy. With the exception of Hororata and Kimberley, all the GXPs peak in winter.

Approximately 65% of our consumers depend on the Islington GXP 220/66kV interconnection made up of two 200/266MVA transformers and one 250/310MVA transformer.

We have 18 urban 66/11kV zone substations, six urban 33/11kV zone substations and eight 11kV zone substations. This plan envisages up to three (and one conversion from 33kV to 66kV) new urban zone substations in the period until 2024. However the number, size, and location of these will depend on the magnitude and geographic distribution of actual load growth in the intervening period.

In our rural area we have one 66/33/11kV, eight 66/11kV zone substations and thirteen 33/11kV zone substations. This AMP envisages up to four new zone substations and the conversion of up to three zone substations from 33kV to 66kV in the period until 2025. This plan also makes provision for new substations to connect distributed generation at three locations. However the number, size, and location of these will depend on the magnitude and geographic distribution of actual load growth in the intervening period.

1.4.3 Planning criteria

The first stage of planning a distribution network is to ensure that existing network loads are monitored and tested against existing network capacity. The capacity test involves checking adequacy during contingencies defined in our Security Standard and also predefined utilisation thresholds.

When network inadequacy is identified, the process of developing solutions begins. Each potential solution is assessed for compliance with our design standards including safety compliance, capacity adequacy, quality, reliability, security of supply and economic consequences.

We monitor loads on our major zone substation 11kV feeder cables at half hour intervals. This information is used to prepare an annual reinforcement programme for our network. Reinforcements recommended in this plan are generally based on winter loading for the Christchurch urban area and on summer loading for the rural area.

When a capacity or security gap is identified on the network it is necessary to consider different capacity options as solutions. For example, a constrained 11kV feeder can be relieved by installing an additional 11kV feeder to the area. But if the zone substation supplying the area is near full capacity then it may be more cost effective to bring forward the new zone substation investment and avoid the 11kV feeder expense altogether. We discuss our approach to increased capacity in our documents NW70.60.16 - Network Architecture Review: Subtransmission, NW70.60.06 - Urban 11kV Network Architecture Review, and NW70.50.05 - Network design and overview.

Prioritisation of network solution projects for capacity and constraints is a relatively complex process that involves multiple factors that are both external and internal to Orion.

The primary factors to be considered when prioritising projects, in decreasing order of significance, are:

- coordination with NZ Transport Authority and local authority civil projects
- satisfying individual or collective consumer expectations
- managing contractor resource constraints
- coordination with Transpower
- our asset replacement programme
- our asset maintenance programme.

When the network becomes constrained it is not always necessary to relieve that constraint by investing in new zone substations, 11kV feeders and 400V reinforcement. Before implementing network investment solutions, we consider the following alternatives:

- demand side management
- distributed generation
- uneconomic connections.

For further detail on the potential of consumer DSM initiatives to defer or avoid investment, see section 5.6.12.

1.4.4 Energy, demand and growth

To effectively plan the future of our network, we need to estimate the size and location of future loads. Long-term growth in energy consumption has shown a consistent trend until the major earthquakes of FY11. This trend provides a first estimate of load growth. However any load forecasting is an approximation. There is some uncertainty due to the drop in peak demand and energy consumption from a population decrease (particularly in the east of the city), timing of the commercial rebuild in central Christchurch and increased electricity use for space heating in homes with damaged insulation and removal of solid fuel burners in damaged houses.

Energy and demand growth is a function of many inputs. Network development is driven by growth in peak demand (not energy); therefore we focus on demand growth rather than energy. At a national level it is reasonably easy to forecast population growth but when broken down to regional level the accuracy is less, but still useful in predicting future demand growth.

Our DSM strategies discussed in section 5.3.5 impact on our peak load forecast. Our network peak demand forecast assumes that 2MW of diesel generation will be added to our network each year. This is commensurate with growth in diesel generation over the last five years. Because it is difficult to predict the location of new diesel generation, we have not attempted to apply the growth in diesel generation to the zone substation load forecasts. Instead we encourage diesel generation in constrained areas on our network by publishing the area specific network deferral value of DSM initiatives (see section 5.6.12).

Energy throughput (GWh)

Network energy throughput for FY13 was 3,162GWh (including export from distributed generation of about 5GWh), down 0.1% on the previous year.

The 25-year pre-earthquake history shows an average steady growth rate of about 1.8% each year. For the five years prior to the earthquakes, energy growth was lower than the long term average at 1.4%. Environment Canterbury's CAP has had only a modest impact on energy use, as surveys suggest that the high conversion rates of solid fuel burners to heat pumps has been balanced in part by consumers switching from resistive heating to higher efficiency heat pumps. The economic downturn and closure of several major customers had led to a slowing in energy growth prior to the earthquakes. The future trend is unclear.

We have observed a downward step change in energy demand as a result of the February 2011 earthquake. While there has been some recovery, demolition work in the Central City and planned demolition in the east is significantly affecting volumes in those areas. Longer term, we expect the new business and residential buildings will be more energy efficient than the older buildings they replace, and the CERA Central City Recovery plan also implies fewer, much smaller rebuilds. Energy volumes started trending up in 2012 but have since stabilised and the medium term view is very uncertain. The particularly mild 2013 winter lowered usage for FY14. Christchurch airport mean temperature in June 2014 was 1.2°C above normal, according to NIWA data. This contributed to a particularly low FY15 volume. Figure 5-4a shows the projections of short and long term pre-quake growth rates.

Maximum demand (MW)

Maximum demand is the major driver of investment in our network. This measure is very volatile and varies by up to 10% depending on winter weather. Because our network demand peaks during the winter, we can publish the FY15 peak in this AMP.

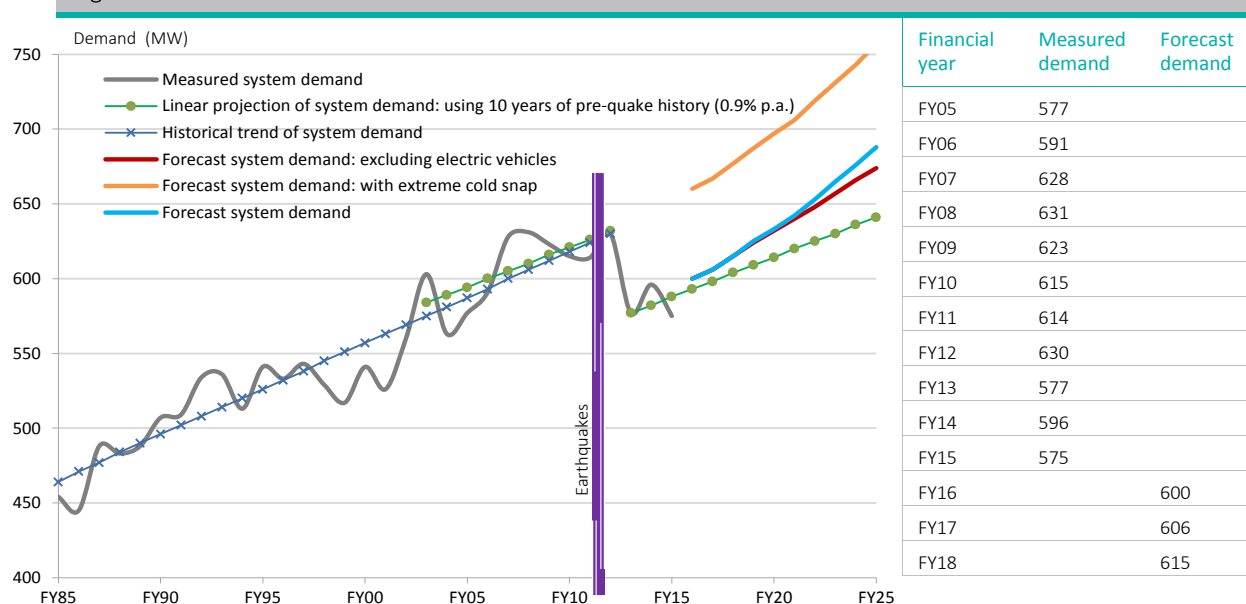
Our network maximum half hour demand, based on load through the Transpower GXPs, for FY15 was 575MW (the peak that occurred on 21 July 2014), down 21MW from the previous year. Forecasting peak demand at the moment has its challenges (on top of the earthquakes) including uncertainties with the global economy and unprecedented applications for embedded generation. Excluding earthquake effects, the long and short term trends suggest future on-going maximum demand growth rate of around 1% per annum. Historic and forecast network demand is shown in figure 5-4b.

Load duration

With constantly changing load on our network, the peak demands that determine network capacity generally only occur for very short periods in the year. Demand side management (DSM) has been successful in flattening the load curve in recent years. Control of the dominant winter maximum demand depends heavily on suitable price signals, and consumers' response to them. If this is to continue to be effective then it is important that electricity retailers continue to support DSM initiatives. Of particular importance is the promotion of night-rate tariffs and load control via the on-going installation and maintenance of ripple receivers.

The Transpower grid requires sufficient capacity to meet load during extreme weather conditions that may last for only a few hours. Generation at peak times can help to delay the need for increases in Transpower's network capacity. Generation may also be used to reduce Transpower's charges. If used for this purpose, longer hours of operation might be needed, especially to avoid reductions in water heating service levels.

Figure 5-4b Overall maximum demand trends on the Orion network



Rural load growth

Growth rates for our summer peaking rural areas have been high over the last 10 years.

Since FY02, consumer applications to connect new load to our rural network have been reasonably consistent. However, the yearly variations in weather and in particular low summer rainfall resulted in an increase of 8 to 12MW during the summers of FY04, FY08 and FY12. This demonstrates how variable peak loads can be, and how weather dependent they are – a dry summer on the Canterbury Plains causes an increase in peak demand as irrigation is required simultaneously across a large area.

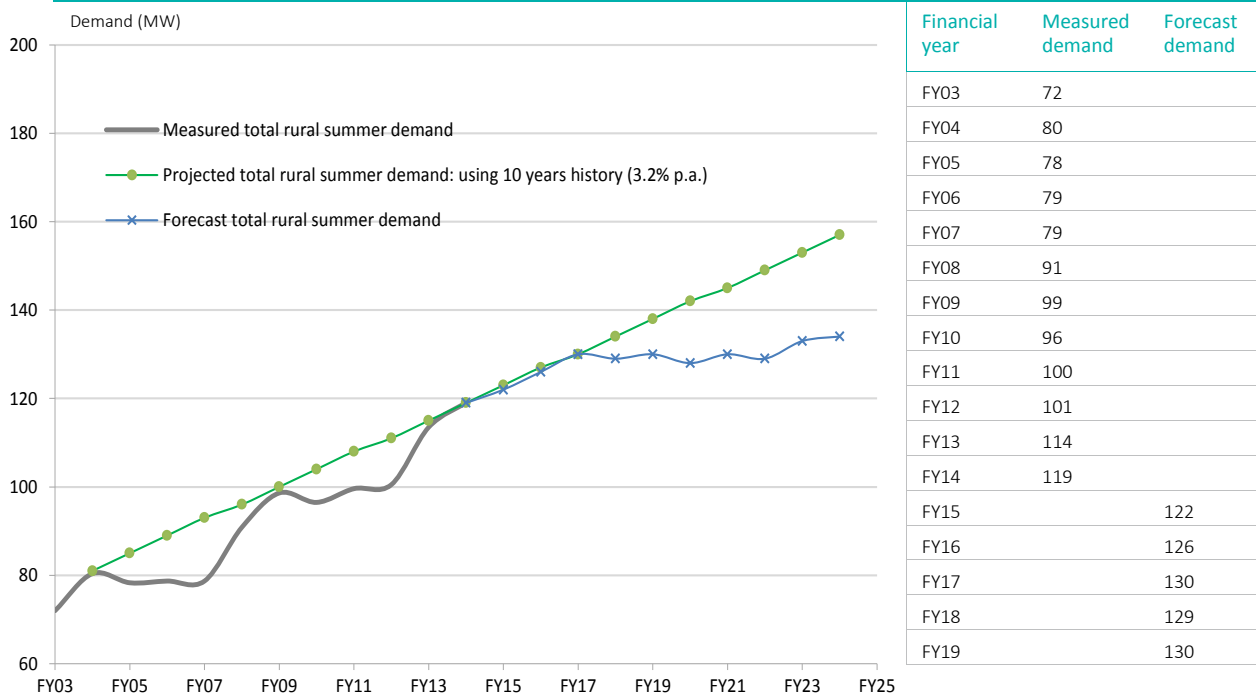
The Central Plains Water Scheme (CPW) reached the required subscription threshold late in 2013, and in March 2014 awarded contracts to commence stage 1 supplying 20,000Ha between Rakaia and Hororata rivers, inland from SH1. Restrictions due to ground water availability and nutrient leaching will restrict irrigation load growth. Increased surface water irrigation within the scheme however will allow irrigation load growth between the scheme and the coast due to greater ground water recharge. Within the CPW area, conversion of existing ground water pumps to the pressurised CPW scheme is forecast to substantially reduce summer power load on five zone substations and the Hororata GXP.

The following graph shows recent summer load growth in our rural area. FY13 was a good indication of a dry summer. FY14 irrigation demand was subdued due to rain during the summer months. This was offset by the addition of a second drier at Fonterra's processing plant near Darfield.

Approximately 80% (20MVA) of the forecast increase in rural peak demand over the next 10 years is due to the increase in milk processing capability. The existing milk processing load is around 18MVA.

Rural winter load growth has been steady at just over 3% per annum over the last 10 years. The 2011 peak is due to a significant August snowstorm. The 2014 peak was low due to a mild winter. The recent Urban Development Strategy (UDS) indicates that significant growth is expected to continue around Rolleston and Lincoln townships. We forecast winter rural load growth to average between 3% and 4% per year over the next 10 years.

Figure 5-4f Rural summer maximum demand (MW)



Load growth forecasting

Our network feeds both high density urban loads and diverse rural loads. Growth in electricity consumption can occur from an increase in population and also the introduction of new end use applications.

As stated in section 5.4.1, we estimate that future demand growth will average 1.7% (9MW) per annum over the next 10 years, with some one-off additional business increases such as milk processing plants in the next few years. Significant volatility can be expected in actual maximum demands. Capital investment plans will be modified each year in accordance with load growth that has actually been observed.

The network development projects listed in this ten year plan seek to ensure that capacity and security of supply can be maintained for the growth rates described above. Actual growth rates are monitored on an annual basis and any change would be reflected in next year's development plan.

1.4.5 Network gap analysis

On an annual basis, our network planning group updates contingency plans for all valid subtransmission (220kV, 66kV, 33kV) and 11kV contingencies. In some cases the Security Standard criteria for 'no interruption' or 'restoration time' of load cannot be economically met.

In general, network security gaps fall into one or more of the following categories:

- solution is currently uneconomic and an economic solution is not anticipated in the foreseeable future
- solution is currently uneconomic but is expected to become economic as load grows in the area under study
- local solution is uneconomic but future network expansion in adjacent areas is expected to provide a security improvement
- solution requires co-ordination with Transpower's asset replacement programme and/or is subject to Transpower/Commerce Commission approval.

The economic analysis for each network gap determines the value of lost load (VOLL) when a defined contingency occurs and then utilises probability theory to determine the annual VOLL.

The network gaps identified in the tables in section 5.5 arise because the cost of reinforcing the network to the performance level identified in our Security Standard would be economically prohibitive.

1.4.6 Network development proposals

The network development projects proposed in this AMP are driven mainly by the need to meet the capacity and security requirements of load growth. Where economic, project solutions have been designed to meet our security of supply standard requirements.

This ensures that our network configuration and capacity is constructed in a consistent way and the impact on our reliability of

supply service levels will be predictable. It should be noted that reliability of supply service levels are a function of many inputs and, while network configuration and capacity is a major input, it is not the only factor. Project solutions also need to consider our safety, power quality, environmental and efficiency forecasts.

Urban 66kV subtransmission review

In the last five years we have met growth within our urban network without the need to invest significantly in the urban subtransmission network. The capacity of our pre-earthquake 66kV subtransmission network in the north of Christchurch City was not sufficient to supply any proposed new zone substation. Damage sustained from the earthquakes has further reduced capacity. We will need to invest significantly to replace capacity in the east and meet forecast growth in northern Christchurch.

A reconsideration of our Christchurch subtransmission network was carried out in FY12. This review is described in our Network Architecture Review: Subtransmission (NW70.60.16).

Transpower spur assets

Transpower owns a number of 66kV, 33kV and 11kV assets in our network area (see figure 5-6a). Many of these assets deliver electricity solely to our network. We call these assets 'spur assets' to Transpower's grid and they fundamentally serve local distribution rather than national transmission.

Although our spur asset purchases included in this AMP reflect the most likely outcome, they are subject to Orion and Transpower board approval.

1.5 Risk management

1.5.1 Introduction

Our risk management process is based on the risk management standard AS/NZS 31000. Acceptable risk is determined on the basis of likelihood and consequences of risk events. The evaluated ranking of these two factors is used to establish priorities for managing risk.

We have aligned our Civil Defence responsibilities using the ‘four R’s’ approach to resilience planning—reduction, readiness, response and recovery.

Independent experts have advised on our risk assessment processes, and our network was part of an ‘engineering lifelines’ study in the mid-1990s into the potential impact of natural disasters on Christchurch city. After the earthquakes in FY11 we commissioned Kestrel Group to carry out an independent review of how we performed. Kestrel’s review endorsed our approach to prior planning and prior risk mitigation measures, our preparedness and our emergency response. We take into consideration Kestrel’s report and recommendations as part of our on-going asset management and planning.

1.5.2 Governance and operational business risks

Governance risk management is the responsibility of the Orion board. The board approves our statement of intent, our business plan and our AMP.

Operational risk management is the responsibility of the CEO, but is overseen by the Orion board. Key operational risks are delegated to managers. Some risks are common to all business groups, but key risks are directly managed by the group with the greatest expertise.

We have assessed our greatest risks as safety, legislative compliance, network performance, commercial management, reputation, environment and human resources.

1.5.3 Safety

We are committed to providing a safe, reliable network and a safe, healthy work environment—we take all practicable steps to minimise harm to the community, our staff, contractors and the environment. We control hazards through training, guidelines and standards. Potential hazards, in particular electrical hazards, are also considered when new network installations are being designed and constructed.

With long life networks there is inevitably a number of legacy assets that do not meet improved operational or safety standards. When we become aware of assets or safety issues that do not meet modern expectations, we prioritise risk mitigation measures. These actions may include replacement over time or strategies to reduce risk until replacement can be achieved.

We are committed to consultation and co-operation between management and employees. Maintaining a safe and healthy work environment benefits everyone and is achieved through co-operative effort. We focus on line managers taking responsibility for themselves, their staff and contractors to manage hazards.

Since almost all work associated with our network is carried out by contractors, we have developed registers of known hazards along with recommended actions to control them. Contractors must have their own documented health and safety management systems.

We monitor concerns about health and electrical fields and run community education courses teaching children to stay safe around electricity. We also run an on-going advertising campaign to promote public safety around our network.

1.5.4 Environmental management

We follow a policy of environmental sustainability, initiate energy efficiency programmes and work to optimise electrical losses on our network. Our environmental sustainability policy covers protection of the biosphere, sustainable use of natural resources, reduction/disposal of waste, wise use of energy, risk reduction, restoration of environment, disclosure, commitment of management resources, stakeholder consultation, assessment and annual audit. We instigated oil spill management systems several years ago and have managed any significant spills since.

1.5.5 Impact of natural events

Earthquakes create the most significant risk of impact on our network, since both likelihood and consequence are currently rated as high and long equipment replacement times are a major consideration. We are having another look at our earthquake risk in the light of what we now know after the earthquakes in FY11.

We continue to invest significant time and money to ensure we can respond well to natural events such as storms and earthquakes. Orion is a founding member of the steering committee of the Canterbury engineering lifelines group. The purpose of this group is to increase the resilience of Canterbury’s infrastructure and to assist lifeline utilities to participate in all phases of civil defence emergency management.

During the mid-1990s our network was part of an ‘engineering lifelines’ study into how natural disasters would affect Christchurch. The study concluded that electricity supply would be essential for almost all service authorities after a natural disaster, with most service authorities’ head offices located in the central city area.

Since this study we have made the following improvements:

- spent \$13m to secure power supply to the central city via a second point of supply
- strengthened power supply to the port, airport and main communications sites
- spent \$4.5m on earthquake strengthening for bridges, cable supports and buildings. All of our zone substations and all major 33kV and 66kV cables now meet the seismic structural standard
- undertaken regular risk assessment and response studies to ensure we are well prepared for any disaster.

We have also reviewed how susceptible Transpower's GXP's are to liquefaction. Our reviews show that Addington and Bromley GXP's could be subject to differential settlement in an earthquake – this may affect our 66kV feeder cable terminations. Due to differing soil types, settlement should not occur at both GXP's during a single event.

1.5.6 Asset failure

We assess all of our key assets based on known past performance. We also use partial discharge detection technology to manage the risk of premature asset failure. Two major asset classes present the biggest risk – our 66kV cable subtransmission network and our major zone substation transformers:

- The 66kV cable network's main identified failure risks are thermo-mechanical buckling of the cores within the joints of the oil-filled cables. We instigated a joint replacement programme that has prioritised the joints most at risk. This programme to replace these joints was completed in FY10.
- Comprehensive half-life maintenance of all major zone substation transformers is also being carried out. This programme was coordinated with our 66kV joint replacement programme.

We check insulators on overhead lines with a 'corona' camera. This technology can detect excessive discharge on line insulators not normally detectable by other means. It is used to locate faults and assess the general condition of insulators.

Risk of ripple plant failure, which could result in loss of network peak load control, is addressed through system spares. Our decision to replace the existing 66kV injection system with multiple independent 11kV plants has significantly reduced risk as plants can provide back-up to each other.

Our distribution management system (DMS) with its integrated SCADA module is a key tool for monitoring and operating our assets in real time. It is also the primary source of control for our ripple plants. In addition to warranty and maintenance agreements that provide software and systems support, the system is made fault tolerant through the use of backup hardware and communications routing. Multiple identical servers are configured at independent sites with databases mirrored between them. In the event that any of these servers fail, the DMS will continue to operate.

Administration building

We moved to a level 4 "Lifelines" (IL4) compliant building located at 565 Wairakei Rd in May 2013. This site meets our head office and operational requirements. The building has a current building warrant of fitness and is inspected six monthly by the Orion Health and Safety Committee.

Currently we have retained our computer hot-site capability at our Armagh St site until we relocate our data centre to an alternative site. We have also established portable emergency office accommodation at our Papanui zone substation site.

1.5.7 Insurance

The following mitigation measures are in place:

- Our material damage insurance policy insures us against physical loss or damage to buildings, plant, equipment, zone and network substation buildings and contents and is based on assessed replacement values.
- Our business interruption insurance policy indemnifies us for increased costs as a consequence of damage to insured assets, with an indemnity period of 12 months.
- Orion has several liability policies, including directors and officers, professional indemnity, public liability and statutory liability
- Key uninsurable risks are:
 - i. lost revenues (e.g. due to depopulation following a catastrophic event)
 - ii. damage to overhead lines and underground cables

These risks are effectively uninsurable for all electricity distribution businesses in Australasia.
- Contractors that work for us are required to arrange appropriate insurance for the work being undertaken, giving cover for:
 - i. third party liabilities
 - ii. contract works
 - iii. plant and equipment
 - iv. motor vehicle third party.

1.6 Financial forecasts

1.6.1 Network Opex and Capex

Our forecasts are based on our network opex and capex programmes and projects as detailed in sections 4 and 5. These forecasts are based on the best information available regarding the timing and extent of the post earthquake key recovery projects. Whether or not these projects will proceed, and the timing of them, is determined by Government and local Authorities and/or Developers.

A summary of our forecast expenditure is shown in the table below.

Budget	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Opex - Network	29,490	27,380	27,300	26,455	26,425	26,315	26,435	26,390	26,435	26,355
Capex - Network	94,903	61,377	82,999	62,143	51,506	40,037	54,688	49,285	41,261	47,366

1.6.2 Changes from previous forecasts

Changes described in these budgets are referenced to our last published AMP (for the period from 1 April 2014 to 31 March 2024). All forecasts are now in FY16 dollar terms (previously in FY15 dollar terms).

Opex budgets - Network

Details of our maintenance plans are described by asset type in section 4 – Lifecycle asset management.

Our maintenance forecasts are generally consistent with last year's forecasts.

Capex budgets - Network

ASSET REPLACEMENT

Our replacement plans are described by asset type in section 4 – Lifecycle asset management.

In real terms our switchgear replacement reduced by \$14.7m, underground cable replacement reduced by \$18.5m along with minor adjustments across all other assets. The net result is a reduction of \$32.1m.

CONSUMER CONNECTIONS AND NETWORK EXTENSIONS

Our load demand forecasts are detailed in section 5 – Network development. Our network extensions and consumer connection cost forecasts are based on our current and forecast business and residential growth forecasts. In general, demand growth has continued to be slow while decisions are finalised regarding earthquake affected land in the east of the city. Over the next few years we expect connection growth to be high as proposed subdivisions become available to meet the requirements of people relocated from the east, and development begins in the CBD.

ASSET RELOCATIONS

Underground conversions are carried out predominantly with road works, at the direction of Selwyn District Council, Christchurch City Council and/or the New Zealand Transport Agency (NZTA). Costs associated with these works can vary depending on council or roading authority demands. Currently the Christchurch City Council has indicated they will not be carrying out undergrounding within the next four years. Selwyn District Council is continuing with its on-going programme. Undergrounding associated with NZTA projects has currently provided works that have compensated for the reduction by CCC. We estimate that activity will decrease after the major 'Roads of National Significance' (RONS) Programme is completed by NZTA over the next few years.

REINFORCEMENT

Our reinforcement forecasts have been reduced from \$4.5m to \$3.5m per annum. This reflects the benefits of our change in 11kV network architecture in 2007, the completion of 11kV inter-zone substation links and reduced irrigation growth on the rural network. Our reinforcement forecasts are in section 5 – Network development.

MAJOR PROJECTS

Our major projects have a long term focus to meet forecast growth while delivering our network resilience, reliability and security of supply objectives. They typically include new 66kV subtransmission lines or cables and or new 66/11kV zone substations.

Our earthquake recovery works to the east and north of the city remain largely unchanged from our FY13 and FY14 AMP. We have made a minor change to bring forward the Papanui bus coupler from FY18 to FY16 (\$0.35m). Our FY17 budget includes \$6.2m for the rebuild of Lancaster zone substation to remedy earthquake damage.

Changes to forecast growth and the plans of some major customers has enabled deferral of works as follows:

- Moffett 33kV and Belfast generation from FY16 to FY17
- Milton to Lancaster 66kV link from FY16 to FY18

- Shands 66kV from FY17 to FY19
- Prebbleton upgrade from FY21 to FY26+
- Hawthornden works from FY18 to FY19
- Porters village from FY16 to FY19
- Westland Milk related projects from FY17 to FY19
- Dunsandel transformer upgrade from FY17 to FY18

We have seen an increase in the cost of tendered civil works as the post earthquake Christchurch rebuild puts upward pressure on civil costs and other costs in general. However, we have been able to refine our approach to upgrades in the Darfield area and other small project adjustments to offset these costs. This year's major projects forecast for FY16 to FY24 of \$157m compares with a \$144m forecast in our last AMP for the equivalent period.

Spur assets

We have made significant progress on the acquisition of Transpower spur assets with the purchase of Papanui in August 2012, Springston and Bromley 66 and 11kV on 31 March 2014 and 1 April 2014 respectively and Addington and Middleton on 1 April 2015 (appear as FY16 forecast in this AMP). Our forecasts for the acquisition of further spur assets (Castle Hill, Arthur's Pass, Hororata 33kV and Islington 33kV) have been delayed slightly to FY18 while we and Transpower further assess the options and appropriateness of these final smaller transfers.

1.7 Evaluation of performance

1.7.1 Introduction

This section reviews our performance against the forecasts in our previous AMP. These may be service forecasts as stated in section 3 or a forecast to carry out a particular maintenance or risk reduction function. We discuss whether or not a budget was met and offer explanations for any variances. This section also outlines some current and future initiatives along with a gap analysis.

1.7.2 Consumer service

Reliability

As shown in the table below, our FY14 SAIDI and SAIFI results were over our forecast and the Commerce Commission's DPP reliability limit. This was almost entirely due to severe NW wind storms in July and September 2013 that had a major impact on our rural network. The wind storm in September was the 3rd biggest event on our network in the last century, exceeded only by the Canterbury earthquakes in FY11. The storm caused a loss of over 60 million consumer minutes. The earthquakes caused the loss of 718 million consumer minutes.

As shown in figure 8-2a, there were also heavy snow storms in FY93, FY03 and FY07 that caused significant network outages.

Even though major emergency earthquake repairs are finished, there is still much work ahead of us to restore network resiliency and reliability. Significant infrastructure rebuild activity in the city will also likely see an increase in damage and disturbance of our network assets. We expect to restore our network to near pre-earthquake reliability levels by FY19.

Table 8-2a Orion network reliability results for FY14 and last five year average

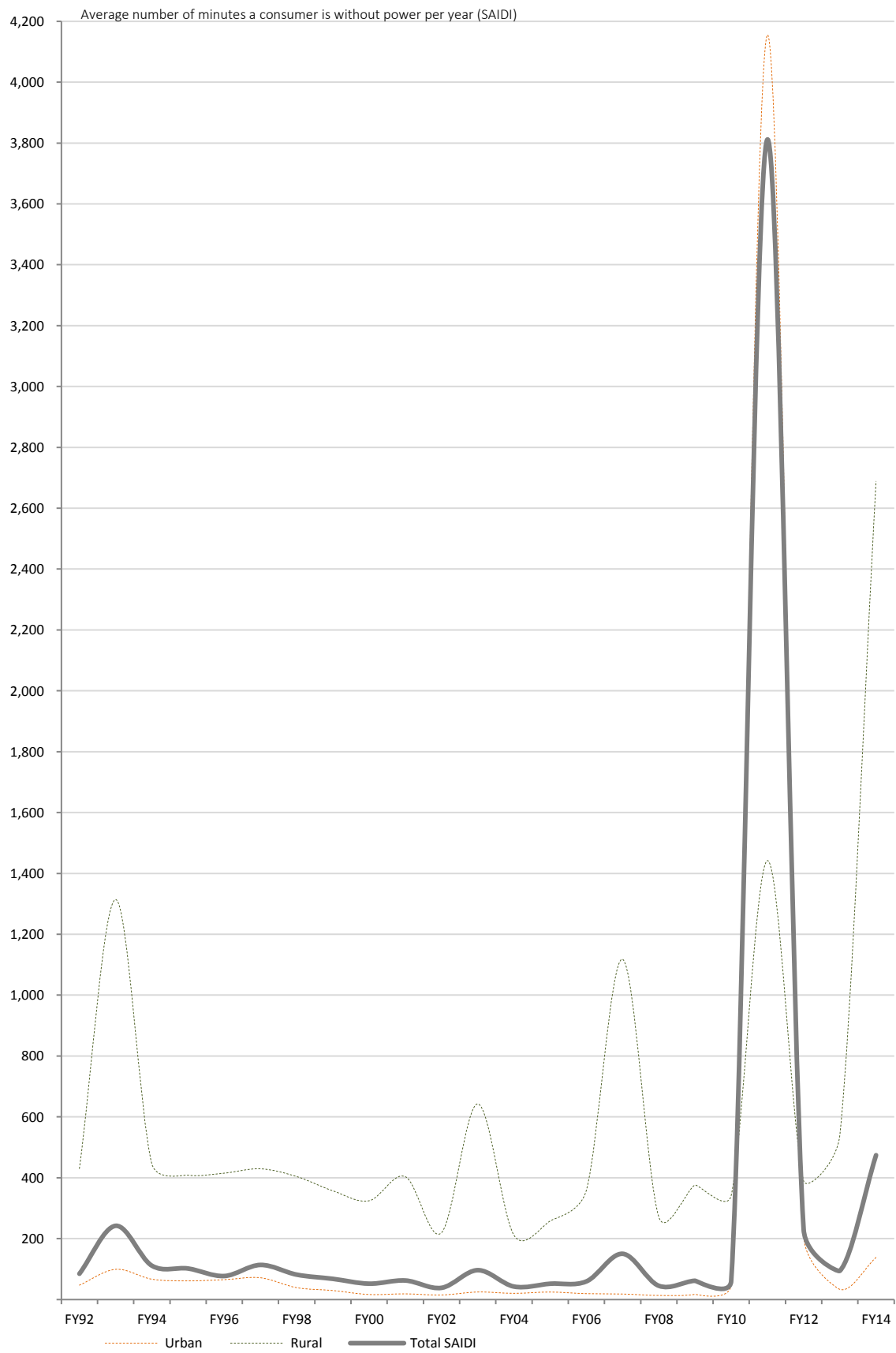
Category	FY14 Orion forecast	FY14 actual result**	FY10-FY14 average	FY14 DPP reliability limit	FY14 DPP normalised result***
SAIDI	< 137	474	934	59.2	105
SAIFI	< 1.8	1.3	1.6	0.78	1.22
Faults restored within 3 hours (%)	> 60	57.8	60.3		
Subtransmission lines faults per 100km*	-	6.9	-		
Subtransmission cables faults per 100km*	-	0	-		
Distribution lines faults per 100km*	-	23.2	-		
Distribution cables faults per 100km*	-	3.3	-		
Subtransmission other faults*	-	1	-		
Distribution other faults*	-	108	-		

* As per Disclosure schedule 10(v).

** Full result, no daily limits applied to major events.

*** Major event daily boundary values applied in accordance with DPP.

Figure 8-2a Orion network SAIDI FY92 - FY14



Power quality

Our main objective in relation to power quality issues is to identify and resolve consumer quality of supply enquiries. This is achieved by fitting test instruments close to the point where ownership changes between Orion's network and the consumer's electrical installation.

Data gathered from the test instruments is analysed against the New Zealand Electricity Regulations 1997. By applying key regulations (Voltage, Frequency, Quality of Supply and Harmonics) we are able to determine which quality problems originate within our network.

Our network has performed well in terms of voltage and quality. A number of voltage complaints are received every year but the problem is found to be in our network in only approximately 30% of complaints.

Table 8-2b Service level results for FY14 – Network power quality

Category	Measure	Forecast	Achieved FY14	Performance indicator	Measurement procedure
Power quality	Voltage complaints (proven)	<70	39	Non compliances per annum	Tracking of all enquiries
	Harmonics (wave form) complaints (proven)	<2	0	Non compliances per annum	Checks performed using a harmonic analyser

1.7.3 Efficiency

We use several measures, as stated in the table below, to gauge our effectiveness at running an efficient network. We have achieved our outcomes by following good industry practice with sound network investment and design principles.

Capacity utilisation measures the utilisation of transformers in our network. It is calculated as the maximum demand experienced on the network divided by the distribution transformer capacity on the network. See section 3.3.8 for reasoning behind not setting a specific forecast for capacity utilisation.

Table 8-3a,b,c Efficiency results for FY14 and 5 year average FY10-FY14

Category	Forecast	Achieved FY14	Achieved 5 year average
Capacity utilisation (%)	No forecast	29.5	30.5
Load factor (%)	No forecast	58.3	60
Electrical losses (%)	No forecast	<5 estimated	<5 estimated

Annual load factor is calculated as the average load that passes through a network divided by the maximum load experienced in a given year. We always seek to optimise load factor as this indicates better utilisation of capacity in our network. Load factor has trended upwards over the last 15 years by just over 0.7% per annum. See section 5.4.1 for our load factor forecasts.

Electrical losses are contained by choosing and maintaining appropriate transmission and distribution voltages and through using appropriate conductor sizes that suit our load density. We purchase transformers using an industry standard evaluation formula that means we often spend more to purchase lower loss transformers, rather than purchasing cheaper higher loss transformers. Overall, electrical losses do not have much impact on the design and operation of our network because other factors tend to dominate. See section 8.3.4 for our reasoning behind not setting a specific forecast for losses.

1.7.4 Works expenditure in FY14

The previous AMP figures shown here are from our AMP for the period 1 April 2013 to 31 March 2023.

Maintenance

Our network maintenance costs for FY14 were \$24m, compared with our forecast of \$27m. The under-expenditure was largely due to deferred works due to the uncertain requirements around earthquake recovery third-party works and constrained resources.

Capex

CONSUMER CONNECTIONS AND EXTENSIONS

Our consumer connection and extension costs for FY14 were \$14.6m, compared with our forecast of \$12.6m. The over-expenditure was largely due to a significant increase in subdivisions as part of the wider post-earthquake rebuild.

REINFORCEMENT

Our reinforcement costs for FY14 were \$2.7m, compared with our forecast of \$4.9m. The under expenditure was due to deferred NZTA works and developer driven works.

UNDERGROUND CONVERSIONS

Our underground conversion costs for FY14 were \$3.6m, compared with our forecast of \$6.6m.

This expenditure is dependent on project timing associated with the needs of the Roding Authorities, the Christchurch City Council, Selwyn District Council, NZTA and developer requirements.

The under-expenditure is due to delays in road construction programmes and developer driven projects.

MAJOR PROJECTS

Major project costs for FY14 were \$23.9m, compared with our forecast of \$39.1m. The under-expenditure was largely due to:

- delays to the Bromley - Dallington and Bromley - Rawhiti 66kV cable projects due to co-ordination with earthquake road/bridge repair contract works
- deferred land purchases for 66kV substations (Burnham, Greenpark and Rossendale) until suitable land and agreements can be completed
- deferred Central Plains Water canal pumps until upgrade agreement has been negotiated
- deferred Larcomb zone substation 66kV upgrade and associated new Springston connection until acquisition of Transpower's Springston GXP assets occurred.

REPLACEMENT

Our replacement costs for FY14 were \$15.7m, compared with our forecast of \$24.9m. The under-expenditure reflects the variable and unpredictable nature of our work as we recover from the earthquakes. The difference is largely due to the following factors:

- allowance for replacement of earthquake impaired cables not required in the period
- less distribution transformer replacement due to lower energy demand
- deferred works associated with control systems
- switchgear replacement deferred due to our architecture review, network access issues and decisions in regard of disestablished earthquake zones.

1.7.5 Safety

We report all employee injury incidents in our Human Resources database. We separately collect similar statistical incident data from our contractors. These contractor statistics, our own statistical data and our incident investigations, enable us to provide staff and contractors with indicators of potential harm.

Table 8-5a Personal safety – performance results

Key asset management driver	Measure	Forecast	Achieved FY14	Performance indicator	Measurement procedure
Personal safety	Injuries to staff	0	2	Number of 'lost-time' injury accidents	Accident/incident reports
	Injuries to our contractors	0	5		
	Injuries to public	0	0		

1.7.6 Environment

All our service providers are required to adhere to our environmental management manual and procedures.

No significant environmental incidents occurred on our network in FY14.

1.7.7 Improvement initiatives

Subtransmission network

We have identified the need for improvements in security and performance in our subtransmission network since this asset affects the largest number of consumers. Some of the initiatives taken on this asset are as follows:

UNDERGROUND

- thermal engineering checks to determine/confirm the current rating of cables
- specific trench backfill to provide the required thermal and mechanical support
- replace the 66kV oil-filled cable joints and 33kV oil-filled cables.

OVERHEAD

- replaced insulators, install vibration dampers and re-rate conductors for 75°C operating temperature
- applied dynamic ratings
- assessed condition of tower foundations and repaired where required.

SUBSTATIONS

- increased reliability at Addington by splitting the 66kV bus
- rearranged existing 11kV supplies at Addington to increase security
- constructed a 66kV bus at Springston.
- installed a 66kV bus zone scheme at Bromley

Transpower GXP

- major alterations at Islington GXP to increase capacity and alter vector grouping along with replacing half of the 33kV outdoor switchgear with indoor equipment

Distribution network

Over the past 23 years our rural 11kV overhead line fault rate has decreased from approximately 25 faults per 100km per year to around 12. The main reasons for this are that we have completed major maintenance projects and improved tree control. In addition, live-line work practices have reduced planned outages, while more line circuit breakers have been installed. Feeders have been shortened as new zone substations are built, which has also provided performance improvements.

We have installed ground fault neutralisers (GFN) at our rural zone substations. This has the potential to significantly improve network reliability. The potential to cost effectively improve reliability using more traditional methods is fairly limited. GFNs and associated equipment can reduce the residual earth-fault current close to zero during earth-faults and thereby make it safe to leave the distribution network alive with permanent earth-faults while the faults are located and isolated.

We have also instigated initiatives to reduce problems with switchgear, primary transformers and terminations.

Power quality project

As part of a three year project to install 30 power quality instruments, 10 power quality instruments were installed at various locations within our distribution network. These instruments collect power quality trend data plus triggered transient event information.

The PQView power quality analysis package was also purchased to archive data and provide an analysis tool. Preliminary analysis of data collected to date discovered the very high harmonic levels on the network supplied from the Hororata GXP. These findings have assisted Transpower to analyse the effect of transposing 220kV lines as part of a project to reduce voltage imbalance.

We also use the power quality instruments and PQView to discover and monitor the increasing harmonic distortion caused by everyday domestic consumer electronic equipment.

At Darfield, total harmonic voltage distortion exceeded 8% at times during the summer of FY09. During the summer of FY10 after the transformers were changed and despite an increase of 50% in the VSD load, the total harmonic voltage decreased to approximately half that of the previous summer.

Emergency stock

Our emergency stock holdings valued at approximately \$4m have been reviewed by looking at the reliability statistics of each asset, and systematically identifying the benefits of components that make up that asset. It was necessary to set a reasonable level of risk to ensure that we balanced the need for carrying emergency spares with the costs of holding these items. For our overhead line asset we set this level at about a one-in-50 year event. As risk assessment of individual network components is further refined some items may be released or additional critical items will be held.

1.7.8 Gap analysis**Asset management processes**

The Commerce Commission released new Information Disclosure (ID) requirements in 2012. As part of these requirements EDBs must provide an overview of asset management documentation, controls and review processes using an instrument known as the Asset Management Maturity Assessment Tool (AMMAT). While the AMMAT does not formally specify a standard upon which to assess compliance, the requirements are clearly aligned with 31 questions from the 121 questions prescribed by the PAS 55 Assessment Methodology (PAM). These questions have been selected to provide information not previously required by the Information Disclosure (ID) requirements.

AMMAT reviews are usually self-assessment. However we engaged EA Technology Ltd to undertake an independent assessment. They found that we comply with the requirements in a number of important, high impact areas and that we are making steady improvement. EA Technology notes that “While the scores allocated in some cases suggest that systems and processes do not meet the requirements, this should not be interpreted as Orion’s systems and processes necessarily being deficient or not fit for purpose.” In areas where we score below a maturity level of 3, we believe that our existing systems are appropriate for our business. Further documentation would provide the necessary evidence to increase our score, but we don’t believe this is necessary at this stage. For scores see section 8.9.1.

Reliability

Our network has improved over the 23 years that we have compiled detailed reliability statistics. These statistics indicate that most interruptions in the rural area are due to trees, vehicles hitting poles/lines and equipment failure. Over the years we have made considerable effort to control tree growth (where the Tree Regulations allow) and instigate various maintenance

programmes on our rural 11kV lines. A project to install reflectors on roadside poles to reduce the incidence of vehicles hitting poles has also been completed.

Our plant failure statistics show that as loads increase in parts of our network, we have to work harder to keep ageing equipment performing satisfactorily. We now use a UV corona imaging camera in a move that utilises the latest technology in an effort to identify potential problems before they cause an interruption.

We have also completed a project to shorten the interrupted portions of our feeders by installing additional line circuit breakers. Line circuit breakers are relocated to more appropriate locations as the network is altered and currently total over 50 in our rural network.

We have installed and put into service 23 Ground Fault Neutralisers (GFN). These units are equipped with 5th harmonic residual current compensation and are starting to contribute to an improvement in rural network reliability and safety.

Security standard

Our security standard provides a useful benchmark to identify areas on our network that may not currently receive the high level of security that the majority of our network has. Any gaps against our security standard are discussed in section 5.5 – Network gap analysis.

Background and objectives



2

2.1	Purpose of our AMP	37
2.2	Business plans and goals	37
2.2.1	Relationship of our AMP to our 'mission'	37
2.2.2	Relationship of our AMP to our SOI and business plans	38
2.3	Stakeholders	40
2.4	Management responsibilities	42
2.4.1	Asset management structure	42
2.4.2	Board and executive governance	43
2.4.3	Corporate services	43
2.4.4	Infrastructure	43
2.4.5	Commercial	43
2.4.6	Information solutions	44
2.4.7	Human resources	44
2.4.8	Consultants and contractors	44
2.5	Assumptions	45
2.5.1	Significant assumptions	45
2.5.2	Changes to our existing business	45
2.5.3	Sources of uncertainty	46
2.5.4	Cost inflation	46
2.5.5	Potential differences between our forecast and actual outcomes	46
2.5.6	Information sources	46
2.6	Asset management drivers	48
2.6.1	Investment principle	48
2.6.2	Business drivers	48
2.7	Asset management process	50
2.7.1	Introduction	50
2.7.2	Planning priorities	51
2.7.3	Construction standards and working practices	51
2.7.4	Introduction of new equipment types	52
2.7.5	Routine asset inspection and maintenance	52
2.7.6	Performance measurement	53
2.7.7	Network development	53
2.8	Systems and information	54
2.8.1	Systems	54
2.8.2	Asset data	58
2.9	Development of systems and processes	60
2.9.1	Short term developments	60

List of figures and tables in this section

Figure	Title	Page	Table	Title	Page
2-2a	Interaction of plans and processes	39			
2-4a	Asset management structure	42			
2-6a	Optimal cost versus quality principle	48			
2-7a	Asset management system	50			
2-7b	Process to introduce new equipment	52			
2-7c	Process for routine asset inspection and maintenance	52			
2-7d	Process for performance measurement	53			
2-7e	Process for network development	53			
2-8a	Management systems and information flows	55			

2.1 Purpose of our AMP

Our AMP documents the asset management practices we use as part of an optimised lifecycle management strategy for our electricity assets. This means the overall objective of our AMP is:

To consistently deliver a safe, secure and cost-effective supply of electricity to our customers.

This AMP looks ahead for the 10 years from 1 April 2015.

The main focus of this AMP is on the first three to five years. Beyond this period, analysis is more indicative. Based on long term trends and, depending on consumer demand growth, it is likely that new projects will arise and some projects in this plan could be eliminated in the years six to ten of this AMP.

We update and publish our 10-year AMP just prior to the start of each financial year (April).

We created our first AMP in 1994. This AMP meets the requirements of the Electricity Distribution Information Disclosure Determination 2012. These requirements include:

- a summary
- background and objectives
- target service levels
- details of assets covered and lifecycle management plans
- load forecasts, development and maintenance plans
- risk management, including policies, assessment and mitigation
- performance measurement, evaluation and improvement initiatives.

As the format of our AMP does not completely follow the order as suggested in the regulatory disclosure requirements a cross reference table to the relevant sections of our AMP is shown in Appendix B.

Our AMP goes beyond regulatory requirements. We use our AMP on a day-to-day basis. We aim to demonstrate responsible stewardship of our electricity distribution network — in the long term interests of our consumers, shareholders, electricity retailers, government agencies, contractors, electricity end users, financial institutions and the general public.

In this AMP, we aim to optimise the lifecycle costs for each network asset group (including creation, operation, maintenance, renewal and disposal) to meet agreed service levels and future demand. Each year we aim to improve our AMP to take advantage of new information and changing technology. These innovations help us to maintain our ranking as one of the most resilient, reliable and efficient electricity networks in the country.

Our AMP does not cover how we derive and apply our network pricing. This information is available on our website; oriongroup.co.nz.

2.2 Business plans and goals

2.2.1 Relationship of our AMP to our 'mission'

Our activities are guided by what we call our 'mission', that consists of a purpose statement, a vision statement for the future state of the company and a set of company values as detailed below. Necessary competencies to achieve this mission include; asset management, stakeholder communication, risk management and network pricing. This AMP is consistent with, and is an important part of, our mission.

We now detail the three key elements of our mission.

Our purpose

To consistently deliver a safe, secure and cost-effective supply of electricity to our customers.

Our vision

We will:

- provide excellent customer service
- foster strong stakeholder relationships
- lead collaboration across the electricity industry to benefit all New Zealanders
- apply technology and demand side management to benefit our customers
- excel in leadership and management
- attract, develop and retain the very best people
- protect and create value for our shareholders and customers.

Our values:

We will	Meaning
Value relationships	We build and maintain positive relationships with our internal and external stakeholders (our employees, customers, shareholders, suppliers, contractors, regulators, community organisations etc.)
Be trustworthy	We demonstrate honesty, sound judgement, understanding and empathy. We earn the trust and respect of our community
Be proactive	We create opportunities and promptly respond to challenges with initiative. We empower our employees to be accountable and focus on results
Maintain a long term focus	Decisions we make must not compromise the achievement of our purpose
Be effective and efficient	We strive for competence, effective planning and execution, consistency in application and efficiency
Be innovative	We maintain a learning environment. We explore and adopt ideas that create value
Value safety and wellbeing	We provide a safe and healthy work environment to protect ourselves, other people and property
Value our natural environment	We are mindful of our impact on the natural environment and seek ways to minimise our effects

2.2.2 Relationship of our AMP to our SOI and business plans

Our AMP is a key component of our business planning process that combines management, financial and technical practices to ensure that the level of service required by consumers is provided by us at the lowest long term cost.

Other key documents that are part of our annual business planning process are:

1. **Statement of intent (SOI):** In accordance with section 39 of the Energy Companies Act, we submit a draft SOI to our shareholders prior to each financial year. After carefully considering shareholders comments/suggestions on the draft, the Orion board approves our final SOI. Our SOI is then sent to our shareholders and placed on our website.

Our SOI sets out our overall strategic/corporate objectives, intentions and performance targets for the next three financial years.

Section 36 of the Energy Companies Act stipulates that our principal objective shall be to operate as a successful business. We state in our SOI that in order to achieve this outcome we seek to:

- achieve our objectives, both commercial and non-commercial, as specified in our SOI
- be a good employer
- exhibit a sense of social and environmental responsibility by having regard to the interests of the community in which we operate
- conduct our affairs in accordance with sound business practice.

Our SOI states: *“Our top priority is the safe, efficient and effective management of our electricity network. We aim to provide customers with a safe, resilient and efficient electricity service and efficient prices”*. These two sentences drive the philosophies and practices inherent in our AMP—in particular our aim to provide the level of service required by consumers at the lowest long term cost.

We also aim to provide our shareholders with an attractive risk adjusted return on their investment.

Section 37 of the Energy Companies Act states: *“All decisions relating to the operation of an energy company shall be made pursuant to the authority of the directorship of the company in accordance with the statement of corporate intent”*. It is therefore important that the scope of our activities, as defined in our SOI, includes the ownership and operation of our local electricity distribution network. This is achieved in our SOI - where we state that our activities are to plan, construct and maintain a reliable and secure electricity distribution network in the Christchurch/central Canterbury region.

Our SOI also states that we will:

- plan, construct and maintain a safe, resilient and reliable electricity distribution network in the Christchurch and central Canterbury region
- recover our prudent and efficient costs
- provide efficient processes that support competition among electricity retailers and generators
- seek investment/acquisition opportunities in the infrastructure and energy sectors

- manage, grow and, if appropriate, realise our other subsidiary and associate company interests.

Our AMP is consistent with the goals of our SOI although not all of our SOI is relevant to our AMP.

Our other planning documents all seek to achieve the aims of our SOI.

Our SOI has a number of specific targets each year related to:

- network reliability
- environmental performance
- community and employment
- financial performance.

The network reliability targets (SAIDI/SAIFI) in our SOI are consistent with our AMP targets.

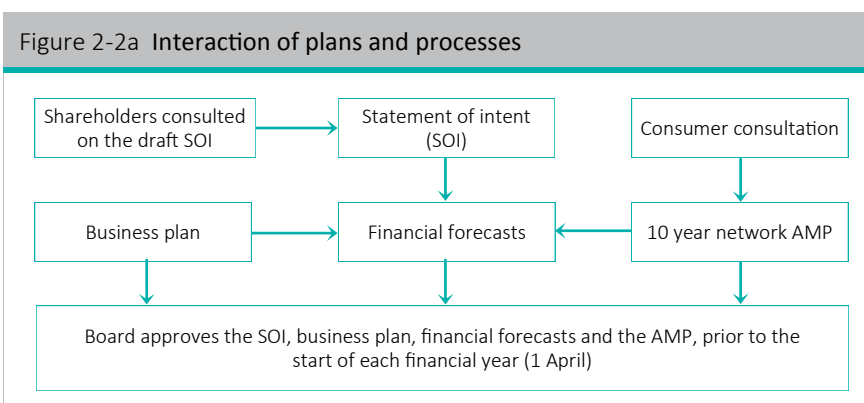
The environmental performance targets in our SOI are outside the scope of our AMP. However, some of these targets can impact on our AMP. For example, a recent SOI target to incorporate the cost of carbon into network investment decisions is now embedded in our network management practices (see section 2.6.2 of this AMP).

The community and employment targets in our SOI are consistent with the scope of our AMP. However, some of our SOI targets are outside the scope of our AMP. For example, our SOI targets related to zero lost-time accidents and our on-going engineering trainee programme.

The financial targets in our SOI are for our company and group as a whole and are therefore outside the scope of our AMP.

2. **Business plan:** Our company strategies and business targets are consistent with our approved SOI. Our AMP is one part of our plan and we also have other strategies and targets that are unrelated to our electricity distribution network. Our business plan is not a public document.
3. **Financial forecasts:** Our financial forecasts and targets, and our forecast funding requirements.

Figure 2-2a shows how our business plans and processes interact with each other.



2.3 Stakeholders

Our key stakeholders are:

- shareholders: Christchurch City Council Holdings Limited and Selwyn District Council
- retailers, contracted customers and consumers
- employees
- Transpower
- government agencies
- contractors and suppliers
- financial institutions.

We have identified our key stakeholder interests through the following forums:

- consumer surveys, meetings and informal discussions
- major customer forums and industry seminars
- reviews of major events (storms)
- quality of supply studies
- employee satisfaction surveys
- specific project consultations
- supplier technical assessment meetings
- contract performance reviews
- consultation papers and submissions.

The interests of our key stakeholders can be summarised as:

- **Shareholders:**
 - i. a fair return on investment commensurate with the risk of that investment
 - ii. efficiency
 - iii. long term value
 - iv. prudent financial management and planning
 - v. security of supply.
- **Retailers, contracted customers and consumers:**
 - i. a reliable electricity supply
 - ii. value for money
 - iii. efficient fault restoration with good communication during events
 - iv. consistency with the Commerce Act Part 4A purpose to “provide services at a quality that reflects consumer demands”.
- **Employees:**
 - i. a safe work environment
 - ii. clear direction, responsibilities and accountability
 - iii. job satisfaction.
- **Transpower:**
 - i. load forecasts
 - ii. security of supply
 - iii. technical connection issues
 - iv. new investment.
- **Government agencies:**
 - i. economic efficiency
 - ii. compliance.
- **Contractors and suppliers:**
 - i. fair access to business
 - ii. consistent terms
 - iii. clear specifications
 - iv. clear information to assist efficient resource planning
 - v. support.

- **Financial institutions:**
 - i. prudent financial management and planning
 - ii. capacity to repay debts as they fall due
 - iii. timely and accurate information
 - iv. transparent key forecast assumptions
 - v. access to senior management.

We accommodate these stakeholder interests in our asset management practices through:

- consumer demand forecasts
- security of supply standards
- safety plans, auditing and compliance programmes
- coherent network planning, standards and procedures
- clear contracts with counterparties
- risk management
- use of professional judgment and experience
- key resource management principles (e.g. managing a sustainable pool of competent network contractors)
- use of independent experts
- prudent financial management and planning.

We manage any conflicting stakeholder interests by:

- considering the needs of stakeholders as part of our high level planning
- a balance between the cost of non-supply and the investment to provide the security desired
- cost/benefit analysis
- our principal objective under the Energies Company Act being to operate "*...as a successful business*".

If a conflict between stakeholder interests is identified then we adopt an appropriate conflict resolution process to suit the issue and stakeholder concerns. Our consumers sometimes have different network resilience and/or reliability needs. Consumers do not always agree on the standards that they prefer and the price they are willing to pay for our service.

We aim for levels of network resilience and reliability that meets our overall consumers' views as best we can.

Each year, our newly revised AMP is made publicly available free of charge (including on our website) within a week of it being approved by our board. We welcome comments and suggestions on our AMP from stakeholders and interested parties at any time.

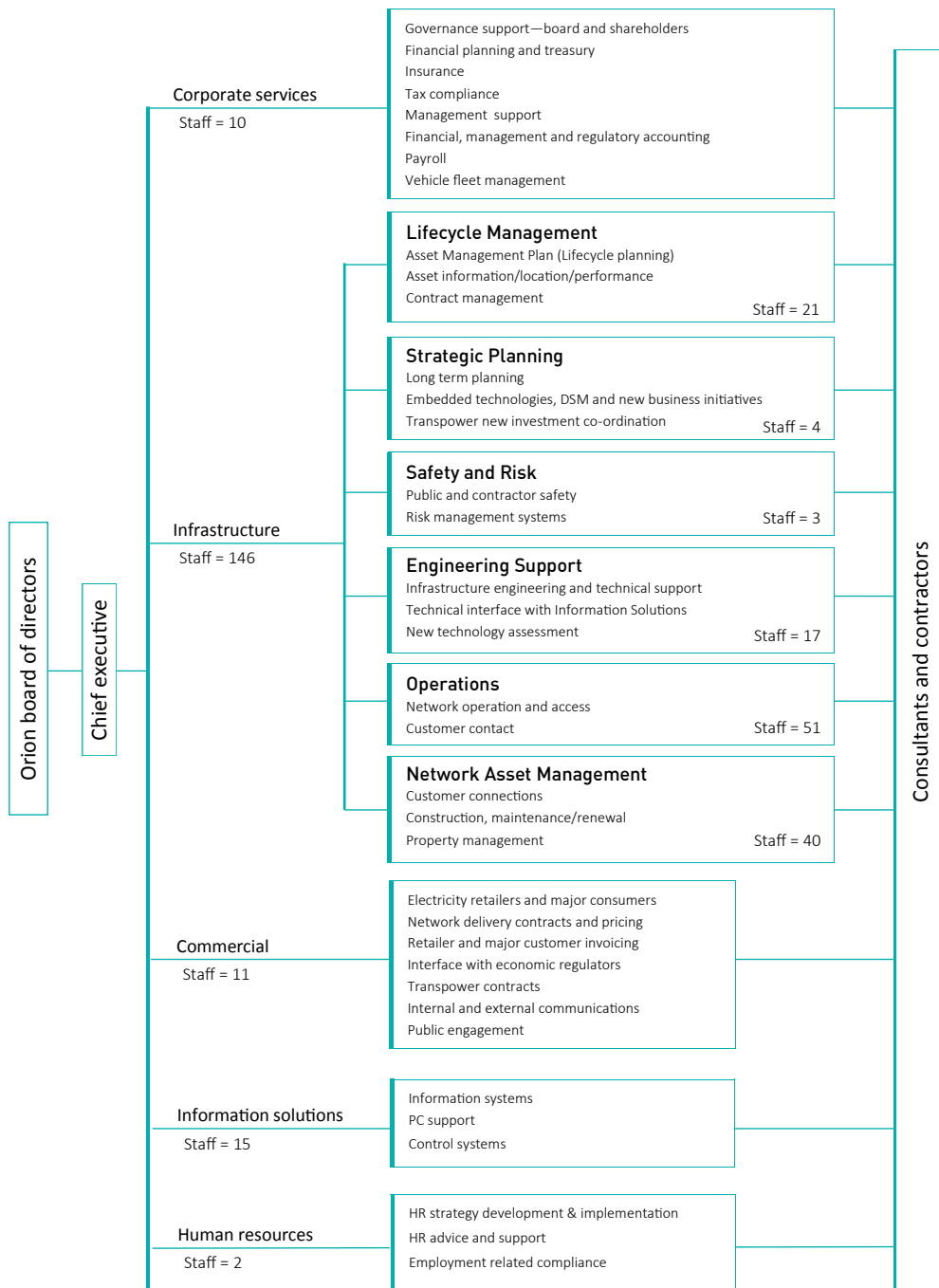
Consumer research is covered further in section 3 – Service levels.

2.4 Management responsibilities

2.4.1 Asset management structure

Our network is managed and operated from our Christchurch office at 565 Wairakei Rd. Our governance/management structure is as follows:

Figure 2-4a Asset management structure



2.4.2 Board and executive governance

Orion's directors are appointed by its shareholders to govern and direct Orion's activities. The board of directors is the overall and final body responsible for all decision-making within the company.

The board is responsible for the direction and control of the company including commercial performance, business plans, policies, budgets and compliance with the law. The board reviews and approves our revised 10 year AMP prior to the start of each financial year (1 April).

The board also formally reviews and approves our key company policies each year, including our a delegated authorities and spending authorities.

Each corporate manager is responsible for their budget and operating within their delegated authorities.

The board usually meets monthly and receives formal updates from management of progress against objectives compliance and performance against targets.

We summarise the main responsibilities of each of our corporate groups below.

2.4.3 Corporate services

Our corporate services group is responsible for supporting the other corporate groups in areas such as:

- governance support for the board and shareholders
- reporting to the board and shareholders, including regulatory and statutory requirements
- financial planning and treasury management
- insurance
- debtors and creditors
- financial, management and regulatory accounting
- financial management information systems (FMIS)
- tax compliance
- reporting to the board and shareholders, including regulatory and statutory requirements
- payroll
- fleet management.

2.4.4 Infrastructure

We maintain in-house technical and administrative competence within our infrastructure group to:

- keep the public and our staff/contractors safe
- manage safety and environmental compliance systems
- manage risk to our assets as well as operational and environmental risk
- manage and develop asset and network policies along with design and construction standards
- scope network extension and maintenance work and prepare budgets
- manage projects/contracts and interact with contractors
- maintain strategic asset records and reliability statistics
- manage and monitor the network
- manage corporate property
- assess new technologies
- monitor asset emergency spares and supply systems
- analyse and forecast load, asset capability monitoring and contingency planning etc.
- interface with Transpower over technical connection issues and national grid capacity
- investigate the potential and impact of embedded generation

2.4.5 Commercial

Orion's commercial group is responsible for:

- pricing, billing and contracts with retailers
- relationships with economic regulators (such as the Electricity Authority and Commerce Commission)
- compliance with the industry rule-book

- commercial contracts with Transpower
- advice to retailers and major customers
- communications planning and implementation
- consultation and engagement on substantial projects
- managing Orion's brand.

2.4.6 Information solutions

Orion's information solutions group is responsible for:

- procurement, delivery and management of our information systems infrastructure
- the provision, support and enhancement of information systems that support our business processes
- managing our control systems.

2.4.7 Human resources

Orion's human resources function is responsible for:

- human resource strategy development & implementation
- human resource advice and support
- employment-related compliance.

2.4.8 Consultants and contractors

We have a number of consultants, contractors and independent experts that work with us to meet our asset management objectives. They do not have direct network management responsibilities but operate on a fixed scope and/or period contract to meet the specific needs of the work/project requirements.

It's our responsibility to identify our capital works and maintenance programmes as detailed in sections 4 and 5 of this AMP, subsequently approved in an annual budget. We then specify the work to be done by competent and appropriate consultants or contractors.

All network maintenance and construction work (where practicable) is competitively tendered to selected contractors. Contract works are tendered, processed and managed by the Infrastructure group.

The scope of out-sourced works to consultants and contractors can be outlined as:

Consultants

- expert advice
- detailed design.

Field services

- emergency response services
- spares and major plant services
- some specialist asset inspections and non-invasive/non-destruction testing
- maintenance of existing network infrastructure
- installation and replacement of new or existing network infrastructure.

2.5 Assumptions

2.5.1 Significant assumptions

Business structure and management drivers

This AMP assumes that we will continue to restore the resilience and reliability of our network, following the Canterbury earthquakes. We also assume no major changes in the regulatory framework, asset base through merger, changes of ownership and/or requirements of stakeholders. We forecast increased levels of expenditure for earthquake repairs over the next few years and the acquisition of local Transpower spur assets.

Service level targets

We have based our service level targets on consumers' views about the quality of service that they prefer. Extensive consultation over many years tells us that consumers want us to deliver network resilience and reliability and keep prices down. To meet this expectation we look for the right balance between costs for consumers and network investment.

Any spur assets purchased or newly developed distribution assets are expected to perform well. We continue to assess the condition of assets that may have been damaged by the earthquakes. We are focused on returning the reliability of our network to pre-earthquake levels by FY19.

We aim to continue to improve our network service over time. We expect continued incremental improvement as a result of our on-going routine network maintenance, asset replacement and network development practices.

For some projects, we expect more than incremental improvement. These projects include:

- our recently-installed network management system, part of a distributed management system, to provide better business service (sections 2.8.1 and 4.22),
- the installation of Ground Fault Neutralizers to improve rural network safety and reliability (sections 4.19 and 5.6.7) and
- improved physical security and barriers around our equipment in public places (section 4.15.5).

Lifecycle management of our assets

We have assumed no significant purchase/sale of network assets or forced disconnection of uneconomic supplies other than those discussed in the development of our network (section 5).

The planned maintenance and replacement of our assets is largely condition and risk based. This assumes prudent risk management practises associated with good industry practise to achieve the outcomes in line with our targeted service levels. Our risk assessments are based on the context of no significant changes to design standards, regulatory obligations and also our other business drivers and assumptions discussed in this section.

Network development

Section 5 of this AMP outlines projects that will ensure that our network will continue to meet our consumer's expectations of supply, including earthquake recovery in the northeast and increased capacity in areas of growth

We assume that the structure of our network pricing will remain substantially unchanged. Our network pricing aims to promote active participation from consumers (for example, many of our major customers respond to our price signals and reduce their demand when our network is running at peak demand) and we have assumed this participation will continue. We envisage that the uptake of new technology such as electric vehicles and solar panels will accelerate but have assumed that they will not make a material difference in the 10 year time frame.

Similarly with embedded generation, we have seen connection of relatively small amounts of generation (small in scale) into our network. This has had a small impact on our network and we have assumed no larger scale generation connections. We have assumed that industry rules will ensure that generation connections will not be subsidised by other industry participants (including us) or consumers.

Risk management

The assumptions regarding management of risk are largely discussed in section 6. Although we have planned for processes and resources to ensure business continuity as a result of a major event or equipment failure, we have not included the actual consequences of a forecast/hypothetical major event in our AMP forecasts.

2.5.2 Changes to our existing business

No changes are proposed to the existing business of Orion. All forecasts in this AMP have been prepared consistent with the existing Orion business ownership and structure.

2.5.3 Sources of uncertainty

Potential uncertainties in our key assumptions include:

- Regulation. Future changes to regulation are unlikely to reduce our targeted service levels and are likely to continue the pressure for ensuring cost effective delivery of network services. We believe that the structure of our network pricing and our management processes encourage the economic development of the network and the chances of adverse significant changes in the regulatory framework in this regard are low.
- The city's rebuild. The pace of the CBD and 'red zone' recovery is influenced by The Crown, CERA/ CCDU and local roading authorities. It's also influenced by private developers. There is uncertainty regarding the timing and extent of some key recovery projects as the cost of the rebuild escalates.
- Our ownership. We assess that the level of uncertainty related to our ownership is relatively low.
- Consumer demand. Significant changes in consumer demand are unlikely because most changes in consumer demand require investment. Our experience is that stable price signals are needed to ensure consumers' willingness to invest in changes. Although electricity retailers have invested in 'smart meter' technologies, we believe that the likelihood of significant changes in consumer demand is low to medium over the 10 year AMP period.
- Our forecast for demand growth is in the order of 1% per year. The impact of significant changes to this forecast has minimal affect on our ability to undertake works. We estimate that we would need to see annual load growth in the order of 5% for use to encounter significant short-medium term resourcing issues. We rate the impact of this uncertainty as low.
- Resourcing of skilled contractors and staff due to demand.

2.5.4 Cost inflation

The key assumptions for our cost forecasts are discussed in section 7.1 where all dollars are in FY16 terms and no allowance has been made for CPI adjustments, changes in foreign exchanges rates, or local labour, plant and material market rate changes. Refer to appendices for the expenditure schedules in nominal (inflation-adjusted) terms.

2.5.5 Potential differences between our forecast and actual outcomes

Factors that may lead to material differences include:

- Regulatory requirements may change.
- Our ownership may change, leading to new management drivers.
- Customer demand may change and/or the requirement for network resilience/reliability could change. This could be driven by economic and/or technology changes. This could lead to different levels of network investment.
- Changes in demand and/or connection growth could lead us to change the timing of our network projects.
- One or more large energy consumers/generators may connect to our network requiring specific network development projects.
- Major equipment failure and/or a major natural disaster may impact on our network requiring significant response and recovery work. This may delay some planned projects during the period until the network is fully restored.
- Input costs and exchange rates and the cost of borrowing may vary influencing the economics associated with some projects. If higher costs are anticipated, some projects may be abandoned, delayed or substituted.
- Changes to industry standards, inspection equipment technologies and understanding of equipment failure mechanisms may lead to changing asset service specifications.
- Requirements for us to facilitate the rollout of a third party communications network on our overhead network could lead to substantial make ready work ensuring the network is capable of meeting required regulatory and safety standards. This could lead to resource issues and short-medium term increases in labour costs.

2.5.6 Information sources

Our business structure and management drivers

Our management drivers are primarily driven directly from our statement of intent, and company mission and vision statements. These are summarised in section 2.2.

Our service levels

Our understanding of our stakeholders is largely sourced through consultation processes. Stakeholders include shareholders, electricity retailers and contracted customers and consumers, employees, Transpower, government agencies, contractors and suppliers and financial institutions. The primary sources of information include:

- consumer surveys, meetings and informal discussions
- major customer forums and industry seminars
- quality of supply studies
- employee satisfaction surveys
- specific project consultations
- supplier technical assessment meetings
- consultation papers and submissions.

Lifecycle management of our assets

We have experienced management, engineers and practitioners some of whom are actively involved in industry standards groups and working parties, technical forums and seminars. This helps us to make prudent judgements associated with new equipment, practises and processes that benefit the operation and development of our network.

Network Development

The basis and sources of information that underpin our forecasts for growth are discussed fully in section 5.4.

Risk Management

The development of our risk management processes is based on our ability to understand and assess practical solutions to identified risks. The principal sources of information involved in this process include:

- industry incident notifications
- Orion incident reporting
- participation in Industry Safety Strategy group
- participation in national and local CDEM lifeline activities
- specific asset class condition and risk assessments
- business continuity plans.

Financial

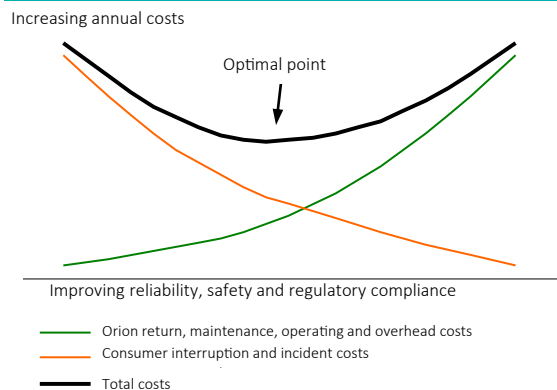
We base the updating of our cost estimates on recently completed project costs, and where appropriate utilise CPI and Primary Producer Indices.

2.6 Asset management drivers

2.6.1 Investment principle

When we extend, replace, maintain and operate our network we consider the balance between cost and the quality of supply provided. The optimum point of investment in the network is achieved when the value of further expenditure would have exceeded the value of benefits to our consumers. This concept is illustrated in the following Figure 2-6a.

Figure 2-6a Optimal cost versus quality principle



Put simply, we need to find the right balance between cost and the quality of our electricity delivery service. We seek to achieve this optimal point by economic analysis when we develop and review our asset management practices.

To achieve optimal outcomes, we also commit significant resources to participate actively in the consultation phase of national rules and regulations. It is important that rules and regulations that affect our industry are well-informed, principled and practical.

The speed at which new asset and systems technologies become available has increased in the last decade. We welcome these new initiatives and are committed to keeping up-to-date with technological advancements.

In line with our 'optimal point' approach above, we introduce new technology only when it results in an economic balance of cost and network performance. We then modify our standards and specifications to include the initiative.

More detail on technology initiatives is discussed in context within the various sections of our AMP.

2.6.2 Business drivers

Our top priority is the efficient and effective management of our electricity network. We aim to provide consumers with a high level of service, a reliable and secure supply and competitive prices. We also aim to provide our shareholders with an attractive risk adjusted return on their investment.

The main business drivers which define the need, priority and scope for improved asset management practices within Orion are summarised below:

Safety

We are committed to meeting our safety obligations. We will:

- keep the public and our staff/contractors safe
- adopt appropriate safety standards for the creation of new assets
- specify works to maintain assets in a safe condition
- operate and work safely with documented procedures
- develop appropriate risk management practices.

Like all companies we are subject to the general provisions of the Health and Safety in Employment Act, which has far-reaching impacts. Other specific safety requirements are found in the Electricity Act, the Electricity Safety Regulations, Fire Services Act and the Building Act.

We also continue to run an advertising campaign to inform the public about how to stay safe around electricity.

Customer service

Consumers require electricity to be delivered safely, reliably, efficiently and economically. We use asset management techniques and good industry practice to satisfy these requirements and we seek to:

- identify and satisfy consumer requirements
- improve understanding of service level options, measures and associated costs.

Environmental responsibility

We aim to be environmentally responsible. Legislation such as the Resource Management Act 1991 and our own environmental sustainability policy guide our activities.

Our major identified responsibilities are our duty:

- to avoid discharge of any contaminants into the environment
- to avoid unreasonable noise
- to avoid, remedy or mitigate any adverse effect on the environment.

We also aim to minimise our environmental impact by incorporating the cost of carbon into our network purchasing decisions. Approximately 77% of our carbon footprint is due to electrical losses in our network. We have now included specific carbon costs to the cost of electrical losses into our investment process.

Underground conversion projects are an asset enhancement driven partly by our concern for the visual environment.

Economic efficiency

We aim to ensure that the financial returns on our network investment are appropriate. Our asset management practices support economic efficiency as they:

- provide a basis to monitor asset performance and utilisation
- enable asset managers to plan and prioritise maintenance, renewal and growth expenditure
- quantify risk, and minimise high impact failures
- extend the life of assets and optimise the trade-off between maintenance and replacement
- tender all work to competent contractors and thus ensure the best price for specific works
- conduct an economic cost benefit analysis on all major projects
- optimise distribution network losses and network utilisation (load factor).

Legislation

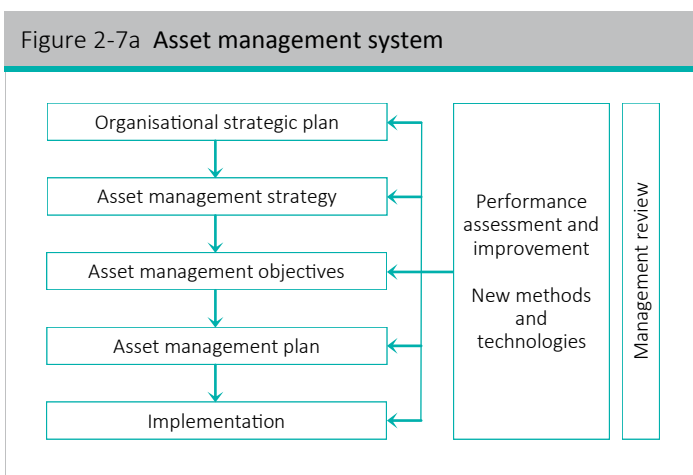
Our aim is to achieve material compliance with all relevant legislation, regulations and codes of practice that relate to how we manage our electricity distribution network, including:

- | | |
|--|---|
| • Electricity Act | • Local Government Act |
| • Electricity Amendment Act | • Resource Management Act |
| • Electricity Reform Act | • Building Act |
| • Electricity Industry Act | • Health and Safety in Employment Act |
| • Electricity Regulations | • Health and Safety in Employment Regulations |
| • Electricity (Hazards from Trees) Regulations | • Public Bodies Contract Act |
| • Civil Defence Emergency Management Act | • Public Works Act |
| • NZ Electrical Codes of Practice | • Electricity Distribution Information Disclosure Determination |

2.7 Asset management process

2.7.1 Introduction

We undertake lifecycle management and asset maintenance planning using whole of life cost analysis, reliability-centred maintenance, condition based maintenance and risk management techniques. The techniques are based on performance and reliability targets. The high level targets are discussed in section 3. Our overall asset management process is as follows:



Reliability-centred maintenance

Our network management philosophy is reliability-centred and based on retaining asset function. To do this we ask the following questions:

- what is the functional requirement of this asset?
- what is it that may fail and prevent this function?
- what can we do to retain the asset function?

Cost and benefit are considered and the results are monitored to gauge the effectiveness of any significant changes. This works well for overhead line assets that have a higher failure rate, providing sufficient information to make meaningful decisions. However, when applying reliability-centred maintenance to assets with much lower failure rates, such as switchgear, information has to be obtained from a wide range of equipment before we decide on cost-effective actions.

Condition based risk management

Condition based maintenance is an extension of reliability-centred maintenance. Where appropriate, maintenance is performed based on the condition of the asset and the consequence of its failure (see 6.1), rather than on the traditional time-based approach.

We engaged EA Technology Limited to develop condition based risk management (CBRM) models for the majority of our network assets. These models utilise asset information, engineering knowledge and experience to define, justify and target asset renewal. They provide a proven and industry accepted means of determining the optimum balance between on-going renewal and Capex forecasts. We are currently integrating this practice into our business processes and have used the CBRM models to develop a number of our replacement programmes.

The CBRM models calculate the health index (HI) and probability of failure (PoF) of each individual asset. This effectively gives the asset a ranking which can be used to help prioritise replacement strategies. Note, the models utilise some averaging/generalising of asset information to calculate the asset ranking so it is still up to the asset managers to prioritise the replacement schedule.

We are still in the process of collating and refining information on the condition of our earthquake damaged assets and fully integrating the CBRM process into our business.

2.7.2 Planning priorities

Recent changes in regulations and industry codes of practice have highlighted the need to mitigate safety risks for the public, employees and contractors. Therefore we:

- continue to remove or modify high-risk equipment
- increase security around substations and equipment
- tighten controls on equipment access.

In recent years we have focused our ability to meet the growth needs of the community while ensuring appropriate reliability and security. Network security is always compromised during times of change when capital or maintenance works are carried out.

To mitigate risk associated with reduced security during these periods of change we:

- endeavour to plan work methods and contingencies to minimise any impact on the network
- use programmes that allow for contingency events
- programme works in a manner that provides consistent work for the skilled resources available
- are proactive in the development and retention of skilled resources for the future.

2.7.3 Construction standards and working practices

Design standards

In order to manage the safety, cost, efficiency and quality aspects of our network we seek to standardise network design and work practices. To achieve this consistency we have developed design standards and drawings that are available to approved designers/contractors. Normally we only accept designs that conform to these standards. However, this should not be construed as a desire on our part to limit innovation. Design proposals that differ from normal are considered if they offer significant economic, environmental and operational advantages.

Technical specifications

These specifications are intended for authorised contractors working on the construction and maintenance of our network and refer to the relevant codes of practice and industry standards as appropriate. Specifications are listed in section 4 against the asset group they relate to.

Equipment specifications

We also seek to standardise equipment used to construct components of our network. To this end we have developed specifications that detail accepted performance criteria for significant equipment in our network. Usually new equipment must conform to these specifications. However, this should not be construed as a desire on our part to limit innovation. Equipment that differs from normal is considered if it offers significant economic, environmental and operational advantages. See following section 2.7.4 – Process to introduce new equipment.

Asset management reports

We have a report for each of the asset groups set out in section 4. They detail the criteria and asset management practices we use to obtain effective performance and acceptable levels of service from our assets. The CBRM results and the maintenance/replacement budgets for the asset group are detailed here.

Equipment operating instructions

To ensure the wide variety of equipment on our network is operated safely with minimum impact on our consumers, we have developed operating instructions that cover each different type of equipment on our network. We create a new operating instruction each time any new equipment is introduced. See following section 2.6.4 – Process to introduce new equipment.

Operating standards

To ensure our network is operated safely we have developed standards that cover such topics as the release of network equipment, commissioning procedures, system restoration, worker training and access permit control.

Document control process

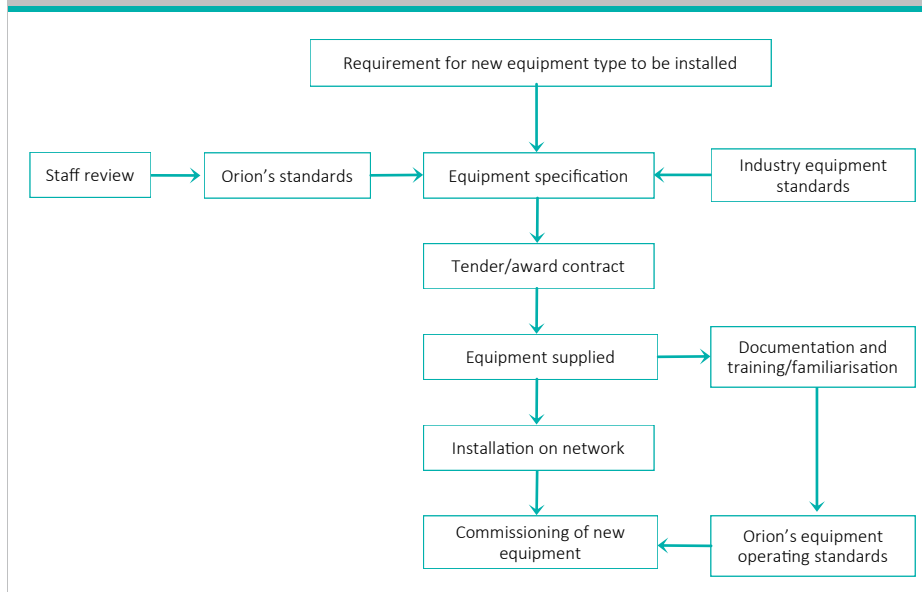
To ensure that all these documents and drawings are maintained as accurately as possible, each is 'owned' by one person who is responsible for any modifications to it. Our Network Data Systems Manager is responsible for processing these controlled documents using a process set out in our document control standard.

Email and a restricted-access area on our website are used to make documents and drawings accessible to approved contractors and designers.

2.7.4 Introduction of new equipment types

New equipment types are reviewed to carefully establish any benefits they may provide. Introduction is carried out to a plan to ensure that the equipment meets our technical requirements and provides cost benefits. It must be able to be maintained and operated to provide safe, cost effective utilisation to support our supply security requirements.

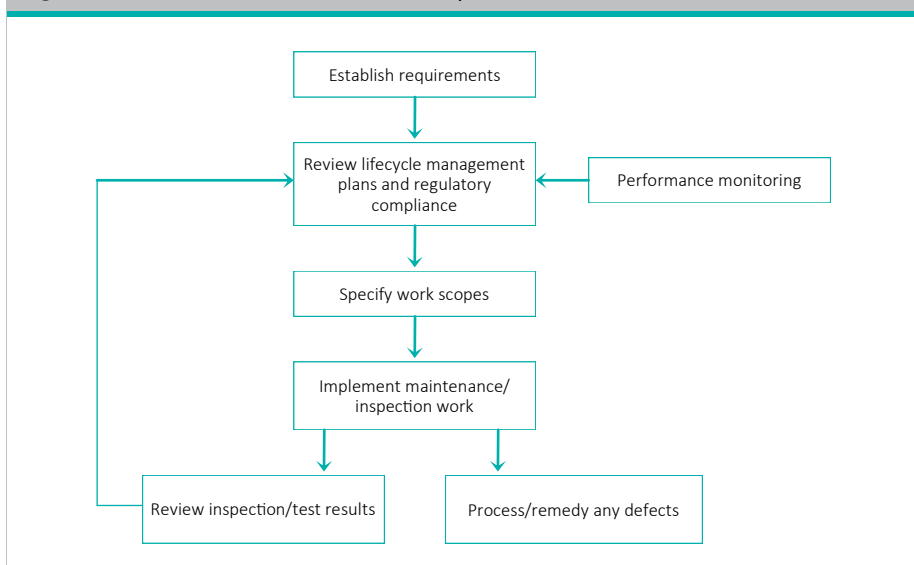
Figure 2-7b Process to introduce new equipment



2.7.5 Routine asset inspection and maintenance

The main function of our routine asset inspection and maintenance process is to ensure that optimal levels of asset performance allow us to meet our service level objectives.

Figure 2-7c Process for routine asset inspection and maintenance



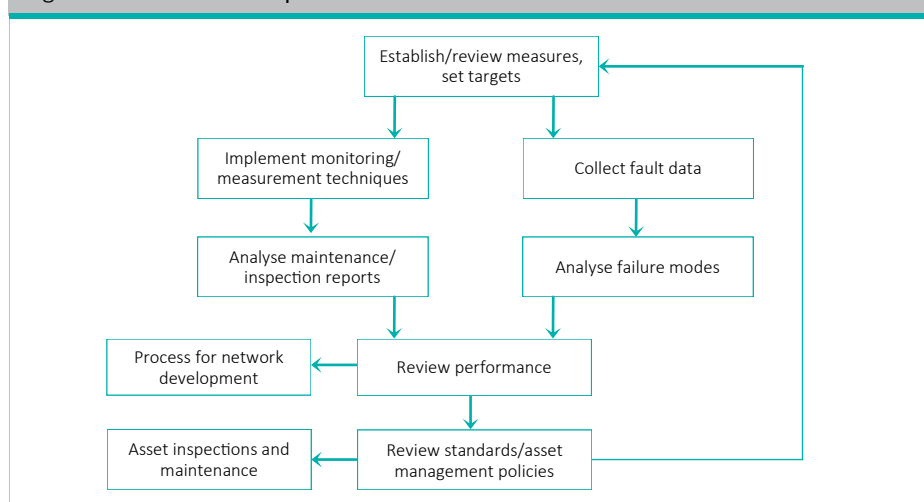
2.7.6 Performance measurement

The main function of our performance measurement process is to maintain levels of network performance. This allows us to set optimal asset/network management standards to meet customer and regulatory requirements.

We currently collect network performance data and rigorously review all network outages logged in our control centre. This process is independently audited on an annual basis and has been automated with the introduction of our network management system that utilises SCADA information and a real-time network model.

SAIDI and SAIFI figures are monitored and reported on a monthly basis to allow appropriate management of the network. A more detailed formal documented review of network performance is undertaken on an annual basis.

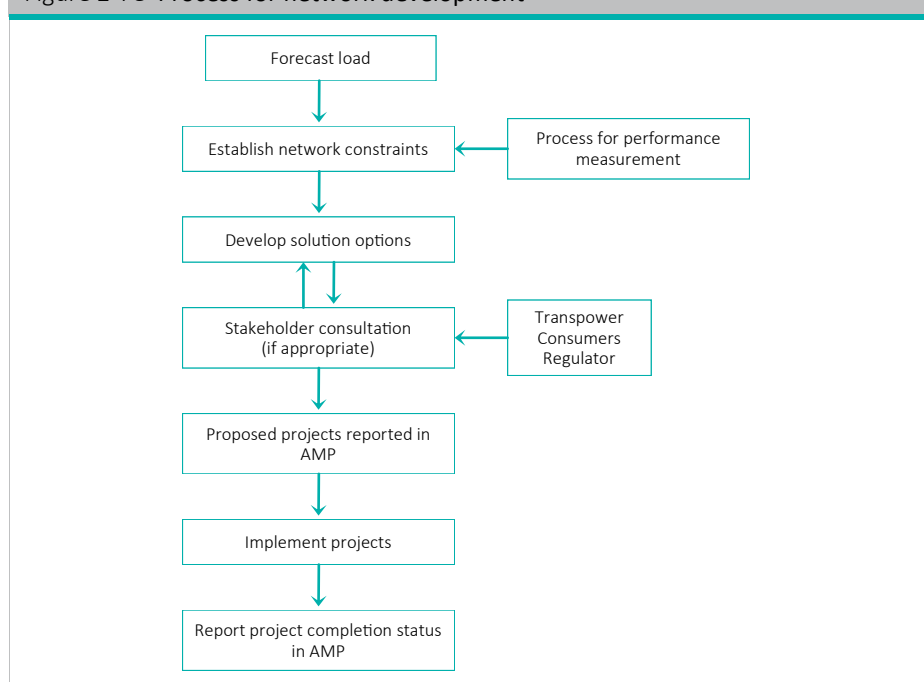
Figure 2-7d Process for performance measurement



2.7.7 Network development

The main function of our network development process is to meet the capacity and security requirements of load growth. See section 5.6 for a description of network development at Orion.

Figure 2-7e Process for network development



2.8 Systems and information

2.8.1 Systems

Our management systems are used to document the existing asset components of our network and provide access to data to develop, maintain and operate our business. The various systems and information flows between them are shown in Figure 2-8a on the following page. A description of the function of the main systems is detailed below:

1. Orion desktops

It is our policy to standardise and simplify our computing environment as much as possible. We deliver a single model of desktop and laptop configured with standard images, one version of Microsoft's operating system for network clients and one for servers and a single set of desktop productivity tools (Microsoft Office).

2. Geographic asset information

Our geographic information system (GIS) records our network assets according to their location and electrical connectivity. It interfaces with our other main information systems such as substation asset attribute data stored in our asset register.

Orion's GIS is accessible to all our staff for use at all times. Modified information deemed more "fit for purpose" is available to several external parties via a secure web site. Access by external parties is governed by Orion's business rules via a signed "Terms of Use" document.

Access to our GIS can be from any location at any time using various applications. In the case of field access, GIS datasets may be stored directly on a laptop device. This is a reliable way of accessing information when internet website access is unavailable. In another case we have provided GIS data to an external party to be 'layered' with other utility information.

Information stored in our GIS includes:

- land-base
- aerial photography
- detailed plant locations for both cable and overhead systems
- a model of our electricity network from the Transpower GXP's to the consumer connection
- conductor size and age.

See section 4 for more specific detail of information held on each asset group.

Our GIS mapping staff update and maintain the GIS data. Data integrity checks between our asset register and the GIS are automatically run every week.

Systems are in place to facilitate and manage GIS business development in-house.

3. Asset register

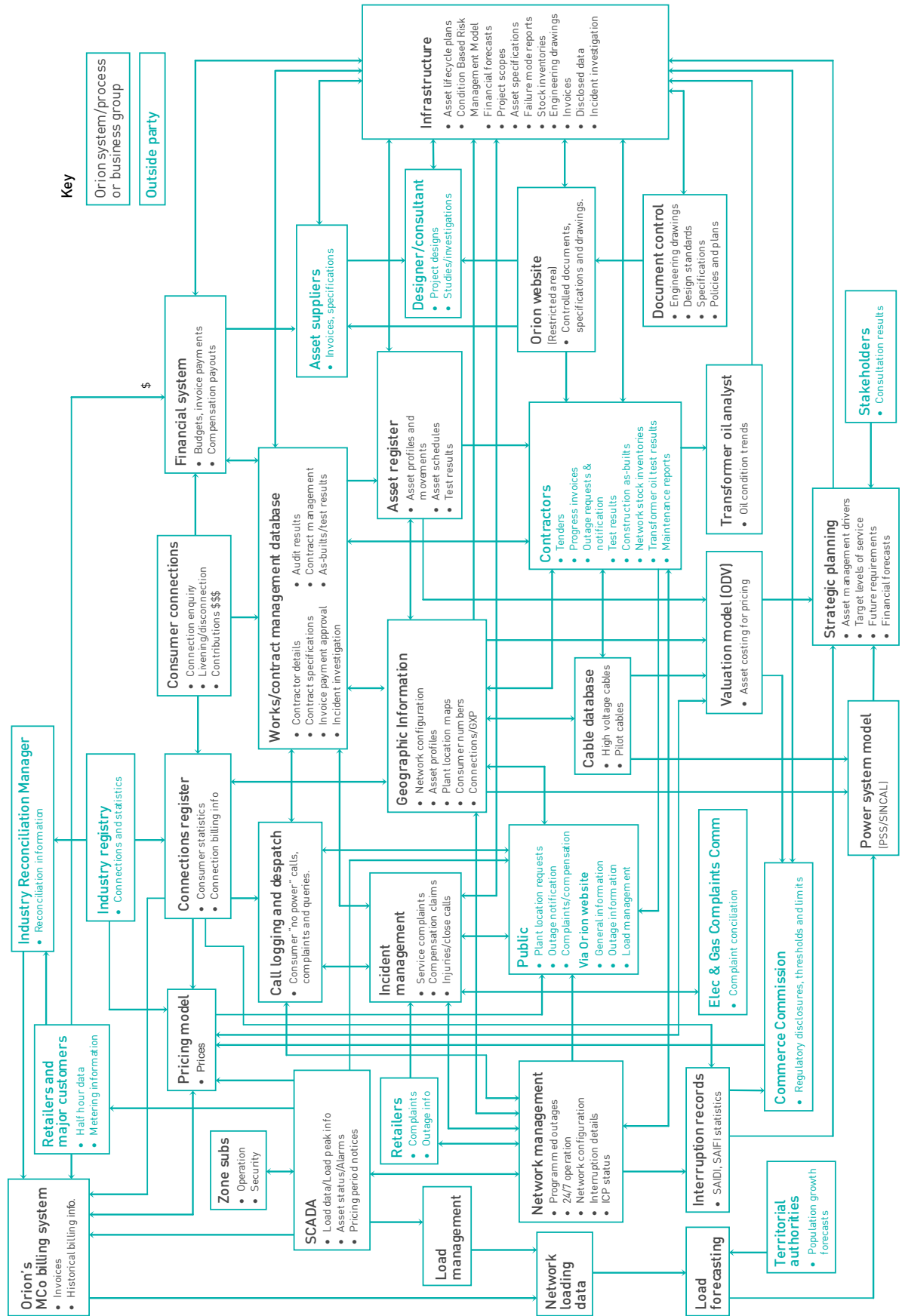
Our asset register provides a central resource management application for holding details of key asset types. The assets covered include all our major equipment. Schedules extracted from this database are used for preventative maintenance contracts and network valuation purposes.

Information held in our asset register includes details of:

- substation land (title/tenure etc.)
- transformers
- high voltage switchgear and ancillary equipment
- test/inspection results for site earths, poles and underground distribution assets
- transformer maximum demand readings
- protection relays
- substation inspection/maintenance rounds
- poles and attached circuits
- valuation schedule codes and modern equivalent asset (MEA) class
- field SCADA and communication system
- links to documentation and photographs.

See section 4 for more specific detail of information held on each asset group.

Figure 2-8a Management systems and information flows



4. Works management system

All types of works activity are managed using a purpose-built application. Integration with our financial system allows a work order to be raised directly in the Works management system.

Information held in works management includes:

- contractor/tendering details
- contract specifications and drawings
- management of consumer connection requests
- auditing outcomes
- contract management documentation
- financial tracking
- job as-built documentation.

5. Connections-related service requests

A web-based application accessed from our website allows contractors and the public to lodge a request for a variety of connections-related services including a request for a new connection, a request for livening, and various similar services. It is integrated with the Works management system and is designed to help with the anticipated volume of connection requests associated with the earthquake rebuild.

6. Connections register

Our connections register holds details of all installation control points (ICP) on our electrical network. This is linked with the industry registry. Links with our GIS systems enable accurate derivation of GXP information by ICP and the association of ICP with an interruption. Interruptions are now routinely traced within PowerOn (for the high voltage network) and the GIS (for the low voltage network) using the in-built connectivity model. Accurate information about the number of customers and interruption duration are recorded and posted overnight to the Electricity Authority's registry.

7. Financial management information system (FMIS)

Our FMIS delivers our core accounting functions. Our core FMIS is 'Microsoft Navision', and it includes the following main systems—general ledger, debtors, creditors, job costing, fixed assets and tax registers. Detailed network asset information is not held in the FMIS but is held in other network systems described in this section.

There is an interface between the Works management system and the financial system to link project activities to jobs.

8. Network monitoring system (SCADA)

The electricity distribution system is monitored and controlled in real time by the SCADA system. Apart from three small rural substations, SCADA is installed at all zone substations and line circuit breakers. We are also progressively installing SCADA at network substations throughout the urban area as old switchgear is replaced. See section 4.21 for more detail.

Systems have been built to retrieve half hour network feeder loading data from the SCADA historical storage system on a weekly basis. This data is then analysed to derive and maintain maximum demands for all feeders monitored by the SCADA system. Loading data is also archived for analysis in the future.

9. Network management system (NMS)

The NMS is a real-time software model of our high voltage distribution network. It allows interaction in real time with indication and control devices to provide better information on network configuration. This significantly improves our ability to decide on how to respond to network outages (especially big events such as storms) and manage planned maintenance outages to minimise the impact on consumers. The system also allows us to automate some functions, therefore improving response times. Information will be available to inform non-operational parties about events and their impact on our consumers.

10. Outage management system (OMS)

The OMS is the third component (along with the SCADA and NMS functions) of a comprehensive "Smart" Distribution Management System that underpins much of our operational activity. Outages are inferred from SCADA 'trippings' or from consumer call patterns and are tracked through their lifecycle. Key performance statistics are automatically calculated and an audit trail of HV switching activity is logged. The previous call-taking application has been decommissioned.

Integrated into the NMS and OMS is a mobile extension which delivers switching instructions to field operators in real time, and returns the actions they have taken. It also delivers fault jobs to field workers and tracks the progress of the job as it is worked on. Jobs requiring further work by an emergency contractor are automatically dispatched to the contractors' administration centre. Contractors enter completion information directly into a web-based application, and the job details automatically flow through into the works database.

11. Outage reporting

A web-based application is used to display details of planned, current and past outages both internally and to the public via the Internet. Currently this is updated manually, but is about to be replaced by a version that extracts its information directly out of the PowerOn OMS. This will allow accurate real-time reporting of customer numbers affected by an outage. We are also planning a web-based real-time Outages map to be available internally and to the public. The existing applications for reporting planned and unplanned outages will be dismantled.

12. Livening and demolition management

The previous generic call-taking function is now used just to manage demolitions. Jobs are dispatched to handheld devices in the field and demolition details returned electronically. At present this process is no longer integrated with other systems. A previously used handheld-based system for managing the livening of both temporary and permanent supply has been converted to a web-based application and is used by our livening agents to pick up authorized work and return livening details.

Over the next year we intend a major streamlining of these processes to reduce the needed back-office intervention and to provide seamless integration with our Works management system.

13. Interruption statistics

An automated posting of outage statistics out of the PowerOn OMS and into our regulatory reporting database is under construction. This tracks each switching step associated with an outage. After checking, the data will be summarized along with cause and location in an Microsoft Access-based interruptions register. Reports from this register provide all relevant statistical information to calculate our network reliability statistics (such as SAIDI and SAIFI) and analyse individual feeder and asset performance. The current more manually intensive process will become redundant.

14. Load Management

A high-availability Load Management system is used to perform load shedding to reduce the magnitude of our peak load and to respond to Transpower constraints. This system is aging and a replacement strategy is being developed.

We also run an “umbrella” Load Management system that co-ordinates the load management systems of each of the seven distributors in Transpower’s Upper South Island region. This co-operative venture provides a number of significant benefits both to Transpower and to each of the participating distributors.

15. Incident management

We have implemented an incident recording system extension to our externally hosted Payroll system. This will allow staff-related incidents and injuries to be captured alongside other staff information. We continue to use in-house designed databases for managing non-staff related incidents (e.g. incidents affecting our network) and customer complaints. Incident information can be added progressively and all relevant documents can be stored electronically. Incidents can be graphed by type for reporting purposes.

16. Valuation model

The purpose of the valuation model is to determine the regulatory optimised deprival value (ODV) of our electricity network assets. The valuation follows the methodology prescribed in the Commerce Commission’s ODV Handbook. Some key valuation handbook data is held against assets in our asset register (WASP) and GIS, and additions and removals of assets from the network are captured in our works management system. This raw data is extracted and imported into a purpose-built valuation model developed using desktop application tools.

17. Pricing model

We maintain a financial pricing model that supports our derivation of delivery charges. We assign connections to several connection categories (depending on size and load characteristics) and use the model to allocate assets and costs to each category. We then establish a set of cost-reflective prices to collect the allocated costs. Asset, asset valuation and loading information are key inputs to a purpose-built pricing model developed using desktop application tools.

18. Orion’s Mco billing system

We have contracted Mco, a leading data services and market place support company, to provide our delivery billing system. The system receives connection and loading information, calculates delivery charges and produces our monthly invoices to electricity retailers and directly contracted major customers.

19. Network asset loading history

A database of well over 100 million half-hour loading values is available for trend analysis at a wide range of monitoring points in our network. The database also includes Transpower grid injection point load history and major customer load history. Several tens of thousands of new data point observations are being added daily.

20. Power system modeling software

An integral part of planning for existing and future power-system alterations is the ability to analyse and simulate its' impact off-line using computer power-flow simulation. We use a power-flow simulation software package called PSS/Sincal, and have the ability to model our network from the Transpower connection points down to the customer LV terminals if required. An automated interface developed in-house is used to enable power-flow models to be systematically created for PSS/Sincal. These models are created by utilising spatial data from our GIS, and linkages to conductor information in our as-laid cables database and customer information in our connection database records.

Because of harmonic problems encountered on the network supplied from Hororata GXP, we have also purchased the PSS/SINCAL harmonics module to allow us to model the network harmonics.

We are studying the feasibility of implementing the online power flow analysis package as part of our new network management system.

21. Cable databases

Separate Microsoft Access databases are used to hold information on 66, 33 and 11kV underground cables and pilot/communication cables. Cable lengths, joint and termination details are held and linked to our GIS by a unique cable reference number.

22. Transformer oil analyst

Transformer oil analysis (TOA) software provides a centralised database for new and past oil test results for all primary transformers. TOA provides dissolved gas diagnostics, the trending of key oil performance indicators and reporting capabilities. Reports from the TOA software are reviewed annually for all primary transformers.

23. Document control

Our engineering drawings and standard documents are controlled using a custom built system. This system is used to process the release of CAD drawings to outsourced contractors and return them as "as-built" drawings at the completion of works contracts. Standards and policies maintained in-house are also controlled using this system. Standard drawings and documents are then posted directly on our 'restricted' website and the relevant contractors/designers are advised via an automated email process.

24. Orion website

Our website has two distinct areas. One part which is open to the general public and another that is restricted to those parties that have a business requirement to use our drawings and specifications.

OPEN WEBSITE

Our open website is used to convey information to our customers and others. Some of the subjects covered are:

- load management, with near real-time network loadings, peak pricing periods and hot water control
- pricing
- publications, disclosures and media releases
- unscheduled interruptions, advised to street level
- planned shutdowns – each retailer is advised of customers that will be affected
- public safety and tree information.

RESTRICTED WEBSITE

The restricted section of our website is an area where we can place information but maintain some control over who we share it with. It is generally used to give network designers, construction contractors and equipment suppliers access to our:

- annual work plan
- standard drawings
- plant location maps
- design standards
- construction specifications
- equipment specifications
- operating standards.

The level of access into our restricted area is controlled by using a unique login and password. This enables us to determine that what is available to each login is consistent with the type of relationship we have with them.

2.8.2 Asset data

The majority of our primary asset information is held in our asset register, GIS system and cable databases. We hold information about our network equipment from GXP connections down to individual LV poles with a high level of accuracy. The data has improved over time due to various inspections and projects since we introduced our GIS system and asset register.

Requirements to improve information have been driven by improved asset management plans, regulatory compliance and better risk identification and management. This has ensured that we have the ability to locate, identify and confirm ownership of assets through our records.

Although there will inevitably be some minor errors and improved information will always be required, we believe that our information for the majority of the network is accurate. Some information for older assets installed more than 25 years ago has been estimated based on best available data. Examples of this include:

- the conductor age for some lines older than circa 1990
- timber poles that went into service prior to the use of identification discs
- older air break switches and cut-out fuses.

Refinement of data is an ongoing process. Compliance inspections and maintenance regimes are the main source from which to confirm or update data. As we replace aging assets with new assets over time all estimated data will be superseded.

Currently the only area identified where information needs to be improved is associated with determining accurate connection assets of individual LV consumers. This information is not easily accessible as it requires manual searches through archived information. The requirement for this information is not deemed high priority and information will be sourced associated with other inspection programmes over the next five years.

Details of current data, compliance inspections and maintenance regimes for each asset group are shown in section 4 – Lifecycle asset management – (*relevant asset*) – Standards and asset data.

2.9 Development of systems and processes

2.9.1 Short term developments

Network management system

A major upgrade of our Network Management system (SCADA, NMS and OMS) was completed in FY14. In parallel with this we have implemented a companion Historian and migrated much of our historic network asset loading information into it. Once fully implemented it will provide a continuous historic record of trends for a wide variety of monitored network values.

Document management system

Microsoft Sharepoint has been implemented and is being used across the business. The initial focus is to improve the management of “Office” documents and scanned images, but over time it will become used for a wide variety of information sharing features as well as providing framework for a replacement Intranet. Migration of documents from the historic file share into the new system will be progressively rolled out across the business.

Condition based risk management model

We have engaged EA Technology Ltd to develop condition based risk management (CBRM) models for the majority of our network assets. We are currently integrating the use of these models into our business processes to develop our replacement programmes. The models have been used this year in the development of the replacement plans for our high voltage circuit breakers, high voltage and low voltage switchgear and protection systems. Over the next few years it is our intention to streamline the processes for updating our condition information and to underpin the replacement expenditure for our other network assets by using the CBRM models.

Service levels



3

3.1	Introduction to service levels	63
3.2	Consumer consultation	64
3.3	Service level measures	66
3.3.1	Network reliability	66
3.3.2	Network restoration	67
3.3.3	Network capacity	68
3.3.4	Power quality	68
3.3.5	Safety	69
3.3.6	Customer service	69
3.3.7	Environmental	69
3.3.8	Efficiency	70
3.4	Service level forecasts	71
3.4.1	Forecasts for current year	71
3.4.2	Forecasts for future years	72

List of figures and tables in this section					
Figure	Title	Page	Table	Title	Page
3-3a	Orion SAIDI – five year trend and 10 year forecast	66	3-4a	Service descriptions, forecasts and measures for CY	71
3-3b	Orion SAIIFI – five year trend and 10 year forecast	67	3-4b	Service descriptions, forecasts and measures for future years	72
3-3c	Unplanned interruptions - % restored in < 3hrs	67			

3.1 Introduction to service levels

This section of our plan outlines our performance forecasts. It deals with consumer-related service requirements and other requirements relating to our asset management drivers as defined in section 2.6. Those drivers are:

- customer service
- safety
- environmental responsibility
- investment principles
- efficiency
- legislation.

We aim to meet the expectations of our consumers and other stakeholders. This is consistent with our 'mission' and statement of intent (SOI). Our SOI contains specific service level forecasts for reliability (SAIDI, SAIFI) and other aspects of our business, some of which are outside the scope of this AMP.

Our service level forecasts are based on a balance of:

- consumer and stakeholder consultation
- safety considerations
- regulatory requirements
- international best practice
- past practice.

We endeavour to provide a level of service that meets the expectations of our consumers' in the long term. We also recognise the differing requirements of consumers and endeavour to ensure that, as far as practicable, all consumers are satisfied with the level of service we provide and that no one party is unfairly advantaged or disadvantaged.

Keeping abreast of changing consumer expectations is fundamental to optimal asset investment and asset management practices. To determine consumer expectations with regard to the level of service that we provide, we utilise five main methods of consultation. We detail information on these consultation methods in section 3.2.

In summary, we:

- involve consumers in setting our security of supply standard
- undertake consumer surveys
- engage with consumers via retailers
- obtain direct consumer feedback
- consult consumers on selected major projects.

In setting our service level forecasts we believe we have achieved an appropriate balance between legislative, regulatory and stakeholder requirements and consumer expectations.

For a review of service level performance against our forecasts, see section 8 – Evaluation of performance.

3.2 Consumer consultation

Consumers are our key stakeholders. We recognise that their individual expectations will differ and we endeavour to ensure that, as far as practicable, all are satisfied with the level of service we provide in the long term and that no one party is unfairly advantaged or disadvantaged.

Consultation with our consumers has shown that they expect a reliable and secure supply of electricity. Since the earthquakes, our consultation has shown that customers want a return to near pre-earthquake levels of resilience and reliability.

We have undertaken the following methods of consultation:

Direct consumer engagement

All of our major customers are invited to at least two seminars a year. At these seminars we take the opportunity to explain the quality of our delivery service and our pricing strategy. Our CEO and key members of our senior management team attend the seminars to answer any questions from major customers.

We meet with our shareholders and consumer groups to discuss the quality and price of supply we provide. Feedback is also received from consumers through our contact centre and distribution services connection group.

Given the impact of the earthquake and our customised price- quality path application to the Commerce Commission, in late 2012 we asked consumers whether they still wanted pre-earthquake levels of reliability and resilience. We used multiple approaches to inform consumers and other stakeholders about our proposed pricing and network reliability forecasts and invited feedback. These approaches included:

- stakeholder briefings including a PowerPoint presentation
- a media briefing
- phone briefings with other stakeholders
- information packs sent to stakeholders and other interested parties
- extensive newspaper advertising
- a seminar for our major customers, supplemented with letters and information packs
- information packs sent to local community boards and public libraries
- radio and television interviews
- relevant information included on our website
- Twitter updates
- a public information day.

The feedback we received showed good support for our proposal to restore the network to pre earthquake levels, spread the cost of doing so over time and recover costs from consumers. Some submitters suggested that the costs should be met by a range of parties, such as our Council shareholders and the Government.

Consumer surveys

Over the last 10 years five consumer surveys have been undertaken by Orion.

- **Network reliability consumer survey**
We commissioned independent researchers in February 2004 to conduct a telephone survey with approximately 1,000 households in the Christchurch area. This survey indicated that 92% of respondents were satisfied with the current reliability of their power supply while 87% considered rapid restoration of power important.
- **Urban and rural network reliability consumer survey 2005**
We commissioned an independent research company in December 2005 to survey a random sample of 400 rural and 400 urban households in the Orion network area. This survey indicated that 94% of urban respondents were satisfied with the current reliability of their power supply while 88% considered rapid restoration of power important. Of rural respondents, 85% were satisfied with the current reliability of their power supply while 83% considered rapid restoration of power important. Of those surveyed, 99% of urban respondents and 98% of rural respondents were not prepared to pay more for improved supply reliability.
- **Snow storm survey**
We commissioned an independent research company in July 2006 to survey a random sample of over 400 rural consumers. This survey focussed on consumer attitudes and opinions to our response to the severe snow storm in June 2006. The survey captured both consumers that lost power (245 respondents) and those that did not lose power (170 respondents) during the storm. Unsurprisingly, the overall level of satisfaction with reliability of rural power supply fell slightly in this survey from what it had been in late 2005. Of the survey respondents, 76% were satisfied with the reliability of their power supply compared to 85% in 2005.
- **Rural consumer reaction to paying for greater reliability**
In June 2007 we commissioned an independent research company to survey a random sample of 400 rural residential consumers. The focus of this survey was to gauge if consumers were willing to pay more for increased reliability. The

increase in reliability would be gained by reducing outages, due to both momentary and permanent faults, through introducing the Ground Fault Neutraliser (GFN) technology at substations where the majority of the medium voltage network is still overhead. The survey indicated 68% of our residential rural consumers would be willing to pay an extra \$1 per month on their electricity bill for a “20% reduction in the number of lengthy power cuts and, hopefully, the complete elimination of momentary one or two second interruptions” (this was the expected performance gain from the installation of GFNs). Those consumers not willing to pay the extra \$1 were more likely to be older (60+), have smaller electricity bills (less than \$150 per month) and fewer lengthy power interruptions in the last six months (one or none) than those willing to pay. If the cost of new technology was reduced to 50c extra per month on their electricity bill then an additional 6% of residential rural consumers (a total of 74% of consumers) would be willing to pay for improved reliability.

- **Post-earthquake pricing and reliability**

In late 2012 we invited our consumers to complete an online survey about our proposed post-quake pricing and reliability. The survey results showed good support for our proposal to the Commerce Commission to restore our network to pre earthquake levels, spread the cost of doing so over time and recover costs from consumers. Some submitters suggested that the costs should be met by a range of parties, such as our Council shareholders and the Government.

Consumer engagement with retailers

On a daily basis, electricity retailers represent the consumers connected to our network, so we rely, in part, on retailers to let us know how consumers feel about the price and quality of our network service. In late 2012 some retailers provided direct feedback about our proposed post-quake pricing and reliability forecasts. Based on our dealings with retailers, we are not aware of any systemic concerns with the level of reliability we propose to provide.

Consumer consultation over major projects

We consult with various parties ranging from local councils to business and residential groups about selected major projects that we undertake. This consultation includes discussion about the benefits and costs of specific projects.

3.3 Service level measures

This section details the measures used to monitor our performance as an asset management business. All our consultation methods show that, almost without exception, a reliable supply of electricity at a reasonable price is our consumers' greatest requirement of us. We measure our performance against this primary consumer requirement in a number of ways as shown in section 3.3.1.

Other service measures such as efficiency, safety, environmental and legislative compliance reflect a range of performance measures that we monitor. Our performance in these areas often provides advance notice about where Orion's performance is heading prior to any change being noticed in our primary reliability forecasts.

For some of these other service measures we have not set a specific forecast value. In those cases we explain our position as to why we believe doing so would be counter productive. All our forecasts are set out in table 3-4a.

Our performance against the forecasts shown in this section are in section 8 - Evaluation of Performance.

3.3.1 Network reliability

Network reliability is measured by the quantity and duration of interruptions to the supply of electricity to our consumers. Our goal is to ensure that our reliability performance meets our regulatory requirements and our consumers' expectations as ascertained by the means discussed in the previous section.

Our primary network reliability measures are applied as required by the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012. These measures are:

- **SAIDI**, system average interruption duration index, measures the average number of minutes per annum that a consumer is without electricity.
- **SAIFI**, system average interruption frequency index, measures the average number of times per annum that a consumer is without electricity.

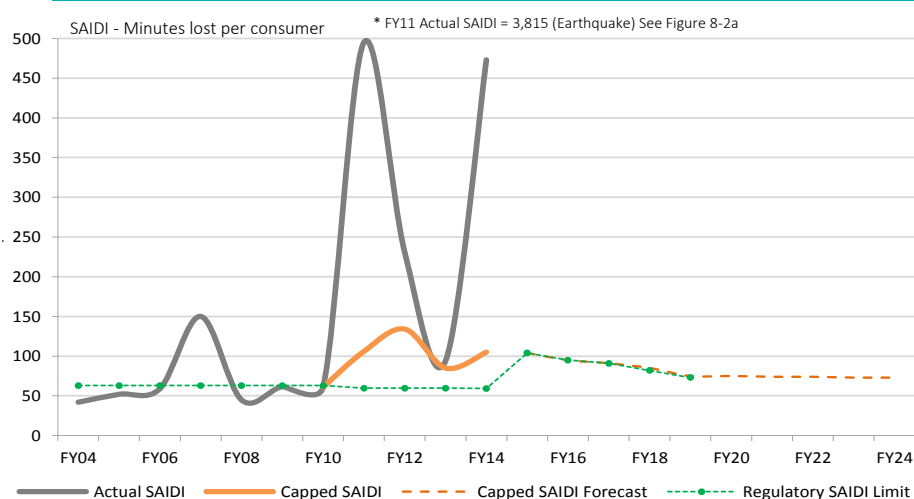
Both the SAIDI and SAIFI measures consider planned and unplanned interruptions of a duration longer than one minute on our subtransmission and high voltage distribution system. Low voltage interruptions and those that originate in Transpower's transmission system are not included. Planned interruptions to carry out work on our network would normally account for approximately 34% of our SAIDI minutes and 14% of our SAIFI.

Extreme environmental events can have a major impact on the reliability of an electricity network (this can be seen in the actual SAIDI values in figure 3-3a). To moderate this impact, the current regulatory regime calculates a daily boundary value to cap the number of consumer-minutes lost in the case of extreme events. Our annual network reliability limits and daily boundary values are currently set by the Commerce Commission under the Customised Price-quality Path (CPP) regime determined for Orion after the earthquakes of FY11. These limits will run from FY15 through to FY19 when they will be evaluated. Orion's SAIDI and SAIFI forecasts are set in relation to the same calculation methodology and daily boundary values.

It is not realistic to expect that we can continually improve network reliability as there comes a point where the added costs outweigh the added benefits, particularly in a predominately overhead rural network. For example, a major improvement in rural reliability would require a large capital investment and a correspondingly large increase in line charges.

Consumers have indicated across our various consultation methods that they are generally satisfied with our present level of network reliability and that they have concerns re price increases. In practical terms this means that we do not believe our consumers wish to see increasing levels of reliability beyond current levels if it means higher prices.

Figure 3-3a Orion SAIDI – 10 year history and 10 year forecast



NOTES.

Actual SAIDI

SAIDI value without any daily boundary values applied.

Capped SAIDI

SAIDI value capped to daily boundary values for any extreme event days as per CPP requirements.

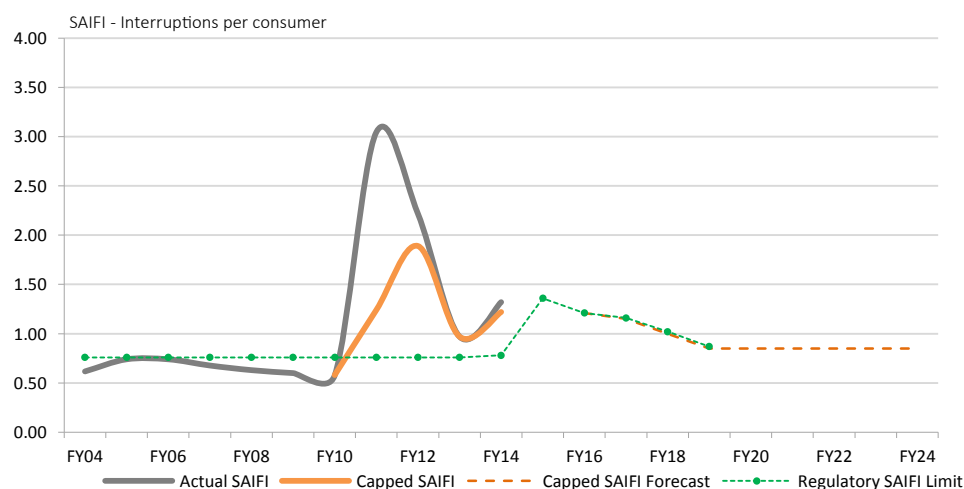
Capped SAIDI forecast

Orion forecast with daily boundary values applied.

Regulatory SAIDI limit

Regulatory annual limit value, with daily limit applied to cap extreme events as per CPP requirements.

Figure 3-3b Orion SAIIFI – 10 year history and 10 year forecast



Another network reliability forecast we use is 'faults/100km' of network. We set our forecast after reviewing international reliability data. This measure is how each asset class has performed rather than the impact on our consumers. We have decided not to set faults/100km forecasts until our post-earthquake network condition becomes clearer.

3.3.2 Network restoration

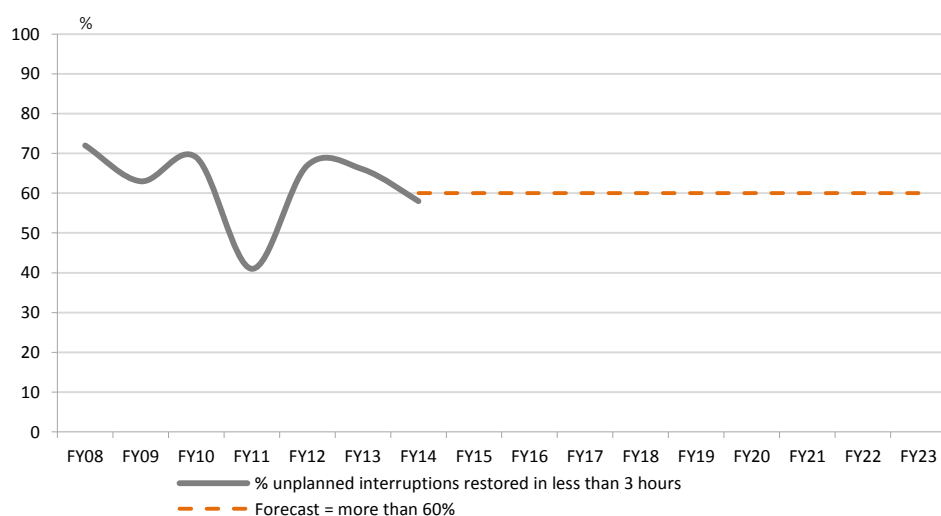
Consumer consultation has told us that if a power failure does occur, then rapid restoration of power is the most important concern. Surveys show that 83% to 90% of consumers consider this important following a power failure. Consequently our consumer focused measure is the percentage of unplanned interruptions restored within three hours.

Consumers across our various consultation methods say they are generally satisfied with our present level of service and that they are concerned about increased electricity prices. In practical terms this means that we do not believe our consumers wish to see increased levels of service beyond current levels if this would mean higher prices.

We have engaged an emergency contractor to manage our distribution asset spares and provide adequate response to any event on our network. Reasonable response times to effect a repair have been established and enshrined in a contract between us and our emergency contractor.

Our percentage of unplanned interruptions restored within three hours is based on providing a reasonable level of service at a reasonable cost.

Figure 3-3c Unplanned interruptions - % restored in less than three hours



3.3.3 Network capacity

Orion has a security standard that was developed in consultation with external advisors and adopted in 1998. It is based on the United Kingdom's P2/6 which is the regulated standard for distribution supply security in the UK.

Security of supply is the ability of a network to meet the demand for electricity in certain circumstances when electrical equipment fails. Note that security of supply differs from reliability. Reliability is a measure of how the network performs and is measured in terms of things such as the number of times supply to consumers is interrupted.

During 2007 we reviewed our security standard to ensure it takes into account consumer preferences for the quality and price of service that we provide. As a result of our review and consumer consultation, our security standard has been improved to better reflect the current needs of our consumers. Our revised security standard may result in slightly lower reliability for our outer-urban consumers but will also reduce the need for future price rises.

These kinds of trade-offs between price and electricity supply reliability are a constant focus for us. Generally, the more we spend, the more reliable our community's electricity supply becomes. However, the trade-off is that the more we spend the higher our prices become, as we need to recover our costs. We are committed to seeking our consumers' views on the price/quality trade-off and we want to ensure that our network investment decisions reflect consumer preferences.

The demand group thresholds in our security of supply standard tend to err on the side of caution and generally provide a level of security that is slightly above the requirements of the average consumer connection. Our analysis has also shown that it is appropriate to provide a slightly higher level of network security for the Christchurch CBD.

This approach ensures that consumers who place a high value on security of supply are reasonably represented in areas where a mix of consumer types exists.

Our security standard is detailed along with proposed improvement work in section 5 – Network development.

3.3.4 Power quality

Power quality is defined by a group of performance attributes of the electricity power supply. Two of the most common and important power quality attributes that are mostly under our control are:

- the steady state level of voltage supplied to consumers
- the level of harmonics or distortion of voltage of the power supply.

The reason why these attributes are only 'mostly' under our control is because the power quality that is supplied to us by Transpower (and to it by the generators) provides a baseline level of performance that we can only pass on to consumers. We contract with Transpower to provide a suitable level of power quality performance at the GXPs.

We have undertaken a three year project to install power quality measurement equipment at selected sites throughout our distribution network. The aim is to undertake a long term survey to determine the power quality performance of our distribution network and how it changes over time. The measurement sites chosen represent the average and worst performing parts of our network over a variety of consumer types.

Steady state voltage

The range of steady state voltage supplied to consumers is mandated by regulation, as 230 volts \pm 6%. We design and operate our network to meet this requirement. However, despite our efforts and usually due to unanticipated changes in consumer loads, some consumers will experience voltages outside these limits for some period of time. When a complaint is made, we will investigate. If the complaint is proven (i.e. the investigation shows that the non-complying voltage or harmonic originated in our network) we will upgrade our network to rectify the problem.

The level at which we have set our forecast for steady state voltage non-compliance (proven) is a pragmatic consumer-focused ratio of no more than one case per 2,500 consumers per year.

Harmonics/distortion

The allowable level of harmonics or distortion of the power supply provided to consumers is also covered by regulation. In most cases the consumers themselves have distorted their power supply, for example, by the use of electronic equipment. We provide an initial investigation service to measure the levels of harmonics or distortion and will determine whether other consumers are affected. If others are affected, we will require that the offending consumer rectify the problem. If no other consumers are affected, we will suggest suitable consultants who can offer a solution to the problems, but will leave the consumer to rectify at their cost.

We use harmonic allocation methods defined in joint International Electrotechnical Commission (IEC)/Australian/New Zealand standards to determine acceptable consumer levels of harmonic injection. These allow each consumer to inject a certain acceptable amount of harmonic distortion depending on the strength of the power supply at their premises.

The level at which we have set our forecast for proven harmonics/distortion complaints is no more than one per 50,000 consumers per year. This forecast is based on historical Orion data and international data.

3.3.5 Safety

Operating and maintaining an electrical network involves hazardous situations that cannot be eliminated entirely. We are committed to consultation and co-operation between management and employees to provide a safe reliable network and a healthy work environment – we take all practical steps to minimise the risk of harm to the public, our contractors and staff. Maintaining a safe healthy work environment benefits everyone and is achieved through co-operative effort.

Our objectives are to:

- keep the public and our staff/contractors safe
- provide safe plant and systems to ensure worker and public safety
- ensure compliance with legislative requirements and current industry standards
- provide safety information, instruction, training and supervision to employees and contractors
- provide support and assistance to employees
- set annual goals and objectives, and review the effectiveness of policies and procedures
- take all practicable steps to identify and then either eliminate, isolate or minimise hazards.

Further information on these objectives is available in our statement of intent and our performance against them is detailed in our annual report.

Our forecast of zero accidents is the only prudent forecast we could have for this measure.

3.3.6 Customer service

Consumers consider it important to get a quick response from us following an interruption to their electricity supply, and to get accurate information on when it will be restored. Of the 3% of urban consumers and 20% of rural consumers who try to contact us following a power cut, around 75% state that it is important to get through quickly if they call. In relation to the ability to call Orion, we operate a 24/7 contact centre from our head office.

We aim to answer calls promptly and typically 92% of calls to our contact centre are answered within 20 seconds, with an average wait time of about 11 seconds. However, our focus in call management is not on call answering times, or call duration, but rather providing information quickly, accurately and politely.

3.3.7 Environmental

We are committed to being environmentally responsible. This fits within our principal objective, which is to operate as a successful business and be financially sustainable. We have established a number of environmental sustainability policies that are published on our website. These policies are reviewed annually. Further information on each of these policies is available in our statement of intent which is also on our website.

The environmental measures related to the operation of our network are:

- the amount of SF₆ gas lost into the atmosphere (as a percentage of the total volume in use on our network)
- the number of oil spills that are not contained by our oil containment facilities or mitigation procedures.

Our forecast for loss to the atmosphere of the insulating gas SF₆ is based on a percentage of the total volume of the gas in use on our network. The level is set by an undertaking we have signed with the Ministry of the Environment to comply with the “Memorandum of Understanding relating to Management of Emissions of Sulphur Hexafluoride (SF₆) to the Atmosphere”. In addition to this we have a policy not to purchase equipment containing SF₆ gas if a technically and economically acceptable alternative exists.

In respect to oil spills, we operate oil containment facilities and have implemented oil spill mitigation procedures and training. Our forecast of zero uncontained oil spills is the only prudent forecast we could have for this measure.

In FY08 we undertook a study, in conjunction with international consulting firm MWH, to map our key impact on the environment and identify where we can improve our environmental performance. This ‘mapping’ exercise was very wide ranging and went beyond the factors normally considered in carbon footprint exercises. As a result of MWH’s report we identified the following activities to focus on (five have been accomplished and the others are on-going; date completed shown in brackets):

- incorporate the cost of carbon into our network investment decisions (June 2009)
- assess the feasibility and desirability of becoming carbon neutral (September 2009)
- work with Community Energy Action to insulate at least 500 low income homes in Christchurch (March 2010)
- undertake a safety and efficiency driving course for all Orion and Connetics employees who regularly drive operational vehicles (March 2011)
- consider the potential to replace operational vehicles with more fuel efficient models. Then work with other contractors servicing the Orion network to encourage them to run their vehicle fleet as efficiently as possible (March 2011)
- continue to undertake and encourage demand side management (on-going)
- reduce and where practical eliminate the installation of new network cables containing lead (on-going)
- continue our support for and sponsorship of CEA (on-going)

- support the Christchurch City Council's sustainable energy strategy (on-going).

Other aspects of our operations that support our environmental commitment are that we:

- facilitate the easy connection of renewable low-carbon generation (for example wind and PV) to our network
- signal load peaks in our network pricing to encourage the efficient use of our network
- maintain and operate an efficient water cylinder load control system so that significant loads can be shifted away from peak times to less expensive off peak times – at minimal inconvenience to customers
- are looking at possible wind generation sites in our network area.

3.3.8 Efficiency

Economic efficiency

Economic efficiency reflects the level of asset investment required to provide network services to consumers, and the operational costs associated with operating, maintaining and managing the assets.

We have adopted the following measures of economic efficiency:

- capital expenditure per annum per MWh of electricity supplied to consumers
- operating expenditure per annum per MWh of electricity supplied to consumers
- operating expenditure per annum per year end number of ICPs (connection points).

Our forecast is to perform better than the New Zealand industry average.

Capacity utilisation ratio

This ratio measures the utilisation of transformers installed on our network. It is calculated as the maximum demand experienced on the network divided by the distribution transformer capacity on the network.

Our management process aims to ensure maximum economic efficiency by ensuring good design and lifecycle management practices. If we specifically forecast levels of capacity utilisation, there could be an incentive to design inefficiently, for example to install long lengths of low voltage distribution or uneconomically replace transformers early in their lifecycle due to shifts in area load profiles.

Although we monitor this ratio, we do not have a specific forecast.

Load factor

The measure of annual load factor is calculated as the average load that passes through a network divided by the maximum load experienced in a given year. We always seek to optimise load factor as this indicates better utilisation of capacity in the network.

Although we do not have a specific forecast, our load factor forecasts are shown in section 5.4.1.

Energy loss

All electricity networks have energy losses caused mainly by heating of lines, cables and transformers. Electrical losses are natural phenomena that cannot be avoided completely and consequently retailers have to purchase more energy than is delivered to their consumers.

Electrical losses are the difference between energy volumes entering our network (mainly at Transpower GXP's) and the energy volumes leaving our network at consumer connections. We estimate that these losses are around 5% with a margin of error of +/- 1 percentage point. Significant deviations from this value exist in some parts of our network, for example, when we compare urban areas against rural areas.

When considering losses in network design and asset purchase, we do not aim for a forecast percentage of loss. Instead the lifetime annual cost of losses is converted to a net present capital value which can be added to the capital value of the asset concerned. We implement the least cost overall (asset cost + capitalised loss cost) solution. This approach provides the optimal economic level of losses.

See section 8.3.4 for a more detailed evaluation of our approach to network losses.

3.4 Service level forecasts

This section describes our forecasts set inline with Orion's asset management strategy for all the measures discussed in the previous section 3.3.

There is still much work ahead of us to restore network resilience and reliability to near pre-earthquake levels. Significant infrastructure rebuilding activity in the city will also likely see an increase in damage and disturbance of our network assets. We expect to restore our network reliability to near pre-earthquake levels by FY19.

Our forecasts for FY16 and future years are shown in the following tables.

3.4.1 Forecasts for current year

Table 3-4a Service descriptions, forecasts and measures for (FY16)

Service class	Service measure	FY16 forecast	Performance measure	Measurement procedure
Network reliability	SAIDI - system average interruption duration index	< 94	Orion network– average minutes lost per consumer per annum for all interruptions (planned and unplanned). Orion network only.	Tracking of all interruptions to our network (process audited annually). All 400V faults and HV faults <1min in duration are excluded. Capped to daily boundary values for any extreme event days as per CPP requirements (see section 3.3.1).
	SAIFI - system average interruption frequency index	< 1.2	Orion network- average number of times a consumer's supply is interrupted per annum for all interruptions (planned and unplanned). Orion network only,	
Network restoration	Unplanned interruptions restored within 3 hours	> 60%	% of total number of unplanned interruptions where the last consumer is restored in three hours or less. Orion network only, See section 3.3.2.	
Network capacity	Delivering reasonable levels of network security	To meet our security standard	Any gaps identified against our security standard. See section 5.5	
Power quality	Steady state level of voltage	< 70	Voltage complaints (proven). See section 3.3.4	Tracking of all enquiries
	Level of harmonics or distortion	< 4	Harmonics (wave form) complaints (proven). See section 3.3.4	Checks performed using an harmonic analyser
Safety	Safety of employees and contractors	Zero	Number of lost time accidents. See section 3.3.5.	Accident/incident reports
	Safety of public	Zero	Number of accidents involving members of the public (excluding car v pole accidents) See section 3.3.5.	Accident/incident reports
Environment	SF ₆ gas lost	< 1% loss	Gas lost expressed as a % of the total contained in our network equipment. See section 3.3.7.	Set out in Orion Procedure NW70.10.01
	Oil spilt	Zero spills	Oil spills not contained. See section 3.3.7.	Set out in Orion Procedure NW70.10.02
Economic efficiency	Capacity utilisation ratio	No forecast	Maximum demand on network divided by distribution transformer capacity.	See section 3.3.8.
	Load factor	No forecast	Average load on network divided by the maximum load experienced in a given year.	
	Losses	No forecast	The % of energy lost between the points of injection (mainly Transpower GXPs) and the point of off-take (consumer connections).	

3.4.2 Forecasts for future years

Table 3-4b Service descriptions, measures and forecasts for future years

Service class	Service measure	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Network reliability	SAIDI – system average interruption duration index	91	82	73	73	73	73	73	73	73
	SAIFI – system average interruption frequency index	1.15	1.0	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Network restoration	Unplanned interruptions restored within three hours	>60%▶								
Capacity	Delivering reasonable levels of network security	To meet our security standard								
Power quality	Steady state level of voltage	< 70▶								
	Level of harmonics or distortion	< 4▶								
Safety	Safety of employees and contractors	Zero▶								
	Safety of public	Zero▶								
Customer service	Prompt response to enquiries									
Environment	SF ₆ gas lost	<1% loss▶								
	Oil spilt	Zero spills▶								
Economic efficiency	Capacity utilisation ratio	No forecast—see 3.3.8								
	Load factor	No forecast— see 3.3.8								
	Losses	No forecast— see 3.3.8								

Lifecycle asset management



4

4.1	Network overview	77
4.2	Network justification	82
4.3	Asset management approach	84
4.4	Substations	86
4.5	Overhead lines – 66kV	91
4.6	Overhead lines – 33kV	96
4.7	Overhead lines – 11kV	99
4.8	Overhead lines – 400V	102
4.9	Underground cables – 66kV	105
4.10	Underground cables – 33kV	109
4.11	Underground cables – 11kV	113
4.12	Underground cables – 400V	117
4.13	Communication cables	120
4.14	Circuit breakers – high voltage	122
4.15	Switchgear – high and low voltage	129
4.16	Power transformers and regulators	135
4.17	Distribution transformers	139
4.18	Generators	142
4.19	Protection systems	144
4.20	Communications	147
4.21	Load management systems	150
4.22	Distribution management systems	154
4.23	Information systems - corporate	157
4.24	Information systems - asset management	160
4.25	Metering	163
4.26	Network property	165
4.27	Corporate property	169
4.28	Vehicles	171

List of figures and tables in this section

Figure	Title	Page	Table	Title	Page
4-1a	66,33kV and 11kV subtransmission – Urban area	78	4-1a	Orion's electricity network asset quantities	77
4-1b	66kV and 33kV subtransmission network – Rural area	79	4-4a	Zone substation equipment schedule	88
4-1c	Network voltage level/asset relationships	80	4-4b	Distribution substation types	90
4-3a	Condition score conversion - CBRM to ComCom 12a	85	4-5a	66kV tower line circuits	91
4-5a	66kV Subtransmission – Overhead lines	92	4-6a	Standard 33kV conductors	96
4-5b	66kV Overhead lines – asset failures/100km	93	4-7a	Standard 11kV conductors	99
4-5c	66kV Overhead poles and towers – age profile	93	4-8a	Standard 400V conductors	102
4-6a	33kV Subtransmission network	96	4-9a	66kV cable circuits	106
4-6b	33kV Overhead lines – asset failures/100km	97	4-10a	33kV cable circuit listing	111
4-6c	33kV Overhead line poles - age profile	97	4-11a	11kV feeder cable circuit listing	114
4-7a	11kV Overhead lines – asset failures/100km	99	4-14a	Circuit breaker quantities	123
4-7b	11kV Overhead line poles – age profile	100	4-14b	Circuit breaker ratings	124
4-8a	400V Overhead line poles – age profile	103	4-14c	Line circuit breaker ratings	124
4-9a	66kV Subtransmission – Christchurch urban area	105	4-14d	Circuit breaker average age (years)	124
4-9b	66kV Underground cables – asset failures/100km	107	4-14e	Switchgear inspection and maintenance schedule	126
4-9c	66kV Underground cables – age profile	107	4-15a	Switchgear quantities	130
4-10a	33kV Subtransmission – Christchurch urban area	109	4-16a	Power transformer quantities	135
4-10b	33kV Underground cables – asset failures/100km	110	4-16b	Regulator quantities	135
4-10c	33kV Subtransmission – Lincoln and Springston area	110	4-17a	Distribution transformer quantities	139
4-10d	33kV Underground cables – age profile	111	4-18a	Generator listing	142
4-11a	11kV Underground cables – asset failures/100km	113	4-19a	Relay types in Orion's network	144
4-11b	11kV Underground cables – age profile	115	4-26a	Distribution kiosk quantities	165
4-12a	400V Underground cables – age profile	118	4-28a	Vehicle quantities	171
4-13a	Communication cables – age profile	120			
4-14a	Circuit breakers - health index profile	125			
4-14b	Circuit breakers 33 and 66kV - age profile	125			
4-14c	Circuit breakers 11kV - age profile	125			
4-15a	Switchgear 11kV - health index profile	132			
4-15b	Ringmain units 11kV - age profile	132			
4-15c	Line ABI 11kV and 33kV - age profile	132			
4-16a	Power transformers - health index profile	136			
4-16b	Power transformers - age profile	136			
4-17a	Distribution transformers - age profile	140			
4-19a	Protection systems - health index profile	145			
4-19b	Protection systems - age profile	145			
4-20a	Radio communication network repeater sites	147			
4-21a	Ripple injection system control diagram	150			
4-22a	SCADA remote terminal units (RTU) - age profile	155			
4-26a	Substation buildings (owned by Orion) - age profile	166			
4-26b	Kiosks - age profile	167			

4.1 Network overview

4.1.1 Asset description

We own and operate the electricity distribution network in central Canterbury. Our network covers 8,000 square kilometres across central Canterbury between the Waimakariri and Rakaia rivers and from the Canterbury coast to Arthur's Pass. Consumer densities range from five consumers per km in rural areas to 26 in urban areas. Approximately 88% of our consumers are located in the urban area of Christchurch with 12% in the rural area.

Urban

Our urban network consists of both a 66kV and a 33kV subtransmission system. Our urban 66kV system supplies 17 zone substations in and around Christchurch city and is supplied from Transpower's 66kV GXP's at Bromley and Islington. Our urban 33kV system supplies another six zone substations in the western part of Christchurch and is supplied from Transpower's Islington 33kV GXP. Both systems consist of overhead line and cable in the quantities shown in the table. A further nine zone substations in the urban area take supply at 11kV from our 66kV zone substations.

The urban zone substations supply a network of 11kV cables connected to 219 network substations. These network substations in turn supply over 4,000 distribution substations on a secondary 11kV cable network. The low voltage (400V) system to which most of our consumers are connected is supplied from these distribution substations. The reasons for the structure of our network are further discussed in section 4.2.

Rural

Our rural network also consists of both a 66kV and a 33kV subtransmission system that supplies 21 zone substations from Transpower's Islington, Hororata and Kimberley GXP's. The rural distribution system primarily consists of 11kV overhead radial feeders from our rural zone substations and three small Transpower GXP's at Coleridge, Castle Hill and Arthur's Pass.

4.1.2 Canterbury earthquakes

While the earthquakes and large aftershocks of 2011/12 caused extensive damage throughout the region, our prior investment in a programme to increase the resiliency of our infrastructure was a major factor in limiting the amount of damage to our network. As the rebuild of the region gains momentum we will continue to use these principles and lessons learnt to bring the network back to pre-earthquake levels of resilience and reliability.

Table 4-1a Orion's electricity network asset quantities

Category	Description	31 March 2014	31 March 2013
Total network	Lines and cables (km)	15,016	14,983
	Zone substations	53	52
	Distribution substations	10,891	10,747
Overhead lines (km)	66kV	216	191
	33kV	306	306
	11kV	3,219	3,221
	400V	1,873	2,077
	Street lighting	932	935
Underground cables (km)	66kV	54	49
	33kV	34	34
	11kV	2,408	2,366
	400V	2,745	2,661
	Street lighting	2,167	2,079
	Communication	1,061	1,063
	Total cables	8,469	8,252
Zone substations	66kV	24	21
	33kV	20	22
	11kV	9	9
Distribution substations	Building (network)	219	225
	Building (distribution)	252	253
	Ground mounted	4,339	4,215
	Pole mounted	6,300	6,279
Embedded generation	Greater than 1MW	10 Consumer-owned sites	10 Consumer-owned sites
Major business consumers	Loads between 0.3 MW and 11MW	325	325

Figure 4-1a 66kV, 33kV and 11kV subtransmission network – Christchurch urban area

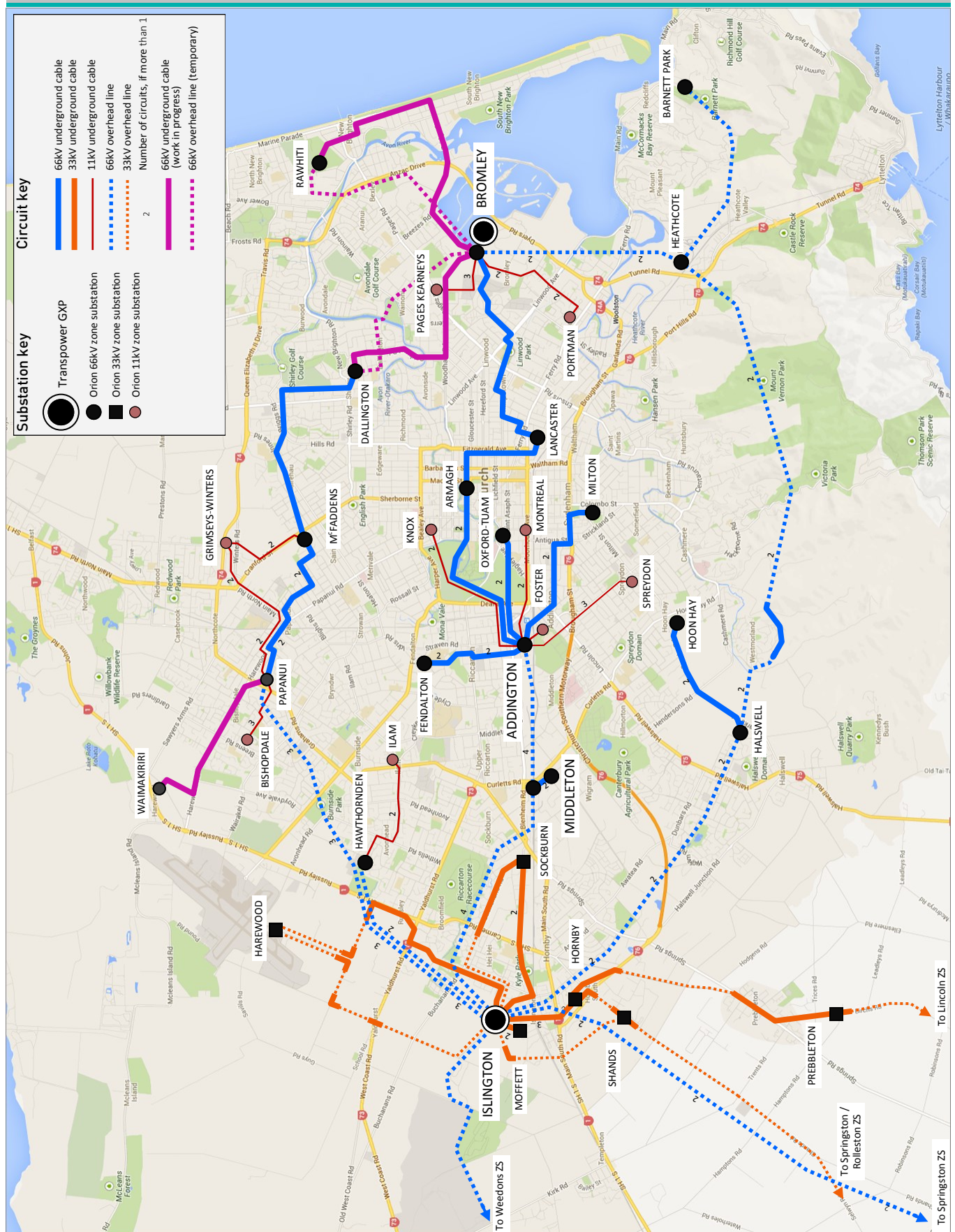


Figure 4-1b 66kV and 33kV subtransmission network – Orion’s Canterbury rural network area

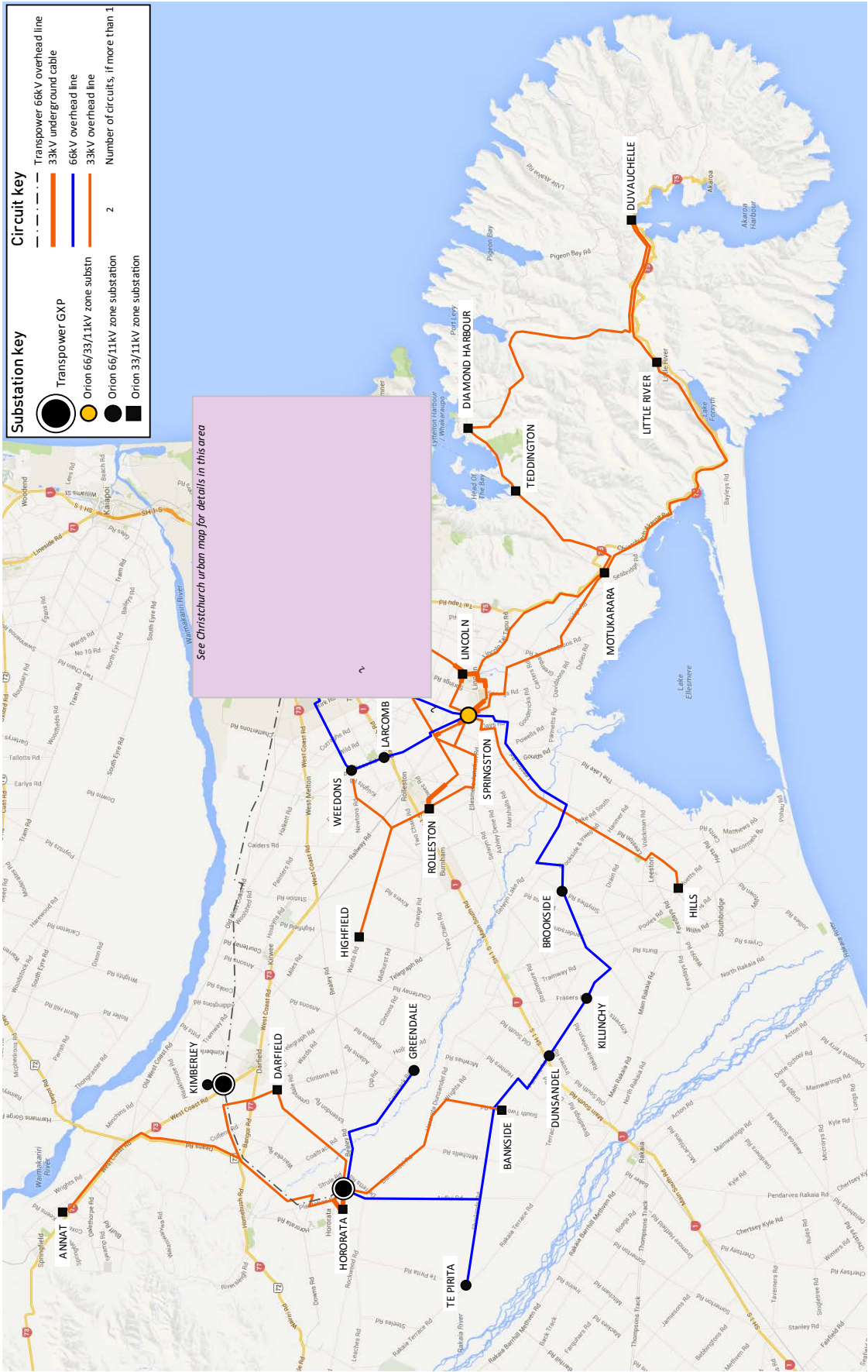
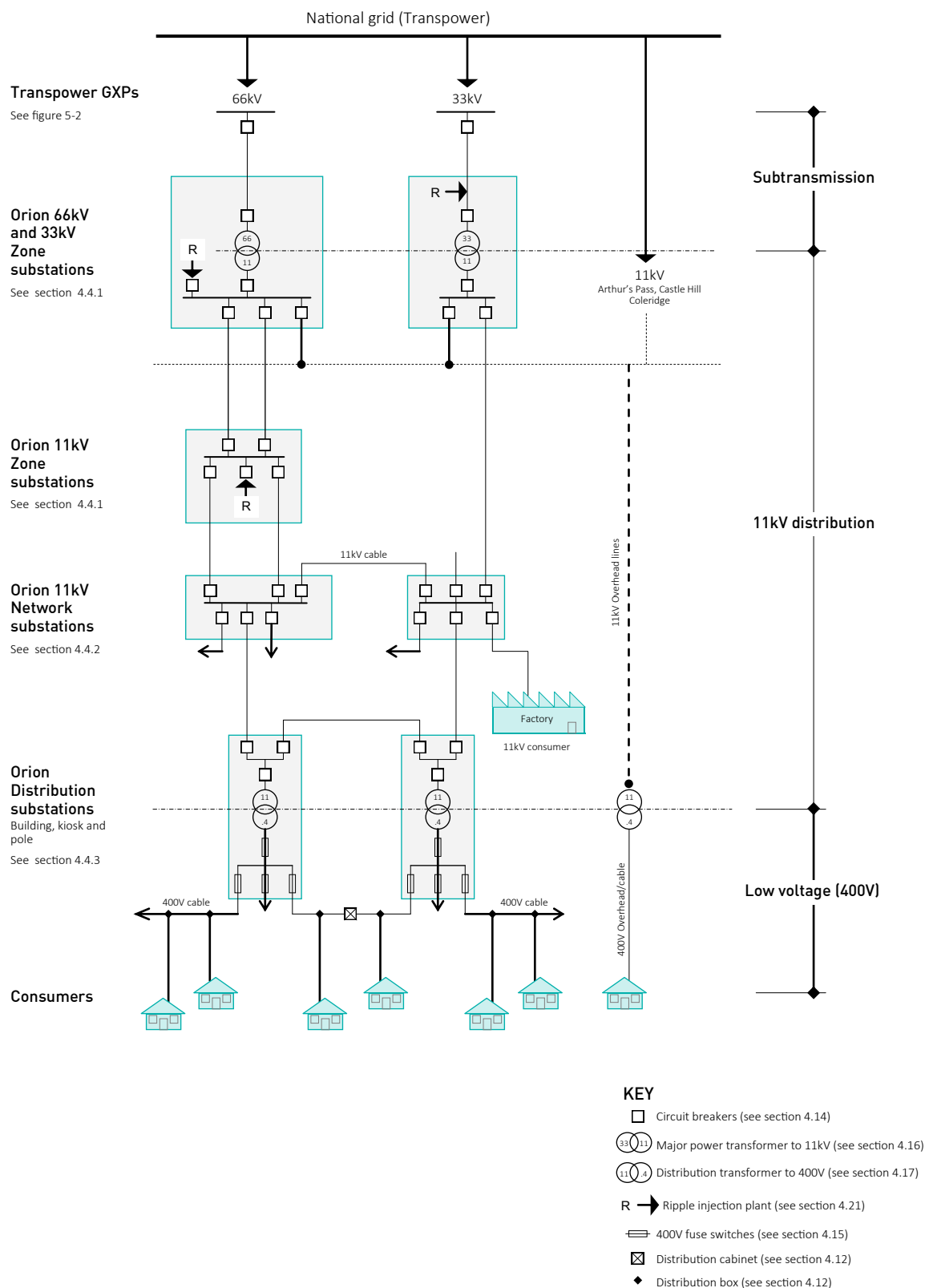


Figure 4-1c Network voltage level/asset relationships



Our key priorities are:

- work with the community to meet their needs as they rebuild
- integrate and react to the changing requirements of the network
- restore the resilience and reliability of our network by around 2019.

The on-going impact on our asset management practices is discussed in the individual asset sections. Specifically, these assets are cables and substation buildings detailed in sections 4.9 to 4.12 and 4.24.

4.1.3 Large consumers

The Canterbury area and business sectors are largely service and/or agricultural based. This is reflected in the mix of approximately 325 major business customers connected to our network with loads ranging from 0.3MW to 11MW. The largest single load in this category is less than 2% of our total maximum demand.

Currently we have 17 consumers that have an anytime maximum demand of greater than 2MVA. These consumers are represented in the following activities:

- | | |
|-------------------|---|
| • food processing | 6 |
| • industrial | 3 |
| • hospital | 2 |
| • university | 2 |
| • airport/seaport | 2 |
| • shopping mall | 2 |

Each of these major consumers is charged on a 'major customer connection' delivery charge basis. We individually discuss their security and reliability of supply requirements in relation to our normal network performance levels at the time of connection or upgrade. Generally our operating regimes and asset management practices do not specifically provide enhanced levels of service for these consumers. We run six monthly seminars to update our major consumers and provide them with a forum for open discussion. Typically we discuss asset management priorities, enhancement projects and current industry issues. We explain and promote pricing options (demand side management, power quality etc.).

If major consumers require enhanced network performance, we work with them to achieve their requirements by either enhanced connection or on-site generation options. Our delivery pricing allows charges for dedicated equipment for enhanced supply to be made, or incentives to run embedded generation if it benefits our network.

Many major customers run generators in response to our pricing signals and we have specific arrangements to run generators at approximately 40 connections at other times when it is beneficial for our delivery service (see section 5.3.5 for details of our DSM initiatives). Connected generation at consumer sites can vary from just a few kilowatts to as much as 2.5MW. We have 20 connections with more than 1MVA installed capacity.

Although there are issues to be co-ordinated when sites with generation are established, there is minimal impact on the operation and asset management of the local area networks. Most of these sites have installed generators for security reasons and running of the generators generally only reduces or off-sets their established load requirements. A small number of sites have the ability to export surplus energy into the network with metering and protection systems appropriately installed. The largest net energy export into the Orion network is 1.2MW.

As part of obligations under the Civil Defence and Emergency Management Act we have on-going discussions with life-line services such as the hospitals, seaport and airport to ensure appropriate levels of service are provided for in our future planning.

Two rural milk processing plants have a significant impact on our network operations or asset management priorities. The Synlait plant located at Dunsandel was commissioned during 2008. Its load including the predicted expansion was significant in the context of our rural network design in that area. The installation required a new zone substation at Dunsandel providing enhanced security. Similarly, the Fonterra plant commissioned during 2012 also required a new zone substation (Kimberley) to provide enhanced security. This has required us to revisit proposed current and future rural network design in Darfield and the surrounding area. Both connections are part of a 'large capacity connection' category to accurately reflect the cost of supply to this type of connection. The on-going delivery charges reflect an appropriate return on the assets needed to supply electricity to these consumers.

Irrigators (agricultural and dairy) are one consumer group that significantly impacts on the operation and asset management of our network in the rural area. Irrigation growth over the last 15-20 years has required substantial reinforcement of our network. In discussions with this consumer group, we were able to determine that as a group they could endure a slightly reduced level of security of supply. To reduce our investment in the rural network, we were able to offer an appropriate pricing scheme for irrigation connections that allows us to control their irrigation use during network emergencies. For further details refer to section 5.3.5

Irrigation connections are also impacting on our rural network power quality. We observed excessive harmonic levels generated by non-linear control devices (variable speed drives) associated with the irrigation pumps. This led to the introduction of new requirements for limiting harmonics generated from new connections.

4.2 Network justification

4.2.1 Introduction

Our electricity network serves high-density urban areas, medium density rural countryside and remote rural locations. Approximately 88% of our consumers are located in the urban area of Christchurch with the remaining 12% in the rural portion of our network.

The first electricity consumer in Christchurch was connected in 1903. In 1912 11kV was adopted as the primary distribution voltage. Construction of the Coleridge power station around 1918 significantly shaped the initial network, with the introduction of low cost hydropower and a 66kV transmission system that is still in service today.

In the early 1920s, development in rural areas was based on overhead power lines serving rural communities in very diverse geographical locations such as Banks Peninsula, the Canterbury plains and the high country of Canterbury.

4.2.2 Urban system design

The first electricity distribution systems in Christchurch were a mix of underground cable and overhead lines originating from the Government's Addington substation. Additional 11kV grid connection points evolved at Bromley and Papanui, providing quite large capacity at high fault levels. A comprehensive underground cable network based on electrical districts then grew from these three main grid connection points.

This network served the city until the rapid development period of the 1960s, when demand grew by 7% per year. Increased demand was met by building 66/11kV zone substations. These substations are the backbone of the present urban system. The initial design of our 66kV system was radial in nature with the installation of short, duplicated 66kV oil-filled feeder cables directly connected to transformers without 66kV switching facilities. The exception to this approach was the double circuit 66kV line around the Port Hills which was built in 1957 as a radial feed to Bromley but later became an interconnection between Bromley and Islington GXP. During the 1990s and subsequent decade we saw continued load growth and New Zealand/worldwide system blackout events. We reviewed our network risks and introduced security standards. This resulted in changes to our network design philosophies which meant increased investment in interconnected 66kV sub-transmission and zone substations. In 2000 a new underground 66kV interconnection cable was laid from Bromley to the CBD to provide a second connection between Islington and Bromley GXP. A further review of our 66kV network design/architecture was undertaken in 2012 following the series of Christchurch earthquakes which caused significant damage to our northeast 66kV subtransmission network. The review provided confirmation of our recent approach to increase the interconnection of our 66kV network. Consequently it was decided to rebuild our northeast 66kV network with two links between Islington and Bromley GXP. The combined effect of four 66kV links and our cable and line route diversity provides a secure and resilient 66kV subtransmission network and also reduces the reliance on our 11kV network to transport power over large distances.

The original 11kV distribution system, supplied by a small number of large grid connection points, led to the design philosophy of a primary 11kV cable network, capable of handling relatively large amounts of power (at high fault levels) over long distances around the city. Local 11kV distribution circuits of smaller size cables were laid to supply substations that convert the voltage to 230/400 volts for consumer use. To allow even greater power density to be serviced 66/11kV transformers were introduced, while fault levels could be controlled through suitable choice of transformer impedance. This evolutionary process resulted in a network of primary 'closed' rings of 11kV distribution cables which connect network substations to zone substations. From each network substation, radial 11kV cables provide an interconnected 11kV secondary distribution network which services kiosk substations around the city. A review of our 11kV architecture in 2006 led to a change in our approach and the era of building new primary rings and associated network substations came to an end. Our new approach recognises the change to a stronger 66kV subtransmission network which enables a simpler radial approach to our 11kV network. The primary ring network is well established in our urban network and the conversion to a radial approach will take many decades to complete in an economic fashion as aging infrastructure is replaced over time.

Similar to the primary ring network, the new radial 11kV feeder network will continue to have strong interconnections between feeders and zone substations. The interconnected nature of the secondary network means that supply can be switched, allowing restoration of power to most consumers within a relatively short time. Interconnection at the low voltage (400V) network level is also generally available, and enables us to restore power supply quickly when local distribution substations (transformers or switchgear) are damaged by faults. This high degree of network interconnection allows us to carry out routine maintenance and repair faults with minimal disruption to consumer supply – it contributes significantly to our overall system reliability performance.

4.2.3 Rural system design

The earliest rural electricity distribution networks in Orion's area were based on 3.3kV and 6.6kV systems supplied from connection points off the Coleridge transmission lines, mainly at Hororata and Addington. These systems were simple radial lines, and were up-rated to 11kV over time to service increasing demand.

Load growth required the introduction of 33kV subtransmission in the mid 1960s. The 33kV was used to supply an increasing number of 'zone' substations, usually consisting of a 7.5MVA transformer with 11kV radial feeders interconnected to adjacent substations. Subtransmission of 33kV was always needed to get power to Duvauchelle in Banks Peninsula, because of the long distance from the old GXP at Motukarara.

This 33kV subtransmission/11kV distribution system was eventually extended over most of the rural area, and into the western fringes of Christchurch city, including the international airport.

The ‘urban’ part of this otherwise largely rural network evolved into a high load density area, with strong growth and higher reliability requirements. Therefore, the system is now a number of 20MVA firm capacity substations with two transformers, 11kV distribution feeders and a paralleled 33kV cable/line subtransmission network.

Overhead radial 11kV feeders have gradually been replaced with underground 11kV cables on this urban 33/11kV network.

In recent years, very high growth in irrigation loads has meant the rural 33kV subtransmission system has approached its design capacity. We decided the most economical reinforcement method was to build additional 66/11kV zone substations equipped with 7.5/10MVA transformers within the existing 11kV distribution network, while retaining (and converting to 66kV over time) the existing 33/11kV zone substations and 33kV lines. This methodology retains our existing network investment while shortening 11kV feeder lengths, resulting in improved system reliability.

As growth continues in the rural townships, and specific larger consumers are connected, single transformer substations become unsuitable to meet future demand. Our rural network design now incorporates dual transformer substations with firm capacity of 10MVA (Lincoln and Rolleston) with new substations around Rolleston and its developing industrial park, supported by dual transformer substations with a firm capacity of 23MVA, similar to our western urban network.

4.3 Asset management approach

4.3.1 Asset management process

We undertake lifecycle management and asset maintenance planning using whole of life cost analysis, reliability centred maintenance (RCM), condition based maintenance and risk management (CBRM) techniques. These techniques are used to improve our performance to enable us to meet our network reliability limits.

Generally assets are not replaced on age alone, but are kept in service until their continued maintenance is uneconomic or until they pose a safety, environmental or reliability risk. Reliability performance is measured and used to identify areas where further maintenance is needed to improve our delivery service or where maintenance may be reduced without affecting service levels.

We develop our maintenance and replacement programmes in-house and use a competitive tender process to contract out all works.

4.3.2 Management planning

Our asset management planning process involves the creation of:

- **Maintenance Plan**

We maintain our network assets to ensure:

- i. the safety of the public, contractors and our staff is maintained
- ii. reliable, cost effective electricity for our consumers
- iii. we prevent premature deterioration or failure of the network.

We have specific maintenance programmes for each of our asset classes however all works roughly fall into the following categories:

- i. Scheduled Maintenance – work carried out to a predetermined schedule and allocated budget
- ii. Non-scheduled Maintenance – work that must be performed outside the predetermined schedule, but does not constitute emergency work
- iii. Emergency Maintenance – work that must be carried out on a portion of the network that requires immediate repair.

- **Replacement Plan**

Traditionally asset replacement programmes were based on the age of assets. We identified very early on that this was not the most effective approach and have been using other factors such as condition and risk to safety, reliability and performance to help develop our replacement programmes. We have adopted a condition based risk management (CBRM) approach for the replacement of our network assets. This framework utilises asset information, engineering knowledge and experience to define, justify and target asset replacements.

4.3.3 Format of asset sections

The following sections (4.5 to 4.28) describe Orion's existing assets by category. All references to years such as FY10, are to be taken as the financial year ending that year i.e. 31 March 2010. For each category the asset and its management approach are discussed under the following headings:

Asset description

A brief description giving an idea of the type, function and location of each asset group.

Asset capacity/performance

Design capacity and utilisation with any constraints, failure modes and deterioration specific to this asset.

Note: The definition of asset failure as shown in the graph of failures per 100km for an asset is any interruption to supply caused by a plant failure. This excludes being damaged by a third party or environmental event.

Asset condition

A summary of the asset's current condition including an age profile and health index profile.

Figure 4-3a Condition score conversion table - CBRM to Commerce Commission schedule 12a

Condition	HI Range	Remnant Life	Probability of Failure	Health Index	Schedule 12a Terms	Definition
Unknown					Grade unknown	Condition unknown or not yet assessed
Bad	10	At EOL (< 5yrs)	High	10 + [9 - 10]	Grade 1	End of serviceable life, immediate intervention required
Poor		5 - 10 yrs	Medium	[8 - 9] [7 - 8]	Grade 2	Material deterioration but asset condition still within serviceable life parameters. Intervention likely to be required within 12 months.
Fair		10 - 20 yrs	Low	[6 - 7] [5 - 6] [4 - 5] [3 - 4]	Grade 3	Deterioration requires assessment and ongoing monitoring
Good	0	20yrs +	Very Low	[2 - 3] [1 - 2] [0 - 1]	Grade 4	Good or as new condition

The health index scoring is different to that set out in Schedule 12a of the information disclosure requirements. The following table shows the method used to convert our CBRM scores to those required in Schedule 12a.

Design standards and asset data

A list of design standards and technical specifications pertaining to the asset. These may be industry standards or our own standards.

Also discusses asset data completeness, improvement sources and the system where the data is held (see section 2 for systems used at Orion).

Maintenance plan

The ongoing day to day work plans required to keep the asset serviceable and prevent premature deterioration or failure.

Replacement plan

These are major work plans that do not increase the asset's design capacity but restore, replace or renew an existing asset to its original capacity.

Creation/acquisition plan

This is capital work that creates a new asset or improves an existing asset beyond its existing capacity.

Disposal plan

This is any of the activities associated with disposal of a decommissioned asset.

4.4 Substations

A 'substation' encompasses buildings, switchgear, transformers, protection and control equipment used for the transformation and distribution of electricity. Our network structure has three identified levels of substations – zone, network and distribution (see figure 4-1c). The lifecycle asset management plans for assets making up a substation are discussed in the relevant parts of section 4. A substation is not described as an asset in its own right.

4.4.1 Zone substations

A zone substation is a building substation usually with a high voltage structure that has been identified as a zone substation because of its importance in our network. Orion has 55 zone substations and, in general, they include a site where one of the following takes place: voltage transformation of 66kV or 33kV to 11kV, two or more incoming 11kV feeders from a Transpower GXP are redistributed or a ripple injection plant is installed. Zone substations are inspected every two months and given an infra-red scan every two years.

66/11kV zone substations

We have 26 66/11kV zone substations and one 66/33/11kV zone substation at Springston. Eighteen of them are in the Christchurch urban area. Twelve of the urban substations have an exposed bus structure. The largest structures are at Bromley, Heathcote and Papanui. The Armagh, Dallington, McFaddens and Waimakariri structures are inside a building. Construction dates for the urban structures are:

• Addington	1962	• Halswell	1974	• Middleton	2008
• Armagh	2001	• Hawthornden	2004	• Papanui	1968
• Barnett Park	1981	• Heathcote	1968	• Rawhiti	2011
• Bromley	1973	• Lancaster	2000	• Waimakariri	2014
• Dallington	2013	• McFaddens	2012		

Most of the urban zone substations are supplied by two cables connected to a pair of 66/11kV transformers. Each cable and associated transformer has an emergency rating equivalent to the full load of the zone substation (traditionally 40 MVA) and can maintain supply should the other cable or transformer fail. The rating of the transformer and cable are currently limited by the thermal capacity of the 66kV cables. The transformers supply 11kV switchgear housed in two, three or four fire and explosion resistant rooms. This switchgear may supply up to 20 feeder cables and can be sectioned using bus-couplers between the rooms.

Our rural Springston 66/33/11kV zone substation is supplied by tower line from Transpower's Islington GXP. It has an outdoor structure with two 66/33kV 60/70MVA transformers and one 33/11kV 7.5MVA transformer.

The eight rural 66/11kV zone substations at Brookside, Dunsandel, Killinchy, Larcomb, Kimberley, Greendale, Te Pirita and Weedons are supplied by overhead lines and have 7.5/10 or 11.5/23MVA transformers. All have outdoor structures. The indoor 11kV switchgear may supply up to five feeder cables.

Four other substations at Annat, Bankside, Little River and Highfield have 66kV structures but are currently operating at 33kV. See section 5.6.7 for details of the projects to convert them to operate at 66kV.



Armagh zone substation, with its neon 'Nebula Orion' artwork, contains an 'outdoor' 66kV structure.



Weedons 66kV rural zone substation

33/11kV zone substations

Orion has 19 33/11kV zone substations, mainly in the Canterbury rural area and on the western fringe of Christchurch city. Most have some form of outdoor structure and bus-work. Where economically viable we are replacing outdoor 33kV switchgear with an indoor type, negating the need for outdoor structures. Capacity of these substations is split into three groups as follows:

1. Larger urban substations have two or three independent dual rated transformers. These have separate supplies, with each transformer and supply rated to carry the full substation load. The 11kV switchgear may supply up to 11 feeder cables and is housed in two or more switch-rooms linked by a bus-coupler.
2. Smaller urban and larger rural substations have a pair of single rated transformers of 7.5MVA.
3. Smaller rural substations have one single rated transformer of 7.5 or 2.5MVA. Single transformer zone substations (largely in rural areas) rely on back-up capacity from adjacent single transformer substations to provide firm capacity.

11kV zone substations

We have nine of these substations, all in the Christchurch city urban area. They are directly supplied by either three or four radial 11kV cables and do not have power transformers. The cables have usually been laid along the same route and have sufficient capacity to supply the full zone substation load. The 11kV switchgear may supply up to 12 feeder cables and is housed in either two or three switch-rooms linked by bus-couplers.

None of the 11kV zone substations have any form of outdoor structure or bus-work.

Table 4-4a Zone substation equipment schedule

Zone substations	Circuit breakers			Power transformers			
	66kV	33kV	11kV	66/33kV	66/11kV	33/11kV	Rating (MVA) ¹
Addington ³	14		25		5		29/34 x3 and 20/40 x2
Annat	1 ²		4			1	2.5
Armagh	5		33		2		20/40
Bankside	1 ²		5			1	7.5/10
Barnett Park			12		1		11.5/23
Bishopdale			18				
Bromley	11		24		3		30/37
Brookside	3		10		1		7.5/10
Dallington	3		26		2		20/40
Darfield		1	6			1	7.5
Diamond Harbour		3	4			1	7.5
Dunsandel	4		10		2		7.5/10
Duvauchelle		5	9			2	7.5
Fendalton			20		2		20/40
Foster			20				
Greendale	1		6		1		7.5/10
Grimseys Winters			18				
Halswell	8		11		2		11.5/23
Harewood		2	9			2	7.5
Hawthornden			28		4		20/40 x2 and 11.5/23 x2
Heathcote	8		26		2		20/40
Highfield	1 ²		6			1	7.5
Hills Rd		1	5			1	7.5
Hoon Hay			26		2		20/40
Hornby		10	11			2	10/20
Hororata		3	5			1	7.5
Ilam			13				
Killinchy	3		6		1		7.5/10
Kimberley	3		11		2		11.5/23
Knox			21				
Lancaster	3		24		2		20/40
Larcomb	3		9		2		11.5/23
Lincoln		3	9			2	7.5
Little River		2	3			1	2.5
McFaddens	5		24		2		20/40
Middleton	2		19		2		20/40
Milton			23		2		20/40
Moffett St		3	14			2	11.5/23
Montreal			18				
Motukarara		6	6			2	2.5 and 7.5
Oxford-Tuam			24		2		20/40
Pages Kearneys			16				
Papanui	10		36		4		30/36 x2 and 20/24 x2
Portman			18				
Prebbleton		2	8			1	11.5/23
Rawhiti	3		16		2		20/40
Rolleston		2	9			2	7.5
Shands Rd		4	12			2	11.5/23
Sockburn			18			3	10/20 x2 and 11.5/23 x1
Spreydon			18				
Springston	6	14	6	2		1	60/70 x2 and 7.5 x1
Te Pirita	1		6		1		7.5/10
Teddington		1	3			1	2.5
Waimakariri	5		18		2		20/40
Weedons	3		9		2		11.5/23
Totals	55	107	62	794	2	55	30

NOTES:

1. Dual rated transformers have been installed with a design nominal rating/emergency rating.
2. Currently operating at 33kV.
3. Spur asset transfer 1 April 2015.

4.4.2 Network substations

There are 219 network substations in our 11kV network, all within the Christchurch urban area. They contain at least one 11kV circuit breaker per connected primary cable and one or more circuit breakers for radial distribution feeders. They may also contain secondary 11kV switchgear, one or more distribution transformers and an 800 or 1500 amp 400V panel with fuse assemblies using high rupturing current (HRC) links for local distribution.

Network substations have historically been installed whenever the load on radial feeders exceeded the design limit of cable capacity and when primary cables with adequate spare capacity were available nearby. The original policy was that no radial secondary loads were to be supplied from zone substations and all such loads were to be supplied from network substations. In recent years this policy has been modified so that if suitable spare switchgear is available at a zone substation, and it is more economical to do so, secondary cables may be laid from the zone substation to reinforce overloaded cables. This avoids the need for additional network substations.

Due to changes in the location of load during their lifetime, network substations may become under-utilised. In these cases, and when it is economical to do so, the primary cables supplying the substation may be through-jointed and the secondary load transferred to other feeders and the network substation decommissioned.

Network substations are inspected every six months. This involves a complete visual component inspection and the reading of any transformer loading maximum demand indicators (MDIs). Any minor maintenance is also done at this time and any larger maintenance work is reported back to the relevant asset manager.



A network substation design from the late 1930s.



Network substation refurbished as a standalone building after being part of a larger consumer building that was demolished due to earthquake damage.

4.4.3 Distribution substations

A distribution substation can take the form of any of the types shown in the following table. They take supply at 11kV from either a zone substation, a network substation or from another distribution substation. In respect of the building substations, in many situations a consumer will own the building that houses our electrical equipment.

The types of substation that make up the total 10,890 substations in this asset category are shown in the following table.

Type	No.	Description
Building	252	These are similar to network substations in all aspects except for their status in the network. The substations vary in size and construction and 75% of the actual buildings are privately owned. All usually contain at least one transformer, with an 11kV 250MVA Magnefix switch unit (MSU) and 400V distribution panel containing fuse assemblies using high rupturing current (HRC) links.
Kiosk	3,002	Full kiosks vary in size and construction but all usually contain a transformer, up to 500kVA, with an 11kV 250MVA Magnefix switch unit (MSU) and a 400V distribution panel containing fuse assemblies using HRC (high rupturing current) links. For details of kiosk types in service see section 4.26.1.
Outdoor	621	These vary in configuration, but usually consist of a half-kiosk with 11kV switchgear and a 400V local distribution panel as per a full kiosk. An outdoor transformer is mounted on a concrete pad at the rear or to the side of the kiosk. This design allows the installation of a transformer up to 1500kVA.
Pole	6,300	Mainly single pole substations (less than 10 are a 2-pole structure), usually with 11kV fusing and a transformer up to 200kVA.
Pad transformer	716	These are transformer only, mounted on a concrete pad and supplied by high voltage cable from switchgear at another site. Transformers are generally uncovered.

We inspect our distribution substations every six months with the exception of single-pole mounted substations. This inspection is a complete visual inspection of all the components and the reading of any transformer loading maximum demand indicators (MDIs). Minor maintenance is also done at this time and any larger maintenance work is reported back to the asset manager responsible.

Substation earthing

A risk based approach has been taken for the inspecting and testing of our site earths. In general, earth systems in our rural area are subject to deterioration because of highly resistive soils, stony sub-layers of earth and corroded earthing systems. Between 2,000 and 2,600 sites are tested in any year and those sites requiring repairs are scheduled for remedial work in the following year.



A recently developed kiosk with precast concrete sides, designed to be embedded into a hillside.

4.5 Overhead lines – subtransmission 66kV

4.5.1 Asset description

Tower lines

Our 66kV subtransmission tower lines consist of 95km of double circuit. These tower lines provide important security to the Christchurch city subtransmission network by providing limited alternative connection between Transpower's Islington and Bromley GXPs.

We have recently purchased three tower lines from Transpower (Islington GXP to Addington, Papanui and Springston). Refer to section 5.6.4 for further information regarding Orion's purchase of Transpower spur assets.

Table 4-5a 66kV tower line circuits

Circuit	Kilometres	Towers	Poles	Circuits
Bromley-Heathcote	4.2	22	0	2
Halswell-Heathcote	9.5	30	4 ¹	2
Heathcote-Barnett Park	4.1	19	0	2 ²
Islington-Addington A ³	17.2	57	0	2
Islington-Addington B ³	17.2	57	0	2
Islington-Halswell	7.8	35	6 ¹	2
Islington-Hawthornden	4.7	30	1	2
Islington-Papanui A	8.9	56	1	2
Islington-Papanui B	8.9	56	1	2
Islington-Springston	13	34	1	2
Total	95	396	14	20

Notes:

1 These poles replaced towers relocated to allow land subdivision to proceed.

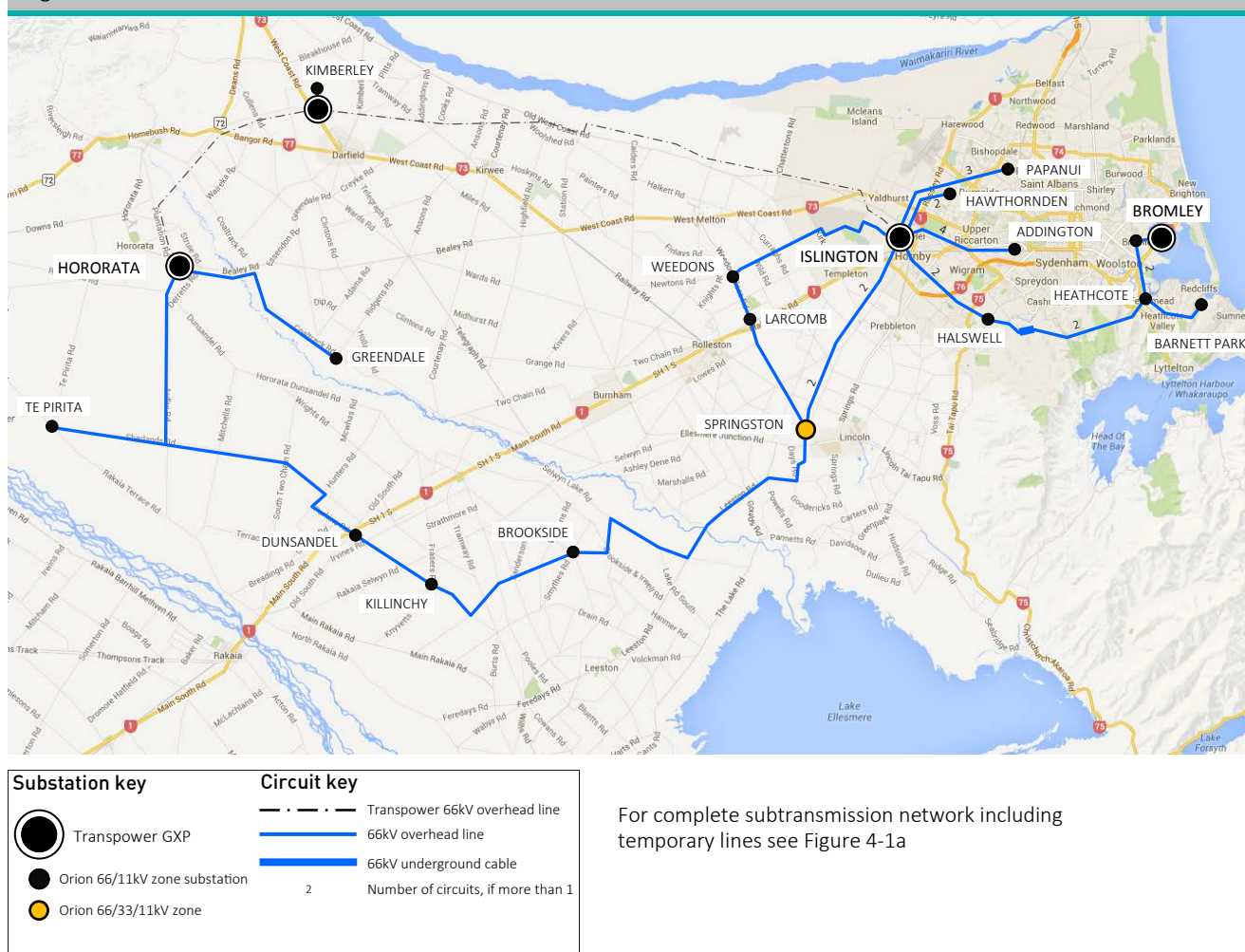
2 One of these circuits is operating at 11kV.

3 Spur asset transfer 1 April 2015



Tower replacement with steel monopole

Figure 4-5a Subtransmission 66kV overhead lines



Pole lines

Our 66kV subtransmission pole lines consist of 104km of single circuit on mainly timber poles. The lines run from Transpower's Hororata, and Islington GXP's to our 66/11kV zone substations Te Pirita, Springston, Dunsandel, Killinchy, Greendale, Brookside Larcomb and Weedons (see Figure 4-5b on following page).

Due to damage to 66kV cables out of Bromley, eight kilometres of temporary pole line has been built from Bromley to Dallington and from Bromley to Rawhiti. The line to Rawhiti is via the now decommissioned Brighton substation. This first part to Brighton was built in the days immediately following the February 2011 earthquake to allow a temporary transformer at Brighton to function. The line was continued on to Rawhiti once a site had been acquired and Brighton zone substation decommissioned.

These lines have consent for three years and are in the process of being replaced by new underground cables (see Figure 4-1a).

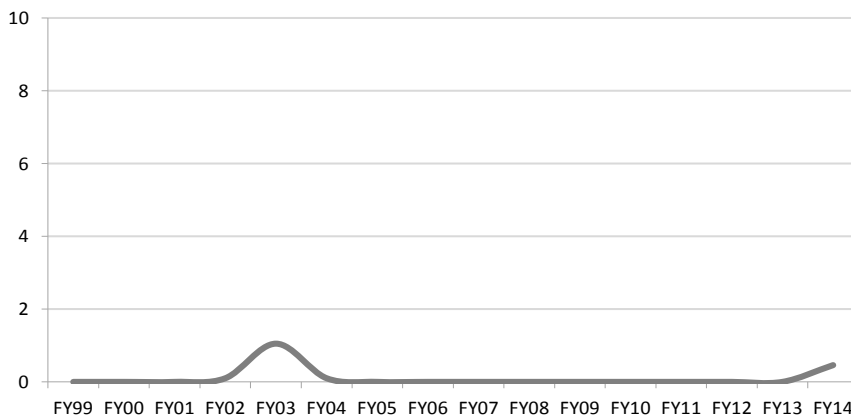
4.5.2 Asset capacity/performance

The conductors used for the urban tower line circuits are 'Wolf' and 'Zebra'.

The dual circuit Islington-Bromley is rated 494 amps per circuit at 75°C. The Islington-Hawthornden and Heathcote-Barnett Park circuits are rated 424 amps at 60°C. The Islington-Papanui circuits are rated 1,248 amps at 50°C. The conductors in this circuit are in a bundled configuration with two Zebra conductors per phase. This is reflected in the rating.

The conductor for the rural circuits is 'Dog'. The single circuit is rated 355 amps at 70°C. The Islington-Springston circuits are rated 531 amps at 75°C.

Figure 4-5b Overhead lines 66kV – asset failures/100km

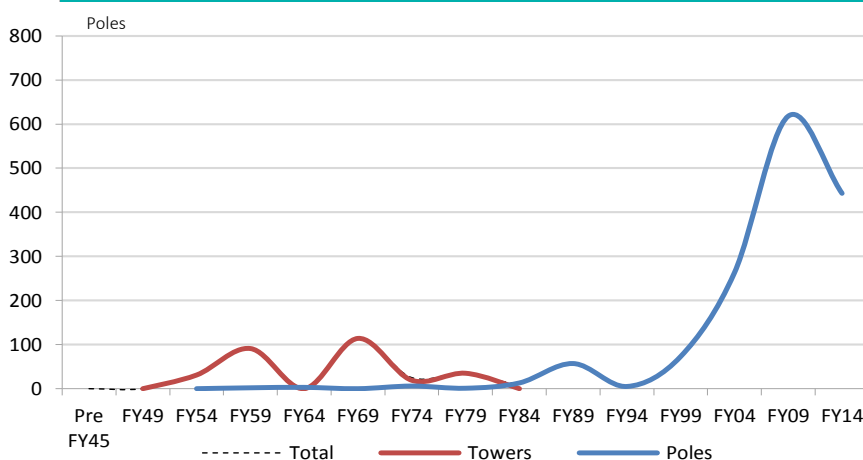


4.5.3 Asset condition

The overall condition of the steel towers is good. Assessments of tower corrosion are being undertaken and a prioritised programme of tower painting will be implemented. Tower signs and anti-climbing barriers were upgraded in 2006 to provide better security.

The tower foundations are a mixture of concrete footings and grillage. Our investigations have indicated that the worst corrosion on buried foundation steel is between 300 and 600mm below ground level, with little or no corrosion below that point. A refurbishment programme to extend the life expectancy of steel tower legs/foundations has seen most of the grillage foundations completed. The remaining sites have access issues but we anticipate completing them in the next few years.

Figure 4-5c Overhead 66kV poles and towers – age profile



4.5.4 Standards and asset data

Standards and specifications

Asset management report:

- NW70.00.26 - Overhead lines - subtransmission

Design standards developed and in use for this asset are:

- NW70.51.01 – Overhead line design standard.

Technical specifications covering the construction and ongoing maintenance of this asset group are:

- NW72.21.03 – Retightening of components
- NW72.21.05 – Tower painting
- NW72.21.06 – Tower maintenance painting
- NW72.21.11 – Overhead line inspection and assessment
- NW72.21.10 – Thermographic survey of high voltage lines
- NW72.21.18 – Standard construction drawing set – overhead lines
- NW72.21.19 – Tower inspection
- NW72.24.01 – Vegetation work adjacent to overhead lines.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.08 – Poles – hardwood
- NW74.23.17 – Conductor – overhead lines
- NW74.23.19 – Cross-arms.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GPS)
- pole identification numbers
- tower/pole age, type and condition score
- conductor size, age and phasing (the age of some conductors is estimated)
- tower/pole and fittings condition assessments
- construction and as built drawings for renewals and extensions.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the condition of the asset and the fittings/attachments.

4.5.5 Maintenance plan

The condition of this asset is monitored by:

- visual inspection including a check for clearance violations in the urban area
- corona/thermal imaging scans every two years
- lifting inspection of tower suspension assemblies
- tower foundation inspections/refurbishment in corrosive soil zones
- paint and steelwork condition assessment.

The maintenance work planned is as follows:

- suspension hardware assemblies will be assessed for corrosion damage
- tower foundation refurbishment continues
- live-line retightening of pole line components.

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: Subtransmission overhead lines.

4.5.6 Replacement plan

There are plans to convert some sections of overhead line to underground 66kV cables to accommodate new subdivisions.

We do not have any towers scheduled for replacement due to their condition.

Our pole replacement programme is based on our condition assessment survey.

Our budgeted replacement costs are shown in section 7.1.9 - Replacement budgets: 66kV overhead lines.

4.5.7 Creation/acquisition plan

For a list of projects containing this asset see section 5.6 – Network development proposals.

4.5.8 Disposal plan

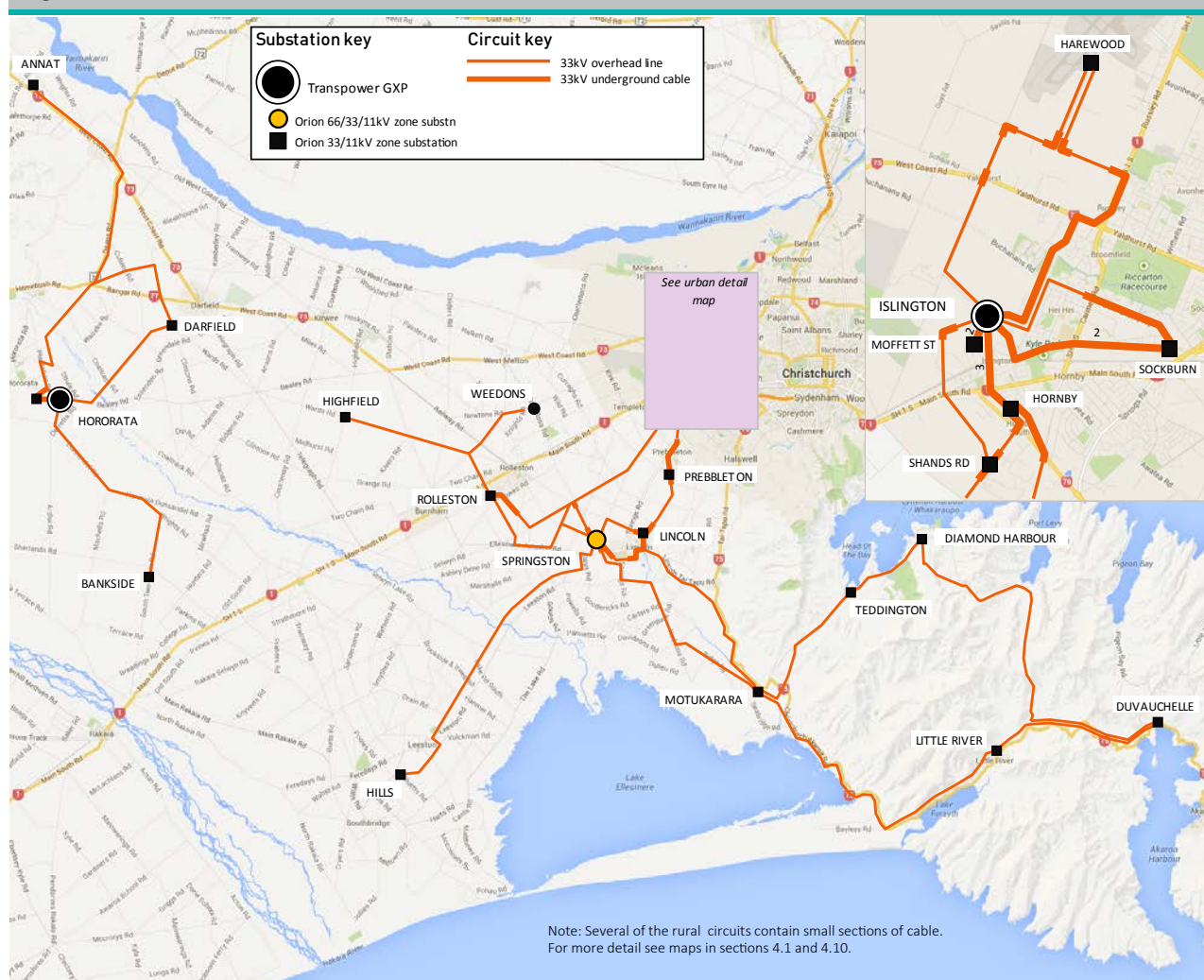
We have no plans to dispose of any of the 66kV overhead line asset.

4.6 Overhead lines – subtransmission 33kV

4.6.1 Asset description

The 33kV subtransmission overhead system consists of 306km circuit length of lines that take supply from Transpower's Islington, and Hororata 33kV GXP's to form a network of interconnecting lines in the rural area of central Canterbury, Banks Peninsula and into the western edge of Christchurch city. These lines are built using timber and concrete poles, some of which also carry 11kV distribution lines.

Figure 4-6a Subtransmission 33kV network



4.6.2 Asset capacity/performance

The standard conductors in our 33kV network are shown in the table below. (Ratings are based on 20°C ambient and 30°C conductor rise.)

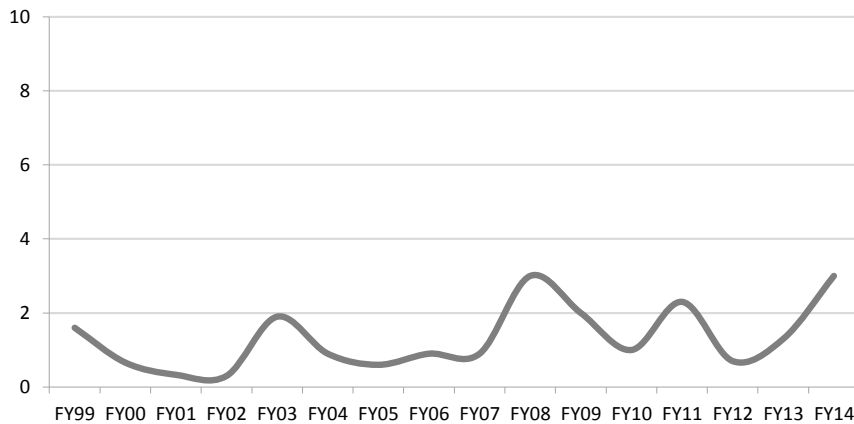
Most of the 33/11kV zone substations have an alternative 33kV supply, except Hills Rd, Bankside, Highfield and Annat.

Table 4-6a Standard 33kV conductors

Conductor (Aluminium)	Rating (Amps)	Conductor (Copper)	Rating (Amps)
Jaguar ACSR	412	19/0.083 HD	265
Dog ACSR	277	19/0.064	181

Retightening hardware and hotspot repairs made soon after infra-red scans have proved beneficial and improved the security of these lines. New 'distribution ties' have been installed on exposed areas of Banks Peninsula in an effort to reduce the incidence of broken binders.

Figure 4-6b Overhead lines 33kV – asset failures/100km

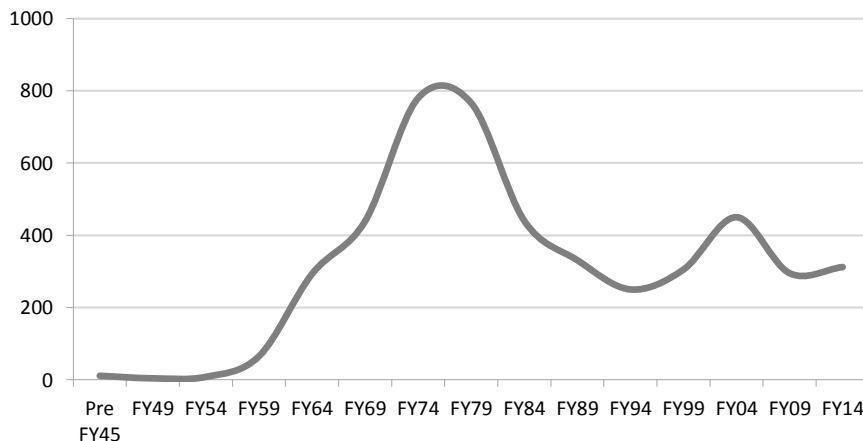


4.6.3 Asset condition

Old green glass insulators (pilkington type) on lines in the Lincoln and Springston areas are nearing the end of their life. Samples of these insulators with crab feet type cracks have been taken for closer inspection. We are replacing these insulators in conjunction with other works.

Older (non-type tested) concrete and hardwood poles may be replaced in conjunction with the insulators identified above.

Figure 4-6c Overhead lines 33kV poles - age profile



4.6.4 Standards and asset data

Standards and specifications

Asset management report:

- NW70.00.26 - Overhead lines - subtransmission

Design standards developed and in use for this asset are:

- NW70.51.01 – Overhead line design.

Technical specifications covering the construction and ongoing maintenance of this asset are:

- NW72.21.01 – Overhead line work

- NW72.21.18 – Standard construction drawing set – overhead
- NW72.21.03 – Retightening of components
- NW72.21.11 – Overhead line Inspection and Assessment
- NW72.21.10 – Thermographic survey of high voltage lines
- NW72.24.01 – Vegetation Work Adjacent to Overhead Lines.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.08 – Poles – hardwood
- NW74.23.17 – Conductor – overhead lines
- NW74.23.19 – Cross-arms.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GPS)
- pole identification numbers
- pole age, type and condition score
- conductor size, age and phasing (the age of some conductors is estimated)
- pole condition assessments
- construction and as built drawings for renewals and extensions.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition and the fittings/attachments on our poles.

4.6.5 Maintenance plan

The condition of this asset is monitored by:

- pole inspections/assessments (the same as for 11kV poles)
- complete visual inspection and thermographic scan every two years.

Maintenance work planned is as follows:

- to cut trees (in conjunction with 11kV lines)
- UV corona imaging scan of older insulators
- retightening hardware
- other work that results from inspections.

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: Subtransmission overhead lines.

4.6.6 Replacement plan

Due to reliability issues we are replacing green glass insulators in conjunction with other works.

Poles, crossarms and insulators are replaced as required.

Our budgeted replacement costs are shown in section 7.1.9 - Replacement budgets: 33kV overhead lines.

4.6.7 Creation/acquisition plan

For planned projects containing this asset see section 5.6 – Network development proposals.

4.6.8 Disposal plan

These assets are disposed of as part of the reconstruction costs.

4.7 Overhead lines – distribution 11kV

4.7.1 Asset description

Our 11kV distribution overhead system is 3,219km circuit length of lines in the rural area of central Canterbury, Banks Peninsula and outer areas of Christchurch city. Supply is taken from zone substations as feeder lines which form a network to supply distribution transformers. These lines are built using approximately 50,000 timber and concrete poles, some of which also support subtransmission and 400V conductors. The 11kV system includes 11kV lines on private property that serve individual consumers.

Single wire earth return (SWER) lines on Banks Peninsula total 103km circuit length in 10 separate systems. These lines supply power to remote areas, and at times are exposed to severe weather conditions.

Our 11kV lines are supplied from the zone substations shown on the 66kV and 33kV subtransmission network maps in the previous sections. Supply is also taken directly at 11kV from the GXP's at Coleridge, Castle Hill and Arthur's Pass.

4.7.2 Asset capacity/performance

The standard 11kV conductors are listed in the table below. Ratings are based on 20°C ambient and 30°C conductor rise. To improve the performance of smaller conductors, we are using smooth body Flounder ACSR conductor more in the rural areas when new conductor is required. The use of Flounder conductor should reduce breakages in lines exposed to snow and high winds.

There have been issues in the past with bi-metallic joints corroding on our 11kV overhead network. These joints are being replaced in conjunction with our re-tightening programme or when they are found during other scheduled works.

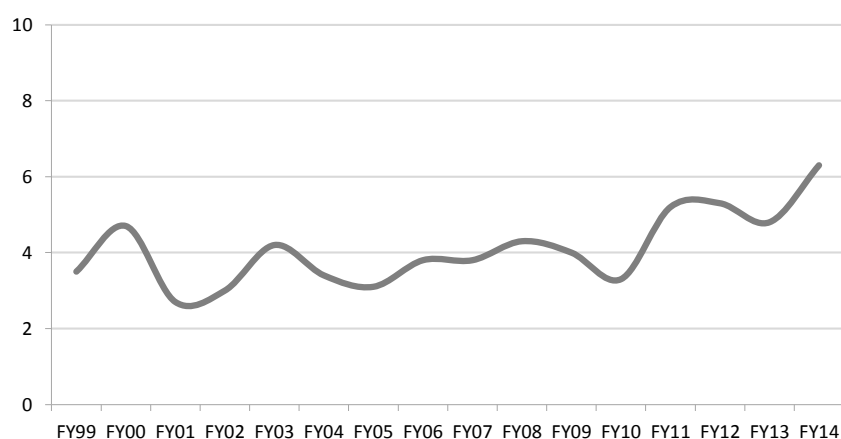
Table 4-7a Standard 11kV conductors

Conductor (Aluminium)	Rating (Amps)
Dog ACSR	277
Mink ACSR	204
Flounder ACSR	107
Squirrel ACSR	106

The Port of Lyttelton depends on a secure power supply and could be critical to Christchurch after any natural disaster. A double circuit line is the only supply to the Port. The status of this line has been raised to that of the subtransmission system. This means a higher level of maintenance and more regular inspections are undertaken than for other 11kV lines. The poles were replaced in 1999 and the phasing has been aligned with our standard. Increased clearances now allow maintenance on this line to be performed with the line alive, causing no interruption in supply to Lyttelton. These lines suffered no damage during the 2010/2011 earthquakes.

The 2003 tree regulations introduced a notice regime that defines responsibilities for problem trees. This has brought significant extra costs for us to meet, but gradual improvement in reliability statistics is expected.

Figure 4-7a Overhead lines 11kV – asset failures/100km



In the 4 September 2010 earthquake we had a small number of poles fail, with the majority of failures attributed to pole foundations succumbing to liquefaction or land subsidence. The robustness of our overhead line network can in some part be attributed to our targeted strengthening programme instigated after the June 2006 snow storm.

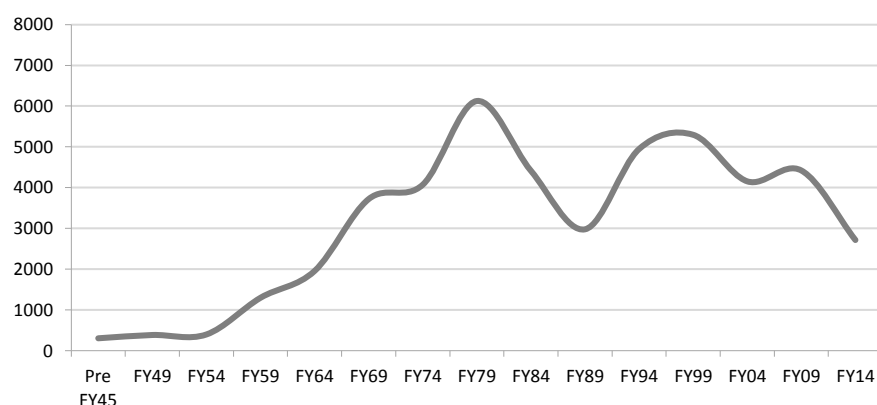
4.7.3 Asset condition

The condition of our main feeder lines is good. Rebuilding, now based on a condition assessment, is confined to smaller sections of main line and spur lines. Some concrete poles, mainly in the Lincoln, Springston, Rolleston and Weedons areas, are reaching the end of their life expectancy. These poles are McKendry-type cast concrete with a 3kN top loading.

Conductor replacement based on a condition assessment and/or performance issues is carried out during rebuilding. If the existing conductors are steel or 7/.064Cu they are replaced with aluminum.

We are retightening older lines where cross-arms have been damaged by loose equipment and insulators are leaning over. This type of maintenance is ongoing and will extend to newer lines where treated softwood timber poles and treated hardwood cross-arms have been used.

Figure 4-7b Overhead lines 11kV poles – age profile



4.7.4 Standards and asset data

Standards and specifications

Asset management report:

- NW70.00.27 - Overhead lines - 11kV

Design standards developed and in use for this asset are:

- NW70.51.01 – Overhead line design standard
- NW70.51.02 – Overhead line design manual
- NW70.51.03 – Overhead line design – worked examples.

Technical specifications covering the construction and ongoing maintenance of this asset are:

- NW72.21.01 – Overhead line work
- NW72.21.03 – Retightening of components
- NW72.21.11 – Overhead line Inspection and Assessment
- NW72.21.10 – Thermographic survey of high voltage lines
- NW72.21.18 – Standard construction drawing set – overhead
- NW72.24.01 – Vegetation Work Adjacent to Overhead Lines.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.06 – Poles – softwood
- NW74.23.08 – Poles – hardwood
- NW74.23.10 – Insulators – high voltage
- NW74.23.17 – Conductor – overhead lines
- NW74.23.19 – Cross-arms
- NW74.23.20 – Earthing equipment and application.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GPS)
- pole identification numbers
- pole age, type and condition score
- conductor size, age and phasing (the age of some conductors is estimated)
- pole and fittings condition assessments
- construction and as built drawings for renewals and extensions.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan, as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition and the fittings/attachments on our poles.

4.7.5 Maintenance plan

The condition of our 11kV overhead lines is monitored, following the guidelines of NZCEP 34, by:

- a visual inspection at least every five years
- UV corona imaging inspection carried out every two years
- a thermal imaging scan (selected areas as required)
- an inspection of poles within the Christchurch urban area
- an inspection of poles in the rural area.

Maintenance work planned is as follows:

- to cut trees (in conjunction with 66/33kV lines)
- to re-tighten components
- do other work that results from inspections.

Work to re-tighten components to reduce wear and fatigue is ongoing. The visual inspection and pole data capture project is now complete. This data will be used to manage pole condition monitoring by visual inspection and thermographic survey.

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: 11kV overhead lines.

Earthing

We take a risk based approach to inspection and testing of site earths. Urban areas have good bonding between earths. Therefore we concentrate earthing maintenance in the rural area. Earthing in these areas is subject to deterioration because of highly resistive soils, stony sub-layers of earth and corroded earthing systems. Between 2,100 and 2,700 sites are tested in any one year and those requiring repairs are identified and scheduled for repair in the following year.

4.7.6 Replacement plan

Our replacement programme is based on asset condition as determined by our inspection regime.

We continue to replace any two pole platform substations with a single pole substation, or a kiosk if the line is likely to be removed. This is done to satisfy issues of safety and seismic risk.

Our budgeted replacement costs are shown in section 7.1.9 - Replacement budgets: 11kV overhead lines.

4.7.7 Creation/acquisition plan

We now only build 11kV lines in our rural area as they are prohibited in urban areas by planning requirements.

Additional 11kV lines are constructed as a result of the following:

- reinforcement plans (refer to section 5.6 – Network development proposals)
- new connections and subdivision developments.

4.7.8 Disposal plan

We dispose of lines to meet consumer requirements or to implement city/district council underground conversion projects.

4.8 Overhead lines – distribution 400V

4.8.1 Asset description

Our 400V distribution overhead system is 2,805km circuit length of lines, mainly within the Christchurch urban area. This length includes 932km of street lighting circuit. These 400V lines are constructed using timber and concrete poles.

The urban 400V network is a multiple earthed neutral system operating at 400 volts between phases and 230 volts to earth. In the city the network can be interconnected with adjacent substations by installing ties at various normally open points.

Lines on private property

Owners are responsible for the safety of lines that they own. We provide a maintenance service to our consumers for lines that they own, and the cost of this service forms part of our line charge.

4.8.2 Asset capacity/performance

The standard 400V polyvinyl-chloride (PVC) covered conductors are itemised in the table below. Ratings are based on 20°C ambient and 30°C conductor rise.

Conductor (Aluminium)	Rating (Amps)	Conductor (Copper)	Rating (Amps)
Weke AAC	299	37/0.083 HD	395
Rango AAC	221	19/0.083 HD	265
Namu AAC	114	19/0.064 HD	195
		7/0.083 HD	144
		7/0.064 HD	106

4.8.3 Asset condition

An assessment of the design of our 400V poles has indicated that, in some cases, the pole foundation strength is inadequate for the loading. This has been determined using the requirements of the adopted standard NZS 4203 – General Structural Design and Design Loadings for Buildings. Standards are now in place for installing all new poles.

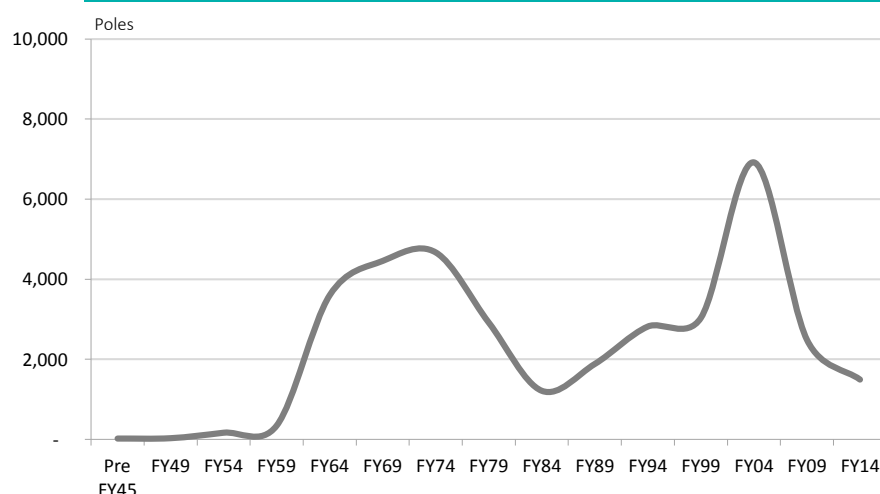
During 2001 and 2002 a telecommunications company installed a network in a large portion of the Christchurch urban area. This required a major inspection and assessment programme to determine if our existing poles were capable of supporting the communication infrastructure. As a result of this analysis, we replaced approximately 4,300 poles.

Timber poles are used extensively for all new/replacement work. The life expectancy of these poles is 35 to 55 years. Improved treatment procedures mean that we expect poles will last longer than this in future. Poles in more exposed areas such as Banks Peninsula and Arthur's Pass may need to be replaced at 30 to 35 year intervals due to harsh environmental conditions (high winds and heavier snow/rainfall).

The 400V network conductors are predominantly PVC covered, but in some older areas triple braid (TB), that has poor insulation properties, is still in use. Conductors with this type of insulation are replaced during scheduled pole replacement work.

The age profile of our 400V poles is shown in the following figure.

Figure 4-8a Overhead lines 400V poles – age profile



4.8.4 Standards and asset data

Standards and specifications

Asset management report:

- NW70.00.25 - Overhead lines - 400V

Design standards developed and in use for this asset are:

- NW70.51.01 – Overhead line design standard
- NW70.51.02 – Overhead line design manual.

Technical specifications covering the construction and ongoing maintenance of this asset are:

- NW72.21.01 – Overhead line work
- NW72.21.03 – Retightening of components
- NW72.21.11 – Overhead line Inspection and Assessment
- NW72.21.18 – Standard construction drawing set – overhead
- NW72.24.01 – Vegetation Work Adjacent to Overhead Lines.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.06 – Poles – softwood
- NW74.23.08 – Poles – hardwood
- NW74.23.17 – Conductor – overhead lines
- NW74.23.19 – Cross-arms.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GPS)
- pole identification numbers (urban poles not physically labelled)
- pole age, type and condition score
- conductor size and age (the age of some conductors is estimated)
- pole and fittings condition assessments
- construction and as built drawings for renewals and extensions.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition and the fittings/attachments on our poles.

4.8.5 Maintenance plan

Maintenance is primarily based on a periodic pole inspection cycle. See section 4.7.5 Overhead line – 11kV, for pole inspections/assessments details.

We continue to focus on clearing trees from 400V lines to comply with the Tree Regulations.

Other maintenance work is on an as-required basis.

Requests from lighting authorities to install various outreach street lighting arms on existing poles requires some poles to be changed to meet the additional load.

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: 400V overhead lines.

4.8.6 Replacement plan

The condition of our overhead lines is generally good. Our pole replacement programme is derived from a condition assessment survey. This is an on-going process and any poles deemed not satisfactory are replaced.

Our budgeted replacement costs are shown in section 7.1.9 - Replacement budgets: 400V overhead lines.

4.8.7 Creation/acquisition plan

We now only create 400V distribution lines in our rural area as they are prohibited in urban areas by city/district plan requirements. They are generally constructed in response to consumer connection requirements only.

4.8.8 Disposal plan

We dispose of overhead lines to meet consumer requirements or to implement city/district councils underground conversion projects.



Liquefaction during the earthquakes lowered some 400V overhead lines as the poles were vibrated into the ground.

4.9 Underground cables – subtransmission 66kV

4.9.1 Asset description

Our subtransmission 66kV cable asset is 71km of circuit length of underground cable. Traditionally, pairs of radial 66kV 3-core aluminum, oil filled, aluminum sheathed cables were installed to supply most of our 66/11kV zone substations. In 2000-2002, a 3x1core copper, XLPE cable was installed from Bromley to Lancaster and Armagh zone substations. This cable provides additional system security to the Christchurch CBD.

There is 40km of circuit length of aluminum cable in our network. Each cable has an emergency rating equivalent to the full load of the zone substation (nominally 40MVA). These cables have an outer cover of semi-conducting plastic sheath over the aluminum. They are installed either encased in weak mix concrete with cross-sectional dimensions of 600mm wide by 300mm high, and capped by a 50mm layer of hard concrete dyed red or supported on a reinforced concrete strip footing. For each zone substation the two cables have been laid in a common trench spaced 300mm apart at a minimum depth of 750mm.

The 7.2km of 1,600mm² 3x1core copper XLPE cable has a continuous rating of 160MVA. This rating allows for the contingency of a loss of supply at Addington, and enables the Christchurch CBD and surrounding areas to be supplied from Bromley. The single core cables have been installed in a weak mix of thermally stabilised concrete and capped with a 50mm layer of stronger concrete dyed red. Two fibre optic cables have been installed with the 66kV cables, one of which is strapped to the 66kV cable to facilitate monitoring of thermal performance. The second fibre optic cable is part of the cable protection system.

Additionally, short lengths of 66kV single core cable are located within the zone substations to link primary equipment. These cables are shown in the circuit listing, along with the main cables.

As a result of the Canterbury earthquakes we undertook a review of how our subtransmission cables have been installed. One of the key findings was that while we had good current carrying capacity between zone substations the fact we had dual circuits in the same trench meant we experienced common mode failures due to lateral spread. To mitigate this we are increasing the interconnection of our 66kV cable network and using route diversity for future installations. Significant progress has been achieved with our programme of works to restore resiliency in the northeast of the city. Refer to section 5.6.3 For subtransmission architecture review.

Figure 4-9a Subtransmission 66kV underground cables – Christchurch urban area

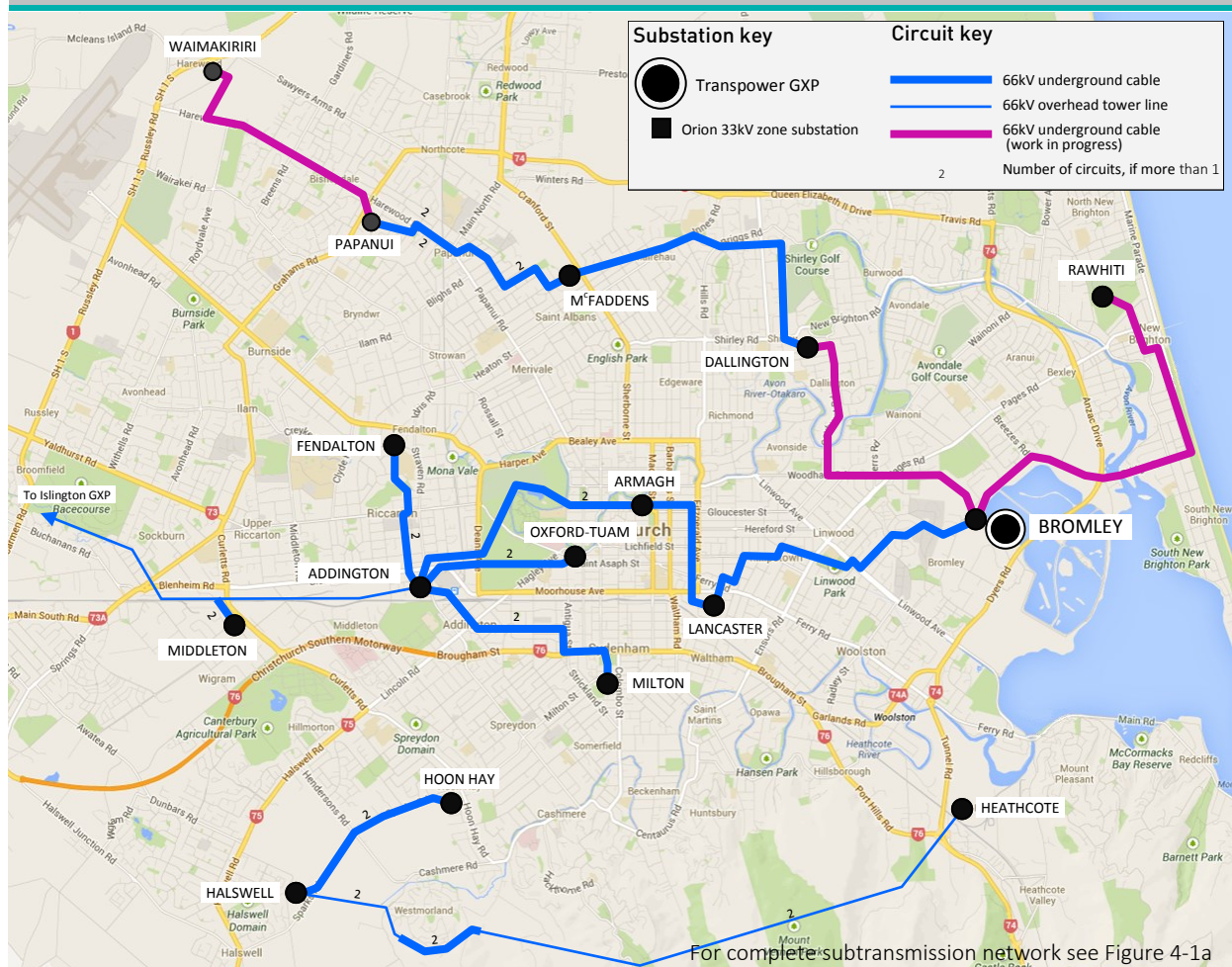


Table 4-9a 66kV cable circuits

Cable circuit	Install year	Cable type/ manufacturer	Size	Rating (A)* summer/winter	Length (m)
Addington 66-Armagh No.1	1981	3c Oil (Pirelli)	300 Al	343/370	4,280
Addington 126-Armagh No.2	1981	3c Oil (Pirelli)	300 Al	343/370	4,416
Addington 66-Fendalton T1	1978	3c Oil (Hitachi)	300 Al	345/393	2,464
Addington 176A-Fendalton T2	1978	3c Oil (Hitachi)	300 Al	345/393	2,345
Addington 46-Milton T1	1979	3c Oil (Hitachi)	300 Al	330/384	3,990
Addington 176B-Milton T2	1979	3c Oil (Hitachi)	300 Al	330/384	4,089
Addington-Oxford Tuam T1	1975	3c Oil (Dainichi)	0.45 Al	330/350	2,661
Addington-Oxford Tuam T2	1975	3c Oil (Dainichi)	0.45 Al	330/350	2,562
Bromley-Lancaster	2000	3x1c XLPE (Olex)	1600 Cu	1400/1400	4,884
Bromley-Dallington**	2014	3x1c XLPE (Olex)	1600 Cu	1400/1400	4,804
Bromley-Rawhiti **	2015	3x1c XLPE (Olex)	1600 Cu	1400/1400	6,552
Dallington-McFaddens	2013	3x1c XLPE (Olex)	1000 Cu	1050/1050	5,410
Halswell 196-Hoon Hay T1	1969	3c Oil (AEI)	0.45 Al	289/356	2,644
Halswell 136-Hoon Hay T2	1969	3c Oil (AEI)	0.45 Al	289/356	2,647
Halswell-Heathcote 1 (Westmorland)	2015	3x1c XLPE	630 Cu	700/700	1,055
Halswell-Heathcote 2 (Westmorland)	2015	3x1c XLPE	630 Cu	700/700	1,055
Middleton T1	2008	3x1c XLPE	300 Cu		375
Middleton T2	2008	3x1c XLPE	300 Cu		365
Papanui 136-McFaddens T1	1972	3c Oil (Dainichi)	0.45 Al	348/396	4,163
Papanui 206-McFaddens T2	1972	3c Oil (Dainichi)	0.45 Al	348/396	4,091
Papanui - Waimakariri**	2015	3x1c XLPE	1000 Cu	1,050/1,050	4,016
Barnett Park	1987	3 core Oil	300 Al	330/350	120
Lancaster-Armagh	2002	3x1c XLPE (Olex)	1600 Cu	1400/1400	2,363
Armagh (T1/T2)	2001	3x1c XLPE (Olex)	300 Cu		75
Heathcote (T2)	1968	3x1c PCCAS	0.25 Cu		12
* Ratings are single cable contingency, that is second parallel cable is out of service (assumes that condition of cables and joints are capable of design rating).					
* Cable laid. Not commissioned at publication of AMP.					

4.9.2 Asset capacity/performance

The 66kV underground cables are predominantly 300mm² Al (paper insulated, oil filled and aluminum sheathed) with a nominal rating of 425A or 48.5MVA at 85°C. The Bromley-Lancaster-Armagh cable, is a 1,600mm² Cu XLPE lead sheathed cable with a design rating of 1400A or 160MVA at 90°C. The McFaddens-Dallington cable is a 1000mm² Cu XLPE Aluminum sheathed cable with a design rating of 1050A or 120MVA at 90°C

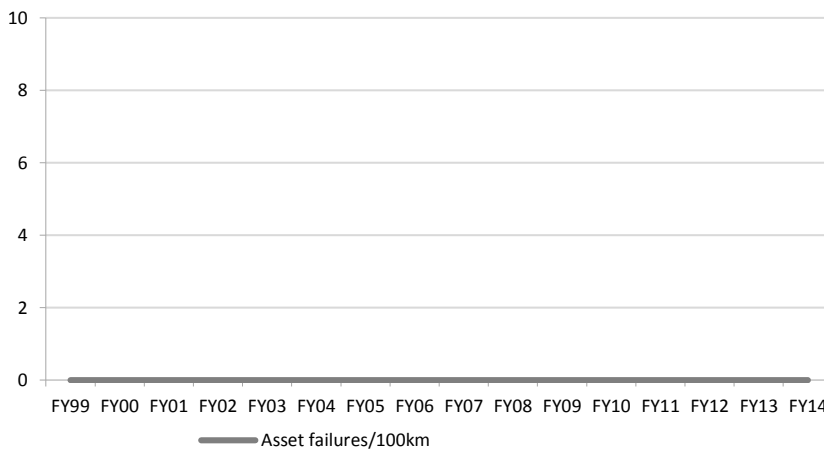
Failure modes have predominately been related to the terminations and third party damage. We are proactively addressing these issues.

Oil filled cables are particularly vulnerable to damage from:

- unrelated work, for example other services trenching
- differential ground settlement that can occur as a result of poorly compacted fill material or naturally soft ground for example organic clays and peat
- movement as a result of an earthquake (as observed during the 2010/2011 earthquakes).

The cable routes have been assessed to ascertain the vulnerability of the cables to a seismic event.

Figure 4-9b Underground cables 66kV – asset failures/100km



4.9.3 Asset condition

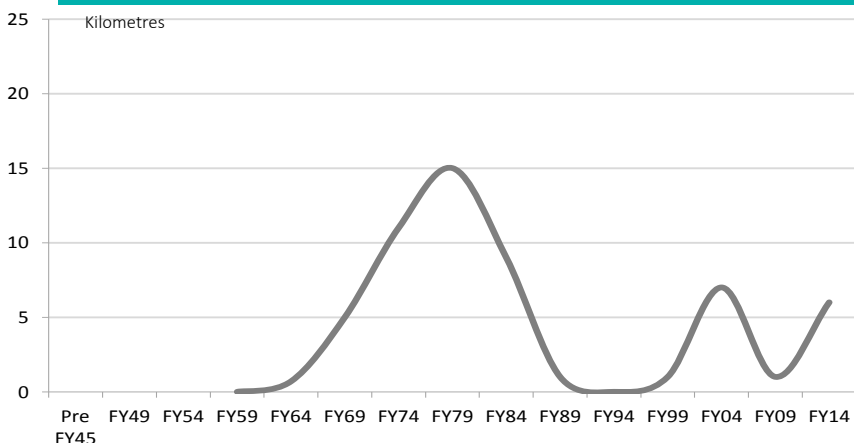
Our 66kV cables have a low average age, with the oldest cables being laid in 1967. The cables to date have been operated conservatively and therefore not been subject to electrical aging mechanisms. We monitor the cables to ensure the integrity of the mechanical protection of the cables is maintained.

During the recent earthquakes there was significant ground movement in areas around the Avon River where our Brighton and Dallington 66kV cables traversed. An inspection was carried out on the Dallington cables after the September 2010 earthquake and while there was some minor damage the cables were returned to service with a lower load rating. The M6.3 earthquake in February 2011 caused further significant damage to these cables and other 66kV cables in our urban network. The cables to Brighton and Dallington zone substations could not be made serviceable and have been replaced.

We are currently developing plans to repair, replace or diversify our assets in these areas. Additional cable reinforcement projects are underway. Refer section 5.6.6 for details of these projects.

All the joints that indicated excessive movement of conductors have now been replaced. We continue to inspect the joints that have shown no signs of damage or buckling as part of an ongoing maintenance plan. These joints have been assessed as being a low risk of failure due to thermal expansion/movement of conductors.

Figure 4-9c Underground cables 66kV – age profile



4.9.4 Standards and asset data

Standards and specifications

Cables are installed to manufacturers' specifications and to specific design on a case-by-case basis by suitably qualified engineering consultants. Any design includes thermal modelling of soil and ground conditions for the cable to achieve the required level of service.

Asset management report:

- NW70.00.32 - Underground cables - 66kV

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.30 – Cable - Subtransmission - 66kV - 300mm² Cu XLPE
- NW74.23.31 – Cable - Subtransmission - 66kV - 1600mm² Cu XLPE
- NW74.23.35 – Cable - Subtransmission - 66kV - 1000mm² Cu XLPE.

Risks associated with alternative standards include operating cables at temperatures above the recommended levels. This could reduce the service life of the cables concerned.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS)
- circuit ratings
- sheath test results
- cable type, size and age
- joint age, type and condition
- seismic risk assessments and profile drawings of cable routes.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the condition of the asset.

4.9.5 Maintenance plan

The condition of our 66kV underground cables is monitored by:

- an annual inspection and sheath test of all cables with any planned repairs completed the next year
- alarms fitted to give early warning of low oil pressure and oil level via the SCADA system. Immediate investigation and rectification of the problem follows any oil alarm. To give better monitoring and analysis we install pressure transducers at the ends of cables in conjunction with joint upgrading
- continuous temperature monitoring at a potential 'hot spot' on the Addington-Armagh T1 cable – this also reports via the SCADA system
- other cables are currently being identified for further monitoring work.

The following maintenance work is planned:

- ensure contractors with suitable skills are available for oil filled cable jointing
- review the thermal properties of backfill material where tests indicate that the cable's rating is compromised
- continue inspecting joints for signs of thermal-mechanical damage.

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: Subtransmission underground cables.

4.9.6 Replacement plan

We do not have any 66kV cable replacement programmed in the next 10 years.

Our budgeted replacement costs are shown in section 7.1.9 – Replacement budgets - 66kV underground cables.

4.9.7 Creation/acquisition plan

Cables are laid in the city to conform with the requirements of the Christchurch city plan.

For details of projects to reinforce our 66kV cable network see section 5.6 – Network development proposals.

4.9.8 Disposal plan

We have no plans to dispose of any 66kV cable assets.

4.10 Underground cables – subtransmission 33kV

4.10.1 Asset description

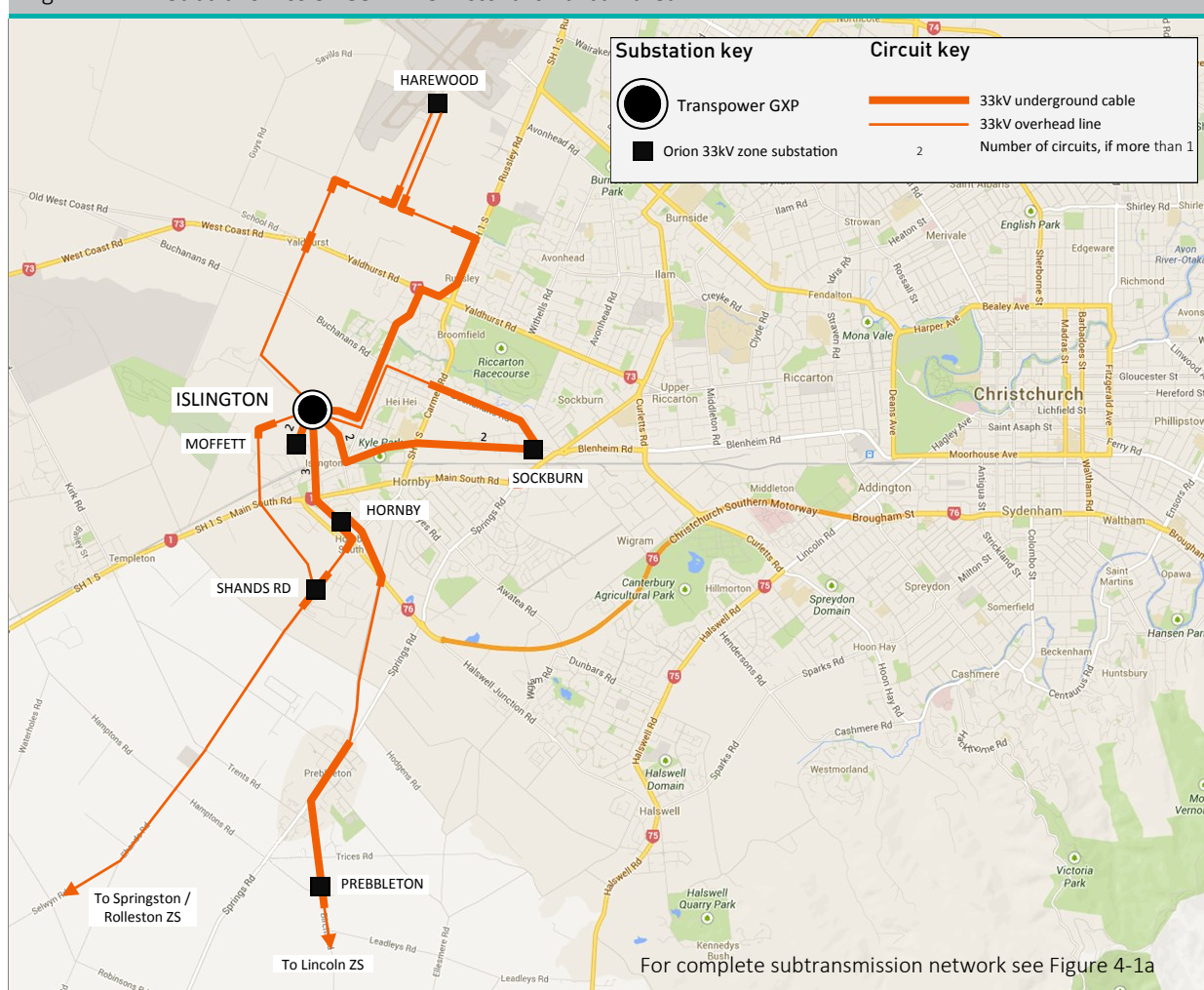
Our subtransmission 33kV cable asset is 36km of circuit length of underground cable, buried directly in the ground. It is mostly situated in the western part of Christchurch city, with sections of cable in Rolleston, Lincoln, Prebbleton and Springston, and is made up approximately as follows:

- PILCA 3km installed 1978-1988
- XLPE 33km installed 1992-2014

In recent years there has been an increasing amount of 33kV overhead line replaced by underground cables as land has been developed and road controlling authorities have requested removal for road upgrades.

We have completed a programme to replace our oil filled cables with XLPE cables. Given the relatively short lengths involved this was a cost effective way to address the risk of joint failure in our oil filled cables.

Figure 4-10a Subtransmission 33kV – Christchurch urban area



4.10.2 Asset capacity/performance

The cable sizes are as shown in the circuit listing (Table 4-10a) and are solid insulation with a nominal rating of 425A or 24MVA.

In 2006 we had an outdoor termination fail and termination/joint oil leaks in our oil-filled cables (now replaced with XLPE). Our XLPE cable failures were due to incorrect installation practices. This has been addressed with new standard joint/termination kits and jointer training. Spare joints and terminations are held as a contingency against cable failure.

We are pro-active with contractors and council staff to maintain awareness of the location of subtransmission cables.

Figure 4-10b Underground cables 33kV – asset failures/100km

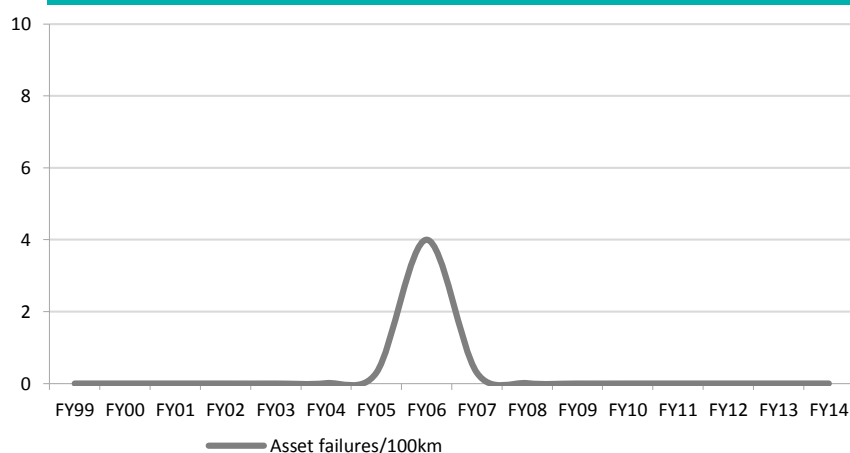


Figure 4-10c Subtransmission – Lincoln and Springston area

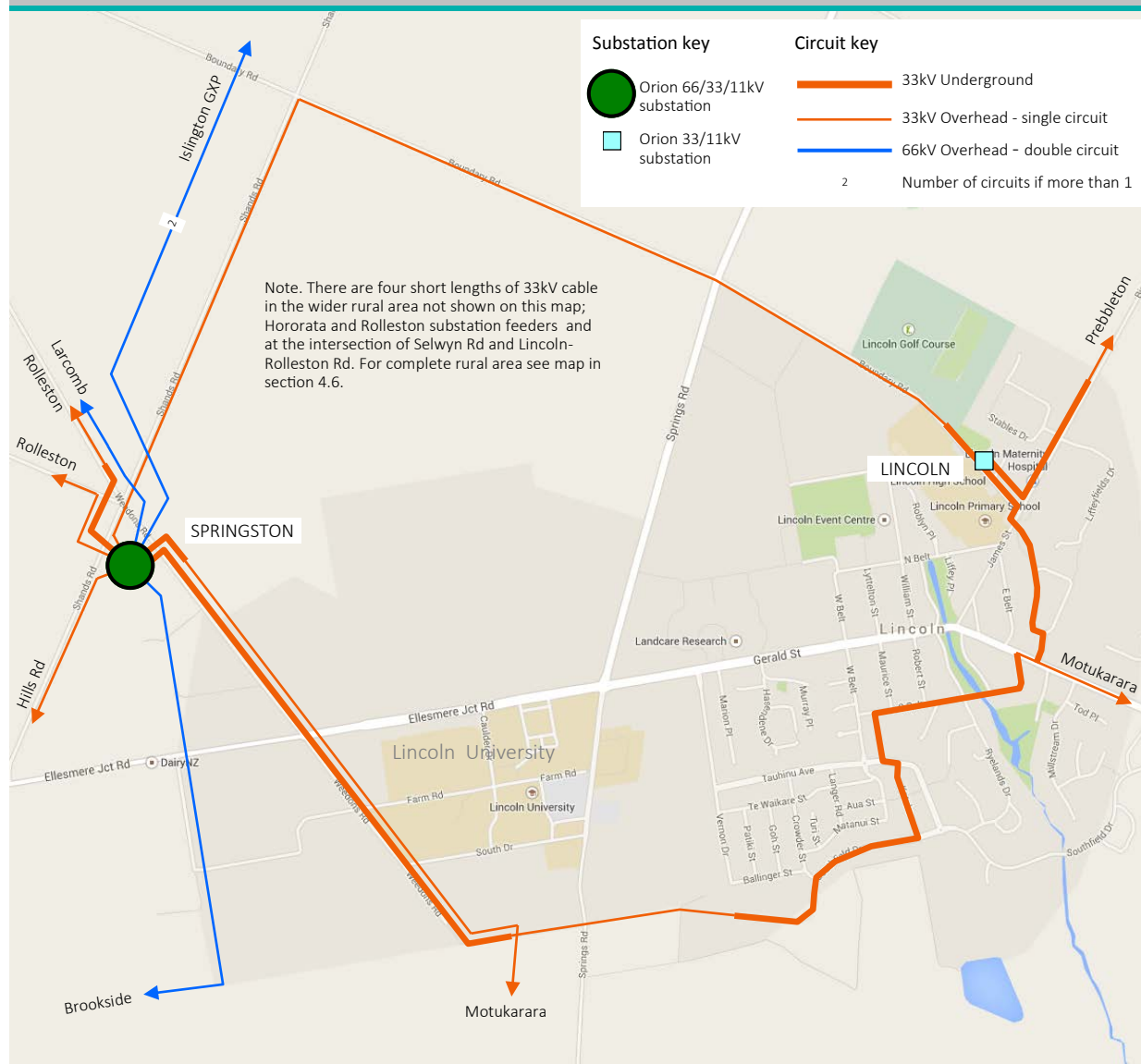


Table 4-10a 33kV cable circuit listing

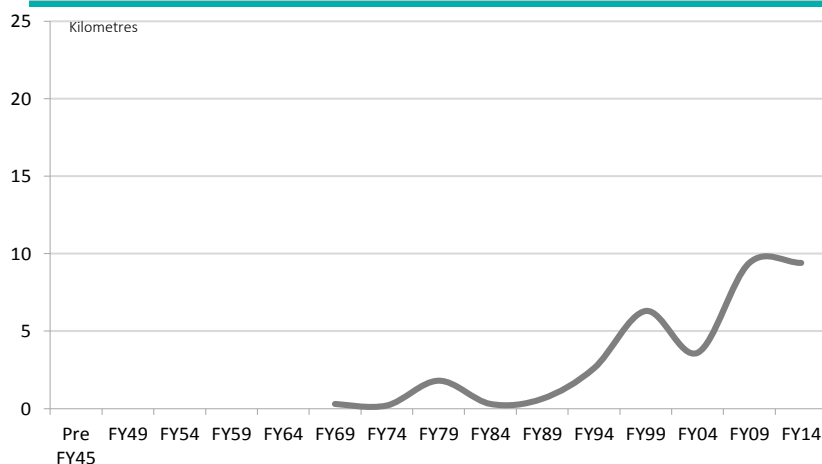
Cable circuit	Length (m)	Type	Size	Winter rating (A)
Islington 2102 - Harewood 234.	690	XLPE	300 Al	475*
Islington 1036 - Moffett St 334	172	Paper lead	.3 Cu	313
Islington 2092 - Moffett St 344	136	Paper lead /XLPE	300Al/.3 Cu	313
Islington 936 - Sockburn T1	2,019	XLPE	300Al	475*
Islington 2062 - Sockburn T2	3,513	XLPE	300Al/630Cu	372
Islington 976 - Sockburn T3	3,486	XLPE	300Al	319
Islington 886 - Harewood 224	4,507	PILCA /XLPE	300Al	319
Islington 966 - Hornby 572-582	1,848	XLPE	300Al	306*
Islington 2072 - Hornby 532-542	1,852	XLPE	300Al	338*
Springston 1206 - Shands Rd 436	67	PILCA	300Al	365*
Hornby 502-512 - Shands Rd 454	830	PILCA/XLPE	300Al	365*
Hornby 562-572-Prebbleton 4832	3,499	XLPE	300Al	365*
Prebbleton 4842 - Lincoln 3434	781	XLPE	300Al	365*
Hororata 1226 - Hororata 924	95	PILCA	.3Al	280*
Hororata 1206 - Annat 1106/Kimberley 4926	65	PILCA	.3Al	280*
Springston 1206 - Rolleston 3234	2,945	XLPE	300Al	475*
Springston 1146 - Springston 3554	74	PILCA	.3Al	280*
Springston 1186 - Springston 3544	80	PILCA	185Cu	355*
Springston 1176 - Motukarara 3612/3622	5,026	XLPE	300Al	
Springston 1196 - Larcomb 4736	371	PILCA	185Cu	355*
Springston 1226 - Lincoln 3432	177	XLPE	300Al	
Springston 3532 - Motukarara 3632/3642	154	PILCA/XLPE	300Al/185Cu	355*
Motukarara 3642/3652 - Little River 3812	79	XLPE	300Al	
Motukarara 3602/3612 - Teddington 3704	105	XLPE	300Al	
Springston 1166 - Brookside 3114	172	XLPE	300Al	475*
Islington 1026 - Hornby 512-522	1,836	XLPE	300Al	
Islington 2082 - Shands Rd 444	1,000	XLPE	300Al/150Cu	
Hornby zone substation	151	XLPE	300Al/630Cu	
Motukarara zone substation	70	XLPE	300Al	
Duvauchelle zone substation	50	XLPE	300Al	
Lincoln zone substation	62	XLPE	300Al	
Shands Rd zone substation	12	XLPE	300Al	
Prebbleton zone substation	19	XLPE	300Al	

Note: Some of these circuits may have an overhead line component that will affect overall circuit rating.
*Nominal rating – investigation to determine full rating to be completed.

4.10.3 Asset condition

These cables are in good condition and, to date, no sheath faults have occurred.

Figure 4-10d Underground cables 33kV – age profile



4.10.4 Standards and asset data

We install 33kV cables in compliance with manufacturers' specifications and industry standards to suit the ground conditions where they are located.

Standards and specifications

Asset management report:

- NW70.00.31 - Underground cables - 33kV

Design standards developed and in use for this asset are:

- NW70.52.01 – Underground cable design.

Technical specifications covering the construction and ongoing maintenance of this asset are:

- NW72.21.01 – Cable testing
- NW72.22.01 – Cable installation and maintenance
- NW72.22.02 – Excavation, backfilling and restoration of surfaces
- NW71.12.03 – Cabling and network asset recording.

Equipment standards:

- NW74.23.14 – Subtransmission cable 33kV
- NW74.23.20 – Earthing equipment and application.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS)
- circuit ratings
- sheath test results
- cable type, size and age
- joint age, type and condition
- route profile drawings for some cables.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of asset condition.

4.10.5 Maintenance plan

The condition of this asset is monitored by an inspection and sheath test, where practicable, every year.

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: Subtransmission UG cables.

4.10.6 Replacement plan

We have replaced the 33kV oil-filled cables due to issues with joints similar to the those on the 66kV oil-filled cables. With 33kV cables it was more cost effective to replace the entire oil-filled cable rather than upgrade the joints.

Any further cable installations will be carried out as a major project or as part of overhead to underground conversion works driven by the local authority. We have no plans to replace any of the existing cables in the next 10 years.

Our budgeted replacement costs are shown in section 7.1.9 - Replacement budgets: 33kV underground cables.

4.10.7 Creation/acquisition plan

33kV cables are laid in the city to conform to the requirements of the Christchurch city plan.

For a list of projects containing this asset, see section 5.6 – Network development proposals.

4.10.8 Disposal plan

We have no plans to dispose of any other 33kV cable assets.

4.11 Underground cables – 11kV

4.11.1 Asset description

Our 11kV cable network is 2,408km of circuit length of underground cable and is largely concentrated in the urban area of Christchurch (approximately 90% of total length).

These cables are classed as subtransmission (feeder and primary) and distribution (secondary) cables as follows:

- feeder cables that supply our 11kV zone substations (see the table on the following page)
- primary cables which supply network substations from zone substations
- secondary cables which supply distribution substations from network substations.

The reason for having these classes is largely historical and is explained further in section 4.2.2 – Asset justification.

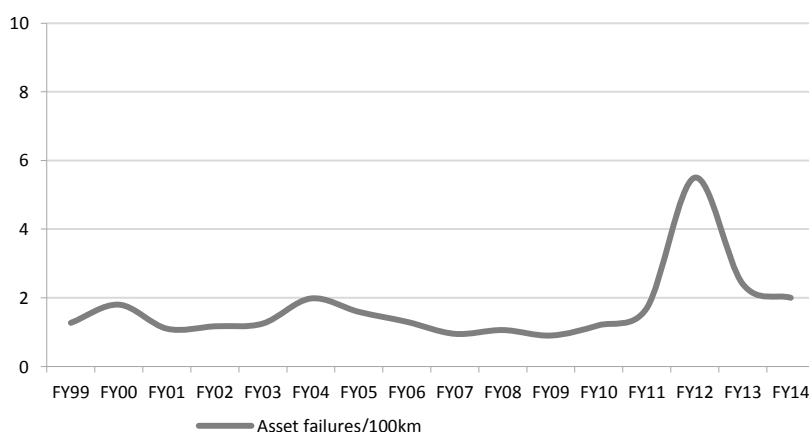
The 11kV cable is predominantly of the paper lead variety with an expected life of 70 years.

4.11.2 Asset capacity/performance

The September 2010 and February 2011 earthquakes caused a number of 11kV cable faults. They were mainly confined to areas subjected to large lateral movement of the ground in Brighton, Dallington and Avondale. These areas contain approximately 90km of cable.

The majority of cables that failed were PILCA type having been installed for an average of 40-50 years. Some of these cables had multiple faults. The failure modes were either joints (typically older pitch filled types) being pulled apart or significant movement of the cables causing failure of the cables' outer sheath and subsequently the paper insulation.

Figure 4-11a Underground cables 11kV – asset failures/100km



11kV feeder system

These cables mainly supply our 11kV zone substations. The rating of each cable has been assessed based on the thermal resistivity of the cable bedding material. These assessments have shown the present loading requirements of the substations do not exceed the cable capability. We manage the development and operation of the network to ensure the cable ratings are not exceeded during contingency events.

Primary 11kV system

This system is designed to be run in single or multiple closed rings. Each ring usually starts at a zone substation bus and includes one or more network substations before returning via a different route to the starting zone substation. To provide additional 11kV tie capacity, primary circuits may also be provided in some cases to alternative zone substations. A primary ring consists of dedicated runs of cable between a zone substation bus and a network substation or between network substations. Each end of a primary cable is protected with a circuit breaker using differential protection. No distribution substation load is supplied directly from the primary cable system. The primary system is designed to be loaded up to the point where, in the event of a single cable fault contingency, no primary cables will become overloaded and no loss of supply will result. The standard conductor is 300mm² Al/0.25in² Cu PILCA giving each circuit a rating of 365A or 7MVA. As per the 2006 11kV architecture review findings, the primary 11kV system will be changed over time. As assets come up for replacement, the associated network will be converted to a secondary system and therefore peak loads will tend to be around 50% of the cable capacity.

Table 4-11a 11kV feeder cable circuit listing

Cable circuit	Install year	Type	Size	Rating (A)** summer/winter	Length (m)
Addington 1/2688-Foster 12 (2 cables)	1950/93	PILCA	0.5 Al and 300 Al	700*	160
Addington 1/2722-Foster 6 (2 cables)	1993	PILCA	2x 300 Al	700*	160
Addington 1/2802-Foster 19 (2 cables)	1950/93	PILCA	0.3 Cu and 300 Al	700*	150
Addington 2/10/Foster 4-Knox 13	1965/2001	PILCA	0.5 Cu and 400 Cu	273/324**	2,960
Addington 2/3-Knox 3	1965	PILCA	0.5 Cu	273/324**	3,185
Addington 2/11-Knox 17	1965	PILCA	0.5 Cu	273/324**	3,175
Addington 2/4-Spreydon 15	1964	PILCA	0.5 Cu	282/338**	2,955
Addington 2/5-Spreydon 9	1964	PILCA	0.5 Cu	282/338**	2,955
Addington 2/9-Spreydon 3	1964	PILCA	0.5 Cu	282/338**	2,975
Addington 1/2782-Montreal 10	1963/2000	PILCA	0.5 Cu and 400 Cu	306/334**	2,500
Addington 1/2822-Montreal 15	1963/2000	PILCA	0.5 Cu and 400 Cu	306/334**	2,500
Addington 1/2642-Montreal 4	1963/94	PILCA	0.5 Cu	306/334**	2,500
Bromley 5-Pages Kearneys 4	1966/73	PILCA	0.5 Cu	375/466	1,560
Bromley 6-Pages Kearneys 10	1966	PILCA	0.5 Cu	375/466	1,560
Bromley 7-Pages Kearneys 16	1966	PILCA	0.5 Cu	375/466	1,560
Hawthornden 31-Ilam 2	2005	XLPE	400 Cu	220*	2849
Hawthornden 32-Ilam 14	2005	XLPE	400 Cu	220*	2849

* Nominal rating - investigation to determine full rating to be completed.
 ** Rating when one cable is out of service.
 *** Rating when one circuit is out of service.



Overhead line 11kV cable termination with surge arrestors fitted

Secondary 11kV system

This system consists of radial feeders, most of which are supplied from network substations, however, as we transition our 11kV system to the new architecture, more 11kV feeders will be supplied directly from the zone substation bus. Depending on the area and load supplied, secondary feeders have nominal ratings ranging between 2 and 7MVA. Secondary feeders are loaded to the extent that, in the event of a single fault contingency, it should be possible to split the faulty feeder so that the healthy portions can be supplied from adjacent feeders without overloading those feeders. Historically this would mean that, under normal circumstances, any individual feeder should not be loaded above 70% of cable rating. The new architecture requires that the size of the 11kV feeders is sufficient to provide the full load of adjacent feeders.

The age of the cables making up this asset covers a wide range. The cable failure modes are monitored to ensure the high reliability of cables. To date the majority of failure modes have included:

- third party damage
- damage of cable during installation or other disturbance
- failure of terminations.

To manage these issues the following actions are taken:

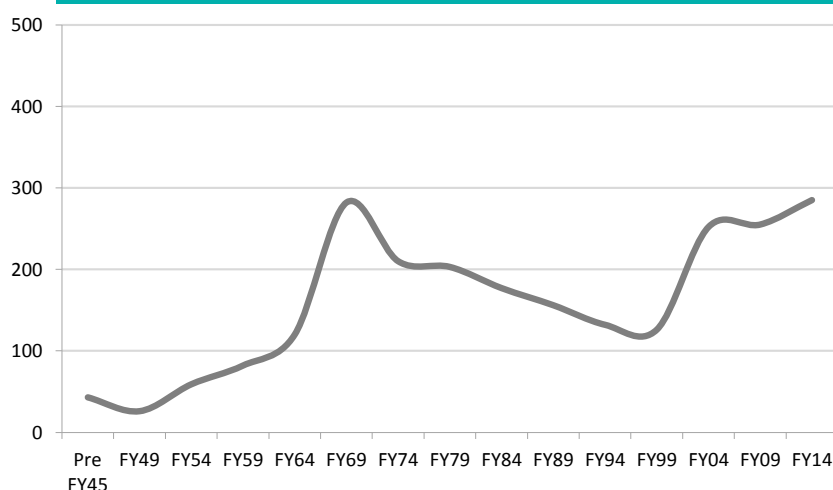
- proactive promotion to contractors of cable maps and locating services
- free training (including a DVD) on working safely around cables, including reading cable location maps
- extensive safety advertising in the media
- inspection of contractors during the laying of cables
- ultrasonic and partial discharge monitoring of terminations in zone and network substations
- new cables installed with an orange coloured sheath to allow easier identification.

4.11.3 Asset condition

The condition of these cables is largely assessed by monitoring any failures. Condition testing of a sample of varying cable types and ages has been undertaken using the partial discharge mapping technique. A limited amount of partial discharge was noticeable in a few joints. However, there were no major areas of concern. This indicates that cables are in good condition.

We anticipate that cables that have been subjected to stresses caused by the earthquakes will have higher failure rates in the next few years as compromised cable sheaths and insulation develop faults. A programme has been developed to test 11kV (and other) cables in areas that were subjected to significant earthquake damage to determine whether maintenance or replacement is required.

Figure 4-11b Underground cables 11kV – age profile



4.11.4 Standards and asset data

Standards and specifications

Asset management report:

- NW70.00.30 - Underground cables - 11kV

Design standards developed and in use for this asset are:

- NW70.52.01 – Underground cable design.

Technical specifications:

- NW72.21.01 – Cable testing
- NW72.22.01 – Cable installation and maintenance
- NW71.12.03 – Cabling and network asset recording
- NW72.22.02 – Excavation, backfilling and restoration of surfaces.

Equipment standards:

- NW74.23.04 – Distribution cable 11kV
- NW74.23.20 – Earthing equipment and application.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS)
- circuit ratings
- cable type, size and age
- joint age and type

Data improvement is ongoing but there are limited opportunities to improve what we already know about this asset group. We closely monitor the cause of any failures to see if any trends develop with a particular cable/joint type.

4.11.5 Maintenance plan

We have programmes in place to address identified failure modes of cables. These failure modes have been predominately related to the terminations where an inspection and maintenance programme has been implemented.

We will undertake an on-going testing programme on 11kV cables identified within the areas that were subjected to significant earthquake damage.

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: 11kV underground cables.

4.11.6 Replacement plan

We currently do not have a replacement programme for this asset. Any significant replacements will be undertaken as part of other works such as a reinforcement/switchgear replacement project or a local authority driven underground conversion project.

Our budgeted replacement costs are shown in section 7.1.9 - Replacement budgets: 11kV underground cables.

4.11.7 Creation/acquisition plan

Additional 11kV cables are installed as a result of the following:

- reinforcement plans (refer to section 5.6 – Network development proposals)
- conversion from overhead to underground as directed by Christchurch City and Selwyn District Councils
- developments as a result of new connections and subdivisions.

4.11.8 Disposal plan

We have no plans to dispose of any of this asset, other than minor disposal associated with changes and rearrangements in the network. No decision has been made as to the fate of assets in the 'red zone'.

4.12 Underground cables – distribution 400V

4.12.1 Asset description

Our 400V cable network is 2,745km of circuit length and is largely concentrated in the urban area of Christchurch. The earlier cables are of paper/lead construction. PVC insulation was introduced in 1966 to replace some paper/lead cables. XLPE insulation was introduced in 1974, mainly because it has better thermal properties than PVC.

We have some 5,800 distribution cabinets installed on our 400V cable network. Sufficient cabinets are needed to allow the system to be reconfigured (that is, each radial feeder must be capable of supplying or being supplied from the feeder adjacent to it) in the event of component failure or other requirements. Distribution cabinets are all above ground. Older ones are generally steel and the later ones are a PVC cover on a steel frame.

We have approximately 35,000 distribution boxes in our 400V cable network. These are generally installed on alternate boundaries on both sides of the street. Several types of distribution box are in service. All are above ground. The majority are a PVC cover on a steel base frame, although some older types are concrete or steel.

Street-lighting cables are also included in this asset group. The street-lighting cable network consists of 2,167km circuit length of underground cable and is largely concentrated in the urban area of Christchurch. Approximately 60% of this cable is included as a fifth core in the 400V distribution cables.

4.12.2 Asset capacity/performance

Many system configurations are used for 400V cable distribution, depending on the area to be supplied, but generally it is a two-sided system with cables on both sides of a street. These cables are fed from a kiosk distribution substation via multiple feeders, each with a rating of around 250A. The cables are buried directly in the ground. Jointing methods have been changed to improve performance.

The earthquakes in FY11 caused a number of 400V cable faults. They were mainly confined to areas subjected to large lateral movement of the ground in Brighton, Dallington and Avondale.

To date the majority of failure modes have included:

- third party damage
- damage of cable during installation or other disturbance causing premature failure.

To manage these issues the following actions are taken:

- proactive promotion to contractors of cable maps and locating services
- free training on working safely around cables, including map reading and a DVD
- extensive safety advertising in the media
- inspection of contractors during the laying of cables
- new cable is now required to be installed with an orange coloured sheath to allow easier identification.

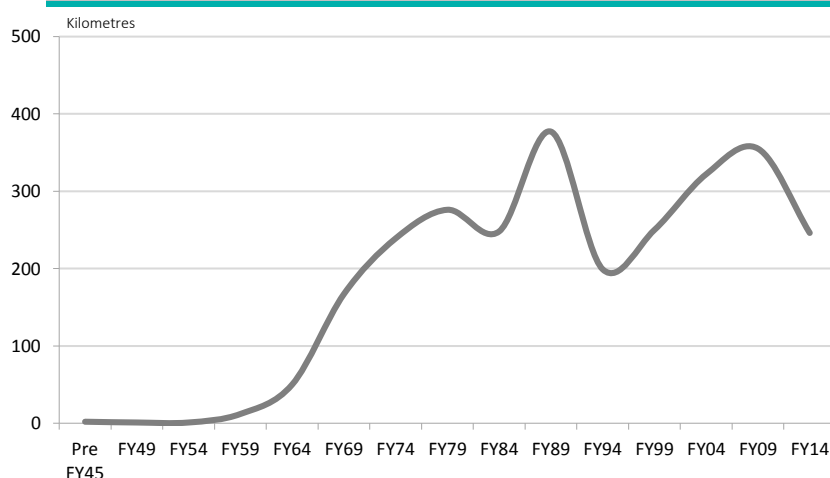
4.12.3 Asset condition

Cable laying has been performed to a good standard and we are not exposed to any great extent from external damage or faulty joints.

We anticipate cables that have been subjected to earthquake stress will have higher failure rates as faults develop in sheaths and insulation. A programme has been developed to run over the next few years to test the 400V and other cables in areas that were subjected to significant earthquake damage to determine whether maintenance or replacement is required.

The distribution cabinets and boxes are in reasonable condition. We inspect them every five years, with any defects remedied in a subsequent contract.

Figure 4-12a Underground cables 400V – age profile



4.12.4 Standards and asset data

Asset management report:

- NW70.00.29 - LV underground cables and hardware

Standards and specifications

Design standards developed and in use for this asset are:

- NW70.52.01 - Underground cable design.

Technical specifications:

- NW72.21.01 - Cable testing
- NW72.22.01 - Cable installation and maintenance
- NW72.22.02 - Excavation, backfilling and restoration of surfaces
- NW72.22.03 - Distribution enclosure installation
- NW72.27.01 - Unit protection maintenance
- NW71.12.03 - Cabling and network asset recording
- NW72.21.12 - Network inspection.

Equipment standards:

- NW74.23.11 - Distribution cable LV
- NW74.23.20 - Earthing equipment and application.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS)
- cable type, size and age
- distribution box types/condition.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan, as well as specific inspections carried out as required. All inspections are used to further our knowledge of the condition of the part of the asset that is above ground. We also closely monitor the cause of any failures to see if trends develop with a particular cable/joint type.

4.12.5 Maintenance plan

The condition of this asset is monitored through:

- an above ground five-yearly visual inspection programme of the asset and its terminations.

Maintenance work planned is as follows:

- insulation is being upgraded on cables connected to the overhead system, where insulation is identified as degraded due to the effects of ultra violet light
- to remedy safety issues old cast iron cable termination boxes with heat shrink are being replaced.

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: 400V underground cables.

4.12.6 Replacement plan

We have made an allowance for 400V cables that may need replacement due to damage caused by the earthquakes. We also plan to upgrade our existing distribution cabinets to a safer and more secure design, see section 6.2 – Risk management-safety.

Our budgeted replacement costs are shown in section 7.1.9 - Replacement budgets: 400V underground cables.

4.12.7 Creation/acquisition plan

We will install additional 400V cables as a result of the following:

- conversion of reticulation from overhead to underground as directed by the city and district councils
- developments as a result of new connections and subdivisions.

4.12.8 Disposal plan

We have no plans to dispose of any of this asset, other than minor disposals associated with changes and rearrangements in the network.

No decision has been made as to the fate of assets in the 'red zone'.

4.13 Communication cables

4.13.1 Asset description

Our 1,061km of communication cables are predominantly located in Christchurch. Most are armoured construction. They are laid to most building substations and are used for SCADA, telephone, data services, ripple control, metering and many other purposes in addition to their original function of providing unit (pilot wire) protection communications.

The distribution network in the urban area is predominantly underground cable made up of primary and secondary 11kV systems. The primary system is operated in closed rings with the secondary system operated radially from network substations on the primary system. Because of the low electrical impedance of cables at 11kV, there is very little variation in fault level throughout the distribution network and thus little opportunity for application of inverse-time based protection co-ordination. To obtain protection co-ordination in the 11kV network it has thus been necessary to use differential or unit protection on all but the last radial sections of the network.

The most common and effective differential protection uses common twisted-pair communication cables for end-to-end measurement of electrical parameters on the protected section of cable. Therefore as new lengths of primary network cable are laid, a communication cable is laid with the electrical power cable. In general it is uneconomic to lay single pair communication cables, as required only for the unit protection, and thus multi-pair cables are installed.

It is not possible to use a dedicated communications provider's network for unit protection. The unit protection signal levels are incompatible with normal commercial communications and, in addition, it is not possible to obtain the very high reliability levels provided by a dedicated end-to-end cable laid with the power cable.

4.13.2 Asset capacity/performance

The standard cables laid are 0.9mm² Cu. These are reasonably heavy cables in communication terms, but this large conductor size is required for the unit protection communications over longer cable routes.

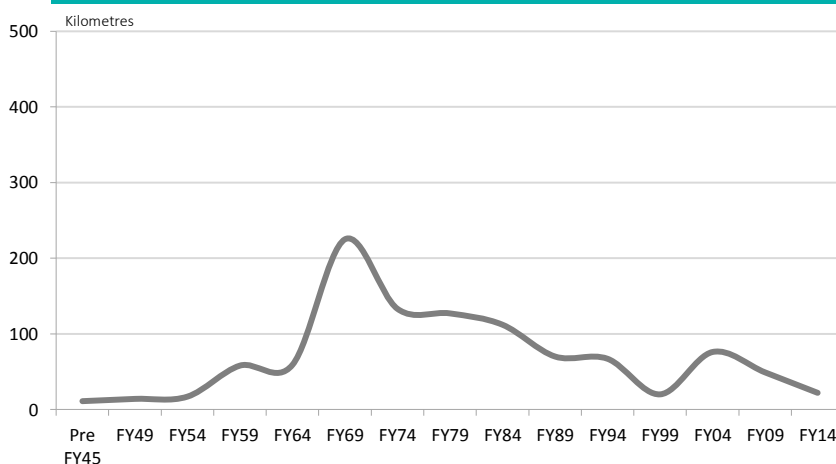
Two separate types of optical-fibre cable, each containing multiple fibres have been laid with new 66kV cables, multi-mode for cable temperature measurement and single mode for communications purposes. The protection equipment for the 66kV cables use single mode fibres.

The common failure point for these cables is the joints. Epoxy filled joints do not stop the ingress of moisture.

4.13.3 Asset condition

These communication cables are in very good condition, with the steel wire armoured variety being the most robust. Some older unarmoured cables of the 2core/2pair type are prone to failure. Where condition is proven to be poor, these cables are replaced or bypassed when additional power cables are installed during system reinforcement. Other options include the use of radio communication channels or the use of dedicated communication providers for services other than power system protection.

Figure 4-13a Communication cables – age profile



4.13.4 Standards and asset data

Standards and specifications

Asset management report:

- NW70.00.28 - Underground cables - communication

Design standards developed and in use for this asset are:

- NW70.52.01 – Underground cable design.

Technical specifications covering the construction and ongoing maintenance of this asset are:

- NW72.21.01 – Cable testing
- NW72.22.01 – Cable installation and maintenance
- NW71.12.03 – Cabling and network asset recording
- NW72.22.02 – Excavation, backfilling and restoration of surfaces.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.11 – Distribution cable LV
- NW74.23.20 – Earthing equipment and application.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS)
- cable type, size and age
- distribution box types/condition
- database of the cables and their connections.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan, as well as specific inspections carried out as required. All inspections are used to further our knowledge of the condition of the part of the asset which is above ground. We also closely monitor the cause of any failures to see if any trends develop with a particular cable/joint type.

The communication cables form a critical part of our network control system.

4.13.5 Maintenance plan

The condition of this asset is monitored by a test of the unit protection system every four years, this includes the most important of these cables. The remaining cables are generally monitored by the services using them, such as SCADA and unit protection. Communication error rates are tracked and recorded by SCADA.

Maintenance work is carried out to repair cables as required when faults occur.

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: Communication cables.

4.13.6 Replacement plan

An allowance has been identified for cable replacement where repair is shown to be costly.

Our budgeted replacement costs are shown in section 7.1.9 - Replacement budgets: Communication cables.

4.13.7 Creation/acquisition plan

New cables are installed as required to form part of new sections of the 11kV primary distribution system. Optical fibre cables are installed as part of any new 66kV or 33kV cable installation.

4.13.8 Disposal plan

We have no plans to dispose of any part of this asset, other than minor disposal associated with changes and rearrangements in the network.

4.14 High voltage circuit breakers

4.14.1 Asset description

Circuit breakers are installed to provide safe interruption of both fault and load currents during power system faults. They are strategically placed in the network for line/cable, local transformer and ripple plant protection.



66kV circuit breakers

66kV circuit breakers are installed at zone substations predominately in outdoor switchyards. The exceptions being Armagh, Dallington and McFaddens zone substations where the 'outdoor' circuit breakers have been installed indoors in specially designed buildings (see photo in section 4.4.1).

The majority of our 66kV circuit breakers use SF₆ gas as the interruption medium. We have not found a viable vacuum option for this voltage.

As part of our spur asset purchases we have recently acquired a number of bulk-oil units.



33kV circuit breakers

A mix of outdoor and indoor 33kV circuit breakers are installed in the 33kV zone substations.

Those installed pre-circa 2001 are mainly outdoor minimum oil interruption type (shown top left). We are now moving from outdoor to indoor switchgear. This has the advantage of improved security and public safety.

The newer circuit breakers at Duvauchelle, Hornby (shown lower left), Lincoln, Motukarara and Prebbleton zone substations are an indoor metal-clad vacuum interruption type.

As part of our spur asset purchases we have recently acquired a number of bulk-oil units.





11kV substation circuit breakers

These substation circuit breakers are installed indoors and used for the protection of primary equipment and the distribution network. The older units use oil or SF₆ gas as an interruption medium, while those installed post 1992 are a vacuum interruption type. 11kV circuit breakers are used throughout the entire rural and urban networks.

Those shown (left) are the vacuum type used in our 11kV switchgear replacement programme.



11kV line circuit breakers (Pole mounted)

Overhead line circuit breakers are pole mounted and have a reclose capability. They are installed in selected locations to improve feeder reliability by isolating a portion of the overall substation feeder. Here the circuit breaker is shown with its associated SCADA control and UHF communication equipment mounted below the circuit breaker.

Table 4-14a Circuit breakers in service

Location	66kV outdoor	66kV indoor	33kV outdoor	33kV indoor	11kV
Zone substations	75	13	38	31	751
Network/distribution substations					1,015
Overhead line					49

4.14.2 Asset capacity/performance

Substation circuit breakers

The rating requirements of circuit breakers are determined by the local load of the network. As a result load current and fault current interruption capabilities vary for circuit breakers of a given operating voltage.

Table 4-14b Circuit breaker ratings

Circuit breaker voltage	Current rating	Fault rating
66kV	1,200A-2,500A	21.9kA-31.5kA
33kV	400A-1,600A	6kA-29kA
11kV	200A-2,500A	2kA-26.5kA

The overall performance of circuit breakers is satisfactory. Isolated cases of common mode faults have occurred in some of the older circuit breakers. As part of our spur asset purchases we have recently acquired a number of 33kV bulk-oil units. Six of these were assessed as having a high probability of failure and have been replaced.

The 33kV and 11kV indoor switchgear units are securely fixed to concrete floors. The auxiliary and voltage transformers are strapped to the switchgear frames and spare circuit breakers are also restrained. These precautions proved to be very effective in the 2010/2011 earthquakes.

Pole mounted 11kV line circuit breakers

Although line circuit breakers are performing satisfactorily, we have encountered problems with the electronic protection and control equipment on the older switches. Suitable alternatives to these units have been investigated and are now being installed in the network as part of the replacement project.

Table 4-14c Line circuit breaker ratings

Type	Current rating	Fault rating
11kV older 3 phase	400A	6kA
11kV newer 3 phase	630A	12.5kA
11kV SWER single phase	200A	3kA

4.14.3 Asset condition

All circuit breakers at zone substations are in satisfactory working condition. New methods of condition monitoring have enabled us to detect defects at an early stage. Older minimum-oil type units are approximately 50 years old and insulation levels are slowly deteriorating.

Table 4-14d Circuit breaker average age (years)

Circuit breaker interruption type	66kV	33kV	11kV
Oil	44	36	41
Vacuum	n/a	7	10
Gas (SF ₆)	6	n/a	23
All	13	23	29

In FY11 EA Technology Ltd was engaged to develop a condition based risk management (CBRM) model for our high voltage circuit breakers. This model utilises asset information, engineering knowledge and experience to define, justify and target asset renewal. It provides a proven and industry accepted means of determining the optimum balance between on-going renewal and Capex forecasts.

The CBRM model calculates the health index and probability of failure of each individual circuit breaker. This effectively gives the circuit breaker a ranking which is used when determining the replacement strategy. Note that while the model calculates the asset ranking it is still up to the engineer to prioritise the replacement schedule.

The results of this process have shown that the overall condition of our circuit breakers is very good and we are on target with our replacement programme. The following graphs show the health index profile and age profile of our circuit breakers.

Figure 4-14a Circuit breakers - health index profile

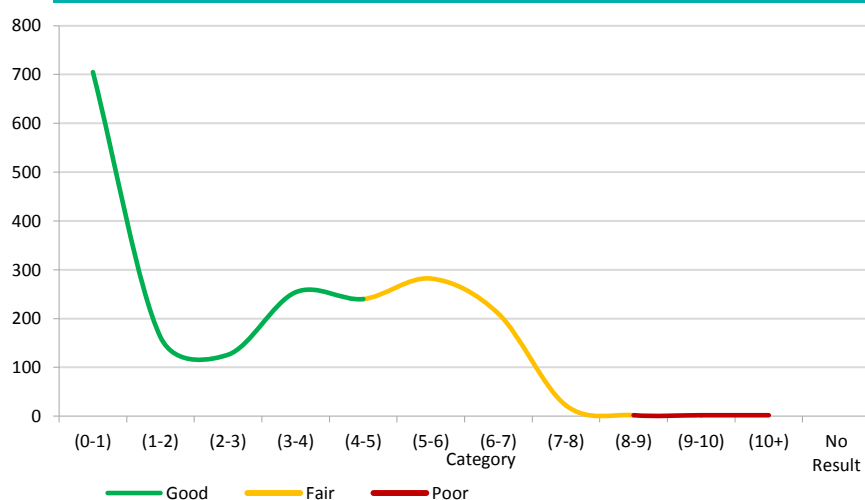


Figure 4-14b Circuit breakers 33 and 66kV - FY14 age profile

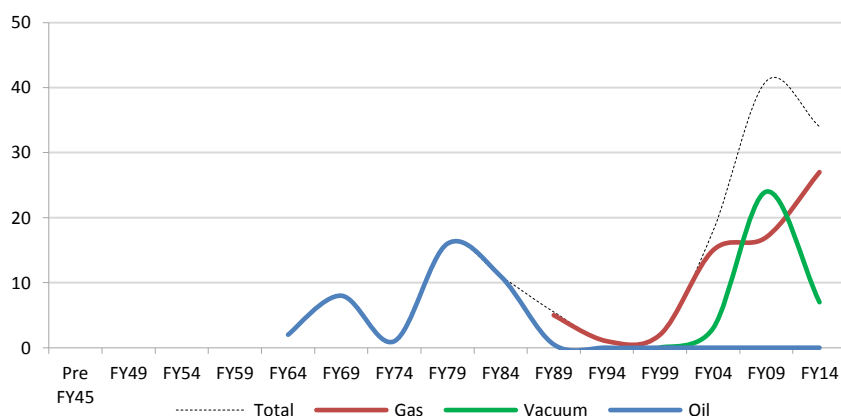
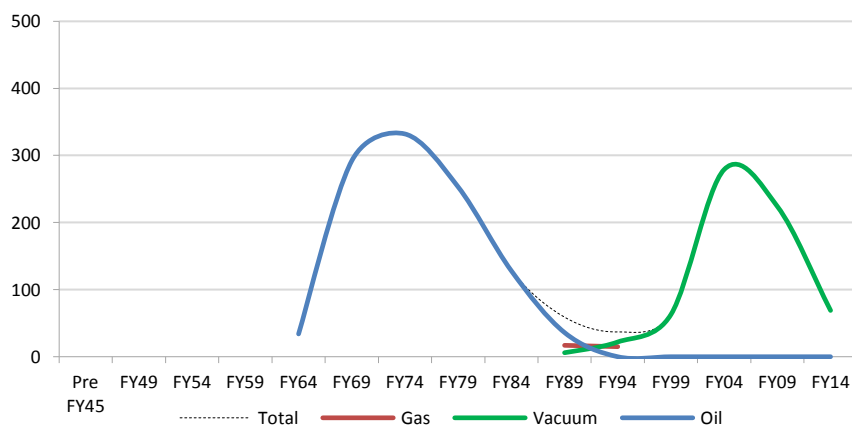


Figure 4-14c Circuit breakers 11kV - FY14 age profile



4.14.4 Standards and asset data

Asset management report:

- NW70.00.33 - Circuit breakers

Design standards developed and in use for this asset are:

- NW70.53.01 – Substation design
- NW70.57.01 – Protection design
- NW70.59.01 – Earthing design.

Technical specifications covering the construction and ongoing maintenance of this asset are:

- NW72.23.03 – Zone substation inspection
- NW72.23.07 – Zone substation maintenance
- NW72.23.15 – Oil circuit breaker servicing after operation under fault conditions.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.23 – Switchgear - 400V indoor
- NW74.23.25 – Circuit breaker - 66kV
- NW74.23.28 – Circuit breaker - 33kV indoor.

Operator instructions, developed in-house, are used for each different type of circuit breaker in our network.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS and asset register)
- type and serial numbers
- age
- circuit diagrams
- test results
- movement history

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition.

4.14.5 Maintenance plan

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: Switchgear (this includes switchgear and circuit breakers).

All circuit breakers are visually inspected for oil leaks and general condition. Major invasive maintenance is carried out at regular intervals as shown in the following table.

Table 4-14e Switchgear inspection and maintenance schedule

Switchgear location	Inspection frequency (months)	Major maintenance frequency (years)
Zone substation	2	4
Network substation	6	8
Distribution substation	6	8
Outdoor ground mounted	6	4
Outdoor pole mounted circuit breaker	12	8
Outdoor pole mounted air break isolator - Load-break types	24	

As part of this maintenance we:

- inspect
- clean and lubricate
- repair or replace contacts, insulators and mechanisms
- profile the tripping function
- service or replace the oil
- thermal image outdoor equipment to identify hotspots
- monitor the levels of all SF6 we use and report any loss-to-atmosphere
- monitor partial discharge as follows:

With the age spread of the switchgear, additional testing has been introduced to detect breakdown in the insulation at an early stage. This means that targeted remedial work can be undertaken without disruption to consumers.

This is achieved by partial discharge non-invasive locating and monitoring. This technology provides excellent results and has revealed potential problems at an early stage. Partial discharge checks are carried out at different intervals depending on the age and location of the switchgear:

Zone substations

- location testing – this is done at six-monthly intervals on circuit breakers over 40 years old and annually on the balance
- monitoring – is a system that is set up to continuously monitor any transient earth voltage signals. For circuit breakers more than 40 years old, it is installed on site for seven days annually. Circuit breakers less than 40 years old are monitored for three days every four years.

Network substations

- location testing – this is done annually on circuit breakers over 30 years old and every two years on the balance
- monitoring – for circuit breakers more than 40 years old, it is installed on site for three days every four years.

Line circuit breakers

- The line circuit breakers have a regular maintenance procedure carried out every eight years. The exterior and control relay are inspected annually. Our SCADA provides initial indication of problems.

4.14.6 Replacement plan

Our budgeted replacement costs are shown in section 7.1.9 – Replacement budgets: Switchgear (this includes switchgear and circuit breakers).

All circuit breakers have been reviewed based on a number of factors:

- safety
- performance
- condition
- maintenance issues
- operation
- logistical support
- working environment
- age.

Safety issues are given priority to ensure protection of the public, employees and contractors. Performance and asset condition are considered on an individual basis and are used to develop the replacement programme. The criticality and location, i.e. zone or network substation, is also considered and factored into the programme.

Older circuit breakers are normally replaced with a modern equivalent, however in some cases they are replaced with a high voltage switch if it is deemed suitable. The replacement programme is regularly reviewed to take into account the changing requirements of the network.

Batteries

A four-year cycle of stand-by battery replacement is carried out in tandem with our switchgear inspections. Alkaline batteries previously used have been replaced with sealed lead-acid batteries with a five-year design life. Significant savings can be achieved over the previous situation where the existing alkaline batteries were maintained at a high per unit cost. Replacement lead-acid batteries can be purchased for a fraction of the previous cost.

4.14.7 Creation/acquisition plan

The decision to install additional circuit breakers is generally driven by consumer demand.

For a list of projects containing this asset see section 5.6 - Network development proposals.

4.14.8 Disposal plan

Circuit breakers are disposed of as part of the replacement costs.

4.15 Switchgear-high and low voltage

4.15.1 Asset description



Magnefix ring-main unit

These switches are independent manually operated, quick-make, quick-break design with all live parts fully enclosed in cast resin. Each phase is switched separately or three phases are operated simultaneously with a three phase bridge. These switches are the predominant type installed in our 11kV cable distribution network. They are mainly installed in distribution kiosks and as secondary switchgear in network substations. They range in configuration from a two cable unit to a five cable unit, making a total of over 10,000 individual outlets in our network.

Ring-main units (RMU)

These units are arc-contained, fully enclosed metal-clad 11kV switchgear. They combine both load-break switches and vacuum circuit breakers. With the addition of electronic protection relays they can be fully automated. They are usually installed in kiosks or as secondary switchgear in zone and network substations. They are three or four panel units.



Oil switch, fused and non-fused

These switches were installed in our 11kV cable distribution network as secondary switchgear in network and distribution building substations. They were installed before low maintenance oil-free Magnefix ring-main units were proven. We no longer install these switches.

Some of the installations have locally designed bus connections that are below our current standards. Incidents and difficulties in arranging outages to carry out servicing have occurred, therefore we are gradually replacing these switches with ring-main units.





Air break isolator (ABI)

11kV and 33kV line ABIs are pole mounted in our rural overhead network. The substation 66kV and 33kV ABIs are used as isolation points in the substation structures and are mounted on support posts or hang from an overhead gantry.



Sectionaliser

11kV sectionalisers are oil filled and pole mounted. The operation is automated, with the sectionaliser opening after detecting a pre-set number of unsuccessful attempts to re-liven by an upstream circuit breaker.

Sectionalisers are not remotely monitored.



Low voltage switch

Installed generally in distribution substations, these switches form the primary connection between 11kV/400V transformers and the 400V distribution network, giving isolation points and fusing capability using high rupturing current (HRC) links. All new installations are of the DIN type (shown left).

The majority of existing older panels (approximately 3,000) are an exposed-bus (skeleton) and V-type fuse design. As accidental contact is a risk with these designs, we have a programme to replace them with the modern DIN type.

Table 4-15a Switchgear quantities FY14

Device type	Quantity
66kV Substation air break isolator	150
33kV Substation air break isolator	90
33kV Line air break isolator	17
11kV Ring-main vacuum switch/VCB	24
11kV Magnefix ring-main unit	4,000
11kV Oil switch	83
11kV Line air break isolator	950
11kV Sectionaliser	3

4.15.2 Asset capacity/performance

Magnefix ring-main unit

An MSU is a manually operated quick-make, quick-break switch design rated at 400A. Any failure is usually due to secondary factors such as a cable termination failure.

Ring-main unit

These units combine both 630A load-break switches and 400A or 200A vacuum circuit breakers. Any failures in these units are usually due to secondary factors such as cable terminations.

Oil switch

Oil switches are manually operated. They have caused some problems over the years due to oil leaks and jammed operating mechanisms.

These units combine both 630A load-break switches and 400A or 200A vacuum circuit breakers. Any failures in these units are usually due to secondary factors such as cable terminations.

Air break isolator (ABI)

A standard existing ABI installed on our rural network (33 and 11kV) is rated at 400A. Load-breaks have been installed on a number of isolators in key locations to increase the current rating to 600A. All new ABIs are 600A with load-break. The substation ABIs are unable to break circuit load current.

The performance of our ABIs is generally good, although isolators that have not operated for a long time have a tendency to seize up. Loose terminations and contacts can also cause problems on older ABIs.

Sectionaliser

Sectionalisers installed on the network are rated at 200A continuous, 9kA fault. As they age, they are unreliable in their operation.

Low voltage switch

The standard rating of the low voltage DIN switches is 630A, with panel busbar ratings of 800A or 1500A installed to meet distribution substation and feeder capacities.

The older 'skeleton' type panels and switches have good electrical performance, however, the exposed busbars create safety issues.

Some issues have become apparent with DIN type switches. These have generally been related to overheating created by the quality of connection and installation. Overheating is a more significant issue for DIN switches than for other switches, due to their enclosed construction.

4.15.3 Asset condition

Magnefix ring-main unit

The condition of Magnefix units within the network is very good.

Ring-main unit

The condition of the ring-main units within the network is very good.

Oil switch

Oil switches are maintained in good operational condition. Any with problematic operating mechanisms can be replaced with a ring-main unit.

Figure 4-15a Switchgear 11kV - health index profile

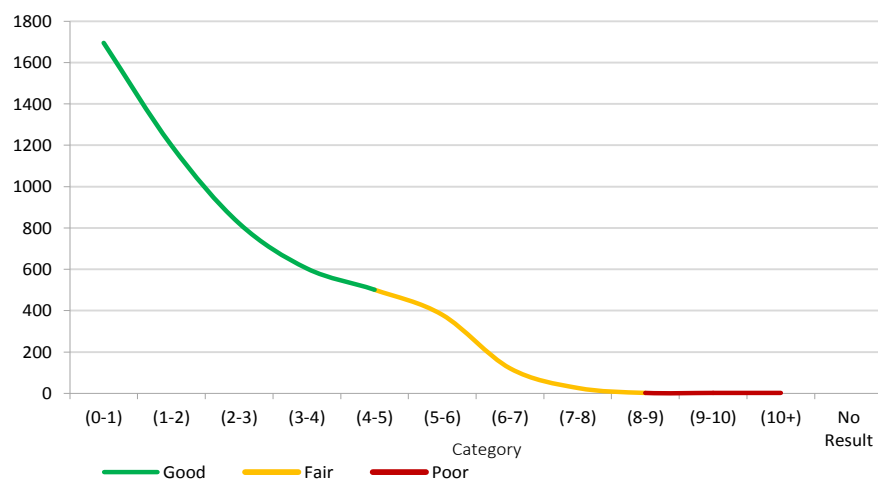
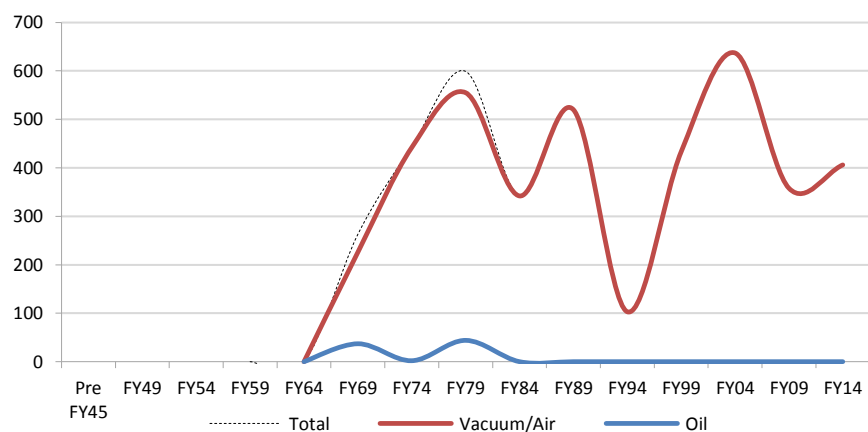
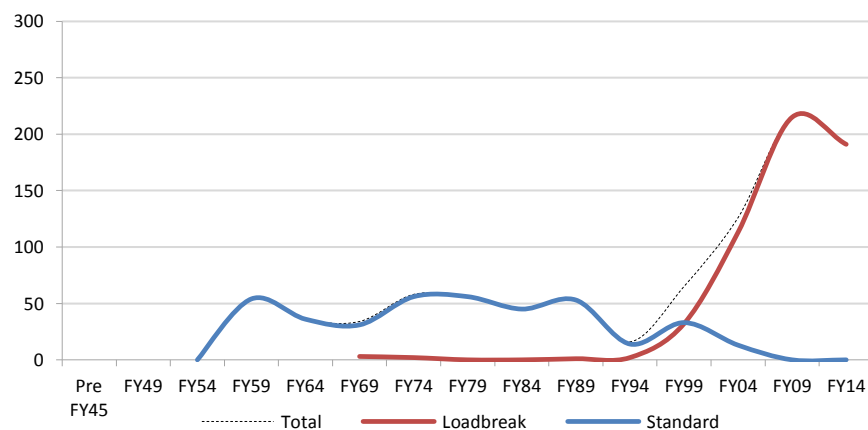


Figure 4-15b Ringmain units 11kV - age profile

**Air break isolator (ABI)**

The condition of our line ABIs on the network is good. However, the older types are reaching the end of their economic life.

Figure 4-15c Line ABI 11kV and 33kV - age profile



Sectionaliser

The condition of some sectionalisers is deteriorating, and a detailed assessment is being carried out on all units. A few have reached the point where replacement is the most economic option.

Low voltage switch

The low voltage panels and switches are generally in good condition.

CBRM model

In 2011 EA Technology Ltd was engaged to develop a condition based risk management (CBRM) model for our HV and LV switchgear. This model utilises asset information, engineering knowledge and experience to define, justify and target asset renewal. It provides a proven and industry accepted means of determining the optimum balance between on-going renewal and Capex forecasts.

The CBRM model calculates the health index and probability of failure of each individual switch. This effectively gives the switchgear a ranking which is used when determining the replacement strategy. Note that while the model calculates the asset ranking it is still up to the engineer to prioritise the replacement schedule.

The results of this process have shown that the overall condition of our switchgear is very good and we are on target with our replacement programme. The graphs on the following page show the health index profile and age profile of our switchgear assets.

4.15.4 Standards and asset data

Asset management report:

- NW70.00.24 - Switchgear HV and LV

Standards and specifications

Design standards developed and in use for this asset are:

- NW70.51.01 - Overhead line design
- NW70.52.01 - Underground cable design
- NW70.53.01 – Substation design
- NW70.57.01 – Protection design
- NW70.59.01 – Earthing design.

Technical specifications covering the construction and ongoing maintenance of this asset group are:

- NW72.21.04 – 11kV Air break isolator maintenance
- NW72.23.04 — Network substation inspection
- NW72.23.06 — Network substation maintenance.

We have developed operator instructions for each of the different types and models of switchgear installed in our network.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS and asset register)
- type
- serial numbers (except for older ABIs)
- age (estimated for older ABIs)
- test results
- movement history (except for ABIs)

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition.

4.15.5 Maintenance plan

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: Switchgear (this includes switchgear and circuit breakers).

Magnefix ring-main unit

11kV Magnefix switch units are virtually maintenance free, with the exception of minor dusting from time-to-time. The exceptions are those units in close proximity to the sea. They are maintained every four years.

Ring-main units

11kV ring-main units are virtually maintenance free, with the exception of minor dusting from time-to-time. The exceptions are those units in close proximity to the sea. They are maintained every four years.

Oil switch

Oil switches in indoor situations are maintained as part of the programme of work (four or eight yearly) for the substation in which they are installed.

Air break isolator (ABI)

A check on the operation of standard ABIs is included when a line retighten contract is carried out each year. Other maintenance work is on an as-required basis.

Sectionaliser

Sectionalisers are maintained every eight years, with an annual external inspection.

Low voltage switchgear

We have an inspection regime for panels and switches. Substation low voltage panels are inspected every six months. Other switches are inspected on a five yearly basis. We are over halfway through a four-year programme to install safety screens over the exposed live busbars and switches.

4.15.6 Replacement plan

Our budgeted replacement costs are shown in section 7.1.9 – Replacement budgets: Switchgear (this includes switchgear and circuit breakers).

Ring-main units

We have an ongoing replacement programme for older Magnefix units. Our newer RMUs are in good condition and do not need replacing.

Oil switch

Most of these switches are nearing the end of their useful lives, and are progressively being replaced with ring-main units.

Air break isolator (ABI)

A programme to replace older ABIs commenced in FY06, and will run through to FY20. The replacement switches have polymer insulators and corrosion resistant bearings that will not seize. They do not have operating handles and are instead operated by a hot-stick. This makes them more secure, and removes the need for earthing.

Sectionaliser

We plan to replace all of the sectionalisers. Based on operational and economic criteria line circuit breakers are being installed in their place. There are only three left in service.

Low voltage switchgear

We plan to upgrade all exposed skeleton panels with DIN type disconnects.

4.15.7 Creation/acquisition plan

We plan to install additional switchgear during projects that improve the reliability of the network, and in works to satisfy consumer demand.

4.15.8 Disposal plan

These assets are disposed of as part of replacement costs.

4.16 Power transformers and regulators

4.16.1 Asset description



Transformer

Power transformers are installed at zone substations to transform subtransmission voltages of 66 and 33kV to a distribution voltage of 11kV. The majority are fitted with on-load tapchangers and electronic management systems to maintain the required delivery voltage on the network.

The larger 40MVA transformers weigh approximately 45 tonnes. The smaller 10MVA transformers weigh approximately 30 tonnes. The cooling radiators are both integral with the main tank and stand-alone.

All our transformer mounting arrangements have been upgraded to current seismic standards, and all transformers have had a bund constructed to contain any oil spill that could occur.

Table 4-16a
Power transformer quantities
(includes emergency spares)

Rating MVA	66kV	33kV
60/70	2	
30/40	2	
30/36	5	
29/34	3	
20/40	25	
20/24	2	
11.5/23	11	7
10/20		4
7.5/10	6	6
7.5		12
2.5		3
Totals	56	32

Table 4-16b
Regulator quantities
(includes emergency spares)

Rating MVA	11kV
20	3
4	12
1	2
0.75	2
0.65	1
Total	20



Line voltage regulator

Regulators are installed at various locations to perform two different functions:

- provide capacity (via voltage regulation) for security against the loss of a zone substation
- provide automatic voltage regulation on fixed tap transformers.

We use a wide range of ratings, from 650kVA to 20MVA, to cater for different load densities within our network. All regulators are oil filled, with automatic voltage control by an on-load tapchanger or induction. The installation designs allow for quick removal and re-installation.

4.16.2 Asset capacity/performance

Power transformers in our network are capable of operating continuously at their rated capacity, or at a higher rating for short periods, depending on the ambient air temperature. Detailed data records of electrical loading on the transformers are compiled via the SCADA system. This data is analysed regularly.

Two distinct peak load periods affect the urban and rural networks at different times. The rural peak load occurs in summer, predominately due to irrigation. With increased development of residential subdivisions to the south and south west of the city, winter load in the rural area is increasing. However, when compared to the peak summer load, this increase is relatively low. The peak load period for the urban network occurs in winter.

Our transformers suffered virtually no damage in the earthquakes. Our work to upgrade the transformer mountings has proven to be very effective. While some oil surge-protection units operated, our restoration times were very quick.

4.16.3 Asset condition

Transformers

Oil and winding insulation condition significantly impact on how a transformer performs. Through a variety of assessments, including visual inspection, insulation testing and other condition-monitoring techniques, we have determined the useful life expectancy of each transformer. These techniques have shown that in general the power transformers are in good condition and should achieve the industry nominal life expectancy.

Figure 4-16a Power transformers - health index profile

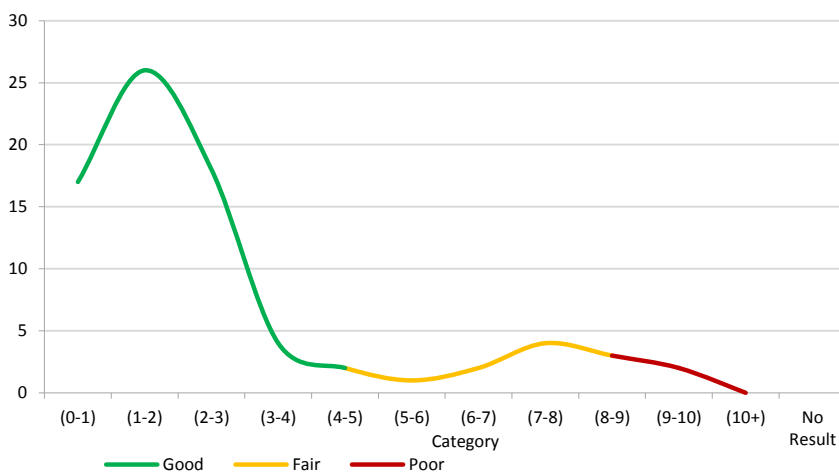
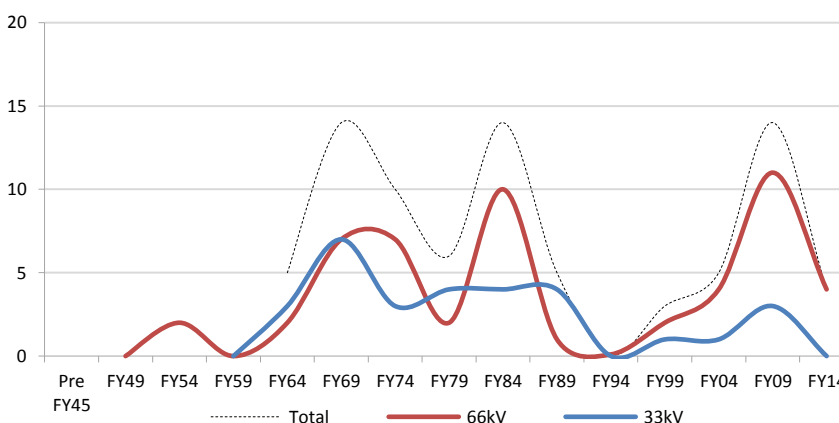


Figure 4-16b Power transformers - age profile



Tap-changer mal-operation has historically caused the most significant failures in transformers. As a result, a proactive tap-changer maintenance/refurbishment programme has been implemented.

The two transformers at Brighton zone substation were submerged in water as a consequence of liquefaction during the February 2011 earthquake. The transformers were removed from service and a half-life refurbishment was carried out. By bringing forward this planned maintenance by two years we were able to save them from permanent damage. Once the refurbishment was completed they were returned to service at our new Rawhiti zone substation (built after the earthquake to replace Brighton). We relocated a 23MVA transformer from Hawthornden zone substation to Brighton to maintain the electricity supply to the eastern suburbs while this work was undertaken.

A condition assessment and subsequent review of the single phase transformers at Papanui, Addington and Bromley (recently purchased from Transpower) found that the condition of these transformers does not meet our current standard. Our long-term goal is to replace these transformers with 3 phase 20/40MVA units. The Bromley transformers are currently scheduled for the later stages of the disclosure period. Refer to 4.16.6 for replacement plan.

Voltage regulators

The three regulators at Heathcote are an older design. The first two were refurbished before going into service with Orion and are working satisfactorily. In FY10 a third regulator was installed to provide security for the Lyttelton supply.

4.16.4 Standards and asset data

Asset management report:

- NW70.00.23 - Power transformers

Standards and specifications

Design standards developed and in use for this asset are:

- NW70.53.01 – Substation design
- NW70.57.01 – Protection design
- NW70.59.01 – Earthing design.

Technical specifications covering the construction and ongoing maintenance of this asset group are:

- NW72.23.25 – Power transformer servicing
- NW72.23.01 – Mineral insulating oil maintenance
- NW72.23.03 – Zone substation inspection
- NW72.23.07 – Zone substation maintenance.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.07 – Major power transformer 7.5/10MVA 66/11kV
- NW74.23.15 – Voltage regulator 11kV
- NW74.23.16 – Major power transformer 11.5/23MVA 66/11kV
- NW74.23.22 – Major power transformer 2.5MVA 33/11kV
- NW74.23.24 – Major power transformer 20/40MVA 66/11kV.

Engineering drawings, as well as electrical drawings, are held for all transformers and related components.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS and asset register)
- type and serial numbers (transformer and tap-changer)
- age
- circuit diagrams/maintenance history
- test results/oil analysis results
- movement history.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition.

4.16.5 Maintenance plan

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: Transformers (this includes distribution transformers).

Transformers

Transformers are inspected every two months and tested regularly, with corrective action when required. Tests include a four-yearly test of the winding insulation, and annual oil tests for breakdown, moisture, acidity and dissolved gas analysis.

The oil in on-load tap-changers is reconditioned annually. Invasive maintenance is done every four years as part of the zone substation maintenance cycle. Introduction of electronic devices has improved the monitoring and control of transformer equipment. Therefore, it is now possible to analyse the trending of transformer operating parameters and mitigate any issues as they occur, rather than picking them up during cyclic maintenance.

Voltage regulators

Voltage regulators installed at the zone substations are included in the annual and four-yearly tap-changer maintenance programmes. The new 4MVA regulators are included in a separate section of the distribution maintenance round and are serviced on an eight-yearly cycle.

4.16.6 Replacement plan

As a result of the condition assessment carried out on the Papanui transformers we have decided to replace the single phase units with two 20/40MVA three phase units. This work will be coordinated to take place once Waimakiriri zone substation has been commissioned. This zone substation is required to take some of the load off Papanui substation.

Our budgeted replacement costs are shown in section 7.1.9 – Replacement budgets: Transformers (this includes distribution transformers).

Tap-changers

A project to replace unreliable tap-changers with vacuum units on some older 33/11kV transformers was completed in FY13.

4.16.7 Creation/acquisition plan

For projects containing this asset group see section 5.6 - Network development proposals.

4.16.8 Disposal plan

The transformer at Springston zone substation will be removed from service and disposed of in the next few years. The Papanui units will be disposed of as part of the replacement works.

4.17 Distribution transformers

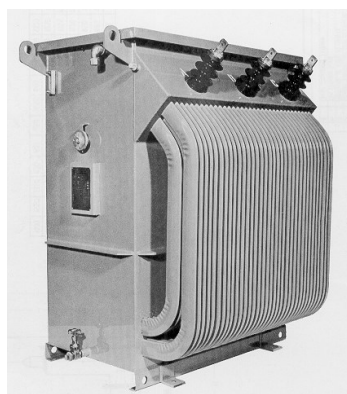
4.17.1 Asset description

Distribution transformers are installed on our network to transform the voltage to a suitable level for consumer connections. They have a ratio of 11000/400V, and range in capacity from 5kVA to 1,500kVA.

Sizes up to 200kVA can be installed in the overhead system on a single pole. The larger sizes are only ground-mounted, either outdoors or inside a building/kiosk.

Table 4-17a Distribution transformer quantities owned by Orion (in-service FY14)

Rating kVA	5	7.5	10	15	25	30	50	75	100	150	200	300	500	750	1000	1250	1500	Total
Quantity	55	286	179	1,454	358	1,952	1,155	167	712	158	1,512	1,713	783	300	153	3	7	10,969



Typical 300kVA transformer (Circa 1980).

4.17.2 Asset capacity/performance

Transformer utilisation is measured as the ratio of maximum demand in kVA to installed nameplate rating. For individual transformers, this ratio typically ranges from below 30% to above 130%.

The measure of overall distribution transformer utilisation required for disclosure is the ratio of the total system demand to total distribution transformer capacity. This has fallen slowly over the last 20+ years to its present value of approximately 29%.

Small pole-mounted transformers usually serve only a small number of consumers. Capacities are normally only reviewed when significant new load is connected. Utilisation factors are typically low.

Larger transformers are fitted with thermal maximum-demand meters which are read twice-yearly. Measured utilisation factors range up to about 140%. For typical cyclic loads, we have determined that maximum demands of about 130% of rated continuous ratings are acceptable, before upgrading action is required.

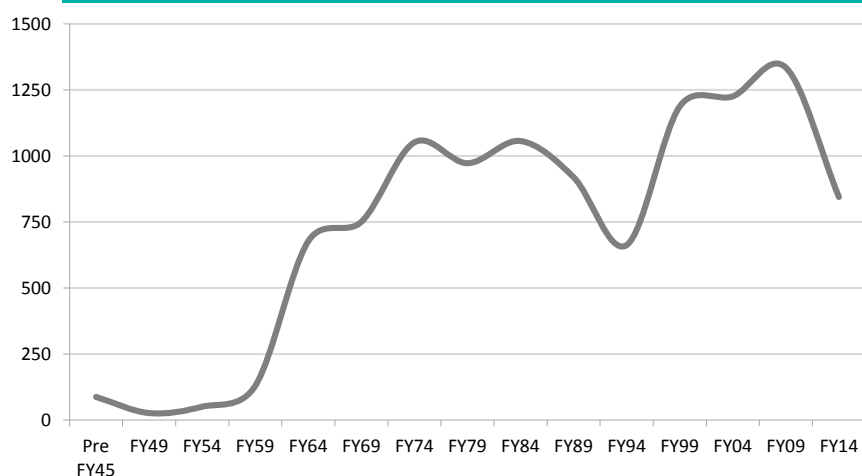
When distribution transformer maximum demand exceeds 130% of nameplate rating, a larger transformer is installed or load transferred to another substation if available. Where substation utilisation is low (<50% with no load growth predicted), the transformer will be changed or removed when this can be economically justified.

4.17.3 Asset condition

Our larger ground-mounted distribution transformers are in good condition and are inspected on site every six months. The condition of the pole-mounted transformers varies depending on their age and location. They are only maintained, if this is considered appropriate, when removed from service for other reasons.

There are seven single-phase banks of transformers over 50 years of age. Manufactured between 1937 and 1950, they have iron losses that are four to six times; and copper losses that are two to three times that of a modern transformer. Most have a high oil acidity, indicating that they are nearing the end of their lives.

Figure 4-17a Distribution transformers - age profile



4.17.4 Standards and asset data

Asset management report:

- NW70.00.40. - Distribution transformers

Standards and specifications

Design standards developed and in use for this asset are:

- NW70.53.01 – Substation design.

Technical specifications covering the construction and ongoing maintenance of this asset group are:

- NW72.23.16 – Transformer installation
- NW72.23.02 – Transformer maintenance (distribution).

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.05 – Transformer - distribution 200-1000kVA.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS and asset register)
- type and serial numbers
- age and rating
- test results
- movement and maintenance history
- maximum demand load records.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition.

The actual substation where they are located is unknown for some 550 transformers, although this number is steadily reducing as works are undertaken that identify specific transformers.

4.17.5 Maintenance plan

With the exception of the network substation transformers, distribution transformers are normally maintained when they are removed from the network for loading reasons or substation works. Their condition is then assessed on a lifetime costs basis and we decide, prior to any maintenance, whether it would be more economic to replace them. If we decide to maintain them they will be improved to a state where it can be expected the transformer will give at least another 15 to 20 years service without maintenance.

Some on-site maintenance is carried out on transformers which are readily accessible from the ground. This work mainly relates to those within building substations that require maintenance as identified during inspection programmes.

Remaining single-phase transformer banks are to receive minimal maintenance to extend their usable life until replaced.

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: Transformers (this includes power transformers).

4.17.6 Replacement plan

Transformers taken out of the network due to capacity changes or faults are replaced where repair or maintenance proves uneconomic. An allowance has been made in the replacement budget to cover this.

Our budgeted replacement costs are shown in section 7.1.9 – Replacement budgets: Transformers (this includes power transformers).

4.17.7 Creation/acquisition plan

For a list of projects that contain this asset group see section 5.6 - Network development proposals.

4.17.8 Disposal plan

We dispose of transformers when they reach the end of their economic life, as detailed in the maintenance plan.

4.18 Generators

4.18.1 Asset description

Diesel generators provide a mobile source of energy to enable Orion to keep the power on or provide power quickly in the short term until our network is able to be restored. We have various generators which are used for different applications; mobile truck-based for use during planned work and faults, fixed for load lopping and mains failure and skid-mounted for isolated emergency response.

We have 18 medium to large diesel generators. Ten of these are 550kVA generators that can be strategically placed throughout our urban network. They are used for emergency backup and can be switched on-line in a short time frame if there is a loss of supply. Three of them have synchronisation gear fitted.

Along with these generators we also have three truck mounted units of 375, 400 and 440kVA (mobile) and one 110kVA trailer mounted generator, which are used to restore supply at a distribution level during a fault or planned work. The truck mounted units are all fitted with synchronisation gear. We have a further 550kVA unit attached to our main office building with synchronisation gear, two 2,500kVA 11kV generators with synchronisation gear and a 30kVA without synchronisation gear.

To maintain a fuel supply for the generators we own six diesel tanks, with capacities ranging from 2,900 to 16,155 litres, and a 1,500 litre trailer mounted tank. All the diesel tanks are new and are bunded or double skinned.

Table 4-18a Generator listing

Description	Generator kVA	Generator kW
Mobile (truck-mounted)	440	352
Mobile (truck-mounted)	400	320
Mobile (truck-mounted)	375	300
Mobile (trailer-mounted)	110	88
Transportable (400V)	550 x 10	440 x 10
Static (11,000V)	2,500 x 2	2000 x 2
Wairakei Rd administration building	550	440
Armagh hot-site	30	24
Total generating capacity	12,405	9,924

4.18.2 Asset capacity/performance

All generators are operated within their nameplate ratings.

A number of our generators were used to supply electricity to the worst affected areas in the eastern suburbs immediately after the February 2011 earthquake. These units were run continuously until our network was repaired. During this time they performed well.

4.18.3 Asset condition

All generators are checked, tested and maintained in good operational condition.

Most of our generator fleet is relatively new. Because they need to be ready for emergency use they are tested and maintained on a regular basis. As a result all of our generators and diesel tanks are in good operational condition.

4.18.4 Standards and asset data

Asset management report:

- NW70.00.39 - Generators

Contingency plans:

- NW20.40.02 - Contingency plan for emergency generators.

Orion standards:

- NW21.03.04 - Emergency supply generator (criteria for use).

Operator instructions:

- NW72.13.97 – Standby generator truck – 350kVA
- NW72.13.98 – Standby generator truck – 440kVA
- NW72.13.109 – Standby generator truck – 400kVA
- NW72.13.113 – Static generator set - 2,500kVA.
- NW72.13.114 – Standby generator trailer – 110kVA
- NW72.13.115 – Building generator – 550kVA

4.18.5 Maintenance plan

Scheduled maintenance for our generator fleet has increased due to a number of new units as a direct response to the Canterbury earthquakes. These units are maintained as part of a service agreement with the suppliers.

Maintenance includes:

- inspection before use
- monthly testing
- service checks every six months
- fully serviced at 250 or 500 hour intervals depending on the engine.

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: Generators (fixed).

4.18.6 Replacement plan

There is no renewal plan for the generator fleet. When a generator gets to the end of its economic life an analysis will be done to see if it will be replaced. It is planned to replace Mobile Truck V751 in FY16 with a new truck and using one of the existing GEP550-2 generators.

Our budgeted replacement costs are shown in section 7.1.9 – Replacement budgets: Generators (fixed).

4.18.7 Creation/acquisition plan

We have resource consents to install 11.5MW of diesel generating capacity at both Bromley and Belfast (23MW in total). Proceeding with either of these sites is subject to a viable business case being developed. The earthquake damage to our network in the eastern suburbs has caused us to temporarily locate 4MW of transportable generation at QEII Park for several years commencing April 2012. After the security of supply is improved at Rawhiti this generation may be relocated to our Belfast site to cope with increased peak loads as new housing develops in that area.

4.18.8 Disposal plan

These assets are disposed of by auction when they become surplus to our requirements or they become uneconomic to operate. As seismic activity lessens, the level of risk to our network will reduce. Therefore we will continue to review our needs for the generator fleet.

4.19 Protection systems

4.19.1 Asset description

Protection systems are installed to protect the network during power systems faults. These systems protect all levels of the network including the low voltage system where fuses are used.

Protection systems are becoming more complex as expectations of higher standards of network safety, quality and performance are increasing. This is more so with increasing focus on networks becoming ‘smart’. Predominantly the primary function of our protection systems is to protect the electrical network in the event of power system faults. These systems generally consist of current transformers (CT), voltage transformers (VT) and protection relays that protect items of high voltage primary plant by isolating the faulted section.

Historically, substation protection, control and metering functions were performed with electro-mechanical equipment. This electro-mechanical equipment has been superseded firstly by analogue electronic equipment, most of which emulates the single-function approach of their predecessors. More recently, micro-processor based equipment has begun to provide protection, control and metering functions. The functions performed by these micro-processor based devices are so wide they have been labelled Intelligent Electronic Devices (IED). Along with IEDs the introduction of Merging Units (Bricks) has created a paradigm shift in protection system architecture.

While electronic relays have additional benefits, some consequences need to be considered, such as shorter life cycles, software and firmware upgrades and increased standing load on the substation batteries.

Recently we have introduced ground fault neutralisers (GFN) into our rural network. These are another system we use to limit the amount of fault current in our 11kV overhead network during single phase earth-faults. The GFN enables us to keep power flowing through the two un-faulted phases while reducing the current in the faulted phase to a safe level. This can reduce the number of outages for single phase faults while ensuring better safety outcomes for public, personnel and plant.

Table 4-19a Relay types in Orion’s network

Relay type	Number in network as % of total relays	Average age (years)
Electro-mechanical	54	30
Analogue electronic (first generation IED)	6	24
Micro-processor based (second generation IED)	40	7

4.19.2 Asset capacity/performance

Electro-mechanical relays have performed adequately in the past, but with increasingly complex control requirements they are not always suitable. They are becoming difficult to maintain due to their intricate design and unavailability of spare parts. Electronic relays offer better sensitivity, increased functionality, communication capability and less maintenance and are replacing electro-mechanical relays in new substations and as part of switchgear upgrades. However, in areas where fault levels and clearance times are not onerous the reliability of our electro-mechanical relays is proving satisfactory.

The accuracy on a small number of our CTs and VTs is outside our present standards and some early electronic relays are becoming problematic due to nuisance tripping and the failure of individual electronic components. There is a programme in place to phase out and upgrade these systems. The overall performance of our protection systems is satisfactory and major incidents are avoided with on-going monitoring and maintenance.

The GFNs are new to our network. The units that have been commissioned and put in to service are operating satisfactorily.

Oil-surge protection on our power transformers operated during some of the larger earthquakes and caused interruptions to the supply of electricity. As a consequence we have reviewed the performance of our transformer protection and made minor adjustments to reduce the sensitivity of oil-surge protection. The determination of these protection settings and trigger points is a fine balance between protecting the transformer and avoiding unnecessary interruptions.

All of our protection schemes performed well to protect our network, personnel and the public during the earthquakes.

4.19.3 Asset condition

In 2011 EA Technology Ltd was engaged to develop a condition based risk management (CBRM) model for our protection relays. Prior to the introduction of the CBRM model all of our protection systems were reviewed against a number of performance criteria – failure rates, post-event diagnostic capability, manufacturer support, network suitability and age. A ranking system was created to help identify any relay types that may cause us issues. These criteria are now embedded in the data used in the CBRM model and we can now calculate a health index for individual relays rather than a generic score relay types. The following graphs show the health index profile and age profile of our protection assets.

Figure 4-19a Protection systems - health index profile

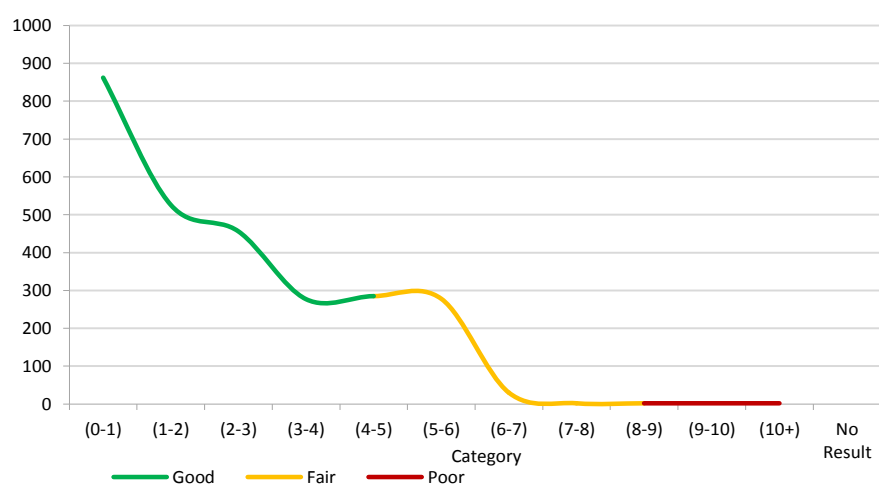
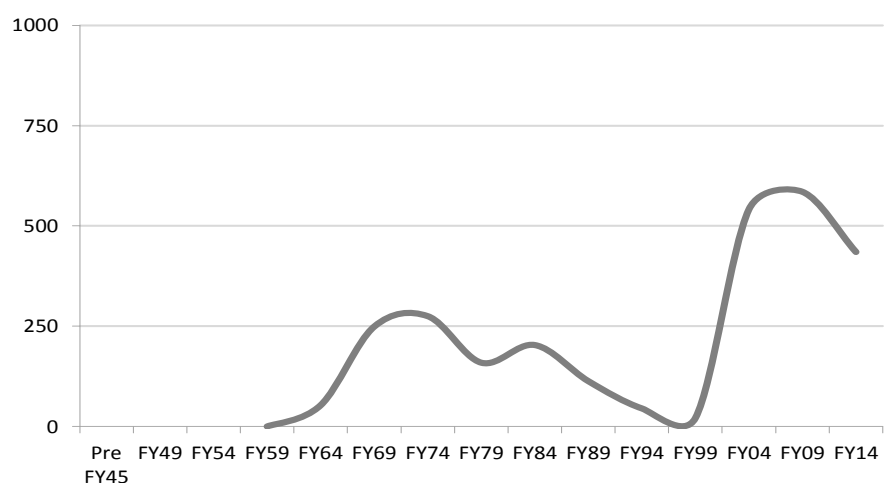


Figure 4-19b Protection systems - age profile



4.19.4 Standards and asset data

Asset management report for this asset:

- NW70.00.22 - Protection systems

Design standards developed and in use for this asset are:

- NW70.53.01 - Substation design
- NW70.57.01 - Protection design.

Technical specifications covering the construction and ongoing maintenance of this asset are:

- NW72.27.01 - Unit protection maintenance
- NW72.27.02 - Protection
- NW72.27.04 - Testing and commissioning of secondary equipment.

We use operator instructions developed in-house for electronic relays installed in our network.

Asset data

Data currently held in our information systems for this asset group includes:

- location (asset register)
- type and serial numbers
- age
- setting configuration
- test results
- relay movement history.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All these inspections are used to further our knowledge of the asset condition .

We keep details of all relays and their current location in our network asset register. A specialised protection database manages relay firmware and settings.

Details of the on-site installations are shown on our schematic diagrams of the substation equipment.

4.19.5 Maintenance plan

Protection systems are checked for calibration and operation during the substation maintenance rounds. Results are recorded and minor adjustments made if necessary. Major faults result in the system being removed from service and overhauled.

The GFNs are maintained as part of the substation maintenance rounds.

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: Protection.

4.19.6 Replacement plan

Traditionally our protection replacement programme has been directly linked to the replacement of switchgear. Usually both asset groups were installed at the same time and had similar lifecycles. On some occasions a protection system will be upgraded due to the performance requirements of the network. With the introduction of the electronic relays (both analogue and micro-processor based) synchronisation of the lifecycles with switchgear has been lost.

Protection systems with known performance issues are given a higher priority for replacement. Prior to the CBRM model being available we relied on the ranking system we developed in FY09. This year we used a combination of the CBRM model and other factors such as the upgrading/replacement of substation primary equipment or changes in the requirements of the local network to develop the protection relay replacement programme.

We will refine this process on an annual basis as we move from primarily time based replacement to one based on condition assessment and risk analysis.

Our budgeted replacement costs are shown in section 7.1.9 – Replacement budgets: Protection

4.19.7 Creation/acquisition plan

We have recently installed a GFN in all of our rural zone substations. The replacement plan and upcoming major projects determine the acquisition plan for our other protection systems.

For projects containing this asset group see section 5.6 - Network development proposals.

4.19.8 Disposal plan

We dispose of obsolete types of relays as circuit breakers are replaced or the protection system upgraded.

4.20 Communication systems

4.20.1 Asset description

A communication system is an essential component of our network as it is an integral part of the remote indication and control of network equipment, and provides contact with operating staff and contractors in the field.

We have both data and voice communication systems. Our voice communication system uses very high frequency (VHF) radio links as well as private and public telephone, cellular and paging networks. Our data communication system uses various technologies running over UHF radio, copper communication cables and fibre and is used for SCADA RTU links to provide access to substation engineering data.

Our cable communication system is mainly in the Christchurch urban area, and is used to link the SCADA master station with the RTUs and for unit protection at our urban zone and network substations (see section 4.13 - Communication cables for more information).

In mid 2011 a transportable data centre was commissioned. This facility houses the core server and network infrastructure that supports our information systems and is now located at our Wairakei Rd office. We have recently purchased a second transportable data centre to replace our old backup computer room in our Armagh zone substation. These facilities which are on separate sites and linked by a fibre network ring, create a highly resilient environment for our information systems.

Voice radio link

Voice radio is provided by a number of linked and same-frequency VHF hilltop radio repeaters. Three linked, different-frequency repeaters at Mt Pleasant, Marleys Hill and Roundtop provide coverage to the greater Christchurch and surrounding rural areas. One same-frequency linked repeater at Hilltop provides coverage in the Akaroa and Peninsula Bays area and a different-frequency solar powered repeater at Hamilton Peak provides coverage in the Castle Hill and Arthur's Pass area. All repeaters can be unlinked remotely if required.

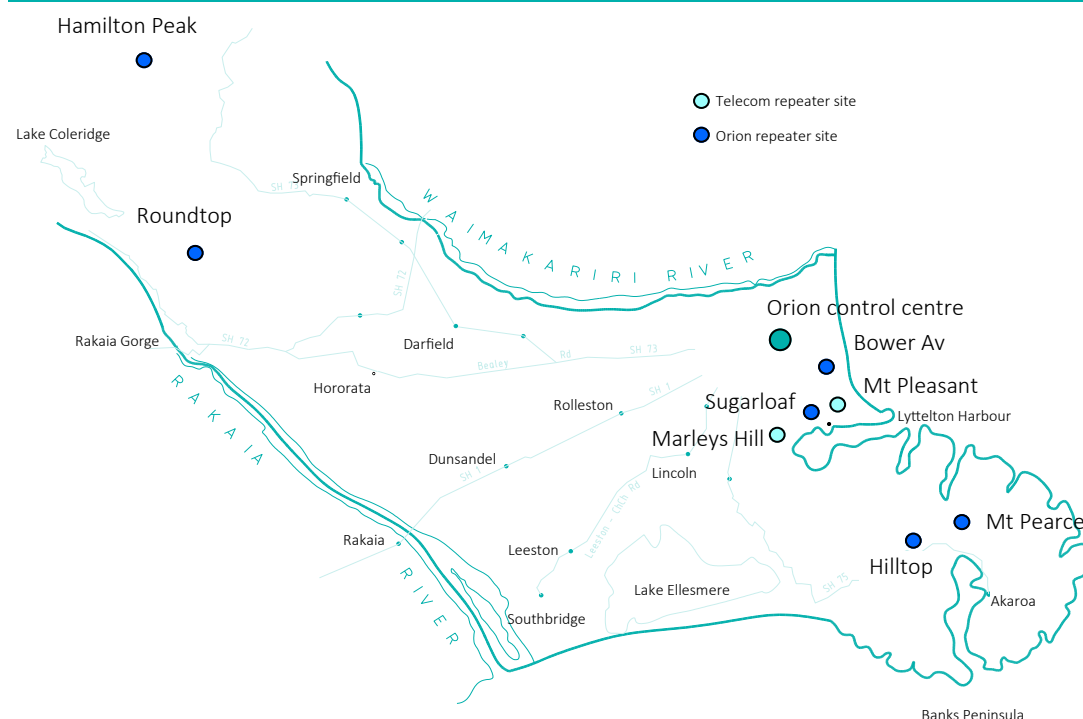
SCADA radio link

The SCADA radio link comprises of a number of dedicated UHF and VHF repeaters sited on various hilltops. The number and location of these repeaters is dictated by the coverage they provide and the number of substations they need to communicate with. Communication from the SCADA master station to the repeaters is by UHF radio, but a very small number of micro SCADA RTUs share the VHF voice repeater network.

UHF IP radio system

The UHF IP radio system is a general purpose radio system which can be used in either point-to-point or point-to-multipoint mode. Significant portions of the SCADA radio link network have been replaced by a UHF IP network. By its nature this system has in built redundancy to improve reliability of our communications network and protection schemes.

Figure 4-20a Radio communication network repeater sites



In point-to-multipoint mode the system provides high speed full duplex Ethernet communications for both SCADA and engineering access to substations. In point-to-point mode it is possible to simultaneously use the communication channels for both protection signalling, and also Ethernet SCADA communications.

The system allows a new high speed, high reliability communication network to be developed for rural substations and will eventually replace the entire older network. During the transition phase a number of substations have and will continue to use cellular data modems and radio data communications provided by a commercial network.

Cellular systems

Where there are gaps in our radio network cellular data modems are used. These systems are effective and will be replaced as the new IP radio system expands. All mobile PDA devices, and data connectivity to vehicles is provided by the public networks.

SCADA cable link

This is comprised of three communication cable technologies:

- audio frequency shift keying (AFSK) modem technology - this has a long reach but a low data transfer rate of 1.2kB
- low frequency modem communication - while this has a higher data transfer rate its reach is typically slightly less than the AFSK technology but data rates are typically 9.6kB
- high bit-rate digital subscriber line (HDSL) modem communications - shorter reach links that support data rates from 64kB through to 2MB. This network is extensive and is arranged in rings so that, if one link is broken, then traffic is routed in a different direction until a repair is completed.

Private telephone network

This is provided by special 'off premises extensions' which are a subset of our business telephone switch. This switch has dual redundant processors, as well as a geographical processor at a remote location. A tested disaster recovery process is in place should this switch network fail.

4.20.2 Asset capacity/performance

As electronic control and monitoring equipment installed in substations has evolved, we have reached the point where existing communication systems dedicated for SCADA (telemetry) are no longer appropriate. We are well into a replacement programme converting communications to our substations over to standard IP based network technology. This communication network is a mix of bandwidths on our existing communication cable network, using long reach HDSL technology and fibre optic communications where these cables exist.

The cable-based networks where practicable will be configured in a ring topology.

There is a significant number of substations where radio communication is the only practical option. This network is being replaced by a radio based private IP point-to-point and point-to-multipoint IP radio system.

4.20.3 Asset condition

The older radio system is being replaced by the new IP radio system and while it is still serviceable it is becoming more challenging to service.

Part of the migration of SCADA communications to modem and HDSL modems is driven by the condition of older modems.

Our business telephone switch is a hybrid TDM and IP system. It is current with supported hardware/software releases.

4.20.4 Standards and asset data

Asset management report:

- NW70.00.34 - Communication systems

All radio equipment is licensed and complies with the relevant regulations imposed by the Ministry of Business Innovation and Employment Radio Spectrum Regulations.

All telephone voice communications equipment complies with the standards imposed by the public telecommunications network operators in New Zealand.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GPS)
- age
- circuit diagrams

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All these inspections are used to further our knowledge of the asset condition.

4.20.5 Maintenance plan

The performance of our UHF stations used to communicate with the SCADA equipment is continually monitored. We ensure the transmitters comply with the Ministry of Business Innovation and Employment Radio Spectrum Regulations.

We have maintenance contracts with several service providers to provide on-going support and fault resolution. A maintenance contract for the telephone switch is in place. Maintenance is carried out on a monthly basis. SHDSL modems, IP radios and other communications equipment are monitored with maintenance scheduled when needed.

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: Communication systems.

4.20.6 Replacement plan

Our replacement programme takes into account the serviceability of equipment, and how appropriate the current deployed technologies are compared to the task they perform. We are replacing older equipment, and a programme of SCADA line communication modem replacement and conversion to IP technology is on-going.

Our budgeted replacement costs are shown in section 7.1.9 – Replacement budgets: Communication systems.

4.20.7 Creation/acquisition plan

We have completed an Ethernet-ring around Christchurch to increase the resilience of our communication and control network by reducing single points of failure. This Ethernet-ring makes use of some of our existing communications infrastructure.

The long term communications design for our communications and control systems will take into account the future locations of our control room and hot-site backup and associated facilities.

Voice radios

Our network operators' vehicles are equipped with back-to-back radios. This allows the vehicle radio to be used when they leave their vehicle with a low power hand-held radio for communication. Associated with this is automatic vehicle location and lone-worker alarm generation. All these tools help ensure the safety of this group of staff. We are about to equip rural operators with a personal satellite tracking unit, which reports a location if activated.

Fibre communication links

Fibre communication paths will be required for:

- protection signalling for the Waimakiriri substation due for construction in FY15
- corporate data between our Wairakei Rd data centre and the new Waterloo Business Park back-up data centre
- communication between Islington and Addington substations as part of the relocation of the Armagh hot-site to the Waterloo Business Park.

A sharing agreement has been reached with Transpower to allow Orion to install a fibre duct in existing Transpower ducts. This duct will run from Papanui substation via 565 Wairakei Rd and Hawthornden substation to Islington GXP and from Islington to Addington substation via Middleton.

Improved external IP network security

The external IP network uses industry standard protocols and equipment and as such is exposed to cyber security threats. It is proposed that an industry standard centralised security access system be installed to control and log all access to the external IP network. This will also require the addition of additional routers to act as security gateways at rural substation sites.

SCADA radios

The roll out UHF IP radio system is on-going and new radios and sites will continue to be installed until those portions of the network working on the old system have been converted. The acquisition plan has a direct correlation to the replacement plan.

4.20.8 Disposal plan

All electronic equipment is disposed of in accordance with current environmental recommendations. In some cases surplus equipment is donated to organisations that support Civil Defence or Search and Rescue communications, or where practicable it is offered to organisations that still use the equipment.

4.21 Load management systems

4.21.1 Asset description

Orion's network load management system is used to control loads on our network and also seven other networks which are part of the Upper South Island load management group, thus deferring energy consumption and peak load, and therefore network investment. Its other main function is tariff switching. It works by injecting an audio frequency signal into the power network that is acted upon by relays installed at the consumer's connection point. The relays in our network are owned by the retail traders, with the exception of some 2,000 Orion owned streetlight control relays.

The system comprises of Orion and Upper South Island master stations, RTUs at each GXP and two injection systems.

Communications between the Orion load manager and the injection plants is via the IP communications system which provides redundant communications paths to all ripple plants.

Load management master station and RTUs

The load management master station is a SCADA system that runs independent of the network operational SCADA system. The master station consists of two redundant database servers and two communication line servers (CLS) on dedicated hardware. The load management software utilises algorithms specifically developed for Orion.

Loading information for the system is derived from RTUs located at the GXPs and zone substations. Sources of information and communication paths are duplicated where reasonably feasible.

Upper South Island load management system

The Upper South Island load management system is a dedicated SCADA system that runs independently of Orion's load management and network operational SCADA systems. The system consists of two redundant servers that take information from Orion, Transpower and seven other Upper South Island distributors' SCADA systems, monitors the total Upper South Island system load (retrieved from Transpower) and sends commands to the various distributors' ripple control systems (including Orion) to control this total load to a predefined target.

Ripple injection system - Telenerg 175 Hz

This system operates within the urban 33kV and 66kV subtransmission network and is the major ripple injecting system controlling the load of approximately 150,000 consumers. It is made up of more than 25 small injection plants connected via circuit breakers to the 11kV network at individual 66/11kV zone substations and Christchurch urban 33/11kV zone substations.

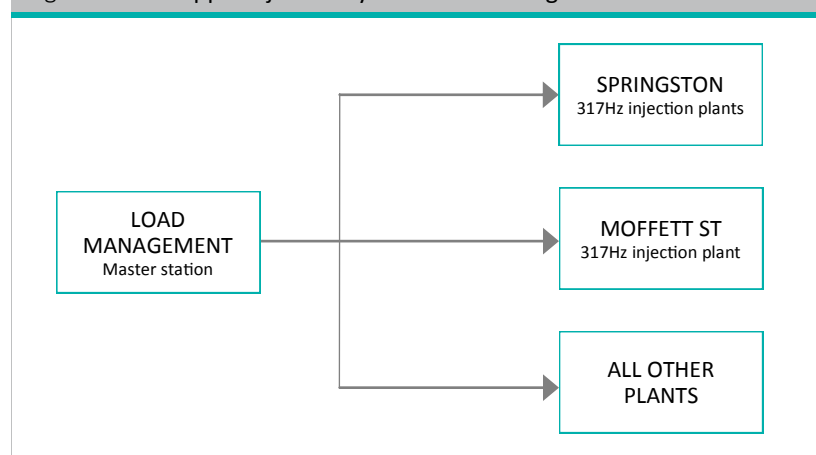
These plants can operate independently with all fixed-time signaling carried out from a timetable stored in the individual plant controller. All 'anytime' signaling is controlled by the SCADA system via individual controllers in response to commands from the load management system running on the master station.

The plants are relatively small and, apart from the coupling cell itself, consist of 19" rack mounting equipment for which spares are held. A complete coupling cell is also kept as a spare. It is possible in an emergency for a single plant to signal an adjacent area.

Ripple injection system - Zellweger Decabit 317Hz

The Decabit system operates within the 33kV subtransmission network and is made up of five plants connected to the 33kV system, via air break isolators and protected by circuit breakers, at Springston (two plants), Moffett, Hornby and Hororata zone substations. Back-up for the injection plants themselves is provided by pairs of plants in each GXP supply area. Two plants are installed at Springston and the plants at Hornby and Moffett provide back-up for each other. One plant of each pair is kept as a cold standby. There is no spare plant for Hororata, however, it would be possible in an emergency to relocate one of the Springston plants to Hororata.

Figure 4-21a Ripple injection system control diagram



With the ability to transfer load between the urban 66/11kV and 33/11kV systems, 11kV Telenerg ripple plants have been installed at Hornby, Moffett, Shands, Sockburn Harewood and Prebbleton zone substations. It is anticipated that the 33kV Decabit plants will be removed from service within the next 10 years once ripple relays within the area have been re-coded or replaced.

With the installation of the rural 66/11kV substations it has become necessary to install a small 11kV Decabit ripple plant at each substation. These plants are connected to the network via indoor 11kV switchgear. Back-up for the 11kV plants is provided by the 33kV injection system.

Like the urban Telenerg system, each Decabit plant operates independently with all fixed time signaling carried out from a timetable stored in the individual plant controller. All anytime signalling is controlled by the load management system via the load management RTUs at each location in response to commands from the load management master station.

4.21.2 Asset capacity/performance

Load management master station

The master station is a proprietary database system with full graphics running on industry standard hardware and software. It currently meets the performance requirements for the network load management.

Upper South Island load management system

The master station is a proprietary database system with full graphics running on industry standard hardware and software. It currently meets the performance requirements for the Upper South Island load management system.

Ripple injection system - urban 175Hz

The 66kV injection system was completely replaced in 2002-2004 with small individual 11kV injection plants.

Additional plants have been installed during 2005-2007 in the urban 33kV subtransmission system as 11kV interconnection capacity has been added between the urban 66 and 33kV subtransmission areas.

A larger number of smaller injection plants will significantly reduce the risk associated with a single plant failure as adjacent plants can cover for it. New 11kV plant capacity is matched to the capacity of the zone substation it is connected to. As load growth occurs, additional plants will need to be installed in conjunction with additional zone substation transformer capacity.

These plants have adequate capacity and performance for the timeframe of this plan.

Ripple injection system - rural 317Hz

The 33kV ripple injection plants have adequate capacity for the networks they are connected to, and would only have problems if GXP transformers with significantly lower impedance were installed. The existing plants have shown no sign of increased failure rates due to equipment aging and, apart from the Hororata plant, complete cold standby plants are available on both the Springston and Islington 33kV networks. Essential spares are held for the Hororata plant to enable rapid repair in the event of a fault. In a worst-case situation it would be possible to move part or all of one of the Springston plants to Hororata.

11kV, 317Hz ripple plants were installed at Kimberley, Killinchy, Brookside, Greendale, Te Pirita, Dunsandel and Weedons when these substations were commissioned because they are physically within the existing 317Hz injection area, but are supplied from the 66kV subtransmission system. They are of similar design and supplied under the same contract as those installed as replacements for the urban 175Hz ripple plants.

4.21.3 Asset condition

Load management master station

The hardware and software of the master station is now over seven years old and while still running reliably, is not being developed by the vendor (Foxboro) any further. The software will not run on later versions of the hardware platform (Sun Solaris) and support and parts are becoming difficult to source.

Upper South Island load management system

This system is approximately three years old and the hardware is just out of warranty. Given the normal life of such equipment it should be acceptable for a further two to three years before its adequacy needs to be reviewed.

Ripple injection system - urban 175Hz system

The majority of the 11kV injection plants on the 66kV system were installed from FY04, and are expected to have a minimum life of 15 years. The annual maintenance programme checks for possible faults and variations in equipment performance.

Ripple injection system - rural 317Hz system

The 33kV ripple plant injection controllers were replaced in FY05 and are expected to have a minimum life of 15 years. The annual maintenance programme checks for possible faults and variations in equipment performance.

4.21.4 Standards and asset data

Standards and specifications

All building construction, methods and materials for any maintenance or replacement are to comply with the requirements of current building codes and the Resource Management Act. Orion standards will apply for all other work.

Asset management report:

- NW70.00.37 - Load management systems

Design standards developed and in use for this asset are:

- NW70.53.01 – Substation design.

Technical specifications covering the construction and ongoing maintenance of this asset group are:

- NW70.26.01 - Ripple control system details
- NW72.26.02 - Ripple equipment maintenance.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.09 – Ripple control system.

Operator instructions in use:

- NW72.13.211 – 11kV Enermet ripple plant.

Operator procedures in use:

- NW21.19.20 – Upper South Island Management.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS and asset register)
- type and serial numbers
- age
- circuit diagrams
- test results.

Data improvement is ongoing. Updated data comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition.

4.21.5 Maintenance plan

Our ripple master maintenance programme consists of a daily operational check during the winter period and a weekly operational check during summer. This is supplemented by an annual hardware maintenance programme similar to that performed on the SCADA master stations. The complexity of the software and availability of technical support increase the difficulty and cost of maintaining the master station system.

Injection plants have a quarterly operational check as well as an annual inspection that includes measurement of installed capacitors and detailed tests on the inverter. If the plant coupling cells are found to have drifted they are retuned. Dusting and physical inspections are considered part of the annual maintenance.

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: Load management.

4.21.6 Replacement plan

It is planned to replace the hardware and software platforms of the load management master station in approximately two years. A review to determine the appropriate enterprise solutions is to be undertaken.

Our budgeted replacement costs are shown in section 7.1.9 – Replacement budgets: Load management.

4.21.7 Creation/acquisition plan

New 11kV ripple injection plants are installed in conjunction with new zone substations.

4.21.8 Disposal plan

We plan to retire the 33kV ripple injection plants at Moffett and Hornby substations in FY17. This will provide spares for the remaining plants at Springston and Hororata.



11kV injection plant at a zone substation.

4.22 Distribution management systems

4.22.1 Asset description

We have had different forms of supervisory control and data acquisition systems (SCADA) on the network since the early 1970s. These systems have traditionally been based on a master station (central control centre) communicating with remote terminal units (RTU). A distribution management system (DMS) integrates real-time data from SCADA with a comprehensive model of the electricity network. The DMS has a suite of applications that enhance the functionality beyond that of a traditional SCADA system. The core and ancillary DMS applications are overviewed below:

CORE DMS APPLICATIONS

(SCADA)

This is the front end that provides our control centre with fully integrated remote control and real time data. It allows for the configuration, trending and management of all the data points.

Network management system (NMS)

At the heart of the DMS is a comprehensive, fully connected network model (including all lines, cables switches and control devices, etc.) that is updated in real time with data from network equipment. The model is used to manage the network switching processes by facilitating planning, enforcing safety rules and generating associated documentation. It also maintains history in switching logs.

A full graphics 'human machine interface' (HMI) is used to display the network model and provide operator interaction with the system.

Outage management system (OMS)

The OMS allows for the identification, management, restoration and recording of faults. In the case of a fault or event, the OMS will assist in determining areas affected by outages utilising predictive algorithms.

Customer details are recorded against faults in the OMS which allows our Contact Centre to call customers back after an outage to confirm that their power supply has been restored.

Mobile field service management

Field services operators are equipped with personal digital assistant (PDA) devices and receive switching instructions directly from the DMS. The network model is immediately updated to reflect physical changes as switching steps are completed and confirmed on the PDA.

Due to the increasing business critical nature of our DMS, the application is running duplicated real-time redundancy on "virtual" servers. The hardware associated with the "virtual" servers is also duplicated in geographically separate "environmentally suitable" sites. The sites also have un-interruptible backup power supplies consisting of a UPS and a generator.

ANCILLARY DMS APPLICATIONS

Historian

The Historian is a database that records time series data (binary and analogue) for future analysis. Our DMS system has only rudimentary time series storage capabilities and a more sophisticated historian is currently being implemented.

The time series data stored in the historian is used by various applications throughout the organisation for planning, network equipment condition analysis and for reporting network operating performance statistics (such as reliability).

Real-time Load Flow Analysis

The DMS has access to large amounts of real time field data and maintains a connectivity model making it possible to undertake near real time load flow calculations. Load flow analysis can be used to predict network operating conditions at locations where no telemetered data is available and can also carry out "what if" scenarios to predict the effects of modified network topologies and switching.

A load flow analysis system is yet to be implemented.

Information Interfaces

Not all information required for operations and planning activities is available from the DMS. Linking DMS records to data from other systems greatly enhances our capabilities in both these areas.

DMS data may be presented in reports or used to populate web pages for organisational and public consumption.

4.22.2 Asset capacity/performance

DMS

The same DMS software that we use is used at some very large electricity distribution companies' overseas (greater than 500,000 connections) and is therefore not constrained by the scale of our business. We also ensure that supporting infrastructure (server, network etc.) has for sufficient capacity for current and credible near future growth.

The DMS is a critical business application and runs on highly resilient infrastructure which employs multiple, mirrored and geographically separated servers. The sites in which the servers are deployed are also highly resilient, with environmental management, smoke and fire detection, un-interruptible backup power supplies and backup generators.

A separate test DMS environment is used for testing all changes to the production system and for training.

There are no current issues with the capacity, performance or availability of the DMS.

RTUs

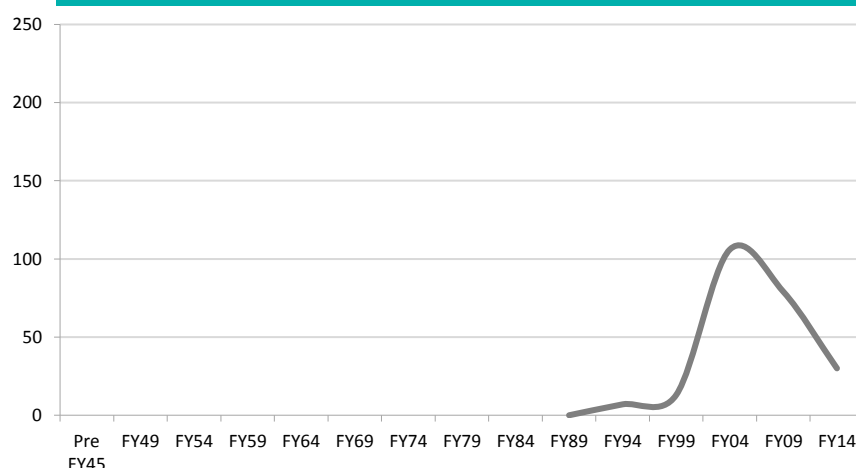
We have a number of older RTUs in our network which are no longer supported by their manufacturer. We hold enough spares to cover these units for maintenance purposes and they are performing adequately. The rest of our units are performing satisfactorily and are capable of meeting the increased requirements of the new master station.

4.22.3 Asset condition

While some of our older RTUs no longer have manufacturer support their condition is satisfactory. Those units that do not meet our current operating criteria have been targeted for removal.

The rest of this asset group is in good condition and proving reliable.

Figure 4-22a SCADA remote terminal units (RTU) - age profile



4.22.4 Standards and asset data

Asset management report:

- NW70.00.36 - Distribution management systems

Standards and specifications

Design standards developed and in use for this asset are:

- NW70.56.01 - SCADA functional specification for remote sites.

Technical specifications covering the construction and ongoing maintenance of this asset group are:

- NW72.26.04 - SCADA master maintenance
- NW72.26.05 - SCADA RTU maintenance.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS and asset register)

- type and age
- circuit diagrams
- test results.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition.

4.22.5 Maintenance plan

The DMS components are maintained on an as-required basis, with component availability the main criteria. This system is supported internally by our own staff and with the maintenance agreement with the vendor.

Inspections we carry out include:

- weekly general operational checks of equipment software
- annual detailed check of hardware and software systems
- annual operational check of all RTU controls and indications.

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: Control systems.

4.22.6 Replacement plan

DMS

A maintenance contract with the DMS vendor includes upgrades of software and firmware as they become available. We intend to install upgrades when necessary to provide desirable new functionality and to stay reasonably up to date with underlying computer operating system releases.

RTU

RTUs are normally replaced as part of substation or communication upgrades, however a replacement plan is being developed to change some of the older models which are no longer supported by the manufacturer or are no longer capable of meeting the requirements of the system.

Our budgeted replacement costs are shown in section 7.1.9 – Replacement budgets: Control systems.

4.22.7 Creation/acquisition plan

A network management system (NMS) is being introduced as a two-to-three year project.

4.22.8 Disposal plan

We dispose of equipment as part of the replacement programme.

4.23 Information systems - corporate

4.23.1 Asset description

Our corporate business information systems and productivity software support cross-organisational processes within Orion. They include financial systems, employee management systems (e.g. Human resources, Payroll, Health and Safety) and personal productivity software (desktop applications, email, web and document management).

Our computer infrastructure hosts, connects and provides the physical tools for access to our information systems. We manage our computer infrastructure rather than outsource to third parties because of the critical nature of some of our information systems and the need for them to be continuously connected in real time to equipment on the electricity network.

Our corporate information systems include:

- corporate financial management system
- HR / payroll
- document management system
- Orion internet website
- email system
- desktop software
- replicated computer room
- VM and SAN
- physical servers
- desktops and laptops.

4.23.2 Asset capacity/performance

Corporate financial management system

This system was implemented in 2009. Its capacity and performance are adequate for the period of this plan and could easily accommodate a significant increase in scale if required.

HR / payroll

As a cloud based application the performance and availability of this system is subject to a service level agreement. Its capacity and performance are adequate for the period of this plan.

Document management system

This is a new system and has been built to cater for projected increases in storage and breadth of function. Its capacity and performance are adequate for the period of this plan.

Orion internet website

The Orion internet website was subject to a review in early 2014. As a result of this review the site will be upgraded. The upgrade includes a new architecture that places the main landing page and supporting static content pages on third party infrastructure while dynamic content and pages to which logins are required, will be hosted on our site. In its new form the capacity and performance of the Orion web site are adequate for the period of this plan.

Email system

The capacity and performance of our Email system are adequate for the period of this plan if there are no further major changes required.

Desktop software

Our choice of operating system and desktop software capacity/performance are adequate for the period of this plan.

Replicated computer rooms

Main computer facility - Transportable Data Centre has been in service for two years and is performing to expectations. Its capacity and performance are adequate for the period of this plan and could easily accommodate a significant increase in scale if required.

Armagh substation facility - A review of this facility concluded that due to its location, aging infrastructure and compromises that had been made to retrofit a storeroom as a computer room, it was not a good long term solution for our second data centre. As a consequence we have purchased a second transportable data centre that will be located in the West of the city. This facility will be commissioned in FY15. The capacity and performance of the new facility is adequate for the period of this plan.

VM and SAN

Our VMware Virtual Server infrastructure has recently been upgraded to replace aging and out of warranty equipment. The capacity of the disk array (SAN) has also recently been upgraded due a rapid increase in the amount of post quake storage (including image files) and also due to projected increases in the early phases of our document management implementation.

The capacity and performance are considered mostly adequate for next three years but necessarily beyond that. We regularly review systems performance and typically expect to replace servers every three to five years.

Physical servers

PowerOn servers and Telephony Servers have been replaced as part of a complete lifecycle upgrade of systems. The health of these servers is monitored and we typically replace servers of this type in three to five years. The capacity and performance is adequate for the period of this plan.

Desktops and laptops

We typically upgrade our desktops and laptops on a three yearly cycle. We expect that the capacity and performance of this equipment will not be adequate for the period of this plan.

Tablets

A number of tough-books (tablets) have just been rolled out to field operations staff. We expect that the capacity and performance of this equipment will not be adequate for the period of this plan.

Network

Several data networks are supported in our information system infrastructure which uses switches and firewalls to provide Gigabit network speeds between servers and to desktops. Our policy is to separate corporate and engineering networks by providing access to each on a least privilege basis.

4.23.3 Asset condition

Corporate financial management system – Microsoft Dynamics Nav

The system is in its current version since 2011 and is to be reviewed in FY14.

Document management system

In-house developed document management solutions are fit for purpose and operating effectively.

Our Microsoft SharePoint stage 1 implementation is complete and in use across the business.

Orion internet website

The Orion website was replaced in FY14

Email system – Microsoft Exchange Server

Our Email system is a mature and well established application. It will be integrated with document management as part of the current implementation.

Desktop software

The desktop operating system is current and subject to regular security and performance updates from Microsoft. Changes may be forced on us in the future as new equipment becomes unsupported on the current version.

4.23.4 Standards and asset data

Asset management report:

- NW70.00.49 - Information Systems – Corporate

4.23.5 Maintenance plan

All systems are supported directly by the Orion Information Solutions group with vendor agreements for third tier support where appropriate.

License costs are considered to provide a degree of application support but are substantially a prepayment for future upgrades. Although licenses guarantee access to future versions of software, they do not pay for the labour associated with implementation. Our experience has been that significant support is required for the vendor to accomplish an upgrade and these costs are reflected as capital projects in our budgets.

Software releases and patches are applied to systems as necessary and only after testing.

Production systems are subject to business continuity standards which include:

- an environment that includes development, test and production versions
- mirroring of systems between two facilities to safeguard against loss of a single system or a complete facility
- archiving to tapes which are stored off site at a third party
- change management processes
- least privilege security practices.

Our budgeted maintenance costs are shown in section 7.1.2 – Opex budgets - Non network.

4.23.6 Replacement plan

We employ a standard change management approach to all software and hardware systems. Major changes to all corporate business information systems will follow the predefined steps of Project proposal / concept socialisation, Business Case and approval, Business requirements and implementation via a Project. All project costs are capitalised.

Our budgeted replacement costs are shown in section 7.1.4 – Capex budgets - Non network.

4.23.7 Creation / acquisition plan

Some recoveries are made from salaries to capital budgets to recognise the contribution of our software development staff in system enhancements.

4.23.8 Disposal plan

There are no specific disposal plans for this asset group.

4.24 Information systems - asset management

4.24.1 Asset description

Our Asset Management Systems hold information about the equipment that comprises the electricity network and support business processes that build and maintain that equipment. The majority of our primary asset information is held in our asset register, geographic information system (GIS) and cable databases. We hold information about our network equipment from GXP connections down to individual LV pole level with a high level of accuracy.

In addition to these asset registers we hold also detailed information regarding customer connections in our Connections Register and track the process of asset creation and maintenance in Works Management.

Geographic Information System (GIS) – Intergraph suites, G/Electric and GeoMedia

Our GIS records our network assets according to their location, type and electrical connectivity. It interfaces with other information systems such as substation asset attribute data stored in our asset register. GeoMedia specialises in reporting and analysing geographic data. In particular; GeoMedia easily combines core GIS and third party datasets such as aerial imagery for both Orion and contractor/consultant use.

Various GIS viewer technologies enable Orion to deliver ‘fit for purpose’ geographic asset information within Orion premises, or off site via a secure website. In areas where internet coverage is limited, GIS datasets may be stored directly on a laptop device

Asset register – EMS WASP

Our asset register, EMS WASP, provides a central resource management application for holding details of key asset types with their current location/status. The assets covered include land, substations and all our major equipment with less strategic types being added over time. Schedules extracted from this database are used for preventative maintenance contracts and it archives any inspection/test data gathered during the contract. Data is also held to facilitate a valuation of our fixed network assets; the GIS holds the distributed assets (lines and cables).

Cable databases (HV and communication cables)

Separate in-house developed MS Access databases are used to hold information on 66, 33 and 11kV underground cables and pilot/communication cables. Cable lengths, joint/termination details are held and linked to our GIS by a unique cable reference number.

Works Management and Enquiry for Supply

All types of works activity are managed using purpose-built in-house developed applications which populate a single works data repository. The applications are optimised for different types of work including new connections management, general network jobs and emergency works.

When a job is created in Works Management a companion job is also automatically created in the financial system (NAV) to track job related invoices.

Connections Register

Our in-house developed Connections Register holds details of all installation control points (ICP) on our network. This is linked with the industry registry. Links with our GIS systems enable accurate derivation of GXP information by ICP and the association of ICP with an interruption. Interruptions are now routinely traced within the GIS using the in-built connectivity model, and accurate information about the number of customers and interruption duration are recorded.

4.24.2 Asset capacity/performance

GIS – Intergraph suites, G/Electric and GeoMedia

G/Electric technology and its supporting Oracle database have the capacity to scale up and extend functionality to support business growth. Geomedia technology is in the process of being upgraded to meet the current growth in business intelligence requests and ‘access to GIS’ demands from external contractors/consultants.

The supporting physical computer infrastructure exists on a high availability Virtual Server environment, and is considered to have adequate capacity and performance for the timeframe of this plan.

Asset register – EMS WASP

We use only a subset of the capabilities of the EMS WASP database which can be applied to Works Management as well as asset tracking. There is also no intention to further develop this system and a systems review to be undertaken within the next three years may result in its replacement.

Although subject to the outcomes of a systems review due in FY16, the performance and capacity of the database is adequate for the timeframe of this plan.

Cable databases (HV and communication cables)

The cables databases are in-house applications written in Microsoft Access and as such may be subject to modification as a consequence of updates to the Microsoft Office Suite. It is our intention that within the timeframe of this plan that these applications will be either integrated with other databases or modified to run as in house Microsoft SQL database.

Works Management and Enquiry for Supply

Works Management and Enquiry for Supply are highly customised to support our business processes.

Although subject to the outcomes of a systems review due in FY17, the performance and capacity of the database is adequate for the timeframe of this plan.

Connections Register

The Connections Register has been modified significantly since its establishment in FY00, to support a range of new business processes. This system has however reached a “tipping point” and without a change to its underlying architecture, there is a high degree of risk in developing it further.

Its capacity and performance are adequate for the period of this plan if there are no further major changes required.

This future of this application is subject to the outcomes of a systems review due in FY16.

4.24.3 Asset condition**GIS – Intergraph suites, G/Electric and GeoMedia**

The G/Electric suite has recently been upgraded to a current release and resides on a high performance, high availability Virtual Server environment.

The upgrade included a review of customised code, which was largely replaced with standard application features, reducing the complexity of the systems from a support perspective.

A review of our use of Geospatial Information was undertaken during FY14 which focused mainly on business process.

Asset register – EMS WASP

EMS WASP will not be further developed and a systems review to be undertaken within the next two years may result in its replacement. Some issues have arisen regarding interfaces to other systems due to upgrades in those systems. It is likely to become more difficult overtime to provide integrated views of data from EMS WASP and other systems.

A systems review due in FY17 will consider the future of EMS WASP.

Cable databases (high voltage and communication cables)

It is undesirable that the cables databases remain as Microsoft Access databases and they will be either integrated with other databases or modified to run as in house Microsoft SQL database.

Works Management and Enquiry for Supply

Although subject to the outcomes of a systems review due in FY17, the performance and capacity of the database is adequate for the timeframe of this plan.

Connections Register

Its capacity and performance are adequate for the period of this plan if there are no further major changes required.

This future of this application is subject to the outcomes of a systems review due in FY16.

4.24.4 Standards and asset data

Asset management report:

- NW70.00.48- Information Systems – Asset management

4.24.5 Maintenance plan**General**

All systems are supported directly by the Orion Information Solutions group with vendor agreements for third tier support where appropriate.

License costs are considered to provide a degree of application support but are substantially a prepayment for future upgrades. Although licenses guarantee access to future versions of software they do not pay for the labour associated with implementation. Our experience has been that significant support is required for the vendor to accomplish an upgrade and these costs are reflected as capital projects in our budgets.

Software releases and patches are applied to systems as necessary and only after testing.

Production systems are subject to business continuity standards which include:

- an environment that includes development, test and production versions
- mirroring of systems between two facilities to safeguard against loss of a single system or a complete facility
- archiving to tapes which are stored off site at a third party
- change management processes
- least privilege security practices.

Our budgeted maintenance costs are shown in section 7.1.2 – Opex budgets - Non network.

GIS

The G/Electric suite and related computer infrastructure are supported directly by the Orion Information Solutions group. In addition, support hours are pre-purchased from Intergraph as part of an annual maintenance agreement.

EMS WASP

EMS WASP and related computer infrastructure are supported directly by the Orion Information Solutions group.

Other systems

All other systems are supported directly by the Orion Information Solutions group. Some recoveries are made from salaries to capital to recognise the contribution of development in system enhancements.

4.24.6 Renewal plan

Changes to asset management information systems are typically incremental in nature and systems are replaced infrequently.

As indicated in the previous sections we employ a standard change management approach to all software systems. Renewal of an information system will follow the predefined steps of project proposal / concept socialisation, business case and approval, business requirements and implementation via a project.

4.25 Metering

4.25.1 Asset description

High voltage (11kV) consumer metering

We own current transformers (CTs) and voltage transformers (VTs) used for metering, along with associated test blocks and wiring, at approximately 75 consumer sites. Retailers connect their meters to our test blocks. All Orion CTs and VTs are certified as required by the Electricity Governance Rules.

Transpower grid exit point (GXP) metering

We adopted GXP-based pricing in 1999, and most of our revenue is now derived from measurements by Transpower's GXP metering.

Orion also owns metering at Transpower GXPs. We input the data from these meters into our SCADA system. Our measurements can also help the Reconciliation Manager to estimate data if Transpower's meters fail, or are out of service.

Transpower has dedicated meters at all metering points. The GXPs at Arthur's Pass and Castle Hill share CTs with our metering. All VTs are shared between Orion and Transpower. Although a truly credible check metering system would have stand-alone components with their own traceable accuracy standards, this is impractical.

Power quality measurement metering

Our power quality management in the past has been mainly reactive. We have responded to consumer complaints (which generally stem from the consumer's own actions) while assuming that the underlying network performance is satisfactory. The general underlying qualitative power quality performance of the network and whether it is deteriorating with time as an increasingly number of non linear loads are connected to the network has been unknown. These non linear loads (which frequently reduce network power quality) are also generally more sensitive to the very power quality issues they help to create.

We have completed a three year project to install approximately 30 permanent standards compliant power quality measurement instruments across a cross-section of distribution network sites which are expected to range from good (generally urban upper network) to poor (generally remote rural) power quality performance.

These instruments will continue to collect power quality data, the analysis of which will provide a long term statistical view of typical network performance across a wide range of network conditions and locations. This data can also be used to provide a view of actual network power quality performance to assist with the development of standards and regulations.

4.25.2 Asset capacity/performance

We check that our metering figures support Transpower's data. If the two sets of data differ significantly, meter tests may be required to establish where the discrepancy has occurred.

The two sets of data will never be identical – our GXP metering cannot definitively check Transpower's half-hourly metering values because:

- some of our meters are in different locations from Transpower's meters
- our meter-class accuracy differs from Transpower
- the error correction factors that apply to Transpower's metering do not apply to us, as our metering uses different CTs
- we sum many metered values through auxiliary current summation transformers. As a result, our meters record more energy than Transpower's meters, which are all fitted with separate class 0.2 meters.

However, our data can be used to identify changing trends in the difference between the two metering systems, and to identify gross errors due to equipment failure.

4.25.3 Asset condition

All metering equipment is in good condition.

4.25.4 Standards and asset data

Asset management report:

- NW70.00.38 - Metering

We have a comprehensive set of GXP metering equipment drawings. These drawings include details of both Orion and Transpower metering equipment.

Documentation on the status and details of our check meters needs to be improved.

4.25.5 Maintenance plan

We regularly inspect the metering sites, carry out appropriate calibration checks and witness the calibration checks on Transpower's metering.

Our meter testing contractors are required to have registered test house facilities which comply with the Electricity Governance Rules. They must also have documented evidence of up-to-date testing methods, and have competent staff to perform the work.

Our budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: Meters.

4.25.6 Replacement plan

In recent years we have replaced all of our GXP metering in conjunction with Transpower's metering changes. We have no plans to carry out further significant replacement work at this stage.

Our budgeted replacement costs are shown in section 7.1.9 – Replacement budgets: Metering.

4.25.7 Creation/acquisition plan

Additional standards compliant power quality measurement instruments may be installed in the future where we connect new major customers to provide them with an assurance of the level of power quality they are being supplied with.

4.25.8 Disposal plan

We have no specific plans to dispose of any of this asset group.

4.26 Network property

4.26.1 Asset description

This section on network property covers all buildings, kiosks and land assets that form an integral part of our distribution network.

All of our zone substations, with the exception of Teddington, have buildings which contain switchgear and control equipment. Most of the buildings are constructed of reinforced and filled concrete block. Eleven of the substation buildings, mostly in the rural area, are of modular design constructed from a series of large rectangular reinforced concrete sections connected together to form a rectangular building.

The 219 network and 252 distribution substation buildings vary in both construction and age. We own approximately 80% of the network buildings and approximately 30% of the distribution substation buildings. Some 150 of them are incorporated in a larger building that we do not own.

Our kiosks are constructed of steel to our own design. The majority fall into two categories; an older high style, and the current low style. The low style kiosk is also constructed in half (shown in photo below) and quarter versions for use where the transformer is mounted externally or at a remote location.

Table 4-26a Distribution kiosk quantities FY14 (owned by Orion)

Kiosk type	Low (full) steel	Low (half) steel	Low (quarter) steel	High steel	Fibreglass	Berm concrete/steel	Transformer cover	Total
Quantity	2,193	532	286	651	15	3	33	3,712

4.26.2 Asset capacity/performance

Our property assets must meet the following three performance criteria:

1. They must be secure. We are aware of increased public safety and risk management expectations surrounding our substations. A programme to run over a 10 year period to upgrade security and safety is underway. This will mainly involve access (locks and gates/doors), fencing and earthing. All ground-mounted installations in industrial and commercial locations have already been independently surveyed to gauge their susceptibility to damage. Solutions to minimise the risk of damage are being developed.
2. They must be environmentally sound to ensure that the installed equipment is not compromised. The main areas of note here are the seismic strength and water-tightness of the buildings. Both these matters are being addressed.
3. They must be visually acceptable. Work such as damage repair, ground maintenance, graffiti removal and painting is on-going to achieve this outcome.

The September 2010 M7.1 earthquake, and subsequent M6.3 earthquakes in February and June 2011, caused minor superficial damage to a number of our substation buildings. Three zone substations incurred more substantial damage.



Outdoor substation - consisting of a half-kiosk and transformer.

Greendale zone substation

Greendale is situated close to the September fault line and underwent some of the most significant ground movement observed in the rural area. The site is now slightly higher at one end but major foundations and the substation building appear to be structurally sound. The substation building appears to have moved approximately 200mm and this has affected water and drainage connections. No further damaged occurred as a result of the February and June 2011 earthquakes.

Pages switchyard

Pages switchyard has been decommissioned. It was subject to significant liquefaction and surface flooding after each of the three bigger earthquakes. The structures and buildings sunk making the site unsuitable for continued use.

Brighton zone substation

Brighton zone substation has been decommissioned. It was situated across the road from Pages switchyard and near the Avon River. As a result of the February 2011 earthquake the site was subject to liquefaction and lateral spread. While the buildings and structures remained structurally sound they sank approximately 1m. Due to this subsidence the site was no longer suitable for a substation and a replacement zone substation (Rawhiti) was built in Keyes Rd.

Distribution substations

Across our network we observed only minimal damage to our distribution substation buildings and kiosks. The worst seismic damage occurred in the Sumner/Redcliffs area due to rock falls and landslides in the February 2011 earthquake. There was minimal extra damage after the June earthquake.

The building substations had been seismically strengthened, and generally we observed movement of plaster between bricks and some cracking in floors and walls. We have observed significant subsidence around two distribution building substations and several kiosks.

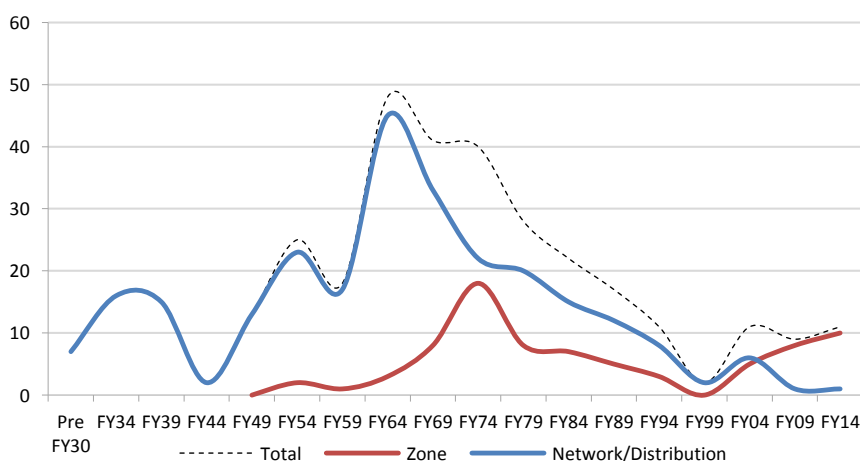
4.26.3 Asset condition

Our zone substation buildings (see section 4.4.1 for examples) are well designed and mostly constructed with reinforced and filled concrete blocks. The structural integrity of all the buildings has been inspected and remedial action taken to bring all zone substations up to the latest building code and related seismic strength code. We are underway mitigating known issues with our zone substation switchyards.

Our network/distribution building substations vary in both construction and age. Those constructed prior to the early 1960s are very brittle in nature, having walls constructed entirely of non-reinforced clay brick. Those that have been constructed since the mid-1960s are of a more substantial nature, namely reinforced concrete framed masonry. A seismic assessment was undertaken on all our substations to determine those which required remedial work to bring them up to the current standard. A risk analysis of the resulting list concentrated on determining the consequences to the network of a loss of a given substation. This information was then used to develop our 'works' programme. There are a small number of distribution substations in Orion owned and consumer owned buildings that have not yet had remedial works undertaken. However, it is considered that these will have a low impact on the network if lost during an abnormal event.

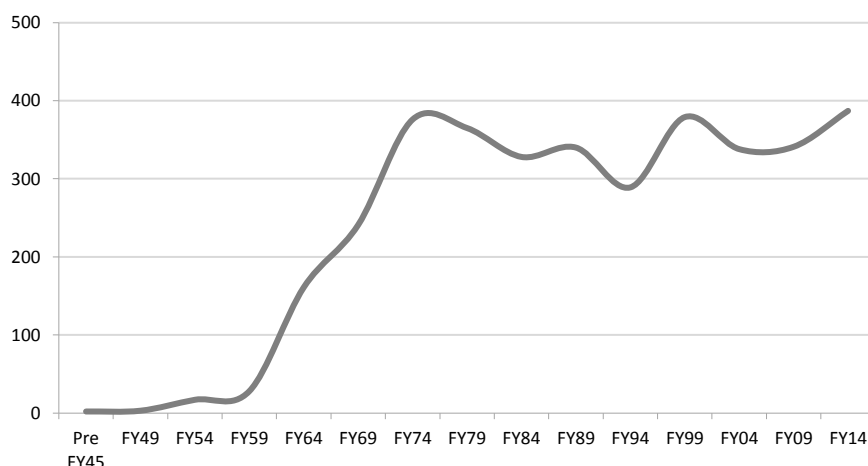
Our kiosks are generally in reasonable condition. Steel kiosks in the eastern suburbs nearer the sea are prone to some corrosion and it is expected that these kiosks will have to be replaced much sooner than those in the remainder of our network. They are being attended to as required. We have 15 kiosks of a fibreglass construction and these have been the subject of a detailed inspection to assess their condition and programme their replacement.

Figure 4-26a Substation buildings (owned by Orion) - age profile



We are currently well over half way through a programme to seismic strengthen our dual pole and single pole substations with large heavy transformers.

Figure 4-26b Kiosks - age profile



4.26.4 Standards and asset data

Asset management report:

- NW70.00.43 - Network property

Standards and specifications

Design standards developed and in use for this asset are:

- NW70.53.01 - Substation design
- NW70.53.02 - Substation design - customer premises.

Technical specifications covering the construction and ongoing maintenance of this asset group are:

- NW72.23.14 - Kiosk installation.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.01 - Kiosk shell - full
- NW74.23.02 - Kiosk shell - half
- NW74.23.03 - Kiosk shell - quarter.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS and asset register)
- construction type and age
- detail drawings
- land ownership/title details
- maintenance/improvement records.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition.

4.26.5 Maintenance plan

A five year maintenance plan has recently commenced with the view to repair all of our buildings which have suffered earthquake damage. All our buildings and land are inspected regularly, and minor repairs are undertaken as they are identified. Major repair and maintenance work is scheduled, budgeted for and undertaken on an annual basis.

Property maintenance is expected to remain at a constant level, although many of the older consumer owned substations will

require seismic upgrading if they are retained. Consumer owned substations that require maintenance or strengthening to remove risk to our equipment may present some problems in relation to who will bear the cost of this work. These will be assessed on a case by case basis.

Our substations are maintained on an as-required basis, with most general maintenance work identified during six-monthly inspections. Work such as damage repair, ground maintenance, graffiti removal, painting, signage and lock replacement is on-going.

Some of the older kiosk foundations have moved due to surrounding land movement. They need to be levelled to relieve stress on the attached cables. A small number of them are being attended to each year.

We maintain and repaint our kiosks as required with more focus to deter rust on the coastal areas. Buildings are repainted approximately every 10 years and we are now using a silicon based product to provide a waterproof membrane and protect the substation from water ingress through the blockwork.

Graffiti is an on-going problem at virtually all of our sites. We remove it as soon as possible after it is reported. We liaise with the local councils and community groups in our area to assist us with this problem. We now have a specific email set up where members of the community can report graffiti.

Our budgeted maintenance costs are in section 7.1.1 – Opex budgets - Network: Buildings and enclosures.

4.26.6 Replacement plan

We do not have a replacement plan for our building substations and will review the need for them as we undertake major works at the sites. These assets are maintained to ensure they provide the required level of performance. However, due to the acquisition of Transpower's spur assets we have made allowance for upgrade work in FY16.

To help maintain the security of our assets we have initiated a programme to replace all locks in our network. This will take up to four years to complete.

There is a programme underway to replace all fibreglass kiosks as well as some steel kiosks due to rust. A number of the steel kiosks are located near the coast. We are also in the process of formulating a roof replacement programme based on a condition assessment.

Allowance has been made for upgrading security fencing and seismic requirements.

Our budgeted replacement costs are in section 7.1.9 – Replacement budgets: Buildings and enclosures.

4.26.7 Creation/acquisition plan

We construct new buildings and kiosks to meet consumer demand for supply to subdivisions or commercial ventures and when necessary to place overhead reticulation underground.

We are investigating the ownership of leased/rented sites with the view to create a more secure tenure of all network land, if required.

For a list of projects containing this asset see section 5.6 - Network development proposals.

4.26.8 Disposal plan

Equipment is disposed of as part of the replacement programme.

We are currently engaged in justifying continued ownership of (or easements over) all unused sites. We will relinquish ownership of sites deemed not required.

4.27 Corporate property

4.27.1 Asset description

Orion's corporate property covers our new administration building at 565 Wairakei Rd and property and land throughout the Canterbury region.

Administration building

We have relocated our administration function to 565 Wairakei Rd, following the FY11 earthquakes, and the former building at 200 Armagh St is no longer occupied. The Crown has purchased the 200 Armagh St building as of September 2013. Future development on the site by CERA will include installing a block wall around our existing Armagh zone substation. Situated at the rear of the substation is our 'hot-site' which we can use if an emergency situation forces us out of our current administration building.



Our building at 565 Wairakei Rd

Rental Properties

We own nine rental properties of which four are residential properties adjacent to zone substations. Some of these were acquired as part of a package when substation land was purchased. Others have been strategically purchased to allow the substation to expand if necessary. We receive income from these properties, provided they are tenanted, and this rental income is in line with the rental market in the Christchurch area.

4.27.2 Asset capacity/performance

As a lifelines utility (Under the Civil Defence Emergency Management Act 2002) providing essential services to the community, we are required to be operational after a significant event. Our new administration building has been built to Importance Level 4 (IL4). This means that the building is designed to remain operational following a 1 in 500 year seismic event. The building is also equipped with a standby generator (with 500 litre diesel tank) which is able to provide back-up power.

Our property assets must meet the following criteria:

- they must be fit for purpose and maintained in a reasonable condition so the tenant can fully utilise the premises
- they shall comply with all building, health and safety standards that may apply
- they must be visually acceptable.

4.27.3 Asset condition

Our corporate properties vary in both construction and age.

Our Wairakei Rd No.565 administration building was new in FY14.

Our residential properties are clad with either brick or timber weather-board with the roofs being a mix of concrete tile or iron. Other than superficial earthquake damage these properties are in good general condition.

The commercial properties that we have at Darfield (Selwyn Gallery) and Duvauchelle (ex line depot) sustained mainly superficial damage during the Canterbury earthquakes. The roof at the Selwyn Gallery is due for replacement and we are in the process of completing this project.

Work has been completed to strengthen and repair the Akaroa Gallery which suffered more substantial damage.

4.27.4 Standards and asset data

Asset management report:

- NW70.00.42 - Corporate property

Standards and specifications

Technical specifications covering the construction and ongoing maintenance of this asset group are:

- NW72.20.07 - Grounds maintenance

4.27.5 Maintenance plan

We have no assigned 'end of life' for our corporate properties. The purpose of our asset management programme is to ensure that our corporate property is managed in a manner that is consistent with Orion's corporate obligations to deliver an effective and efficient service.

We carry out regular inspections of our buildings to ensure that they do not deteriorate further as a result of the seismic activity that the area has experienced. Several databases are used to assist us with the management process such as our asset register (EMS WASP) and our works management system. We also use a 'fault incident report' database to collect any faults or safety issues with our corporate properties. For any instances where further expertise is sought we employ an external consultant to offer an independent judgement to assist in the decision making process for any maintenance or repair programmes. The risks that our corporate buildings are exposed to are listed below in no particular order of importance:

- seismic damage
- liquefaction and subsidence
- defective drainage and guttering
- roof leaks
- vegetation/tree roots
- vandalism- repairs carried out as soon as reported
- rust and rot
- extreme weather conditions
- fire
- graffiti.

Minor repairs are undertaken as they are identified in the inspection process. Major repair and maintenance work is scheduled, budgeted for and undertaken on an annual basis. Vandalism and graffiti is fixed as soon as we are notified. We have maintenance contracts in place with several contractors to ensure that all aspects of our property and land maintenance are covered. These include:

- site security
- grounds maintenance
- building services maintenance
- graffiti removal.

Our budgeted maintenance costs are in section 7.1.2 – Opex budgets - Non network.

4.27.6 Replacement plan

We have no replacement plan for our corporate properties. These assets are maintained to ensure they provide the required levels of performance.

Our budgeted replacement costs are in section 7.1.4 – Capex budgets - Non network/Corporate property.

4.27.7 Creation/aquisition plan

We have no creation plan for our corporate properties at this time.

4.27.8 Disposal plan

We currently have no plans to dispose of any corporate property. We will relinquish ownership of sites we no longer have a use for, or as required under the Christchurch Central Recovery Plan.

4.28 Vehicles

4.28.1 Asset description

We own 92 vehicles to enable us to operate and maintain the electricity network and to respond to any events. Our goal is to ensure we have the right vehicle in the right place at the right time with an appropriately trained driver.

Table 4-28a Vehicle quantities

Description	Quantity	Lifecycle
Generator truck	3	20 years
Network operator utility	17	5 years or 200,000km
Operational vehicle	46	6 years or 140,000km
Van	1	10 years
Other	27	4 years or 100,000km
Total	94	

4.28.2 Asset capacity/performance

The performance criteria vary for each vehicle class. All are operated within their manufacturer specified parameters.

4.28.3 Asset condition

Our vehicles are relatively new and regularly maintained. As a result they are in good condition. Road conditions in some areas of Christchurch are still poor due to the recent earthquakes. As a result of this we have seen a small increase in premature wear on components such as suspension bushings, etc. Our maintenance plan addresses such issues.

4.28.4 Standards and asset data

Asset management report:

- NW70.00.47 - Vehicles

Our vehicles are operated to the requirements of current legislation.

Our financial system is used to hold usage data and schedule all regular maintenance and compliance requirements.

4.28.5 Maintenance plan

All vehicles within their warranty period are serviced according to the manufacturers' recommended service schedule by the manufacturers' agent. For vehicles outside of their warranty the servicing requirements are also maintained in accordance with the manufacturers' specifications by a contracted service agent.

Our budgeted maintenance costs are in section 7.1.2 – Opex budgets - Non network.

4.28.6 Replacement plan

Our fleet replacement plan aims to replace vehicles on a like-for-like basis, where applicable, when the vehicle reaches its designated age or distance covered. If the fundamental needs of the driver change, the change will be reflected in the type of vehicle purchased for replacement. Where possible we purchase vehicles that better fit our purpose and where there is a demonstrable gain in safety, efficiency, reliability and value for money.

Our budgeted replacement costs are in section 7.1.4 – Capex budgets - Non network/Vehicles and mobile plant.

4.28.7 Creation/aquisition plan

The aim is to have the right vehicle and driver to the right place at the right time. This is a critical aspect of operating our network in a safe, reliable and efficient manner.

The key drivers in our vehicle acquisition plan are:

- fitness for purpose
- safety

- reliability
- environment and fuel economy
- value for money / lowest economic cost over the life of the vehicle (including disposal value)
- diversity within the fleet (spreading the risk).

4.28.8 Disposal plan

Our vehicles are typically disposed of via auction. In this way we achieve a market value for the vehicle and also incur the minimum disposal cost in terms of time and money.



Mobile generator truck

Network development



5

5.1	Introduction	175
5.2	Network architecture	176
5.2.1	Transpower GXPs	176
5.2.2	Urban subtransmission	177
5.2.3	Rural subtransmission	177
5.3	Planning criteria	178
5.3.1	Security Standard	178
5.3.2	Network utilisation thresholds	180
5.3.3	Capacity determination for new projects	180
5.3.4	Project prioritisation	181
5.3.5	Non-network solutions	182
5.4	Energy, demand and growth	186
5.4.1	Observed and extrapolated load growth	187
5.4.2	Methodology for determining GXP and zone substation load forecasts	192
5.4.3	Transpower GXP load forecasts	196
5.4.4	Orion urban zone substation load forecasts	197
5.4.5	Orion rural zone substation load forecasts	200
5.4.6	Utilisation of assets	203
5.5	Network gap analysis	205
5.6	Network development proposals	208
5.6.1	Impact on service level targets	208
5.6.2	Overview of projects	208
5.6.3	Urban 66kV subtransmission review	209
5.6.4	Transpower spur assets	210
5.6.5	Major projects – GXPs	211
5.6.6	Major projects – urban	213
5.6.7	Major projects – rural	220
5.6.8	11kV Reinforcement projects – urban	232
5.6.9	11kV Reinforcement projects – rural	237
5.6.10	Network connections and extensions	240
5.6.11	Underground conversions	240
5.6.12	Demand side management value for network development alternatives	240

List of figures and tables in this section					
Figure	Title	Page	Table	Title	Page
5-2	Transpower system in Orion's network area	176	5-3a	Distribution network supply Security Standard	179
5-3	Peak demand capping	183	5-3b	Standard network capacities	181
5-4a	Orion network annual energy trends	187	5-4a	Fletcher EQC response to restoring heating	194
5-4b	Overall maximum demand trends on the Orion network	188	5-4b	GXP substations – load forecasts (MVA)	196
5-4c	System load factor	189	5-4c	Urban 66 and 33kV zone sub – load forecasts (MVA)	198
5-4d	Christchurch urban area network – load duration curves	190	5-4d	Urban 11kV zone substations – load forecasts (MVA)	198
5-4e	Central Plains Water scheme stages	191	5-4e	Rural 66 and 33kV zone sub – load forecasts (MVA)	201
5-4f	Rural summer maximum demand (MW)	191	5-5a	Transpower GXP security gaps	206
5-4g	Rural winter maximum demand (MW) graph	192	5-5b	Orion security gaps	207
5-4h	Take-up of industrial land	193	5-6a	Spur assets, indicative cost to purchase	211
5-4i	GXPs – Maximum demand versus firm capacity	196	5-6b	Affected Transpower new investment agreements	211
5-4j	Urban 66/33 zone substations – max demand v capacity	197	5-6c	Major GXP projects	211
5-4k	Urban 11kV zone substations – max demand v capacity	197	5-6d	Major urban projects	213
5-4l	Zone subs – urban (CY-1 max demand as % of capacity)	199	5-6e	Major rural projects	220
5-4m	Rural zone substations – max demand v firm capacity	200	5-6f	11kV urban reinforcement projects	232
5-4n	Zone subs – rural (max demand as a % of firm capacity)	202	5-6g	11kV rural reinforcement projects	237
5-4o	66kV, 33kV and 11kV zone substation utilisation	203	5-6h	DSM value for network development alternatives	241
5-4p	Zone substation 11kV feeder cable utilisation graph	204			
5-4q	Distribution transformer utilisation graph	204			
5-6a	Transpower core grid and spur assets in Orion's area	210			
5-6b	Urban subtrans 66kV – existing and proposed (Diagram)	214			
5-6c	Urban subtrans 33kV – existing and proposed (Diagram)	214			
5-6d	Urban subtrans 66,33kV – existing and proposed (Map)	215			
5-6e	Rural subtrans 66kV – existing and proposed (Diagram)	221			
5-6f	Rural subtrans 33kV – existing and proposed (Diagram)	221			
5-6g	Rural subtrans 66,33kV – existing and future (Map)	222			

5.1 Introduction

Developing our network to meet future demand growth requires significant capital expenditure. Before spending capital on our network, we consider a number of options including those available in demand side management and distributed generation.

The amount we spend on our network is influenced by existing and forecast consumer demand for electricity and the number of new consumer connections to our network. Other significant demands on capital include:

- meet safety and environmental compliance requirements
- meet and maintain our security of supply standard (see section 5.3.1)
- meet our reliability of supply targets.

The growth rate in overall maximum network system demand (measured in megawatts) traditionally drives our capital investment. Maximum demand is strongly influenced in the short-term by climatic variations (specifically the severity of our winter conditions). For FY14 the peak total injection was 619MW. This was supplied through Transpower's GXP's and by export from distributed generators of 6.8MW. The maximum export recorded from embedded generators during the year was 12.9MW on the evening of 14 August 2014.

During the winter of 2011, prior to the two snow storms, the peak half hour for the winter had been only 533MW (based on load through Transpower GXP's i.e. excluding embedded generation). The July 2011 snow led to a 7% higher half hour peak of 572MW. The August 2011 snow emphasized the effect of climatic variation when the load peaked 10% higher again at 633MW. In the medium-term it is influenced by growth factors such as underlying population trends, growth in the commercial/industrial sector and changes in rural land use.

Another factor that has influenced our network development plan is in-fill housing in existing central suburbs and new housing estates in areas such as Belfast, Halswell, Wigram, Broomfield, Marshland, Rolleston, Lincoln and to a lesser extent in West Melton and Prebbleton – it is likely we will extend our urban 11kV network to meet these developments.

Understanding the impacts of the Canterbury earthquakes and learning from our experiences is vital for our community and a key driver in our network development plan is to ensure that the replacement and upgrade of assets in the north and east of Christchurch occurs in a resilient way and also facilitates growth in northern Christchurch.

In this section we discuss our network architecture, planning criteria, energy demand and growth, network gap analysis and list our proposed projects required to address specific issues. The project list is split into asset type and area concerned, for example, 11kV reinforcement projects (urban) and 11kV reinforcement projects (rural).

The impact of the Canterbury earthquakes

The 2010/2011 earthquakes in Canterbury caused significant damage to our network. We are proud of our pre-earthquake network architecture and engineering strategies to minimise the impact of such events and we are pleased with our operational response during the response and recovery phases. There is much to be learnt from experiencing an event of this scale and this coupled with permanent network damage has led to an inevitable change to our pre-earthquake network development plans.

We are actively gathering new information about the impact of the earthquakes on our present and future communities. Our urban 66kV subtransmission and 11kV network architecture reviews have resulted in refinement of our subtransmission strategy as described in section 5.6.3. We have installed two 2MW generators temporarily at QE2 to provide support for nearby suburbs until our subtransmission network is rebuilt in the north east of the city. Our load forecasts have been updated with post-quake population forecasts that use the March 2013 Census and the Land Use Recovery Plan (LURP) prepared for CERA by Environment Canterbury. The forecast also takes account of CCC vacant industrial land uptake data to June 2014.

5.2 Network architecture

5.2.1 Transpower GXP

Our network is supplied from seven GXP substations – two in the Christchurch urban area, two on the rural plains and three remote GXPs at Arthur's Pass, Coleridge and Castle Hill. The three remote GXPs have a single transformer and a much lower throughput of energy. With the exception of Hororata and Kimberley all the GXPs peak in winter.

Approximately 65% of our consumers depend on the Islington GXP 220/66kV interconnection made up of two 200/266MVA transformers and one 250/310MVA transformer.

Transpower charges users, for example Orion and Mainpower, for the costs of upgrading and maintaining the GXPs. Orion owns all the assets connected to the GXPs. We work with Transpower to plan for GXP connection asset upgrades to ensure that any capital expenditure at the GXP is cost effective.

Security of supply for Orion's subtransmission network largely depends on how Transpower's assets are configured. We continue to review quality and security of supply issues (see our gap analysis in section 5.5).

Urban GXPs

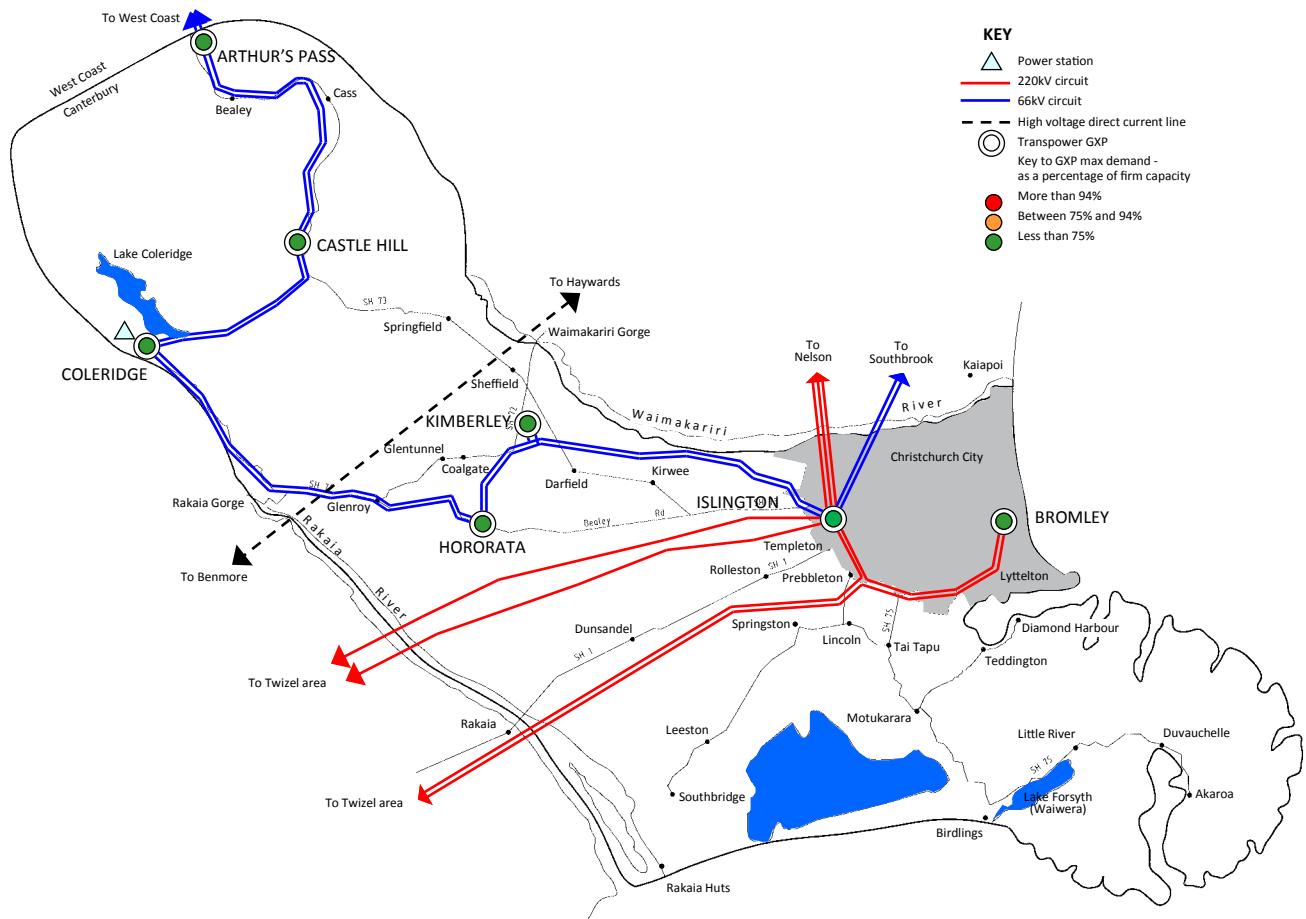
Urban GXPs are located at Islington and Bromley substations. Islington has a 66kV and 33kV grid connection, while Bromley supplies a 66kV grid connection only. Islington and Bromley 220kV substations form part of Transpower's South Island grid. They interconnect between the major 220kV circuits from the southern power stations.

Bromley GXP load has dropped below 75% of firm capacity, as a result of the February 2011 earthquake. The mild 2014 winter has lowered Islington to below 75%.

Rural GXPs

Orion takes connection from five rural GXPs; the two main ones are located at Kimberley and Hororata. Each GXP is supplied via a double 66kV line from the Islington 66kV bus. Hororata supplies Orion at both 66kV and 33kV. Hororata is also connected to the

Figure 5-2 Transpower system in Orion's network area



West Coast via 66kV lines from the Coleridge power station.

The remainder of the rural area is fed at 11kV from three small GXPs at Arthur's Pass, Coleridge and Castle Hill. Together these supply less than 1% of Orion's load. Each GXP is fed from the 66kV Coleridge – West Coast lines.

5.2.2 Urban subtransmission

We have 18 urban 66/11kV zone substations, six urban 33/11kV zone substations and six 11kV zone substations (with no transformer). The 11kV zone substations are being removed as the equipment comes up for replacement, as they do not fit with our current network design architecture. This AMP envisages up to two (and one conversion from 33kV to 66kV) new urban zone substations in the period until 2025. However the number, size, and location of these will depend on the magnitude and geographic distribution of actual load growth in the intervening period.

We can connect most new loads to our urban network at short notice, as required by consumers. The additional load makes use of network capacity held in reserve for contingency situations. That capacity must be replaced by capital expenditure in order to ensure that supply security continues to meet our Security Standard and the needs of our consumers.

Each increment of between 20 and 40MW of new load requires a new zone substation. Zone substations supply an area close to them and free up capacity in adjacent substations. New zone substations require a suitable site, transformers, switchgear and subtransmission connected to Transpower's 66kV or 33kV GXPs.

5.2.3 Rural subtransmission

In our rural area we have one 66/33/11kV and eight 66/11kV zone substations and 13 33/11kV zone substations. This AMP envisages up to four new zone substations and the conversion of up to three zone substations from 33kV to 66kV in the period until 2025. This plan also makes provision for new substations to connect distributed generation at three locations. However the number, size, and location of these will depend on the magnitude and geographic distribution of actual load growth in the intervening period.

Each increment of between 5 and 20MW of new load requires a new zone substation. Zone substations supply an area close to them and free up capacity in adjacent substations. New zone substations require a suitable site, transformers, switchgear and subtransmission connected to Transpower's 66kV or 33kV GXPs.

The existing rural subtransmission network has been designed to meet strong load growth whilst optimising cost. The significant increase in load over the last 15 years has enabled a much more interconnected subtransmission network to be developed. The number of zone substations operating in radial configuration has reduced over time. Most zone substations have only one transformer, generally 7.5MVA or 7.5/10MVA, although substations serving larger townships such as Rolleston and Lincoln or a milk processing plant may have duplicated transformers up to 23MVA. Rural subtransmission capacity is generally limited by voltage drop considerations and hence 66kV (as opposed to 33kV) is technically and economically more attractive for new subtransmission projects.

5.3 Planning criteria

The first stage of planning a distribution network is to ensure that existing network loads are monitored and tested against existing network capacity. The capacity test involves checking adequacy during contingencies defined in our Security Standard and also predefined utilisation thresholds. More detail on our Security Standard and utilisation thresholds is described in the sections to follow.

When network inadequacy is identified, the process of developing solutions begins. Each potential solution is assessed for compliance with our design standards including safety compliance, capacity adequacy, quality, reliability, security of supply and economic consequences.

Sections 5.3.1 to 5.3.5 discuss the main planning criteria considered when solutions are developed.

5.3.1 Security Standard

Security of supply is the ability of a network to meet the demand for electricity in certain circumstances when electrical equipment fails. The more secure an electricity network, the greater its ability to continue to perform or the quicker it can recover from a fault or a series of faults.

Note that security of supply differs from reliability. Reliability is a measure of how the network actually performs and is measured in terms of things such as the number of times supply to consumers is interrupted.

The basic structure of our current Security Standard was developed in consultation with external advisors and adopted by our board in 1998. It is based on the United Kingdom's P2/6 which is the regulated standard for distribution supply security in the UK. Consultation with electricity retailers and industry consumer groups was also carried out. Currently there is only one industry guide published by the Electricity Engineers' Association of NZ (EEANZ) and no regulated national standard is in force. The principle is that the greater the size or economic importance of the demand served, the shorter the interruption time that can be tolerated.

During 2006 we reviewed our Security Standard to ensure it takes into account current consumer preferences for the quality and price of service that we provide. As a result of our review and consumer consultation, our Security Standard has been improved to better reflect the current needs of consumers. Our revised Security Standard may result in slightly lower reliability for our outer-urban consumers but will also reduce the need for future price rises.

These kinds of trade-offs between price and electricity supply reliability are a constant focus for us. Generally, the more we spend, the more reliable our community's electricity supply becomes. However, the trade-off is that the more we spend the higher our prices become, as we need to recover our costs. We are committed to seeking our consumers' views on the price/quality trade-off and we want to ensure that our network investment decisions reflect consumer preferences.

The demand group thresholds in our security of supply standard tend to err on the side of caution and generally provide a level of security that is slightly above the requirements of the average consumer connection. Our analysis has also shown that it is appropriate to provide a slightly higher level of network security for the Christchurch CBD.

This approach ensures that consumers who place a high value on security of supply are reasonably represented in areas where a mix of consumer types exists. The Central City rebuild provides an opportunity to discuss the security and supply requirements with individual consumers as they re-connect to our network.

Given that six years had elapsed since our last Security Standard review and we had new earthquake related information to consider, we undertook a review of our urban 66kV and 11kV network architecture in 2012, with rural 66kV and 11kV and urban low-voltage reviews to follow in 2015/16. Once these are complete they may lead to a further review of our Security Standard.

Further information, including a summary of our 2006 review, can be found on our website oriongroup.co.nz.

We made some semantic changes to our security of supply standard in 2014 to reflect the larger capacity zone substations and subtransmission feeders that we purchased from Transpower. The asset descriptions for some asset 'classes' were changed to better reflect the new asset ownership boundaries. The changes do not impact on our planned levels of security of supply.

In addition to our security of supply standard, consumers are given the opportunity at the time of initial connection to discuss their individual security of supply requirements. We also facilitate changes to individual security of supply arrangements for existing consumers.

Our largest urban consumer connections are relatively small on a national level and have peak loads of approximately 4MW. Our security of supply standard caters for connections of this size and therefore the occurrence of individual security arrangements on our network is minimal. They are mainly limited to high profile services such as hospitals, Christchurch airport and public sports venues. The milk processing plants at Darfield and Dunsandel have peak demands approaching 12MW. We have put in place individual security of supply arrangements for these connections.

Table 5-3a Distribution network supply Security Standard

Class	Description	Size of load (MW)	Cable, line or transformer fault	Double cable, line or transformer fault	Bus or switchgear fault
Urban – Transpower GXPs					
A1	Lines, buses and supply banks	15-600	No interruption	Restore within 2 hours	No interruption for 50% and restore rest within 2 hours
Rural – Transpower GXPs					
B1	Lines, buses and supply banks	15-60	No interruption	Restore within 4 hours ^(Note 1)	No interruption for 50% and restore rest within 4 hours ^(Note 1)
B2	Supply banks	0-1	Restore in repair time	Restore in repair time	Restore in repair time
Urban – Orion network					
C1	Zone substations with CBD or special industrial load	15-40	No interruption	Restore within 1hr	No interruption for 50% and restore rest within 2 hours
C2	Zone substations and subtransmission feeders without CBD or special industrial load	15-20	No interruption	Restore within 2 hours	No interruption for 50% and restore rest within 2 hours
C3	Zone substations or 11kV ring with Christchurch CBD or inner urban load	2-15	Restore within 0.5 hour	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours
C4	Outer, mainly residential zone substations	4-15	Restore within 2 hours	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours
C5	Inner 11kV distribution feeder	0.5-2	Restore within 1 hour	Restore in repair time	Restore 90% within 1 hour and the rest in 4 hours (use generator)
C6	Outer, mainly residential 11kV distribution feeder	0.5-4	Restore within 1 hour	Restore in repair time	Restore 90% within 1 hour and the rest in 4 hours (use generator)
C7	11kV distribution spurs	0-0.5	Use generator to restore within 4 hours	Restore in repair time	Use generator to restore within 4 hours
Rural – Orion network					
D1	Zone substations and subtransmission feeders	15-200	No interruption	Restore within 4 hours ^(Note 1)	No interruption for 50% and restore rest within 4 hours ^(Note 1)
D2	Zone substations and subtransmission feeders	4-15	Restore within 4 hours ^(Note 1)	Restore 50% within 4 hours and the rest in repair time ^(Note 1)	Restore within 4 hours ^(Note 1)
D3	Small zone substations and 11kV distribution feeders	1-4	Restore within 4 hours ^(Note 1)	Restore in repair time	Restore 75% within 4 hours and the rest in repair time ^(Note 1)
D4	11kV distribution spurs	0-1	Restore in repair time	Restore in repair time	Restore in repair time
Note 1. Assumes the use of interruptible irrigation load for periods up to 48 hours.					

5.3.2 Network utilisation thresholds

We monitor loads on our major zone substation 11kV feeder cables at half hour intervals. This information is used to prepare an annual reinforcement programme for our network. Reinforcements recommended in this plan are generally based on winter loading for the Christchurch urban area and on summer loading for the rural area.

Growth at the 11kV distribution level is largely dependent on individual subdivision development and consumer connection upgrades. Growth in excess of the system average is not uncommon and therefore localised growth rates are applied to the region under study. Zone substations, subtransmission and distribution feeder cables are subject to four distinct types of load:

- 1) **Nominal load:** Is the maximum load seen on a given asset when all of the surrounding network is available for service.
- 2) **N-1 load:** Is the load that a given asset would be subjected to if one piece of the network was removed from service due to a fault or maintenance.
- 3) **N-2 load:** Is the load that a given asset would be subjected to if two pieces of the network were removed due to a fault or maintenance.
- 4) **Bus fault load:** Is the load that a given asset would be subjected to if a single bus was removed from service due to a fault or maintenance.

As defined in our Security Standard, the location and quantity of load supplied by a feeder has a bearing on whether all or only some of the four load categories described above should be applied to an asset for analysis.

If the nominal load reaches 70% or the N-1, N-2 or bus fault load reaches 90% then a more detailed review of the surrounding network is instigated.

5.3.3 Capacity determination for new projects

When a capacity or security gap is identified on the network it is necessary to consider different capacity options as solutions. For example, a constrained 11kV feeder can be relieved by installing an additional 11kV feeder to the area. But if the zone substation supplying the area is near full capacity then it may be more cost effective to bring forward the new zone substation investment and avoid the 11kV feeder expense altogether.

When comparing different capacity solutions it is necessary to utilise the net present value (NPV) test. The NPV test is an economic mechanism that converts the value of future projects to present day dollars. NPV analysis generally supports the staged implementation of a number of smaller reinforcements. This approach also reduces the risk of over-capitalisation that ultimately results in stranded assets.

The capacity of a new zone substation and 11kV feeders is generally fixed by the desire to standardise network equipment. The capacity of a zone substation and transformer/s is based mainly on the load density of the area to be supplied and the level of the available subtransmission voltage. The expense of 66kV switchgear and underground 11kV cables, along with the high load densities in urban areas facilitate large zone substations without the issues of excessive voltage drop and losses associated with equivalently sized rural zone substations. Developing a network based on standardised capacities provides additional benefit when considering future maintenance and repair. Transformers and switchgear are more readily interchangeable and the range of spares required for emergencies can be minimised.

When underground cable capacities are exceeded, it is normally most effective to lay new cables. When overhead line capacities are exceeded, an upgrade of the current carrying conductor may be feasible. However the increased weight of a larger conductor may require that the line be rebuilt with different pole spans. In this case it may be preferable to build another line in a different location that addresses several capacity issues.

For new load it is often necessary to extend the network into new areas. As new load is connected it is necessary to reinforce the upper network. Overall a conservative approach is taken. New upper network capacity is installed only once new load growth has or is certain to occur. In the short term, unexpected or accelerated load growth is met by utilising security of supply capacity.

We discuss our approach to increased capacity in our documents NW70.60.16 - Network Architecture Review: Subtransmission, NW70.60.06 - Urban 11kV Network Architecture Review, and NW70.50.05 - Network design and overview.

The following table 5-3b provides a summary of our standard network capacities.

Table 5-3b Standard network capacities

Location/load density	Subtransmission voltage (kV)	Subtransmission capacity	Zone substation capacity (MW)	11kV feeder size (Note 1 and 2) (MW)	11kV tie or spur (Note 1) (MW)	11/400kV substation capacity (MW)	400V feeders (Note 1) (MW)
Urban high density loads	66	40MW radials 40-160MW for interconnected network	40	7	4	0.2-1	Up to 0.3
Urban high density loads	33	23MW radials and interconnected network	23	7	4	0.2-1	Up to 0.3
Rural low density loads	66	30MW radials 30-50MW interconnected network	10-23	6	2	0.025-1	Up to 0.3
Rural low density loads	33	15MW radials and interconnected network	7.5-10	6	2	0.025-1	Up to 0.3

- Notes: 1. Network design requires 11kV and 400V feeders to deliver extra load during contingencies and therefore normal load will be approximately 50-70% of capacity.
2. 11kV feeders in the rural area are generally voltage constrained to approximately 3-4MW so the 6MW capacity only applies if a localised high load density area exists.

5.3.4 Project prioritisation

Prioritisation of network solution projects for capacity and constraints is a relatively complex process that involves multiple factors that are both external and internal to Orion.

The primary factors to be considered when prioritising projects, in decreasing order of significance, are:

1. Coordination with NZ Transport Authority and local authority civil projects:

Where projects are known to occur in the same location, we aim to schedule our projects to coincide with the timing of key civil infrastructure projects by these two parties. This may cause us to bring forward, or even delay if possible, capital works projects to avoid major future complications and unnecessary expenditure which may arise. The most common activity of this type is coordination of planned cable works with any future road-widening or resealing programmes to avoid the need to re-lay cables or excavate and then reinstate newly laid road seal. We are working closely with SCIRT as they rebuild the pipes and roads of Christchurch, and we co-ordinated our Dallington to McFaddens 66kV cable installation with SCIRT's civil works in this area to allow a single trenching and resealing programme.

2. Satisfying individual or collective consumer expectations:

We consider satisfying consumer expectations as the most influential factor and give priority to the constraints that are most likely to impact consumer supply through extended or frequent outages, or compromised power quality.

3. Managing contractor resource constraints:

We aim to maintain a steady work flow to contractors and ensure project diversity is preserved within a given year. This ensures that contractor personnel and equipment levels match our capital build program year-on-year at a consistent level, reducing the risk of our contractors being over or under resourced.

4. Coordination with Transpower:

We endeavour to coordinate any major network structural changes adjacent to a GXP with Transpower's planned asset replacement programmes, and also provide direction to Transpower to ensure consistency with our sub-transmission upgrade plans.

5. Our asset replacement programme:

We extensively review areas of the network where scheduled asset replacement programmes occur to ensure the most efficient and cost-effective solution is sought to fit in with the current and long-term network development structure, for example replacement of switchgear in substations.

6. Our asset maintenance programme:

We seek to schedule any major substation works and upgrades to coincide with asset maintenance programmes, for example zone substation transformer half-life maintenance.

Factors 1-4 are external to the company and 5-6 are internal Orion processes. All are principally objective in nature; however, while specific issues may result in clear outcomes of consumer satisfaction for the consumers involved, feedback from our general consumer base is less directly obtained. Sample sets of consumers are surveyed on some matters, and ultimately direction is provided via the elected representatives of Orion's shareholders, the Christchurch City and Selwyn District councils.

After assessing their relative priorities, the final decision to undertake investment projects in the forthcoming year depends on

urgency. Other factors also apply, such as seasonal timing (to avoid taking equipment out of service during peak loading periods - winter for urban projects, summer for rural), and the necessary order of interconnected projects. Professional engineering judgements based on experience and expertise may come into these decisions.

Projects not selected for next year are provisionally assigned to a future year in the 10-year planning window. When next year's project selection process is undertaken all projects are reviewed and, depending on changes in information and priorities, either maintained in the planning schedule, advanced, deferred, modified, or deleted.

Further details of our approach is in our document NW70.60.14 - Project Prioritisation and Deliverability Process.

5.3.5 Non-network solutions

When the network becomes constrained it is not always necessary to relieve that constraint by investing in new zone substations, 11kV feeders and 400V reinforcement. Before implementing network investment solutions, we consider the following alternatives:

- demand side management
- distributed generation
- uneconomic connections.

Demand side management

Demand side management (DSM) provides an alternative to transmission and distribution network reinforcement.

DSM can be defined as shaping the overall consumer load profile to obtain maximum mutual benefit to the consumer and the grid and network operator.

Since legislation required electricity retailers to be separate from network operators, it has become more difficult to implement a fully integrated DSM strategy. Electricity consumers are generally no longer directly contracted to Orion. Our primary mechanism for achieving better utilisation of the assets is to signal the investment cost implications to electricity retailers in our delivery pricing structure. The derivation and application of delivery pricing is published on our website oriongroup.co.nz.

We are integrating DSM into development of our network. Some of the gains from DSM are:

- increased utilisation of the network
- improved utilisation of Transpower's transmission capacity
- consumers benefit by becoming more efficient in the utilisation of energy and network capacity
- consumer relations improve through less upward pressure on prices.

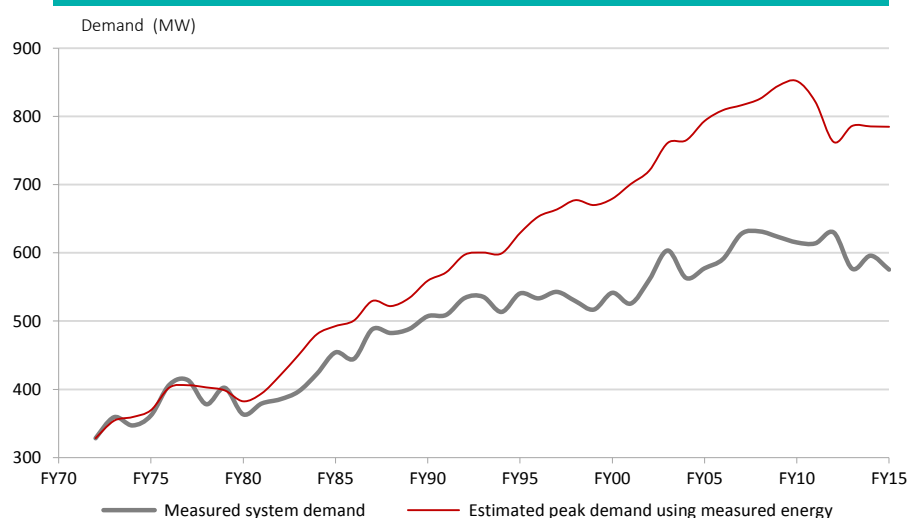
The following DSM strategies are applied by Orion:

- ripple system – anytime hot water cylinder control
- ripple system – night rate price options to spread load more evenly over the day
- ripple system – major consumer price signalling
- ripple system – interruptible irrigation
- ripple system - generation credits
- power factor correction rebate
- coordinated upper south island load management
- diesel fuelled generation.

For further detail on the potential of consumer DSM initiatives to defer or avoid investment, see section 5.6.12.

We also discuss DSM in our network documents NW70.60.10 - Demand Side Management Stage 1 – Issues & Opportunities and NW70.60.11 - Demand Side Management Stage 2 – Potential Initiatives.

Figure 5-3 Peak demand capping



Ripple control

Ripple control is one of the most effective tools available for implementing DSM. Ripple enables us to send a myriad of load control and pricing signals to our consumers. Over the last 30 years, our commitment to demand side management through hot water cylinder control and peak and night rate price signalling has resulted in a dramatic difference between the growth in peak demand and energy. The previous graph shows that significant peak demand capping occurred during the 1990s as a result of our DSM initiatives.

Since 1980 a gap of 200MW has been achieved between energy based estimated peak demand and actual peak demand. Committed utilisation of our ripple control system is thought to have been the driver for approximately 100-150MW of the 200MW gap between demand and energy. The decreased gap following the earthquakes is due to the large drop in energy delivered due to the reduction in connections supplied. There was no drop in demand for the first two years following the earthquakes due to significant snow falls in August 2011 and June 2012.

Ripple control has facilitated the implementation of the following DSM strategies:

- hot water cylinder control – 50MW of peak load deferment
- night store heating – 125MW of night load providing an estimated 50MW peak reduction
- price signalling to major consumers – 25MW (includes embedded generation)
- interruptible irrigation load groups (summer only) – 28MW during contingencies.

To ensure that we can continue to achieve these results, three 66kV ripple plants have been replaced with multiple 11kV ripple plants. 11kV ripple plants avoid overloading issues caused by an increasing number of capacitors being installed on Transpower's grid and also reduce dependence on any one item of plant.

A current issue is our dependency on ripple control receivers located at consumers' premises. Orion does not own these receivers and therefore has limited ability to control their installation and maintenance. In 2007 we modified our Network Code to make it mandatory to install ripple receivers that respond to an emergency signal.

We will continue to work with retailers and meter owners to ensure that the benefits of ripple control continue to be achievable as the implementation of new technology occurs.

Interruptible load groups – irrigation

When an interruption to supply occurs on our network, there is a cost of lost production and the inconvenience to our consumers. Our targets for reliability are based on matching the cost of an interruption to the cost of preventing one. That is, there is a point where investing further in our network is not justified by the cost saving to our consumers from reduced interruption times.

Not all consumers are exposed to the same costs when an interruption occurs. To reduce expenditure on the network and therefore control price, it can be useful to first restore supply to consumers who have a high cost of non supply, and then restore supply to those consumers with a low cost of non supply when the fault is repaired. Following consultation in 2005 with irrigation consumers, we have extended the possible duration of interruptions for irrigators up to 48 hours under extreme conditions. At the time of implementation, the ability to do this prevented the need to construct Ardlui zone substation (\$3m) and delayed several other projects (\$7m in total). The continued application of interruptible irrigation has continued to avoid and delay

further network investment over the last seven years. This has significantly reduced pressure on price rises to our consumers. We will consider the impact of the Central Plains Water scheme on the effectiveness of this arrangement. The proposed 2015/16 review of our rural network architecture will also provide an opportunity to re-examine the economics and implementation of our irrigation interruption scheme.

Power factor correction rebate

If a consumer's load has a poor power factor then our network and the transmission grid is required to deliver a higher peak load than is necessary. This may lead to the need for an upgrade.

Our Network Code requires all consumer connections to maintain a power factor of at least 0.95. During 2010 we introduced a penalty charge for consumers whose power factor falls short of the 0.95 minimum. In the Christchurch urban area where the predominately underground network is high in capacitance (which helps to improve power factor), the minimum 0.95 power factor requirement has resulted in an overall 0.99 GXP power factor at times of network peak. This is a good outcome and any further benefit from offering financial assistance to correct power factor in the urban area would be uneconomic.

However, in the rural area, the predominately overhead network is high in inductance (which reduces power factor) and we offer a financial incentive in the form of a 'power factor correction rebate' to irrigation consumers with pumping loads greater than 20kW. The rebate provides an incentive for irrigators to correct their power factor to at least 0.95. The rebate is set at a level where it is economic for the customer to provide power factor correction, which is lower than the avoided network investment cost associated with power factor related network upgrades.

Heat pump efficiency promotion

The ECAN Clean Air initiative in Christchurch has encouraged many consumers to change from solid fuel burners to electric heating. The high efficiency of heat pumps compared to resistive heating methods has lead to strong uptake of heat pumps in Christchurch. The high variability of efficiency and quality of heat pumps on the market has resulted in us taking a strong interest in the promotion of appropriate models during the initial phases of conversion.

When EECA released the new energy-star label on heat pumps we supported a promotion about 'how to choose your new heat pump'. It is envisaged that encouraging consumers to purchase high efficiency heat pumps will reduce the increase in peak demand on our network.

Coordinated Upper South Island load management

As well as controlling hot water cylinder load to manage peaks on our own network we also coordinate control of hot-water cylinders on other distributors networks to manage peaks on Transpower's Upper South Island network. We do this via a specifically designed Upper South Island load manager which communicates with Transpower and all of the Upper South Island distribution network companies. Through cooperation and the coordination of Upper South Island load control we are able to maximise the potential to reduce peaks without excessive control of hot-water cylinders.

Distributed/embedded generation

The purpose of our distribution network is to deliver bulk energy from the Transpower GXPs to consumers. In certain circumstances it can be more economic for the consumer to provide a source of energy themselves in the form of distributed generation (DG). DG may also reduce the need to extend network capacity.

Our policy (see our website) for DG provides a different treatment for different sizes of distributed generation.

In particular our policy for DG above 750kW gives consideration to the following issues:

- coincidence of DG with Transpower interconnection charges
- benefits of avoided or delayed network investment
- security of supply provided by generators as opposed to network solutions
- hours of operation permitted by resource consents
- priority order for calling on peak lopping alternatives, such as hot-water control versus DG.

Without the ability to store energy from Photovoltaic (PV) generation, it is unlikely that PV generation will reduce peak demand on our urban winter peaking network. Whereas diesel generation can reduce peak loads and so is therefore included in our peak forecast. PV generation may offer a reduction to peak demand on our rural network which is driven by summer irrigation load. There is potential for the proliferation of PV generation to cause over-voltage problems on our low voltage network. We anticipate that we will need to either reinforce some of our low voltage network to provide for PV generation or invest in PV generation management technologies to prevent over-voltage on the worst days of the year. We are currently undertaking research and analysis to better understand the capability of our low voltage network and also the likely uptake of PV generation. The conclusion of this research and analysis will enable us to estimate an appropriate budget in future AMPs.

In order for diesel generation to be effective we require a contract to ensure that peak lopping is reliably achieved. This is done through pricing structures that encourage users to control load at peak times. We will continue to encourage diesel generation through appropriate pricing mechanisms. Given the large investment and significant network constraint deferment associated

with export generators of more than 750kW, we assess them on a case-by-case basis.

We continue to proactively support the installation of diesel generation by major energy users. An incentive for major consumers to generate electricity is provided through our pricing structure which includes an avoidable control period demand charge. We estimate that approximately 15MW of generation is available on control period demand signalling. The total major customer response is about 25MW and some of that is load reduction (rather than generation). There is also a significant quantity of standby generation owned by consumers for their own use during an interruption.

Our peak load forecast assumes that an additional 2MW of peak diesel generation will be installed each year. The series of Christchurch earthquakes has led to an increase in enquiries to connect diesel generation and we anticipate a corresponding period of strong growth in the connection of diesel generation. For this to be effective in deferring network capacity, the generation capacity must be reliably available to support the network in a fault/constraint situation. In general this requires that generation be offered to operate as and when required, which in turn necessitates that fuel is able to be stored.

DG using fuel that cannot be stored does not usually substitute for network capacity unless fuel supplies are stable and reliable. Wind, PV, and run-of-river hydro are three types of generation that provide energy but do not substitute for network capacity. However, with multiple sites and diversity in fuel characteristics, some certainty of availability can be determined through analysis of historic data.

We have resource consents to install a total of 23MW of generation capacity split between sites at Bromley and Belfast. Generation at the Belfast site has the potential to defer investment in a new zone substation at Marshland. The recent Christchurch earthquakes have resulted in significant damage to our 66kV subtransmission network feeding the Christchurch north eastern suburbs. To provide alternative capacity in the area, we have recently installed two 2MW diesel fuelled generators for short term placement at QE2. We will consider relocating these generators to Belfast in the future to defer investment in the Marshland zone substation and general 11kV reinforcement in the area.

Justification for installing generation at the Bromley site will require either an energy-firming contract with an electricity market retailer or suitable market arrangements to reward us for relieving transmission constraints between Twizel and Christchurch. Depending on the nature and duration of any contract, this generation may also provide alternative investment options for our distribution network.

Without creating an 'at arms-length' business, our potential involvement in large scale generation projects is limited by the Electricity Industry Act 2010 to 50MW for embedded generation within the distribution network or 250MW for grid connected generation.

Uneconomic connections policy

When an application for a new or upgraded connection (larger connections only) is submitted for review, we undertake an economic assessment of the connection. This assessment determines whether or not our standard pricing arrangements will cover the cost of utilising existing or new assets associated with the connection. If the connection is uneconomic (i.e. existing consumers would be subsidising the new connection) then a connection contribution is required from the new consumer.

This policy ensures that the true cost of providing supply is passed on to the appropriate consumer and thereby allows them to make the right financial trade-offs. If an economic non-network alternative is available then that option can be chosen.

5.4 Energy, demand and growth

To effectively plan the future of our network, we need to estimate the size and location of future loads. Long-term growth in energy consumption showed a consistent trend until the major earthquakes in FY11. This trend provides a first estimate of load growth both for the full network, and for specific areas within. However any load forecasting is an approximation—load cannot be forecast with 100% accuracy. There is some uncertainty due to the drop in peak demand and energy consumption from a population decrease (particularly in the east of the city), timing of the commercial rebuild in central Christchurch and increased electricity use for space heating in homes with damaged insulation and removal of solid fuel burners in damaged houses.

Energy and demand growth is a function of many inputs. Network development is driven by growth in peak demand (not energy); therefore we focus on demand growth rather than energy. In general, two factors affect load growth:

- population increases
- changes in population behaviour.

At a national level, it is reasonably easy to forecast population growth. When the national forecast is broken down to regional level, the accuracy is less reliable but still useful in predicting future demand growth.

Many variables affect behavioural change. These include technological advancements, available energy options and requirements such as Environment Canterbury's Clean Air Plan (CAP). It is difficult to forecast these variables accurately. As well as these variables, our DSM strategies shape our peak demand load forecast.

As a high level of accuracy is required to build an appropriate electricity distribution network, we treat load forecasts as a guide. A major 66kV or 33kV network development project takes approximately three years to plan, design and build, while smaller 11kV projects take around 18 months. A 400V solution can take several months. In this context it is prudent to apply flexibility in how we implement our network development proposals, rather than rigidly adhere to a project schedule based on an outdated forecast.

We derive our load forecast from a combination of bottom-up inputs, such as household growth forecasts by CCC using the 2013 Census and the December 2013 Land Use Recovery Plan (LURP) prepared for CERA, and historical trends in growth. These are adjusted to reflect significant inputs such as milk processing plant upgrades and DSM initiatives.

The following sections summarise our key load forecasting inputs.

Earthquake February 2011

The February earthquake reduced energy delivery volumes by approximately 10%. Recent energy consumption suggests that energy volumes have recovered a little but are currently stable around 7% below pre quake level. It is too early to draw any conclusions, as the post quake years have included an extreme cold snap (2011) and record mild winters in 2013 and 2014.

Projecting on-going recovery post-earthquake is difficult. For post-quake population projections we are using March 2013 Census data and census area unit projections provided by CCC based on the Land Use Recovery Plan developed for CERA. The post-quake Census information increases forecast confidence, however more than usual uncertainty remains. Contributing factors are the temporary workforce associated with the rebuild and the changing household composition due to residential repairs and housing market constraints.

Impact of economic downturn

Peak demand on our network varies depending on the harshness of the winter weather. Peak demand had not grown since the high peak reached during the 2006 winter snow storm. The pre-earthquake 2010 peak was only 2% above the 2002 winter snow storm peak. The potential impact of the pre-earthquake economic downturn has been somewhat superseded by the earthquake recovery phase. Our underlying growth forecasts are linked (via the Urban Development Strategy and LURP) to Statistics New Zealand population projections. The economic environment can affect network construction costs and we monitor these costs on an annual basis to capture the impact of the economic environment on commodity prices.

Impact of DSM on load forecast

Our DSM strategies discussed in section 5.3.5 impact on our peak load forecast. Our network peak demand forecast assumes that 2MW of DG will be added to our network each year. This is commensurate with growth in DG over the last five years. Because it is difficult to predict the location of new DG, we have not attempted to apply the growth in DG to the zone substation load forecasts. Instead we attempt to encourage DG in constrained areas on our network by publishing the area specific network deferral value of DSM initiatives (see section 5.6.12). In reality, customer investment in DG is usually driven by their own security of supply objectives and the benefits to our network are secondary to the overall business case.

The impact of other DSM initiatives such as price signalling, night rate tariffs and hot water cylinder control is captured in the underlying inputs to our load forecast. For example, we monitor the after diversity maximum demand (ADMD) of new households and apply this figure to the projected number of subdivision lots for an area to determine a forecast which includes the impact of our DSM initiatives.

At the 11kV feeder level, and despite the increased size of households and the increased uptake of electrical appliances and heat pumps, the ADMD has only grown by 0.5kW to around 3.5kW per household. This process is applied to our subtransmission

forecasts for both new subdivisions and urban infill (3kW per infill household). A similar process is also applied on a per hectare basis for industrial subdivisions but we recognise that specific consumer requirements can cause a significant variance from the average case.

This process is described in NW70.60.12 - Long term load forecasting methodology for subtransmission and zone substations. See also section 5.4.2 - Methodology for determining GXP and zone substation load forecasts.

5.4.1 Observed and extrapolated/forecast load growth

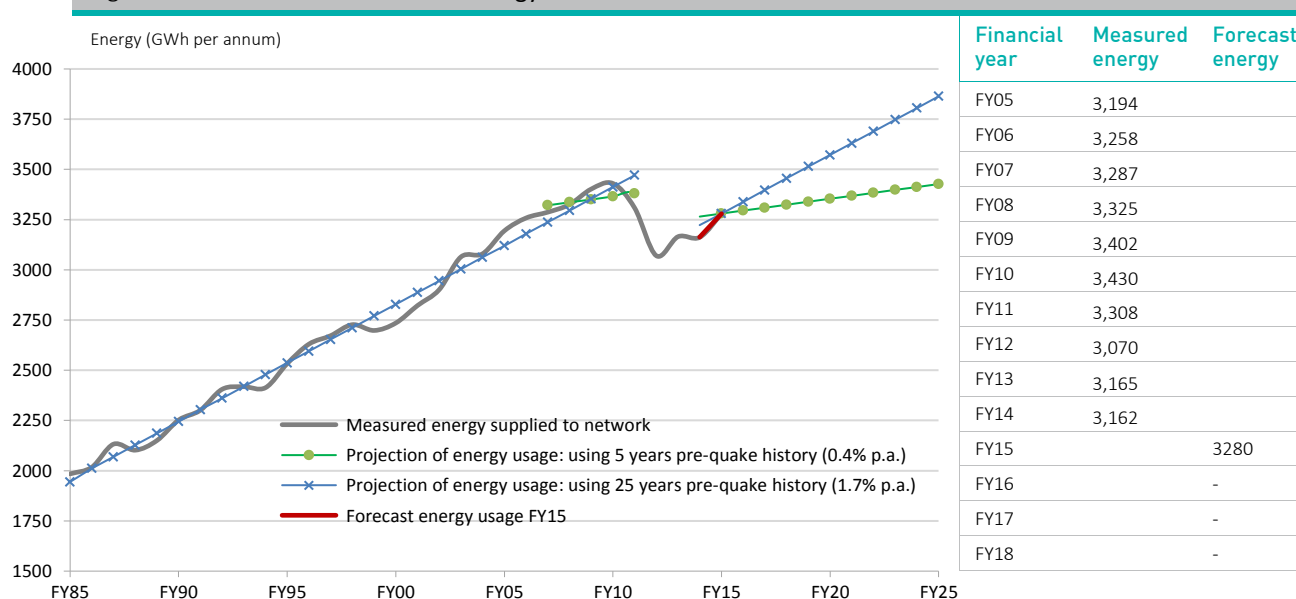
Energy throughput (GWh)

Network energy throughput for FY14 was 3,162GWh (including export from distributed generation of about 5GWh), down 0.1% on the previous year.

The 25-year pre-earthquake history shows an average steady growth rate of about 1.8% each year. For the five years prior to the earthquakes, energy growth was lower than the long term average at 1.4%. Environment Canterbury's CAP has had only a modest impact on energy use, as surveys suggest that the high conversion rates of solid fuel burners to heat pumps has been balanced in part by consumers switching from resistive heating to higher efficiency heat pumps. The economic downturn and closure of several major customers had led to a slowing in energy growth prior to the earthquakes. The future trend is unclear.

We have observed a downward step change in energy demand as a result of the February 2011 earthquake. While there has been some recovery, demolition work in the Central City and planned demolition in the east is significantly affecting volumes in those areas. Longer term, we expect the new business and residential buildings will be more energy efficient than the older buildings they replace, and the CERA Central City Recovery plan also implies fewer, much smaller rebuilds. Energy volumes started trending up in 2012, then a particularly mild 2013 winter lowered usage for FY14. FY15 also had a very mild winter, but then a dry summer led to high irrigation load. The medium term view is very uncertain. Figure 5-4a shows the projections of short and long term pre-quake growth rates.

Figure 5-4a Orion network annual energy trends



Maximum demand

Maximum demand is the major driver of investment in our network. This measure is very volatile and normally varies by up to 10% depending on winter weather. In 2011 the July snowstorm increased the peak by 7%. After the August 2011 snowstorm the peak increased by a further 10%. Because our network demand peaks during the winter, we can publish the FY15 peak in this AMP.

Our network maximum half hour demand, based on load through the Transpower GXP, for FY15 was 575MW (the peak that occurred on 21 July 2014), down 21MW from the previous year. Note that although the maximum (as per agreed service levels) duration of hot water control was applied on 14 August (indicating the load management network limit was optimally set at 575MW) there was only 83% of maximum load shedding capability applied during the 21 July peak. Note that these figures exclude temporary excursions that show up in regulatory disclosure data which are not used for forecasting demand.

Forecasting peak demand at the moment has challenges (on top of the earthquakes) including uncertainties with the global economy and unprecedented applications for embedded generation. Prior to the earthquakes, the long and short term trends showed a demand growth rate of just under 1% per annum. It is not yet clear whether this rate has slowed recently, as the changes are much smaller than the 60MW (10%) variation due to weather. The following Figure 5-4b of historic network demand also includes three forecasts:

- **Forecast system demand (with and without electric vehicles)**

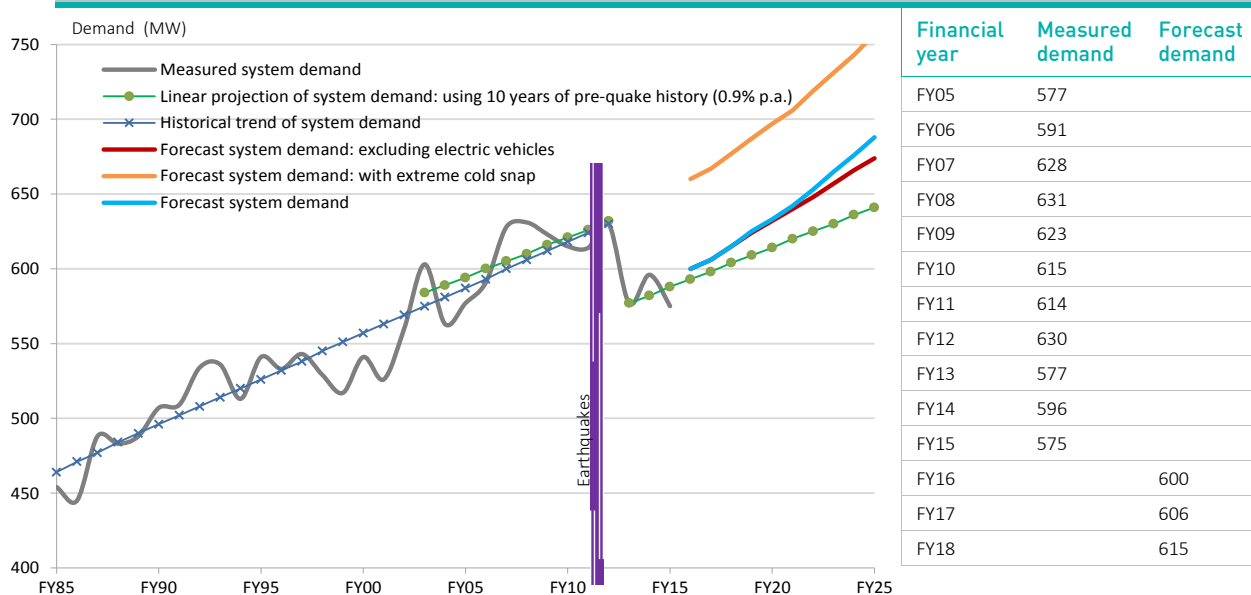
These two forecasts are based on underlying residential growth and industrial uptake models. We have also added an electric vehicle scenario to our forecast demand which assumes that 17% (fast uptake scenario) of households will have an electric vehicle by 2024 and 20% of these vehicles will be charged at peak. Note that the electric vehicle forecast is provided to indicate the effect of electric vehicles only. The accuracy of this forecast will improve over time. Night time charging reduces the impact to the network and provides cost savings for consumers. Network reinforcement included in this AMP is designed to ensure that nominal and security of supply capacity is provided for in this peak demand forecast. The above average increase in the medium term is due to the forecast increase in residential population from the LURP.

- **Potential extreme cold snap peak**

This forecast is based on events similar to those in 2002 (when a severe cold-snap changed consumer behaviour and we experienced a loss of diversity between consumer types) and in 2011 when a substantial snowstorm on 15th August changed consumer behaviour. Despite having no CBD and fewer consumers in the eastern suburbs, we experienced extraordinary loads on 17 August as some schools and businesses reopened after being closed for two days while others remained closed for a third day. This led to very high loads as we experienced a loss of diversity between consumer types. There was significant demand from residential consumers due to some schools and businesses remaining closed, while there was also significant demand from businesses that restarted after several days without operation.

When planning our network, it is not appropriate to install infrastructure to maintain security of supply during a peak that may occur for two or three hours once every 10 years. This forecast is therefore used to determine nominal capacity requirements of our network only.

Figure 5-4b Overall maximum demand trends on the Orion network



Load factor

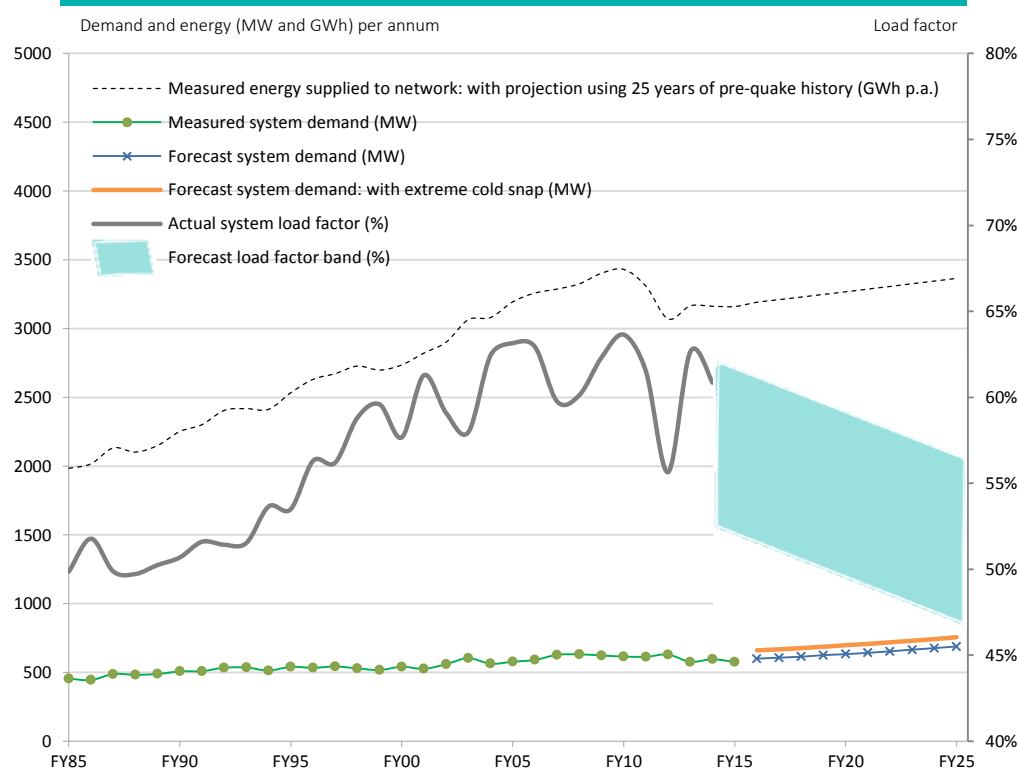
Overall system utilisation

Overall network utilisation is indicated by the system annual load factor (defined as the ratio of average to peak demand). The peak used in this calculation is based on the maximum demand which as noted in the previous section excludes temporary excursions that are not used for forecasting demand.

Orion's annual system load factor had generally improved for 25 years, with significant variations as vagaries in our weather influenced maximum demands. This has plateaued recently and for FY14 the load factor was 61%, down 2% on the previous year. Improvements in load factor had come from increased off-peak loads (irrigation, milk processing plants and summer air conditioning), combined with effective control of winter peak loads through price signalling and encouraging alternative fuel use for on-peak heating. Winters with extreme cold weather such as snow in June 2006 and August 2011 often lead to lower load factors due to the very high peak load.

The impact on load factor from the anticipated reduction of irrigation load is expected to be offset by the Central city rebuild. The uncertainty around the rate of growth in household numbers post-quake and the even greater variability of extreme cold weather leads to a band for possible future load factor. This suggests that load factor may decline from the recent peaks of around 60% to 65%. FY15 is expected to be higher than FY14 due to subdued peaks during winter 2014.

Figure 5-4c System load factor



Load duration

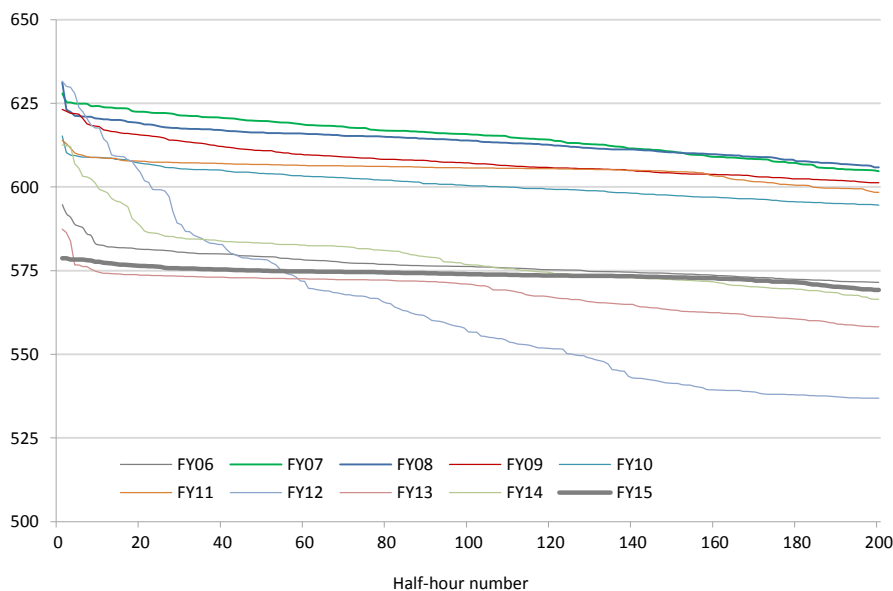
With constantly changing load on our network, the peak demands that determine network capacity generally only occur for very short periods in the year. The following graph shows the load duration curves of our 200 peak half hour demands on Transpower's network over 10 years. The graph shows that demand side management has been successful in flattening the curve in recent years. FY12 is unusual in that consumer demand was reduced due to the earthquakes, but then new peaks were created with the July 2011 snowstorm, followed by extraordinary load due to another snowstorm in August. In the six years prior, an increase in demand side management for 10 hours each year would have reduced our network peak demand by around 10MW. During winter 2012 just 1.5 hours DSM (on the afternoon of 6 June snow) would have been sufficient to reduce the winter peak by 10MW. It is difficult to pick the time to utilise DSM to target these few hours when the curve is so flat. To reduce the peak by a further 10MW would require over 130 hours of DSM in these years. However, extreme weather conditions (as mentioned below) give an on-going incentive for DSM.

The Transpower grid requires sufficient capacity to meet load during extreme weather conditions that may last for only a few hours. Peaking generation can help delay the need for increases in Transpower's network capacity. In the 2011 winter, 30MW of peaking generation, operating for about 20 hours would have reduced our urban network maximum demand by about 30MW. Winter 2013 was similar where about 10 hours of peaking generation could have reduced the peak by 25MW. The 20/21 June storm accounted for eight hours, during which one of the our new 2MW generators located temporarily at QE2 was run to reduce the peak and support hot water service levels. In unusually prolonged cold conditions longer hours of operation might be needed. Winter 2014 stands out as being flat because the absence of very cold weather made managing to our load management limits easier to achieve.

Generation may also be used to reduce Transpower's charges. If used for this purpose, longer hours of operation might be needed, especially to avoid reductions in water heating service levels.

Control of the dominant winter maximum demands depends heavily on suitable price signals, and consumers' response to them. If this is to continue to be effective then it is important that electricity retailers continue to support demand side management initiatives. Of particular importance is the promotion of night-rate tariffs and load control via the on-going installation and maintenance of ripple receivers.

Figure 5-4d Christchurch urban area network – load duration curves



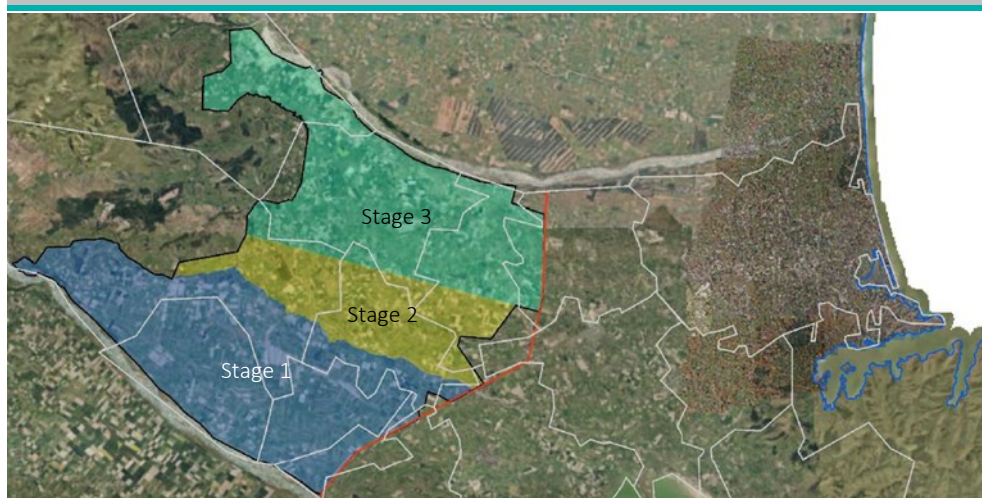
Rural load growth

In contrast to our urban area, growth rates for our summer peaking rural areas have been high over the last 10 years.

Since FY02, consumer applications to connect new load to our rural network have been reasonably consistent. However, the yearly variations in weather and in particular low summer rainfall resulted in an increase of 8 to 12MW during the summers of FY04, FY08 and FY12. This demonstrates how variable peak loads can be, and how weather dependent they are – a dry summer on the Canterbury plains causes an increase in peak demand as irrigation is required simultaneously across a large area.

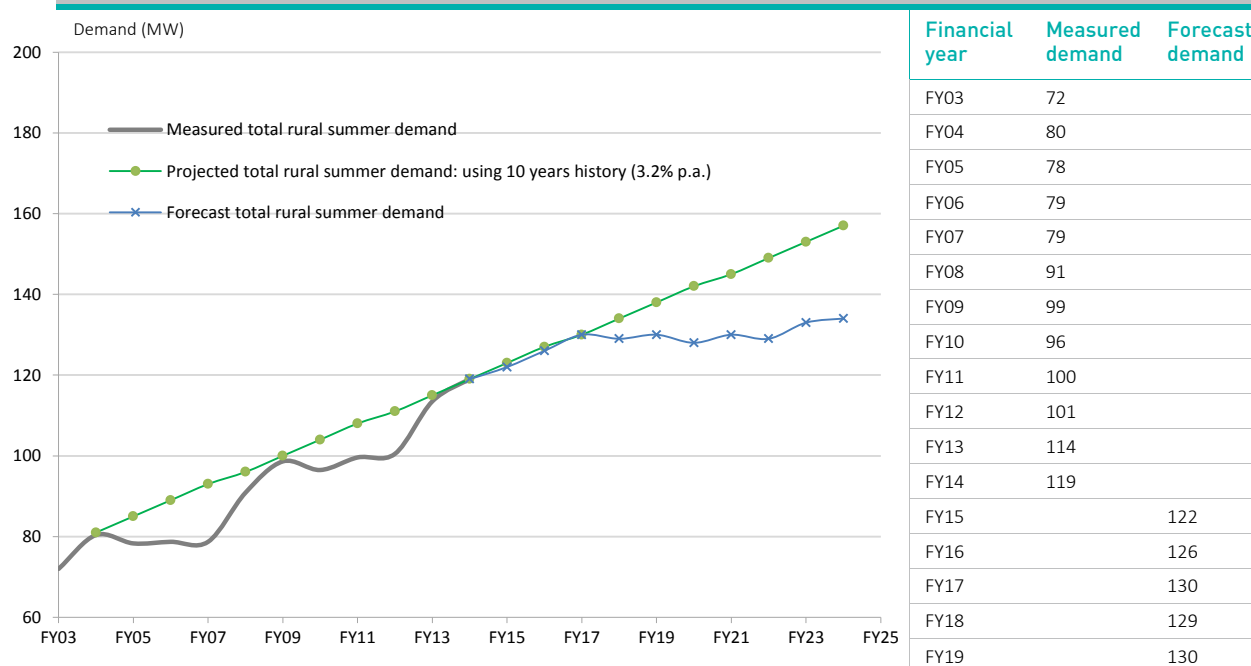
The Central Plains Water Scheme (CPW) reached the required subscription threshold late in 2013, and in March 2014 awarded contracts to commence stage 1 supplying 20,000Ha between Rakaia and Hororata rivers, inland from SH1. Restrictions due to ground water availability and nutrient leaching will restrict irrigation load growth. Increased surface water irrigation within the scheme however will allow irrigation load growth between the scheme and the coast due to greater ground water recharge. Within the CPW area, conversion of existing ground water pumps to the pressurised CPW scheme is forecast to substantially reduce summer power load on five zone substations and the Hororata GXP.

Figure 5-4e Central Plains Water scheme stages



The following graph shows recent summer load growth in our rural area. FY13 was a good indication of a dry summer. FY14 irrigation demand was subdued due to rain events during the summer months. This was offset by Fonterra adding a second drier to their plant near Darfield.

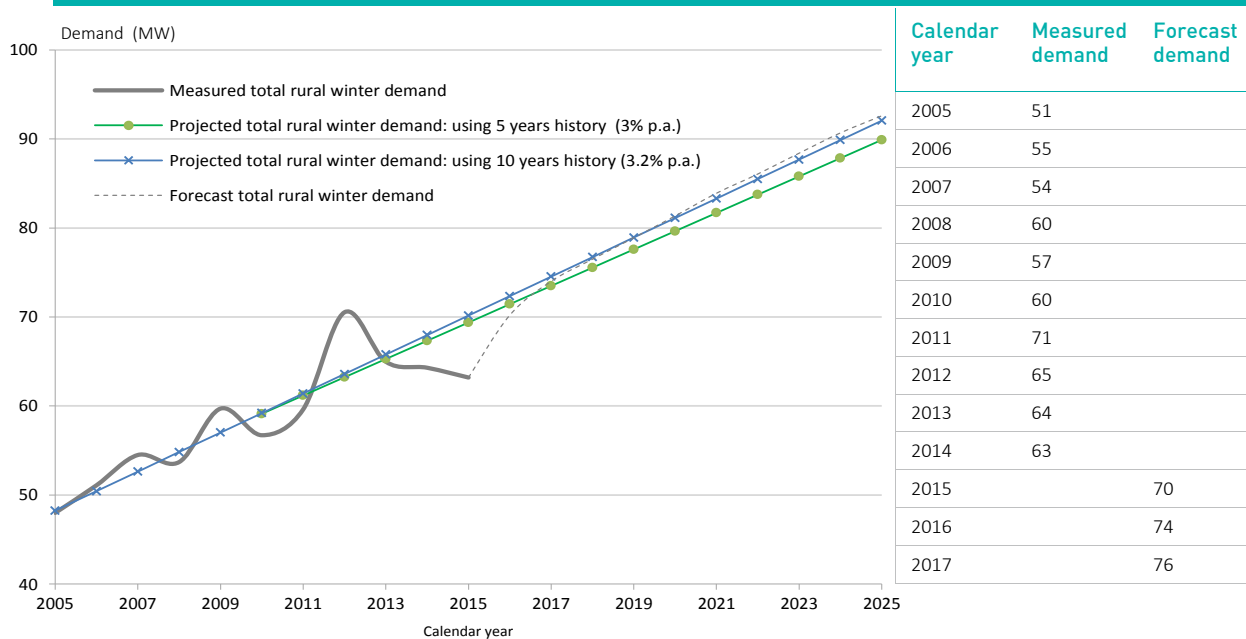
Figure 5-4f Rural summer maximum demand (MW)



Approximately 80% (20MVA) of the forecast increase in rural peak demand over the next 10 years is due to the increase in milk processing capability. The existing milk processing load is around 18MVA.

Rural winter load growth has been steady at just over 3% per annum over the last 10 years. The 2011 peak is due to a significant August snowstorm. The 2014 peak was low due to a mild winter. The recent Urban Development Strategy (UDS) indicates that significant growth is expected to continue around Rolleston and Lincoln townships. We forecast winter rural load growth to average between 3% and 4% per year over the next 10 years.

Figure 5-4g Rural winter maximum demand (MW) graph



5.4.2 Methodology for determining GXP and zone substation load forecasts

We estimate that future demand growth will increase from 1.0% (6MW) to 1.7% (11MW) per annum over the next 10 years. Significant volatility can be expected in actual maximum demands, with 10% variation depending on winter weather. Capital investment plans will be modified each year in accordance with load growth that has actually been observed.

The following sections describe some of the factors and methodologies used to estimate the quantity and location of load growth. We forecast growth at zone substation level and translate this up to Transpower GXPs and finally to a total network demand forecast. This total network forecast is higher than the linear projection shown in section 5.4.1 due to the population increase given in the LURP projections.

This process is described in NW70.60.12 - Long term load forecasting methodology for subtransmission and zone substations.

Territorial local authority planning

Our network spans two territorial authority areas; Christchurch City and Selwyn District. Both territorial authorities publish useful area planning information and we use this extensively to plan for growth on our distribution network.

In addition to individual territorial plans, an urban development strategy (UDS) group was formed in 2004 for the greater Christchurch region. The intention was to develop a sustainable long term strategy for growth in the greater Christchurch region. A draft UDS was released in November 2006 and hearings were held in February and March 2007. A modified UDS has been approved for implementation and the impact of this is also reflected in ECAN's Regional Policy Statement (RPS).

The UDS proposes a greater level of infill development in central Christchurch and encourages growth at Rolleston and Lincoln townships. Because consolidated areas of growth are less costly to service than sparse development, it is expected that the UDS outcome will lead to lower than otherwise costs for our consumers.

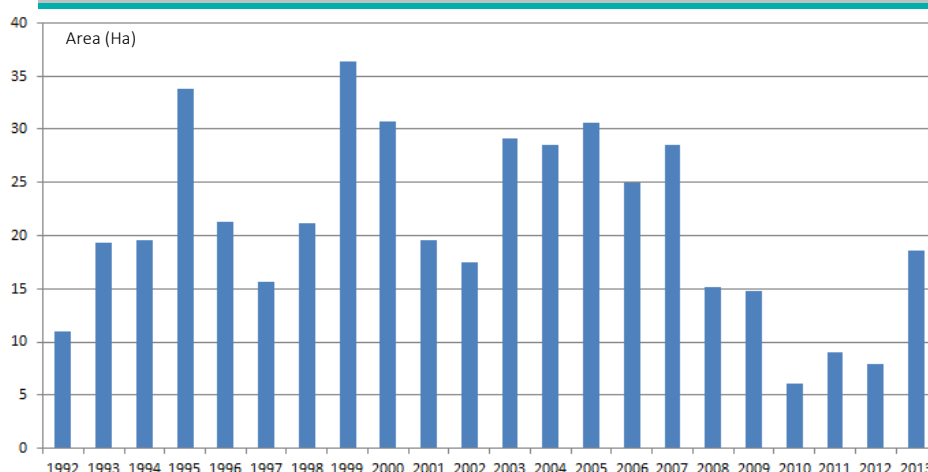
The UDS forecasts the growth in household numbers by defined areas. The UDS was an important input into CERA's land use recovery plan (LURP). CCC used the LURP to develop household growth numbers by census area unit. Further refinement of this data and industrial forecasting is described in the following sections.

Christchurch City

The Christchurch City Council (CCC) reports on vacant land on an annual basis. With the advent of the UDS, the CCC also forecasts yearly household growth by census area unit to 2041. To forecast the growth in residential demand in the CCC area, we map each of the area units to one or more zone substations in our model. The CCC have provided a post-earthquake update using 2013 census data as described in section 5.4.

To forecast industrial growth we utilise the CCC industrial vacant land reports to identify areas developed and zoned for potential growth. We utilise historic uptake rates and market judgement to allocate 20 to 25Ha of growth per annum to the different areas of available land. These allocations are mapped in our model to a zone substation with a forecast load density of 130kW per hectare. The following figure 5-4h shows how the uptake has been affected by the economic slow down and earthquakes.

Figure 5-4h Take-up of vacant industrial land



Finally, we utilise the CCC land zone maps to determine the areas suitable for commercial/industrial infill growth. This part of our forecast is a relatively discretionary process and is heavily dependent on the swings of the commercial development market.

In summary, recognising that earthquakes have largely destroyed the CBD, the UDS/LURP proposal is expected, in the medium term, to increase residential infill within the Central city and areas around the shopping malls. CCC's District Plan review is proposing to achieve this by introducing Medium Density Residential zones and Suburban Density Transition. This information is not yet included in CCC supplied data as they are awaiting the conclusion of the consultation/hearing process. In the short term, major subdivision growth is planned for Wigram, Halswell, Belfast, Yaldhurst and Marshland. Industrial development is expected to mainly continue in Hornby, Islington, Wigram, Woolston and Airport areas in the short term and in Belfast in the medium term. The Canterbury earthquakes and subsequent development of red zones is accelerating growth in some areas.

Selwyn District

Most of our zone substations within Selwyn District are required to meet irrigation load and predominately have their peak load in summer. However significant residential growth has occurred around Rolleston and Lincoln zone substations and these substations have their peak load in winter. As with the CCC, we utilise the LURP/UDS/Selwyn household growth projections informed by the 2013 Census to forecast residential growth in the greater Selwyn region.

The Izone industrial park at Rolleston has also experienced significant growth in recent times and we have recently completed a major upgrade in the area.

Growth drivers and forecasting uncertainty

Our network feeds both high density Christchurch City loads and diverse rural loads on the Canterbury plains and Banks Peninsula. Growth in electricity consumption can occur from an increase in population and also the introduction of new end use applications. Growth in electricity consumption in the city and on Banks Peninsula has historically matched growth in population (holiday population for Banks Peninsula). Conversely, electricity growth on the Canterbury plains has not matched population growth but has been driven by changes in land use and hence changes in electricity use.

Winter peak demand on our network is mainly driven by growth in the city and is anticipated to increase by approximately 80MW (13%) over the next 10 years. Our rural network peaks in the summer and it is anticipated to increase by approximately 15MW (12%) in the next 10 years, with most of this over the next two years.

The following main issues need to be considered when managing growth:

- sufficient time to procure zone substation land and/or negotiate circuit routes (typically one or two years)
- sufficient time for detailed design (typically one year)
- contractor resources managed via a consistent work flow.

The network development projects listed in this ten year plan seek to ensure that capacity and security of supply can be maintained for the growth rates described above. Actual growth rates are monitored on an annual basis and any change would be reflected in next year's development plan.

As well as the impact of the earthquake, there are two other factors that may result in actual demand varying from forecast demand:

1. Clean Air Plan (CAP)

The ECAN CAP largely bans the use of open fires and non-complying solid fuel burners in developed areas. The CAP is being implemented in the context of a national air quality compliance strategy which was published in August 2011 and states maximum levels of PM10 permissible in 2016 and 2020. During 2010, open fires and non-complying burners were prohibited in Christchurch. The impact of this change on electricity demand appears to be minimal at this stage. To meet the national air quality standard it was estimated that 42,000 households would need to convert to clean air heating.

Prior to the earthquakes ECAN had completed more than 20,000 assisted conversions, of which about 60% had used heat pumps. Others had occurred outside the ECAN clean heat program, and statistics on these are difficult to obtain. By 30th June 2014 Fletcher EQR had completed 10,453 (conversions to heat pumps and 5,729 to compliant solid fuel as part of the response to earthquake damage. The rate of conversions has flattened off. The following table shows totals for various components of EQRs heating restoration.

Survey evidence in 2009 indicates that the impact of heat pumps and the supporting insulation program may not lead to an increase in peak demand.

Generally the additional CAP load is spread around the city, although it is slightly more concentrated in the older established suburbs. During early conversions we used the ECAN 'clean air appliance installation' database to monitor the uptake of new heat pump load.

It is difficult to separate out the impact of heat pump installations from underlying high growth associated with a period of strong domestic growth. We have not seen a measurable increase in peak demand on our distribution transformers. A sample of nearly 1,500 houses from the ECAN clean heat programme with installations carried out between 2003 and 2007 indicates there is little further increase to peak demand expected from conversions. Approximately 800 of this sample were converted to heat pumps and show 0.2kW ADMD higher than the average (which include ~300 solid fuel, ~275 pellet and 50 gas).

ECAN are considering making changes to the Air Plan for Christchurch. If the 2016 National Environmental PM10 target of having only three high pollution nights a year is not met, they may phase out the use of all wood burners other than ultra-low emitting wood burners and pellet fires. As at July 2014 there are no ultra-low emission wood burners on the market, and 12 high pollution nights for 2014. We will consider the uncertainty of any potential impact from this Air Plan change in relation to the timing for the proposed Marshland zone substation.

Table 5-4a Fletcher EQC response to restoring heating

Heating Type	Number installed
Gas fire	286
Heat pump	10,453
Log burner	5,258
Night-store	148
Pellet Fire	185
Repair Gas fire	523
Repair Heat pump	314
Repair Log burner	1,512
Repair Pellet fire	396
Grand Total	19,075

2. Development of irrigation load

Orion has experienced rapid growth in summer irrigation load on the Canterbury plains. In order to meet this growing load, substantial investment has been needed in our subtransmission and distribution networks.

We closely monitor trends in rural irrigation. Some factors now influencing planning for irrigation load are:

- ECAN constraints on groundwater extraction
- land in some areas is approaching its full irrigation potential
- interruptible load arrangements to cover short term fault situations

- design and implementation of the CPW irrigation scheme. Construction of Stage 1 commenced in 2014. Given the potential for a significant change to rural peak demand, we are working closely with CPW regarding the detail of future stages planned through to 2019
- Trustpower's potential to install up to 70MW of hydro generation from Coleridge along the north bank of the Rakaia River to its gorge.

The proposed CPW irrigation scheme is likely to change irrigation in the affected area from ground water extraction to pumping from a canal into a piped network delivering on-farm pressure. This gives rise to the medium term potential for stranded assets in the Darfield and Te Piri regions, and downward pressure on total energy delivered. A balance of capacity, security and reliability is required while ensuring that our expectations, and those of our rural consumers, are met.

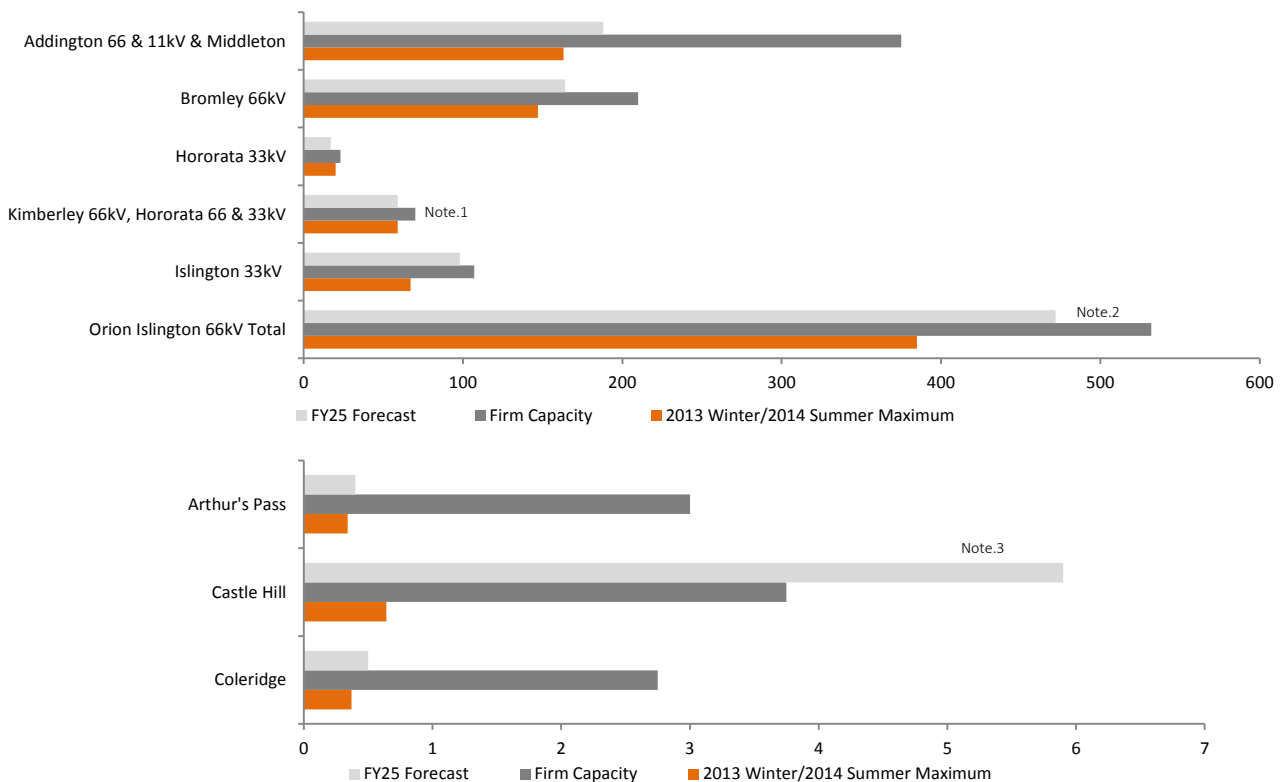
Over the next 10 years, milk processing plants are anticipated to be responsible for approximately 20MW of summer peak growth. However, this growth is expected to be offset by a reduction of approximately 20MW due to the CPW irrigation scheme reducing ground water pumping. This analysis includes the results of a 2014 Aqualinc study of the impact of likely irrigation changes, and development by Westland Milk, Synlait and Fonterra. The timing/demand changes due to the CPW scheme proceeding causes significant uncertainty in this forecast. For this reason we are cautious about our development plans to ensure that we do not install assets that may later become under utilised.

5.4.3 Transpower GXP load forecasts

The forecasts in the following sections have incorporated the impact of the earthquakes, including returning loads to their normal supply points. However there is more uncertainty than usual due to the influx of temporary workers for the rebuild that is expected to last more than five years.

The following graph indicates the capacity of each Transpower GXP that supplies our network. Present and expected 10 year maximum demands are also shown. **Please note** the impact of projects incorporated in this plan is **NOT** reflected in the GXP load forecasts. The tabled loads are those expected if no development work is undertaken. Firm capacity is the capacity of each site should one item of plant fail. See section 5.2.1 for a map of Transpower's system.

Figure 5-4i GXPs – Maximum demand versus firm capacity



Notes:

1. Can be limited to 40MW capacity when Coleridge is not generating or providing reactive support.
2. Assumes only 32% of Mainpower's load is fed from Islington post Islington T6 contingency.
3. Possible upgrade required for the proposed alpine village and winter sports resort near Porters Pass.

MVA

Table 5-4b GXP substations – load forecasts (MVA)

GXP substation	Firm capacity	Winter 2013 / Summer 2013/14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Addington 66 & 11kV & Middleton	375	163	162	164	167	169	172	174	176	179	181	184	188
Bromley 66kV	210	147	145	145	145	146	147	148	150	153	156	159	164
Islington 33kV	107	67	68	71	74	77	80	83	86	88	91	94	98
Orion Islington 66kV	532	385	383	388	395	403	411	419	427	437	448	458	472
Hororata 33kV	23	20	22	22	22	21	17	17	16	16	16	16	17
Kimberley 66kV, Hororata 66 & 33kV	70*	20	61	64	64	62	60	58	58	57	58	59	59

* Assumes full generating capacity available from Coleridge.

5.4.4 Orion urban zone substation load forecasts

The following two graphs compare the firm capacity of each of our urban zone substations with present and forecast load. The winter 2013 value is the peak load recorded June 2013.

Figure 5-4j Urban 66 and 33kV zone substations – maximum demand versus firm capacity

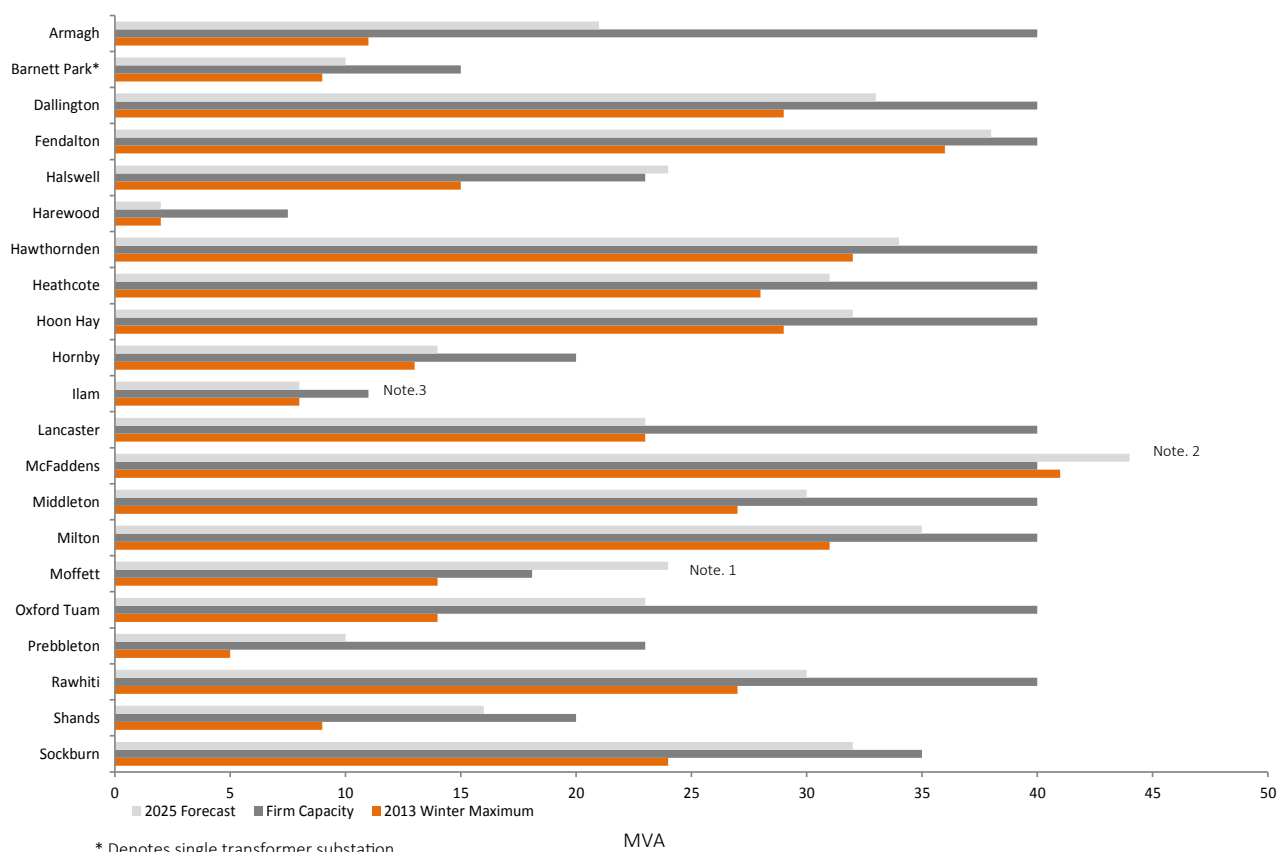


Figure 5-4k Urban 11kV zone substations – maximum demand versus firm capacity

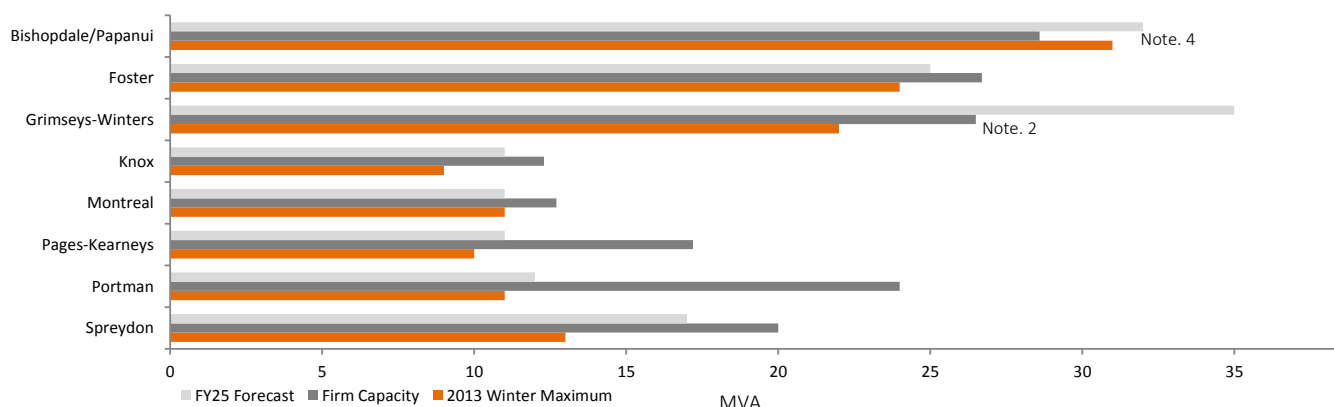


Table 5-4c Urban 66 and 33kV zone substations – load forecasts (MVA)

Zone substation	Security Standard class	Firm capacity	Actual winter 2013	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Armagh	C1	40	11	11	12	13	14	15	16	17	18	19	20	21
Barnett Park	C4	15	9	9	9	9	9	9	9	9	10	10	10	10
Dallington	C2	40	29	29	29	30	30	30	31	31	32	32	33	33
Fendalton	C2	40	36	36	36	36	36	36	37	37	37	38	38	38
Halswell	C4	23	15	15	15	15	16	17	17	19	20	22	23	24
Harewood	C4	7.5	2	2	2	2	2	2	2	2	2	2	2	2
Hawthornden	C2	40	32	32	32	32	32	32	33	33	33	33	34	34
Heathcote	C2	40	28	28	28	28	29	29	30	30	31	31	31	31
Hoon Hay	C2	40	29	29	29	29	29	29	29	30	31	31	32	32
Hornby	C4	20	13	13	13	13	13	14	14	14	14	14	14	14
Ilam	C4	11	8	7	7	8	8	8	8	8	8	8	8	8
Lancaster	C1	40	23	22	22	22	23	23	23	23	23	23	23	23
McFaddens	C2	40	41	40	40	41	41	41	42	42	43	43	44	44
Middleton	C2	40	27	27	27	27	28	28	28	29	29	29	29	30
Milton	C2	40	31	32	33	33	33	33	34	34	34	34	35	35
Moffett	C2	18.1	14	16	17	18	18	19	20	21	22	22	23	24
Oxford-Tuam	C1	40	14	14	17	18	18	19	19	20	21	22	22	23
Prebbleton	C4	23	5	6	6	7	7	8	8	9	9	9	10	10
Rawhiti	C2	40	27	27	27	27	27	27	27	28	28	29	29	30
Shands	C4	20	9	10	11	11	12	12	13	13	14	15	16	16
Sockburn	C2	35	24	25	25	26	27	28	29	30	30	31	31	32

Table 5-4d Urban 11kV zone substations – load forecasts (MVA)

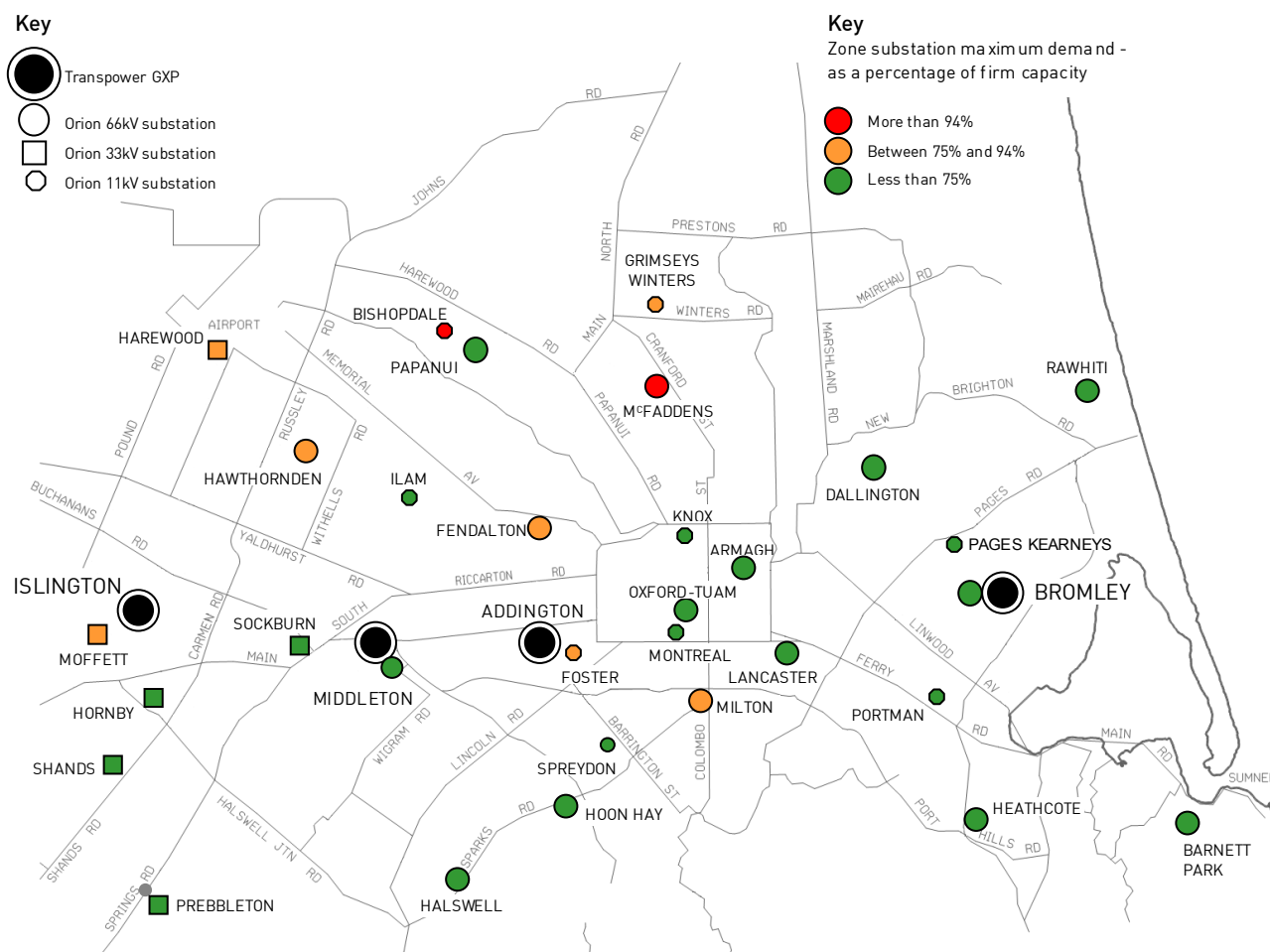
Zone substation	Security Standard class	Firm capacity	Actual winter 2013	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Bishopdale/Papanui	C2	28.6	31	30	30	30	30	31	31	31	32	32	32	32
Foster	C2	26.7	24	24	24	24	24	24	24	24	25	25	25	25
Grimseys-Winters	C2	26.5	22	22	23	25	26	27	29	30	32	33	35	35
Knox	C3	12.3	9	9	9	9	9	9	9	10	10	11	11	11
Montreal	C3	12.7	11	11	11	11	11	11	11	11	11	11	11	11
Pages-Kearneys	C4	17.2	10	10	10	10	10	10	10	10	11	11	11	11
Portman	C4	24	11	11	11	11	11	11	11	11	11	11	12	12
Spreydon	C4	20	13	13	13	14	14	15	15	15	16	16	17	17

See section 5.3.1 for Security Standard Class definitions

The following urban geographical map has been produced to demonstrate areas of high and moderate loading on our network. Substations with load exceeding 94% of firm capacity have been coloured red.

The changes from the previous year were; Bishopdale moved over the 94% threshold and Knox dropped below the 75% threshold.

Figure 5-4I Zone substations – urban (2013 maximum demand as a percentage of firm capacity)

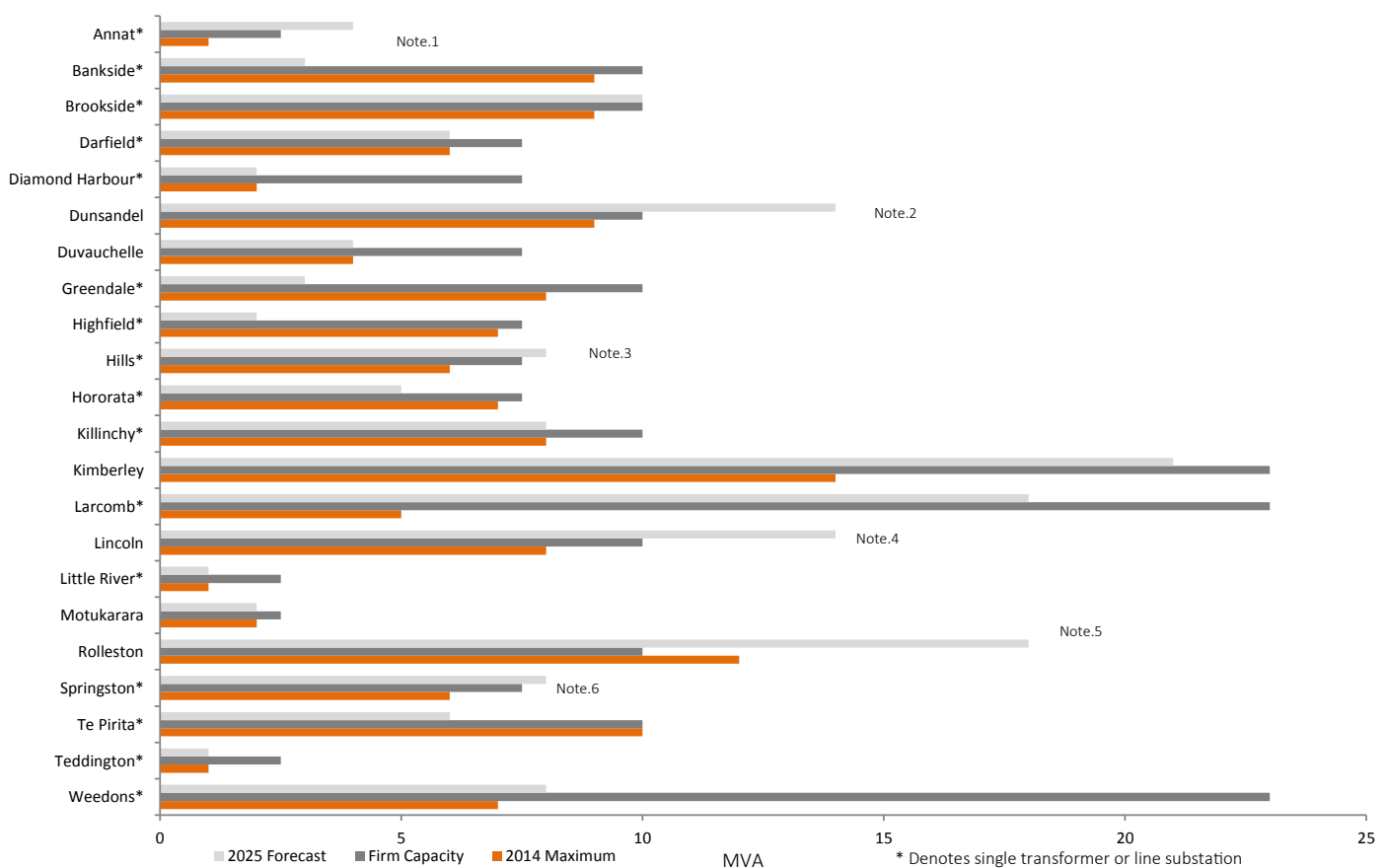


5.4.5 Orion rural zone substation load forecasts

The following graph compares the firm capacity of each of our rural zone substations with present load and forecast load. The 2013 maximum value is the peak load recorded over summer 2012/13, or in June 2013 for winter peaking substations.

A 2014 Aqualinc study on irrigation projections and the CPW scheme indicates that over Orion's rural network, CPW pumps could add nearly 10MVA but associated conversion from ground water to surface water irrigation could reduce load by nearly 30MVA. This net 20MVA decrease shows some site loads increasing partly due to an increase in the irrigated area. Bankside, Greendale, Highfield and Te Pirita could drop around 5MVA in the medium term. However in the short term the growth for Hororata and Te Pirita zone substations may need to be addressed if sufficient existing ground water pumps are not relinquished as soon as the CPW scheme comes online. We are working with CPW to highlight the importance of the timing of relinquishing existing pumps. We will continue to research the implications in this area and adjust our upgrade proposals accordingly in next year's AMP.

Figure 5-4m Rural 66 and 33kV zone substations – maximum demand versus firm capacity



Notes:

1. Annat: Resolve by new transformer
2. Dunsandel: Resolve by upgraded transformers
3. Hills: Resolve by new Southbridge substation
4. Lincoln: Resolved by load-shift to Springston.
5. Rolleston: Resolved by load shift to Larcomb and new Burnham substation.
6. Springston: Convert to 66kV.

Table 5-4e Rural 66 and 33kV zone substations – load forecasts (MVA)

Zone substation	Security Standard class	Firm capacity	Actual Winter 2013/ Summer 2013/14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Annat	D3	2.5	1	1	1	3	3	3	3	3	3	4	4	4
Bankside	D2	10	9	9	9	8	6	3	3	3	3	3	3	3
Brookside	D3	10	9	9	9	9	9	10	10	10	10	10	10	10
Darfield	D2	7.5	6	6	6	6	7	7	7	7	6	6	6	6
Diamond Harbour	D3	7.5	2	2	2	2	2	2	2	2	2	2	2	2
Dunsandel	D2	10	9	10	12	12	14	14	14	14	14	14	14	14
Duvauchelle	D2	7.5	4	4	4	4	4	4	4	4	4	4	4	4
Greendale	D2	10	8	8	8	8	7	5	3	3	3	3	3	3
Highfield	D2	7.5	7	7	7	7	7	7	6	4	2	2	2	2
Hills	D2	7.5	6	6	7	7	7	7	7	7	7	8	8	8
Hororata	D2	7.5	7	7	9	10	8	6	5	5	5	5	5	5
Killinchy	D2	10	8	8	8	8	8	8	8	8	8	8	8	8
Kimberley	D1	23	14	14	14	14	14	20	20	20	21	21	21	21
Larcomb	D2	23	5	6	6	8	8	11	11	14	14	17	18	18
Lincoln	D2	10	8	9	10	10	11	12	12	12	13	13	13	14
Little River	D3	2.5	1	1	1	1	1	1	1	1	1	1	1	1
Motukarara	D3	2.5	2	2	2	2	2	2	2	2	2	2	2	2
Rolleston	D2	10	12	11	12	13	14	15	15	16	16	17	17	18
Springston	D2	7.5	6	6	6	7	7	7	7	7	7	7	7	8
Teddington	D3	2.5	1	1	1	1	1	1	1	1	1	1	1	1
Te Pirita	D2	10	10	10	12	11	9	6	6	6	6	6	6	6
Weedons	D2	23	7	7	7	7	7	7	7	7	7	7	7	8

See section 5.3.1 for Security Standard Class definitions.

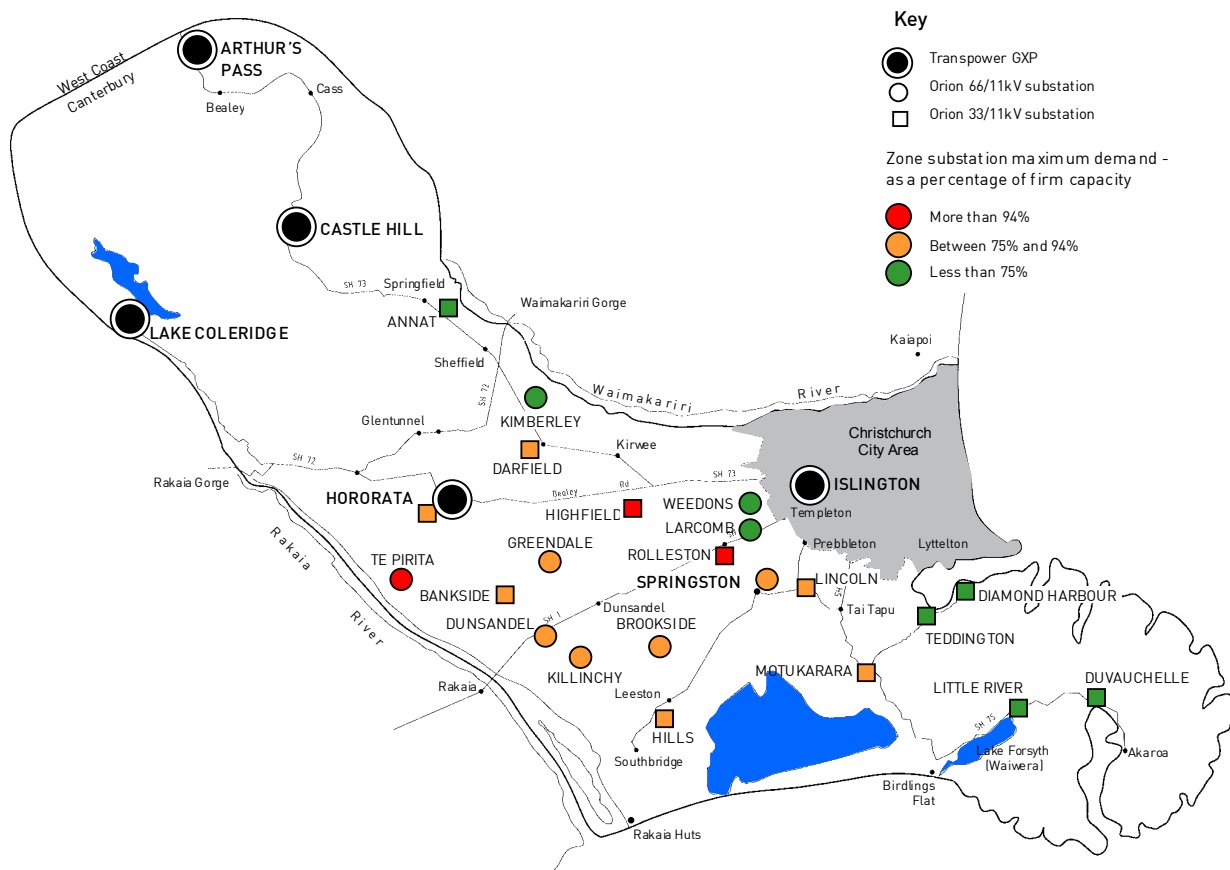
The load growth forecasts for Te Pirita and Hororata between FY15 and FY19 are based on coincident operation of the new CPW pumps with existing groundwater pumps in the area. We are working with CPW to find operational solutions to these short term constraints on our network.

We have produced the following rural geographical map to demonstrate areas of high and moderate loading on our network. Substations with load exceeding 94% of firm capacity have been coloured red.

There are no changes from last year.

Summer 2013/14 did not give irrigation loads as high as experienced previously. This is due to rain events over all the summer months, and possibly still some broken irrigators due to the major wind storm on 10 September 2013. This event damaged over 800 irrigators with possible repair duration estimates as late as February 2014.

Figure 5-4n Zone subs – rural (summer 2013/14 or winter 2013 max demand as a percentage of firm capacity)



Notes:

Load will be transferred onto Larcomb to relieve Rolleston zone substation in the short term before we build a new zone substation at Burnham.

Highfield and Te Pirita loads are expected to drop significantly as a result of the CPW scheme.

5.4.6 Utilisation of assets

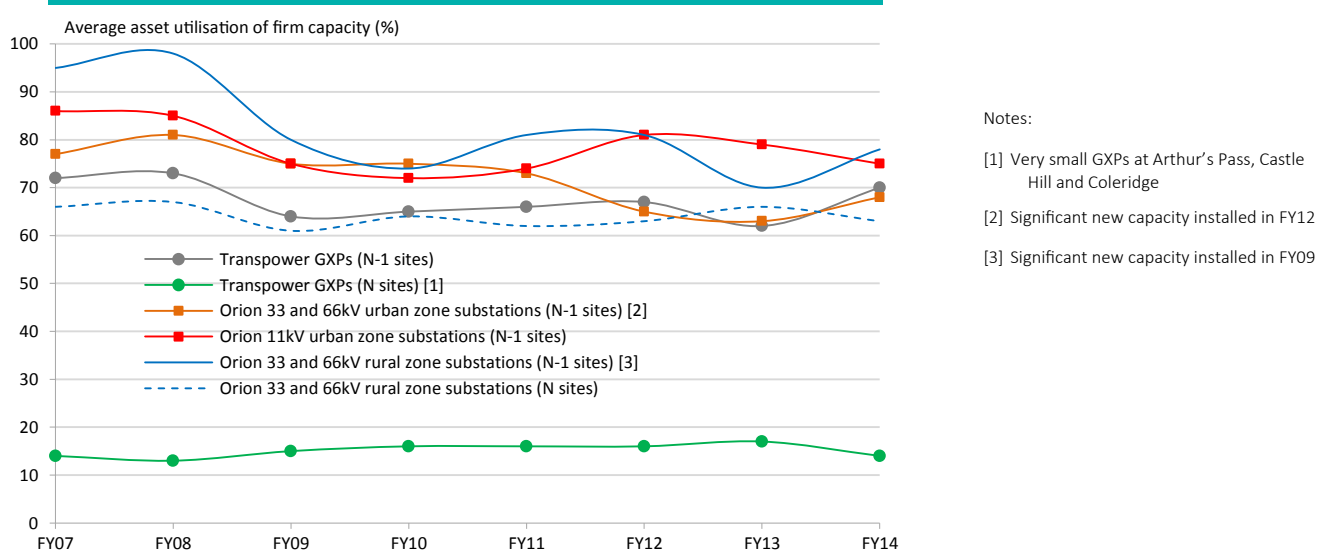
GXP, 66kV, 33kV and 11kV zone substation utilisation

For N-1 sites with dual transformers or parallel 11kV incomers, we calculate utilisation by dividing peak load by the N-1 capacity (capacity available following a single fault) of the site. Utilisation of 100% implies that further increases in load will require further network investment or the security of supply will reduce.

For N security sites with single transformers and/or line or cable supplies, utilisation is calculated by dividing peak load by the installed site capacity. To provide support to neighbouring N security sites during contingencies it is not necessarily desirable to aim for 100% utilisation at these sites. Our interruptible irrigation load initiative has allowed an increase in utilisation of our rural N security sites and utilisation of 70-80% is appropriate in this context.

Note that this graph is produced before the end of FY15 and therefore we are not able to publish FY15 results.

Figure 5-4o GXP, 66kV, 33kV and 11kV zone substation utilisation



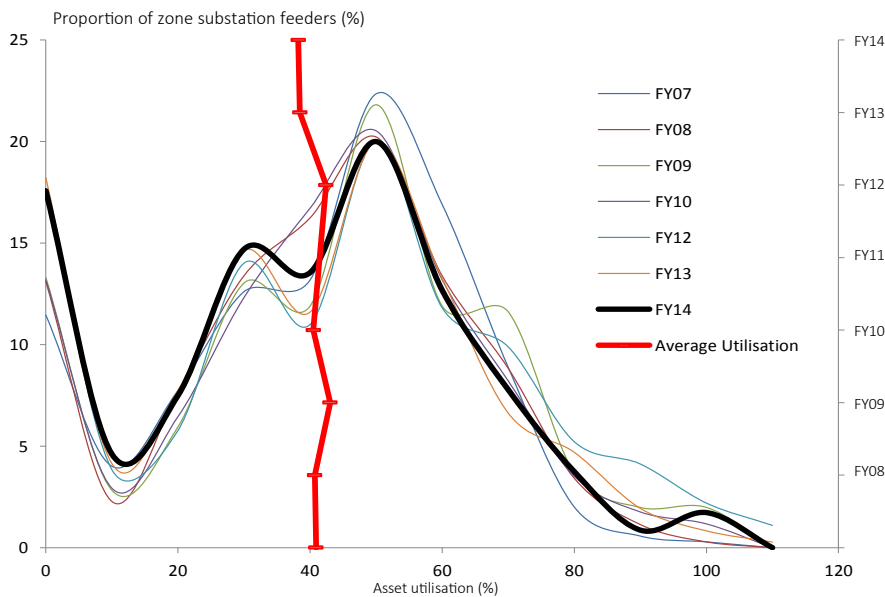
11kV feeder cable utilisation

We have calculated cable utilisation for all urban zone substation 11kV network feeders from recorded SCADA values. It is based on peak load under normal system conditions with respect to the nominal design capacity of the smallest cable section between the zone substation circuit breaker and the first downstream load. A de-rating to 80% of the normal book value has been applied to the cable capacity to allow for the common thermal environment where cables are laid in parallel.

The following graph 5-4p shows average 11kV feeder cable utilisation is around 40%. Ideally, considering our N-2 urban architecture, the nominal average cable utilisation should be 50%. However, several cables carry zero load under nominal operating conditions which therefore lowers the overall utilisation. This can be attributed to our existing 11kV architecture which historically featured a closed-ring subtransmission network in the urban area. Recent changes to our network design philosophy should see an increase in cable utilisation over time. Over the city rebuild period however, numerous feeders will have zero utilisation (especially in the CBD) and 'normal' conditions will take time to develop.

Note: in FY11 the data was not meaningful due to serious earthquake disruption (utilisations are meant to be for 'normal' network conditions). In FY12 and to a lesser extent FY13-14, parts of the network are still in transition, there remain cable faults, and switching rates are higher. While this reduces the usefulness of these curves for year-on-year comparison, the increase in feeders with zero utilisation can be seen.

Figure 5-4p Zone substation 11kV feeder cable utilisation graph



Distribution transformer utilisation

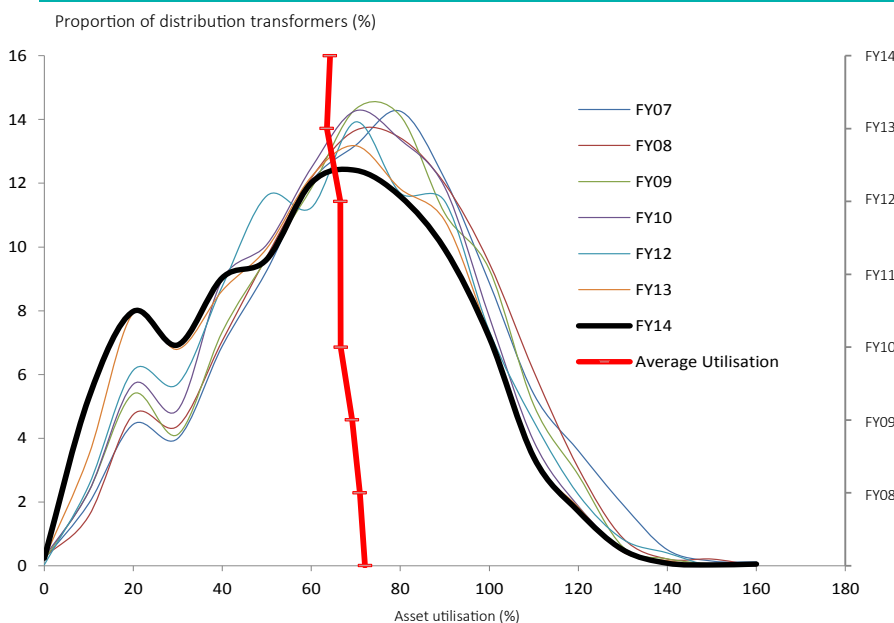
The following graph 5-4q shows the distribution of utilisation factors for our 11/0.4kV distribution transformers. The graph has been determined by dividing the maximum distribution transformer demands, as recorded on the 20 minute maximum-demand-indicators (MDIs), by the nominal transformer rating.

The graph shows that the majority of distribution transformers have peak loads in the range of 60 to 100% of their continuous rated load, with an average around 70%.

While the graph also shows that around 18% of distribution transformers are above 100% loaded at peak, the load factor for most distribution transformers is usually quite low. This is certainly true for the transformers that supply mainly residential consumers. Consumers with higher load factors, such as large industrials, tend to have a dedicated supply transformer that is closely matched to their load requirements. They therefore know the supply capacity limitation and will usually request formally any supply capacity changes. Also, transformers have a large thermal capacity and can tolerate cyclic loads higher than their continuous rating. Therefore we deem it appropriate to allow peak loads on the majority of distribution transformers to rise to 130% of the continuous rating before investigating possible replacement/upgrades.

The effects of the earthquakes mean that transformer utilisation will depart from a normal pattern for a few years.

Figure 5-4q Distribution transformer utilisation graph



5.5 Network gap analysis

Our 'deterministic' Security Standard provides a useful benchmark to identify areas on our network that may not currently receive the same high level of security as the majority of our network.

Economically robust solutions to actual and anticipated network gaps caused by imminent load growth are quickly provided for by our annual capital spend. Network security is maintained on our 11kV distribution network by ensuring that the design of new connections is consistent with our Security Standard.

On an annual basis, our network planning group updates contingency plans for all valid subtransmission (220kV, 66kV, 33kV) and 11kV contingencies. In some cases the Security Standard criteria for 'no interruption' or 'restoration time' of load cannot be economically met.

The network gaps identified in the following tables arise because the cost of reinforcing the network to the performance level identified in our Security Standard would be economically prohibitive. That is, the cost to provide the Security Standard level of performance would exceed what consumers are prepared to pay for it.

In general, network security gaps fall into one or more of the following categories:

- solution is currently uneconomic and an economic solution is not anticipated in the foreseeable future
- solution is currently uneconomic but is expected to become economic as load grows in the area under study
- local solution is uneconomic but network expansion in adjacent areas is expected to provide a security improvement in the future
- solution requires co-ordination with Transpower's asset replacement programme and/or is subject to Transpower/Commerce Commission approval.

The economic analysis for each network gap determines the value of lost load (VOLL) when a defined contingency occurs and then utilises probability theory to determine the annual VOLL. This VOLL is calculated using \$6.97 per kW for the initial interruption and \$16.26 per kWh thereafter. The Electricity Authority (formerly Electricity Commission) undertook surveys and a review of VOLL in 2010, 2011 and 2012 to better understand the range of VOLL values for different customer groups and also provide a check on inflationary impacts since the last survey (1992) and review (2006). The Electricity Authority (EA) has undertaken further surveys (including in Christchurch) to refine the results, which were released in August 2013. The EA conclusion for an eight hour outage in Christchurch is \$18.69 per kWh. The EA report also supports using higher VOLL values for small to medium commercial consumers (CDB type loads). Our review of the report does not suggest that a change to our VOLL values (as stated above) are necessary but it does highlight the large variance in VOLL for different consumer groups.

Although the VOLL of contingencies can be very high, the low probability of occurrence can often lead to a very low annualised VOLL and therefore render the proposed solution uneconomic. This often results in the timing of the solution being largely dependent on the timing of other related network development proposals which are required for load growth or asset replacement in the area.

Because annualised VOLL figures can hide the high VOLL of a particular event it is important to consider the implications of rare but costly (High Impact Low Probability) events if they were to occur. The Canterbury earthquakes have reiterated the importance of building a resilient network and any economic analysis should be considered alongside the asymmetric nature of the risks involved.

Notes to the following tables:

The Electricity Participation Code includes a national transmission grid reliability standard. This standard states that Transpower is required to maintain an N-1 level of security for the core grid. The GXP gaps identified below are based on the application of our Security Standard to Transpower's core-grid, spur or GXP assets. Proposed projects for Transpower's core grid assets will be subject to Commerce Commission approval.

The table includes current Security Standard gaps only. Additional projects listed in the ten year AMP provide solutions for future forecast gaps that are not stated here.

Several projects address more than one security gap and are therefore quoted in more than one location. Transpower meets the initial capital cost and then charges us an annualised amount for the use of the additional assets. Transpower costs are essentially passed through to us to be recovered from our consumers. Transpower project costs are estimates only.

Table 5-5a Transpower GXP security gaps

Network gap	VOLL per event \$000	VOLL p.a. \$000	Solution	Cost \$000	Cost p.a. \$000	Benefit cost ratio	Proposed date
Addington							
Single Addington No.2 11kV GXP busbar fault causing complete loss of supply to 23MW of load. Restoration achievable in 2 hours.	534	8.0	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	Orion 27	2.9	2.8:1	2016 during switchboard replacement and following Orion purchase of the assets
Islington							
Partial loss of restoration for an Islington 220/33kV dual transformer failure.	2,200	4	Convert Shands zone substation to 66kV (Project 669) or Templeton 66kV zone substation (Project 502). ^(Note 1)	Orion 6,455 or 4,416	930 or 636	1:233 or 1:160	Timing is influenced by load growth at Hornby, Wigram and Templeton and not driven by closing this gap
Hororata							
Interruption to all Hororata GXP load for a 66kV bus fault (restorable).	830	19	Install a 66kV bus coupler (75% of load will remain on).	TP 500	55	1:2.9	Uneconomic. No date proposed. The planned 66kV links from Highfield to Greendale and Darfield will significantly reduce the restoration time for some load
Partial loss of restoration for a Hororata 66/33kV dual transformer failure.	1,180	11	Convert Hororata to 66kV. ^(Note 1)	Orion 1,527	168	1:15.3	Hororata conversion in FY22
Interruption to all Hororata 33kV GXP load for a 33kV bus fault (restorable).	TBA	TBA	Install a 33kV bus coupler (will halve VOLL values).	TP 250	28	TBA	This will be investigated as part of Hororata 33kV switchboard replacement in FY18 to FY20.

Note 1. Shared mobile generation could provide an alternative solution.

Table 5-5b Orion security gaps

Substation	Network gap	Solution	Cost \$000	Proposed date
Dallington	Loss of 29MW of load for a single 66kV line or transformer failure. Restoration achievable in 5 minutes.	Complete a 66kV loop from Bromley via Rawhiti and Marshland by installing a cable from Marshland to McFaddens zone substation (Project 491).	6,000	FY20
Halswell	Single Halswell 66kV busbar fault causing complete loss of supply to 42MW of load. Restoration achievable in 2 hours.	Installation of a bus coupler at this stage is uneconomic. In the longer term the Halswell 66kV bus arrangements may need to change to a ring bus to accommodate other changes, and this will resolve the security gap.	TBA	TBA
Hoon Hay	Single Hoon Hay 11kV busbar fault causing complete loss of supply to 28MW of load. Restoration achievable in 2 hours.	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	80	FY25
Lancaster	Loss of 23MW of load for a single 66kV cable failure. Restoration achievable in 5 minutes.	Complete a 66kV loop from Hoon Hay to Milton.	6,401	FY25
Moffett	Single Moffett 11kV busbar fault causing complete loss of supply to 14MW of load. Restoration achievable in 2 hours.	Install bus zone protection to create two bus zones as part of the protection upgrade for safety.	TBA	FY16
Papanui	Interruption to all Papanui load for a 66kV bus fault (restorable).	We propose to install a new 66kV bus coupler at Papanui (Project 853)	460	FY16
	Single busbar fault at Northcote Rd No.123 network substation on the Belfast 11kV ring causing a cascading loss of supply to 24MW of load. Restoration achievable in 2 hours.	Uneconomic to install an 11kV bus coupler at Northcote Rd No.123. The impact will be reduced by the installation of Waimakariri (Project 525) and Marshland zone substations (Project 488) and the Belfast diesel generators (Project 634); and then fully solved by Belfast zone substation or reconfiguring Northcote Rd No.123.	TBA	FY15, FY17, FY18, FY30
Rawhiti	Single 66kV supply to Rawhiti zone substation due to the February 2011 earthquake. Loss of 27MW of load for a single 66kV cable failure. Restoration achievable in 2 hours, using QEII Park generators.	Install a new cable from Waimakariri zone substation (Projects 650&651). These projects also provide security of supply for Waimakariri substation and Marshland substation in the future.	24,294	FY16
Bishopdale	Single Bishopdale zone substation 11kV busbar fault causing cascading loss of supply to 30MW of load. Restoration achievable in 2 hours.	This security gap will be resolved when Bishopdale is decommissioned.	NA	FY16
Springston	Interruption to all Springston 33kV load for a 33kV bus fault (restorable).	The staged conversion of the substations on the Springston 33kV network to 66kV will progressively reduce this vulnerability.		FY25+

5.6 Network development proposals

The previous sections tabled network capacity, growth projections and the security constraints on our network. This section lists our proposals to remove capacity and security constraints.

5.6.1 Impact on service level targets

The network development projects listed in this section are driven mainly by the need to meet the capacity and security requirements of load growth. Where economic, project solutions have been designed to meet our security of supply standard requirements.

This ensures that our network configuration and capacity is constructed in a consistent way and the impact on our reliability of supply service levels will be predictable. It should be noted that reliability of supply service levels are a function of many inputs and, while network configuration and capacity is a major input, it is not the only factor.

Project solutions also need to consider our safety, power quality, environmental and efficiency targets.

Safety performance during construction is influenced by factors such as site security, operating standards and contract management practices. Upon completion, high levels of safety performance are achieved by appropriate choice of network equipment, site security and operating standards.

Power quality is influenced mainly by ensuring that network capacity is adequate. Undersized reticulation or high impedance transformers will increase the risk of power quality issues. Some projects provide for the connection of equipment (for example variable speed drives) which can create high levels of harmonic distortion and it may be necessary to install harmonic filtering equipment to reduce the distortion to acceptable levels.

Environmental targets are met with new projects by ensuring that substation design includes appropriate oil bunding and, where possible, precludes the installation of SF₆ switchgear. On-going environmental targets are met by adhering to appropriate resource management standards.

Our efficiency target is met by ensuring that upgrades or extensions to the existing network are not oversized. During development projects it may be necessary to reconfigure adjacent parts of the network and consideration is given to economic downsizing of existing underutilised distribution transformer capacity.

5.6.2 Overview of projects

The projects identified in this AMP are sorted into the following categories:

- major projects – GXP
- major projects – urban
- major projects – rural
- 11kV reinforcement – urban
- 11kV reinforcement – rural.

Within these categories the projects are banded within the following timeframes:

- the current financial year (FY16)
- the next four years (FY17-FY20)
- the remainder of the period (FY21-FY25)

All FY years refer to financial year ending 31 March.

Projects for the current year can be considered firm. Those planned for later years will be reviewed annually, and may not proceed as currently envisaged. Projects for the remainder of the period (FY21 and beyond) are indicative only because of the uncertainties as to the nature and magnitude of future loads.

A summary of the options for the major projects has been provided. Because most of the projects beyond FY16 are still subject to a final review and refinement, it is possible that actual implementation may differ from that proposed if new information becomes available before the need to start detailed design. For projects beyond FY17, the value per kW of deferral has been tabled later in this section (5.6.12) to provide a guide to potential DSM providers.

Although GXP alterations are not carried out directly by us, they are included here to provide a greater understanding of the capacity and security issues we face. Transpower is to undertake the GXP projects to improve the capacity, security and quality of supply to our consumers. They will meet the initial capital cost and then charge us an annualised amount for the use of the additional assets. Transpower costs are essentially passed through to us to be recovered from our consumers.

5.6.3 Urban 66kV subtransmission review

From FY08 - FY12 we met growth within our urban network without the need to invest significantly in the urban subtransmission network. Following the earthquake we anticipated that new zone substation capacity will be required towards the north of Christchurch City at Waimakiriri and Marshland. The capacity of our pre-earthquake 66kV subtransmission network in the area was not sufficient to supply any proposed new zone substation. Permanent damage sustained to our 66kV network from the earthquake meant our network capacity was further reduced.

In FY14 we started to invest significantly to replace capacity in the east and meet the electrical needs of northern Christchurch consumers. These investments and future development decisions made over the next five years will significantly shape the long term security and reliability of supply outcomes for the northern part of Christchurch City.

In an environment where our standard of living and health is so heavily dependent on a reliable electricity supply it has become increasingly important that our network is resilient to a wide range of factors. The earthquakes have prompted the need to review the architecture of our network and our network security of supply standard and a reconsideration of the Christchurch subtransmission network was carried out in FY12. This review is described in our Network Architecture Review - Subtransmission (NW70.60.16).

Our 66kV subtransmission options analysis not only considered the impact of normal network contingencies but also the widespread impact of natural events on our assets and the flexibility of our network architecture to restore power following these events. We work hard to apply preventative maintenance measures to ensure that the chance of electrical, mechanical or external forces causing failure of our assets is economically minimised. However, it is important to consider the impact of major events such as that seen at Otahuhu in 2007 which caused several hours of lost electricity supply to the majority of Auckland City and the series of Christchurch earthquakes in 2010 and 2011 which caused widespread outages for a few hours and isolated area outages for many days.

The review confirmed and refined the approach we have been taking since the year 2000. For future work, we will continue to move away from zone substations being radially fed from GXP's to a more resilient layout. Future design will be based on a closed-ring network topology so the failure of any single route will not interrupt supply to a zone substation. Cables will be sized to give sufficient cross-GXP link capacity to provide full support in the loss of either Islington or Bromley 66kV supply. The preferred layout for 66kV zone substations is to have a ring-bus which has better fault performance than a conventional bus arrangement for either circuit breaker failures or bus faults.

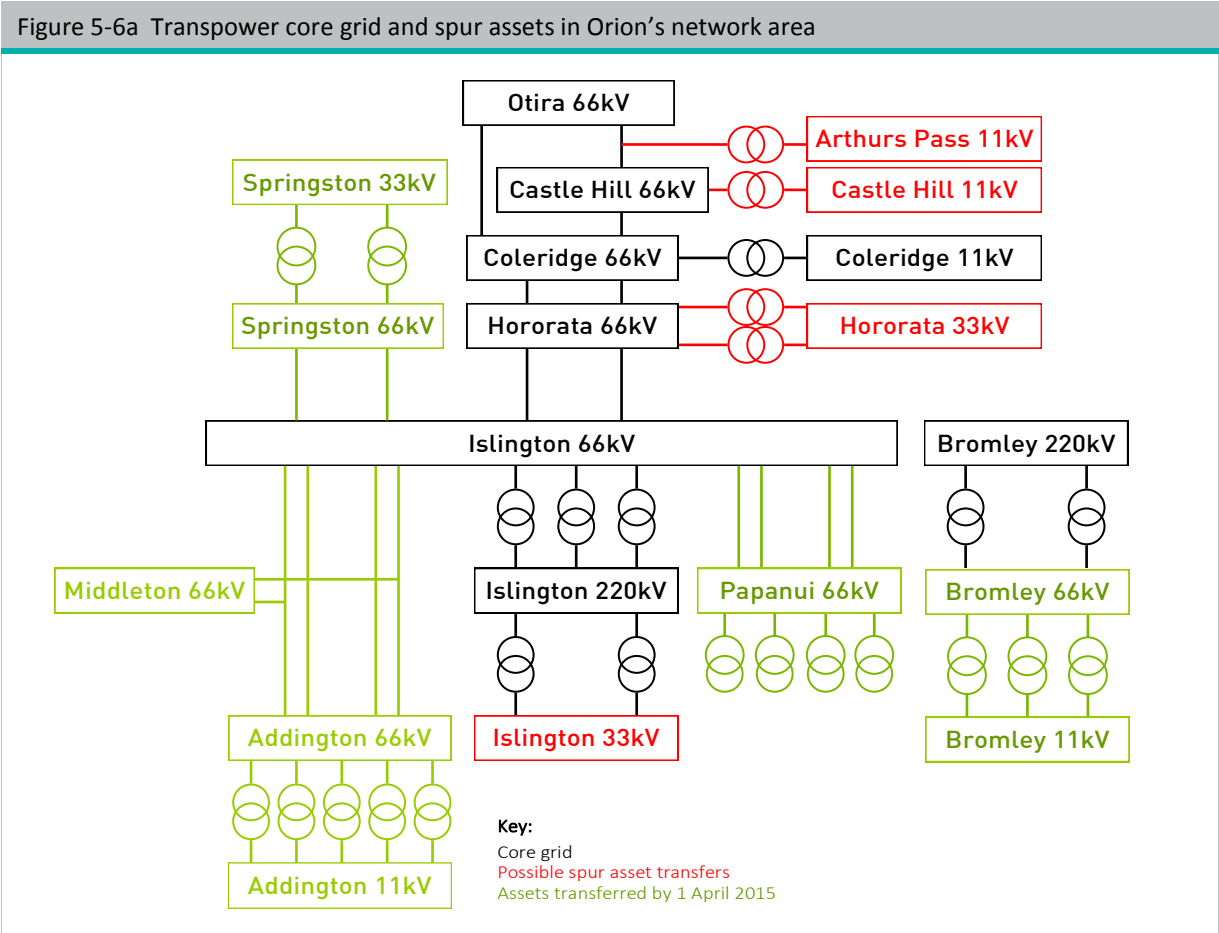
5.6.4 Transpower spur assets

Transpower owns a number of 66kV, 33kV and 11kV assets in our network area (see map, section 5.2.1). Many of these assets do not form part of Transpower’s core grid and deliver electricity solely to our network. We call these assets ‘spur assets’ to Transpower’s grid and they fundamentally serve the same purpose as our own 66kV, 33kV and 11kV distribution network assets.

The possibility of Transpower selling spur assets New Zealand wide has been discussed in the industry several times over the last 25 years. This can mainly be attributed to the recognition that these assets serve the purpose of local distribution rather than national transmission. A change of ownership would enable configuration and construction efficiency benefits to be achieved through integration into local distribution network asset planning, management, maintenance and operations which would result in downward pressure on prices to our consumers.

The Commerce Commission gazetted a new set of ‘Input Methodologies’ in December 2010 which sets out the upfront regulatory methodologies, rules, processes, requirements and evaluation criteria on which lines businesses will be regulated. As part of our submissions on the draft input methodologies we have encouraged the Commerce Commission to develop rules that enable lines companies to make a regulated return on the purchase of spur assets. In our view the input methodologies encourage Orion to purchase spur assets from Transpower and thereby achieve benefits for our consumers. These benefits are relevant as we focus on the redevelopment of Christchurch with different patterns and location of growth. The Commerce Commission 2013 Customised Price Path decision supported spur asset transfers.

We have worked with Transpower to determine the appropriate ownership boundary between Transpower and Orion and the following diagram provides a summary of the agreed core grid and spur assets in Orion’s network area.



The following table provides an indicative purchase value and date for each of the GXP spur assets. The estimated spur asset purchase costs are based on the forecast Transpower ‘Regulatory Book Value’ of the assets at the time of forecast transfer. These forecasts include the forecast value of Transpower planned replacement or enhancement work prior to the purchase date and also some transaction costs.

Table 5-6a Spur assets, indicative cost to purchase – \$000

Spur asset to be purchased	FY16	FY17	FY18
Bromley 66kV and 11kV			
Addington and Middleton including Islington-Addington 66kV transmission lines	9,000	200	
Castle Hill 66/11kV transformer and 11kV		50	1300
Hororata 33kV * (including 66/33kV transformers)		100	1300
Arthurs Pass 66/11kV transformer and 11kV		50	550
Islington 33kV*		50	1000
Spur assets total	9,000	450	4,150

*Assumes EA rule change so that Transpower can use customer equipment for GXP metering, thus avoiding a \$0.5M - \$1M project to shift metering.

In recent years, we have also entered into New Investment Agreements (and other small agreements) with Transpower for the upgrade of Transpower spur assets at some of these GXPs. The indicative 'buy-out' value of these agreements is also included below.

Although the spur asset purchases included in this AMP reflect the most likely outcome, they are subject to Orion and Transpower board approval. The exception is Addington/Middleton which was approved on 7 May 2014. The timing for three transfers has been delayed from last year's AMP to facilitate further planning.

In addition to the purchase and new investment agreement buy-out costs tabled below, the ownership of Transpower spur assets will also require an increase in our budgets for reinforcement, replacement, maintenance and operations. Additional capital expenditure as a result of the spur asset purchases associated with growth, reinforcement and replacement has been incorporated into this AMP. Following receipt of further age and asset condition data from Transpower we will analyse future options in more detail to refine the impact to our capital replacement, maintenance and operations budgets.

Table 5-6b Affected Transpower new investment agreements – \$000

Agreement affected	FY16	FY17	FY18	FY19
Middleton 66kV GXP connection	1,420			
Hororata 33kV			130	
Total	1,420		130	

5.6.5 Major GXP projects

Table 5-6c Major GXP projects

Project	FY16	FY17	FY18	FY19	FY20	FY21	FY22
784 Addington metering relocation	1,000						
859 Arthurs Pass Transformer			1,000				
860 Castle Hill Transformer			1,000				
325 Hororata 66kV bay for Hororata substation							615
629 Hororata 66kV bay for Hororata-Darfield line							615
GXP total	1,000	0	2,000	0		0	1,230

Table 5-6c.1 Major projects details – GXP – Current year FY16

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
784	Addington metering relocation	The purchase of Transpower's Addington substation and lines means that the revenue metering must be shifted from Addington to Transpower's Islington GXP.	This project installs metering for the four overhead circuits from Islington to Addington.		1,000	2016

Table 5-6c.2 Major projects details – GXP – FY17 to FY20

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
859	Arthurs Pass Transformer	Arthurs Pass transformer is due for replacement.	As part of the proposed spur asset transfer it is proposed that Orion replace the transformer before the GXP transfer.	It is expected that Orion can carry out this work more cost effectively than Transpower. Removing the GXP and supplying from Castle Hill was considered but rejected due to the difficulty of running a circuit through DOC land. Supplying from Otrira was also rejected due to the difficulty of running a circuit through the tunnel.	1,000	2018
860	Castle Hill Transformer	Castle Hill transformer is due for replacement.	Orion propose to replace the transformer prior to spur asset transfer.	Building a new GXP at Porter Heights for the proposed village and using this to supply Castle Hill village was more expensive, and the village development is uncertain.	1,000	2018

Table 5-6c.3 Major projects details – GXP – FY21 to FY25

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
325	Hororata GXP 66kV bay for Hororata substation	When Hororata zone substation is converted to 66/11kV (Major Rural Project 601) a new 66kV bay will be required on Transpower's bus.	This is a Transpower project to provide a new bay with the costs recovered through our new investment agreement with Transpower.		615	2022
629	Hororata GXP 66kV bay for Hororata-Creyke line	The installation of the Hororata-Darfield 66kV line (Major Rural Project 579) will require a new 66kV line termination bay on the bus.	A new 66kV bay will be installed at Hororata GXP. This is a Transpower project to provide the extra bay, where the costs are recovered through a new investment agreement between Orion and Transpower.		615	2022

5.6.6 Major urban projects

Table 5-6d Major urban projects - \$000

Projects	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
650 Rawhiti to Marshland 66kV link	12,666									
651 Marshland to Waimakariri 66kV link	11,626									
853 Papanui bus coupler	350									
332 Moffett zone substation replace 33kV feeders	192									
634 Belfast Diesel Generation - Stage 1		1,286								
694 Land acquisition for Milton 66kV switchroom		1,000								
727 Lancaster zone substation rebuild		6,396								
488 Marshland zone substation			9,002							
542 Waimakariri zone substation stage 2			2,241							
589 Lancaster to Milton 66kV link			4,098							
721 Land acquisition for Shands 66kV switchyard			500							
723 Milton 66kV switchgear for Lancaster cable			4,515							
541 Hawthornden T-off				1,136						
669 Convert Shands zone substation to 66kV				6,244						
491 McFaddens to Marshland 66kV link					7,134					
522 Yaldhurst zone substation					8,785					
707 Shands zone substation 66kV Stage 2								799		
722 Land acquisition for Hoon Hay 66kV switchyard										200

Figure 5-6d Urban subtransmission 66kV and 33kV – existing and proposed

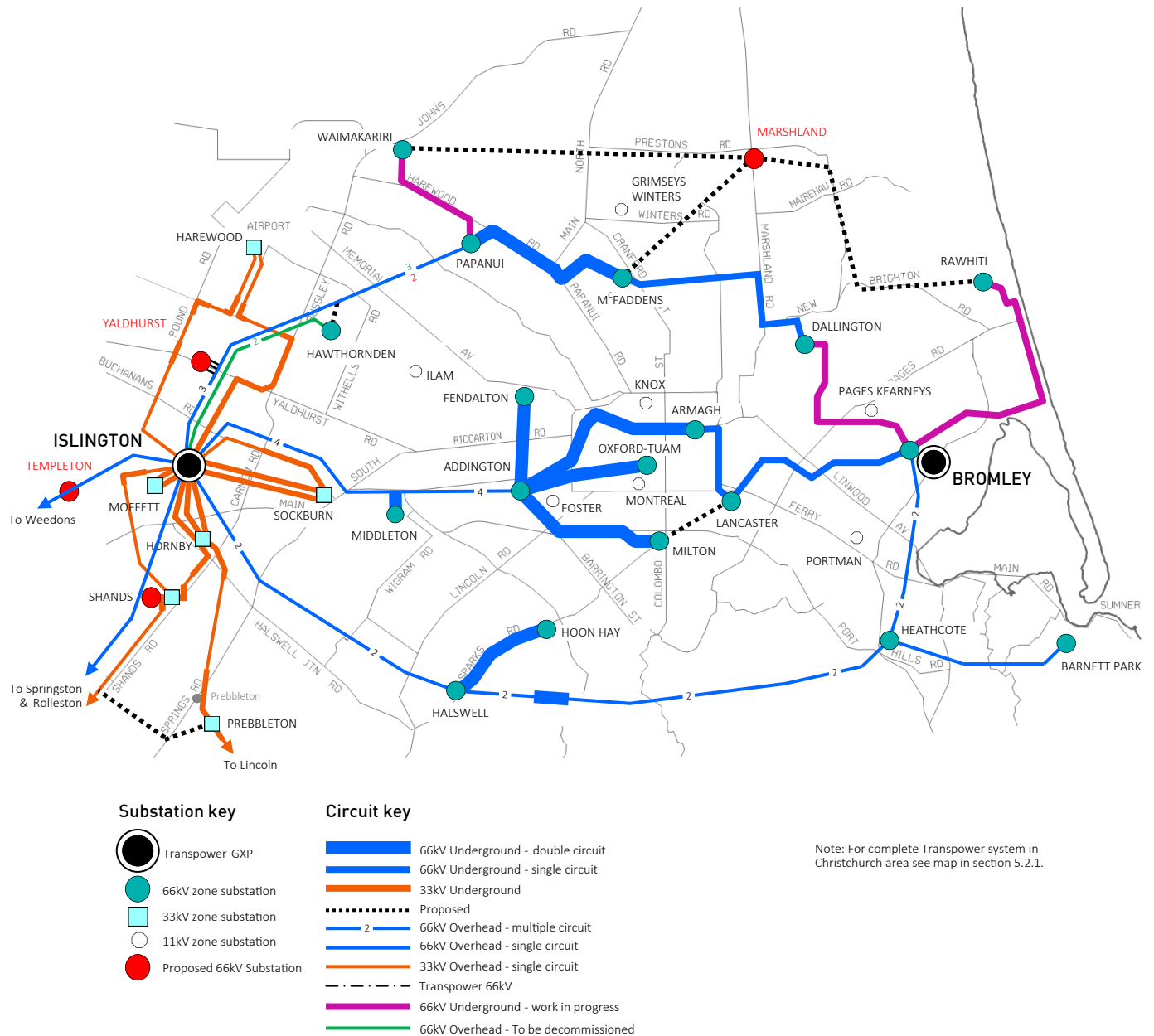


Table 5-6d.1 Major project details – urban – current year FY16

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
650	Rawhiti to Marshland 66kV link	The cables from Bromley to our Brighton zone substation were damaged beyond repair by the earthquakes. A temporary overhead line was built from Bromley to our new Rawhiti zone substation (replaced the damaged Brighton zone substation). A permanent solution is required.	A 66kV cable is being installed between Bromley and Rawhiti. A second supply from Islington GXP will also be provided (Projects 651 and 794). This project installs a 66kV cable between Rawhiti and the future Marshland zone substation (Project 488) and forms part of the Islington-Rawhiti link. It also provides supply to Waimakariri and Marshland zone substations.	A detailed investigation was carried out (Rawhiti 66kV Options, 2012) to consider various underground and overhead alternatives, taking seismic data into account. This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	12,666	2016
651	Marshland to Waimakariri 66kV link	The cables from Bromley to our Brighton zone substation were damaged beyond repair by the earthquakes. A temporary overhead line was built from Bromley to our new Rawhiti zone substation (replaced the damaged Brighton zone substation). A permanent solution is required.	A 66kV cable is being installed between Bromley and Rawhiti. A second supply from Islington GXP will also be provided (Projects 650 and 794). This project installs a 66kV cable between Rawhiti and the future Marshland zone substation (Project 488) and forms part of the Islington-Rawhiti link. It also provides supply to Waimakariri and Marshland zone substations.	A detailed investigation was carried out (Rawhiti 66kV Options, 2012) to consider various underground and overhead alternatives, taking seismic data into account. This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	11,626	2016
853	Papanui bus coupler	The Papanui zone substation 66kV switchyard supplies approximately 50MVA of local load and provides through subtransmission for a further 60MVA of load. A 66kV bus fault will result in an outage of up to 110MVA of load and approximately 30,000 consumers.	It is proposed to install a new 66kV bus coupler and associated bus-zone protection to create two separate bus zones. The customer outage impact will be eliminated for faults on one half of the bus and significantly reduced for faults on the other half of the bus	An option to operate the 66kV bus with a permanent split in place was explored but powerflow results for other network faults would introduce a risk of cascade tripping or asset overload.	350	2016
332	Moffett substation replace 33kV feeders	The firm capacity of Moffett zone substation is currently limited to 18MVA by the 33kV incomer cables. Major industrial developments around Islington will require the substation to operate at the full transformer capacity of 23MVA.	We propose to increase the firm capacity to 23MVA (the transformer capacity) by replacing the incomer cables.	This capacity limitation is likely to create a security of supply gap in either FY17 or FY18. The timing of this project has been set to coordinate with other Transpower related works occurring in the same trenching corridor.	192	2016

Table 5-6d.2 Major project details – urban – years FY17 to FY20

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
634	Belfast diesel generation - stage 1	Load growth in the north of Christchurch has fully utilised the capacity of McFaddens zone substation and will erode security of supply on the 11kV primary ring from Papanui zone substation in FY18.	Marshland (Project 488) and ultimately Belfast zone substations will progressively address this constraint as growth continues, but these are expensive assets. Each investment may be deferred for a period by emergency generation in Belfast which will provide supply during planned and unplanned outages. Once security of supply for Dallington and Rawhiti zone substations is restored, the two 2MVA emergency generators at QEII will not be needed at that site. We intend to install these at our Factory Rd substation in Belfast. Consents have been obtained.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	1,286	2017
694	Land acquisition for Milton 66kV switchroom	The Milton-Lancaster (Project 727) and Milton-Hoon Hay 66kV cables will require switchgear installations at each substation. A new indoor 66kV switchroom (Project 723) will be built on land adjacent to Milton zone substation.	A site will be secured adjacent to Milton zone substation.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	1,000	2017
727	Lancaster zone substation rebuild	The Lancaster zone substation must be rebuilt after earthquake damage.	This project provides for the removal and replacement of the existing structures. An extra 66kV bay will be provided for the proposed Milton-Lancaster cable (Project 589). An extra 11kV circuit breaker will be provided for Urban Reinforcement Project 622.	This site was insured and the insurance settlement is still in progress.	6,396	2017
488	Marshland zone substation	Load growth in the north of Christchurch has fully utilised the capacity of McFaddens zone substation and will erode security of supply on the 11kV primary ring from Papanui zone substation in FY18. The results of the Urban Development Strategy (UDS) and subsequent ECAN Regional Policy Statement (RPS) project further residential growth to the north of Christchurch (mainly Belfast). The CCC Belfast Area Plan indicates significant industrial growth in the Belfast area is likely when the new northern motorway is constructed.	A new 66/11kV zone substation will be commissioned, with 66kV connections to Waimakariri and Rawhiti zone substations (Projects 650 and 651). This significantly enhances the security of supply for our consumers in the northern half of Christchurch city.	Where economically viable, a substation to the north of the city will be delayed by diesel generation at Belfast (Project 634). This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	9,002	2018
542	Waimakariri substation stage 2	The end-of-life replacement of the four Papanui zone substation 66/11kV transformers by two 20/40MVA transformers in FY15 will reduce the substation's firm capacity from 76MVA to 40MVA. This capacity and security of supply must then be provided by adjacent substations.	To replace this capacity and security of supply we will commission Marshland zone substation (Project 488) and complete Waimakariri zone substation as a full N-1 40MVA site by installing a second transformer.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	2,241	2018

Table 5-6d.3 Major project details – urban – years FY17 to FY20 (continued from previous page)

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
589	Lancaster to Milton 66kV link	The post-earthquake architecture review highlighted that the high value CDB load requires additional subtransmission support. In particular, improved cover for the loss of Addington is needed.	An 95MVA circuit between Lancaster and Milton zone substations will provide extra security of supply for the CBD. In addition, it contributes our goal of providing for stronger cross-city connections between Islington and Bromley 220kV GXP's to mitigate a major outage at either site. See also Projects 694, 723 and 727.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	4,098	2018
721	Land acquisition for Shands 66kV switchyard	A site is needed for the extension to Shands zone substation - see Project 669.	We propose to purchase additional land around our existing Shands zone substation	We will undertake more options analysis before we commit to this project and land purchase.	500	2018
723	Milton 66kV switchgear for Lancaster cable	The Milton-Lancaster 66kV cable (Project 589) will require installation of switchgear at both zone substations. See also Project 727.	This project will commission a new indoor 66kV switchroom on land (Project 694) adjacent to Milton zone substation.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	4,515	2018
541	Hawthornden T-off	Future load growth will mean that the loss of the two Islington-Hawthornden/lam overhead line circuits can no longer be covered by 11kV ties from adjacent substations.	We intend to supply Hawthornden, Valdhurst and Papanui zone substations from the three Islington-Papanui high-capacity tower lines currently in service. This project provides for these connections and 66kV re-arrangements at Papanui zone substation.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	1,136	2019
669	Convert Shands zone substation to 66kV	Two large-scale commercial/industrial developments in Islington and South Hornby are planned and we anticipate an additional 20MVA of peak demand in the area. The existing zone substations in the area will need to be augmented to provide this capacity.	Several solutions have been considered. The conversion of Shands 33/11kV 20MVA zone substation to 66/11kV 40MVA is a leading candidate; the Islington-Springston 66kV double overhead circuit is adjacent, and a 66kV substation in the centre of our 33kV urban network will provide better cover for 33kV network contingencies. The upgrading of Moffett zone substation (Project 332) will also assist. The location and timing of growth will inform our final decisions.	We will undertake more options analysis before we commit to this project and associated land purchase (see project 721).	6,244	2019
491	McFaddens to Marshland 66kV link	Orion's urban subtransmission strategy proposes two 66kV closed rings supplied from Bromley. This cable completes the northern ring with Rawhiti, Marshland, McFaddens and Dallington zone substations. New 66kV bays will be needed at McFaddens and Marshland.	This circuit will connect the two major 66kV routes to the north of the city (Bromley-Dallington-McFaddens-Papanui-Islington and Bromley-Rawhiti-Marshland-Waimakariri-Hawthornden-Islington). It will provide more load transfer options between Islington and Bromley GXP's, and improves reliability of supply by allowing the four zone substations to operate in closed subtransmission rings with uninterrupted N-1 security. It will also limit N-2 events to the loss of a single zone substation. The network robustness in HILP events will be markedly improved.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	7,134	2020

Table 5-6d.4 Major project details – urban – years FY17 to FY20 (continued from previous page)

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
522	Yaldhurst zone substation	A new zone substation is required to allow the decommissioning of Harewood zone substation (due to expansion at CIAL) and to maintain security of supply to the CIAL area and western outer city suburbs as load grows.	It is planned to use the transformers from Iram zone substation with the 66kV supply taken from the Islington-Papanui tower lines.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	8,785	2020
707	Shands zone substation 66kV Stage 2	Shands 66kV zone substation (Project 669) will initially be supplied from a tee off one of the Islington-Springston circuits. When the Birdlings zone substation (Major Rural Project 576) is commissioned, the Springston-Birdlings overhead line circuit will no longer terminate on the Springston bus but will tee off the Islington-Shands-Springston overhead line (Major Rural Projects 447, 583, 697, and 725). For protection design reasons, the tee at Shands will be replaced by cutting the line in and out of the Shands 66kV bus.	This project installs another 66kV bay at Shands zone substation and the line works necessary to bring the line into the switchyard.	There is considerable uncertainty about the need and timing of this project. We will continue to monitor developments affecting this proposal and adjust our plans accordingly.	799	2023
722	Land acquisition for Hoon Hay 66kV switchyard	The proposed Hoon Hay-Milton 66kV link (outside the ten-year AMP scope) requires 66kV switchgear installations at each zone substation. Both substations will require land purchases for new switchyards - see also Project 694.	A site will be secured adjacent to Hoon Hay zone substation.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	200	2025

5.6.7 Major rural projects

Table 5-6e Major rural projects - \$'000

Project	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
500 Land acquisition for Burnham 66kV zone substation	1,200									
846 Rural transformer spare	500									
698 Central Plains Water	615									
415 Weedons to Highfield Tee 66kV line conversion		1,685								
671 Castle Hill Generators		187								
672 Arthurs Pass Generators		71								
716 Land acquisition for Southbridge zone substation		100								
114 Convert Highfield zone substation to 66/11kV			845							
505 Springston T2 - 66/11kV transformer			1,129							
587 Te Pirita 66kV bays			845							
609 Dunsandel to Norwood 66kV line + switchgear			3,279							
626 Norwood to Highfield/Weedons tee 66kV line			2,403							
670 Steeles Rd substation and 66kV line			3,101							
699 Dunsandel transformer upgrade			2,327							
728 Springston 11kV switchroom			777							
306 Annat transformer upgrade				420						
637 Railway Rd 11kV substation (Westland Milk)				3,051						
639 Burnham 66kV substation stage 1				5,774						
666 Porters Village				4,276						
527 Land acquisition for Templeton 66kV zone substation					100					
610 Southbridge 66kV zone substation						3,359				
627 Southbridge 66kV line						1,146				
579 Hororata to Darfield 66kV line upgrade							1,243			
581 Highfield to Darfield 66kV line							3,543			
601 Convert Hororata zone substation to 66/11kV							1,228			
654 Land acquisition for Norwood 66kV zone substation							250			
842 Greenpark 66kV substation							6,491			
849 Convert Darfield zone substation to 66/11kV							3,901			
577 Windwhistle to The Point 66kV line								2,028		
588 Te Pirita to Windwhistle 66kV line								1,175		
597 Norwood 66kV zone substation								3,390		
608 The Point 66kV zone substation								3,491		
705 Greendale to Dunsandel-Norwood line + switchgear								2,355		
502 Templeton 66kV zone substation									4,654	
447 Greenpark to Motukarara 66kV line conversion										1,677
576 Birdlings 66/33kV substation										3,943
583 Tancred tee to Greenpark 66kV line										685
725 Birdlings to Motukarara 66kV line										1,904

Figure 5-6e Rural subtransmission network 66kV – existing and proposed

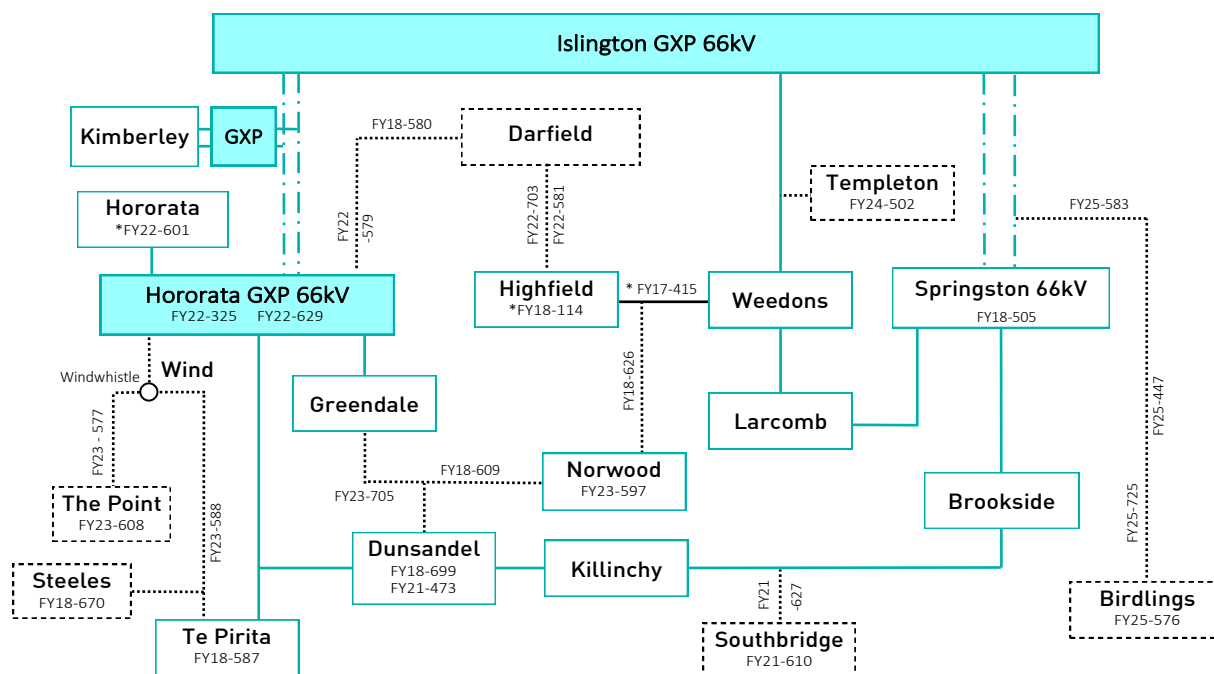


Figure 5-6f Rural subtransmission network 33kV – existing and proposed

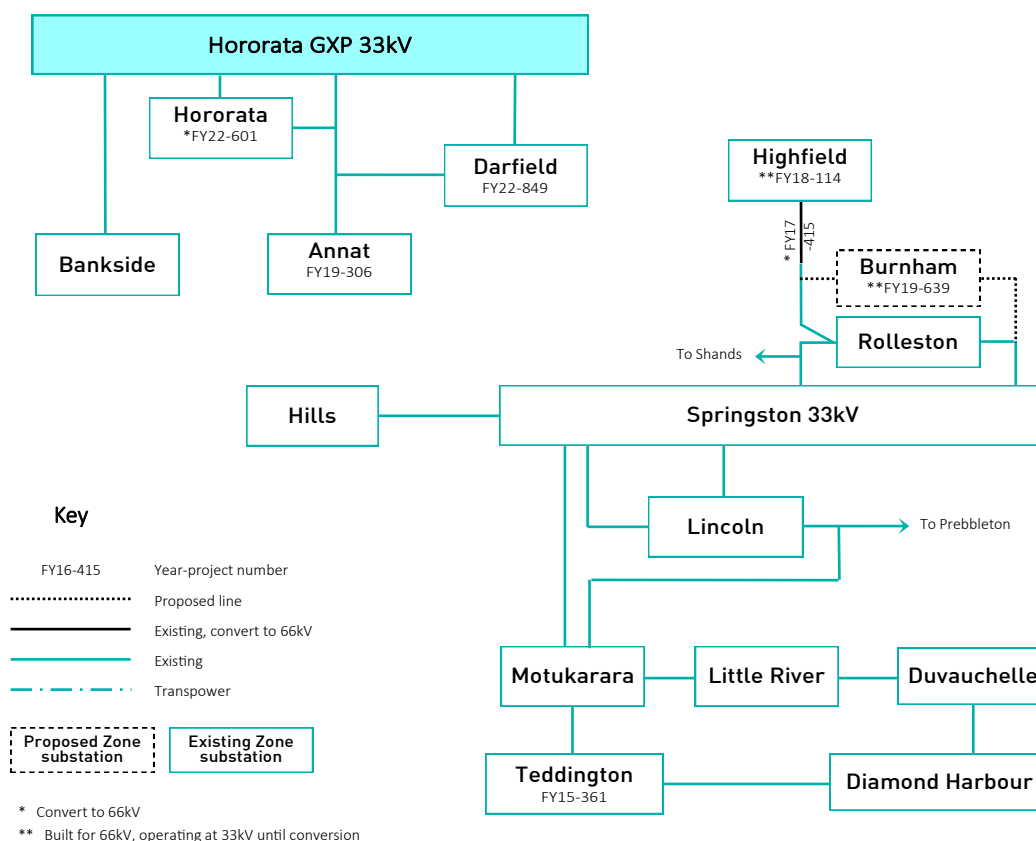


Figure 5-6g Rural subtransmission network 66 and 33kV – existing and future

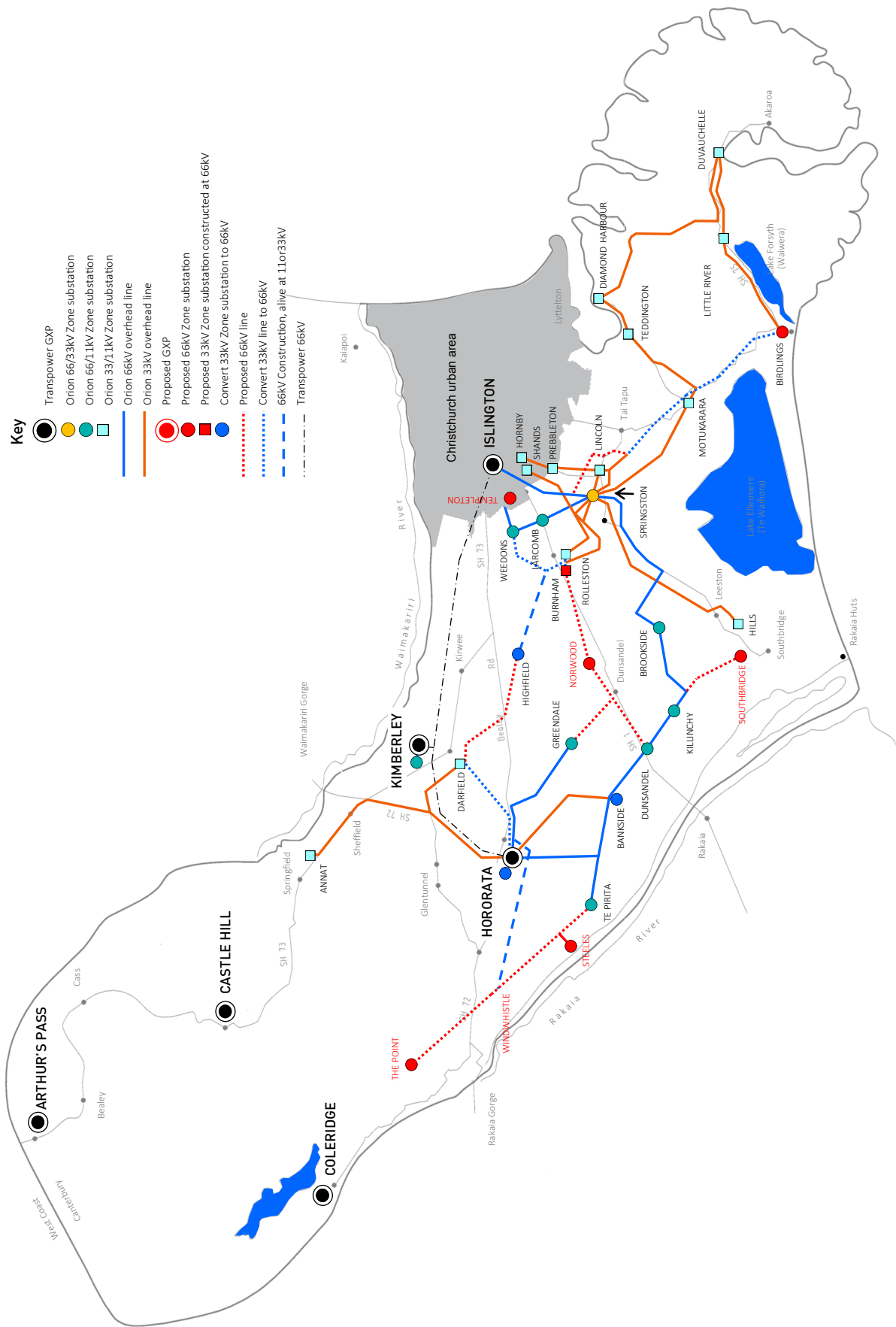


Table 5-6e.1 Major project details – rural – Current year FY16

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
500	Land acquisition for Burnham 66kV zone substation	Rolleston 33kV zone substation will be converted to 66kV in the future, in accordance with our strategy to exit 33kV when opportunities arise. The existing site is not large enough for a 66kV switchyard thus a new zone substation will be built on a site nearby. Growth in the Rolleston/Izone area (see Project 638) will shortly exceed the capacity of the existing substation.	We will build stage 1 of the new 66kV substation (Project 639) and operate it at 33kV initially. A suitable site was identified in 2012 however acquisition was unsuccessful and therefore a new site is being sought. The value of suitable sections will more than likely be greater than the previous budget.	A new substation in a new location was considered but the cost of altering the subtransmission network and 11kV feeder cables makes a more expensive site closer to the existing site more economic despite the higher land value.	1,200	2016
846	Rural transformer spare	The network spare 66/11kV 10MVA transformer is located at Dunsandel zone substation. Developments at the Synlait dairy factory mean that this transformer will no longer be available as a spare. A new spare is therefore required.	A new transformer will be acquired.	Other options investigated included adapting the existing sites so that the 23MVA spare could be used instead, however these options were not considered practical or economic.	500	2016
698	Central Plains Water	The Central Plains Water (CPW) canal project has recently gained approval to proceed. Providing supply for several large pumps along the first stages of the canal will require 11kV reinforcement.	The reinforcement plan depends on the exact pump sizing and locations, and also on yet to be determined reductions in existing pump loads. Conductor upgrades, new spur lines and/or voltage support are expected to be required.	The flat load duration curve for irrigation does not enable load management to work effectively on a daily basis during hot weather. This upgrade work avoids or at least defers the more expensive option to install a new zone substation in Windwhistle.	616	2016

Table 5-6e.2 Major project details – rural – years FY17 to FY20

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
415	Weedons to Highfield tee-off 66kV line conversion	See Project 114 (conversion of Highfield zone substation to 66/11kV).	To enable the conversion of Highfield zone substation to 66kV, the existing redundant 33kV line from Weedons to the Highfield tee-off will be converted to 66kV Jaguar construction. The line from the tee-off to Highfield and the breaker at Highfield are already rated at 66kV. Two additional line termination bays will be installed at Weedons to complete the ring bus.	This project relieves the Rolleston 33kV line constraint and is also the first part of making extra 66kV line capacity available towards Dunsandel which is approaching full capacity.	1,685	2017
671	Castle Hill generators	The geography of this remote location means that outages are not uncommon and can take a long time to restore.	Our fleet of emergency generators was extended in the aftermath of the earthquakes. We now have several units at our disposal and locating two at Castle Hill substation will improve security of supply for this area.	A second GXP transformer would not be economic given the small load.	187	2017
672	Arthur's Pass generators	The geography of this remote location means that outages are not uncommon and can take a long time to restore. The Arthurs Pass Town supply is interrupted more than any other part of the Orion network. The generator would offer a cost effective N-1 solution.	Our fleet of emergency generators was extended in the aftermath of the earthquakes. We now have several units at our disposal and locating one at Arthur's Pass Substation will improve security of supply for this area. A new step-up transformer and earthing transformer will be required.	A second GXP transformer would not be economic given the small load.	71	2017
716	Land acquisition for Southbridge zone substation	Forecast growth in the wider Southbridge and Leeston area will exceed the Hills Rd substation network capacity at both 11 kV and 33 kV. See Project 610.	A suitable zone substation site will be acquired.	Further analysis is required to determine the ideal location.	100	2017
114	Convert Highfield zone substation to 66kV	Highfield zone substation is currently supplied by a 33kV line from Springston zone substation. This line also supplies Rolleston zone substation. During peak summer loads the Highfield transformer reaches its maximum tap range due to voltage drop in the 33kV line and the contingency loading on the Rolleston 33kV circuits is approaching capacity.	Consistent with our strategy to exit 33kV as replacement and growth opportunities arise, we propose to convert Highfield zone substation to 66kV. A new 11kV ripple plant will also be required since the 33kV ripple signal will no longer be received. See also Project 415.	The timing of this plan maximises our assets by re-deploying a 66/11kV transformer from Dunsandel rather than purchasing a new bank.	845	2018

Table 5-6e.3 Major project details – rural – years FY17 to FY20

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
505	Springston T2 - 66/11 kV transformer	The greater Christchurch urban development strategy proposes further residential zoning of land at Lincoln, thus provision is required to increase capacity.	When required, we propose to install one of the 66/11kV 7.5/10MVA transformers from Dunsandel (Project 699) at Springston. The existing 33/11kV 7.5MVA bank will remain until the 33kV network is decommissioned.	The increase in load could be supplied by the existing Lincoln and/or Springston zone substations. Investment at Lincoln is not preferred since it will be replaced by a 66kV substation at Greenpark. The Greenpark substation could be advanced instead of this project, but would be more expensive. This project also makes efficient use of an existing transformer asset.	1,129	2018
587	Te Pirita 66kV bays	The Central Plains Water scheme will create an opportunity for a (upto)7MVA hydro generation scheme near Steeles Rd. Assets will be required to connect this into our 66kV network (see Project 670).	Two 66kV circuit breaker bays will be installed at Te Pirita zone substation for the existing Hororata circuit and the Steeles Rd line. If the generator does not proceed, these bays will still be required when the Windwhistle (Project 348) and/or The Point (Project 608) substations are commissioned.	A 66kV switching substation at Ardlui Rd and Sharlands Rd corner (the Hororata-Te Pirita-Bankside tee) would be more expensive and would not provide the same security benefits. A 66kV tee at Te Pirita would create a double tee situation which we avoid due to protection complications.	845	2018
609	Dunsandel to Norwood 66kV line + switchgear	Projected load growth in the area (mainly Synlait) requires expansion of the 66kV network to increase both capacity and security of supply. The proposed Southbridge zone substation (Project 610) will also increase load on the Springston-Killinchy 66kV circuit.	It is planned to build a 66kV Jaguar circuit between Dunsandel and Weedons zone substations. This project constructs the line from Dunsandel to the proposed Norwood site. A new 66kV bay will be needed at Dunsandel. Project 626 will construct a line from Norwood to the Weedons-Highfield tee. Dunsandel (currently supplied from Hororata GXP under normal conditions) will be transferred to Islington GXP on the new circuit.	A Dunsandel-Greendale link is an option and may be installed at a later date for different reasons, but the proposed connection from Weedons provides capacity from a recently upgraded 66kV ring from Islington.	3,279	2018
626	Norwood to Highfield/Weedons tee 66kV line	See Project 609.	A new 66kV line will be constructed from the Norwood site to the Highfield/Weedons tee.	A section of the line from Burnham School Rd up Dunns Crossing Rd has already been constructed at 66kV but operating at 33kV.	2,403	2018
670	Steeles Rd substation and 66kV line	The Central Plains Water scheme will create an opportunity for a (upto)7MVA hydro generation scheme near Steeles Rd. Assets will be required to connect this into our 66kV network.	A dedicated substation will be installed at the generator site. The substation would be a simple voltage step up site without the need for a substantial building to house 11kV switchgear, ripple and the usual protection and control equipment. We will build a 66kV line from this substation to Te Pirita zone substation. Switchgear will be required at Te Pirita (Project 587).	This project is completely dependent on the requirements of Central Plains Water or another party developing hydro generation at the site. Smaller amounts of generation could be directly connected to our 11kV network and therefore prevent the need for a new substation.	3,101	2018

Table 5-6e.4 Major project details – rural – years FY17 to FY20 (continued from previous page)

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
699	Dunsandel transformer upgrade	Load at Dunsandel will exceed the 10MVA N-1 capability of the site during the summer of 2015/16. An 11kV intertrip scheme has been installed during 2014/15 to provide load management capability at the site if one transformer should fail. A 4th Synlait milk drier in 2017 (estimated date) will mean that the capacity constraint can no longer be managed by the intertrip scheme.	We envisage that Synlait will request an upgrade of the 2 x 7.5/10MVA transformer to 2 x 11.5/23 MVA. One transformer will go to Springston (Project 505) and the other bank to Highfield (Project 114).	The decision to upgrade will be largely made by Synlait to meet their security and reliability of supply requirements.	2,327	2018
728	Springston 11kV switchroom	The 11kV switchgear at Springston zone substation is housed in two buildings which have operational and maintenance drawbacks, and do not provide room for expansion. Extra circuit breakers for the 66kV transformer (Major Project 505), bus coupler, new feeders and an 11kV ripple plant will be needed.	A new switchroom will be constructed to deliver the requirements.	The increase in load could be supplied by upgrading the existing Lincoln zone substation. Investment at Lincoln is not preferred since it will be replaced by a 66kV substation at Greenpark. The Greenpark substation could be advanced instead of this project, but would be more expensive.	777	2018
306	Annat transformer upgrade	The Central Plains Irrigation Scheme is likely to require an increase in capacity at Annat to pump water from the Waimakariri or Kowai Rivers to Springfield and Sheffield.	We propose to replace the Annat 2.5MVA transformer with a spare 7.5MVA transformer.	11kV reinforcement from Kimberley substation may provide an alternative solution but this is a relatively low cost project and is therefore expected to be the most economic. More information is required before we commit to this solution.	420	2019
637	Railway Rd 11kV substation (Westland Milk)	The proposed Westland Milk Products (WMP) processing plant in the Izone industrial park will require up to 8MVA. Steady load growth around this district also means further 11kV reinforcement is necessary to maintain security of supply.	We will build an 11kV switching station at the site with two dedicated cables from Larcomb zone substation and a backup circuit from Rolleston zone substation, all along Jones Rd. While the trenches are open we will also take the opportunity to complete the undergrounding of our remaining overhead 11kV lines in Jones and Hoskyns Rds and install an extra cable from Larcomb into Izone.	The magnitude of the point load, plus the ongoing growth around Rolleston, meant that a new zone substation near WMP was considered as an option. The fact that there are three nearby substations with sufficient capacity (especially after Rolleston is converted to 66kV), and that the 11kV feeders to adjacent substations in this project would still be needed for contingent support, means an 11kV solution is much cheaper and makes more efficient use of existing assets. When a new zone substation is finally needed, the Rossendale site (Project 528) will be a more optimal location.	3,051	2019

Table 5-6e.5 Major project details – rural – years FY17 to FY20 (continued from previous page)

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
639	Burnham 66kV zone substation stage 1	Rolleston 33kV substation will be converted to 66kV at some point in the future. The current site is not large enough for a 66kV switchyard, so a new zone substation will be built on a site nearby. Growth in the Rolleston/Izone area will shortly exceed the capacity of the existing substation.	We will build stage 1 of the new Burnham 66kV zone substation and operate it initially at 33kV. A suitable site will be identified (Project 500). The existing Rolleston zone substation will continue in service until the 66kV conversion.	One alternative is to bring forward the 66kV conversion. This is interconnected with a number of other subtransmission projects and would be very expensive, taking place before these investments are strictly necessary. Deferring the conversions makes the most of our 33kV assets for as long as possible. Another option is to transfer load to Larcomb, but significant 11kV reinforcement would be required and security of supply becomes problematic with no increase in capacity at Rolleston.	5,774	2019
666	Porters Village	A large resort development near Porters Pass ski field is proposed and if it proceeds it will require a connection to our network. Existing electrical load at the site is supplied by 'off grid' generators.	The magnitude of the load and distance from existing assets makes the requirements very challenging. Preliminary studies have been undertaken to provide an initial estimate of the costs but detailed design is yet to be undertaken. The solution may involve major business decisions such as GXP changes or the adoption of 22kV assets.	A comprehensive study is yet to be done and there is significant uncertainty about whether the proposal will eventuate and/or the timing.	4,276	2019
527	Land acquisition for Templeton 66kV zone substation	The districts and townships to the southwest of Christchurch are expected to show strong growth over the next decade and our zone substations and 11kV overhead feeders in the area are becoming constrained.	It is proposed to purchase a site for a future Templeton substation (see Project 502) adjacent to the 66kV line between Islington and Weedons.	We will continue to monitor the location and timing of load growth in the area (quarries have driven recent growth) and progress site investigation accordingly.	100	2020
610	Southbridge 66kV zone substation	Forecast growth in the wider Southbridge and Leeston area will exceed the Hills zone substation network capacity at both 11 kV and 33 kV.	It is planned build a new 66/11kV zone substation at Southbridge. The substation will be supplied from the Brookside-Killinchy circuit (Project 627). This location means that 11kV reinforcement is not necessary. Hills Rd 33/11kV zone substation will remain until the Springston 33kV network is decommissioned.	Options include increasing capacity at Hills zone substation. This involves investment in a 33/11kV transformer which is not consistent with strategy to exit 33kV in the long term and additional 11 kV circuits and regulators would still be required. Converting Hills to 66kV is an option but Southbridge is a more optimal location, being closer to the load growth in Rakaia.	3,359	2021

Table 5-6e.6 Major project details – rural – FY21 to FY25

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
627	Southbridge 66kV line	Forecast growth in the wider Southbridge and Leeston area will exceed the Hills Rd substation network capacity at both 11kV and 33kV. See Project 610.	A 66kV line will be built from Southbridge to tee onto the Killinchy-Brookside circuit.	An N-1 solution (two 66kV lines to Southbridge) could be considered. However, the most economic solution is to continue to utilise the 11kV network as a back up supply for 66kV line faults. Interruption of irrigation provides the key demand side management response needed to make this solution feasible.	1,146	2021
579	Hororata to Darfield 66kV line upgrade	See Project 849 (Darfield zone substation 66kV conversion).	We will upgrade the Hororata-Darfield circuit to 66kV (this project), connecting to the line (Project 581) from Darfield to Highfield zone substation. A new GXP bay at Hororata is required (GXP Project 629).	The Hororata-Annat-Darfield circuit could be used. However this would involve upgrading Annat zone substation to 66kV also.	1,243	2022
581	Highfield to Darfield 66kV line	The prospect of significant generation on the Rakaia River requires planning for increased subtransmission capacity from our western region into the Springston network. A new 66kV link between Hororata and Islington GXPs via Darfield and Highfield substations assists with this objective.	We intend to build a new 66kV line from Highfield to Darfield and install a 66kV bus with two new bays at Highfield. At a later date a line from Greendale zone substation may tee onto this circuit.	There is significant uncertainty about the level of generation investment on the Rakaia and therefore the extent to which we need to upgrade our subtransmission network. We will continue to monitor plans to install generation and in the meantime maintain flexibility in our approach.	3,543	2022
601	Convert Hororata zone substation to 66kV	Orion's and Transpower's 33kV switchgear at Hororata zone substation is due for replacement. Current standards require 33kV switchgear to be built indoors.	Our strategic plan is to upgrade our rural 33kV assets to 66kV when replacement or reinforcement is required. Rather than building an expensive 33kV switchroom we intend to replace the 33/11kV 7.5MVA transformer at Hororata with a new 10MVA 66/11kV unit. The remaining 33kV network can be supplied without a 33kV bus. A new Transpower 66kV bay at Hororata GXP will be needed (Project 325). The Darfield zones substation will also need to be converted (Project 849).	Retaining the Hororata 33kV network will be more expensive, and less suited to transmission for the proposed Trustpower generation projects.	1,228	2022
654	Land acquisition for Norwood 66kV zone substation	It is envisaged that load growth in the Norwood district (including two large industrial plants) will exceed the capability of our 11kV network in the area over the next decade (see Project 597).	A suitable zone substation site will be acquired.	There is not expected to be a shortage of options for the location of this site as the area is largely rural with plenty of good sites in locations remote from people.	250	2022

Table 5-6e.7 Major project details – rural – FY21 to FY25 (continued from previous page)

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
842	Greenpark 66kV zone substation	The greater Christchurch urban development strategy proposes further residential zoning of land at Lincoln and it is proposed to meet this load growth in the long term by the installation of a new zone substation.	It is proposed to install a new 66/11kV zone substation on the eastern fringes of Lincoln township. It will operate at 33kV (making use of existing 33/11kV transformers) initially until load growth requires the conversion of the existing 33kV lines from Springston to 66kV.	Other options worthy of consideration include a further upgrade at Springston or Lincoln. A Lincoln upgrade would involve the purchase of new 33/11kV transformers that in the medium term may become redundant as we convert to 66kV over time. The Springston upgrade option will be considered in more detail as the location and quantity of new load becomes more certain.	6,491	2022
849	Convert Darfield zone substation to 66kV	Load growth at or around Darfield and the need to replace 33kV switchgear at Hororata creates an opportunity to challenge the appropriateness of 33kV subtransmission when growth on our rural network has caused the transition to 66kV.	We propose to replace the 33/11kV Darfield zone substation with a 66/11kV site. Four 66kV bays will be needed for two transformers and two lines (Major Rural Projects 579 and 581).	It may be possible to defer or avoid this upgrade by 11kV reinforcement form Kimberley and finding a short term 33kV switchgear solution at Hororata. Other options will be investigated closer to the time.	3,901	2022
577	Windwhistle to The Point 66kV line	Proposed hydro generation on the Rakaia river/canal will need to be connected to either Transpower's grid or the Orion network. Transmission capacity is limited and there are commercial incentives for generator owners to embed their generation into distribution networks	The proposed solution is a new 66kV zone substation near 'The Point' (Project 608) below Roundtop. This project connects it to Windwhistle zone substation (Project 348) with a new 66kV line. A connection to Te Pirita zone substation is also planned (Project 113).	A Transpower GXP would be more expensive and also require some new 66 kV line construction and/or upgrades. Depending on generation capacity, other lower cost options may be viable.	2,028	2023
588	Te Pirita to Windwhistle 66kV line	Trustpower's proposed generation on the upper Rakaia River will require subtransmission reinforcement to adequately connect to our network. In addition, the zone substations at Windwhistle (Project 348) and The Point (Project 608) share a radial feed, and Te Pirita zone substation is also on a radial feed. A 66kV connection between Windwhistle and Te Pirita will form part of the generation solution while improving security of supply to the three zone substations.	It is proposed to install a 66kV Jaguar tie line between Windwhistle and Te Pirita zone substations. This project constructs a line from Windwhistle to tee onto the Steeles Rd-Te Pirita line (Project 670) above the existing 11kV along Rakaia Terrace Rd. Part of the 11kV circuit along the route already has poles built to 66kV construction. It is also proposed to join the 1.45km gap between the two 11kV circuits along the same road under the 66 kV.	A Transpower GXP would be more expensive and also require some new 66 kV line construction and/or upgrades. Depending on generation capacity, other lower cost options may be viable.	1,175	2023

Table 5-6.e.8 Major project details – rural – FY21 to FY25 (continued from previous page)

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
597	Norwood 66kV zone substation	It is envisaged that load growth in the Norwood district (including two large industrial plants) will exceed the capability of our 11kV network in the area over the next decade.	A 66/11kV 10MVA zone substation will be installed and supplied by new 66kV lines from Weedons-Highfield Tee (Project 626) and then Dunsandel (Project 609) at a later date. The substation will also help the Brookside N-1 contingency which is presently stretched.	The cost of this proposal will be compared with the 11kV reinforcement options at the time before making a decision on the best solution.	3,390	2023
608	The Point 66kV zone substation	Proposed hydro generation on the Rakaia river/canal will need to be connected to either Transpower's grid or the Orion network. Transmission capacity is limited and there are commercial incentives for generator owners to embed their generation into distribution networks	A new 66kV zone substation will be commissioned near The Point below Roundtop. A circuit (Project 577) will be constructed back to Windwhistle zone substation (Project 348). A connection to Te Pirita zone substation is also planned (Project 113).	A Transpower GXP would be more expensive and also require some new 66 kV line construction and/or upgrades. Depending on generation capacity, other lower cost options may be viable.	3,491	2023
705	Greendale to Dunsandel-Norwood line + switchgear	The prospect of significant generation on the Rakaia River requires planning for increased subtransmission capacity from our eastern region into the Springston network (see also Project 703). A new 66kV link between Hororata GXP and Springston zone substation via Greendale (the proposed) Norwood zone substations provides for this and improves security of supply for Hororata, Greendale and Burnham zone substations.	This project installs a line connecting Greendale zone substation to the Dunsandel-Norwood line. A 66kV bus will be needed at Greendale and this project also installs bays to terminate the new line and the Hororata-Greendale line.	Depending on generation capacity, this project may not be required.	2,355	2023
502	Templeton 66kV zone substation	The districts and townships to the southwest of Christchurch are expected to show strong growth over the next decade and our zone substations and 11kV overhead feeders in the area are becoming constrained.	A new zone substation will be required to provide security of supply to the Templeton township and surrounding district. The new substation will be supplied from the Islington to Weedons 66kV line.	We have already reconfigured the 11kV feeders in the area to share load more evenly and have installed an 11kV regulator to increase capacity. The close proximity of the Islington to Weedons 66kV line makes a new zone substation cost effective when compared to 11kV reinforcement from constrained zone substations in the area.	4,654	2024
447	Greenpark to Motukarara 66kV line conversion	The Birdlings Flat 66/33kV zone substation (Project 576) requires the conversion of the 33kV circuit from Springston to 66kV.	This project upgrades the section between the Greenpark zone substation site and Motukarara zone substation from 33kV Dog over 11kV to 66kV Jaguar over 11kV. See also Projects 583, 578, 697, and 725.	A second 33kV line is an option that can be explored if and when more detail unfolds.	1,677	2025

Table 5-6e.9 Major project details – rural – FY21 to FY25 (continued from previous page)

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
576	Birdlings 66/33kV zone substation	The possibility of wind generation at various sites on Banks Peninsula is being explored. If generation exceeds 17MW then a 66/33kV zone substation will be required.	The substation would require a 66/33kV transformer and a circuit breaker. One of the Springston 33kV ripple plants will need to be shifted to Birdlings zone substation. The 33kV circuit from Springston to Birdlings would be upgraded to Jaguar conductor at 66kV (Projects 447, 583, 697, and 725). See also Project 578.	A second 33kV line is an option that can be explored if and when more detail unfolds.	3,943	2025
583	Tancred tee to Greenpark 66kV line	The Birdlings 66/33kV zone substation (Project 576) requires the conversion to 66kV of the 33kV circuit from Springston to Motukarara and Birdlings. The circuit will no longer terminate at Springston zone substation but will tee off one of the Islington-Springston 66kV lines. See also Major Urban Project 707.	A new 3.54km 66kV Jaguar over 11kV circuit will tee off the Islington-Springston circuit and run along Tancreds Rd. It will connect to Greenpark zone substation site. The tee will avoid another 66kV bay at Springston zone substation. If the Birdlings zone substation is not commissioned, this project will still be required when Lincoln 33kV zone substation is replaced by Greenpark 66kV zone substation. See also Projects 447, 697, and 725.	This project is part of an integrated solution to Lincoln and Banks Peninsula and also recognises the long term objective of exiting 33kV. Depending on the which constraint (Lincoln load growth or Banks Peninsula wind generation) drives the need for an upgrade, the final solution will be adjusted accordingly.	685	2025
725	Birdlings to Motukarara 66kV line	The Birdlings 66/33kV zone substation (Project 576) requires the conversion of the 33kV circuit to 66kV	The Motukarara-Birdlings section of part of the Motukarara-Little River line will be upgraded from 33kV Dog over 11kV to 66kV Jaguar over 11kV. See also Projects 447, 583, and 697.	A second 33kV line is an option that can be explored if and when more detail unfolds.	1,904	2025

5.6.8 11kV urban reinforcement projects

Table 5-6f 11kV urban reinforcement projects

Project	FY16	FY17	FY18
512 Birmingham Dr rearrangement - stage 2	291		
18 Bridle Path Rd reinforcement	110		
839 Shands Rd north cables	173		
807 Aidanfield Dr cable	210		
635 Remote Indication	100		
485 Addington-Fielding St circuit	56		
856 Hornby 113 cable upgrade	80		
681 Marshs Rd cable		384	
851 Moffett rearrangement		150	
809 Jessons Rd switchgear		82	
854 Halswell Junction Rd		173	
785 Hayton Rd cable		33	
788 Travis Rd reinforcement		129	
855 Waterloo Rd		560	
622 Lancaster-Milton tie - stage 2			78

The Canterbury Earthquake Recovery Authority's Christchurch Central Recovery Plan was released to the public on 30 July 2012. Our underground 11kV network in the central city does not appear to have suffered major damage, although much of it is carrying no load at present as demolition continues and few new buildings are finished and occupied. The network is probably adequate in general terms to supply the proposed rebuild as the total CBD demand is unlikely to reach pre-earthquake levels. Some alterations and reinforcement will be necessary, in particular for large point loads such as the Convention Centre, Metro Leisure Centre and stadium. CBD reinforcement projects have not been included in this list as the nature and timing of load growth is yet to be established.

Table 5-6f.1 11kV reinforcement project details – urban – current year FY16

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
512	Birmingham Dr rearrangement stage 2	Load in the Wigram area south of Middleton zone substation is at the limit of the network's capacity during a Middleton zone substation outage.	The 11kV network in Birmingham Dr is being reworked in two stages to strengthen ties between Middleton and Addington zone substations and allow for the eventual decommissioning of Birmingham Dr No. 46 Substation. This project connects the Annex Rd cable from Halswell Rd along Magdala Place and into Wigram Rd Showgrounds providing further 11kV support into Wigram.	The project will be coordinated with Christchurch City Council roadworks in Magdala Place.	291	FY16
18	Bridle Path Rd reinforcement	The 11kV network in the Heathcote valley requires reconfiguration and strengthening to provide a connection for the Lyttelton tunnel cable (Project 50).	There is an existing 300mm2 aluminium cable from Heathcote zone substation to the tunnel with low utilisation (Cd4732). An alternative 11kV feed into the Port Hills area is required to free up this cable for use as the tunnel feeder. This project replaces some low-capacity overhead line with cable, and also lays cable near the tunnel entrance to allow connection of the 300mm2 aluminium tunnel cable in Project 50.	A new high-capacity cable from Heathcote zone substation to the tunnel is a much more expensive option.	110	FY16
839	Shands Rd north cables	The overhead circuit north of Shands zone substation is at capacity after a Hornby zone substation outage. New industrial load is also planned in the South Hornby area, requiring capacity and contingency support.	We will lay two new cables from Shands zone substation to Edmonton Rd. One will connect west through a new industrial subdivision to Produce Place. The other will become a direct feed to the existing Edmonton Rd circuit currently supplied from the overhead line.	This project is a tactical reinforcement option to mitigate the need to install a higher 300mm2 aluminium cable (Project 700) along the new motorway. It frees up circuit breakers to deliver capacity to the new developments in the area and enables the lower cost Project 854: Halswell Junction Rd to replace Project 700.	173	FY16
807	Aidanfield Dr cable	The Wigram development is supplied from Middleton zone substation with limited backup from Hoon Hay zone substation. Increasing load requires an increase in tie support between the zone substations in the area.	A 185mm2 aluminium cable from Aidanfield Drive No. 36 Substation to McMahon Drive No. 61 Substation will allow the full capacity of the new Wigram Rd cable to support the Wigram-Middleton area. The circuit is currently constrained by a section of 95mm2 aluminium cable.	A new feeder from Sockburn zone substation into Wigram would be more expensive and would not improve the links between Middleton and Hoon Hay zone substations.	210	FY16
635	Remote Indication	In preparation for smart grid developments and the penetration of electric cars, we have undertaken a major study of our distribution network. To enable a more accurate assessment of current loads and network performance we require more data points on our network.	We intend to install 50 remote indication sites with smart meters located at distribution transformers/low voltage feeders and the associated back office systems. This will provide real time data on load and power quality within the low voltage and 11kV networks. It also provides an opportunity to investigate the best metering and communications technologies for our network and this project is as much about these solutions as it is about the network data.	It is envisaged that more data about our network performance will show that some areas have more spare capacity than our planning analysis (load flows) show. This will enable us to defer capacity upgrades. Conversely, we will be able to address unforeseen constraints early.	100	FY16

Table 5-6f.1 11kV reinforcement project details – urban – current year FY16 (continued from previous page)

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
485	Addington-Fielding St circuit	The decommissioning of Foster and Montreal zone substations and replacement of Addington #2 11kV switchgear requires re-arrangement of the 11kV network to maintain supply to the Addington area and maintain a closed ring for the Trotting Grounds.	A new section of cable from Fielding St kiosk has been joined to an existing out of service cable. This project will connect this to the Trotting Grounds feeder which passes Lincoln Rd No. 235 from Addington. The Trotting Grounds will be fed from a currently unused breaker at Lincoln Rd No. 235. This provides tie support from Addington zone substation into the Addington commercial area.	An alternative is to lay a completely new cable all the way back to Addington zone substation. This would not utilise the existing out of service assets and would increase costs.	56	FY16
856	Hornby 113 Cable Upgrade	A major commercial/Industrial development is planned for the area between Halswell Junction, Shands and Marshs Rds. The 11kV network will need reinforcement to provide capacity to this development.	Two lengths of 0.15Cu and 185mm ² Al XLPE will be upgraded to 300mm ² Al XLPE on Hornby zone substation CB113 which will provide the required capacity into the new development.	An alternative is to lay a new cable from Hornby zone substation into the development, however this is a more expensive option and we are space constrained for new circuit breakers at Hornby zone substation.	80	FY16

Table 5-6f.2 11kV reinforcement project details – urban – years FY17 to FY20

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$000	Year
681	Marshs Rd cable	A major commercial/industrial development (Waterloo Park) is planned for the former Islington freezing works site. There is a supply from Moffett zone substation, however little backup capacity is available.	A new 300mm2 aluminium cable is proposed from Shands zone substation along Marshs Rd and into the Waterloo Park development. Part of this cable will be laid as part of the Calder Steward development on the corner of Shands and Marshs Rd and part will be considered as part of the NZTA plans for the intersection of Main South Rd/Marshs Rd.	An option exists to install a new 33kV zone substation to address the increasing utilisation on the existing 33kV network in the South West. This is a costly option in which significantly lower cost tactical reinforcement projects, including this Project 681, can delay or mitigate.	384	FY17
851	Moffett rearrangement	New Waterloo Park and Calder Stewart developments to the West and South West of Moffett zone substation require capacity from Moffett zone substation and alternative backup capacity.	This project rearranges the feeders and frees up a circuit breaker at Moffett zone substation for a new cable into Waterloo Park (Project 855) and provides several main trunk routes through the two developments to Shands zone substation.	The installation of a new 33kV zone substation between Moffett and Shands zone substations is being considered. Alternatively conversion of Shands zone substation to 66kV is also an option. However, in the short term the Moffett 33kV incomers will be upgraded to provide 23MVA of capacity at Moffett. This project makes use of that investment by reconfiguring the 11kV cables to enable 23MVA of capacity to be distributed to the new developments.	150	FY17
809	Jessons Rd switchgear	11kV alterations are required in the McLeans Island area to realise the full benefit of the new Waimakariri zone substation (Major Urban Project 525).	We will install a ring-main unit at the corner of Pound Rd and Jessons Rd. This project allows the transfer of load in the McLeans Island area to Waimakariri zone substation from the more distant Hawthornden and Bishopdale substations. This improves the utilisation of a lightly loaded feeder, and improves sectionalising of overhead circuits.	An alternative is to lay a new cable from Logistics Dr along McLeans Island Rd, however this is more expensive and leaves a 240mm2 aluminium cable underutilised.	82	FY17
854	Halswell Junction Rd	Load growth resulting from new subdivisions in the Awatea area require capacity and contingency support.	This project makes use of the Shands Rd north cables (Project 839) by reconfiguring the network in Edmonton Rd and by laying a new 300mm2 aluminium cable from Columbia Ave No. 52 through to Wilmers Rd No. 5 to deliver capacity to the new subdivisions and industrial developments down Halswell Junction Rd.	This project mitigates the need for the more expensive southern motorway cable (Project 700).	173	FY17
785	Hayton Rd cable	In a Middleton contingency, one Sockburn feeder supplying capacity to the area is overloaded while an adjacent feeder has spare capacity thus limiting the backup supply.	Swapping the two cables at a distribution substation, the load is better balanced between the two feeders, removes the overload issue and provides backup capacity into the Middleton area.		33	FY17

Table 5-6f.3 11kV reinforcement project details – urban – years FY17 to FY20 (continued from previous page)

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
788	Travis Rd reinforcement	A cable in Travis Rd has a section of 95mm ² aluminium cable which is overloaded during a Rawhiti zone substation contingency.	The section of 95mm ² aluminium cable will be replaced by a 185mm ² aluminium cable to remove the overload during contingency events.		129	FY17
855	Waterloo Rd	A major commercial/industrial development is planned off Waterloo Rd in Hornby. A supply is planned from Shands zone substation (Project 681) for the south western end of the development and this project provides capacity to the north eastern end of the development from Moffett zone substation.	A cable will be laid from Moffett zone substation CB115 down Waterloo Rd and into the development. A second cable will connect from Fulham St down Waterloo Rd and through-joint on to an existing cable to provide extra capacity into the existing Brixton St network.		560	FY17
622	Lancaster-Milton tie stage 2	Contingency support between Milton and Lancaster zone substations following an outage is approaching constraint.	We will lay the second of two new cables from Lancaster zone substation into the Sydenham area, providing an further 7MVA of tie support to Milton zone substation. This capacity will also enable the transfer of load between Milton and Lancaster zone substations and keep Milton zone substation load below it's 40MVA firm capacity. The nature and pace of redevelopment around the southern city centre and Sydenham will determine the timing of this investment.		78	FY18

5.6.9 11kV rural reinforcement projects

Table 5-6g 11kV rural reinforcement projects			
Project	FY16	FY17	FY18
828 Rolleston developments - Dynes Rd to Lowes Rd	534		
829 Rolleston developments - Brookside Rd (South)	157		
840 Rolleston developments - Burnham School Rd	251		
844 Rolleston developments - Levi Rd	46		
808 Edward St Lincoln cables		631	
663 Darfield township reinforcement from Kimberley			642
791 West Melton cable			388
806 Gerald St Lincoln cable			122
701 Southern motorway reinforcement - stage 2			282
803 Lincoln feeders (Weedons Rd)			636

Table 5-6g.1 11kV reinforcement project details – rural – current year FY16

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget \$'000	Year
828	Rolleston Developments – Dynes Rd to Lowes Rd	Ongoing residential development in Rolleston township requires substantial reinforcement to maintain security of supply. The Farringdon subdivision will add several MVA to the south of the township where the network is weak. The Rolleston zone substation is close to capacity and while there is plenty of transformer capacity at Larcomb and Weedons, the 11kV network needs to be augmented into the township.	This project consists of 185AL cable reinforcement along Springston Rolleston Rd and Dynes Rd. This circuit will become part of Larcomb CB112. Thus the Farringdon subdivision load will be shared with Rolleston zone substation.	Alternative routes were considered but the chosen route involves the least construction and best benefit for future Farringdon subdivision load.	534	2016
829	Rolleston South - Brookside Rd cables	The network development in the Rolleston area has led to network reconfiguration. Once the 300AL cable from Dunns Rd crossing to Granite drive is complete, then further network reconfiguration will occur along Brookside Rd.	This involves installing 300AL XLPE cable along Brookside Rd. This will improve the reliability of supply for the mainly new subdivision loads fed from Rolleston zone substation feeders CB112 and CB113.		157	2016
840	Rolleston Developments - Burnham School Rd	The residential development on Burnham School Rd has provided the opportunity to reconfigure the 11kV cable network.	It involves reconfiguring Rolleston Substation CB111 and CB123 feeders. This is achieved by installing 300AL cable and by further replacing OH section along East Maddisons Rd. This will increase the capacity and improve reliability of supply to the new subdivisions.		251	2016
844	Rolleston Developments - Levi Rd	New residential sub divisions are currently under construction along the Levi Rd. This reinforcement supports the ongoing development in the Rolleston area, refer project 828	This project involves replacing 150m of existing overhead squirrel conductor with 185AL cable to increase the capacity and thus meet the requirements for the new subdivision.		46	2016

Table 5-6g.2 11kV reinforcement project details – rural – years FY17 to FY20

No.	Project title	Issue	Chosen solution	Remarks/ alternatives	Budget \$000	Year
808	Edward St Lincoln, cables	Due to the continuous residential development in the Lincoln area, it is envisaged to increase feeder capacity and meet the security of supply standards.	The remaining 11kV lines in Edward St (Lincoln) will be undergrounded as the sequence of reinforcement is completed. This project lays cable which will become feeders for the proposed Greenpark zone substation.		631	2017
663	Darfield Township reinforcement from Kimberley	Growth at Darfield township is expected to reach the 4MVA threshold for security of supply class D2, which requires some switchable restoration after N-2 events. Also, while Darfield has N-1 33kV line security, it only has a single transformer so is strictly on N security.	An 11kV cable will be laid from Kimberley ZS to Darfield. This will carry the township load in the event of a Darfield zone substation outage or dual 11kV feeder fault. Support for Kimberley from Darfield zone substation is also improved. Investment at Darfield (e.g. second transformer) is not economic, as it will be decommissioned in 2020. Its replacement, the proposed Greyke 66/11kV zone substation, will also be permitted to have a single transformer because of the security offered by this cable, resulting in substantial savings.	804	642	2018
791	West Melton cable	The residential development at West Melton has become a township. A large area of OH network is also supplied by this cable network, reducing reliability for the township. There is also low voltage on the northern fringes in a Weedons contingency.	We will lay a cable through the township so that the northern overhead network can be supplied from a separate circuit from the village. The low voltage problem is also improved, allowing for some growth before other solutions such as capacitors become necessary.		388	2018
806	Gerald St Lincoln, cable	This project (along with Project 808) concludes our reinforcement of the main road circuits in Lincoln township, including the removal of overhead lines.	The remaining 11kV lines in Gerald St will be undergrounded as the sequence of reinforcement is completed.		122	2018
701	Southern Motorway reinforcement stage 2	NZTA's SH1 widening project requires network undergrounding in the affected area. While the trenches are open, an opportunity is provided to also install new circuits at a much reduced cost. See also Urban Reinforcement Project 700.	We will lay a new feeder cable into east Rolleston township from Larcomb zone substation. This is an area of prolonged expansion requiring significant capacity increase in the 11kV network. Part of this route involves trenching beyond the NZTA road works.		282	2018
803	Lincoln feeders (Weedons Rd)	Steady residential development south of Lincoln township will exceed the backup capacity from Springston zone substation, and eventually exceed the transformer capacity at Lincoln zone substation.	Two new cables will be laid from Springston in to the Lincoln underground network. This will allow for contingency support and load transfer between the zone substations. It will also allow the separation of rural overhead network from the township's underground network, improving reliability.		636	2018

5.6.10 Network connections and extensions

Overview

Network connections can range from a 60 amp single-phase connection to a large industrial connection or a big subdivision of several thousand kVA.

Consumer connections

We anticipate that we will continue to connect consumers to our network at the present rate of approximately 3,000 each year. Supplying these connections creates a need for:

- kiosk substations
- pole substations
- network or large consumer building substations
- low voltage services
- network extensions.

Subdivisions

The level of subdivision activity depends on economic conditions and population growth. The Land Use Recovery Plan forecasts the combined Selwyn district and Christchurch City council areas will develop more than 2,000 new residential lots per annum over the next 10 years. In our rural area most subdivisions are for lifestyle reasons. In our urban area it can be industrial, commercial or residential, though most developments are residential. Our subdivision investment is made after negotiating with the developer on the basis of a commercial rate of return.

5.6.11 Underground conversions

The local authority or the New Zealand Transport Agency instigates conversions from overhead line to underground cable. In conjunction with the relevant roading authority we consider converting overhead lines on highways and other places where safety is a major issue. Where a capacity increase requires us to reinforce our network, we may replace overhead lines with underground cables as per the local authority's district plan.

5.6.12 Demand side management value for network development alternatives

Demand side management (DSM) initiatives can provide alternatives to investment in traditional network development solutions. This section is included in our AMP to assist potential DSM providers to determine the approximate funding available from Orion when specific projects are deferred through DSM.

The table on the following page is a high level assessment of the annual per kW cost of proposed network solutions where DSM could be used to defer the project. If a DSM solution is presented, then further detailed analysis is undertaken to compare options. Multiple projects are sometimes required to resolve network constraints – these have been grouped together by colours in the table. The \$/kW available for DSM solutions is the sum of all similarly coloured projects.

For example:

Upgrading Shands substation to 66kV scheduled for FY19 has a capital cost of \$6.2m and an annual capital funding cost of \$0.75m. It provides capacity and security of supply for 500kW of load growth per annum. For a DSM solution to be economic and provide a one year deferral of a network solution, the cost per kW must be lower than \$1,500 (\$0.75m/500kW). If the DSM solution can provide three years of deferral (1.5MW at peak) then the DSM proposal cost must be lower than:

- \$1,500 for 0.5MW in the first year
- \$750 for 1.0MW in the second year
- \$500 for 1.5MW in the third year.

The values in the following table assume that the DSM solution is provided in the year required and therefore discounted values apply for DSM solutions implemented earlier than required.

Table 5-6h DSM value for network development alternatives

Year	Project description	Budget capital (\$000)	Growth per year (kW)	\$ per kW available for DSM alternative		
				Year 1	Year 2	Year 3
2016	Moffett substation replace 33kV feeders	190	1,000	20	10	10
2018	Marshland zone substation	9,000	1,900	570	290	190
2018	Springston T2 - 66/11 kV transformer	1,130	700	190	100	60
2019	Burnham 66kV substation stage 1	5,770	900	770	390	260
2019	Convert Shands to 66kV	6,240	500	1,500	750	500
2019	Annat transformer upgrade*	420	1,000	50	30	20
2019	Porters Village	4,280	5,000	100	50	30
2020	Yaldhurst zone substation	8,790	200	5,270	2,640	1,760
2021	Southbridge 66kV substation	3,360	200	2,020	1,010	670
2021	Southbridge 66kV line	1,150	200	690	350	230
2022	Convert Hororata substation to 66/11kV	1,230	50	2,950	1,480	980
2022	Hororata 66kV bay for Hororata substation	653	50	1,570	790	520
2024	Templeton zone substation	4,650	1,000	560	280	190
2023	Shands 66kV Stage 2	800	800	120	60	40

Risk management



6

6.1	Introduction	245
6.1.1	Risk management context	245
6.1.2	Risk management responsibilities	245
6.1.3	Risk management process	246
6.1.4	Risk management plans	247
6.2	Governance and operational business risks	248
6.2.1	Safety	248
6.2.2	Legislative compliance	248
6.2.3	Network performance	249
6.2.4	Internal control	249
6.2.5	Commercial management	249
6.2.6	Reputation	250
6.2.7	Environment	250
6.2.8	Human resources	250
6.3	Safety	251
6.4	Environment	252
6.4.1	Management process and documentation	252
6.5	Network risk analysis	253
6.5.1	Assessment of risks	253
6.6	Interdependence	254
6.6.1	Interdependence with other services	254
6.6.2	Transpower sites	255
6.7	Natural disaster	255
6.7.1	Management system	255
6.7.2	Earthquake	256
6.7.3	Flooding	257
6.7.4	Snowfall	257
6.7.5	Wind	257
6.7.6	Tsunami	257
6.8	Asset failure	258
6.8.1	Administration building	258
6.8.2	66kV cable network	258
6.8.3	Ripple system	258
6.8.4	Distribution management (DMS) system	258

Continued overleaf



6.9	Mitigation measures	259
6.9.1	Procedures and plans	259
6.9.2	Engineering measures	260
6.9.3	Avoidance of major supply failure	261
6.9.4	Mitigation of major supply failure	262
6.9.5	Historic examples	263
6.9.6	Insurance	263

List of figures and tables in this section					
Figure	Title	Page	Table	Title	Page
6-1a	The three components of risk	245	6-5a	Primary risk for major assets	253
6-1b	Key risk responsibilities	245	6-5b	Possible cause of contaminant discharge and risks	253
6-1c	Orion risk acceptability matrix	246	6-6a	Interdependence of lifelines (1 week after EQ)	254
6-1d	Orion risk acceptability chart	246	6-6b	GXP – Liquefaction potential and related damage	255
6-4a	Environmental management documentation	252	6-7a	Orion – Liquefaction potential and related damage	256
6-4b	Environmental management process	252			

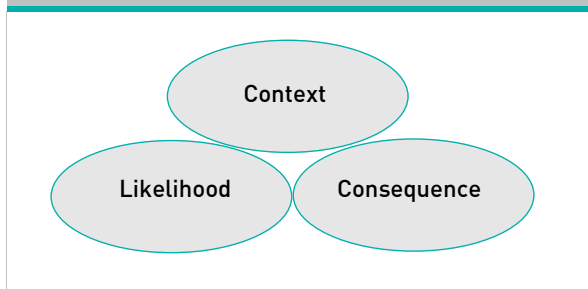
6.1 Introduction

6.1.1 Risk management context

To maintain a sustainable business we perform risk management to identify acceptable levels of risk. Risk needs to be understood and, where it cannot be eliminated, we use training, competency, safe work practices and network design to control the level of risk. Risk needs to be identified and mitigated within acceptable limits to achieve the most satisfactory outcome.

Risk is often measured or quantified as the product of a probability and consequence. However, a less obvious but important factor is context. While the consequence of some risks is similar, their contexts, such as location, may result in a difference in risk rating.

Figure 6-1a The three components of risk

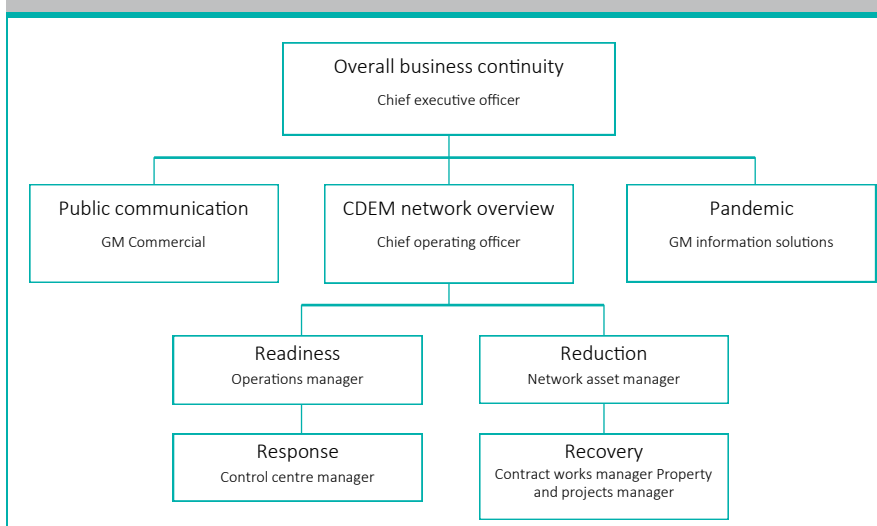


6.1.2 Risk management responsibilities

The following chart shows the responsibilities of key Orion staff who help to manage risk. These responsibilities help us to plan and respond to situations that may arise from any of the causes discussed in the remainder of this section.

Note: We have aligned our Civil Defence responsibilities using the ‘four R’s’ approach to resilience planning—reduction, readiness, response and recovery.

Figure 6-1b Key risk responsibilities



6.1.3 Risk management process

Our risk management process is based on the risk management standard AS/NZS 31000.

The acceptability of risk is determined on the basis of likelihood and consequences of the event associated with the risk occurring. The evaluated ranking of these two is used to establish the priority for managing the risk.

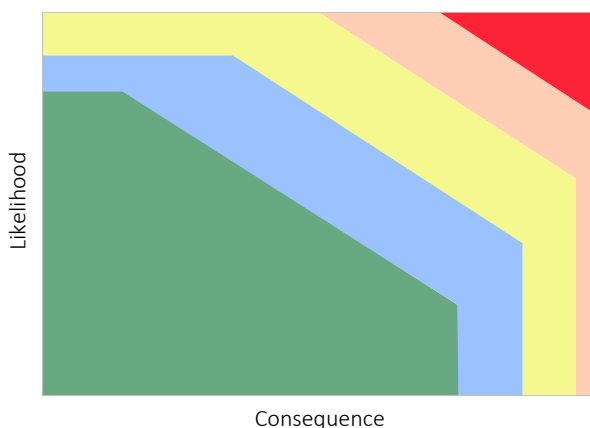
We have two risk assessment tools, both of which have been calibrated to present the risk acceptability ranking in a similar manner:

- Desktop—paper based work area assessment utilising the following risk acceptability matrix.

Figure 6-1c Orion risk acceptability matrix					
Likelihood					
Frequent (happens often)	H	H	VH	E	E
Likely (happens sometimes)	M	H	VH	VH	E
Possible (happens rarely)	L	M	H	VH	VH
Unlikely (happens somewhere)	L	M	M	H	VH
Rare (hasn't happened yet)	L	L	L	M	VH
Consequence	Minor	Moderate	Serious	Major	Catastrophic
Classification	Escalation				
E = Extreme	Board to be informed				
VH = Very high	CEO to be informed				
H = High	Corporate manager to be informed				
M = Moderate	Line manager to be informed				
L = Low	No escalation				

- Quantate—a dedicated risk management software application that allows us to document and prioritise risk across our business with results presented on the bands of the following risk acceptability chart.

Figure 6-1d Orion risk acceptability chart



In the following sections we concentrate on the physical aspects of risk associated with managing network assets. The objective is to avoid catastrophe, reduce uncertainty and improve predictability.

6.1.4 Risk management plans

We have several risk management plans for different aspects of our network. We summarise these below:

- **Disaster resilience summary – (NW70.00.14)**

We created this document to inform Civil Defence and others of our network resilience.

- **Asset risk management plan – (NW70.60.02)**

The Civil Defence Emergency Management Act also requires us to plan for major events. In particular it requires us to:

- function to the fullest extent during and after an emergency
- hold plans which show how we plan to function during and after an emergency
- participate in civil defence emergency planning at national and regional level if requested
- provide technical advice on civil defence emergency management issues where required.

As part of these requirements, our asset risk management plan focuses on the physical aspects of risk associated with managing network assets in the event of a major incident or emergency. Topics covered include:

- exposure to natural disaster with details of specific hazards
- establishing a rating system to easily identify those areas most at risk
- mitigation measures and practical solutions to reduce risk or impact
- the location, likely reasons for failure and contingency provisions for each asset group
- a schedule of the risk-based spares we hold.

For further discussion on natural disaster and asset failure see sections 6.7 and 6.8.

- **Security standard**

Our security standard is key to how we plan to meet the demand for electricity in certain circumstances when electrical equipment fails on our network. It is discussed in detail in section 3.3.3 and section 5.3.1.

- **Network physical access security plan – (NW70.60.03)**

Our network physical access security plan details our security policies, principles and procedures that restrict physical access to our electrical network and associated infrastructure. The principles defined in this document underpin our stated commitment to provide a safe reliable network and a safe and healthy environment for the public, employees and contractors.

The predominant focus of the plan is to restrict access by unauthorised personnel. However, some of the risks associated with access to equipment, together with mitigation measures, also directly affect authorised personnel.

In terms of security, the general principle is to prevent unauthorised entry by the public and opportunist intruders without specialised tools, and slow determined intruders. This is achieved by:

- reasonable measures to prevent access by members of the public to potentially fatal voltages
- additional measures to deter, detect and slow determined intruders at higher risk sites.

For further discussion on safety see section 6.3.

- **Environmental risk register – (NW70.10.06)**

The aim of this register is to summarise the environmental risks that relate to our business and operations, including likelihood of occurrence, consequences and mitigation.

Environmental risks associated with loss of supply or fluctuations in supply are not included, either generally, or in relation to particular large industrial users. At this stage we consider these risks are more appropriately addressed through the asset management process, Lifelines Project and individual users' own environmental risk assessments.

We have assessed the risk (likelihood, consequence) of an event and our mitigation-effectiveness based on a subjective estimate. This assessment is therefore not supported by historical data or records.

The register is a tool that helps us to manage risk – it is not an exhaustive list of all risks. Its value is that it identifies general risk to the company and highlights any areas of high risk that may require particular management attention.

- **Business continuity plans**

The aim of these plans is to provide an assessment of the risks that relate to the continuity of our business and operations due to the loss of systems or personnel.

Each corporate manager is responsible for their functional part of these plans.

6.2 Governance and operational business risks

Governance risk management is the responsibility of the Orion board. The board approves our statement of intent, our business plan and our AMP. The board also approves the group's insurance programme.

Our board has established an audit committee to liaise with Orion's auditor and provide additional assurance regarding the quality and reliability of internal controls for financial information used by and issued by the board.

Operational risk management is the responsibility of the CEO, overseen by the Orion board. Key operational risks are delegated to managers. Some risks are common across the business. Key risks are directly managed by the group with the greatest expertise.

We have assessed our greatest risks as:

- safety
- legislative compliance
- network performance
- internal control
- commercial management
- reputation
- environment
- human resources.

6.2.1 Safety

Refer to section 6.3 - Safety.

6.2.2 Legislative compliance

Material compliance is assessed using standard risk assessment methods to prioritise and quantify our known risks. As part of our regular reporting to the board, specific issues associated with our compliance programmes are reported.

The following Acts and Regulations are those that we consider key to the management of our business:

- Electricity Act 1992
- Electricity Regulations 1997
- Electricity Industry Act 2010
- Resource Management Act 1991
- Hazardous Substances and New Organisms Act 1996
- Health and Safety in Employment Act 1992
- Building Act 2004
- Fire Service Act 1975
- Fire Safety and Evacuation of Buildings Regulations 1997
- Commerce Act 1986
- Companies Act 1993
- Energy Companies Act 1992
- Electricity Industry Reform Act 1998
- Financial Reporting Act 1993
- Taxation Legislation
- Consumer Guarantees Act 1993
- Fair Trading Act 1986
- Sale of Goods Act 1908
- Employment Relations Act 2000
- Holidays Act 2003
- Human Rights Act 1993
- Injury Prevention, Rehabilitation and Compensation Act 2001
- Minimum Wage Act 1983
- Wages Protection Act 1983
- Parental Leave and Employment Protection Act 1987
- Smoke Free Environments Act 1990
- Privacy Act 1993.

6.2.3 Network performance

Refer to section 6.7 - Natural disaster, 6.8 - Asset failure and 6.9 - Mitigation measures.

6.2.4 Internal control

The board of directors is responsible for the proper direction and control of the company and approves and/or is responsible for:

- key objectives, business plans, budgets, key governance policies and delegations of authority
- key financial and dividend policies
- risk management
- legislative compliance
- external reporting
- relationships with stakeholders and external parties
- internal controls
- management oversight
- liaison with the company's external auditor.

The board delegates certain authorities and accountabilities to the chief executive and senior management, and formally reviews these at least annually. The board receives regular reports from management and regularly reviews:

- the company's objectives
- whether the company is meeting its objectives
- key risks to the company meeting its objectives.

Senior management and the board seek independent expert advice when appropriate.

All of the above are key parts of the company's internal controls and risk management process.

6.2.5 Commercial management

The commercial management of Orion includes governance, finance, insurance, auditing, pricing, valuation, industry submissions and information technology.

Ensuring that sufficient financial resources are available to support the continued operation, maintenance, replacement and growth of the network is a key task of management. Central to this is managing revenue risk and the relationship between cost and income. Several activities assist in the management of this risk:

- **Prudential requirements**

The most common form of contract for network delivery services in the electricity industry is 'interposed' -where a distributor will charge electricity retailers for the delivery service provided to many thousands of consumers. As a result our network's prudential risk is concentrated in the hands of a small number of electricity retailers. We use of a range of contractual measures—including payment terms, bonds and bank guarantees to manage this risk.

- **Managing contracts and potential liabilities**

It is prudent to cap liabilities for network delivery services and we manage our liabilities, where we are able, in our contracts.

- **Relationship between price and cost**

We utilise dynamic peak pricing to link a core driver of cost in our business (capital spend due to peak demand growth) with our income.

- **Regulatory matters**

Under Part 4 of the Commerce Act the Commerce Commission has developed Input Methodologies which set upfront regulatory methodologies, rules, processes, requirements and evaluation criteria for services that we provide. There will be a general review of these Input Methodologies in 2017.

In the interim, the Commerce Commission continues to review elements of the regulatory price control and information disclosure regime.

The electricity industry is also regulated by the Electricity Authority. One of the Authority's functions is to develop, administer and enforce the Electricity Industry Participation Code (the Code), which is a set of rules that govern nearly every aspect of New Zealand's electricity industry including generation, transmission, system operation, security of supply, market arrangements, metering, distribution and retail. One key area of risk (and focus) for us is our obligations under the Code to maintain common quality (Common quality refers to those processes and technical requirements placed on asset owners and the system operator that impact on power systems).

We take an active part in formal submissions on proposed changes to the regulatory regime to the extent they impact on us.

6.2.6 Reputation

We value our reputation and relationship with our customers and aim to be recognised for excellence in customer service and stakeholder relationships, lead collaboration across the electricity industry for the benefit of all, apply technology and demand side management to benefit our customers, and be recognised for excellence in leadership and management. To achieve these aims we have developed the following values:

We will	Meaning
Value relationships	We build and maintain positive relationships with our internal and external stakeholders (our employees, customers, shareholders, suppliers, contractors, regulators, community organisations etc.)
Be trustworthy	We demonstrate honesty, sound judgement, understanding and empathy. We earn the trust and respect of our community
Be proactive	We create opportunities and promptly respond to challenges with initiative. We empower our employees to be accountable and focus on results
Maintain a long term focus	Decisions we make must not compromise the achievement of our purpose
Be effective and efficient	We strive for competence, effective planning and execution, consistency in application and efficiency
Be innovative	We maintain a learning environment. We explore and adopt ideas that create value
Value safety and wellbeing	We provide a safe and healthy work environment to protect ourselves, other people and property
Value our natural environment	We are mindful of our impact on the natural environment and seek ways to minimise our effects

6.2.7 Environment

See section 6.4 Environmental management.

6.2.8 Human resources

A sophisticated network of electrical assets is central to how we function. The skilled employees who operate this equipment are also critical to our business.

We are committed to providing a work environment that enables professional and personal growth—we recognise our responsibility to ensure our people achieve the best mix of skills they can while they are here.

An aging workforce and an industry shortage of skilled staff remain issues and we continue to plan ahead to recruit and retain skilled employees. To ensure that we are not left short of skilled employees in the future, we support several initiatives that focus on training, recruitment and staff retention:

In-house development programme

These programmes are designed to train employees to a level where they are sufficiently skilled to replace employees who we expect to retire in the next five to 10 years.

CPIT Trades Innovation Centre

We continue to advise on ways to retain and attract people into electricity related trades. We have invested in a distribution trades training centre as a partner with CPIT.

Power Engineering Excellence Trust

The Trust and University of Canterbury have established an Electric Power Engineering Centre to support power engineering education.

Wellness programme

Our wellness programme helps our employees maintain good standards of health and wellbeing. Wellness activities include; health and wellbeing seminars, on-site health nurse, full health checks, flu vaccinations, fitness activities, healthy eating lunches, employee counselling, earthquake-related support and subsidised visual examinations.

As an employer committed to developing the potential of our employees we believe it is important to understand their concerns. Each year we survey our employee's to get their view on their working environment.

6.3 Safety

We are committed to providing a safe, reliable network and a safe, healthy work environment—we take all practicable steps to minimise harm to the community, our staff, contractors and the environment. We control hazards through training, guidelines and standards. Potential hazards, in particular electrical hazards, are also considered when new network installations are being designed and constructed.

We are implementing a plan to achieve compliance with the proposed Health and Safety at Work Act which will come into force sometime after 1 April 2015. Worksafe has advised that the Act will not commence until the associated Regulations are also finalised, a process which could take several months.

As part of our plan we have engaged consultants Lloyd-Jones Meakin who assisted Ausgrid, our counterpart electricity distributor in Sydney, to transition through the implementation of similar legislation in Australia. This will enable us to leverage off the Australian experience. Lloyd-Jones Meakin has wide experience in integrating safety as a mainstream business practice and has worked successfully with Rio Tinto, BHP, McConnell Dowel, Dampier Port Authority and other similar companies around Australia.

Legacy assets

With long life networks there are inevitably a number of legacy assets that do not meet current improved operational or safety standards. When we become aware of assets or safety issues that do not meet modern expectations, we prioritise risk mitigation measures. These actions may include replacement over time or strategies to reduce risk until replacement can be achieved.

Key areas where we are currently managing these types of risk are: low voltage panels at our older substations; low voltage panels in older distribution cabinets (link-boxes), and our legacy low voltage system where consumer service mains are t-jointed into our distribution network cables.

Staff

We are committed to consultation and co-operation between management and employees. Maintaining a safe and healthy work environment benefits everyone and is achieved through co-operative effort. We focus on line managers taking responsibility for themselves and their staff to manage hazards.

We systematically identify, assess and manage potential hazards in the work place. Our Health, Safety and Environment Committee and support from health and safety practitioners are also important.

Contractors

Since almost all work associated with our network is carried out by contractors, we have developed registers of known hazards along with recommended actions to control hazards. Contractors must have their own documented health and safety management systems and they are further reminded of their health and safety obligations when they sign a new contract. We carry out regular site audits to ensure compliance.

Most hazards can be successfully managed if access to hazardous areas is restricted to competent personnel, and industry-recognised safe working practises are used.

Public

We have an on-going advertising campaign to promote public safety around our network and we monitor concerns about health and electrical fields. Due to the disruption to schools over the recent past, and the schools preference for interactive teaching methods, we have suspended our in-school education programme in the short term.

Thousands of additional contractors are now working on repairs to the infrastructure and buildings in the city. Many of these repairs will necessitate working in close proximity to our live network.

We have increased our public safety resource to educate these contractors and to provide a process for issuing minimum safe approach consents as mandated by Regulation.

Following advice from a security consultant we have implemented a physical security plan to reduce risks where access to our network could be considered a significant hazard to the public. As a general principle, significant electrical hazards within the public arena are controlled using two barriers of protection. Signage on the initial locked barrier alerts visitors to the general hazard and that access is restricted to authorised personnel only. The second barrier has further warning signage and a barrier preventing inadvertent contact with the hazard. The form of the barriers may differ depending on the level of risk and the practicality of implementation.

6.4 Environment

We follow a policy of environmental sustainability and work to optimise electrical losses on our network.

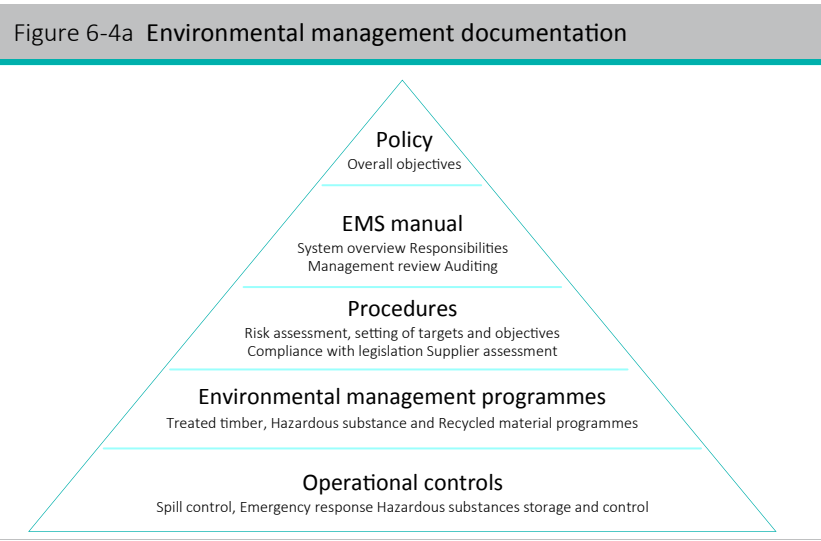
Our environmental sustainability policy covers protection of the biosphere, sustainable use of natural resources, reduction and disposal of waste, wise use of energy, risk reduction, restoration of environment, disclosure, commitment of management resources, stakeholder consultation, assessment and annual audit.

Our major identified responsibilities are a duty to avoid discharge of any contaminants into the environment, unreasonable noise and any adverse effect on the environment.

Target levels of service for our environmental measures are detailed in section 3.3.7.

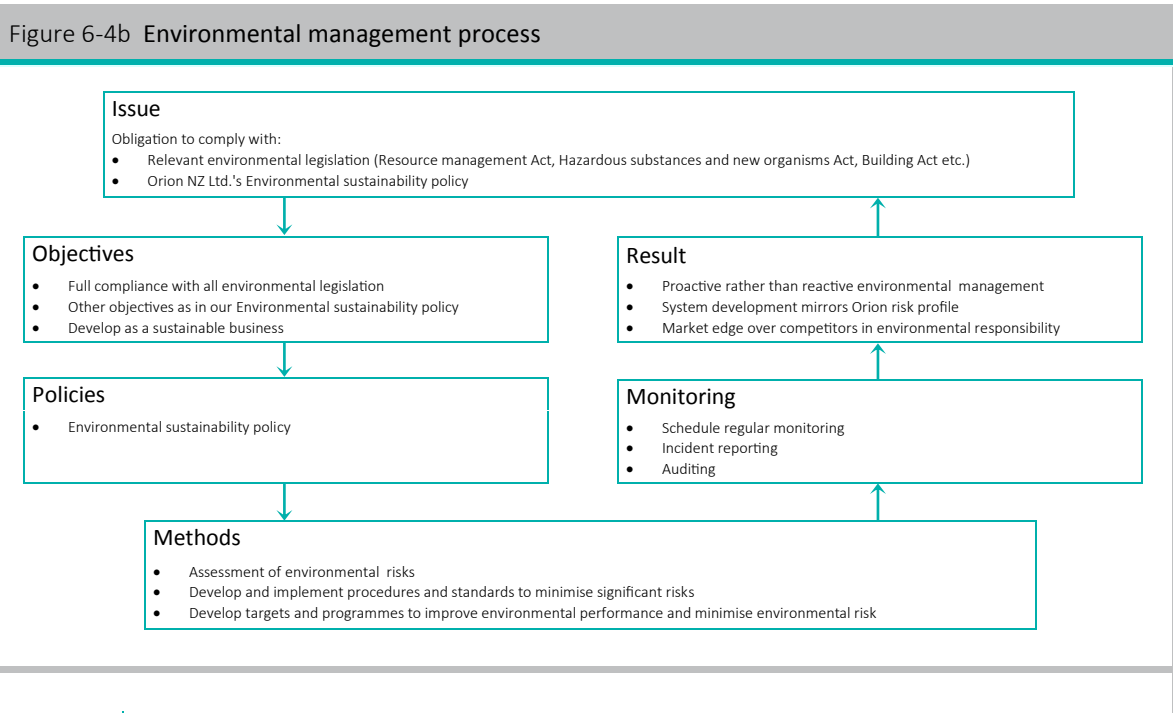
6.4.1 Management process and documentation

We are committed to being environmentally responsible. Legislation such as the Resource Management Act 1991 and our own environmental sustainability policy govern our activities.



Several years ago we documented specific management systems that our service providers are required to adhere to for the handling of:

- SF₆ gas - NW70.10.01 SF₆ gas management procedures
- Oil and fuel - NW70.10.02 environmental management procedures for oil and fuel.



6.5 Network risk analysis

6.5.1 Assessment of risks

We assess critical assets for risk to clearly establish the impact of asset failure, based on expected failure rates for given assets. This work includes the likely impact or consequence of failure and takes into account aspects such as the availability of equipment and the lead time required to purchase replacement equipment. This, coupled with the impact from the most credible natural events, establishes the justifiable spares levels.

The need for spares is created by the likelihood of two events in addition to average failure mode levels. These additional events are earthquakes (65% chance in the next 50 years) and storm conditions (100% chance in the next 50 years).

Earthquakes create the most significant risk to our network, since both likelihood and consequence is high and long equipment replacement times are a major consideration. We are having another look at our earthquake risk in the light of what we now know after the September 2010 and February 2011 earthquakes. These recent earthquakes have given us new data that we now need to consider. The table below shows that earthquakes dominate our asset exposure.

Table 6-5a Primary risk for major assets

Asset	Type	Main risk
Cables	All	Earthquake
Lines	All	Storm
Switchgear	All	Earthquake
Transformers	Ground mounted	Earthquake
	Pole mounted	Lightning
	With auto tap-changer	Earthquake
	Regulator	Earthquake

Table 6-5b Possible causes of contaminant discharge and their relative risks

Cause of discharge	Risk of discharge of contaminant – (low, moderate, high)										
	Transformer oil spill				Inside/ outside OCB oil spill	PCB capacitor leak	Holding tank spill	Transport accident	Portable tank spill	Oil filled cable leak	Battery fluid spill
	Zone substn	Building substn	Pole substn	Pad or kiosk							
External/natural *1	L	L	M	L	L	L	L	L	L	L	L
Accident	L	L	M	L	L	L	L		L/M	M	L
Vandalism	L	L	L	L/M	L	L	L	L	L	L	L
Fire	L	L	L	L	L	L	L	L	L	L	L
Vehicle collision	L	L	M	L/M	L	L	L	L/M	L/M	L	L
Human error	L	L	L	L	M/H	L	M	M	M	M	L/M
Design fault	L	L	L/M	L	L	L	L	L	L	L	L
Plant failure	L	L	L	L	L/M	L	L	L	L/M	L/M	L
Probable severity of outcome *2	H	M/H	L/M	L/M	L	H *2	M/H	L/H	M/H	H	L
Note.*1 Includes discharge of contaminants occurring as a result of damage caused by earthquake, wind, snow, flood, lightning or other causes.											
Note.*2 Severity of outcome with respect to contravention of the Resource Management Act.											

6.6 Interdependence

6.6.1 Interdependence with other services

Many service organisations rely on the services of others to perform. In particular communication systems are of critical importance to all lifeline utilities. It is important to understand this 'interdependence' in the recovery stage of any disaster.

The following table was produced as part of a lifelines study into how natural disasters would affect Christchurch. It indicates various interdependencies from a lifelines point of view one week after an earthquake.

Since this table was produced there has been consolidation of fuel supply storage from contractor's yards and small local service stations to larger centralised service stations. These stations have electronic controlled pumps that depend on a power supply for their operation.

Table 6-6a Interdependence of lifelines (one week after earthquake)

	Water supply	Sanitary drainage	Storm drainage	Mains electricity	Standby electricity	VHF radio	Telephone systems	Roading	Railways	Sea transport	Air transport	Broadcasting	Fuel supply	Fire fighting
Water supply		2	#	#	#	#	#	#	#	#	#	#	#	3
Sanitary drainage	#		#	#	#	#	#	#	#	#	#	#	#	#
Storm drainage	#	2		#	#	#	#	#	#	#	#	#	#	#
Mains electricity	2	3	2		#	3	3	#	2	#	3	1	#	#
Standby electricity	3	3	2	#		3	3	#	#	#	3	3	2	#
VHF radio	1	1	2	3	#		3	2	2	2	2	2	2	3
Telephone systems	2	1	#	1	1	#		#	#	#	1	3	1	2
Roading	2	2	2	3	2	2	2		2	3	3	2	3	3
Railways	#	#	#	#	#	#	#	#		1	#	#	#	#
Sea transport	#	#	#	#	#	#	#	#	#		#	#	1	#
Air transport	#	#	#	1	#	#	#	#	#	#		#	#	#
Broadcasting	1	2	#	#	#	#	1	1	#	#	#		#	1
Fuel supply	3	2	1	#	3	2	1	3	2	#	1	1		3
Fire fighting	#	#	#	#	#	#	1	#	#	#	2	#	1	
Equipment	3	3	2	3	3	2	3	3	3	3	3	3	2	2

3. High dependence 2. Moderate dependence 1. Low dependence # No dependence

Restoration after a disaster, such as an earthquake, has a very high dependence on an adequate fuel supply. We have purchased an above-ground diesel tank to provide an emergency reserve supply for up to three days for our operator vehicle fleet and building generator should the Christchurch supply lines become disrupted. The plan is to maintain a reserve of 8,000 litres and take delivery of 7,000 litres at a time.

6.6.2 Transpower sites

Transpower's transmission lines, buildings and equipment have in general been designed and strengthened to withstand damage from most credible hazard events, with minimal damage. However, notwithstanding this, the ground conditions at Transpower's sites may be susceptible to liquefaction, which could result in relatively significant differential settlement. While this may cause some problems in the switchyards, the major problems would be damage to control buildings and underground cables.

Support from non-liquefiable ground could reduce the vulnerability of cables to damage although this would be a very costly remedy. A more practical solution is to build diversity into future network development.

The following table is an attempt to quantify the relative risk between the urban GXPs.

Table 6-6b Transpower GXP sites – Relative liquefaction potential and related damage

Substation	Liquefaction susceptibility			Potential for foundation failure	Potential for settlement induced damage	Settlement estimation (mm)
	150 year	450 year	1000 year			
Bromley	Low	Medium	Medium	Possible	Possible	20-40
Islington	Low	Low	Low	Unlikely	Unlikely	

After the September 2010 earthquake, minimal damage with equipment was observed. Supply was interrupted at Transpower's major GXPs and one minor GXP and constrained at one further GXP. Supply was able to be restored at all the major GXPs within three hours of the earthquake.

After the February 2011 earthquake, damage with equipment was observed and supply interrupted for five hours at Bromley GXP. Liquefaction was minor and most damage was due to severe shaking.

6.7 Natural disaster

6.7.1 Management system

Orion is a founding member of the steering committee of the Canterbury engineering lifelines group. The purpose of this group is to increase the resilience of Canterbury's infrastructure and to assist lifeline utilities to participate in all phases of civil defence emergency management.

Our integrated emergency management approach is based around the four R's—reduction, readiness, response and recovery:

- **Reduction**

Risk management is an integral component of the reduction phase; identifying and analysing risks and developing plans and systems to reduce risk. As part of this process we analyse and identify the probability, magnitude and consequences of risk. We also establish what are acceptable levels of risk.

- **Readiness**

This involves developing operational systems and capabilities before an emergency happens. We maintain a range of plans and documents in readiness for an emergency, including an asset risk management plan, major outage communication plan, contact lists for the electricity industry and emergency contractors and a recovery plan.

We regularly contribute to emergency readiness programmes. We have a backup control centre so we can continue to function if anything happens to our primary control centre.

- **Response**

In our response to emergencies, our first concern is the preservation of life. The safety of the public, contractors and staff is paramount. During an emergency situation we assess the scale of the event before planning our response.

We have operational procedures in place detailing the actions we need to take immediately before, during and directly after an emergency. We have contingency plans in place for natural event/equipment failure, supply of emergency generators, loss of supply to the CBD, zone substations and GXPs, and energy shortage (rolling power cuts).

Communication is the key to recovery after a disaster. The most secure of our communication systems is our own radio network installed in key Orion vehicles and emergency contractors' vehicles. We have also entered into a mutual aid arrangement with several other power companies.

- **Recovery**

This involves rehabilitation and restoration to provide original functionality of the Orion network. As part of our recovery plan for an emergency situation, we review our customers' needs and our interdependencies with other services, and set priorities to restore full functionality.

During and after an emergency situation, we provide regular updates to keep the public and stakeholders informed, advise them of the severity of the problem and likely time to restoration. Customers and suppliers are also advised of any situation on our website, which is updated on a regular basis.

Earthquakes and storms are our major natural event risks. We continue to invest significant time and money to ensure our network is prepared for such events. During the mid-1990s our network was part of an 'engineering lifelines' study into how natural disasters would affect Christchurch. Since this study, further detailed studies have been undertaken and we have minimised the overall risk to our network in a cost-effective manner.

After the 2010/2011 Canterbury earthquakes we commissioned Kestrel Group to carry out an independent review of how we performed. Kestrel's review endorsed our approach to prior planning and prior risk mitigation measures, our preparedness and our emergency response. We take into consideration Kestrel's report and recommendations as part of our on-going asset management and planning.

We have addressed risk to communications at the two main communication sites – Sugarloaf and Marleys Hill. Sugarloaf is operated by others and now takes its primary power supply from our urban underground network. This site has generator back-up. The adjacent site at Marleys Hill has many operators. Primary power supply is from our rural network which diversifies the source of power to our two main lifeline communication sites. We have replaced the 'most at risk' section of the overhead line supplying Marleys Hill with underground cable. Key operators at the site have a back-up power supply.

Post event improvements

Lyttelton Port is an important lifeline site. We are currently negotiating to install an 11kV cable through the road tunnel to provide an alternative supply to the Port.

We have also installed a cable to allow the airport to be supplied by both Harewood and Hawthornden zone substations. This dual feed improves security of supply to the airport, an important lifeline site.

6.7.2 Earthquake

Although we have had several significant earthquakes and thousands of aftershocks during 2010/11, there still remains a 1 in 123 chance that an M8 earthquake on the Alpine Fault will occur in any year.

Liquefaction hazard evaluation

In 1998 we engaged Soils and Foundations (geotechnical consulting engineers) to evaluate the liquefaction hazard at key substation sites. Based on knowledge of local ground conditions, the following sites in Table 6-7a were selected as potentially sitting on liquefiable material.

Table 6-7a Orion sites – Relative liquefaction potential and related damage

Zone substation	Liquefaction susceptibility			Potential for foundation failure	Potential for settlement induced damage
	150 year	450 year	1,000 year		
Addington	Medium/High	Medium/High	Medium/High	Possible	Likely
Armagh	Medium	Medium	Medium	Unlikely	Unlikely
Bromley	Low	Medium	Medium	Possible	Possible
Dallington	Low	Medium	Medium	Unlikely	Unlikely
Heathcote	Medium	Medium	Medium/High	Unlikely	Possible
Lancaster	Medium/High	Medium/High	Medium/High	Possible	Likely
Milton	Medium	Medium	Medium/High	Possible	Unlikely
Papanui	High	High	High	Possible	Likely
Portman	Medium/High	Medium/High	Medium/High	Unlikely	Unlikely

The Engineers estimated the most severe damage due to liquefaction would be failure of the substation building foundations, towers and associated structures. A less severe, but more likely, cause of damage is post-earthquake settlement. The potential for liquefaction-related damage is summarised in the following table.

Note that the earthquake events used to assess the probability of liquefaction hazard in the study were taken from the seismicity model developed by Elder et al in 1991 and subsequently amended in 1993.

During the 2010/2011 earthquakes liquefaction occurred at our Brighton and Pages 66kV zone substations. Both these substations have since been decommissioned and a replacement substation built (Rawhiti) at a site that did not suffer liquefaction. No damaging liquefaction occurred at any of our other zone substations.

Substation seismic risk evaluation

We engaged consultants to evaluate substation seismic risk in 1995. A sample of 30 network substations was chosen (by the consultants) from a possible 528 to determine structural ability to withstand a moderate-to-severe earthquake. A seismic risk assessment report was prepared. This report showed that significant improvement in seismic performance could be achieved by internally strengthening the substations. A generic strengthening system was developed for a typical pre-1965 substation and we have now strengthened these substations. All network substations were graded on their importance in the network and we used this grading to prioritise the strengthening work. Strengthening work was substantially completed in 2008. During the 2010/2011 earthquakes minor superficial damage occurred, however no catastrophic failures (as seen in similarly constructed buildings) occurred.

Kiosk substations are likely to survive a moderate earthquake because the transformers are connected to flexible cables and can't move far because of the kiosk housing. Most transformers have metal cable boxes over the high voltage bushings that should protect them from impact damage. A severe earthquake may cause more substantial damage; several kiosks sank or developed a lean due to liquefaction in the 2010/2011 earthquakes.

We expect most cables to cope well in an earthquake, although damage can be expected where cables are stretched due to ground movement. Damage to the overhead reticulation system should be easily repaired.

6.7.3 Flooding

In general our distribution network is not exposed to any great flooding risk. Flooding in excess of 800mm above foundation level would be required before catastrophic failure of most high voltage equipment would occur.

Events such as the August 1992 storm, its associated snow melt and high spring tides have already shown the network is quite robust, with only localised flooding around substations close to the Heathcote and Avon rivers. It would be possible, where localised flooding deeper than 800mm occurs, to electrically isolate substations as needed before electrical equipment is significantly damaged. Our control centre on the first floor of our Wairakei Rd site is not considered a flood risk.

6.7.4 Snowfall

The last big snow storm in June 2006 disrupted power supplies to some consumers on our network for up to six days. The storm was generally considered a 1-in-20 year event with localised areas considered a 1-in-50 year event. Approximately 60% of individual outages during the storm were related to trees affecting our overhead line.

After we restored all power we engaged an independent consultancy to review our line design and construction practices. The review also looked at our efforts to restore power and suggested enhancements we could make to reduce the effects of further storms.

The review showed that our current standards were adequate, however some weaknesses were determined in the existing network. As a result approximately 150 sections of line were identified with more than 10 poles in a row without a strong point. We have now installed additional stays on these line sections.

6.7.5 Wind

Wind damage is considered a high risk to our overhead line network. The most devastating winds in Canterbury have been from the northwest. History has shown that lines crossing this wind direction suffer more damage than others. Northwest windstorms have caused major damage in our rural area, however the city urban area is less affected. Trees falling and flying debris cause most damage and repairs usually cannot be made until the wind subsides to a safe level.

6.7.6 Tsunami

In light of recent world events we are reviewing our risk in this area. New information available from the emergency management group suggests a number of scenarios will determine the effect a tsunami will have on our network.

These scenarios identified an impact on our emergency contractors and emergency spares store located in the Heathcote valley. We have been working with our emergency contractors to mitigate these risks. One contractor has already relocated to the west of the city. Plans are underway for the second emergency contractor and emergency spares to be relocated to the west of the city within the next two - three years.

6.8 Asset failure

We analyse our exposure to asset failure by assessing individual key assets based on known past performance. Asset life for electrical distribution equipment is very difficult to predict because data on actual life expectancy is limited for most assets. In the absence of hard information we make judgments based on perceived trends and our experience of what happens in practice.

Modern testing technology such as partial discharge testing has minimised the risk of asset failure, especially within switchgear. This has helped with end-of-life planning and asset replacement. Further work is underway to establish a history of failure modes for other assets to help minimise risk and establish end-of-life planning.

6.8.1 Administration building

We moved to a level 4 “Lifelines” (IL4) compliant building located at 565 Wairakei Rd in May 2013. This site meets our head office and operational requirements. The building has a current building warrant of fitness and is inspected six monthly by our Health and Safety Committee.

Risk review

We also reviewed the environmental risks associated with the Wairakei Rd site. The risks assessed included seismic events, flooding from the Waimakariri River, localised weather events (rain, wind and snow), tsunami and land movement (slips and subsidence). In addition we looked at the likelihood and consequences of fire within the building.

Our conclusion was that the Wairakei Rd site was appropriate for our requirements and that the IL4 building standard dealt with many of the risks we identified.

Currently we have retained our computer hot-site capability at our Armagh St site until we relocate our data centre to an alternative site. We have also established portable emergency office accommodation at our Papanui zone substation site.

6.8.2 66kV cable network

The most significant risk of catastrophic asset failure is in our 66kV oil-filled cables. Unsatisfactory joint systems connect the aluminium conductors of each section of cable. Thermal expansion of conductors during load cycling can cause buckling and excessive core movement within the joints. We engaged an international consultancy to help quantify the risk across the various cable types and sizes.

We instigated a joint replacement programme that prioritised the joints most at risk. The joints were replaced as quickly as is practicable, consistent with available resources and the need to avoid undue stress on neighbouring cables during the relatively long outages required. This programme to replace all of the at-risk joints was completed in 2010.

Our 66kV cables to Brighton and Dallington zone substations were damaged and subsequently abandoned after the 2010/2011 earthquakes. The Dallington cable has been replaced by a temporary overhead line and Brighton zone substation has been decommissioned. Installation of new cables to replace the damaged ones is mostly completed. These cables traverse different routes to spread the risk of damage.

6.8.3 Ripple system

We use the ripple system to control load and limit maximum demand and therefore reduce the need for network investment. Risk of ripple plant failure, which could result in loss of network peak load control, is addressed through system spares. Our decision to replace the existing 66kV injection system with multiple independent 11kV plants has significantly reduced risk as plants can provide back-up to each other.

While we own and control the ripple injection plants, the ripple receivers, which actually control load at consumers’ premises, were sold to the retailers in late 1998 when distribution and retailing were split into separate businesses. This introduced significant risk. If retailers choose not to install or maintain ripple receivers we may progressively lose control over system peak load. This would result in an increase of up to 15% in maximum demand and we would need to invest more heavily in our network.

To counter this risk, our contracts with retailers enable us to continue to control network system load using the ripple control system with existing ripple control receivers. We also introduced a mandatory requirement from 1 April 2007 that existing ripple receivers must be maintained and all new connections must have a ripple receiver, or its equivalent, to enable us to control any available suitable controllable load, such as an electric water-heater, at least in an emergency.

Our pricing structure also encourages retailers to continue to install and maintain existing ripple control receivers.

6.8.4 Distribution management (DMS) system

Our DMS with its integrated SCADA module is a key tool for monitoring and operating our electricity network assets in real time.

Through alarms it notifies of potential or actual equipment failure. The DMS can be used to view the electrical state of devices and is invaluable in diagnosing faults and delivering solutions to network related problems.

The DMS aggregates and interprets incoming data which is accessed from throughout our network using software located on an array of servers. Loss of the DMS and SCADA system could significantly reduce our ability to detect, diagnose and respond to important network events.

In addition to warranty and maintenance agreements that provide software and systems support, the system is made fault tolerant through the use of backup hardware and communications routing. Multiple identical servers are configured at independent sites with databases mirrored between them. In the event that any of these servers fail, the DMS will continue to operate. All servers must be lost for the system to fail completely.

Future work will focus on communications lines to remote field devices, which currently have single points of failure will be able to be routed to both server sites in the future.

6.9 Mitigation measures

6.9.1 Procedures and plans

We mitigate risk on several fronts, starting with plans and procedures to handle events beyond our control, and work practices and systems to prevent events within our control from occurring. In particular we:

- inspect assets and identify risks, using maintenance programmes, before they become a problem, which allows time to engineer measures to minimise or remove the risk of failure
- introduce modern technical monitoring systems to give early warning of imminent failure
- use design standards and technical specifications to maintain a high degree of integrity in the construction and maintenance of our network (these are detailed under the individual assets in section 4 – Lifecycle asset management)
- we closely manage contracts and audit construction to enforce these standards and specifications
- regularly train and certify staff and contractors in the correct procedures to access the network in a safe manner that does not compromise either staff, the Public or the network
- have operational procedures that enable us to respond promptly to electricity outages caused by a wide range of emergencies, as part of our routine operations. These include plans to address oil spills
- have contingency plans and emergency procedures for disaster training that will assist in the event of a major system disruption. These plans include:

- **Contingency plan – natural event/equipment failure – NW20.40.01**

This plan covers:

- i. activating the plan
- ii. notification of senior management
- iii. priority of restoration (*preservation of life*)
- iv. the roles of personnel associated with the plan
- v. customer communication
- vi. preliminary action on notice of a tsunami.

- **Contingency plan – supply of emergency generators – NW20.40.02**

This plan covers:

- i. activating the plan
- ii. notification of senior management
- iii. priority of restoration (*preservation of life*)
- iv. generators owned by Orion
- v. consumer-owned embedded generation
- vi. details of generator hire companies.

- **Contingency plan – loss of supply to the CBD, zone substations and GXP – NW20.40.03**

This plan contains site specific information for the Christchurch CBD and each of our zone substations. It provides:

- i. low, medium or high risk grading for each zone substation
- ii. details of major plant installed
- iii. details of specific problems
- iv. some restoration options.

- **Security of supply - Participant outage plan – NW20.40.09**

This plan was created to comply with the Electricity Authority's Security of Supply Outage Plan and supersedes our Contingency Plan - Rolling Outages (NW20.40.04).

The procedures outlined in the plan are in response to major generation shortages and/or significant transmission constraints. Typical scenarios include unusually low inflows into hydro-generation facilities, loss of multiple thermal generating stations or multiple transmission failures.

The main energy saving measure listed is rolling outages and how these are structured and implemented is discussed. How an event is declared and how the Electricity Authority should communicate its requests are also detailed.

Under the regulations, participant outage plans (POP) are required to specify the actions that would be taken to:

- reduce electricity consumption when requested by the Electricity Authority
- comply with requirements of the Electricity Authority's Security of Supply Outage Plan
- comply with Electricity Industry (Enforcement) Regulations 2010
- supplement the Electricity Authority's Security of Supply Outage Plan.

Reducing demand by disconnecting supply to customers would be a last resort after all other forms of savings including voluntary savings had been exhausted. Orion will always endeavour to keep supply on to customers.

- **Disconnection of demand as required by the Electricity Authority rules – NW20.40.05**

The purpose of this plan is to mitigate the effects of manual disconnection and demand shedding at points of connection as required by the Electricity Authority Rules through:

- maintaining an up-to-date process to disconnect demand for points of connection, including the provision to Transpower System Operator of a feeder priority based on a 'regional or GXP emergency requiring demand shedding'
- assisting Transpower with their automatic under frequency load shedding (AUFLS) by providing a schedule of our preferred locations and AUFLS provision where embedded in our network
- assisting Transpower with automatic under voltage load shedding (AUVLS) for upper South Island (Zone 3) transmission constraints by providing a schedule of Orion's preferred locations and AUVLS provision where embedded in our network
- Providing blocks of load to Transpower for emergency demand shedding.

6.9.2 Engineering measures

We have implemented the mitigation measures outlined below.

We have engaged an emergency contractor to manage distribution equipment spares and provide adequate response to any event on our network. Emergency equipment is stored in a secure environment and we carry out regular audits of stock availability and security. This process is driven by a risk analysis of the possible failure of specific equipment. The spares held support the contingency plans in place to meet our security standard. We hold complete units of some equipment if it is no longer supported by the manufacturer.

Structural checks are ongoing to ensure network installations are structurally sound and have adequate hold-down provisions should an earthquake occur. Those buildings and structures found in need of strengthening are the subject of strengthening programmes detailed in section 4 – Lifecycle asset management.

We have installed oil containment bunds at sites that hold oil in excess of 1,500 litres. This limits the possibility of oil entering the environment. These sites are also inspected regularly. More appropriate methods exist other than to install bunds for sites with oil volumes below 1,500 litres.

During the earthquakes, our 66kV oil filled cables and 11kV cables were largely damaged in areas subject to significant lateral land spread. Engineering mitigation work, such as strengthening bridge abutments, minimized some of the impact on our cables. The impact of any future earthquakes has been mitigated by:

- our 11kV cables are now not as exposed to issues due to changes in land use
- our 66kV architecture has changed to a meshed/interconnected network, refer section 5.6.3
- our installation standards for 66kV cables make allowance for liquefiable land.

Installation of a new 11kV ripple system to replace the overloaded 66kV plants was completed in 2004.

We are committed to on-going contracts to inspect, test and maintain key assets. These contracts are identified in section 4 – Lifecycle asset management.

6.9.3 Avoiding major supply failure

The plans and processes in the preceding section are designed to manage a wide range of identified risks associated with our day-to-day business of delivering electricity safely and efficiently to all our consumer connections.

There is another class of event – ‘high impact low probability’ (HILP) – that would cause huge economic losses to our consumer base and the community because of its unexpected occurrence. The cause could be a major storm, earthquake or multiple failure of major network assets.

Examples include the Canterbury earthquakes, the 1998 failure of the 110kV subtransmission cables that supply Auckland’s CBD and the Penrose substation fires in 2014. In the Auckland cases, a network with an apparent N-2 security standard sustained a complete failure of four main cables (i.e. N-4 failure) in 1998 and nineteen (N-19 failure of mainly 33kV cables) in 2014, leaving the CBD, etc. with severely restricted power supply for many days and/or weeks. It is clear from these events that common mode failure mechanisms exist with large economic consequences for electricity consumers.

To avoid this form of ‘cascade plant failure’ we need good knowledge of asset ratings and condition, clear operational and monitoring rules and an inventory of key emergency spares, along with good operational contingency and system security planning.

Our main network plant failure modes which we consider could lead to a HILP situation have been identified as:

(a) **Major subtransmission 66kV cable failure leading to loss of supply from two or more urban zone substations**

In most cases N-2 failures in the urban network can be managed with pre-prepared emergency switching plans. This off-loads the affected major zone substation using our existing interconnected 11kV distribution network. In times of very high peak system loading it could be necessary to shed all water-heating load, plus additional load, to manage these events within the remaining available capacity.

However, if an event occurs that causes outages to more than two major 66kV subtransmission feeders, the potential of more serious overload and potential plant damage to the remaining 66kV cables increases. A 66kV cable failure has a relatively long repair time (up to one week for oil filled cables).

In our network the most likely cause of this type of failure is electrical failure of the joints or terminations of 66kV oil-filled cables due to heat from high power loadings (see section 6.7.1).

Because most 66kV oil-filled cables are laid as pairs separated by only 600mm, it is also likely that physical damage to the cables could arise from road excavation work or severe differential settlement of the surrounding ground due to earthquake.

Multiple failures of cable terminations at GXPs could also cause outages to two or more urban substations.

Repair times for this type of failure would be two or three weeks, due to the complexity and resource requirements involved in repairing oil-filled cable plant.

(b) **Multiple major transformer failures**

The failure of one urban zone substation transformer (typically 20–40MVA capacity) is not necessarily a major problem as all such substations have two transformers with dual rating to cope with this type of contingency.

However, if both transformers became unavailable for extended periods (N-2 contingency) then the potential for overloading adjacent substations and possibly losing additional customer load is significantly increased, especially during winter peak load periods. Transformer repair times can be weeks or many months.

The main reason for operating with less than two zone substation transformers is to carry out planned maintenance. We have an on-going programme to undertake half-life maintenance of major transformers to ensure that their expected life can be fully realised. This process involves removing the transformers from site to a suitable maintenance workshop for three to six months depending on their condition. We could thus be subject to a higher risk of interruption to supply from faults on the remaining ‘in-service’ transformers during this half-life maintenance period.

The most likely causes of a transformer fault are high loadings, lightning strikes or high fault currents resulting in either mechanical or electrical breakdown, causing tap-changer, or winding failure. Mal-operation of cooling equipment or overloading can also contribute to excessive temperature rise and subsequent over-temperature protection trip operation.

Avoiding cascade failure of major transformers is therefore dependent on good understanding of their capability and condition, as well as co-ordinating their extended maintenance with other major plant outages. The mere act of removing transformers from service for extended periods requires careful management, as it is in itself a significant risk factor.

Earthquake damage could also cause common mode multiple transformer failures on our network and at Transpower GXPs.

(c) **Switchgear**

Catastrophic failure of high voltage switchgear units (66, 33 or 11kV) can cause a complete section of busbar to fail, either by associated collateral physical damage from explosions or extensive conductive combustion products shorting out internal busbars.

Cascade failures involving multiple busbar sections are rare in our network due to the physical partitioning of switchgear in separate fire-rated compartments (e.g. indoor 11kV switchgear), therefore the consequence of failure is generally lower than that for major cables and transformers.

Repair time for switchgear failures are generally also a lot less than for major cables and transformers (i.e. 12 – 24 hours) however there is still potential for a HILP situation.

Earthquake damage to 66kV and 33kV outdoor switchgear and structures is also a potential common mode failure for both Orion and Transpower substations.

6.9.4 Mitigation of major supply failure

Our main mitigation strategies and initiatives to avoid a HILP situation from the three plant failure modes described above are:

- We have replaced all at risk 66kV oil-filled cable joints with newly designed joints that will withstand thermo-mechanical buckling forces. We will continue to inspect the other manufacturer's joints (Dianichi) that are assessed to be low-risk. They will be replaced on a case-by-case basis following inspections of their condition.
- Careful co-ordination of work plans for any cable joint replacement and transformer half-life overhauls to avoid excessive risk and a potential cascade failure due to exceeding plant capacity.
- The purchase of two spare transformers so that our zone substations are not left for extended periods with only one in-service transformer while transformer half-life overhauls are carried out.
- We cover-off general 11kV switchgear failures by deploying system emergency spares, largely from stock.
- If multiple 66kV oil-filled cables fail, our plan is to assess the repair times and compare time and costs with the construction of temporary 66kV overhead lines. Such lines would be constructed on public roads and run parallel with the faulted cable sections where feasible. Feasible routes servicing the CBD have been assessed. Standard construction designs would be implemented.
- Buildings that house a 66kV zone substation transformer have been modified to allow the roof to be removed for bushing type connection to any emergency 66kV lines.
- We ensure that our network has sufficient capacity to restore supply for N-2 events on our subtransmission network. This is necessary because, unlike Transpower's overhead tower lines that have a relatively short repair time, our 33 and 66kV oil-filled cables may require up to a week to repair. During that time an undersized (N-1) network is exposed to high loads which increase the chance of further failures. By providing N-2 capacity we reduce the risk of cascade failure during cable repair. In the event that further failure does occur, supply can be restored using the N-2 security assets.
- N-2 contingency plans for switching load away from zone substations are in place and arrangements to maximise the use of existing customer-owned standby diesel generators and obtain additional ones have been identified.
- We make significant efforts to understand and access all reasonable and prudent emergency ratings of existing in-service plant.
- We hold one major transformer emergency spare for each of our standard ratings and voltages.
- Our extensive power system modelling software and applications can assist in understanding resultant power flows and avoid excessive loadings of network elements caused by network configuration changes. This capability also assists in mitigating plant failure due to excess loading.
- Earthquake damage has potential to cause significant damage to multiple major Orion substations and Transpower GXP's. Our risk mitigation to date has targeted network substation building strengthening and diversity of supply through improved interconnection between such substations and grid exit points over time.
- We have minimised the risk of major zone substation 11kV switchgear failure through assessing switchgear condition and the importance of each site to network security. On this basis, we prioritised the replacement of switchgear at Armagh, Fendalton, Grimseys Winters and Milton zone substations before proceeding on to other substations as their risk of failure increases over time.
- Implemented a network management system (PowerOn) so that restoration of supply through switching can be undertaken quickly and safely. This also enables us to prioritise works efficiently.

6.9.5 Historic examples

The following two examples of network failure illustrate the above strategies and initiatives being applied in the past.

Heathcote N-2

In 2004, an N-2 transformer contingency at Heathcote zone substation caused loss of supply to 25MW. We avoided an extended outage of approximately six hours and restored supply in 40 minutes because of the following mitigation measures:

- our network was built to meet an appropriate N-2 security standard
- we had completed asset capability modelling of the surrounding network and loaded the network capability ratings into our SCADA system
- pre-contingency load flow modelling complete and N-2 contingency plans pre-written.

Sockburn/Middleton N-2

In 2006 an N-2 cable contingency on the Sockburn/Middleton 33kV subtransmission feeders caused a loss of supply to 15MW. We avoided a cascade failure of remaining assets that could have caused outages of several days and restored supply within two hours because of the following mitigation measures:

- our network built to meet an appropriate N-2 security standard
- we reduced load to ratings established through asset capability modelling to avoid cascade failure of the remaining 33kV feeder. It took slightly longer to restore power using 11kV feeders, but we chose not to risk extended outages through potential cascade failures of the 33kV subtransmission network
- pre-contingency load flow modelling was complete and N-2 contingency plans were pre-written.

6.9.6 Insurance

The following mitigation measures are in place:

- Our material damage insurance policy insures us against physical loss or damage to buildings, plant, equipment, zone and network substation buildings and contents and is based on assessed replacement values.
- Our business interruption insurance policy indemnifies us for increased costs as a consequence of damage to insured assets, with an indemnity period of 12 months.
- Orion has several liability policies, including directors and officers, professional indemnity, public liability and statutory liability
- Key uninsurable risks are:
 - i. lost revenues (e.g. due to depopulation following a catastrophic event)
 - ii. damage to overhead lines and underground cables

These risks are effectively uninsurable for all electricity distribution businesses in Australasia.

- Contractors that work for us are required to arrange appropriate insurance for the work being undertaken, giving cover for:
 - i. third party liabilities
 - ii. contract works
 - iii. plant and equipment
 - iv. motor vehicle third party.

Financial



7

7.1	Financial forecasts	267
7.1.1	Opex - network	267
7.1.2	Opex - non network	268
7.1.3	Capital contributions revenue	268
7.1.4	Capex - summary	268
7.1.5	Capex - non network	268
7.1.6	Capex - major GXP projects	269
7.1.7	Capex - urban reinforcement	269
7.1.8	Capex - rural and total reinforcement	270
7.1.9	Capex - replacements	271
7.1.10	Capex - urban major projects	272
7.1.11	Capex - rural major projects	273
7.1.12	Capex - Transpower spur asset purchases	274
7.1.13	Transpower new investment agreement buyouts	275
7.1.14	Transpower new investment agreement charges	275
7.1.15	Transpower connection and interconnection charges	275
7.2	Changes from our previous forecasts	275

List of figures and tables in this section					
Figure	Title	Page	Table	Title	Page
			7-1.1	Opex - network	267
			7-1.2	Opex - non network	268
			7-1.3	Capital contributions revenue	268
			7-1.4	Capex - summary	268
			7-1.5	Capex - non network	268
			7-1.6	Capex - major GXP projects	269
			7-1.7	Capex - urban reinforcement	269
			7-1.8	Capex - rural and total reinforcement	270
			7-1.9	Capex - replacement	271
			7-1.10	Capex - urban major projects	272
			7-1.11	Capex - rural major projects	273
			7-1.12	Capex - Transpower spur assets, purchase values	274
			7-1.13	Transpower new investment agreement buyouts	274
			7-1.14	Transpower new investment agreement charges	275
			7-1.15	Transpower connection and interconnection charges	275

7.1 Financial forecasts

Our forecasts are based on our network opex and capex programmes and projects as detailed in sections 4 and 5. These forecasts are based on the best information available regarding the timing and extent of the post earthquake key recovery projects. Whether or not these projects will proceed, and the timing of them, is determined by Government and local Authorities and/or Developers.

All figures in section 7.1 are in 'real' (FY16) dollar terms. Appendix A has the same tables, reworked to include general CPI inflation and other cost escalators.

Changes described are referenced to our last published AMP for the period from 1 April 2014 to 31 March 2024.

No provisions have been made in the forecasts for inflation but a \$1.5m contingency provision has been added to the opex estimates. This contingency provision covers future unknowns such as:

- further regulatory compliance costs
- road authority access costs
- additional worker and public safety compliance costs
- additional uncertainty around land access
- uncertainty around the local impact of economic growth, for example the proposed Central Plains Water irrigation scheme

The following financial forecasts exclude costs for major projects substantially started in FY15 (carry-over costs in FY16). Carry-over costs in FY16 are likely to be largely offset by delays/deferrals of spending on forecast FY16 projects into FY17.

7.1.1 Opex - network

Category	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Subtransmission overhead lines	1,825	1,790	1,790	1,790	1,790	1,790	1,790	1,790	1,790	1,790
11kV overhead lines	4,545	3,985	3,985	4,405	4,405	4,405	3,985	3,985	4,405	4,405
400V overhead lines	4,990	4,255	4,255	3,835	3,835	3,835	4,255	4,255	3,835	3,755
Earths	265	265	265	265	265	265	265	265	265	265
Subtransmission underground cables	865	845	995	995	995	995	995	995	995	995
11kV underground cables	3,010	2,625	2,625	2,625	2,485	2,485	2,485	2,485	2,485	2,485
400V underground cables	2,970	2,555	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230
Asset information management	65	65	65	65	65	65	65	65	65	65
Storms	245	245	245	245	245	245	245	245	245	245
Meters	70	70	70	70	70	70	145	145	145	145
Protection	590	550	540	540	540	540	540	540	540	540
Communication cables	320	305	305	305	305	305	305	305	305	305
Communication systems	775	780	780	780	845	780	780	780	780	780
Control systems	780	705	750	705	750	705	750	705	750	750
Load management	385	380	440	300	300	300	300	300	300	300
Switchgear	2,320	1,190	1,190	1,190	1,190	1,190	1,190	1,190	1,190	1,190
Transformers	1,415	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375
Substations	880	865	865	505	505	505	505	505	505	505
Buildings and enclosures	1,840	1,700	1,700	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Grounds	645	645	645	645	645	645	645	645	645	645
Generators (fixed)	220	215	215	215	215	215	215	215	215	215
Asset storage	470	470	470	470	470	470	470	470	470	470
Sub totals	29,490	25,880	25,800	24,955	24,925	24,815	24,935	24,890	24,935	24,855
Contingency		1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Grand totals	29,490	27,380	27,300	26,455	26,425	26,315	26,435	26,390	26,435	26,355
Grand totals from 1 April 2014 AMP	30,885	27,170	26,870	26,755	26,670	26,525	26,680	26,640	26,680	n/a

7.1.2 Opex - non network

Table 7-1.2 Opex - non network - \$000

Category	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
System operations and network support	17,321	17,222	17,077	16,903	16,804	16,774	16,759	16,759	16,764	16,759
Business support	13,830	13,796	13,624	13,535	13,579	13,333	13,311	13,334	13,351	13,344
Totals	31,151	31,018	31,701	30,438	30,383	30,107	30,070	30,093	30,115	30,103

7.1.3 Capital contributions revenue

Table 7-1.3 Capital contributions revenue - \$000

Category	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Asset relocations	(3,920)	(2,995)	(2,845)	(1,195)	(945)	(945)	(945)	(945)	(945)	(945)
Consumer connections/Network extensions	(1,477)	(1,137)	(1,007)	(837)	(827)	(827)	(827)	(827)	(827)	(827)
Major projects			(2,553)	(4,068)						
Totals	(5,397)	(4,132)	(6,405)	(6,100)	(1,772)	(1,772)	(1,772)	(1,772)	(1,772)	(1,772)

7.1.4 Capex summary

Table 7-1.4 Capex summary - \$000

Category	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Consumer connections/Network extensions	17,512	15,587	13,072	12,057	10,967	10,707	10,707	10,707	10,707	10,707
Reinforcement	3,007	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Asset relocations	17,000	11,150	5,850	1,850	1,350	1,350	1,350	1,350	1,350	1,350
Major projects	27,149	10,725	35,062	20,901	16,019	4,505	16,656	13,238	4,654	8,409
Replacement	21,235	19,965	21,365	23,835	19,670	19,975	22,475	20,490	21,050	23,400
Transpower spur asset purchases	9,000	450	4,150							
Network capex totals	94,903	61,377	82,999	62,143	51,506	40,037	54,688	49,285	41,261	47,366
Non network capex totals	15,931	14,250	1,972	3,159	2,015	2,223	1,670	2,628	2,152	2,087
Capex grand totals	110,834	75,627	84,971	65,302	53,521	42,260	56,358	51,913	43,413	49,453

7.1.5 Capex - non network

Table 7-1.5 Capex - non network - \$000

Category	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Sundry land and buildings	252	252	352	352	352	352	352	352	352	352
Vehicles and mobile plant	1,108	690	939	1,179	971	669	551	725	1,101	1,001
Information solutions	583	1,071	600	1,518	479	1,078	543	1,328	673	758
Sundry tools and equipment	565	529	349	364	396	349	399	364	349	349
Construction of a depot	13,700	11,900								
Capex totals	16,208	14,442	2,240	3,413	2,198	2,448	1,845	2,769	2,475	2,460
Less disposals:										
Sundry equipment	277	192	268	254	183	225	175	141	323	373
Totals	15,931	14,250	1,972	3,159	2,015	2,223	1,670	2,628	2,152	2,087

7.1.6 Capex - major GXP projects

Table 7-1.6 Capex - major GXP projects - \$000

Category	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Addington metering relocation	1,000									
Arthurs Pass transformer			1,000							
Castle Hill transformer			1,000							
Hororata 66kV bay for Hororata substation							615			
Hororata 66kV bay for Hororata-Darfield line							615			
Totals	1,000	0	2,000	0	0	0	1,230	0	0	0

7.1.7 Capex - urban reinforcement

Table 7-1.7 Capex - urban reinforcement - \$000

Project	FY16	FY17	FY18
512 Birmingham Dr re-arrangement - stage 2	290		
18 Bridle Path Rd reinforcement	110		
839 Shands Rd north cables	173		
807 Aidanfield Dr cable	210		
635 Remote Indication	100		
485 Addington-Fielding St circuit	56		
856 Hornby 113 cable upgrade	80		
681 Marshs Rd cable		384	
851 Moffett St re-arrangement		150	
809 Jessons Rd switchgear		81	
854 Halswell Junction Rd		173	
785 Hayton Rd cable		33	
788 Travis Rd reinforcement		129	
855 Waterloo Rd		560	
622 Lancaster-Milton tie - stage 2			78
Urban reinforcement totals	1,019	1,510	78

For details of individual projects see section 5.6.8 – 11kV urban reinforcement projects.

7.1.8 Capex - rural and total reinforcement

Table 7-1.8 Capex - rural and total reinforcement - \$000				
Project		FY16	FY17	FY18
828	Rolleston developments - Dynes Rd to Lowes Rd	534		
829	Rolleston developments - Brookside Rd (South)	157		
840	Rolleston developments - Burnham School Rd	251		
844	Rolleston developments - Levi Rd	46		
808	Edward St Lincoln cables		631	
663	Darfield township reinforcement from Kimberley			642
791	West Melton cable			388
806	Gerald St Lincoln cable			122
701	Southern motorway reinforcement - stage 2			282
803	Lincoln feeders (Weedons Rd)			636
Rural reinforcement totals		988	631	2,071
Urban reinforcement totals		1,019	1,510	78
General				
196	Non scheduled reinforcement	1000	1000	1000
205	Non identified reinforcement	0	359	351
Reinforcement grand totals		3,007	3,500	3,500
Grand totals from 1 April 2014 AMP		4,500	4,500	4,500

For details of individual projects see section 5.6.9 – 11kV rural reinforcement projects.

7.1.9 Capex - replacement

Table 7-1.9 Capex - replacement - \$'000

Project	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
66kV overhead lines	0	0	0	2,395	0	0	2,395	0	0	0
33kV overhead lines	420	420	420	420	420	420	420	420	420	420
11kV overhead lines	2,450	2,450	2,450	2,450	2,450	2,450	2,450	2,450	2,450	2,450
400V overhead lines	550	550	550	550	550	550	550	550	550	550
66kV underground cables	0	0	0	0	0	0	0	0	0	0
33kV underground cables	0	0	0	0	0	0	0	0	0	0
11kV underground cables	0	0	0	0	0	0	0	0	0	0
400V underground cables	150	150	150	150	150	150	150	150	150	150
Communication cables	175	175	175	175	175	175	175	175	175	175
Meters	195	275	165	165	225	165	225	165	165	165
Protection	1,915	2,410	3,225	2,105	2,305	2,250	2,575	2,805	2,945	3,165
Asset management systems	600	0	120	55	55	130	55	55	130	55
Communication systems	850	765	660	615	615	660	660	660	660	660
Control systems	920	1,035	845	875	515	650	515	570	725	515
Load management	895	1,630	1,080	715	395	740	215	395	215	215
Switchgear	7,005	6,730	8,465	10,355	9,005	8,825	9,280	9,285	9,655	9,570
Transformers	3,385	2,335	2,020	2,020	2,020	2,020	2,020	2,020	2,020	4,520
Substations	520	360	360	360	360	360	360	360	360	360
Buildings and enclosures	1,205	680	680	430	430	430	430	430	430	430
Generators (fixed)	0	0	0	0	0	0	0	0	0	0
Replacement totals	21,235	19,965	21,365	23,835	19,670	19,975	22,475	20,490	21,050	23,400
Totals from 1 April 2014 AMP	27,395	26,345	24,190	24,200	23,915	22,905	24,900	24,650	23,780	n/a

7.1.10 Capex - urban major projects

Table 7-1.10 Capex - urban major projects - \$'000

Project	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
650 Rawhiti to Marshland 66kV link	12,666									
651 Marshland to Waimakariri 66kV link	11,626									
853 Papanui bus coupler	350									
332 Moffett St substation replace 33kV feeders	192									
634 Belfast diesel generation - Stage 1		1,286								
694 Land acquisition Milton 66kV switchroom		1,000								
727 Lancaster substation rebuild		6,396								
488 Marshlands substation			9,002							
542 Waimakariri substation stage 2			2,241							
589 Lancaster to Milton 66kV link			4,098							
721 Land acquisition Shands Rd 66kV switchyard			500							
723 Milton 66kV switchgear for Lancaster cable			4,515							
541 Hawthornden T-off				1,136						
669 Convert Shands Rd to 66kV				6,244						
491 McFaddens to Marshland 66kV link					7,134					
522 Yaldhurst substation					8,785					
707 Shands Rd 66kV Stage 2								799		
722 Land acquisition Hoon Hay 66kV switchyard										200
Major urban project totals	24,834	8,682	20,356	7,380	15,919	0	0	799	0	200
Major rural project totals	2,315	2,043	14,706	13,521	100	4,505	16,556	12,439	4,654	8,209
Grand totals	27,149	10,725	35,062	20,901	16,019	4,505	16,556	13,238	4,654	8,409
Totals from 1 April 2014 AMP	38,580	21,540	18,985	6,520	37,015	8,335	4,410	8,820	n/a	n/a

For details of individual projects see section 5.6.6 – Major urban projects.

7.1.11 Capex - rural major projects

Table 7-1.11 Capex - rural major projects - \$'000

Project	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
500 Land acquisition Burnham 66kV substation	1,200									
846 Rural transformer spare	500									
698 Central Plains Water	615									
415 Weedons to Highfield tee 66kV line conversion		1,685								
671 Castle Hill generators		187								
672 Arthurs Pass generators		71								
716 Land acquisition Southbridge substation		100								
114 Convert Highfield substation to 66/11kV			845							
505 Springston T2 - 66/11 kV transformer			1,129							
587 Te Pirita substation 66kV bays			845							
609 Dunsandel to Norwood 66kV line + switchgear			3,279							
626 Norwood to Highfield/Weedons tee 66kV line			2,403							
670 Steeles Rd substation and 66kV line			3,101							
699 Dunsandel transformer upgrade			2,327							
728 Springston 11kV switchroom			777							
306 Annat transformer upgrade				420						
637 Railway Rd 11kV substation (Westland Milk)				3,051						
639 Burnham 66kV substation stage 1				5,774						
666 Porters Village				4,276						
527 Land acquisition Templeton 66kV substation					100					
610 Southbridge 66kV substation						3,359				
627 Southbridge 66kV line						1,146				
579 Hororata to Darfield 66kV line upgrade							1,243			
581 Highfield to Darfield 66kV line							3,543			
601 Convert Hororata substation to 66/11kV							1,228			
654 Land acquisition for Norwood 66kV substation							250			
842 Greenpark 66kV substation							6,491			
849 Convert Darfield substation to 66/11kV							3,901			
577 Windwhistle to The Point 66kV line								2,028		
588 Te Pirita to Windwhistle 66kV line								1,175		
597 Norwood 66kV substation								3,390		
608 The Point 66kV substation								3,491		
705 Greendale to Dunsandel-Norwood line + swgr								2,355		
502 Templeton 66kV substation									4,654	
447 Greenpark - Motukarara 66kV line conversion										1,677
576 Birdlings 66/33kV substation										3,943
583 Tancred tee to Greenpark 66kV line										685
725 Birdlings to Motukarara 66kV line										1,904
Rural major projects subtotal	2,315	2,043	14,706	13,521	100	4,505	16,656	12,439	4,654	8,209

For details of individual projects see section 5.6.7 – Major rural projects.

7.1.12 Capex - Transpower spur assets, purchase values

Table 7-1.12 Capex - Transpower spur assets, purchase values - \$'000

Spur asset to be purchased	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Addington and Middleton including Islington-Addington 66kV transmission lines	9,000	200								
Castle Hill 66/11kV transformer and 11kV		50	1,300							
Hororata 33kV * (including 66/33kV transformers)		100	1,300							
Arthur's Pass 66/11kV transformer and 11kV		50	550							
Islington 33kV*		50	1,000							
Totals	9,000	450	4,150							

*Assumes EA rule change so that Transpower can use customer equipment for GXP metering, thus avoiding a \$0.5M - \$1M project to shift metering.

7.1.13 Transpower new investment agreement buyouts

Table 7-1.13 Transpower new investment agreement buyouts - \$'000

Agreement affected	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Arthurs Pass transformer		1,100								
Castle Hill transformer		1,100								
Middleton 66kV GXP connection	1,420									
Hororata 33kV			130							
Totals	1,420	2,200	130							

7.1.14 Transpower new investment agreement charges

Table 7-1.14 Transpower new investment agreement charges - \$'000

Project	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Islington GXP additional 33kV feeder	32	16								
Hororata GXP additional 66kV feeder	24	24	24	24	24	24	24	24	24	24
Islington GXP 66kV bay for Weedons line	15	15	15	15	15	15	15	15	15	15
GXP Metering relocation from Papanui and Springston to Islington	126	126	126	126	126	126	126	126	126	126
305 Bromley GXP 220/66kV transformer upgrade	847	847	847	847	847	847	847	847	847	847
632 Hororata GXP 33kV bus alterations	24	24	24	24	24	24	24	24		
704 Kimberley GXP	1,188	1,188	1,188	1,188	1,188	1,188	1,188	297		
784 Addington metering relocation	370	370	370	370	370					
325 Hororata GXP 66kV bay for Hororata zone substation							190	190	190	190
629 Hororata GXP 66kV bay for Hororata-Darfield line							190	190	190	190
Totals	2,626	2,610	2,594	2,594	2,594	2,224	2,604	1,713	1,392	1,392

Note: Assumes 5 year contracts for new agreements.

7.1.15 Transpower connection and interconnection charges

Table 7-1.15 Transpower connection and interconnection charges - \$'000

Project	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Interconnection charges	66,181	67,116	67,789	67,886	68,268	67,598	66,936	66,279	65,630	64,986
Connection charges	4,634	4,589	3,703	3,666	3,629	3,592	3,555	3,518	3,482	3,445
Totals	70,815	71,704	71,493	71,552	71,897	71,190	70,491	69,798	69,111	68,431

7.2 Changes from our previous forecasts

Changes described in these budgets are referenced to our last published AMP (for the period from 1 April 2014 to 31 March 2024). All forecasts are now in FY16 dollar terms (previously in FY15 dollar terms).

Opex - network

Details of our maintenance plans are described by asset type in section 4 – Lifecycle asset management.

Our maintenance forecasts are generally consistent with last year's forecasts.

Capex - network

ASSET REPLACEMENT

Our asset replacement plans are described by asset type in section 4 – Lifecycle asset management.

In real terms, our switchgear replacement capex for the next nine years has reduced by \$15.5m, underground cable replacement reduced by \$18.5m along with minor adjustments across all other assets. The net result is a reduction of \$32.1m over the next nine years relative to last year's AMP for the same period.

CONSUMER CONNECTIONS AND NETWORK EXTENSIONS

Our load demand forecasts are detailed in section 5 – Network development. Our network extensions and consumer connection cost forecasts are based on our current and forecast business and residential growth forecasts. In general, demand growth has continued to be slow while decisions are finalised regarding earthquake affected land in the east of the city. Over the next few years we expect connection growth to be high as proposed subdivisions become available to meet the requirements of people relocated from the east, and development begins in the CBD.

ASSET RELOCATIONS

Underground conversions are carried out predominantly with road works, at the direction of Selwyn District Council, Christchurch City Council and/or the New Zealand Transport Agency (NZTA). Costs associated with these works can vary depending on council or roading authority demands. Currently the Christchurch City Council has indicated they will not be carrying out undergrounding within the next four years. Selwyn District Council is continuing with its on-going programme. Undergrounding associated with NZTA projects has currently provided works that have compensated for the reduction by CCC. We estimate that activity will decrease after the major 'Roads of National Significance (RONS)' Programme is completed by NZTA over the next few years.

REINFORCEMENT

Our reinforcement forecasts have been reduced from \$4.5m to \$3.5m per annum. This reflects the benefits of our change in 11kV network architecture in 2007, the completion of 11kV inter-zone substation links and reduced irrigation growth on the rural network. Our reinforcement forecasts are in section 5 – Network development.

MAJOR PROJECTS

Our major projects have a long term focus to meet forecast growth while delivering our resilience, reliability and security of supply objectives. They typically include new 66kV subtransmission lines or cables and/or new 66/11kV zone substations.

Our earthquake recovery works to the east and north of the city remain largely unchanged from our previous two AMPs. We have made a minor change to bring forward the Papanui bus coupler from FY18 to FY16 (\$0.35m). Our FY17 forecast includes \$6.2m for the rebuild of Lancaster zone substation to remedy earthquake damage.

Changes to forecast growth and the plans of some major customers has enabled deferrals as follows:

- Moffett 33kV and Belfast generation from FY16 to FY17
- Milton to Lancaster 66kV link from FY16 to FY18
- Shands 66kV from FY17 to FY19
- Prebbleton upgrade from FY21 to FY26+
- Hawthornden works from FY18 to FY19
- Porters Village from FY16 to FY19
- Westland Milk related projects from FY17 to FY19
- Dunsandel transformer upgrade from FY17 to FY18

We have seen an increase in the cost of tendered civil works as the Christchurch earthquake rebuild puts upward pressure on civil and other costs in general. However, we have refined our approach to upgrades in the Darfield area and other small project adjustments to offset these costs. This year's major projects forecast for FY16 to FY24 of \$157m compares with a \$144m forecast in our last AMP for the equivalent period.

SPUR ASSETS

We have made significant progress on the acquisition of Transpower spur assets with the purchase of Papanui in August 2012, Springston and Bromley 66 and 11kV on 31 March 2014 and 1 April 2014 respectively and Addington and Middleton on 1 April 2015 (appear as FY16 forecast in this AMP). Our forecasts for the acquisition of further smaller spur assets (Castle Hill, Arthur's Pass, Hororata 33kV and Islington 33kV) have been delayed to FY18 while we and Transpower assess the options and appropriateness of these final transfers.

Evaluation of performance



8

8.1	Introduction	279
8.2	Review of consumer service	279
8.2.1	Review of reliability	279
8.2.2	Least reliable feeders	281
8.2.3	Cause of interruptions	282
8.2.4	Reliability performance comparisons	282
8.2.5	Power quality	282
8.3	Efficiency	283
8.3.1	Economic efficiency	283
8.3.2	Capacity utilisation	284
8.3.3	Load factor	284
8.3.4	Losses	284
8.4	Works	287
8.4.1	Expenditure in FY14	287
8.4.2	Project completion status	288
8.5	Safety	289
8.6	Environment	289
8.7	Legislation	289
8.8	Improvement initiatives	290
8.8.1	Subtransmission network	290
8.8.2	Distribution overhead lines	290
8.8.3	Substations	293
8.8.4	Power quality	293
8.8.5	Emergency stock	294
8.9	Gap analysis	295
8.9.1	Asset management processes	295
8.9.2	Reliability	296
8.9.3	Security standard	296

List of figures and tables in this section

Figure	Title	Page	Table	Title	Page
8-2a	SAIDI - Orion network FY92-Current year	280	8-2a	Orion network reliability for CY and 5 year average	279
8-2b	SAIFI - Orion network FY92-Current year	281	8-2b	Service forecasts and results for network power quality	282
8-2c	Least reliable rural feeders CY-5 to CY (SAIDI)	281	8-3a	Capacity utilisation results for CY and 5 year average	284
8-2d	Cause of interruptions CY-15 to CY	282	8-3b	Load factor results for CY and 5 year average	284
8-3a	Capex per annum per MWh supplied to consumers	283	8-3c	Loss results for CY and 5 year average	284
8-3b	Opex per annum per MWh supplied to consumers	283	8-3d	Network loss contributors	284
8-3c	Opex per annum per ICP	283	8-3e	Transformer loss values	285
8-9a	Orion's maturity level scores	296	8-3f	Underground cable versus overhead line comparison	285
			8-4a	Project completion status	288
			8-5a	Personal safety – performance results	289
			8-6a	Environmental responsibility – performance results	289
			8-8b	Installation of GFN – reliability savings	292

8.1 Introduction

In this section we review our performance against forecasts stated in our previous AMP. These forecasts may be actual values as stated in section 3, or a declaration to carry out particular maintenance or reduce risk. We also include whether or not budgets were met and explain any variances.

Also included is a discussion on some current and future initiatives along with a reliability gap analysis.

8.2 Review of consumer service

8.2.1 Review of reliability

Interruption data recorded in our control centre OMS (see section 2.8.1 10) provides all relevant statistical data needed to calculate our reliability statistics using the international measures of SAIDI and SAIFI (see the Glossary for a definition of these measures).

It is important to note that one-off factors such as bad weather and earthquakes can heavily influence the results in any one year.

As shown in the table below, our FY14 SAIDI and SAIFI results were over our forecast and the Commerce Commission's DPP reliability limit. This was almost entirely due to NW wind storms in July and September 2013 that had a major impact on our rural network. The storm in September was the biggest event on our network since the Canterbury earthquakes in FY11 and caused a loss of over 60 million consumer minutes. The earthquakes caused the loss of 718 million consumer minutes.

Table 8-2a Orion network reliability results for FY14 and last five year average

Category	FY14 Orion forecast	FY14 actual result**	FY10-FY14 average	FY14 DPP reliability limit	FY14 DPP normalised result***
SAIDI	< 137	474	934	59.2	105
SAIFI	< 1.8	1.3	1.6	0.78	1.22
Faults restored within 3 hours (%)	> 60	57.8	60.3		
Subtransmission lines faults per 100km*	-	6.9	-		
Subtransmission cables faults per 100km*	-	0	-		
Distribution lines faults per 100km*	-	23.2	-		
Distribution cables faults per 100km*	-	3.3	-		
Subtransmission other faults*	-	1	-		
Distribution other faults*	-	108	-		

* As per Disclosure schedule 10(v).

** Full result, no daily limits applied to major events.

*** Major event daily limits applied in accordance with DPP.

As shown in the following figures, there were also heavy snow storms in FY93, FY03 and FY07 that caused significant damage to our network.

Even though major emergency earthquake repairs are finished, there is still much work ahead of us to build strength back into our network. Significant infrastructure rebuilding activity in the city will also likely see an increase in damage and disturbance of our network assets. We expect to restore our network to near pre-earthquake reliability levels by FY19.

Figure 8-2a SAIDI - Orion network FY92-FY14

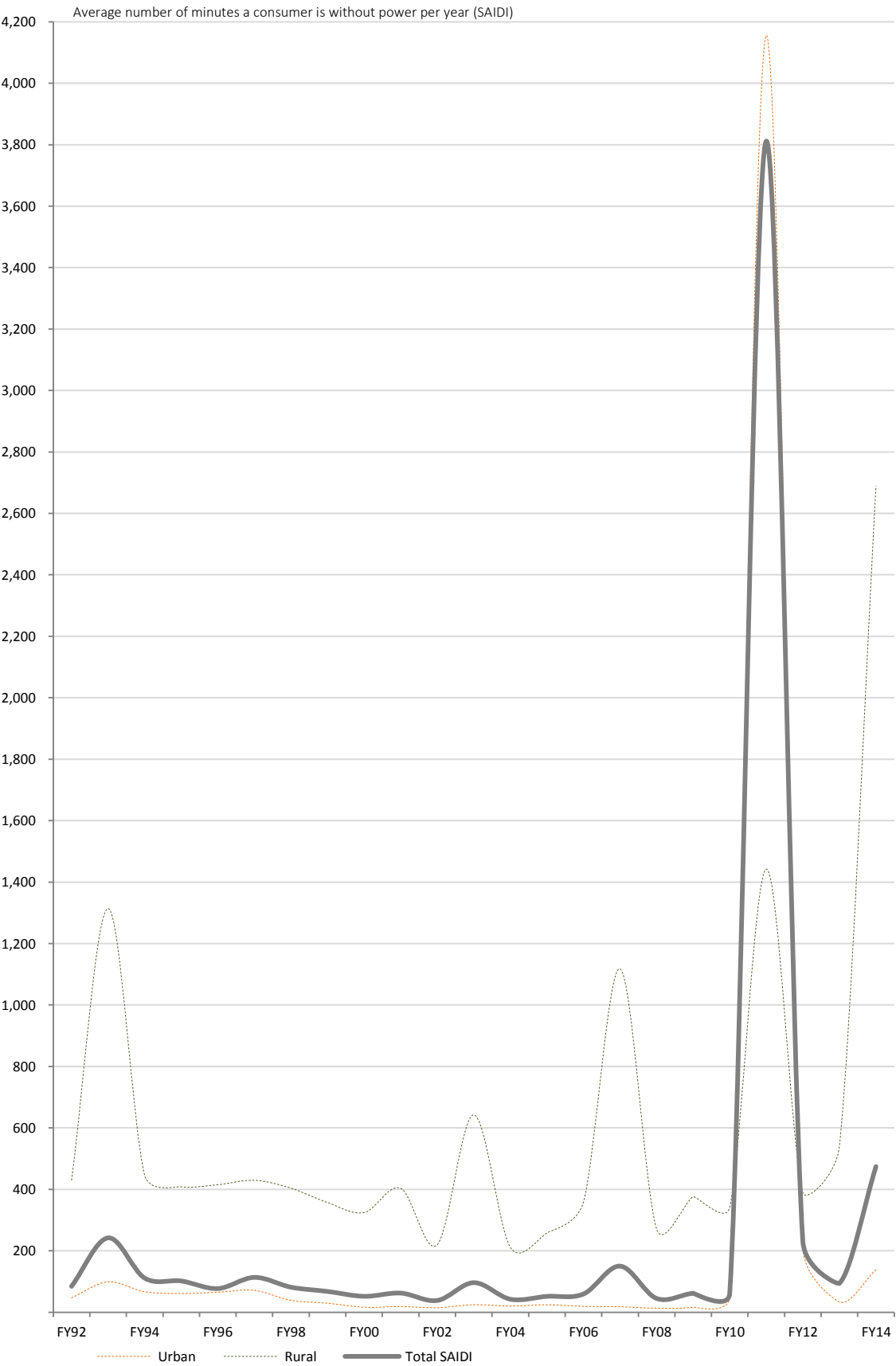
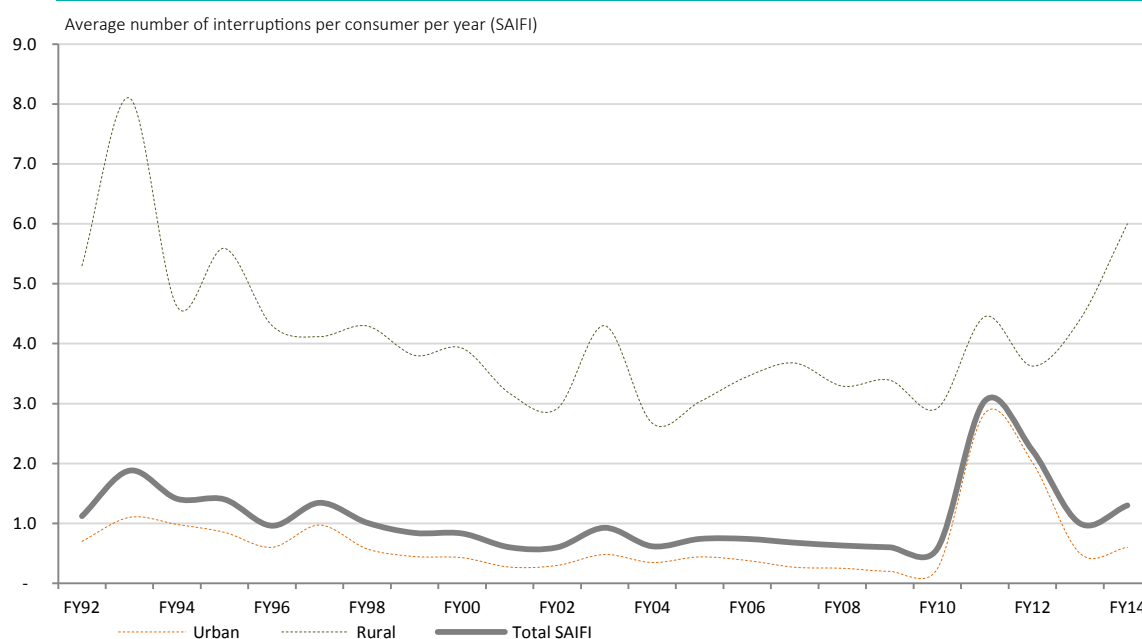


Figure 8-2b SAIFI - Orion network FY92-FY14

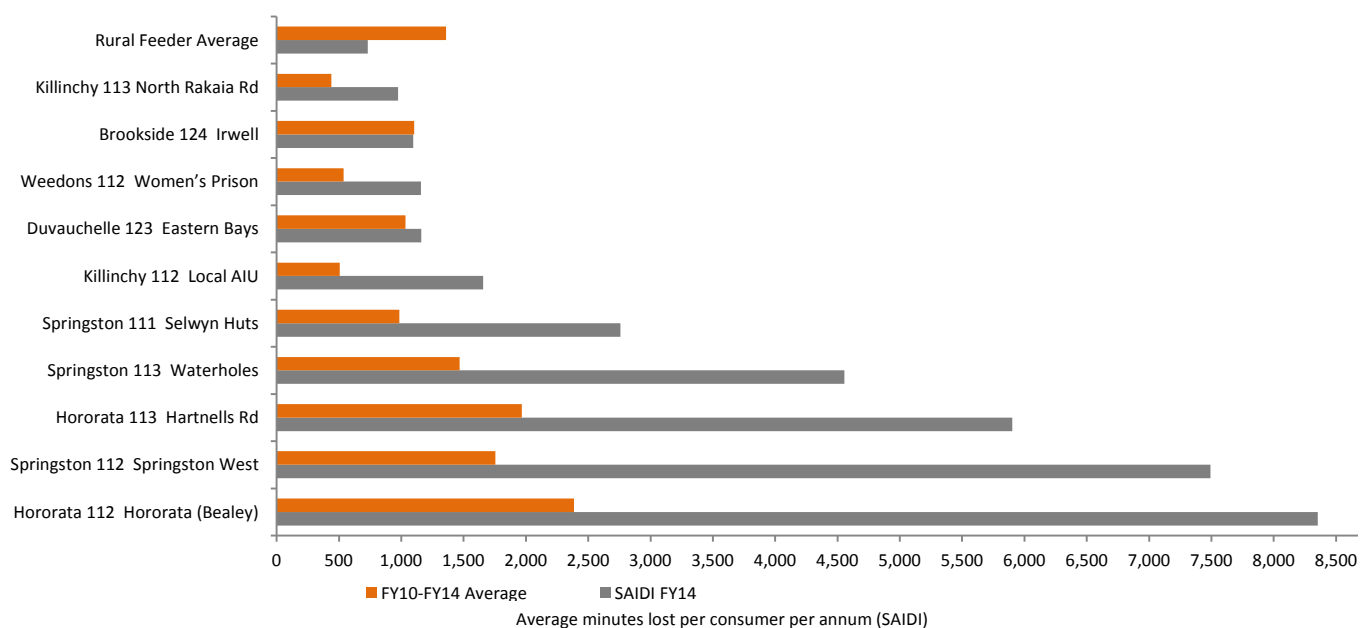


8.2.2 Least reliable feeders

Our network has 94 rural and 336 urban 11kV feeders that originate from our zone substations.

The 10 least reliable feeders on our rural network are shown below. All of these feeders were adversely affected by recent storms and some were also affected by the earthquakes in FY11.

Figure 8-2c Orion's 10 least reliable rural feeders FY10-FY14 (SAIDI) (unplanned interruptions only)

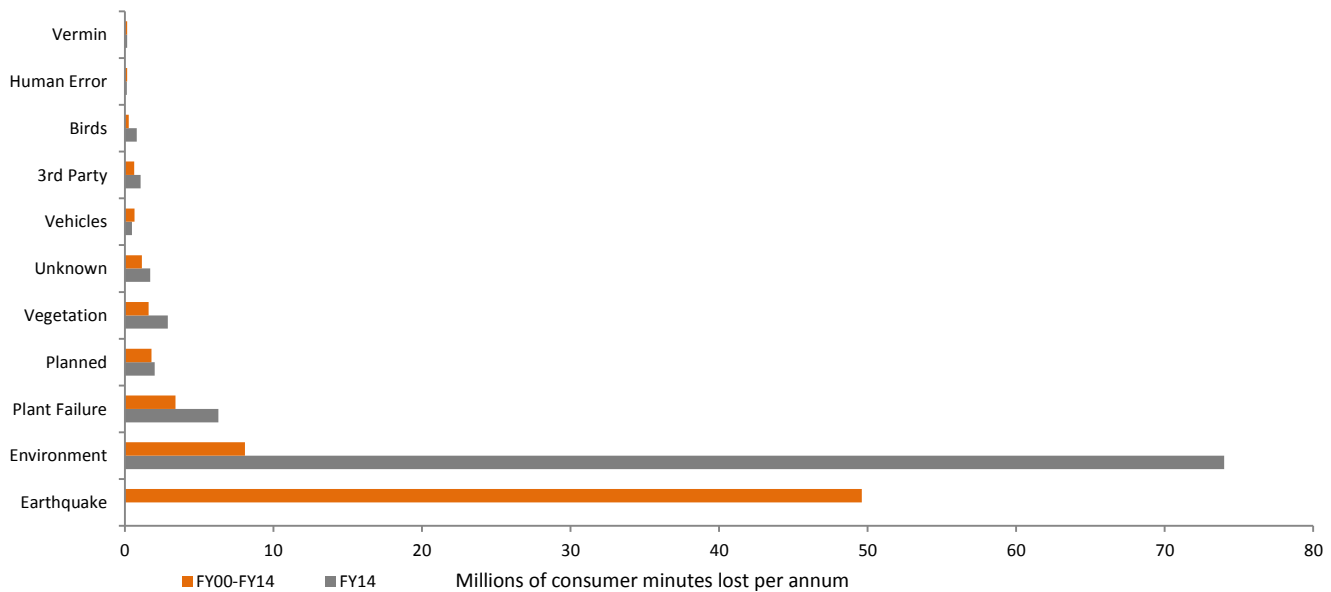


8.2.3 Cause of interruptions

The chart below compares the cause of consumer minutes lost per annum on our network over the 15 year period FY00 to FY14 against the most recent year (FY14).

Where plant-failure and vegetation interruptions have been caused by severe abnormal weather conditions, such as a snow or wind storm, they are placed in the 'environment' category.

Figure 8-2d Cause of interruptions FY00-FY14



8.2.4 Reliability performance comparisons

When compared with other New Zealand line companies, the reliability of our urban network (when not subjected to earthquakes) appears to be above average, while our rural network (when there are no storms) is slightly below average. There is still scope to improve our performance and we discuss improvement initiatives later in this section.

8.2.5 Power quality

Our main objective in relation to power quality is to identify and resolve consumer quality of supply enquiries. To achieve this we fit test instruments close to the point where ownership changes between Orion's network and the consumer's electrical installation.

Data gathered from the test instruments is analysed against the current New Zealand Electricity Regulations. By applying key regulations in relation to voltage, frequency, quality of supply and harmonics we are able to determine which quality problems have originated within our network.

Our network performs well in terms of voltage and quality. We receive a number of voltage complaints every year but only approximately 30% of complaints are due to a problem in our network. In the following table, 'proven' means that the non-complying voltage or harmonic originated in our network.

Table 8-2b Service level forecasts and results for FY14 – network power quality

Category	Measure	Forecast	Achieved FY14	Performance indicator	Measurement procedure
Power quality	Voltage complaints (proven)	<70	39	Non compliances per annum	Tracking of all enquiries
	Harmonics (wave form) complaints (proven)	<2	0	Non compliances per annum	Checks performed using a harmonic analyser

8.3 Efficiency

8.3.1 Economic efficiency

Economic efficiency reflects the level of asset investment required to provide network services to consumers, and the operational costs associated with operating, maintaining and managing the assets.

Figure 8-3a Capex per annum per MWh supplied to consumers FY04-FY14

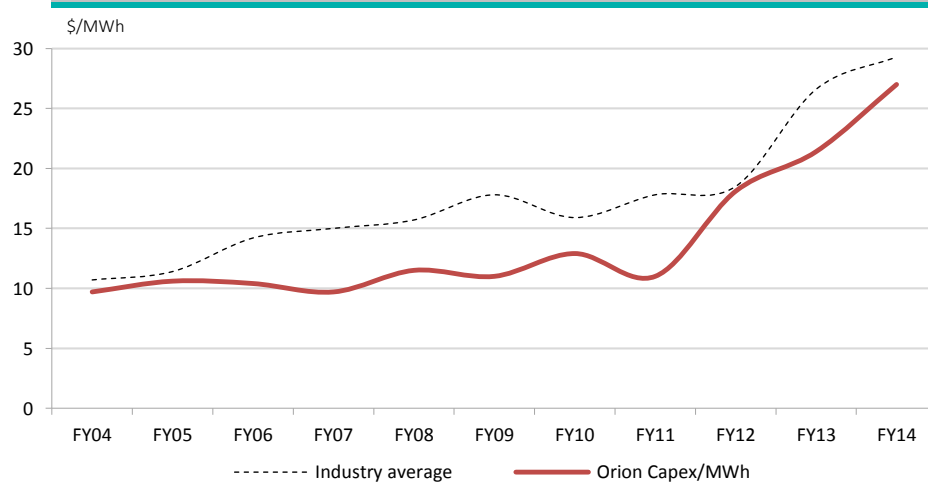


Figure 8-3b Opex per annum per MWh supplied to consumers FY04-FY14

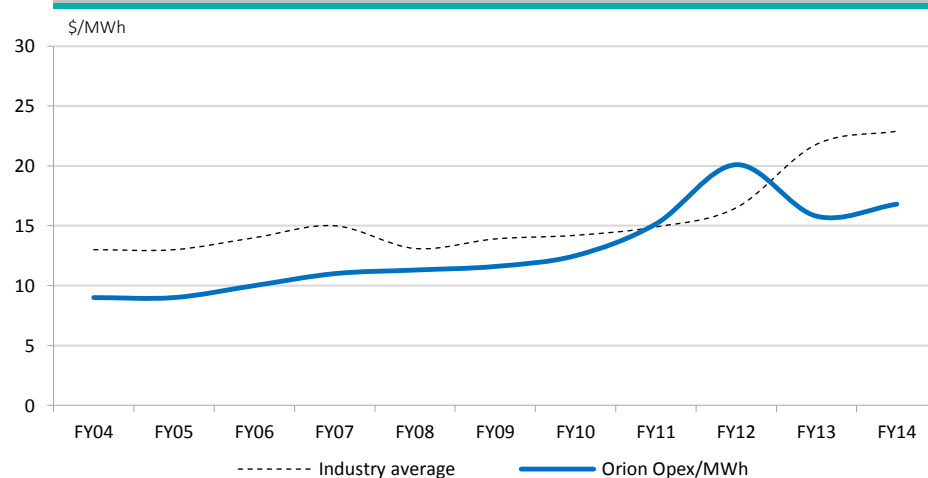
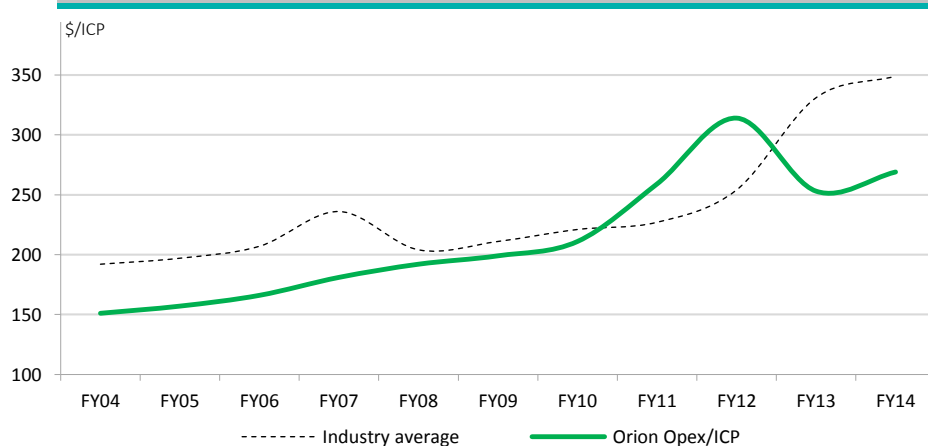


Figure 8-3c Opex per annum per ICP FY04-FY14



8.3.2 Capacity utilisation

This ratio measures the utilisation of transformers in our network. It is calculated as the maximum demand experienced on our network divided by the network distribution transformer capacity.

Table 8-3a Capacity utilisation results for FY14 and five year average FY10-FY14

Category	Forecast	Achieved FY14	Achieved five year average
Capacity utilisation (%)	No forecast set*	29.5	30.5

* See section 3.3.8 for reasoning why no specific forecast is set for capacity utilisation.

8.3.3 Load factor

Annual load factor is calculated as the average load that passes through our network divided by the maximum load experienced in a given year. We always seek to optimise load factor as this indicates better utilisation of capacity in the network.

Load factor has trended upwards from 1990-2009 by ~0.6% per annum, and has since levelled off. The impact on load factor from the anticipated reduction of irrigation load due to CPW scheme is expected to be offset by the Central City rebuild.

Table 8-3b Load factor results for FY14 and five year average FY10-FY14

Category	Forecast	Achieved FY14	Achieved five year average
Load factor (%)	No forecast set*	58.3	60

* See section 5.4.1 for our load factor forecasts.

8.3.4 Losses

Measurement of losses

Electrical losses are the difference between energy volumes entering our network (mainly at Transpower GXPs) and the energy volumes leaving our network at consumer connections. We estimate that these losses are around 5% with a margin of error of +/- 1 percent. Significant deviations from this value exist in some parts of our network, for example, when we compare urban areas against rural areas.

Table 8-3c Loss results for FY14 and five year average FY10-FY14

Category	Forecast	Achieved FY14	Achieved five year average
Losses (%)	No forecast set*	<5 estimated	<5 estimated

* See the following for reasoning why no specific forecast is set for losses.

Source of losses

Our assessment of the main contributors to our loss ratio is as follows:

NETWORK

Table 8-3d Network loss contributors

Asset	Urban	Rural	Average
Subtransmission lines and cables	0.4%	1.0%	
Zone substation (power) transformers	0.4%	0.4%	
11kV lines and cables	1.4%	3.5%	
Subtotal subtransmission + 11kV	2.2%	5.0%	
Distribution transformers	1.1%	1.0%	
230/400V lines and cables	1.2%	0.3%	
Subtotal low voltage	2.3%	1.3%	
Totals	4.5%	6.2%	5%

OTHER SOURCES

Internal usage by Orion – All our major facilities, such as our administration office, are metered and we purchase electricity from a retailer like any normal consumer. However, many unmetered supplies are needed at our substations to operate equipment that is integral to a safe and reliable network. The annual volume of energy involved is estimated at 0.1% of total energy volume across our network.

Unmetered supplies – Substantial volumes, such as supply to street and traffic lights, are estimated and included with retail sales. Other miscellaneous outlets, such as those at parks, contribute towards losses at insignificant levels.

Theft – Theft may significantly contribute towards losses, although actual volume is unknown. Electricity retailers are responsible for integrity of metering at connections and for reading meters. It is in their interest to minimise theft.

Transformer purchases

New distribution transformers that we purchase must comply with the Minimum Energy Performance Standards (MEPS) as prescribed in AS2374.1. In addition to MEPS, our equipment specification NW74.23.05 – Distribution Transformers 200 to 1,500kVA, includes a ‘no-load loss’ multiplier and a ‘load loss multiplier’ that are used for the capitalisation of loss costs when comparing distribution transformers for purchase. As a result we purchase even lower loss transformers than MEPS requires.

Our equipment specifications for power transformers also use these loss multipliers when we evaluate tenders.

For more detailed assessments in specific circumstances, we also refer to ‘Purchase and Operating Costs of Transformers’, published by the Electricity Engineers’ Association of New Zealand.

Our approach ensures we consider the trade-offs between purchase cost and the future cost of energy losses. It costs more to manufacture a transformer with lower losses because higher quality materials are needed. Our loss capitalisation calculation for transformers assumes a value of 11.055c/kWh for the future cost of energy. This leads to the capitalisation values per kW of losses shown in the table. We review these values when we purchase new power transformers and when we tender distribution transformer supply contracts for transformers up to 1500kVA.

Table 8-3e Transformer ‘loss’ values

Transformer size	Present value of ‘no load loss’ (\$/kW)	Present value of ‘load loss’ (\$/kW)
Up to 200kVA Pole mounted	9,319	833
200 to 500kVA Ground mounted	9,319	1,184
750 to 1500kVA Ground mounted	9,319	1,625
7.5 to 40MVA Zone substation	9,523	1,424

Selecting conductor size

Most electrical losses in our network occur in the conductors. We calculate losses from the expression I^2R , where I is the current, and R is the resistance of the conductor. The connected load determines the current and conductor size, while materials determine the conductor resistance. The larger the conductor size, the lower the resistance and losses. However, larger conductors cost more so a trade-off exists between costs of capital and losses.

Overhead lines

There is a complex trade-off between conductor size, losses, capital cost and alternatives such as regulators and capacitors. We are currently modelling and reviewing our rural 66kV and 11kV architecture to seek the most optimum network. It should be noted that a conductor is typically a low cost component of overhead line construction and therefore larger conductors are often economically effective.

Underground cables

For a given rating, cables cost more and have lower resistance per unit length. A comparative example is shown in the following table:

Table 8-3f Underground cable versus overhead line comparison

Conductor	Rating (amps)	Installed cost (\$/km)	Resistance (ohms/km)
Dog overhead line	350	40,000	0.273
185mm ² Al cable	280	160,000	0.164

Consequently, with much higher capital costs and much lower resistance, we never achieve an economic cross-over because losses are already low – an increase in size cannot be justified by the small reduction in losses alone. However, the collective benefits (increased security of supply, reduced losses and reduced transmission charges) justify the increased cost of the larger

cable. We proved this justification when we reviewed our Security Standard in FY06. Analysis showed it was economic to install an 11kV network capable of restoring power for N-2 faults at zone substations. Two thirds of the additional expenditure required for larger N-2 feeder cables was justified by reduced energy losses and lower peak demand charges due to fewer losses at peak. Our security standard drives economic investment in our 11kV network – the policy to install N-2 capacity creates fewer losses on our network.

Selecting voltage

For the same power or energy volume delivered, losses are lower when conductors are operated at a higher voltage. Capital costs also increase for higher voltage equipment. A continuous range of voltage is not practical. We use discrete voltages of 66kV, 33kV, 11kV and 230/400V.

When extending our network, we model the development and consider all future costs, including the cost of losses. In a rural area, for example, our network may be extended at 11kV, 33kV or 66kV to supply future loading such as large irrigation plants.

For developments at the connection level, we also consider alternatives for supply voltage and whether or not to extend the low or high voltage reticulation. We may consider losses when we make decisions although other factors tend to dominate such as future access to plant, shared land use and customer preferences.

Summary

Overall, losses do not impact significantly on how we design and operate our network – other factors tend to dominate. Losses are significant in some aspects of network design though, and require policies for optimisation. Significant points are:

- lines and cables (around two-thirds) and transformers (around one-third) account for nearly all the losses on our network
- a trade-off exists between capital and loss costs, which results in optimisation of losses, not minimisation
- we give specific consideration to losses when purchasing transformers
- we optimise losses on the 11kV underground network by applying our economically derived security of supply standard to reinforcement
- we consider loss optimisation when we design overhead lines but other factors tend to dominate
- for any major network development, we consider the cost of losses.

8.4 Works

8.4.1 Expenditure in FY14

The previous AMP figures shown here are from our AMP for the period 1 April 2013 to 31 March 2023.

Maintenance

Our maintenance costs for FY14 were \$24m, compared with our budget forecast of \$27m. The under-expenditure was largely due to deferred works due to the uncertain requirements around earthquake recovery third-party works and constrained resources.

Capex

CONSUMER CONNECTIONS AND EXTENSIONS

Our consumer connection and extension costs for FY14 were \$14.6m, compared with our previous budget forecast of \$12.6m. The over-expenditure was largely due to a significant increase in subdivisions being built to meet the high demand.

REINFORCEMENT

Our reinforcement costs for FY14 were \$2.7m, compared with our previous budget forecast of \$4.9m. The under expenditure was due to deferment of approximately \$2m due to co-ordination with NZTA works or developer driven works.

UNDERGROUND CONVERSION

Our underground conversion costs for FY14 were \$3.6m, compared with our previous budget forecast of \$6.6m.

This expenditure is dependent on project timing associated with the needs of the Rounding Authorities, Christchurch City Council, Selwyn District Council, NZTA and developer requirements.

The under-expenditure is due to delays in road construction programmes and developer driven projects.

MAJOR PROJECTS

Major project costs for FY14 were \$23.9m, compared with our previous budget forecast of \$39.1m. The under-expenditure was largely due to:

- Delays to the Bromley - Dallington and Bromley - Rawhiti 66kV cable projects due to co-ordination with earthquake road/bridge repair contract works.
- Deferment of land purchase for 66kV substations (Burnham, Greenpark and Rossendale) until suitable land and agreements can be completed.
- Deferment of Central Plains Water canal pumps until upgrade agreement has been negotiated
- Delay of Larcomb zone substation 66kV upgrade and associated new Springston connection until acquisition of Transpower's Springston GXP assets occurred.

REPLACEMENT

Our replacement costs for FY14 were \$15.7m, compared with our previous budget forecast of \$24.9m. The under-expenditure reflects the variable and unpredictable nature of our work as we recover from the earthquakes. The difference is largely due to the following factors:

- allowance for replacement of earthquake impaired cables not required in the period
- less distribution transformer replacement due to lower energy demand
- deferred works associated with control systems
- switchgear replacement deferred due to our architecture review, network access issues and decisions in regard of disestablished earthquake zones.

8.4.2 Project completion status

Table 8-4a Project completion status			
Project number	Description	Completion date	Comments (if applicable)
Grid exit points			
	Springston (spur asset purchase)	April 2014	
Major projects – urban			
521	Land acquisition for Marshland substation	2014	
656	Bromley to Dallington 66kV link	Delayed	Due to co-ordination with EQ bridge repairs
619	Bromley to Rawhiti 66kV link	Delayed	Due to co-ordination with EQ bridge repairs
709	Awatea substation land remediation	April 2014	
Major projects – rural			
414	Convert Larcomb sub from 33/11kV to 66/11kV	Deferred	Until acquisition of Transpower's Springston GXP
429	Springston 66kV bay for Larcomb substation	Deferred	Until acquisition of Transpower's Springston GXP
494	Rural power factor correction	Deferred	
500	Land acquisition for Burnham 66kV substation	Deferred	Until suitable land and agreements completed
528	Land acquisition for Rossendale 66kV substation	Deferred	Until suitable land and agreements completed
612	Convert Kimberley substation to 66/11kV	July 2013	
637	Railway Rd 11kV substation (Westland Milk)	Deferred	Until agreement completed
675	Ground fault neutralisers	On-going	
676	Land acquisition for Greenpark substation	Deferred	Until land/agreement determined
688	Motukarara transformer upgrade	Sep 2013	
698	Central Plains Water canal pumps	Deferred	Until agreement completed
Reinforcement – urban			
50	Lyttelton cable stage 1	Deferred	Until agreement with NZTA completed
485	Addington-Fielding St circuit	Cancelled	Determined not required
550	Johns Rd feeders stage 2	Deferred	To be completed with NZTA works
564	Wigram reinforce: Parkhouse-Hayton roundabout	n/a	To be completed with subdivision
566	Wigram reinforcement: Awatea Rd feeder	April 2014	
635	Smart meter trial	Deferred	
647	Russley Rd-Memorial Av reinforcement	March 2014	
649	Prestons Rd reinforcement stage 1	Deferred	To be completed with subdivision
684	Chaney's reinforcement	March 2014	
732	Wooldridge Rd reinforcement	Feb 2014	
Reinforcement – rural			
683	Rakaia Island reinforcement	Cancelled	Determined not required

8.5 Safety

We report all employee injury incidents in our Human Resources database. We separately collect similar statistical incident data from our contractors. These contractor statistics, our own statistical data and our incident investigations, enable us to provide staff and contractors with indicators of potential harm.

See section 6.3 – Risk management – Safety, for details of our risk mitigation initiatives.

Table 8-5a Personal safety – performance results

Key asset management driver	Measure	Forecast	Achieved FY14	Performance indicator	Measurement procedure
Personal safety	Injuries to staff	0	2	Number of 'lost-time' injury accidents	Accident/incident reports
	Injuries to our contractors	0	5		
	Injuries to public	0	0		

8.6 Environment

All service providers are required to adhere to our environmental management manual and procedures.

All polychlorinated biphenyls (PCBs) have previously been removed from our network.

Table 8-6a Environmental responsibility – performance results

Key asset management driver	Measure	Forecast	Achieved FY14	Performance indicator	Measurement procedure
Environmental responsibility	SF ₆ gas lost	<1% loss	<1% loss	Identification of environmental problems	Environmental spill/loss report
	Oil spills (uncontained)	0	0		

8.7 Legislation

We have analysed our compliance with relevant statutes and identified the risk, compliance process and managerial responsibility for each.

Statutes analysed include:

- Electricity Act 1992 and associated regulations
- Electricity Industry Act 2010
- Health and Safety in Employment Act 1992 and associated regulations
- Resource Management Act 1991
- Hazardous Substances and New Organisms Act 1996
- Building Act 2004
- Fire Services Act 1975 and associated regulations
- We report our compliance, including any exceptions and corrective actions, to our board twice each year.

8.8 Improvement initiatives

Our initiatives to reduce network risk in areas such as safety, seismic damage and major asset failure are discussed in section 6 – Risk management.

We discuss initiatives to improve network performance and reliability in the following sections.

8.8.1 Subtransmission network

We have identified a need to improve security and performance in the upper network (higher voltage), since this asset affects the largest number of consumers. Initiatives taken in relation to this asset include:

Underground

- carried out thermal engineering checks to determine/confirm the current rating of cables
- specify trench backfill to provide the required thermal and mechanical support
- replaced the 66kV oil-filled cable joints and 33kV oil-filled cables to counter thermo-mechanical effects that may cause the joints to fail – see sections 4.9.3 and 4.10.3.

Overhead

- replaced insulators and install vibration dampers
- re-rated conductor for 75°C operating temperature
- applied dynamic ratings
- assessed condition of tower foundations and repaired where required.

Substations

- increased reliability at Addington by splitting the 66kV bus
- rearranged existing 11kV supplies at Addington to increase security
- constructed a 66kV bus at Springston.
- installed a 66kV bus zone scheme at Bromley

Transpower GXP

- major alterations at Islington GXP to increase capacity and alter vector grouping along with replacing half of the 33kV outdoor switchgear with indoor equipment

8.8.2 Distribution overhead lines

Historical performance

Over the past 23 years our rural reliability performance has improved by a factor of approximately two. During this period the 11kV overhead line fault rate has decreased from approximately 25 faults per 100km per year to around 12.

These improvements are primarily attributed to some major maintenance projects and better tree control. In addition, live-line work practices have reduced planned outages. More line circuit breakers and shortened feeders as new zone substations are installed have also improved performance.

Our major initiatives are:

- completed a review of our overhead line design standards
- use live-line techniques where appropriate
- complete regular tree maintenance on a complete feeder basis
- introduce softwood poles and phase-out concrete poles
- increase the use of thermal/corona scanning to identify potential problems
- install wedge connectors to replace parallel-grove clamps on high voltage lines
- increase use of smooth-body conductors in areas exposed to snow and high winds
- remove Pacific type high voltage transformer fuses (completed)
- re-tighten hardware to minimise damage caused by loose components
- modify protection systems and add remote control to all line circuit breakers
- install additional pole mounted line circuit breakers
- underground selected troublesome consumer high voltage spur lines
- replace older air break switches.

Opportunities for further improvement

The reliability performance of our rural network is driven by the fault rate on overhead lines. Methods to improve performance can either attempt to reduce the overhead line fault rate or minimise its impact. We initially improved our reliability performance by reducing the fault rate. More recent improvements have come from minimising the impact of line faults. In the five years from FY00-FY04 we installed 29 additional line circuit breakers in our rural network – the first significant installation of line circuit breakers in approximately 15 years. Significant performance gains were seen.

We believe it is sensible to compare the costs of reliability improvements with the reduced costs of lost supply to our consumers. The CAE Reliability of Electricity Supply Project Report, 1993, published the values of un-served energy, providing typical values of between \$5.00 and \$10.00 per kWh. Adjusting these costs for inflation, we get un-served energy costs of between \$14 and \$20 per kWh. Further analysis of irrigation consumers during 2005 indicated that the value of supply to irrigation pumps is significantly less than \$14 to \$20 per kWh, but it is thought that the high value placed on milking supply balances the analysis. A value of \$15 per kWh is applied in the analysis below.

We estimate that the average load of a rural consumer is 2kW, so the cost of an outage to the average rural consumer is \$30 per hour. Therefore the annual cost of network enhancement must not exceed the \$30 per hour of consumer reliability improvement. The annual cost of network enhancement is approximately 14% of the capital cost. For example in the case of a \$50,000 line circuit breaker, we require \$7,000 of annual revenue to be charged to consumers.

The first circuit breaker in the FY00-FY04 installation programme was installed in a feeder from our Lincoln zone substation. This programme has continued, identifying locations that provide the maximum improvement in system reliability. However, as circuit breakers have been installed in the most effective locations, the benefits versus costs have decreased.

Current available options to improve rural network reliability come at considerably differing costs and each needs to be assessed for its suitability to the application. These options include:

- 1. Increase our tree trimming programme** – this could improve our network reliability significantly. Of our unplanned interruptions, trees currently cause between 15 and 20% of total consumer-minutes lost. However, our analysis of existing tree trimming programme indicates it probably cannot be expanded in any major way. We trimmed trees to the limit allowed under previous law, i.e. clear of power lines for safety reasons. Tree control legislation that defines clearance corridors has now been passed into law.

If we increased our expenditure on tree trimming around 11kV lines by approximately \$500,000 each year we could reduce consumer minutes lost in the range of 500,000 to 1,000,000 minutes (8,350 to 16,700 hours) at an annual cost of \$15 to \$30 per kWh. The economic benefits of this approach are marginal, but the project is also driven by safety and legislation. Our remaining tree trimming expenditure is in relation to 400V lines and will not be reflected in our interruption statistics.

Another possible way to reduce faults due to trees would be to selectively install covered conductors in areas subject to tree problems. This would be suitable in areas where small branches contact or fall on lines, but would probably provide very little benefit where whole trees fall, pulling down the line including poles. It is very difficult to show a positive cost benefit case for this option.

- 2. Continue to install additional line circuit breakers** – we appear to have reached an incremental level of around 15,000 minutes (250 hours) per \$50,000 line circuit breaker installation (\$14 per kWh). This suggests additional line circuit breakers would have marginal benefit for rural consumers.

- 3. Shorten feeder lengths** by installing additional zone substations. Each additional substation could halve the length of three existing feeders and, if we assume that each feeder supplies 250 consumers and consists of 50km of 11kV line, this strategy could reduce consumer-minutes lost by about 500,000 (8,300 hours). An additional rural zone substation typically costs about \$4m, giving an annualised cost of \$33 per kWh. This exceeds the benefit of reliability improvement. Therefore this method of performance improvement is generally only acceptable as a side-effect of network reinforcement.

- 4. Replace the existing bare conductor with a covered conductor** on a major proportion of the rural overhead network. If we assume the average cost of replacing the existing conductor, including strengthening existing poles and structures and installing modified covered ancillary equipment (switches, transformers etc.) is \$25 per metre, then for 3,200km of rural overhead line, the cost would be approximately \$80m. Covered conductors' impact on reliability has not been comprehensively documented elsewhere in the world. However, a Norwegian network operator has claimed improvement ratios of 10:1. Part of this improvement may be due to the fact that the network was substantially rebuilt when the covered conductor was installed, which in itself would improve reliability, at least transiently, until the aging process reduced the reliability again.

We prefer to be conservative in claiming reliability improvement from covered conductor and choose to assume a long term reduction in consumer-minutes lost to 33% of existing figures. This could result in a reduction of 4.3 million minutes or 71,700 hours (assumes rural SAIDI of 300 and 21,500 consumers giving total minutes of 6.45 million minutes) at an annualised cost of \$78 per kWh. This once again clearly exceeds the benefit of reliability improvement, therefore this method of performance improvement is not viable.

- 5. Replace the existing bare conductor overhead system with underground cable.** The cost to convert our rural network to underground is estimated to be \$600m. This would reduce the loss of customer-minutes by approximately six million (100,000 hours) at an annualised cost of approximately \$870 per kWh.

6. Installing ground fault neutralisers (GFN) at rural zone substations has the potential to significantly improve network reliability. The potential to cost-effectively improve reliability using traditional methods (1-5) is limited and expensive. However, we have successfully trialled a GFN and are completing the installation of this technology at all of our rural zone substations.

A GFN can reduce the residual earth-fault current close to zero during single-phase earth-faults and makes it safe to leave the distribution network alive with permanent earth-faults while faults are located and isolated. The estimated installation cost of each GFN is \$300,000.

Investigation has shown we can conservatively assume that 20% of unplanned long-term outages due to permanent faults, and 30% of all momentary interruptions, can be attributed to single-phase earth-faults, and therefore eliminated.

Our analysis for installing a GFN at all rural zone substations using these conservative estimates yields reliability savings greater than the annual cost to consumers. A breakdown of reliability savings for each of the existing rural substations (excluding Dunsandel) is shown in the table on the following page.

Table 8-8b Installation of GFN – reliability savings

Zone substation/ Transpower GXP	Anticipated savings for long term interruptions p.a. (\$)	Anticipated savings for momentary interruptions p.a. (\$)	Total anticipated savings p.a. (\$)	Benefit/cost ratio
Lincoln	78,432	36,852	115,284	3.07
Rolleston	69,289	32,352	101,641	2.71
Hills Rd	52,623	45,135	97,758	2.61
Weedons	47,319	49,879	97,198	2.59
Hororata	41,738	47,233	88,970	2.37
Springston	55,278	31,414	86,692	2.31
Brookside	35,112	40,554	75,666	2.02
Killinchy	31,213	41,993	73,206	1.95
Darfield	28,321	37,951	66,272	1.77
Duvauchelle	24,558	23,637	48,195	1.29
Bankside	15,546	24,387	39,933	1.06
Motukarara	26,863	9,762	36,624	0.98
Te Pirita	7,230	25,606	32,836	0.88
Greendale	6,772	18,476	25,248	0.67
Annat	10,052	9,272	19,324	0.52
Highfield	4,394	10,417	14,810	0.39
Teddington	11,356	2,878	14,234	0.38
Diamond	5,923	4,255	10,178	0.27
Little River	6,083	3,699	9,781	0.26
Castle Hill GXP	4,223	1,830	6,053	0.16
Coleridge GXP	3,368	2,569	5,937	0.16
Arthur's Pass	2,133	207	2,340	0.06
Average			48,554	1.29

Rural spur lines

We have achieved significant reliability improvements through maintaining our main rural lines. However, to continue to achieve improvements in rural performance, we have for the past 12 years maintained lines right up to the consumer's building at no direct cost to the consumer. This allows us to plan work based on performance and safety rather than on a consumer's willingness to pay.

8.8.3 Substations

We have instigated several initiatives to reduce problems with switchgear, primary transformers and their terminations. These include:

Metal-clad switchgear

- standardise equipment types
- improve installation drawings
- engage internationally recognised consultants to evaluate switchgear in the network
- establish partial discharge testing as ongoing preventive maintenance
- locate and replace older air terminations using tape insulation with heat shrink
- remove dual cable terminations with insufficient clearances
- ventilate air termination cable boxes
- increase levels of training for jointers working on this equipment
- modify older circuit breakers to enable more reliable operation.

Primary transformers

- carry out half-life maintenance programme
- replace/refurbish on-load tapchangers
- replace pressure relief glass bursting diaphragms with pressure relief valves
- conduct tests to establish on-site overload ratings
- install extra cooling as required
- install dynamic controllers at key locations
- perform dissolved gas analysis of transformers.

Interference with telecommunications networks

We have installed neutral earthing resistors (NER) at five urban 33/11kV zone substations in the Hornby area where 11kV reticulation is predominantly overhead. In these areas we frequently connect industrial/commercial consumers with short lengths of underground cable connected to the overhead, with no continuous earth connection back to the zone substation. Faults on these isolated sections of cable can cause extremely high earth potential rise (EPR) on consumer's premises. This may result in severe damage to telecommunications plant and consumer equipment and possible injury to telecommunications workers. NERs restrict earth fault current and minimise damage to telecommunications equipment.

Significant industrial and commercial area development in Rolleston and Darfield townships brings an increased risk of damage to telecommunications equipment from EPR in those areas. Instead of an NER we have now installed a ground fault neutraliser (GFN) at 15 rural zone substations to reduce earth fault levels and are in the process of installing GFNs at other rural zone substations including Rolleston.

8.8.4 Power quality

Although the power quality attributes discussed in section 3.3.4 and other parts of this AMP are well known, until recently considerable disagreement has existed about how to qualitatively measure them. As a result equipment manufacturers have developed their own individual measurement methods. Therefore equipment from different manufacturers gives different results when it measures the same input quantities. This is not ideal as it is impossible to accurately and consistently compare power quality measurement results.

A comprehensive set of international standards (IEC61000) now exists which defines standardised methods to measure power quality. Equipment that conforms to these standards is now available.

Our power quality management has generally been reactive. We respond to consumer complaints which usually arise from the consumer's own activities, and assume that fundamental network performance is satisfactory.

We have therefore undertaken a three year project to install approximately 30 power-quality measurement instruments at selected sites throughout our distribution network. This equipment complies with the standards mentioned above. The aim of the project is to undertake a long term survey to determine the power quality performance of our distribution network and how it changes over time. The measurement sites chosen represent the average and worst performing parts of our network over a variety of customer types.

We have also purchased the 'PQView power quality analysis package' to archive and analyse the data. These instruments collect power quality trend data plus triggered transient event information

We are now collating the results to develop and calculate power quality indices to define the power quality performance of our distribution network.

Our initial analysis of data collected showed very high harmonic levels on the network supplied from Hororata GXP which have been traced to the installation of large numbers of unfiltered variable speed drives on irrigation pumps. This data has helped us to analyse the problem and develop economic solutions. The solutions chosen are in two parts:

1. All new variable speed drive (VSD) pump installations must include harmonic filters that reduce the total harmonic current to less than 10%.
2. Because of the difficulty of retrofitting harmonic filters on existing installations (cost and size), all transformers supplying VSD pump installations were identified and sorted by pump motor size. The transformers supplying approximately half of the total load were replaced with Dzn0 units which provide a 30 degree electrical phase shift from the normal Dyn11 units. This phase shift cancels most of the troublesome harmonic currents and reduces the resulting harmonic voltage.

At Darfield, total harmonic voltage distortion was exceeding 8% during the summer of FY09. During the summer of FY10 after the transformers were changed and despite an increase of 50% in the VSD load, the total harmonic voltage decreased to approximately half that of the previous summer. Note that transformers removed from service are simply put back in stock and used elsewhere so the cost is limited to the actual change-out costs plus a slight premium for the Dzn0 transformer.

The data has also assisted Transpower to analyse the effect of transposing the 220kV lines as part of a project to reduce voltage imbalance and has also been used to discover and monitor the increasing harmonic distortion caused by everyday domestic consumer electronic equipment.

The European Union and the EL/34 joint committee of Standards Australia and New Zealand are currently attempting to develop more statistically defensible methods of measuring the limits on the characteristics of power delivered to customers. The measurements from our power quality instruments will provide invaluable information about how our network currently performs and will help the committee develop the standards.

The New Zealand Foundation for Research, Science and Technology in conjunction with the Electricity Engineer's Association awarded a contract to the University of Canterbury Electric Power Engineering Centre to carry out research into power quality issues in New Zealand electricity networks. The research work developed a set of guidelines for network development and mitigation techniques for existing problems. To assist with this work Orion provided power quality data collected over the past two years from approximately 30 sites within our network.

8.8.5 Emergency stock

Our emergency stock holdings valued at approximately \$4m have been reviewed by looking at the reliability statistics of each asset, and systematically identifying the need for components that make up that asset. It was necessary to set a reasonable level of risk to ensure that we balanced the need for carrying emergency supplies with the cost of holding these items. For the overhead line asset we set this level at about a 1-in-50 year event. As risk assessment of individual items is further refined some items may be released or additional critical items will be held.

8.9 Gap analysis

8.9.1 Asset management processes

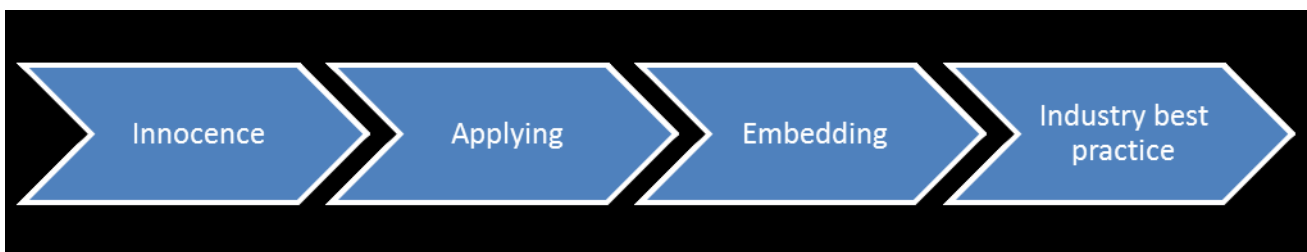
The Commerce Commission released new Information Disclosure (ID) requirements in 2012. As part of these requirements EDBs must provide an overview of asset management documentation, controls and review processes using an instrument known as the Asset Management Maturity Assessment Tool (AMMAT). While the AMMAT does not formally specify a standard upon which to assess compliance, the requirements are clearly aligned with 31 questions from the 121 questions prescribed by the PAS 55 Assessment Methodology (PAM). These questions have been selected to provide information not previously required by the Information Disclosure (ID) requirements.

AMMAT reviews are usually self-assessment. However we engaged EA Technology Ltd to undertake an independent assessment. We wanted EA Technology to:

- identify any blind-spots or gaps in our asset management processes and practices
- give us a true and unbiased indication of our asset management maturity.

Assessment is undertaken against detailed criteria for each question (see full results in Appendix A.13). An overview of the general criteria required to be met for each maturity level is:

- **Maturity Level 0**
The elements required by the function are not in place. The organisation is in the process of developing an understanding of the function.
- **Maturity Level 1**
The organisation has a basic understanding of the function. It is in the process of deciding how the elements of the function will be applied and has started to apply them.
- **Maturity Level 2**
The organisation has a good understanding of the function. It has decided how the elements of the function will be applied and work is progressing on implementation.
- **Maturity Level 3**
All elements of the function are in place and being applied and are integrated. Only minor inconsistencies may exist.
- **Maturity Level 4**
All processed and approaches go beyond the requirements of PAS 55. The boundaries of Asset Management Development are pushing to develop new concepts and ideas.



EA Technology found that we comply with the requirements in a number of important, high impact areas and that we are making steady improvement. They identified a number of areas where our documentation does not fully demonstrate that our asset management systems and processes fully meet the requirements of the AMMAT.

EA Technology notes that “While the scores allocated in some cases suggest that systems and processes do not meet the requirements, this should not be interpreted as Orion’s systems and processes necessarily being deficient or not fit for purpose.” In areas where we score below a maturity level of 3, we believe that our existing systems are appropriate for our business. Further documentation would provide the necessary evidence to increase our score, but we don’t believe this is necessary at this stage.

Figure 8-9a Orion's maturity level scores



8.9.2 Reliability

Our network has generally improved over the 22 years that we have compiled detailed reliability statistics. Statistics from the first few years indicate that most interruptions occurred in the rural area and were due to trees on lines, vehicles hitting poles and equipment failure to a lesser extent.

Since then we have made considerable effort to control tree growth and instigate various maintenance programmes on our rural 11kV lines. A project to install reflectors on roadside poles to reduce the incidence of vehicles hitting poles has also been completed.

Our plant failure statistics show that as loads increase in parts of our network, we have to work harder to keep aging equipment performing satisfactorily. We now use a UV corona imaging camera in a move that utilises the latest technology in an effort to identify potential problems before they cause an interruption.

We have also completed a project to shorten the interrupted portions of our feeders by installing additional line circuit breakers. Circuit breakers are relocated to more appropriate locations as the network is altered and total 50 in our rural network.

We have installed and put into service 23 Ground Fault Neutralisers (GFN). These units are equipped with 5th harmonic residual current compensation and are starting to contribute to an improvement in rural network reliability and safety.

8.9.3 Security Standard

Our Security Standard provides a useful benchmark to identify areas on our network that may not currently receive the high level of security that the majority of our network has. Any gaps against our Security Standard are discussed in section 5.5 – Network gap analysis.

Appendices



A

A	Disclosure schedules 11 - 13	299
11a	Report on forecast capital expenditure	300
11b	Report on forecast operational expenditure	304
12a	Report on asset condition	305
12b	Report on forecast capacity	307
12c	Report on forecast demand	309
12d	Report on forecast interruptions and duration	310
13	AMMAT report	311
B	Cross reference table	328
C	Glossary of terms	329
D	Certificate of compliance (schedule 17)	332

Appendix A - Disclosure schedules

SCHEDULE 11a: Report on forecast capital expenditure	300
SCHEDULE 11b: Report on forecast operational expenditure	304
SCHEDULE 12a: Report on asset condition	305
SCHEDULE 12b: Report on forecast capacity	307
SCHEDULE 12c: Report on forecast demand	309
SCHEDULE 12d: Report on forecast interruptions and duration	310
SCHEDULE 13: AMMAT report	311

Schedule 11a: Report on forecast capital expenditure

Company name:
AMP Planning period:

Orion NZ Ltd.
1 April 2015 - 31 March 2025

7	Current year	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10	
8	For year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
9	11a(i) Expenditure on Assets Forecast											
10	Consumer connection	13,100	17,512	16,139	13,939	13,155	12,256	12,246	12,526	12,807	13,088	13,368
11	System growth	40,420	39,156	15,226	45,563	26,369	21,522	9,206	23,755	20,169	10,051	15,052
12	Asset replacement and renewal	25,275	19,890	19,326	20,900	23,769	19,652	20,437	23,801	21,677	22,810	26,195
13	Asset relocations	1,500	17,000	11,573	6,263	2,023	1,510	1,543	1,577	1,610	1,644	1,677
14	Reliability, safety and environment:											
15	Quality of supply	-	-	-	-	-	-	-	-	-	-	-
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	3,010	1,345	1,396	1,975	2,697	2,759	2,395	2,447	2,761	2,819	2,876
18	Total reliability, safety and environment	3,010	1,345	1,396	1,975	2,697	2,759	2,395	2,447	2,761	2,819	2,876
19	Expenditure on network assets	83,305	94,902	63,661	88,641	68,013	57,698	45,826	64,105	59,024	50,411	59,168
20	Non-network assets	2,428	16,208	14,923	2,376	3,723	2,466	2,822	2,189	3,378	3,104	3,173
21	Expenditure on assets	85,733	111,110	78,584	91,017	71,736	60,164	48,648	66,294	62,402	53,515	62,341
22												
23	plus Cost of financing		-	-	-	-	-	-	-	-	-	-
24	less Value of capital contributions	3,871	5,397	4,289	6,858	6,669	1,981	2,025	2,069	2,113	2,157	2,201
25	plus Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27	Capital expenditure forecast	81,862	105,713	74,295	84,159	65,067	58,182	46,623	64,225	60,289	51,358	60,140
28												
29	Value of commissioned assets	82,862	112,013	89,495	84,159	65,067	58,182	46,623	64,225	60,289	51,358	60,140
30												
32												
33	Consumer connection	13,100	17,512	15,587	13,072	12,057	10,967	10,707	10,707	10,707	10,707	10,707
34	System growth	40,420	39,156	14,676	42,713	24,030	19,149	8,004	20,156	16,738	8,154	11,909
35	Asset replacement and renewal	25,275	19,890	18,620	19,520	21,740	17,575	17,880	20,380	18,175	18,735	21,085
36	Asset relocations	1,500	17,000	11,150	5,850	1,850	1,350	1,350	1,350	1,350	1,350	1,350
37	Reliability, safety and environment:											
38	Quality of supply	-	-	-	-	-	-	-	-	-	-	-
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	3,010	1,345	1,345	1,845	2,466	2,466	2,095	2,095	2,315	2,315	2,315
41	Total reliability, safety and environment	3,010	1,345	1,345	1,845	2,466	2,466	2,095	2,095	2,315	2,315	2,315
42	Expenditure on network assets	83,305	94,902	61,377	82,999	62,142	51,506	40,036	54,687	49,285	41,260	47,365
43	Non-network assets	2,428	16,208	14,442	2,240	3,413	2,198	2,448	1,845	2,769	2,475	2,460
44	Expenditure on assets	85,733	111,110	75,819	85,239	65,555	53,704	42,484	56,532	52,054	43,735	49,825
45												
46	Subcomponents of expenditure on assets (where known)											
47	Energy efficiency and DSM reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
48	Overhead to underground conversion	1,500	17,000	11,150	5,850	1,850	1,350	1,350	1,350	1,350	1,350	1,350
49	Research and development	-	-	-	-	-	-	-	-	-	-	-

Schedule 11a: Report on forecast capital expenditure (cont)

Company Name:
AMP Planning period:

Orion NZ Ltd.
1 April 2015 - 31 March 2025

	For year ended	Current year										
		31 Mar 15	CY+1 31 Mar 16	CY+2 31 Mar 17	CY+3 31 Mar 18	CY+4 31 Mar 19	CY+5 31 Mar 20	CY+6 31 Mar 21	CY+7 31 Mar 22	CY+8 31 Mar 23	CY+9 31 Mar 24	CY+10 31 Mar 25
		\$'000										
	Difference between nominal and constant price forecasts											
	Consumer connection	-	-	553	868	1,099	1,289	1,539	1,820	2,100	2,381	2,662
	System growth	-	-	550	2,851	2,340	2,373	1,202	3,599	3,430	1,897	3,143
	Asset replacement and renewal	-	-	706	1,380	2,029	2,077	2,557	3,421	3,502	4,075	5,110
	Asset relocations	-	-	423	413	173	160	193	227	260	294	327
	Reliability, safety and environment:											
	Quality of supply	-	-	-	-	-	-	-	-	-	-	-
	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
	Other reliability, safety and environment	-	-	51	130	231	293	300	352	446	504	561
	Total reliability, safety and environment	-	-	51	130	231	293	300	352	446	504	561
	Expenditure on network assets	-	-	2,284	5,642	5,871	6,191	5,791	9,418	9,739	9,151	11,803
	Non-network assets	-	-	481	136	310	268	374	344	609	629	713
	Expenditure on assets	-	-	2,765	5,778	6,181	6,459	6,165	9,762	10,348	9,780	12,516

11a(ii) Consumer Connection

Consumer types defined by EDB (see note)

General connections	1,102	3,822	3,152	2,852	2,212	2,212	2,212
Large customers	2,642	2,282	2,082	1,852	1,477	1,327	1,327
Subdivisions	5,335	4,650	3,975	3,200	3,200	3,200	3,200
Switchgear	2,095	2,830	2,540	2,320	2,320	1,740	1,740
Transformers	1,926	3,928	3,838	2,848	2,848	2,488	2,488

Consumer connection expenditure

Capital contributions funding consumer connections	13,100	17,512	15,587	13,072	12,057	10,967	10,967
Consumer connection less capital contribution	1,621	1,477	1,137	1,007	837	827	827
	11,479	16,035	14,450	12,065	11,220	10,140	10,140

11a(iii) System Growth

Subtransmission	22,762	27,484	863	10,709	639	6,212	6,212
Zone substations	11,763	8,074	9,059	28,601	14,414	9,521	9,521
Distribution and LV lines	2,460	26	5	5	31	14	14
Distribution and LV cables	3,267	2,669	3,420	2,846	7,958	3,056	3,056
Distribution substations and transformers	168	1	7	7	4	4	4
Distribution switchgear	-	130	348	316	411	189	189
Other network assets	-	770	973	227	575	154	154
System growth expenditure	40,420	39,156	14,676	42,713	24,030	19,149	19,149
Capital contributions funding system growth	-	-	-	2,553	4,068	-	-
System growth less capital contribution	40,420	39,156	14,676	40,160	19,962	19,149	19,149

11a(ii) Consumer Connection

Consumer types defined by EDB (see note)

General connections
Large customers
Subdivisions
Switchgear
Transformers

Consumer connection expenditure

Capital contributions funding consumer connections
Consumer connection less capital contribution

11a(iii) System Growth

Subtransmission
Zone substations
Distribution and LV lines
Distribution and LV cables
Distribution substations and transformers
Distribution switchgear
Other network assets
System growth expenditure
Capital contributions funding system growth
System growth less capital contribution

Note: Our Capex budgets for new connections are broken down into asset types rather than consumer types and therefore the consumer type definitions in this schedule differ from schedule 12c(i).

Schedule 11a: Report on forecast capital expenditure (cont)

Company name:
AMP Planning period:

Orion NZ Ltd.
1 April 2015- 31 March 2025

	For year ended	Current year	CY+1	CY+2	CY+3	CY+4	CY+5
	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	
	\$'000 (in constant prices)						
	700	420	420	420	2,815	420	
11a(iv) Asset Replacement and Renewal							
Subtransmission	5,445	5,720	2,605	3,310	4,890	2,580	
Zone substations	2,225	2,335	2,335	2,335	2,335	2,335	
Distribution and LV lines	2,200	150	150	150	150	150	
Distribution and LV cables	2,695	3,040	2,880	2,565	2,565	2,565	
Distribution substations and transformers	6,300	2,690	4,360	4,890	4,425	5,105	
Distribution switchgear	5,710	5,535	5,870	5,850	4,560	4,420	
Other network assets	25,275	19,890	18,620	19,520	21,740	17,575	
Asset replacement and renewal expenditure	-	-	-	-	-	-	
less Capital contributions funding asset replacement and renewal	25,275	19,890	18,620	19,520	21,740	17,575	
Asset replacement and renewal less capital contributions							
11a(v) Asset Relocations							
<i>Project or programme</i>							
NZTA and Others	400	5,300	3,450	3,150	650	150	
Christchurch City Council and Others	800	1,050	1,050	1,050	550	550	
Selwyn District Council and Others	300	350	350	350	350	350	
Developer Specific Projects	-	300	300	300	300	300	
Asset Relocation Programme	-	10,000	6,000	1,000	-	-	
All other asset relocations projects or programmes	-	-	-	-	-	-	
Asset relocations expenditure	1,500	17,000	11,150	5,850	1,850	1,350	
less Capital contributions funding asset relocations	2,250	3,920	2,995	2,845	1,195	945	
Asset relocations less capital contributions	(750)	13,080	8,155	3,005	655	405	
11a(vi) Quality of Supply							
<i>Project or programme</i>							
*See note.	-	-	-	-	-	-	
All other quality of supply projects or programmes	-	-	-	-	-	-	
Quality of supply expenditure	-	-	-	-	-	-	
less Capital contributions funding quality of supply	-	-	-	-	-	-	
Quality of supply less capital contributions	-	-	-	-	-	-	
11a(vii) Legislative and Regulatory							
<i>Project or programme</i>							
*See note.	-	-	-	-	-	-	
All other legislative and regulatory projects or programmes	-	-	-	-	-	-	
Legislative and regulatory expenditure	-	-	-	-	-	-	
less Capital contributions funding legislative and regulatory	-	-	-	-	-	-	
Legislative and regulatory less capital contributions	-	-	-	-	-	-	

Note. We have not separated out these portions of our expenditure as any figures would be indicative only. Our predominant drivers are customer connections, system growth, asset replacement, asset relocation and reliability.

Schedule 11a: Report on forecast capital expenditure (cont)

Company name:
AMP Planning period:
Orion NZ Ltd.
1 April 2015- 31 March 2025

		For year ended	Current year 31 Mar 15	CY+1 31 Mar 16	CY+2 31 Mar 17	CY+3 31 Mar 18	CY+4 31 Mar 19	CY+5 31 Mar 20
			\$'000 (in constant prices)					
161			2,000	1,000	1,000	1,500	2,000	2,000
162			510	345	345	345	95	95
163			500	-	-	-	371	371
164								
165								
166								
167								
168								
170								
171								
172			3,010	1,345	1,345	1,845	2,466	2,466
173								
174			3,010	1,345	1,345	1,845	2,466	2,466
178								
179								
180								
181			400	252	252	352	352	352
182			503	1,108	690	939	1,179	971
183			998	583	1,071	600	1,518	479
184			527	565	529	349	364	396
186								
187								
188			2,428	2,508	2,542	2,240	3,413	2,198
189								
190								
191				13,700	11,900			
192								
193								
194								
196								
197								
198			-	13,700	11,900	-	-	-
199								
200			2,428	16,208	14,442	2,240	3,413	2,198

11a(viii) Other Reliability, Safety and Environment

Project or programme

Installation of barriers and T-joint replacement
Security fencing, structures seismic upgrades
Ground Fault Neutralisers

All other reliability, safety and environment projects or programmes

Other reliability, safety and environment expenditure

Capital contributions funding other reliability, safety and environment

Other reliability, safety and environment less capital contributions

11a(ix) Non-Network Assets

Project or programme

Sundry land and buildings
Vehicles and mobile plant
Information solutions
Sundry tools and equipment

All other routine expenditure projects or programmes

Routine expenditure

Project or programme

Construction of a depot

All other atypical expenditure projects or programmes

Atypical expenditure

Non-network assets expenditure

Schedule 11b: Report on forecast operational expenditure

Orion NZ Ltd.
1 April 2015 - 31 March 2025

Company name:
AUP Planning period:

7	Current year	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
9	\$000 (in nominal dollars)										
10	7,275	8,555	7,475	7,385	7,510	7,662	7,814	7,965	8,117	8,269	8,421
11	2,930	3,215	3,352	3,468	3,527	3,599	3,670	3,741	3,812	3,884	3,955
12	15,350	14,585	14,683	15,298	14,960	15,228	15,405	15,843	16,092	16,447	16,650
13	3,690	2,665	2,544	2,794	2,512	2,563	2,614	2,665	2,716	2,766	2,817
14	29,245	29,020	28,053	28,945	28,510	29,052	29,502	30,215	30,737	31,366	31,843
15	15,845	17,321	17,640	17,885	18,051	18,323	18,686	19,048	19,440	19,863	20,255
16	14,672	14,300	14,655	14,823	15,073	15,479	15,559	15,904	16,300	16,713	17,099
17	30,517	31,621	32,295	32,708	33,124	33,802	34,245	34,952	35,740	36,576	37,354
18	59,762	60,641	60,348	61,653	61,634	62,854	63,747	65,167	66,477	67,942	69,197
	Operational Expenditure Forecast										
	Service interruptions and emergencies										
	Vegetation management										
	Routine and corrective maintenance and inspection										
	Asset replacement and renewal										
	Network Opex										
	System operations and network support										
	Business support										
	Non-network opex										
	Operational expenditure										
	\$000 (in constant prices)										
22	7,275	8,555	7,170	6,845	6,845	6,845	6,845	6,845	6,845	6,845	6,845
23	2,930	3,215	3,215	3,215	3,215	3,215	3,215	3,215	3,215	3,215	3,215
24	15,350	14,585	14,085	14,180	13,635	13,605	13,495	13,615	13,570	13,615	13,535
25	3,690	2,665	2,440	2,590	2,290	2,290	2,290	2,290	2,290	2,290	2,290
26	29,245	29,020	26,910	26,830	25,985	25,955	25,845	25,965	25,920	25,965	25,885
27	15,845	17,321	17,222	17,077	16,903	16,804	16,774	16,759	16,759	16,764	16,759
28	14,672	14,300	14,266	14,094	14,005	14,049	13,803	13,781	13,804	13,821	13,814
29	30,517	31,621	31,488	31,171	30,908	30,853	30,577	30,540	30,563	30,585	30,573
30	59,762	60,641	58,398	58,001	56,893	56,808	56,422	56,505	56,483	56,550	56,458
31	Subcomponents of operational expenditure (where known)										
33	-	-	-	-	-	-	-	-	-	-	-
34	-	-	-	-	-	-	-	-	-	-	-
35	-	-	-	-	-	-	-	-	-	-	-
36	2,020	1,400	1,333	1,266	1,233	1,243	1,253	1,263	1,273	1,283	1,293
37	*Direct billing expenditure by suppliers that direct bill the majority of their consumers										
41	Difference between nominal and real forecasts										
42	-	-	305	540	665	817	969	1,120	1,272	1,424	1,576
43	-	-	137	253	312	384	455	526	597	669	740
44	-	-	598	1,118	1,325	1,623	1,910	2,228	2,522	2,832	3,115
45	-	-	104	204	222	273	324	375	426	476	527
46	-	-	1,143	2,115	2,525	3,097	3,657	4,250	4,817	5,401	5,958
47	-	-	418	808	1,148	1,519	1,912	2,289	2,681	3,099	3,496
48	-	-	389	729	1,068	1,430	1,756	2,123	2,496	2,892	3,285
49	-	-	807	1,537	2,216	2,949	3,668	4,412	5,177	5,991	6,781
50	-	-	1,950	3,652	4,741	6,046	7,325	8,662	9,994	11,392	12,739
	Operational expenditure										

Schedule 12a: Report on asset condition

7

Company name:
AMP Planning period:
Orion NZ Ltd.
1 April 2015 - 31 March 2025

Asset condition at start of planning period (percentage of units by grade)

Voltage	Asset category	Asset class	Units	Grade 1 %	Grade 2 %	Grade 3 %	Grade 4 %	Grade unknown %	Data accuracy (1-4) %	% of asset to be replaced in next 5 years
9										
10	All	Overhead line	No.	-	-	11	89	-	3	1
11	All	Overhead line	No.	-	-	11	89	-	3	1
12	All	Overhead line	No.	-	-	-	-	-	N/A	-
13	HV	Subtransmission Line	km	-	-	12	88	-	3	2
14	HV	Subtransmission Line	km	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	km	-	-	-	100	-	3	-
16	HV	Subtransmission Cable	km	-	-	-	100	-	3	-
17	HV	Subtransmission Cable	km	-	-	-	-	-	N/A	-
18	HV	Subtransmission Cable	km	-	-	-	100	-	3	-
19	HV	Subtransmission Cable	km	-	-	-	-	-	N/A	-
20	HV	Subtransmission Cable	km	-	-	-	-	-	N/A	-
21	HV	Subtransmission Cable	km	-	-	-	-	-	N/A	-
22	HV	Subtransmission Cable	km	-	-	-	-	-	N/A	-
23	HV	Subtransmission Cable	km	-	-	-	-	-	N/A	-
24	HV	Zone Substation Buildings	No.	-	-	13	87	-	3	-
25	HV	Zone Substation Buildings	No.	-	-	-	-	-	N/A	-
26	HV	Zone Substation Switchgear	No.	-	-	-	100	-	4	-
27	HV	Zone Substation Switchgear	No.	-	-	18	82	-	4	1
28	HV	Zone Substation Switchgear	No.	-	-	-	-	-	N/A	-
29	HV	Zone Substation Switchgear	No.	-	-	30	70	-	4	-
30	HV	Zone Substation Switchgear	No.	-	-	-	-	-	N/A	-
31	HV	Zone Substation Switchgear	No.	-	-	-	-	-	N/A	-
32	HV	Zone Substation Switchgear	No.	-	-	14	86	-	4	14
33	HV	Zone Substation Switchgear	No.	-	-	33	67	-	4	10
34	HV	Zone Substation Switchgear	No.	-	-	-	-	-	N/A	-

See Section 4.3 for explanation of condition grading methodology

Schedule 12a: Report on asset condition

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2015 - 31 March 2025

42

Asset condition at start of planning period (percentage of units by grade)

Voltage	Asset category	Asset class	Units	Grade 1 %	Grade 2 %	Grade 3 %	Grade 4 %	Grade unknown %	Data accuracy (1-4)	% of asset to be replaced in next 5 years
44	HV	Zone Substation Transformer	No.	4	18	8	70		4	4
45	HV	Distribution Line	km			9	91		3	7
46	HV	Distribution Line	km						N/A	
47	HV	Distribution Line	km			2	98		3	
48	HV	Distribution Cable	km				100		3	
49	HV	Distribution Cable	km			6	94		3	
50	HV	Distribution Cable	km						N/A	
51	HV	Distribution Cable	km						N/A	
52	HV	Distribution switchgear	No.				100		4	
53	HV	Distribution switchgear	No.			39	61		4	14
54	HV	Distribution switchgear	No.			18	82		4	18
55	HV	Distribution switchgear	No.			42	58		4	16
56	HV	Distribution switchgear	No.			13	87		4	7
57	HV	Distribution Transformer	No.			6	94		3	6
58	HV	Distribution Transformer	No.			17	83		3	11
59	HV	Distribution Transformer	No.		6	22	72		3	
60	HV	Distribution Substations	No.			10	90		3	1
61	LV	LV Line	km			1	99		3	
62	LV	LV Cable	km				100		3	1
63	LV	LV Street lighting	km						N/A	
64	LV	Connections	No.			10	90		3	1
65	All	Protection	No.			18	82		4	24
66	All	SCADA and communications	Lot			3	97		3	5
67	All	Capacitor Banks	No.				100		3	
68	All	Load Control	Lot				100		3	5
69	All	Load Control	No.				100		3	
70	All	Civils	km				100		2	

See Section 4.3 for explanation of condition grading methodology

Schedule 12b: Report on forecast capacity										
12b(i) System Growth - Zone Substations (Urban)										
8	Zone substation - Urban	Current peak load (MVA)	Installed firm capacity (MVA)	Security of supply classification (type)	Transfer capacity (MVA)	Utilisation of installed firm capacity %	Installed firm capacity +5 years (MVA)	Installed firm capacity +5 years %	Installed firm capacity constraint +5 years (cause)	Explanation
9	Armagh	11	40	N-2	11	26	40	38	No constraint within +5 years	Earthquake caused a dramatic drop in CBD load
10	Barnett Park	9	15	N-1	9	62	15	61	No constraint within +5 years	Single 66kV line and 23MVA transformer backed up by 11kV but limited to 15MVA by compliance with security of supply standard
11	Dallington	29	40	N-2	29	73	40	76	No constraint within +5 years	
12	Fendalton	36	40	N-2	36	90	40	91	No constraint within +5 years	
13	Halswell	15	23	N-2	15	64	23	72	No constraint within +5 years	
14	Harewood	2	8	N-2	2	24	8	28	No constraint within +5 years	
15	Hawthornden	32	40	N-2	32	80	40	81	No constraint within +5 years	
16	Heathcote	28	40	N-2	28	70	40	73	No constraint within +5 years	
17	Hoon Hay	29	40	N-2	29	72	40	73	No constraint within +5 years	
18	Hornby	13	20	N-2	13	66	20	68	No constraint within +5 years	
19	Ilam	8	11	N-2	8	69	11	70	No constraint within +5 years	
20	Lancaster	23	40	N-2	23	56	40	56	No constraint within +5 years	
21	McFaddens	41	40	N-2	41	102	40	103	Transformer	Constraint to be resolved by new Marshlands zone substation
22	Middleton	27	40	N-2	27	67	40	70	No constraint within +5 years	
23	Milton	24	40	N-2	24	61	40	63	No constraint within +5 years	
24	Moffett	14	18	N-2	14	76	20	97	Subtransmission circuit	Constraint resolved by feeder replacement
25	Oxford Tuam	14	40	N-2	14	34	40	47	No constraint within +5 years	Earthquake caused a dramatic drop in Central City load
26	Prebbleton	5	-	N-2	5	-	-	-	No constraint within +5 years	New zone substation only recently installed
27	Rawhiti	27	40	N-2	27	68	40	67	No constraint within +5 years	
28	Shands	9	20	N-2	9	47	20	61	No constraint within +5 years	
29	Sockburn	24	35	N-2	24	68	35	80	No constraint within +5 years	
30	Bishopdale/Papanui	31	29	N-2	31	107	29	106	Transformer	Constraint to be resolved by new Waimakariri zone substation
37	Continued on next page...									

Schedule 12b: Report on forecast capacity (cont)

Company name:
AMP Planning period:

Orion NZ Ltd.
1 April 2015 - 31 March 2025

7 12b(i) System Growth - Zone Substations (Rural)

8	Zone substation - Rural	Current peak load (MVA)	Installed firm capacity (MVA)	Security of supply classification (type)	Transfer capacity (MVA)	Utilisation of installed firm capacity %	Installed firm capacity +5 years (MVA)	Installed firm capacity +5 years %	Installed firm capacity constraint +5 years (cause)	Explanation
40	Annat	1	-	N-1	1	-	-	-	Transformer	New Transformer planned within 5 years
41	Bankside	9	-	N-1	6	-	-	-	No constraint within +5 years	
42	Brookside	9	-	N-1	6	-	-	-	No constraint within +5 years	
43	Darfield	6	-	N-1	4	-	-	-	No constraint within +5 years	
44	Diamond Harbour	2	-	N-1	2	-	-	-	No constraint within +5 years	
45	Dunsandel	9	10	N-1	6	88	23	59	No constraint within +5 years	Constraint resolved by new transformer within 5 years
46	Duvauchelle	4	8	N-1	4	56	8	54	No constraint within +5 years	
47	Greendale	8	-	N-1	6	-	-	-	No constraint within +5 years	
48	Highfield	7	-	N-1	5	-	-	-	Transformer	Constraint to be resolved by installing larger capacity transformer
49	Hills	6	-	N-1	4	-	-	-	No constraint within +5 years	
50	Hororata	7	-	N-1	5	-	-	-	No constraint within +5 years	
51	Killinchy	8	-	N-1	5	-	-	-	No constraint within +5 years	
52	Kimberley	7	23	N-1	5	30	23	87	No constraint within +5 years	
53	Larcomb	5	23	N-1	4	22	23	46	No constraint within +5 years	
54	Lincoln	8	10	N-1	6	83	10	116	Transformer	Constraint to be resolved by transfers to Springston zone substation
55	Little River	1	-	N-1	1	-	-	-	No constraint within +5 years	
56	Motukarara	2	3	N-1	2	80	3	94	No constraint within +5 years	
57	Rolleston	12	10	N-1	8	119	10	149	Transformer	Constraint to be resolved by transferring load to Larcomb zone substation
58	Springston	6	-	N-1	4	-	8	93	No constraint within +5 years	Constraint to be resolved by installing larger capacity transformer
59	Teddington	1	-	N-1	1	-	-	-	No constraint within +5 years	
60	Te Pirita	10	-	N-1	7	-	-	-	Transformer	Depends on surface water irrigation impact. If needed constraint resolved by transferring load to Hororata -> Greendale.
61	Weedons	7	23	N-1	5	29	23	32	No constraint within +5 years	

12b(ii) Transformer Capacity

61						(MVA)
62						
63	Distribution transformer capacity (EDB owned)				1,868	
64	Distribution transformer capacity (non-EDB owned)				231	
65	Total distribution transformer capacity				2,098	
66						
67	Zone substation transformer capacity				893	

Schedule 12c: Report on forecast network demand

Company name:
Orion NZ Ltd.
AMP planning period:
1 April 2015 - 31 March 2025

12c(i): Consumer Connections

Number of ICPs connected in year by consumer type

For year ended

Consumer types defined by EDB

Street lighting	19	6	6	6	6	6
General	4,956	4,663	3,765	3,665	3,165	3,165
Irrigation	14	18	18	18	18	18
Major customer	11	11	11	11	11	11
Large capacity	-	2	-	-	-	-
Connections total	5,000	4,700	3,800	3,700	3,200	3,200

Distributed generation

Number of connections

Installed connection capacity of distributed generation (MVA)

283	320	320	320	320	320	320
3	4	4	4	4	4	4

12c(ii): System Demand

Maximum coincident system demand (MW)

GXP demand

plus Distributed generation output at HV and above

Maximum coincident system demand

less Net transfers to (from) other EDBs at HV and above

Demand on system for supply to consumer's connection points

Electricity volumes carried (GWh)

Electricity supplied from GXPs

less Electricity exports to GXPs

plus Electricity supplied from distributed generation

less Net electricity supplied to (from) other EDBs

Electricity entering system for supply to ICPs

less Total energy delivered to ICPs

Losses

Load factor (%)

Loss ratio (%)

Current year 31 Mar 15	CY+1 31 Mar 16	CY+2 31 Mar 17	CY+3 31 Mar 18	CY+4 31 Mar 19	CY+5 31 Mar 20
575	600	606	615	625	633
2	2	2	2	2	2
577	602	608	617	627	635
1	1	1	1	1	1
576	601	607	616	626	634
3,276	3,300	3,330	3,360	3,390	3,420
0	0	0	0	0	0
5	5	5	5	5	5
5	0	0	0	0	0
3,275	3,304	3,334	3,364	3,394	3,424
3,140	3,170	3,198	3,227	3,255	3,285
135	134	136	137	139	139
65%	63%	63%	62%	62%	62%
4.1%	4.1%	4.1%	4.1%	4.1%	4.1%

Schedule 12d: Report forecast interruptions and duration									
Company name: AMP Planning period:								Orion NZ Ltd. 1 April 2015 - 31 March 2025	
8									
9									
10									
11	SAIDI	Class B (planned interruptions on the network)	Current year		CY+1	CY+2	CY+3	CY+4	CY+5
12			For year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
			15.5	15.5	15.5	15.5	15.5	15.5	15.5
		Class C (unplanned interruptions on the network)	117.5	105.5	101.5	89.5	78.5	78.5	
13									
14	SAIFI	Class B (planned interruptions on the network)	0.07		0.07	0.07	0.07	0.07	0.07
15			For year ended	1.73	1.63	1.43	1.23	1.13	1.13
		Class C (unplanned interruptions on the network)							

Appendix A.13 - Disclosure schedule 13

Report on Asset Management Maturity

Note:

Schedule 13 is laid out with the questions and Orion's maturity level (Score) results on left hand page with the questions repeated on the facing page along with the detailed maturity level assessment criteria. See section 8.9.1 for information regarding the assessment process.

Schedule 13: Report on asset management maturity

Schedule 13: Report on asset management maturity

Orion NZ Ltd.
AMP Planning period:
1 April 2015 – 31 March 2025
PAS-55

Company name:
AMP Planning period:
AM standard applied:

No.	Function	Question	Score	Evidence-Summary	User guidance	Why	Who	Documented info
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2.5	An asset management policy document has been created and approved by the board. While key staff are generally aware of the existence and broad content of the asset management policy, the document does not appear to completely serve the intended purpose of providing the suite of guiding principles that frame the way that corporate objectives are to be translated into strategy, tactics and plans. The utility of the asset management policy could be improved by refocussing its content on the guiding principles of Orion's asset management system and ensuring that it is effectively communicated.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (e.g., as required in PAS 55 Para 4.2.1). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	Section 2.7 of the asset management plan "Asset Management Processes" defines overall strategies or methodologies employed by Orion to convert asset management objectives (termed Asset Management Drivers in the AMP document) to asset management plans. A suite of Asset Management Reports have been prepared that provide a detailed description of strategies at the asset class level. Section 5.3 of the AMP defines the load and security planning strategy and provides linkage to the corporate objectives by providing guidance on how to achieve the desired price/service level trade-off.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (e.g., as required by PAS 55 Para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 Para 4.3.1 c). Generally, this will take into account the same policies, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	Section 2.7 of the AMP describes strategies covering the lifecycle of the asset. Lifecycle phases covered in the AMP are: (i) planning, (ii) design and construction, (iii) procurement, (iv) operating and (v) inspection and maintenance. Asset Management Reports contain strategies for managing asset lifecycle phases for key asset classes. For planning there are network architecture review documents that describe the overall development strategy at various voltage levels.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plans across the life cycle activities of its assets and asset systems?	3	Orion's asset management work plan is documented in broad terms within the AMP and Asset Management reports. Finer detail of work plans is documented in the annual work plan and project/program specific work package documents. Asset management plan documents are made available to stakeholders as appropriate to their role within the asset management system.		The asset management strategy need to be translated into practical plans so that all parties know how the objectives will be achieved. The development of plans will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset systems, when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Schedule 13: Report on asset management maturity (cont)

Orion NZ Ltd.
1 April 2015 - 31 March 2025
PAS55

Company name:
AMP Planning period:
AM standard applied:

No.	Function	Question	Maturity level 0	Maturity level 1	Maturity level 2	Maturity level 3	Maturity level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's processes surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
26	Asset management plan(s)	How does the organisation establish and document its asset management plans across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13: Report on asset management maturity (cont)

Schedule 13: Report on asset management maturity (cont)

Company name:
AMP Planning period:
AM standard applied:

Orion NZ Ltd.
1 April 2015 - 31 March 2025
PAS-55

No.	Function	Question	Score	Evidence-Summary	User guidance	Why	Who	Documented info
27	Asset management plan(s)	How has the organisation communicated its plan (s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	The AMP is published annually and made public on Orion's web site. Service providers and stakeholders are actively engaged with respect to the content of the AMP, particularly if change to past programs are required. The AMP process is sufficiently mature that stakeholders are aware of the availability of the AMP and may access as required. Detailed work plans are communicated directly with contractors via the outsourcing process.		Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receiver's role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	Overall responsibility of delivery of the AMP is documented to reside with the Network Asset Manager. Asset management tasks are detailed through contract specifications clearly defining requirements for individual work packages. Responsibility for delivery of tasks by service providers is formalised through a commercial contract which is actively managed. A formal delegation of authority document exists and appears appropriate for execution of the AMP.		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	3	Delivery of the asset management work plan is achieved through outsourcing arrangements with service providers. Asset management planning actively considers contractor work levelling in the timing of projects. Publishing long term plans actively signals future workload to the contracting market. While these mechanisms are somewhat informal they appear to be effective in ensuring appropriate capability is available for asset management plan delivery. Mutual aid agreement with other utilities. Emergency response is included in contracts.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	4	Orion has a documented contingency planning process in place and this process has been shown to be effective as demonstrated by Orion's response to earthquake events. Contingency planning includes participation in regional lifelines planning, policy defining emergency roles and responsibilities, and detailed contingency plans for major network scenarios. Orion has load flow contingency plans including switching sheets prepared for total loss of all zone substations. Evidence of continual improvement may be seen in recent work to move contractor bases to outside the tsunami risk zone.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

Schedule 13: Report on asset management maturity (cont)					
No.		Function	Question	Maturity level 0	Maturity level 1
				Maturity level 2	Maturity level 3
				Maturity level 4	
27	Asset management plan(s)	How has the organisation communicated its plan (s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13: Report on asset management maturity (cont)

Schedule 13: Report on asset management maturity (cont)

Orion NZ Ltd.
1 April 2015 – 31 March 2025
PAS 55

Company name:
AM Planning period:
AM standard applied:

No.	Function	Question	Score	Evidence-Summary	User guidance	Why	Who	Documented info
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	The organisation is structured as an asset management organisation. Group roles are defined and overall accountability for the delivery of asset management outcomes resting with the Chief Operating Officer. Being a relatively small organisation by international standards, Orion operates a somewhat flexible management structure with strong interpersonal communication replacing rigid process. This approach is proving appropriate for Orion's scale and operating environment.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets e.g., Para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in Para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan (s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	A management review process exists where achievement of asset management activities are routinely monitored and discussed at General Manager level. Asset management related resourcing is routinely adjusted to ensure that outcomes are achieved. Evidence may be found in a recent review of the customer connections process where additional resources have been made available to ensure that required service levels are met. A strategy is in place for ensuring that sufficient field resources are available for the execution of plans. This includes regular meetings with service providers to discuss long term strategic issues and resource requirements.		Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and charge-hands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the processes for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	A range of strategies are employed to communicate the importance of meeting asset management requirements. These range from (i) weekly management meetings attended by all asset management groups, (ii) regular group manager level meetings with service providers, and road-show presentations to all Orion staff and service providers scheduled as required. Asset management plan briefings are used to communicate technical detail of asset management plan content.		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (e.g. PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-about would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	All field delivered works are managed through an outsourcing arrangement with two principal service providers. Formal processes are in place to assure service provider capability and work quality including a contractor rating system. Control processes include formal project specifications and documentation, capability audits, process audits and practical completion inspections of works. A manager is accountable for the control of compliant delivery of outsourced activities.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (e.g. PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

Schedule 13: Report on asset management maturity (cont)

Orion NZ Ltd.
1 April 2015 – 31 March 2025
PAS-55

Company name:
AMP Planning period:
AM standard applied:

No.	Function	Question	Maturity level 0	Maturity level 1	Maturity level 2	Maturity level 3	Maturity level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate person to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting its asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13: Report on asset management maturity (cont)

Schedule 13: Report on asset management maturity (cont)

Orion NZ Ltd.
1 April 2015 - 31 March 2025
PAS-55

Company name:
AMP Planning period:
AM standard applied:

No.	Function	Question	Score	Evidence-Summary	User guidance	Why	Who	Documented info
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	3	Orion has conducted a review of resourcing requirements which has resulted in the development of a trainee program to provide necessary asset management related skills. To assist in meeting projected requirements for field resources Orion has funded the development of an electricity industry trades training centre. Key competencies are documented in Job profiles and competence is assessed during bi annual performance reviews. Training requirements are identified during the performance review process.		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan (s). Training plan(s), personnel development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3	As for question 48 above, core competencies are identified in the job design process and included in job profiles. Competency is regularly reviewed against the requirements of the job profile and training needs identified. Training requirements are identified and progress is reviewed for individuals during the twice yearly performance review process. Competence requirements for outsourced staff is documented in contractual documents. Compliance is monitored through the contractor management process.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (e.g. PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, coordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organisation ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3	Service provider training and competence requirements are controlled through contractual relationships with the service provider and are audited for compliance. In house asset management skills and competencies are managed less formally via the job profile and twice yearly performance review process. PAS-55 compliance could be enhanced through the development of a formal skills and competence framework linked to process roles.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. Organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership, UK Standard for Professional Engineering Competence, Engineering Council, 2005.

Schedule 13: Report on asset management maturity (cont)

Schedule 13: Report on asset management maturity (cont)

Orion NZ Ltd.
1 April 2015 - 31 March 2025
PAS-55

Company name:
AMP Planning period:
AM standard applied:

No.	Function	Question	Maturity level 0	Maturity level 1	Maturity level 2	Maturity level 3	Maturity level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan (s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organisation ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organisation has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13: Report on asset management maturity (cont)

Schedule 13: Report on asset management maturity (cont)

Orion NZ Ltd.
1 April 2015 - 31 March 2025
PAS-55

Company name:
AMP Planning period:
AM standard applied:

No.	Function	Question	Score	Evidence-Summary	User guidance	Why	Who	Documented info
53	Communication and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	<p>Orion's small size allows a less formal communication strategy to be effective than would be necessary for large PAS-55 compliant organisations.</p> <p>A range of communication strategies are used to facilitate two way communication with staff. For example a weekly trickle down briefing is provided within the infrastructure division, staff and service provider road-shows are employed to brief on the content of asset management plans. The small team and open door approach of management ensures that information flows freely within the company.</p>	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (e.g. s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3	<p>Orion has developed an Asset Management Policy and it has been approved by the board. There is general awareness of the asset management policy and content within the asset management team. Section 2 of the asset management plan contains details of Orion's asset management system.</p>	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (e.g. s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3	<p>The overarching information requirements for asset management are defined in Section 2.8 of the AMP. The overall design of this system is based on a continual review of information needs as part of Orion's business as usual continual improvement processes. Where gaps are identified, changes are initiated. For larger projects (e.g. proposed upgrades to the asset management systems) the Lifecycle Manager surveys stakeholders within Orion to identify potential requirements.</p> <p>An asset information plan for key asset classes is in development. It defines key asset management information, quality and completeness.</p>	Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team.	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	<p>Processes exist to verify the integrity of mission critical asset information such as network connectivity. The asset information plan under development identifies critical information requirements as well as gaps compared with current quality levels.</p>	The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale.	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

Schedule 13: Report on asset management maturity (cont)						
No.	Function	Question	Maturity level 0	Maturity level 1	Maturity level 2	Maturity level 3
Maturity level 4						
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process (es). Pertinent asset information requirements are regularly reviewed. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset management system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset management system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process (es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13: Report on asset management maturity (cont)

Schedule 13: Report on asset management maturity (cont)					
No.		Function	Question	Maturity level 0	Maturity level 1
				Maturity level 2	Maturity level 3
				Maturity level 4	Maturity level 5
64	Information management	How has the organisation's information system been relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.

Company name:
AMP Planning period:
AM standard applied:

Orion NZ Ltd
1 April 2015 - 31 March 2025
PAS55

Maturity level 4

Maturity level 3

Maturity level 2

Maturity level 1

Maturity level 0

The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard.

The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.

The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.

The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.

The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.

How has the organisation's information system been relevant to its needs?

Information management

64

The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard.

The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.

The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.

The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.

The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.

How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?

Risk management process(es)

69

The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard.

The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.

The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.

The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.

The organisation has not considered the need to conduct risk assessments.

How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?

Use and maintenance of asset risk information

79

The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard.

The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.

The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.

The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.

The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.

What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?

Legal and other requirements

82

Schedule 13: Report on asset management maturity (cont)

Schedule 13: Report on asset management maturity (cont)

Orion NZ Ltd.
1 April 2015 - 31 March 2025
PAS 55

Company name:
AMP Planning period:
AM standard applied:

No.	Function	Question	Score	Evidence-Summary	User guidance	Why	Who	Documented info
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	Orion has a comprehensive suite of standards and specifications covering all aspects of the asset lifecycle. These include equipment procurement specifications, design standards, construction standards, operating procedures and maintenance standards. While documented standards are in place, some processes are not clearly documented and rely upon the experience and expertise of key staff. While effective, some benefit may be obtained from more detailed documentation of key asset management processes than is currently included in the AMP.	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that processes and/or procedures for the implementation of asset management plans and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with AM strategy and control cost, risk and performance?	3	Orion's outsourcing processes ensure that only pre-qualified service providers may construct, operate and maintain Orion assets. Contract specifications and standards clearly define scope of work and place requirements on contractor competency and training. An audit process checks for compliance in terms of contractor capability, work process and finished product. Orion asset management staff or approved auditors witness key operations to ensure compliance with standards.	Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (e.g. as required by PAS 55 s 4.5.1).	Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (e.g. as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3	Orion has identified a suite of service levels and associated performance measures. These service levels, associated measures and targets are documented in the AMP. Orion has implemented a comprehensive methodology (CBRM) for using asset condition and performance information to evaluate asset health and risk. The methodology has been consistently applied to all key asset classes.	Widely used AM standards require that organisations establish implement and maintain procedures to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring of results to provide input to corrective actions and continual improvement. There is an expectation that performance & condition monitoring will provide input to improving AM strategy, objectives and plans.	Widely used AM standards require that organisations establish implement and maintain procedures to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring of results to provide input to corrective actions and continual improvement. There is an expectation that performance & condition monitoring will provide input to improving AM strategy, objectives and plans.	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to-end assessment. This should include contractors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting AM strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergencies situations and non conformance is clear, unambiguous, understood and communicated?	3	Orion has a robust system in place for recording customer outage information and collating network performance statistics. Network outages are routinely reviewed. Minor failures are monitored at a statistical level, with action being taken if frequency increases abnormally, major failures and incidents are investigated on a case by case basis. Responsibility for investigation rests initially with the Asset Lifecycle manager. Procedures for emergency response and repair are clear, with this process being initiated from the control room. A manager is responsible for investigating equipment failures and recommending actions. Actions are implemented through normal management channels.	Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior mgmt who review the recommendations. Operational controllers resp for managing the asset base under fault conditions and maintaining services to consumers, contractors and other third parties as approp.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

Schedule 13: Report on asset management maturity (cont)

Company name:
AMP Planning period:
AM standard applied:

Orion NZ Ltd.
1 April 2015 – 31 March 2025
PAS-55

No.	Function	Question	Maturity level 0	Maturity level 1	Maturity level 2	Maturity level 3	Maturity level 4
88	Life Cycle Activities	How does the organisation establish, implement and maintain processes for the implementation of its asset management plans and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that processes and/or procedures for the implementation of asset management plans and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company name:
AMP Planning period:
AM standard applied:

Orion NZ Ltd.
1 April 2015 - 31 March 2025
PAS-55

Schedule 13: Report on asset management maturity (cont)					
No.	Function	Question	Score	Evidence-Summary	Why ? Who Documented info
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	Orion periodically reviews its overall asset management system and capability at a supervisory level using the AMMAT Framework as evidenced by the annual AMMAT review. The asset lifecycle manager has responsibility for the review and for ensuring that the Commerce Commission disclosure is completed. Evidence can be found to demonstrate that recommendations from prior reviews are being managed and that corrective actions are being implemented.	<p>This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).</p> <p>The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments</p> <p>The organisation's asset-related audit procedures. The methodology by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedures by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.</p>
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	2.5	Non conformances or issues are actively managed through normal business activities, roles and responsibilities and the subcontractor management process. Important actions arising from investigations are recorded and managed using the current health and safety database to ensure that they are tracked and managed. Work is in progress to develop a more flexible system as part of the organisations overall risk management framework.	<p>The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.</p> <p>Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews</p>
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	3	Orion has a proven track record for innovation and continuous improvement. Examples include introduction of GFNs, new outage management system, changes in maintenance practices that have reduced reactive maintenance, and the introduction of (CBRM). While Orion does not have a formal innovation or continual improvement process, evidence indicates that a continual improvement is embedded within the Orion culture. A recent example is the development of an asset information plan and involvement in the MBIE green grid project.	<p>The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.</p> <p>Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.</p>
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	Orion obtains information for improvements from a range of sources. External sources of information include: <ul style="list-style-type: none"> - equipment suppliers - consultants - domestic and international conferences - participation in industry groups such as ENA and EEA. A nominated manager is assigned to study and where appropriate implement innovation opportunities.	<p>The top management of the organisation. The manager/team responsible for managing the organisation's AM system, and its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.</p> <p>Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.</p>

Schedule 13: Report on asset management maturity (cont)							
Company name: Orion NZ Ltd. AMP Planning period: 1 April 2015 - 31 March 2025 AW standard applied: PAS-55							
No.	Function	Question	Maturity level 0	Maturity level 1	Maturity level 2	Maturity level 3	Maturity level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company name:
AMP Planning period:
AM standard applied:

Orion NZ Ltd.
1 April 2015 - 31 March 2025
PAS-55

Appendix B - Cross reference table

As our AMP has been structured as a practical planning tool, it does not strictly follow the order laid out in the Electricity Distribution Information Disclosure Determination 2012. We have prepared the cross reference table below to help you find specific sections.

Sections as per the Electricity Distribution Information Disclosure Determination 2012	Orion AMP
1. Summary of the plan	1. Summary
2. Background and objectives	2. Background and objectives
3. Assets covered	4. Lifecycle asset management
4. Service levels	3. Service levels
5. Network development plans	5. Network development
6. Lifecycle asset management planning (maintenance and renewal)	4. Lifecycle asset management
7. Risk management	6. Risk management
8. Evaluation of performance	8. Evaluation of performance

Appendix C - Glossary of terms

ABI: Air Break Isolator, a pole mounted isolation switch. Usually manually operated.

Alternating current (AC): a flow of electricity which reaches maximum in one direction, decreases to zero, then reverses itself and reaches maximum in the opposite direction. The cycle is repeated continuously.

Ampere (A): unit of electrical current flow, or rate of flow of electrons.

Bushing: an electrical component that insulates a high voltage conductor passing through a metal enclosure.

Capacity utilisation: a ratio which measures the utilisation of transformers in the network. Calculated as the maximum demand experienced on an electricity network in a year, divided by the transformer capacity on that network.

Capacitance: is the ability of a body to store an electrical charge.

Circuit breaker (CB): a device which detects excessive power demands in a circuit and cuts off power when they occur. Nearly all of these excessive demands are caused by a fault on the network. In the urban network, where most of these CBs are, they do not attempt a reclose after a fault as line circuit breakers may do on the rural overhead network.

Continuous rating: the constant load which a device can carry at rated primary voltage and frequency without damaging and/or adversely affecting its characteristics.

Conductor: is the 'wire' that carries the electricity and includes overhead lines which can be covered (insulated) or bare (not insulated) and underground cables which are insulated.

CPP: The Commerce Act (Orion New Zealand Limited Customised Price-Quality Path Determination 2013) in effect for FY15 to FY19. This determination applies to Orion, and replaces all terms of the Orion DPP Determination as they apply to Orion.

Current: the movement of electricity through a conductor, measured in amperes (A).

Demand side management (DSM): shaping the overall consumer load profile to obtain maximum mutual benefit to the consumer and the network operator.

DIN: Deutsches Institut für Normung (the German Institute for Standardization).

Distributed/embedded generation (DG): a privately owned generating station connected to our network.

Distribution substation: is either a building, a kiosk, an outdoor substation or pole substation taking its supply at 11kV and distributing at 400V (see sections 4.4.3 and 4.26).

Dog: an aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of 103mm².

DPP: The Commerce Act (Electricity Distribution Default Price-quality Path) Determination

EA Technology Ltd: is an international consultancy based in the UK. They were appointed as peer reviewers to the Auckland CBD cable failure ministerial enquiry and subsequently engaged by us to review our 66kV cable network.

Fault current: the current from the connected power system that flows in a short circuit caused by a fault.

Feeder: a physical grouping of conductors that originate from a zone substation circuit breaker.

Flashover: a disruptive discharge around or over the surface of an insulator.

Flounder: an aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of 20mm². The cores are shaped to give the conductor a smooth surface that offers less resistance to wind and snow.

Frequency: on alternating current circuits, the designated number of times per second that polarity alternates from positive to negative and back again, expressed in Hertz (Hz)

Fuse: a device that will heat up, melt and electrically open the circuit after a period of prolonged abnormal current flow.

Gradient, voltage: the voltage drop, or electrical difference, between two given points.

Grid exit point (GXP): a point where Orion's network is connected to Transpower's transmission network.

Harmonics (wave form distortion): changes an ac voltage waveform from sinusoidal to complex and can be caused by network equipment and equipment owned by consumers including electric motors or computer equipment.

High voltage (HV): voltage exceeding 1,000 volts (1kV), in Orion's case generally 11kV, 33kV or 66kV.

ICP: installation control point, a uniquely numbered point on our network where a consumer(s) is connected.

Inductance: is the property of a conductor by which current flowing through it creates a voltage (electromotive force) in both the conductor itself (self-inductance) and in any nearby conductors.

Insulator: supports live conductors and is made from material which does not allow electricity to flow through it.

Interrupted N-1: a network is said to have 'Interrupted N-1' security or capability if following the failure of 'one' overhead line, cable or transformer the network can be switched to restore electricity supply to customers.

Interrupted N-2: a network is said to have 'Interrupted N-2' security or capability if following the failure of 'two' overhead line, cable or transformer the network can be switched to restore electricity supply to customers.

Jaguar: an aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of 207mm².

kVA: the kVA, or Kilovolt-ampere, output rating designates the output which a transformer can deliver for a specified time at rated secondary voltage and rated frequency.

Legacy assets: assets installed to meet appropriate standards of the time, but are not compliant with current day safety standards.

Lifelines project: an engineering study into the effects of a natural disaster on Christchurch city undertaken in the mid 1990s. (see section 6.6 - natural disaster)

Line circuit breaker (LCB): a circuit breaker mounted on an overhead line pole which quickly cuts off power after a fault so no permanent damage is caused to any equipment. It switches power back on after a few seconds and, if the cause of the fault has gone, (e.g. a branch has blown off a line) then the power will stay on. If the offending item still exists then power will be cut again. This can happen up to three times before power will stay off until the fault repaired. Sometimes an LCB is known as a 'recloser'.

Low voltage (LV): a voltage not exceeding 1,000 volts, generally 230 or 400 volts.

Maximum demand: the maximum demand for electricity, at any one time, during the course of a year.

Mink: an aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of 62mm².

MOCHED: major outage causing huge economic damage.

N: a network is said to have 'N' security or capability if the network cannot deliver electricity after the failure of 'one' overhead line, cable or transformer.

N-1: a network is said to have 'N-1' security or capability if the network continues to deliver electricity after the failure of 'one' overhead line, cable or transformer.

N-2: a network is said to have 'N-2' security or capability if the network continues to deliver electricity after the failure of 'two' overhead lines, cables or transformers.

Namu: an aerial aluminium conductor (AAC) with a cross sectional area of 25mm².

Network deliveries: total energy supplied to our network through Transpower's grid exit points, usually measured as energy supplied over the course of a year.

Network substations: are part of Orion's primary 11kV network all within the Christchurch urban area.

Ohm: a measure of the opposition to electrical flow, measured in ohms.

ORDC: optimised depreciated replacement cost, prepared in accordance with New Zealand International Financial Reporting Standards (NZ IFRS) under International Accounting Standard NZ IAS 16 - Property, Plant and Equipment as at 31 March 2007

Outage: an interruption to electricity supply.

PCB: Polychlorinated biphenyls (PCBs) were used as dielectric fluids in transformers and capacitors, coolants, lubricants, stabilizing additives in flexible PVC coatings of electrical wiring and electronic components. PCB production was banned in the 1970s due to the high toxicity of most PCB congeners and mixtures. PCBs are classified as persistent organic pollutants which bio-accumulate in animals.

Proven voltage complaint: a complaint from a consumer concerning a disturbance to the voltage of their supply which has proven to be caused by the network company.

Rango: an aerial aluminium conductor (AAC) with a cross sectional area of 50mm².

Ripple control system: a system used to control the electrical load on the network by, for example, switching domestic water

heaters, or by signaling large users of a high price period. Also used to control streetlights.

RTU: Remote Terminal Unit. Part of the SCADA system usually installed at the remote substation.

SAIDI: System Average Interruption Duration Index; an international index which measures the average duration of interruptions to supply that a consumer experiences in a given period.

SAIFI: System Average Interruption Frequency Index; an international index which measures the average number of interruptions that a consumer experiences in a given period.

SCADA: System Control And Data Acquisition. See section 4.22.

Sparrow: an aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of 34mm².

Squirrel: an aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of 20mm².

Transformer: a device that changes voltage up to a higher voltage or down to a lower voltage.

Transpower: the state owned enterprise that operates New Zealand's transmission network. Transpower delivers electricity from generators to grid exit points (GXPs) on distribution networks throughout the country.

Voltage: electric pressure; the force which causes current to flow through an electrical conductor.

Voltage drop: is the reduction in voltage in an electrical circuit between the source and load.

Voltage regulator: an electrical device that keeps the voltage at which electricity is supplied to consumers at a constant level, regardless of load fluctuations.

Weke: an aerial aluminium conductor (AAC) with a cross sectional area of 100mm².

Wolf: an aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of 155mm².

XLPE cable: cross linked polyethylene insulated cable.

Zone substation: a major substation where either; voltage is transformed from 66 or 33kV to 11kV, two or more incoming 11kV feeders are redistributed or a ripple injection plant is installed.

Appendix D - Schedule 17

Certificate for Year-beginning Disclosures

We, **Jeremy Brendan Smith** and **Paul Jason Munro**, being directors of **Orion New Zealand Limited** certify that, having made all reasonable enquiry, to the best of our knowledge:-

- a) the following attached information of Orion New Zealand Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Disclosure Determination 2012 in all material respects complies with that determination.
- b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.
- c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Orion New Zealand's corporate vision and strategy and are documented in retained records.



Director

Director

Date 26 March 2015

Orion New Zealand Ltd
565 Wairakei Road
PO Box 13896
Christchurch 8141
New Zealand
Phone +64 3 363 9898
Email info@oriongroup.co.nz
Website oriongroup.co.nz
Twitter twitter.com/OrionNZ

This plan is compiled by Orion's Infrastructure team and has been approved by Orion's board as at March 2015.

© Copyright Orion NZ Ltd. 2015

This document is entitled to the full protection given by the Copyright Act 1994 to the holders of the copyright. Reproduction of any substantial passage from this document is a breach of the copyright. This copyright extends to all forms of photocopying and any storing of material in any kind of information retrieval system. All applications for reproduction in any form should be made to Orion.

Document: NW70.60.01

oriongroup.co.nz