ASSET MANAGEMENT PLAN

A 10-year management plan for Orion's electricity network
from 1 April **2009** to 31 March **2019**

Orion
your NETwork

Front cover image: Fostering the development of our current and future employees, and our contractors, is crucial for the long-term stability and security of the Orion network. Nigel Smith of Orion subsidiary Connetics is one of hundreds of electrical workers each year who learn their trade and refresh their skills at the CPIT Distribution Trades Training Centre, of which Orion is a key partner.

Introduction

Welcome to Orion's 10-year network asset management plan (AMP), which 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, and is a comprehensive, practical resource that captures the valuable insights and experience of our highly-skilled employees.

Extensive consultation tells us that consumers want us to deliver electricity reliably and keep prices down. To meet this expectation we look for the right balance between keeping costs down and investing to provide an excellent service. Our success in achieving this balance is reflected in our prices, which are below average, and in our ranking as one of the most reliable electricity networks in the country.

Key issues discussed in the plan include:

- our forecasts for peak demand growth – the principal driver of investment in our network
- our asset replacement strategies
- a review of our subtransmission system – a comprehensive urban subtransmission options analysis paper is available for comment on our website oriongroup.co.nz
- our measures to mitigate and prevent major electricity outages
- our proactive approach to ensuring public, contractor and employee safety
- our continued investment in new technology to better understand, control and monitor the condition and capability of our network.

Because of recent regulatory changes, it is two years since we last published an AMP. Changes described in this AMP are referenced to our previous edition, which covered the 10-year period from 2007 to 2017.

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

Roger Sutton

CHIEF EXECUTIVE OFFICER

Liability disclaimer

This Asset Management Plan (AMP) has been prepared and publicly disclosed in accordance with the Electricity Information Disclosure Requirements 2004.

Some of the information and statements contained in the 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 in the AMP 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.

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When considering any content of the 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.

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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 provide, maintain and operate Orion's electricity distribution network while meeting agreed levels of service, quality, safety and profitability.

The plan looks ahead for 10 years from 1 April 2009. Our main focus is on the first three to five years – for this period most of our 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 and some planned projects will change in the latter half of the 10 year period of the plan. We will publish an update to this plan in April 2010.

We created our first AMP in 1994 and have since developed the plan to comprehensively meet the requirements of the Electricity Information Disclosure Requirements 2008. These requirements include:

- a summary of the plan
- background and objectives
- target 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 requirements a cross reference table to the relevant sections of our AMP is shown in Appendix B.

Our AMP is also a technical management tool that goes beyond our regulatory requirements. The extensive detail in our plan is used on a day-to-day basis by our employees and demonstrates responsible stewardship of our network assets on behalf of our shareholders, retailers, government agencies, contractors, electricity end users, staff, financial institutions and the general public.

Our plan focuses on optimising 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 reliable and efficient electricity networks in the country.

Please note that our AMP does not cover:

- details of how we derive and apply our network pricing (this information is available on our website oriongroup.co.nz)
- vehicles, non-network related land, buildings, furniture or general office computer equipment
- the overhead costs of operating the network control centre and other indirect overhead costs.

1.1.2 Business plans and goals

We aim to be New Zealand's leading utility network company. To achieve this, we focus on managing our assets prudently to provide a reliable and high quality service into the future. We use innovative asset management practices to ensure electricity is delivered efficiently to consumers over the long term.

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:

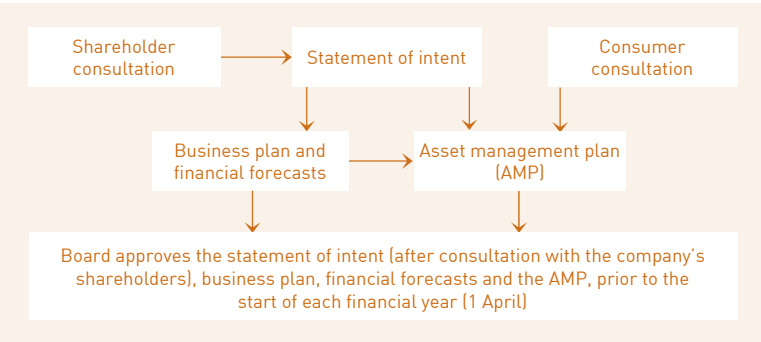
- steady investment in the urban network to meet strong regional growth and the impact of Environment Canterbury's clean air campaign
- continued investment in rural areas to meet strong residential growth at Rolleston and Lincoln and dairy farming loads between the Selwyn and Rakaia rivers
- a steady 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.

Interaction of plans and processes



1.1.3 Stakeholders

Our key stakeholders are:

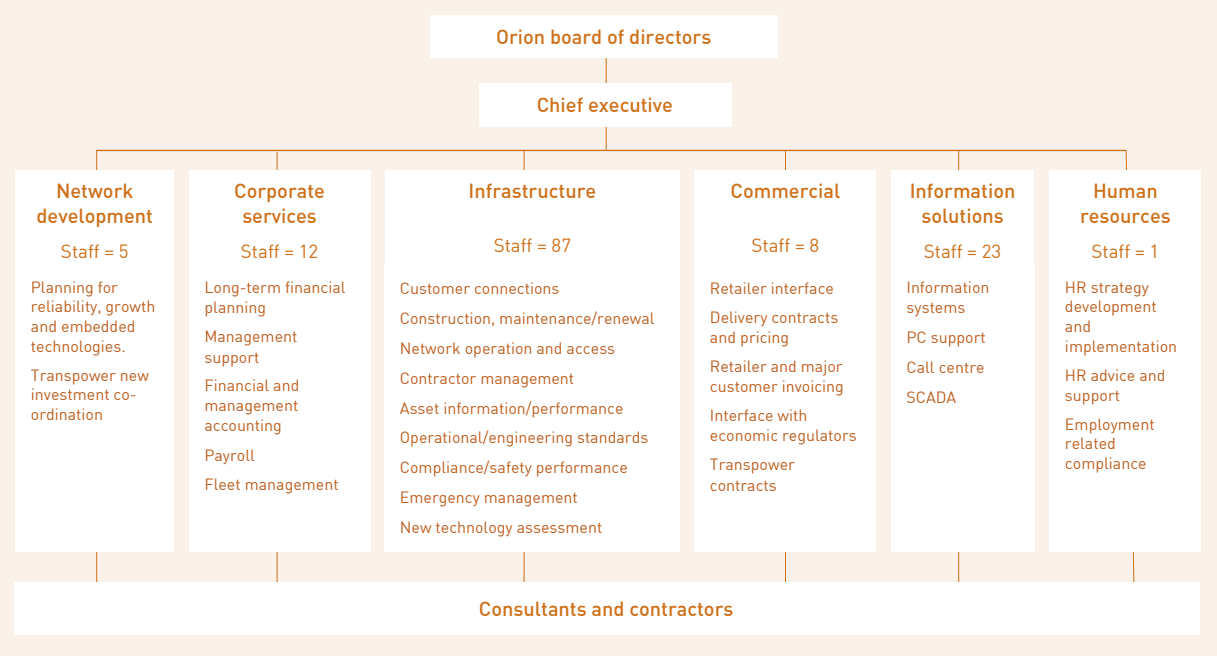
- shareholders – Christchurch City Council Holdings Limited and Selwyn Investment Holdings Limited
- retailers, contracted customers and consumers
- employees
- Transpower
- government agencies
- contractors
- suppliers
- financial institutions.

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

1.1.4 Management responsibilities

We utilise a competitive contracting model – contractors design, construct, connect and maintain our distribution network. Consultants assist in areas where we do not maintain specific expertise. Overall management of our network assets is undertaken at our Christchurch office. The asset management structure for our electricity assets is as follows:

Asset management structure



Orion's directors are appointed by the 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.

1.1.5 Asset management drivers

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

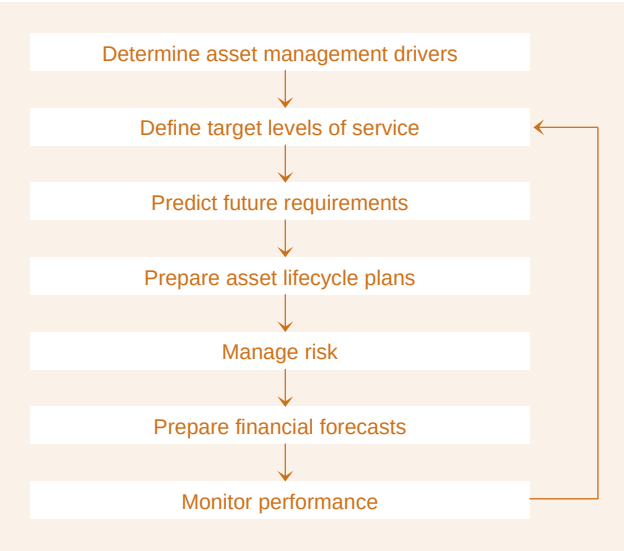
The business drivers which define the need, priority and scope for improved asset management practices within Orion are summarised below:

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

1.1.6 Asset management process

We undertake lifecycle management and asset maintenance planning using whole of life cost analysis, reliability centered maintenance (RCM), condition-based maintenance and risk management techniques. These techniques are used to improve our performance so we can meet our network reliability targets. Our overall asset management process is as follows:

Overall asset management process



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 our ability to meet 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, such as ensuring 66kV oil filled cable joint replacements are not compromised by other works
- 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 network design and work practices. To achieve this we have a developed sets of design standards and standard drawings that are available to approved designers/contractors. Normally we 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 of our network.

We also seek to standardise the equipment used to construct 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 a set of operating instructions covering each different type of equipment on our network. We add to these when any new equipment is introduced. (see section 2.6.3 – process for the introduction of new equipment.)

Our Data Manager processes these 'controlled documents' using our document control process. Extensive use is made of a restricted-access area on our website to make documents and drawings accessible to approved contractors and designers.

Introduction of new equipment types

New equipment types are reviewed to carefully establish any benefits that 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.

1.1.7 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 the diagram in section 2.7. Our main applications are:

- geographic information (GIS)
- asset register (WASP)
- work management
- consumer connections
- financial management
- network valuation
- pricing model
- network monitoring and control (SCADA)
- network loading
- interruption statistics
- power system modelling
- transformer oil analysis
- Microsoft office network
- document control
- incident/accident reporting system
- website.

1.1.8 Development of systems and processes

Network management system

A network management system (NMS) is currently being implemented, which will provide the 'missing piece' to our information systems for network operation. The NMS will allow us to interact in real time with some devices on the electricity network and significantly improve our ability to respond to network outages, especially during big events such as storms, and manage outages related to planned maintenance.

There are three main phases of this project:

- SCADA replacement
- network management and operations
- outage/call management and remote connectivity for field crews.

New finance package

This year we will implement a new corporate financial management system, which will replace our existing 20 year old accounting system. The scope of the initial changeover is to implement functionally 'like for like' systems but in the coming years we look forward to taking advantage of the features of a modern software package. A key driver for this replacement project is dealing with the risk presented by aging computer hardware and software.

Risk management package

We are introducing a computer-based information system to support our risk management activities. Our approach to risk management is comprehensive and extremely effective. We have, however, identified a need to provide a single access point to risk-related information for users and policy makers.

1.2 Service level targets

1.2.1 Introduction

This section of our AMP outlines the performance levels we require from our electricity network and management team. It deals with consumer related service and other requirements relating to our business drivers as defined in section 1.1.5. The service level targets we have adopted are based on a balance of past practice, consumer and stakeholder consultation, international best practice and safety considerations. In setting our targets we believe we have achieved an appropriate balance between legislative, regulatory and stakeholder requirements and consumer expectations.

For some measures we have not set a specific target value. In these cases an explanation of our position has been included. For actual performance against our stated targets see section 7 – Evaluation of performance.

1.2.2 Consumer service

Consumer research

We endeavour to provide a level of service that meets our consumers' requirements in the long term. We 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.

To determine consumer requirements with regard to the level of service that we provide, we utilise five main methods of consumer consultation. 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.

Network reliability

We have improved our network reliability over the last 15 years. But it is not realistic to expect that we can continue to improve our network reliability every year as there comes a point where the added costs outweigh the added benefits, particularly in a predominately overhead rural network. A major improvement in rural reliability would require a large capital investment and a correspondingly large increase in line charges. Recent consumer surveys have indicated that the large majority of our consumers are satisfied with the level of service that we currently provide as one of the most reliable networks in the country.

Our network reliability targets for SAIDI and SAIFI have been set in-line with the targeted price control thresholds implemented by the Commerce Commission. These thresholds were based on the average performance of our network over the five years preceding the introduction of the current targeted price control regime.

- **Target** – The targets shown in the following tables are Orion's network only and exclude Transpower.

Targets for SAIDI, SAIFI, CAIDI and number of interruptions

Network or generation owner	Disclosure regulation class	Classification of interruptions	Targets for years 2009-2013			
			SAIDI	SAIFI	CAIDI	Interruptions
Orion	B	Planned shutdowns	< 8	< 0.08	< 105	< 385
	C	Unplanned cuts	< 55	< 0.67	< 82	< 555
	B and C	All	< 63	< 0.76	< 83	< 940

Targets for faults/100 circuit-km	
Line or cable voltage	Targets for 2008-2012
66kV	< 2
33kV	< 4
11kV	< 12
All	< 11

Security standard

Security of supply is the ability of a network to meet 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 performs and is measured in terms of things such as the number of times supply to consumers is interrupted.

Our security standard and proposed improvement work is detailed in section 5—Network development.

- **Target** – To meet the provisions of our security standard.

Delivery services agreement

Our Delivery Services Agreement (DSA) contains the terms and conditions under which we provide distribution services to an electricity retailer or network user. See section 3.2.4 for the full DSA.

The following power quality targets are pragmatic consumer-focused measures developed by us and found, by experience, to be achievable but challenging.

- **Target** – to meet the provisions of our DSA which includes a target for steady state voltage of no more than 70 proven complaints received per year and a target for harmonics/distortion of no more than two proven non-self inflicted complaints received per year.

1.2.3 Efficiency

Operating a reliable network needs to be done in an efficient and cost effective manner. We monitor the capacity utilisation of our distribution transformers, network losses and load factor as indicators of efficient asset utilisation.

Capacity utilisation ratio

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

- **Target** – although we monitor this ratio, we do not have a specific target. Our management process aims to ensure maximum economic efficiency by ensuring good design and lifecycle management practices. If we specifically targeted levels of capacity utilisation, there could be an incentive to design inefficiently, for example to install long lengths of low voltage distribution or uneconomically replacement of transformers early in their lifecycle due to shifts in area load profiles.

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. It has trended upwards over the last 15 years by just over 0.7% per annum.

- **Target** – for our forecast chart for load factor see section 5.4.1.

Losses

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 result in retailers having to purchase more energy than is delivered to their consumers.

- **Target** – when considering losses in network design and asset purchase, we do not aim for a target 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 lowest economic level of losses to aim for in our network and meets our contractual obligation to adhere to good industry practice.

See section 7.3.3 for an evaluation of our approach to network losses.

1.2.4 Financial forecasts

Maintenance and capex budgets

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

Summary of forecast expenditure – $000, year ending 31 March										
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Capex	30,687	41,900	47,694	42,977	42,758	37,830	36,397	39,587	49,994	44,066
Maintenance	23,376	25,057	25,145	25,059	23,461	23,501	22,588	22,545	22,646	23,049

1.2.5 Changes to previous forecasts

Changes described in these budgets are referenced to our last published AMP for the period from 1 April 2007 to 31 March 2017.

All forecasts are now in 2009 dollar terms (previously in 2007 dollar terms).

Maintenance

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 with continued focus on compliance/risk mitigation.

The only significant change to our forecasts from our previous AMP is the increase for enhanced security surrounding the risk of public access to live equipment. We have budgeted to spend an additional $1.6m each year for the next four years.

Capex

Consumer connections

Our demand forecasts are detailed in section 5 – Network development. Consumer connection costs are based on current and forecast business and residential growth forecasts. In general, demand has been strong but due to economic conditions this is forecast to slow over the next two years. Beyond the next two years we expect demand to return to more normal levels. Moderate cost increases have also impacted on the forecasts in our previous AMP.

Network extensions

Our demand forecasts are detailed in section 5 – Network development. In general, demand growth has been stronger than forecast previously, but is forecast to stabilise or slow moderately over the next two years.

Underground conversion

Underground conversions are carried out within the Orion region, predominantly with road works, at the direction of Selwyn District Council, Christchurch City Council or Transit New Zealand. Costs associated with these works can vary depending on council or roading authority demands.

Reinforcement

The reinforcement budget has remained steady at approximately $4.5m each year for the last five years and is expected to remain at this level for the foreseeable future. Our reinforcement forecasts are in section 5 – Network Development.

MAJOR PROJECTS

The most significant changes to the 2010 forecasts from the 2007-2017 AMP are:

- for load growth and economic reasons, the Belfast substation site development for diesel generation has been carried over from 2008 to 2010
- 11kV switchgear replacement will occur at Papanui in 2010 now that we have negotiated with Transpower to own the Papanui 11kV assets
- Windwhistle district/zone substation is delayed to 2011 until further irrigation growth can be confirmed in the wider Windwhistle area.
- the Teddington transformer upgrade has been delayed until 2013 when further load growth will have occurred and other replacement initiatives will make this project viable.

Further changes in the ten year plan are outlined in section 5. In the period since our 2007 AMP was published, our ten year major projects budget has fallen from $97.7M to $90.3M. This is relatively constant despite the stepped nature of major project investment. Our major project forecasts are in section 5 – Network Development.

1.2.6 Safety

Operating and maintaining an electrical network involves hazardous situations that cannot be eliminated entirely. We are committed to providing a safe reliable network and a healthy work environment – we take all practical steps to see that our operations do not place our staff or community at risk.

Our objectives are to:

- provide safe plant and maintain appropriate 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
- set annual goals and objectives, and review the effectiveness of policies and procedures
- take all practicable steps to identify and eliminate, minimise or isolate hazards.

We are committed to consultation and co-operation between management and employees. Maintaining a safe healthy work environment benefits everyone and is achieved through co-operative effort.

- **Target** – our personal safety targets are detailed in our statement of intent and include:
  - zero lost time accidents for our employees and contractors
  - zero injury accidents (excluding car versus pole traffic accidents) involving members of the public
  - to continue our safety programmes in schools
  - to continue our public safety education and awareness programme about the safe use of electricity.

1.2.7 Environment

We are committed to being environmentally responsible. This fits within our principal objective, which is to operate as a successful business and to be financially sustainable. In addition to this we are investigating establishing our carbon footprint. We use the following principles to guide us toward environmental sustainability:

- stakeholder consultation
- protection of the biosphere
- sustainable use of natural resources
- reduction and disposal of waste
- wise use of energy
- risk reduction
- restoration of the environment
- disclosure
- commitment of management resources.
- **Target** – we have signed an undertaking with the Ministry of the Environment to comply with the ´Memorandum of Understanding relating to Management of Emissions of Sulphur Hexafluoride (SF_6) to the

Atmosphere". Our target of <1% for SF_6 gas lost has been set to reflect this. We will not purchase equipment containing SF_6 if a technically and economically acceptable alternative exists.

- **Target** – in respect to oil spills, our target of zero is the only prudent target we could have for this measure. We operate oil containment facilities and have implemented oil spill mitigation procedures and training. Reported 'uncontained' oil spills relate to incidents that fall outside these precautions.

1.2.8 Legislation

Our aim is to achieve material compliance with all relevant legislation. We obtain ongoing legal advice to keep up-to-date of all our legislative commitments. The legislation that relates to the management of an electricity distribution business is listed as one of our business drivers in section 2.

- **Target** – to comply with all legislation as required by our governing bodies.

1.3 Lifecycle asset management

1.3.1 Asset description

We own and operate the electricity distribution network in central Canterbury – one of New Zealand's largest electricity distribution networks. Our network is both rural and urban, with consumer densities ranging from six consumers per km in rural areas to 30 per km in urban areas.

Urban

Our urban network consists of both a 66kV and a 33kV subtransmission system. Our urban 66kV system supplies 15 district/zone substations in and around Christchurch city and is supplied from Transpower's GXPs at Papanui, Addington, Bromley, Islington and Middleton. Our urban 33kV system supplies another five district/zone substations in and around the western part of Christchurch city and is supplied from Transpower's GXP at Islington. Both systems consist of overhead line and cable. A further 10 district/zone substations in the urban area take supply at 11kV.

Our urban district/zone substations supply a network of 'primary' 11kV cables connected to 270 network substations. These network substations in turn supply some 3,600 distribution substations on a secondary 11kV cable network. The low voltage 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 20 district/zone substations from the Hororata and Springston GXPs. Our rural subtransmission system is primarily overhead and our 11kV network consists mainly of overhead radial feeders from the district/zone substations.

In general we consider our knowledge of our assets is good. Data held for each asset group is noted under the specific asset section (4.4 – 4.24).

Orion's network area

Network summary (Year ending 31 March 2008)	
Description	Quantity
Consumer connections	186,029
Network maximum demand (MW)	631 (Note 1)
Network deliveries (GWH)	3,323
Annual load factor (%)	60.1
Lines and cables (km)	14,404
District/zone substations	50
Distribution/network substations	10,375
Network ODRC $m (per NZ IFRS 16)	900

Note 1. Includes embedded generation exports.

1.3.2 Asset management

We determine our maintenance priorities by following the general principle that the assets supplying the greatest number of consumers receive the highest priority. As our distribution network is hierarchical with the highest voltage at a few input points (Transpower GXPs) and the lowest voltage at the many output points (consumer connections), those parts of the network that operate at higher voltage are given higher maintenance priority. Our operating voltages are 66kV, 33kV, 11kV, 400V and 230V.

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 reducing service.

Typically 67% of current maintenance expenditure on network assets is scheduled (i.e. planned work) in advance. Another 4% of maintenance is not planned but is required to be done, such as pole relocation or for road works. The balance of maintenance expenditure is for emergency work (i.e. fault repairs) to keep the network in service.

Most other electricity distributors maintain electrical equipment only up to the boundary of a property – beyond the boundary it is the property owner's responsibility. We, however, commit to maintaining the lines, poles and all other electrical equipment right up to the point of entry to a house or business building. We do this regardless of whether the electrical equipment between the boundary of the property and the building is owned by us, the property owner or some other third party. We maintain this policy as we wish to provide our community with the best possible service.

1.4 Network development

Developing our network to meet future demand growth requires significant capital expenditure – this development is coming under increasing scrutiny. We note that a focus on energy and financial efficiency, and new non-network solutions to meet energy demand, highlight longer term investment risks.

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:

- meeting safety compliance requirements with existing ageing equipment
- meeting and maintaining our security of supply standard
- meeting shareholder desires for a proactive stance to place existing overhead wires underground.

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.

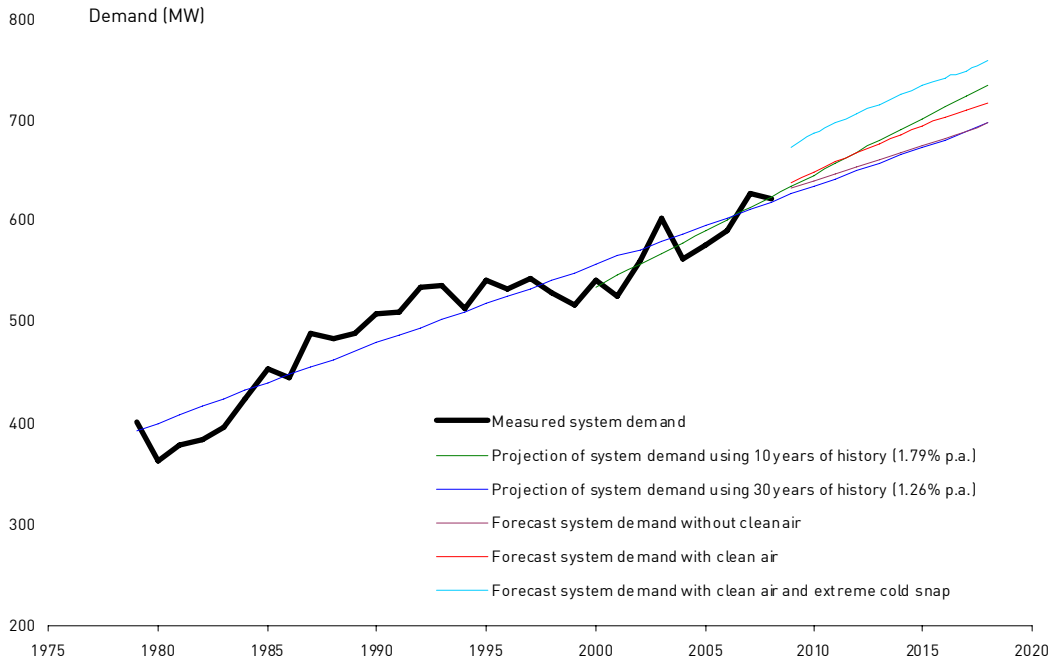
It is likely that we will extend our existing urban network configurations to meet forecast load growth, for example we are currently developing a long term strategic plan for our 66kV urban subtransmission system.

1.4.1 Overall maximum demand

As mentioned above, maximum demand is the major driver for our network investment. This measure is very volatile and varies substantially in Canterbury depending on the vagaries of winter weather.

Network maximum demand including exports from distributed generation for the year ending 31 March 2008 was 623MW, down slightly by 9MW on the previous year due to a warmer 2007 winter. Although the maximum demand was lower than the year previous, the demand was slightly above the long and short term trends. Long and short term trends suggest a demand growth rate of about 1-2% per annum.

Overall maximum demand trends on the Orion network (MW)



1.4.2 Load duration

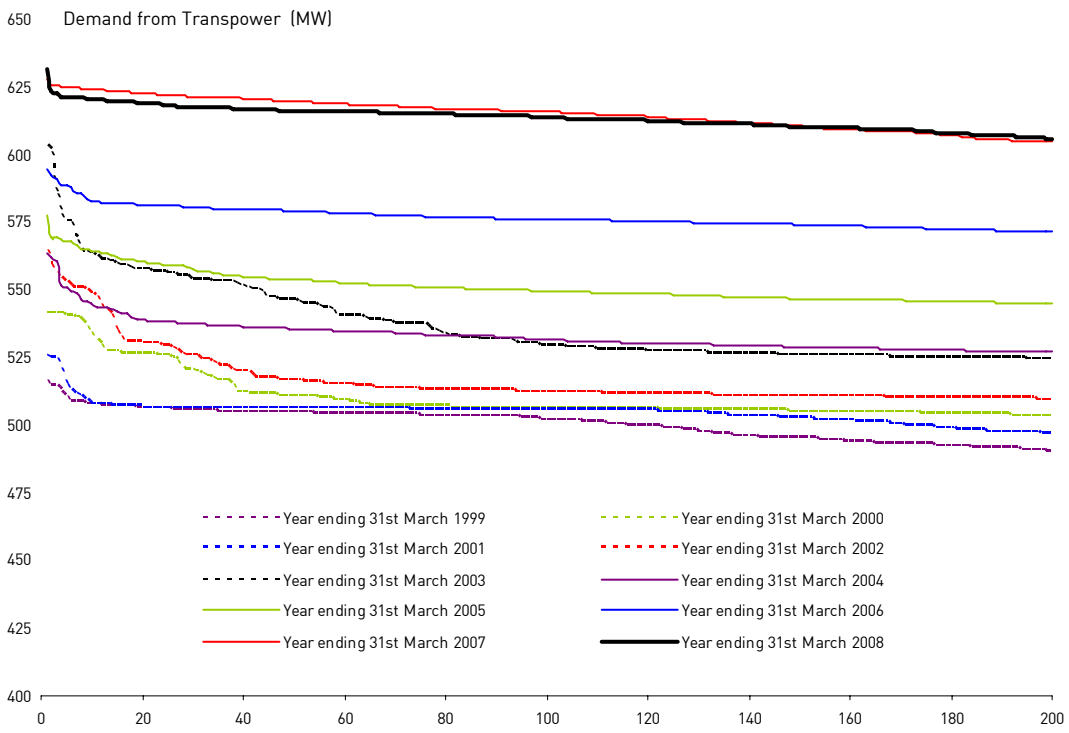
With the constantly changing load on our network, the peak demands that determine the network capacity required generally only occur for very short periods in the year. The following graph shows the load duration curves of our 200 peak half hour demands on the Transpower network over 10 years. The graph shows that in most years an increase in demand side management for 20 hours each year would reduce our network peak demand by 20-50MW. The relatively flat shape of the March 2008 year was a result of a milder than expected 2007 winter compared with 2006.

The Transpower grid requires sufficient capacity to meet load during extreme weather conditions (such as the 2002 snow) that may last for only a few hours. Peaking generation can help to delay the need for increases in the Transpower network capacity. This generation may need to operate for only a few hours over the largest peak demand times, as required to avoid Transpower network constraints. In the 2002 winter, peaking generation of 30MW would only have needed to operate for about four hours to reduce our urban network maximum demand by about 30MW. In unusually prolonged cold conditions longer hours of operation might be needed.

Generation may also be used to reduce Transpower 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 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 ongoing installation and maintenance of ripple receivers.

Christchurch urban area network – load duration curves



1.4.3 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.

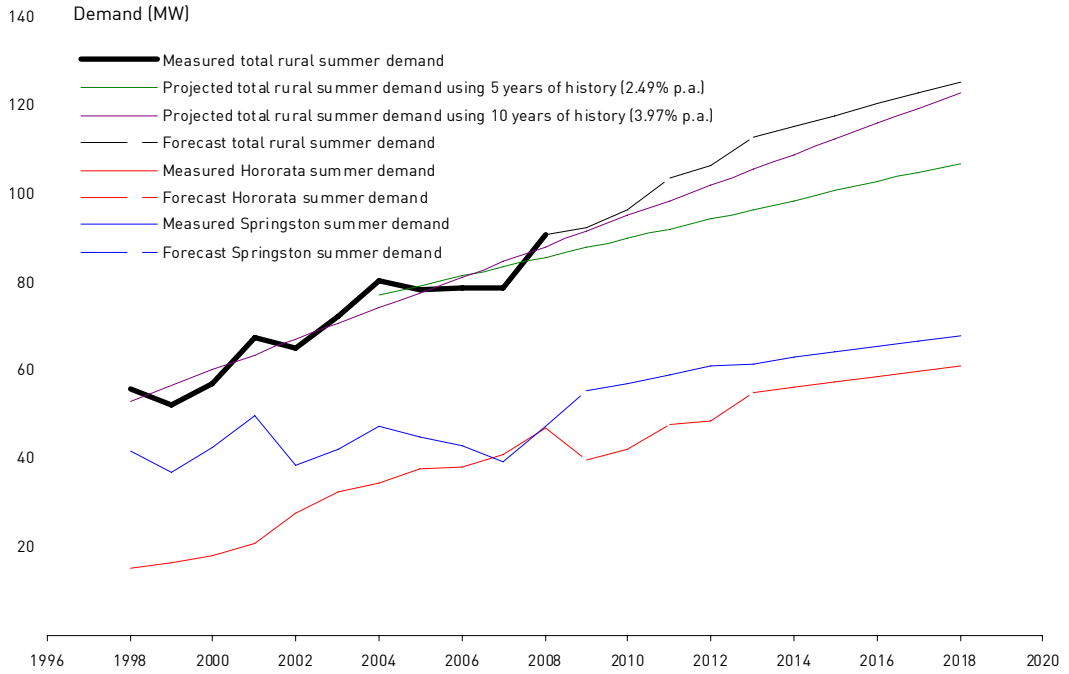
New applications for electrical capacity each year since 2002 have been reasonably consistent, although the summers of 2007/08 and 2003/04 were exceptional seasons with an increase of 12 and 7MW respectively across Hororata and Springston GXPs. This demonstrates how variable peak loads can be, and how weather dependant they are – a dry summer in the Canterbury Plains causes an increase in peak demand as irrigation is required simultaneously across a large area.

Recently some irrigators with large ground-water irrigation schemes have installed surface river-take schemes in parallel with their existing schemes. These surface water schemes need a much smaller electric pump requirement than the equivalent ground-water schemes, but are highly dependant on river flows and rain in the river catchment areas.

Steady irrigation load growth is expected in the next few years, but is expected to ease off due to restrictions in the number of new ground-water consents.

The following graph shows recent load growth in our rural area. Note the effects of load transfers from the Hororata GXP to the Springston GXP in 2007/08 and the forecast impact of the new Synlait milk processing plant near Dunsandel.

Rural summer maximum demand (MW)



1.5 Risk management

1.5.1 Introduction

Our principal risks in managing our network assets are in four main areas:

- health and safety management
- environmental management
- natural events
- asset failure.

We outline each of these areas in more detail below. External consultants have advised on our risk assessment processes, and our network was part of an 'engineering lifelines' study into the potential impact of natural disasters on Christchurch city.

1.5.2 Health and safety management

It is not possible to entirely eliminate all hazards that arise as we operate and maintain our electricity network. However, we are committed to providing a safe, reliable network and a healthy work environment – we take all practical steps to see that we do not place our staff, community or environment at risk. We control hazards through training, guidelines and standards. Potential hazards, in particular electrical hazards, must also be considered when new network installations are designed and constructed.

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

Legacy assets

Our older substation low voltage panels are considered non-compliant. They pose a potential public risk because an unsecured substation door can allow the public direct access to live equipment. A new standard for substation low voltage panels has been developed and all of our new installations are touch safe and compliant with the Electricity Regulations. As it will take a long time (over 30 years) to replace all of these older panels, we intend to fit barriers to the existing panels to reduce the risk to the public.

Legacy linkbox low voltage panels are similar to substation panels and could also be considered non-compliant. They pose a similar potential risk to the public. We have developed a new linkbox standard and all new installations are now touch safe and compliant. As it will take a long time (over 30 years) to replace all of these linkbox panels, we intend to fit barriers to the existing panels to reduce the risk to the public.

1.5.3 Environmental management

We follow a policy of environmental sustainability, initiate energy efficiency programmes and work to minimise electrical losses on our network wherever possible.

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.

We instigated oil spill management systems several years ago and have successfully managed any significant spills.

1.5.4 Impact of natural events

Earthquakes and storms are our major natural event risks. We continue to invest significant time and money to ensure we can respond well to such events. 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. This, combined with numerous diesel generators around the city, gives the Christchurch central business district (CBD) a more secure power supply than equivalent CBDs in Auckland and Wellington
- 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 district 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 substations are to liquefaction. Our reviews show that Addington, Papanui and Bromley GXPs 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 all three GXPs during a single event.

Transpower is reviewing the Papanui and Addington GXPs in detail to determine the remedial work necessary to increase seismic security at these sites.

We note that emergency fuel storage has become a problem due to fewer private fuel tanks in our network area. There are also fewer commercial fuel stations and these all rely on electricity to pump fuel.

1.5.5 Asset failure

We assess all of our key assets based on known past performance. We also use modern 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 district substation transformers.

The 66kV cable network's main identified failure risks are thermo-mechanical buckling and longitudinal movement of the cores within the joints of the oil-filled cables. We are replacing these joints as quickly as is practicable, consistent with available resources and the need to avoid undue stress on neighbouring cables during the relatively long outages for joint renewal work.

We have completed 65% of our current 66kV joint replacement programme. If we decide to also replace another specific manufacturer's joint (Dianichi), then the programme will be extended. A decision on whether to replace these joints will be made in the next 12-24 months.

Comprehensive half-life maintenance of all major district substation transformers is also being carried out. This programme has been coordinated with our 66kV joint replacement programme.

We now 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.

1.6 Evaluation of performance

1.6.1 Introduction

This section reviews our performance against the stated targets in our previous AMP. These targets may be actual target values as stated in section 3 or a declaration 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 reliability gap analysis.

1.6.2 Consumer service

Reliability

We completed the 2008 financial year well ahead of all of our reliability targets. This was helped by reasonably settled weather and our continued investment in technology to better understand, monitor and control the condition and capability of our network.

Only one month of severe weather in the 2008 financial year caused our network any real damage – October 2007 was an unsettled month with gale force winds which caused a significant number of faults.

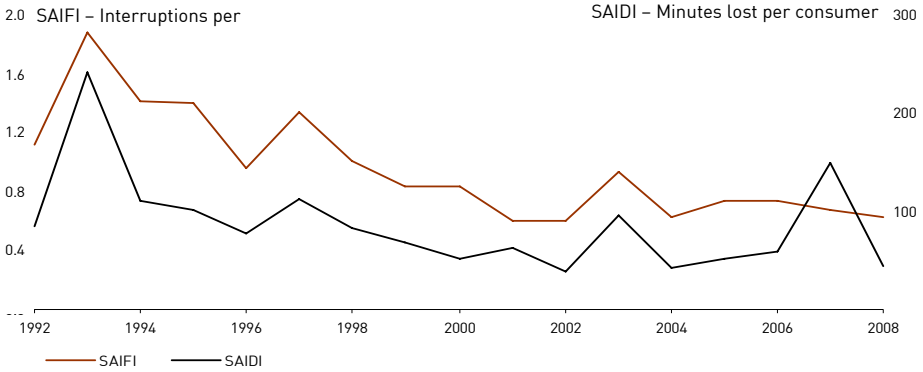
In the 2008 financial year 30% of consumers who experienced a fault had their power supply restored within one hour, and 72% were restored within three hours. In regular consumer surveys of urban and rural consumers, approximately 95% of urban and 80% of rural consumers express satisfaction with the reliability of their power supply.

Orion network reliability results for 2008 and five year average 2004-2008

Category	Target	2008 actual	five year average	NZ average (2007 year)
SAIDI	< 63	45	70	272
SAIFI	< 0.76	0.63	0.68	2.3
CAIDI	< 83	72	103	119
Faults/100 circuit-km	< 11.0	7.3	7.9	9.4
Number of interruptions	< 940	767	764	-

It is important to note that one-off factors such as weather can heavily influence the results in any one year and that the long term average trend is more important and better reflects the reliability of our long life assets. As can be seen in the following graphs, there have been three years where heavy snow storms have caused major damage to our network. These financial years can been seen as 1993, 2003 and 2007. The most recent storm in June 2006 resulted in the loss of some 19 million consumer minutes and accounted for 105 minutes of our final SAIDI total for the 2007 year of 150 minutes.

SAIDI and SAIFI – Orion network 1992-2008



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.

Service level targets and results – Network power quality

Category	Measure	Target	Achieved 2008	Performance indicator	Measurement procedure
Power quality	Voltage complaints (proven)	<70	17	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

1.6.3 Efficiency

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

Efficiency results for 2008 and 5 year average

Category	Target	Achieved 2008	Achieved 5 year average
Capacity utilisation (%)	No target set	37.5	36.8 (2004-08)
Load factor (%)	No target set	60.1	61.6 (2004-08)
Losses (%)	No target set	4.9 estimated	4.9 estimated
Costs per unit delivered	No target set	Not available	1.06 (2003-07)

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, losses do not have much impact on the design and operation of our network because other factors tend to dominate.

Other losses such as un-metered supplies and theft (meter tampering) can add significantly to overall losses if not managed adequately by electricity retailers.

See section 3.3.1 for reasoning behind not setting a specific target for capacity utilisation.

1.6.4 Works expenditure in 2008

The previous AMP figures shown here are from our AMP for the period from 1 April 2007 to 31 March 2017.

Maintenance

Our maintenance costs for 2008 were $17.8m, compared with our previous AMP forecast of $18.6m. The under-expenditure was due to lower than expected insurance/leasing costs, lower SCADA costs due to resources utilised on capital projects and better than average weather conditions during the year. Other works identified for 2008 were substantially completed.

Capex

- Consumer connections

  Our consumer connection costs for 2008 were $4.4m, compared with our previous AMP forecast of $4.2m. There has been consistent strong demand in both the residential and commercial markets.

- Network extensions

  Our network extension costs for 2008 were $3.2m, compared with our previous AMP forecast of $2.6m.

  Demand associated with network extensions and subdivisions has been high due to large and small residential subdivisions.

- Reinforcement

  Our reinforcement costs for 2008 were $4.5m, compared with our previous AMP forecast of $4.6m.

  All works identified to be completed in 2008 were substantially completed.

- Underground conversion

  Our underground conversion costs for 2008 were $1.5m, compared with our previous AMP forecast of $1.7m.

  This under-expenditure was largely due to project timing associated with roading authority needs and works undertaken by the Christchurch City Council.

- Major projects

  Major project costs for 2008 were $14.4m, compared with our previous AMP forecast of $16.5m.

  This under-expenditure was largely due to delay in installing Dunsandel substation. The completion date for this project was driven by the consumer's timetable. Other projects were substantially completed.

- Replacement

  Our replacement costs for 2008 were $8.4m, compared with our previous AMP forecast of $10.3m.

  Resource constraints due to major projects and works in neighbouring networks had significant impact on our works schedule. This under-expenditure will not impact on network performance when we achieve current expected completion times.

1.6.5 Safety

Historically we have reported all employee injury incidents in our incident management database. This database now collects all incident types from our employees. 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 leading indicators of potential harm.

Personal safety – performance results

Key asset management driver	Measure	Target	Achieved 2008	Performance indicator	Measurement procedure
Personal safety	Injuries to staff	Zero	Zero	Number of "serious harm" injury accidents	Accident/incident reports
	Injuries to our contractors	Zero	Note 1		
	Injuries to public	Zero	Note.1		

Note 1 These statistics will be available for our 1 April 2010 AMP.

1.6.6 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 the 2008 financial year.

1.6.7 Improvement initiatives

Subtransmission network

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

Underground

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

Overhead

- replace insulators, install vibration dampers and re-rate conductors for 75^0C operating temperature
- apply dynamic ratings
- assess condition of tower foundations and repair.

Transpower GXPs

- increase reliability at Addington GXP by splitting the 66kV bus
- major alterations at Islington GXP to increase capacity and alter vector grouping along with replacing half of the 33kV outdoor switchgear with indoor equipment
- rearrange existing 11kV supplies at Addington GXP, to increase security
- install a 66kV bus zone scheme at Bromley 66kV GXP
- install a 66kV bus at Springston.

Distribution network

Over the past 17 years our rural reliability performance has improved by a factor of approximately two. During this period the overhead line fault rate has decreased from approximately 25 faults per 100km per year to about 10-15 faults per 100km per year. The main reasons for this are that we have completed major maintenance projects and improved tree control. In addition, live-line work practices have significantly reduced planned outages, while more line circuit breakers have been installed and feeders have been shortened as new district substations are built, which has also provided performance improvements.

We are currently engaged in a programme to install ground fault neutralisers (GFN) at rural district substations. This has the potential to significantly improve network reliability. The potential to cost effectively improve reliability using more traditional methods is fairly limited. However, a GFN (a new initiative for New Zealand) has been investigated, installed and trialled during 2008. A GFN and associated equipment can reduce the residual earth fault current 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 several initiatives to reduce problems with switchgear, primary transformers and their terminations.

Power quality project

As part of a three year project to install 30 power quality instruments, 10 power quality instruments were installed during the year 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 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.

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 one-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.

1.6.8 Gap analysis

Reliability

Our network improved over the 17 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. Our largest plant failure in 2007, in terms of consumer minutes lost, was caused by battery failure in a line circuit breaker at Diamond Harbour.

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 now total 55 in our rural network.

Security standard

Our "deterministic' 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

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 plan is:

To provide, maintain and operate Orion's electricity network while meeting agreed levels of service, quality, safety and profitability.

The plan looks ahead for 10 years from 1 April 2009. Our main focus is on the first three to five years – for this period most specific 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 in the latter half of the 10 year period of the plan. We will publish an update to this plan in April 2010.

We created our first AMP in 1994 and have since developed the plan to comprehensively meet the requirements of the Electricity Information Disclosure Requirements 2004. These requirements include:

- a summary of the plan
- background and objectives
- target 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 requirements a cross reference table to the relevant sections of our AMP is shown in Appendix B.

Our AMP is also a technical tool that goes beyond our regulatory requirements. The extensive detail in our plan is used on a day-to-day basis by our employees and demonstrates responsible stewardship of our network assets on behalf of our shareholders, retailers, government agencies, contractors, electricity end users, staff, financial institutions and the general public.

The plan focuses on optimising 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 reliable and efficient electricity networks in the country.

2.2 Business plans and goals

We aim to be New Zealand's leading utility network company. To achieve this, we continue to focus on managing our assets prudently to provide a reliable and high quality service into the future.

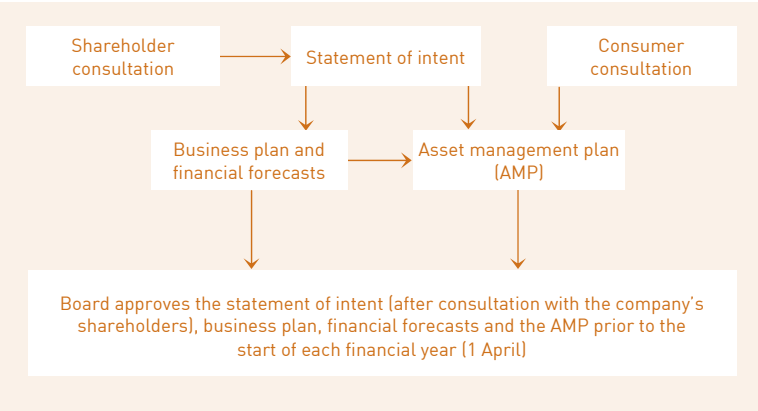
We use innovative asset management practices to ensure electricity is delivered efficiently to consumers over the long term.

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

1. **Statement of intent:** In accordance with section 39 of the Energy Companies Act, we submit a draft statement of intent to our shareholders prior to each financial year. This is a key document that sets out overall strategic/corporate objectives, intentions and financial and performance targets. Section 36 of the Act stipulates that our principal objective shall be to operate as "a successful business" and this is reflected in our Statement of Intent. Our other planning documents all seek to achieve the aims of our statement of intent.
2. **Business plan:** This identifies our overall strategies and business targets, consistent with the approved statement of intent. Our AMP is one part of our plan and we also have other strategies and targets that are unrelated to our electricity distribution network.
3. **Financial forecasts:** These identify our targets relating to what services are to be provided, how they are to be funded and long term funding needs.

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

Interaction of plans and processes



2.3 Stakeholders

Our key stakeholders are:

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

We have identified our 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 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. 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. support.

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

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

- load forecasting
- 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 judgments and experience
- key resource management principles (e.g. managing the pool of competent 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 process
- 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 specific 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 reliability needs. They do not always agree on the level of reliability that they prefer and the price they are willing to pay for our service. Therefore, our reliability represents the average of our consumers' views.

Each revision of our AMP is made available to all stakeholders for their consideration and input is welcome at any time.

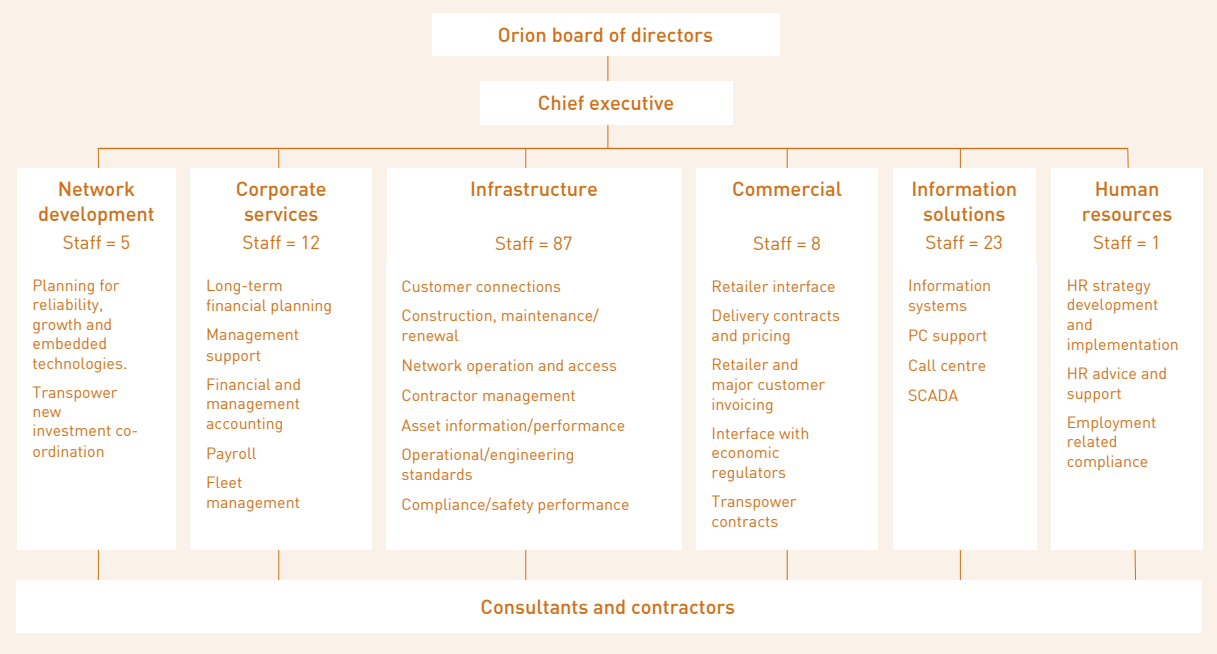
Consumer research is covered further in section 3 – Service level targets.

2.4 Management responsibilities

2.4.1 Asset management structure

We utilise a competitive contracting model – contractors design, construct, connect and maintain our distribution network. Consultants assist in areas where we do not maintain specific expertise. Overall management of our network assets is undertaken at our Christchurch office. The asset management structure for our electricity assets is as follows:

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.

Our board is responsible for the direction and control of the company including stewardship of commercial performance, business plans, policies, budgets and compliance with the law. This includes the annual approval of our 10 year AMP. The Board has approved a delegated authority policy that specifies actions which corporate managers can take within set levels of expenditure without reference to the board. Anything significant outside of this policy is put before the board as required.

Each corporate manager is responsible for gaining board approval for their own budget and for then operating within their budget. Asset management outcomes are reported to the board bi-monthly.

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

2.4.3 Network development

Our network development group is responsible for:

- ensuring that security and reliability levels are maintained when expansion is required to meet load growth
- load analysis and forecasting, asset capability monitoring and contingency planning etc.
- liaison with significant stakeholders who shape the development of our region
- interfacing with Transpower over technical connection issues and provision of future national grid capacity
- technical support on protection and control systems development, power quality and technical standards
- investigating the potential and impact of embedded generation in our network e.g. diesel and wind generation.

2.4.4 Corporate services

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

- insurance and financial planning
- treasury management
- debt management and creditor processing
- tax obligations
- reporting to the board and shareholders, including regulatory and statutory requirements
- payroll
- fleet management.

2.4.5 Infrastructure management

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

- 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
- review designs and prepare contract documents for tendering work
- manage projects/contracts and interact with contractors
- maintain strategic asset records and reliability statistics
- manage and monitor the network
- manage corporate property
- manage safety and environmental compliance systems
- assess new technologies
- monitor asset emergency spares and supply systems.

2.4.6 Commercial

Orion's commercial group is responsible for:

- pricing, billing and contracts with retailers
- relationships with economic regulators (such as the Electricity Commission and Commerce Commission)
- compliance with the industry rulebook
- commercial contracts with Transpower
- advice to retailers and major customers
- Orion's branding initiatives.

Our General Manager Commercial is also Orion's primary contact for media inquiries.

2.4.7 Information solutions

Orion's information services group is responsible for:

- delivery and management of our information systems infrastructure
- the provision, support and enhancement of information systems that support our business processes
- providing customer call answering and distribution network fault management services
- managing our SCADA system.

2.4.8 Human resources

Orion's human resource manager is responsible for:

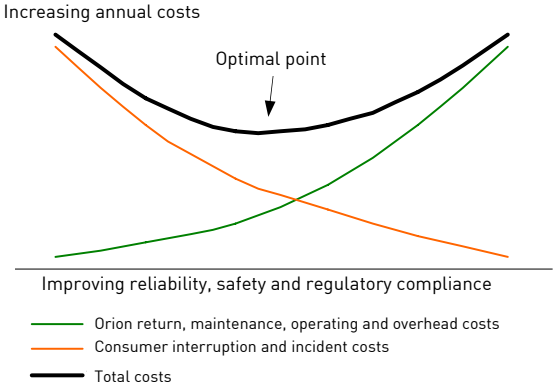
- human resource strategy development & implementation
- human resource advice and support
- employment-related compliance

2.5 Asset management drivers

2.5.1 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 diagram.

Optimal cost versus quality principle



Put simply, we need to find the right balance between costs and the standard of our electricity delivery service. We seek to achieve this optimal point by applying 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 accommodate the new initiative.

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

2.5.2 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:

- 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 1992, which has far-reaching impacts. Other specific safety requirements are found in the Electricity Act, the Electricity Regulations and the Building Act.

In 2005 we started free community education programmes to educate primary school children about the positive aspects of electricity and how to use it safely. We provide materials, tools and support to Canterbury teachers and students, and support the school curriculum in the areas of electricity, science and social needs. We also continue to run an advertising campaign to inform the wider 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 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 are committed to being environmentally responsible. Legislation such as the Resource Management Act 1991 and our own environmental sustainability policy govern our activities.

Our major identified responsibilities are:

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

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

2.6 Asset management process

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

We have developed a RCM culture generally based on retaining the asset function. It does this by asking 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?

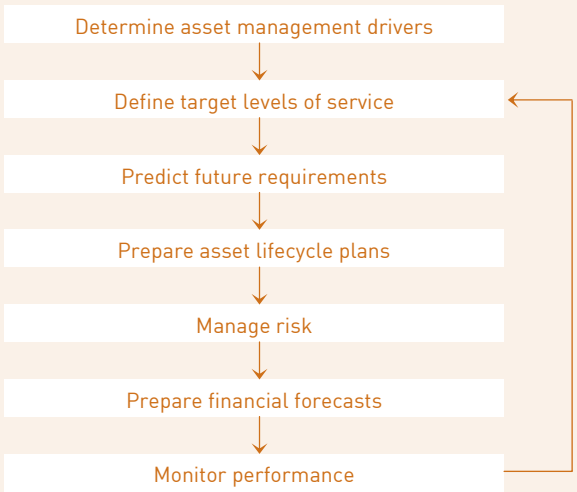
Cost and benefit are considered and the results are monitored to gauge the effectiveness of changes. Monitoring results works well for line assets that have a relatively high failure rate providing sufficient information to make meaningful decisions. However, when applying RCM to assets with much lower failure rates, such as switchgear, information has to be obtained from a wide range of equipment before we decide on effective action.

CBM is an extension to RCM. We continue to improve how we monitor and record the condition of our assets. Where appropriate, maintenance is performed based on the condition of the asset, rather than on the traditional time-based approach.

We continue to assess and replace network equipment that is nearing the end of its life expectancy. This assessment is carried out using a risk based approach and by looking at whole-of-life cost. The risk based approach (see section 6) is based on three characteristics of failure – frequency, consequence and context.

Our overall asset management process is as follows:

Overall asset management process



2.6.1 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 at-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, such as ensuring 66kV oil filled cable joint replacements are not compromised by other works
- 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.

2.6.2 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 a developed 11 design standards and several folders of standard 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

A comprehensive set of approximately 60 specifications for different activities on our network has also been developed. 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 21 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 section 2.6.3 – Process to introduce new equipment.

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 70 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 section 2.6.3 – Process to introduce new equipment.

Operating standards

To ensure our network is operated safely we have developed approximately 20 standards that cover such topics as the release of network equipment, commissioning procedures, system restoration, worker training and access permit control.

Document control process

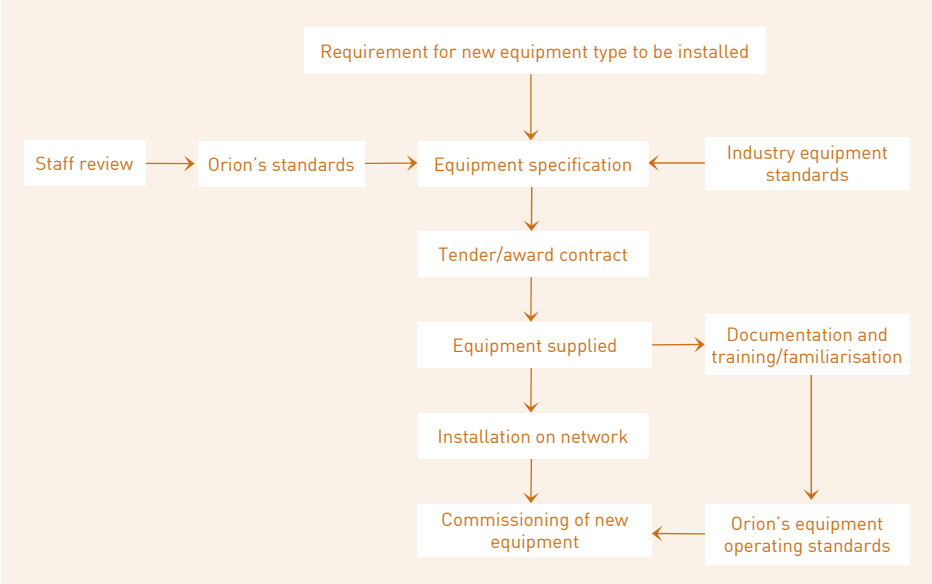
To ensure that all these documents and drawings are maintained as accurately as possible, each is 'owned' by one person who is responsible for any modifications to it. Our Data Manager is responsible for processing these controlled documents using a process set out in our document control standard.

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

2.6.3 Introduction of new equipment types

New equipment types are reviewed to carefully establish any benefits that 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.

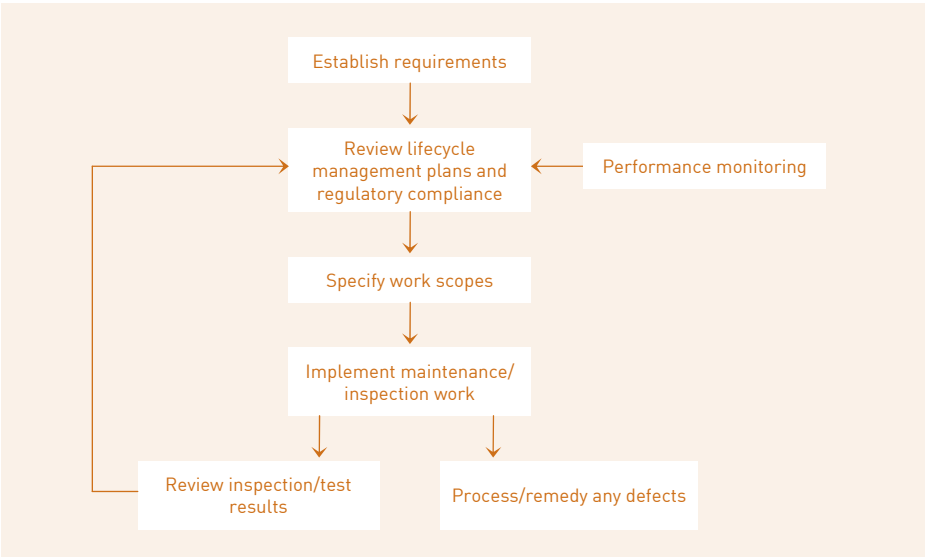
Process to introduce new equipment



2.6.4 Routine asset inspections and maintenance

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

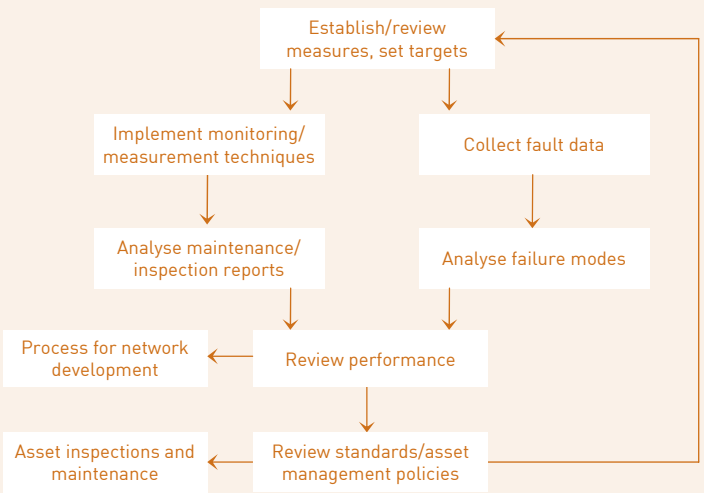
Process for routine asset inspections and maintenance



2.6.5 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.

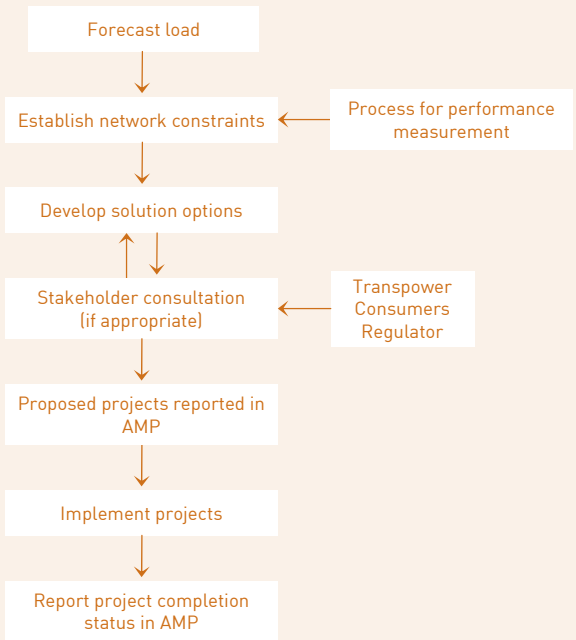
Process for performance measurement



2.6.6 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.

Process for network development



2.7 Systems and information

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 the diagram 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 operating systems 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 and is available to all our staff for use at all times and to some outside parties. Substation asset attribute data is held in our asset register and pulled through to the GIS for display.

Use of the GIS in the field has been introduced through disconnected datasets on laptop devices. Any geographic information available to people outside Orion needs to be 'fit for purpose'. We are currently investigating options for enabling authorised access to relevant geographic information for third parties and general access to information for the public.

Information held 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 GXPs 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.

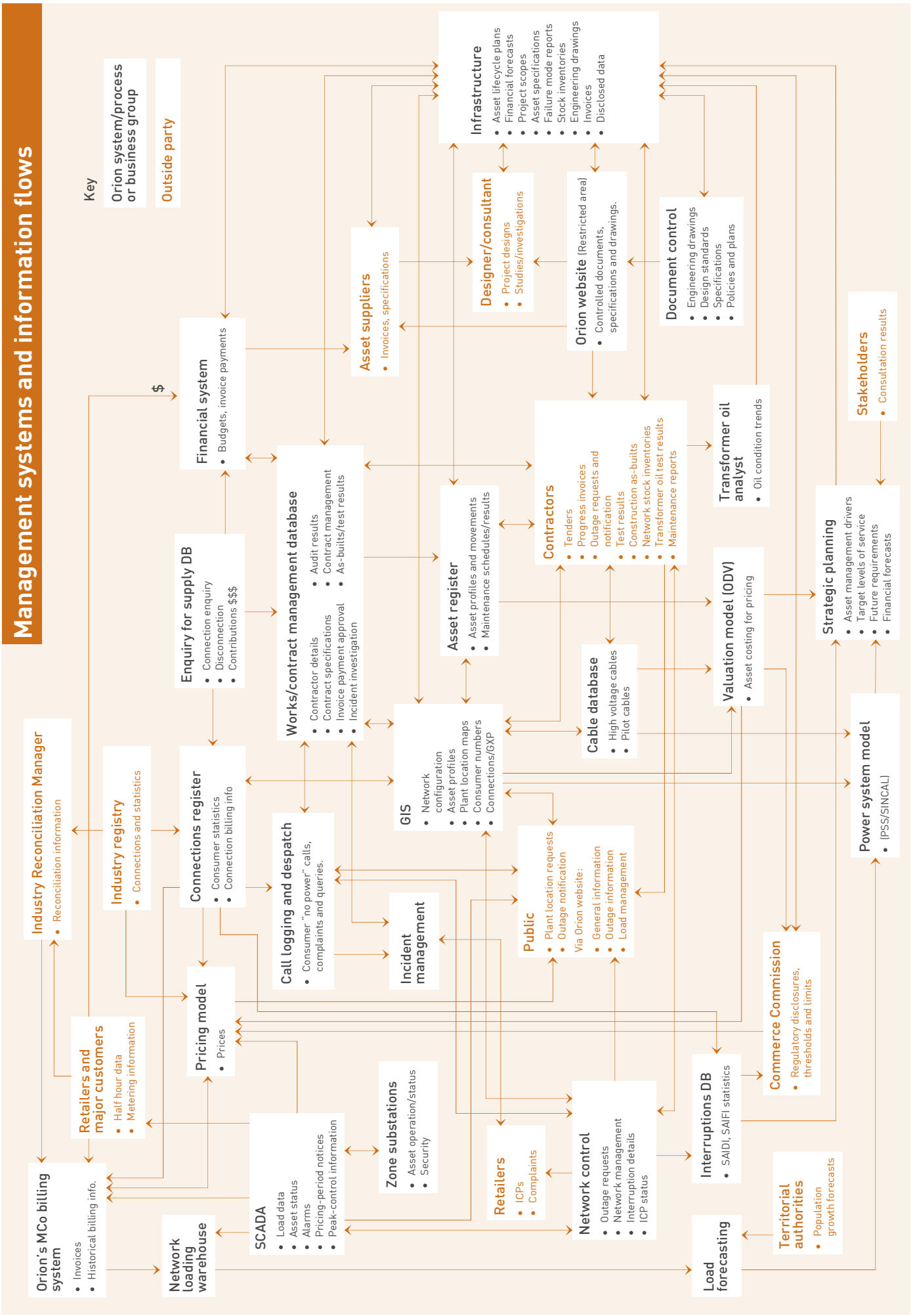
3. Asset register

Our asset management package provides a central resource management application holding details of key asset types. The assets covered include all our major equipment with less strategic types being added over time. 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 results for site earths, poles
- transformer maximum demand readings
- protection relays
- substation maintenance rounds
- poles and attached circuits
- valuation schedule codes and modern equivalent asset (MEA) class
- SCADA and communication system.

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


Management systems and information flows
Key
Orion system/process or business group
Outside party
Infrastructure
• Asset lifecycle plans
• Financial forecasts
• Project scopes
• Asset specifications
• Failure mode reports
• Stock inventories
• Engineering drawings
• Invoices
• Disclosed data
Designer/consultant
• Project designs
• Studies/investigations
Orion website (Restricted area)
• Controlled documents, specifications and drawings.
Document control
• Engineering drawings
• Design standards
• Specifications
• Policies and plans
Asset suppliers
• Invoices, specifications
Stakeholders
• Consultation results
$
Financial system
• Budgets, invoice payments
Contractors
• Tenders
• Progress invoices
• Outage requests and notification
• Test results
• Construction as-builts
• Network stock inventories
• Transformer oil test results
• Maintenance reports
Transformer oil analyst
• Oil condition trends
Works/contract management database
• Contractor details
• Contract specifications
• Invoice payment approval
• Incident investigation
• Audit results
• Contract management
• As-builts/test results
Asset register
• Asset profiles and movements
• Maintenance schedules/results
Strategic planning
• Asset management drivers
• Target levels of service
• Future requirements
• Financial forecasts
Enquiry for supply DB
• Connection enquiry
• Disconnection
• Contributions $$$
Valuation model (ODV)
• Asset costing for pricing
Industry Reconciliation Manager
• Reconciliation information
Industry registry
• Connections and statistics
Connections register
• Consumer statistics
• Connection billing info
GIS
• Network configuration
• Asset profiles
• Plant location maps
• Consumer numbers
• Connections/GXP
Cable database
• High voltage cables
• Pilot cables
Power system model
• (PSS/SINCAL)
Call logging and despatch
• Consumer "no power" calls, complaints and queries.
Public
• Plant location requests
• Outage notification
Via Orion website:
• General information
• Outage information
• Load management
Incident management
Pricing model
• Prices
Commerce Commission
• Regulatory disclosures, thresholds and limits
Retailers and major customers
• Half hour data
• Metering information
Zone substations
• Asset operation/status
• Security
Interruptions DB
• SAIDI, SAIFI statistics
Orion's MCo billing system
• Invoices
• Historical billing info.
SCADA
• Load data
• Asset status
• Alarms
• Pricing-period notices
• Peak-control information
Retailers
• ICPs
• Complaints
Network control
• Outage requests
• Network management
• Interruption details
• ICP status
Network loading warehouse
Load forecasting
Territorial authorities
• Population growth forecasts

4. Works management

All types of works activity are managed using two purpose-built applications added to a single Works data repository, each optimised for a different type of work (new connections management or general network jobs). On job creation, a companion job is automatically created in the financial system.

Information held in works management includes:

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

5. 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 the GIS using the in-built connectivity model, and accurate information about the number of customers and interruption duration are recorded.

6. Financial system

Our financial system focuses mainly on delivering basic accounting functions. Aside from the obvious (general ledger, debtors, creditors, accounts payable etc.) the system is also used to manage fixed-assets, accounting, taxation, some works and our vehicle fleet. Detailed asset information is not held in the financial system but is instead recorded in the most appropriate asset management system (GIS or asset register).

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

7. Enquiry for supply

A specialised system that supports the management of new connections to our network (or changes to existing connections) and the consequent management of the construction process that ensues. The system includes a web interface allowing applicants to apply on-line. It supports the initial application investigation and approval process, the process of monitoring the construction, the tracking of any associated costs and payments, and the management of site audits and any required remedial action. Key connection information is passed through to the connections management application at the stage an ICP is created.

8. Call logging and dispatch management

A purpose-built call taking and dispatching application tracks all calls coming into our call centre. Jobs related to the network automatically appear on a dispatch screen used by our control centre, from where they can be dispatched to handheld devices used by field operators. 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 screen, and the job details automatically flow through into the works database.

The application also manages livening and demolition job activities, with the field workers again using handhelds.

9. Incident management

We operate an in-house designed database which enables a variety of incident types to be captured. These range from a minor personal injury to a customer complaint. Incident information can be added progressively and all relevant documents can be stored electronically. Incidents can be graphed by type for reporting purposes.

10. 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 district 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.

11. Interruption statistics

A copy of our GIS is used to recreate the network switching undertaken to isolate and restore our network after an interruption. The number of ICPs affected at each switching step is obtained and recorded along with the 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.

12. 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.

13. 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.

14. 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.

15. 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.

16. 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 low voltage 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.

Work is underway to study the feasibility of implementing the on line power flow analysis package as part of a new network management system when it is commissioned during 2009.

17. 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.

18. 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 .

19. 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 the as-built drawings at the completion of works contracts. Controlled standards and policies maintained in-house are also processed 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.

20. 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 activities
- pricing
- publications, disclosures and media releases
- unscheduled interruptions, advised to street level
- planned shutdowns – each retailer is advised of customers that will be affected
- network 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, using a unique login and password, is controlled by us and depends on the type of relationship we have with the other party.

2.8 Development of systems and processes

2.8.1 Short term developments

Network management system

A network management system (NMS) is currently being implemented, which will provide the 'missing piece' to our information systems for network operation. The NMS will allow us to interact in real time with some devices on the electricity network and significantly improve our ability to respond to network outages, especially during big events such as storms, and manage outages related to planned maintenance.

There are three main phases of this project:

- SCADA replacement
- network management and operations
- outage/call management and remote connectivity for field crews.

New finance package

This year we will implement a new corporate financial management system, which will replace our existing 20 year old accounting system. The scope of the initial changeover is to implement functionally 'like for like' systems but in the coming years we look forward to taking advantage of the features of a modern software package.

A key driver for this replacement project is dealing with the risk presented by aging hardware and software.

Risk management package

We are introducing a computer-based information system to support our risk management activities. Our approach to risk management is comprehensive and extremely effective. We have, however, identified a need to provide a single access point to risk-related information for users and policy makers.

Service level targets

3

3.1 Introduction

This section of our plan outlines the performance levels we require from our electricity network and management team. It deals with consumer-related service requirements and other requirements relating to our business drivers as defined in section 2. Those business drivers are:

- consumer service
- economic efficiency
- safety
- environmental responsibility
- legislation
- corporate profile

Our service level targets are based on a balance of past practice, consumer and stakeholder consultation, international best practice and safety considerations. In setting our targets we believe we have achieved an appropriate balance between legislative, regulatory and stakeholder requirements and consumer expectations.

For some measures we have not set a specific target value. In those cases we explain our position.

For actual performance against our stated targets, see section 7 – Evaluation of performance.

3.2 Consumer service

3.2.1 Consumer research

We endeavour to provide a level of service that meets our consumers' requirements in the long term. We 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.

To determine consumer requirements with regard to the level of service that we provide, we utilise five main methods of consumer consultation. 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.

Security of supply standard – consumer involvement

In 1998 we adopted a security of supply standard following a detailed review of our AMP. This review was undertaken by Orion and an independent expert engineering company and involved direct consultation with local stakeholders including consumer groups. It also included financial verification based on the value consumers place on supply interruptions. As nine years had passed since we started using the standard, we reviewed it in 2007 to ensure it continued to take into account current consumer preferences for the quality and price of service that we provide. As a result of the review, our security standard has been improved to better reflect the current needs of consumers. The revised security standard may result in slightly lower reliability for our outer-urban consumers but this will reduce the need for future price rises.

Consumer surveys

Results from the following four surveys undertaken by Orion indicate that the large majority of our consumers are satisfied with the level of service that we provide.

- **Research into the strengthening of relationships with landowners**

  We undertook a survey in February 2003 which involved phone interviews with a random sample of 30 rural landowners, who had had contact with us during the previous year. The results indicated the majority of rural landowners were satisfied with the quality of our products and services. Of those who were dissatisfied in some way, a ratio of two to one landowners preferred an increase in reliability to a decrease.

- **Network reliability consumer survey**

  We commissioned an independent research company 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 more than 400 rural consumers. This survey focussed on consumer attitudes and opinions to our response to the severe snow storm which disrupted supply on our rural network in June 2006. The survey captured both those that lost power supply (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**

  We commissioned an independent research company in June 2007 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 in their monthly power bill 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 "twenty percent 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 customers 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 customers (a total of 74% of customers) would be willing to pay for improved reliability.

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. Based on our dealings with retailers, we are not aware of any systemic concerns with the level of reliability we provide.

Direct consumer feedback

All of our major consumers 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 the level and structure of our pricing. Our senior management team attend the seminars to answer any questions from major consumers.

We also meet with our shareholders and consumer groups each year 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.

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.

This consultation has shown that our consumers expect a reliable and secure supply of electricity with no reduction in service from current levels.

3.2.2 Network reliability

We have improved our network reliability over the last 15 years. But it is not realistic to expect that we can continue to improve our network reliability every year as there comes a point where the added costs outweigh the added benefits, particularly in a predominately overhead rural network. A major improvement in rural reliability would require a large capital investment and a correspondingly large increase in line charges.

Our network reliability targets for SAIDI and SAIFI (see the Glossary for a definition of these measures) have been set in-line with the targeted price control thresholds implemented by the Commerce Commission. These thresholds were based on the average performance of our network over the five years preceding the introduction of the current targeted price control regime. We expect to achieve these targets except during extreme events, such as very severe wind or snowstorms or other natural catastrophes such as earthquakes.

Our improvement initiatives are discussed in more detail in section 7 and consultation with consumers about reliability is detailed at the start of this section.

- **Target** – The targets shown in the following tables are only for the Orion network and exclude Transpower's nationwide transmission network.

Targets for SAIDI, SAIFI, CAIDI and number of interruptions						
Network or generation owner	Disclosure regulation class	Classification of interruptions	Targets for years 2009-2013			
			SAIDI	SAIFI	CAIDI	Interruptions
Orion	B	Planned shutdowns	8	0.08	105	385
	C	Unplanned cuts	55	0.67	82	555
	B and C	All	63	0.76	83	940

Targets for faults/100 circuit-km	
Line or cable voltage	Targets for 2008-2012
66kV	2
33kV	4
11kV	12
All	11

3.2.3 Security standard

Our 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.

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.

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

- **Target** – to meet the provisions of our security standard.

3.2.4 Delivery services agreement

Our Delivery Services Agreement (DSA) sets out the terms and conditions under which we provide distribution services to an electricity retailer or network user.

Schedule B of the DSA specifies several of Orion's responsibilities, as indentified below.

B1 – Network performance

B1.1 Maintain the voltage at connections within the range specified in Clause 53 of the Electricity Regulations. The electricity retailer acknowledges that maintenance of voltage within the tolerance range may depend in part on the maintenance of the power factor at connected consumers' installations.

B1.2 Ensure that the levels of harmonic voltages and currents passed into connected consumers' installations conform with the Limitation of Harmonic Levels Notice 1993, Electrical Code of Practice 36, or any other notice in substitution thereof in so far as the harmonic disturbance results from problems arising from a cause within Orion's control.

B1.3 Meet the reliability performance targets, on a five yearly average basis, as published in Orion's approved Statement of Intent. These currently are set out in section 2.3.2.

B1.4 Total number of proven consumer voltage complaints per year where non compliance with B1.1 is proven not to exceed four per 10,000 connections. (Target for year ending 31 March 2003 = <70)

B1.5 On request provide the electricity retailer with reports of its performance against the distribution network performance targets set out in B1.3 and B1.4.

B2 – Response to enquiries

Orion uses reasonable endeavors to respond to the electricity retailers' enquiries as follows:

B2.1 Provide acknowledgement to the electricity retailer of an enquiry or complaint from the electricity retailer within three business days.

B2.2 Complete an investigation relating to such an enquiry or complaint within 10 business days (where reasonably practicable to do so).

B2.3 Provide a report on the findings of an investigation within five business days of the completion of the investigation, if requested to do so.

B3 – Reporting unplanned interruptions to delivery

Orion shall use reasonable endeavors to report interruptions to the electricity retailer to the following timetable. Such reporting shall be by a process that is agreed between the parties:

B3.1 Within 15 minutes of Orion being advised of the occurrence of an unplanned interruption, Orion shall advise the electricity retailer the time and date of the event and the location and/or the connections.

B3.2 As soon as Orion has reliable information, it shall advise the electricity retailer when restoration of delivery is expected and the cause of the unplanned interruption.

B3.3 The previous clauses B3.1 and B3.2 shall also apply with respect to the operation of the Load Management Service.

3.2.5 Network power quality

Power quality is defined by a group of performance attributes of the electricity power supply. Three 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 number and magnitude of transient voltage excursions.

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.

The following targets are pragmatic consumer-focused measures developed by us.

Steady state voltage

The range of steady state voltage supplied to consumers is mandated by regulation, as 230 volts ± 6%. We design and operate our network to meet this requirement. However, despite these 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.

- **Target** – our target level of service for steady state voltage is that there should be no more than 70 proven complaints received 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 the problem 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.

- **Target** – our target level of service for harmonics/distortion is that there should be no more than two proven non-self inflicted complaints received per year.

Transient voltage excursions

The acceptable magnitude and frequency of transient voltage excursions (commonly known as sags, swells, surges and flicker) experienced by power supply consumers is defined by a series of joint Australian/New Zealand and international standards. We subscribe to the levels of performance covered by these standards and design our network to meet the requirements of these standards.

Some transient voltage excursions are caused by faults on Transpower's network or within our network. We design our network to minimise the effects of sags caused by faults.

To limit sags and flicker caused by consumer equipment, our Network Code (available on our website oriongroup.co.nz) limits the types of equipment that may be connected to the network. If it is proven that interference is being caused by consumer equipment that does not comply with either the Network Code or the relevant standard, the consumer may be required to disconnect the equipment.

3.3 Efficiency

Operating a reliable network needs to be in an efficient and cost effective manner. We monitor the capacity utilisation of our distribution transformers, network losses and load factor as indicators of efficient asset utilisation.

3.3.1 Capacity utilisation ratio

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

- **Target** – although we monitor this ratio, we do not have a specific target. Our management process aims to ensure maximum economic efficiency by ensuring good design and lifecycle management practices. If we specifically targeted 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.

3.3.2 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. It has trended upwards over the last 15 years by just over 0.7% per annum.

- **Target** – for our forecast chart for load factor see section 5.4.1.

3.3.3 Losses

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 result in retailers having to purchase more energy than is delivered to their consumers.

- **Target** – when considering losses in network design and asset purchase, we do not aim for a target 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 lowest economic level of losses to aim for in our network and meets our contractual obligation to adhere to good industry practice.

See section 7.3.3 for an evaluation of our approach to network losses.

3.4 Works

3.4.1 Financial forecasts

Financial expenditures are forecast for a 10 year period. These forecasts are based on identified maintenance regimes and proposed projects as detailed in sections 4 and 5.

Changes described in these budgets are referenced to our last published AMP for the period from1 April 2007 to 31 March 2017.

No provisions have been made in the forecasts for inflation but a $1.5m contingency provision has been added to the capex and maintenance estimates. This is to provide a better representation of 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 associated with the local impact of economic growth, for example the proposed Central Plains Water irrigation scheme
- uncertainty associated with Environment Canterbury's clean air requirements.

Maintenance budgets – $000, year ending 31 March

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
66kV overhead	222	262	262	262	262	302	302	302	302	302
33kV overhead	425	425	425	425	425	425	425	425	425	425
11kV overhead	3,625	3,625	3,135	3,135	3,625	3,625	3,625	3,135	3,135	3,625
400V overhead	2,860	2,860	3,310	3,310	2,860	2,860	2,860	3,310	3,310	3,310
Earths	255	255	255	255	255	255	255	255	255	255
66kV underground	2,015	2,015	2,015	2,015	2,015	2,015	1,215	1,215	1,215	1,215
33kV underground	97	97	97	112	112	112	112	112	112	112
11kV underground	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040
400V underground	1,295	1,225	1,225	1,225	1,225	1,195	1,195	1,195	1,195	1,195
Mapping and asset information	529	529	529	529	529	529	529	529	529	529
Storms	150	150	150	150	150	150	150	150	150	150
Meters	130	130	130	130	130	70	70	70	70	70
Protection	593	593	593	593	593	593	593	593	593	593
Pilots	190	200	200	200	200	200	200	200	200	200
SCADA	850	850	950	850	860	950	830	830	930	840
Ripple injection	202	202	202	202	202	202	202	202	202	202
Switchgear	2,771	2,776	2,789	2,789	1,219	1,220	1,226	1,223	1,224	1,228
Transformers	1,480	1,547	1,547	1,547	1,467	1,467	1,467	1,467	1,467	1,467
Substations	434	434	434	434	434	434	434	434	434	434
Buildings and enclosures	1,683	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813
Grounds	285	285	300	300	300	300	300	300	300	300
Generators (fixed)	65	65	65	65	65	65	65	65	65	65
Asset storage	390	390	390	390	390	390	390	390	390	390
Local authority rates (distribution)	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415
Local authority rates (sites)	375	375	375	375	375	375	375	375	375	375
Contingency	0	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Maintenance totals	**23,376**	**25,057**	**25,145**	**25,059**	**23,461**	**23,501**	**22,588**	**22,545**	**22,646**	**23,049**
Totals from 1 April 2007 AMP	21,285	21,250	20,675	20,690	20,530	20,530	19,710	19,710	n/a	n/a

Capex budgets – $000, year ending 31 March	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Consumer connections	3,600	3,800	4,200	5,000	5,400	5,400	5,400	5,400	5,400	5,400
Network extensions	2,000	2,200	2,600	2,800	2,900	2,900	2,900	2,900	2,900	2,900
Reinforcement	4,568	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500
Underground conversions	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
Major projects	5,960	13,915	19,400	13,057	8,675	1,910	1,320	3,950	14,560	7,920
Replacement	12,459	13,885	13,394	14,020	17,683	19,520	18,677	19,237	19,034	19,746
Contingency	0	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Capex totals	**30,687**	**41,900**	**47,694**	**42,977**	**42,758**	**37,830**	**36,397**	**39,587**	**49,994**	**44,066**
Totals from 1 April 2007 AMP	32,465	32,663	41,602	35,447	42,083	41,501	46,891	38,864	n/a	n/a

For details of, and budgets for individual projects see section 5.6 – Network development proposals.

A breakdown of the replacement and reinforcement budgets is shown in the following tables.

Replacement budgets – $000, year ending 31 March	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
66KV overhead	0	0	0	0	1,700	0	0	1,700	0	0
33KV overhead	220	220	330	330	330	330	330	330	330	330
11KV overhead	2,055	2,055	2,055	2,385	2,385	2,385	2,360	2,360	2,360	2,360
400V overhead	1,130	1,130	1,130	1,240	1,240	1,240	1,240	1,240	1,240	1,240
66KV underground	0	0	0	0	0	0	0	0	0	0
33KV underground	300	350	485	50	0	0	0	0	0	0
11KV underground	100	100	100	100	100	100	100	100	100	100
400V underground	100	100	100	300	300	300	300	300	300	300
Metering	15	70	75	75	75	75	75	75	75	75
Protection	935	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025
Pilots	200	200	200	200	200	200	200	200	200	200
SCADA/communications	915	1,295	795	795	815	995	795	795	895	915
Ripple injection	135	55	65	65	65	65	65	565	565	315
Switchgear	4,259	4,510	4,754	4,940	7,008	7,955	8,392	8,107	8,274	8,526
Transformers	890	1,570	1,050	1,285	1,410	3,935	2,905	1,550	2,780	3,470
Substations	685	685	685	685	485	415	415	415	415	415
Property	520	520	545	545	545	500	475	475	475	475
Replacement totals	**12,459**	**13,885**	**13,394**	**14,020**	**17,683**	**19,520**	**18,677**	**19,237**	**19,034**	**19,746**
Totals from 1 April 2007 AMP	11,585	11,948	12,057	12,247	16,083	16,981	15,491	16,264	n/a	n/a

Reinforcement budgets – $000, year ending 31 March										
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Urban reinforcement projects	2,454	2,924	1,113	900	0	0	0	0	0	0
Rural reinforcement projects	1,334	689	730	138	0	0	0	0	0	0
Unscheduled reinforcement	780	780	780	780	780	780	780	780	780	780
Unidentified reinforcement	0	107	1,877	2,682	3,720	3,720	3,720	3,720	3,720	3,720
Reinforcement totals	**4,568**	**4,500**	**4,500**	**4,500**	**4,500**	**4,500**	**4,500**	**4,500**	**4,500**	**4,500**
Totals from 1 April 2007 AMP	4,580	4,500	4,500	4,500	4,500	4,500	4,500	4,500	n/a	n/a

Transpower new investment agreement charges – $000, year ending 31 March										
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Hororata additional 66kV feeder (bay 150)	29	29	29	29	29	29	29	29	29	29
Islington additional 33kV feeder	34	34	34	34	34	34	34			
Springston 66kV GXP and feeder	275	275	275	275	275	275	275	275	275	275
Middleton 66kV GXP connection	114	114	114	114	114	114	114	114	114	114
Papanui 11kV switchgear	27	27	27	27	27	27	27	27	27	27
Bromley 66kV bay upgrade	25	25	25	25	25	25	25	25	25	25
Bromley 220/66kV transformer upgrade		720	720	720	720	720	720	720	720	720
Islington 66kV bay for Weedons line		32	32	32	32	32	32	32	32	32
Hororata 66kV bay for Windwhistle line		32	32	32	32	32	32	32	32	32
Papanui 66kV Bus Zone			84	84	84	84	84	84	84	84
Springston 66kV bay – Springston 66/11kV local				45	45	45	45	45	45	45
Springston 66kV bay – Larcomb					45	45	45	45	45	45
Kirwee GXP								135	135	135
Bromley 66kV bay – Dallington									45	45
Totals	**452**	**1,236**	**1,320**	**1,365**	**1,410**	**1,410**	**1,410**	**1,545**	**1,590**	**1,590**
Note; assumes 35 year contracts.										

3.4.2 Changes to previous forecasts

Changes described in these budgets are referenced to our last published AMP for the period from 1 April 2007 to 31 March 2017.

All forecasts are now in 2009 dollar terms (previously in 2007 dollar terms).

Maintenance

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 with continued focus on compliance/ risk mitigation.

The only significant change to our forecasts from our previous AMP is the increase for enhanced security surrounding the risk of public access to live equipment. We have budgeted to spend an additional $1.6m each year for the next four years.

Capex

Consumer connections

Our demand forecasts are detailed in section 5 – Network development. Consumer connection costs are based on current and forecast business and residential growth forecasts. In general, demand has been strong but due to economic conditions this is forecast to slow over the next two years. Beyond the next two years we expect demand to return to more normal levels. Moderate cost increases have also impacted on the forecasts in our previous AMP.

Network extensions

Our demand forecasts are detailed in section 5 – Network development. In general, demand growth has been stronger than forecast previously, but is forecast to stabilise or slow moderately over the next two years.

Underground conversion

Underground conversions are carried out within the Orion region, predominantly with road works, at the direction of Selwyn District Council, Christchurch City Council or Transit New Zealand. Costs associated with these works can vary depending on council or roading authority demands.

Reinforcement

The reinforcement budget has remained steady at approximately $4.5m each year for the last five years and is expected to remain at this level for the foreseeable future. Our reinforcement forecasts are detailed in section 5 – Network Development.

Major projects

The most significant changes to the 2010 forecasts from the 2007-2017 AMP are:

- for load growth and economic reasons, the Belfast substation site development for diesel generation has been carried over from 2008 to 2010
- 11kV switchgear replacement will occur at Papanui in 2010 now that we have negotiated with Transpower for Orion to take ownership of the Papanui 11kV assets
- Windwhistle district/zone substation is delayed to 2011 until further irrigation growth can be confirmed in the wider Windwhistle area
- the Teddington transformer upgrade has been delayed until 2013 when further load growth will have occurred and other replacement initiatives will make this project viable.

Further changes in the ten year plan are outlined in section 5. In the period since our 2007 AMP was published our ten year major projects budget has fallen from $97.7m to $90.3m. This is relatively constant despite the stepped nature of major project investment. Our major project forecasts are detailed in section 5 – Network Development.

3.5 Safety

Operating and maintaining an electrical network involves hazardous situations that cannot be eliminated entirely. We are committed to providing a safe reliable network and a healthy work environment – we take all practical steps to see that our operations do not place our staff or community at risk.

Our objectives are to:

- provide safe plant and systems of work
- maintain appropriate 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 eliminate, minimise or isolate hazards.

We are committed to consultation and co-operation between management and employees. Maintaining a safe healthy work environment benefits everyone and is achieved through co-operative effort.

Target – our personal safety targets are detailed in our statement of intent and include:

- zero lost time accidents for our employees and contractors
- zero injury accidents (excluding car versus pole traffic accidents) involving members of the public
- to continue our safety programmes in schools
- to continue our local public safety education and awareness programme about the safe use of electricity.

3.6 Environment

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 engaged an international environmental consulting firm to help us map our impact on the environment, and we use the following principles to guide us toward environmental sustainability:

Stakeholder consultation

We will actively consult with stakeholders in our decision making where material trade-offs exist between environmental, social and financial issues.

We will seek to meet stakeholder needs, however, our principal objective is to operate as a successful business and as such we need to be financially sustainable.

We will proactively meet our commitments under current law.

Protection of the biosphere

We will take all practicable steps in our operations to prevent and minimise the release of any pollutant that may cause environmental damage.

Sustainable use of natural resources

We aim to use natural resources in a sustainable way.

In planning, building and operating our network we will take all practicable steps to minimise harmful effects on the environment.

We will seek partnerships with stakeholders that share similar environmental values.

We will actively facilitate the connection of renewable energy sources to our electricity distribution network.

Reduction and disposal of waste

We aim to minimise waste, especially hazardous waste, and wherever practicable recycle materials in our operations.

We will dispose of our waste through safe and responsible methods.

We will seek to purchase long-life network assets and assets that can be re-used within our community.

Wise use of energy

We will take all practicable steps to use environmentally safe and sustainable energy sources to meet our needs.

We will invest in improved energy efficiency and conservation in our operations.

In planning, building and operating our electricity distribution network we will use good industry practice to minimise network losses.

We will actively work with stakeholders to improve the energy efficiency of our community.

We recognise the importance of warm and dry homes to improve health and social outcomes in our community.

Risk reduction

We will seek to understand the risks to the environment that our operations pose and, based on those risks, prioritise our efforts to eliminate or minimise potential environmental hazards caused by our operations.

We will take all practicable steps to employ safe technologies and operating procedures and we will proactively prepare for emergencies.

We aim for continuous improvement in our environmental management performance.

Restoration of the environment

Where we have directly caused harm to the environment through operating other than in accordance with good industry practice we will take all practicable steps to restore the environment to its previous unharmed state.

Disclosure

We will ensure that employees are aware of all known Orion significant environmental risks within their area of work.

We will annually disclose to the public our overall performance against environmental targets and any incidents that cause significant environmental harm.

Commitment of management resources

We will commit financial and management resources to maintain these principles, including training resources to meet these principles.

Review

We will work toward the timely creation of sustainable management procedures that will be reviewed on a regular basis. The results of these audits will be made available to stakeholders.

Targets

We aim to adhere to the principles stated above to guide us toward environmental sustainability and to meet the following targets:

- **Target** – we have signed an undertaking with the Ministry of the Environment to comply with the "Memorandum of Understanding relating to Management of Emissions of Sulphur Hexafluoride (SF_6) to the Atmosphere". Our target of <1% for SF_6 gas lost has been set to reflect this.

  Note: We will not purchase equipment containing SF_6 if a technically and economically acceptable alternative exists.
- **Target** – in respect to oil spills, our target of zero is the only prudent target we could have for this measure. We operate oil containment facilities and have implemented oil spill mitigation procedures and training. Reported 'uncontained' oil spills relate to incidents that fall outside these precautions.

3.7 Legislation

Our aim is to achieve material compliance with all relevant legislation. We obtain ongoing legal advice to keep up-to-date of all our legislative commitments. The legislation that relates to the management of an electricity distribution business is listed as one of our business drivers in section 2.

Target – to comply with all legislation as required by our governing bodies.

Lifecycle asset management

4

4.1 Network description

We own and operate the electricity distribution network in central Canterbury – one of New Zealand's largest electricity distribution networks. Our network is both rural and urban, with consumer densities ranging from six consumers per km in rural areas to 30 consumers per km in urban areas. Approximately 88% of our consumers are located in the urban area of Christchurch with the remaining 12% in the rural area. We have some 365 major business consumers with loads between 0.3 MW and 5MW.

Urban

Our urban network consists of both a 66kV and a 33kV subtransmission system. Our urban 66kV system supplies 15 district/zone substations in and around Christchurch city and is supplied from Transpower's GXPs at Papanui, Addington, Bromley, Islington and Middleton. Our urban 33kV system supplies another five district/zone substations in and around the western part of Christchurch city and is supplied from Transpower's GXP at Islington. Both systems consist of overhead line and cable in the quantities shown in the table. A further nine district/zone substations in the urban area take supply from Transpower at 11kV and one (Ilam) that is supplied from two dedicated 66/11kV transformers at our Hawthornden district/zone substation.

The urban district/zone substations supply a network of 'primary' 11kV cables connected to 270 network substations. These network substations in turn supply some 3,600 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

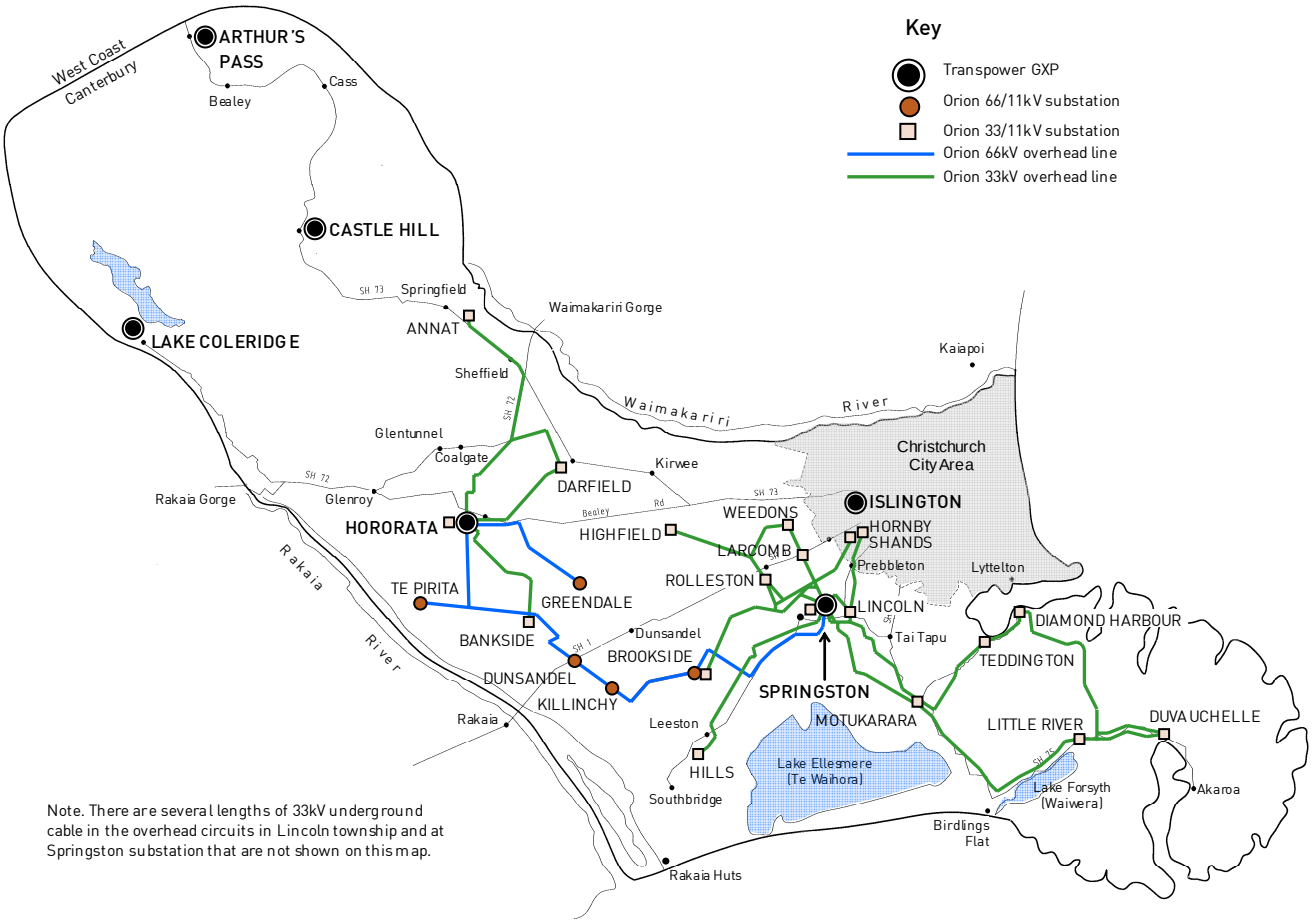
Our rural network also consists of both a 66kV and a 33kV subtransmission system that supplies 20 district/zone substations from the Hororata and Springston GXPs. The rural subtransmission system is primarily overhead and our 11kV network consists mainly of overhead radial feeders from the district/zone substations.

In general we consider that our knowledge of our assets to be good. Data for each asset group is noted under the specific asset later in this section.

Orion's electricity network summary (as at 31 March 2008)

Category	Description	Quantity
Total network	Lines and cables	14,404 km
	Zone/district substations	50
	Distribution substations	10,375
Overhead lines	66kV	144 km (950 poles/towers)
	33kV	302 km (5,500 poles)
	11kV	3,263 km (50,000 poles)
	400V	2,117 km (39,000 poles)
	Street lighting	961 km (600 poles)
Underground cables	66kV	64 km
	33kV	27 km
	11kV	2,157 km
	400V	2,470 km
	Street lighting	1,856 km
	Communication	1,043 km
	Total cables	7,617 km
District/zone substations	66/11kV	19
	33/11kV	21
	11kV	10
Distribution substations	Building (network)	271
	Building (distribution)	275
	Ground mounted	3,680
	Pole mounted	6,150
Embedded generation	Greater than1MW	6 Consumer-owned sites

66kV and 33kV subtransmission network – Orion's central Canterbury rural network area



Note. There are several lengths of 33kV underground cable in the overhead circuits in Lincoln township and at Springston substation that are not shown on this map.

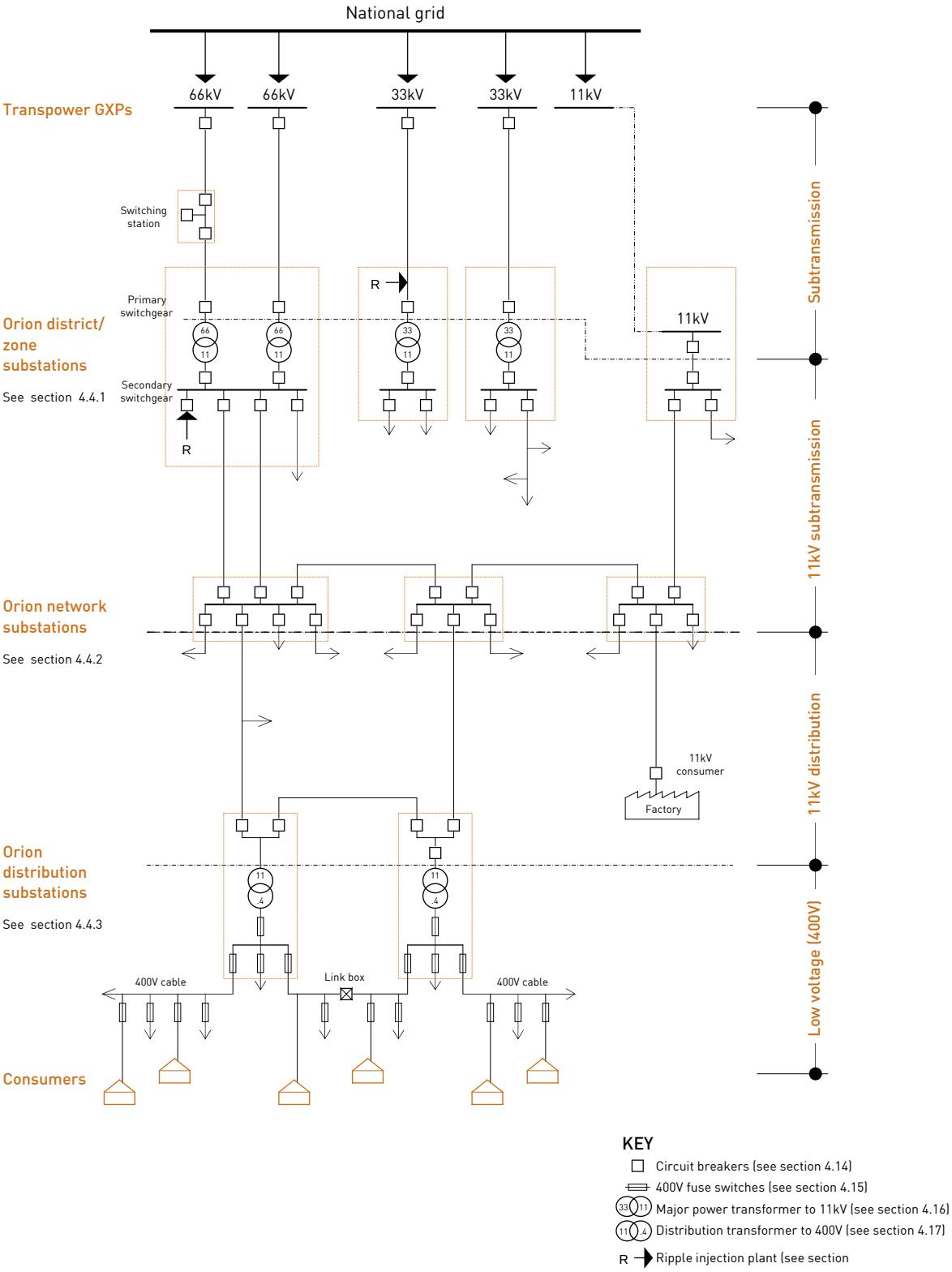
4.1.1 Large consumers

We have approximately 365 major business consumers with loads between 0.3MW and 5MW. The largest single consumer load in this category is less than 1% of our total maximum demand.

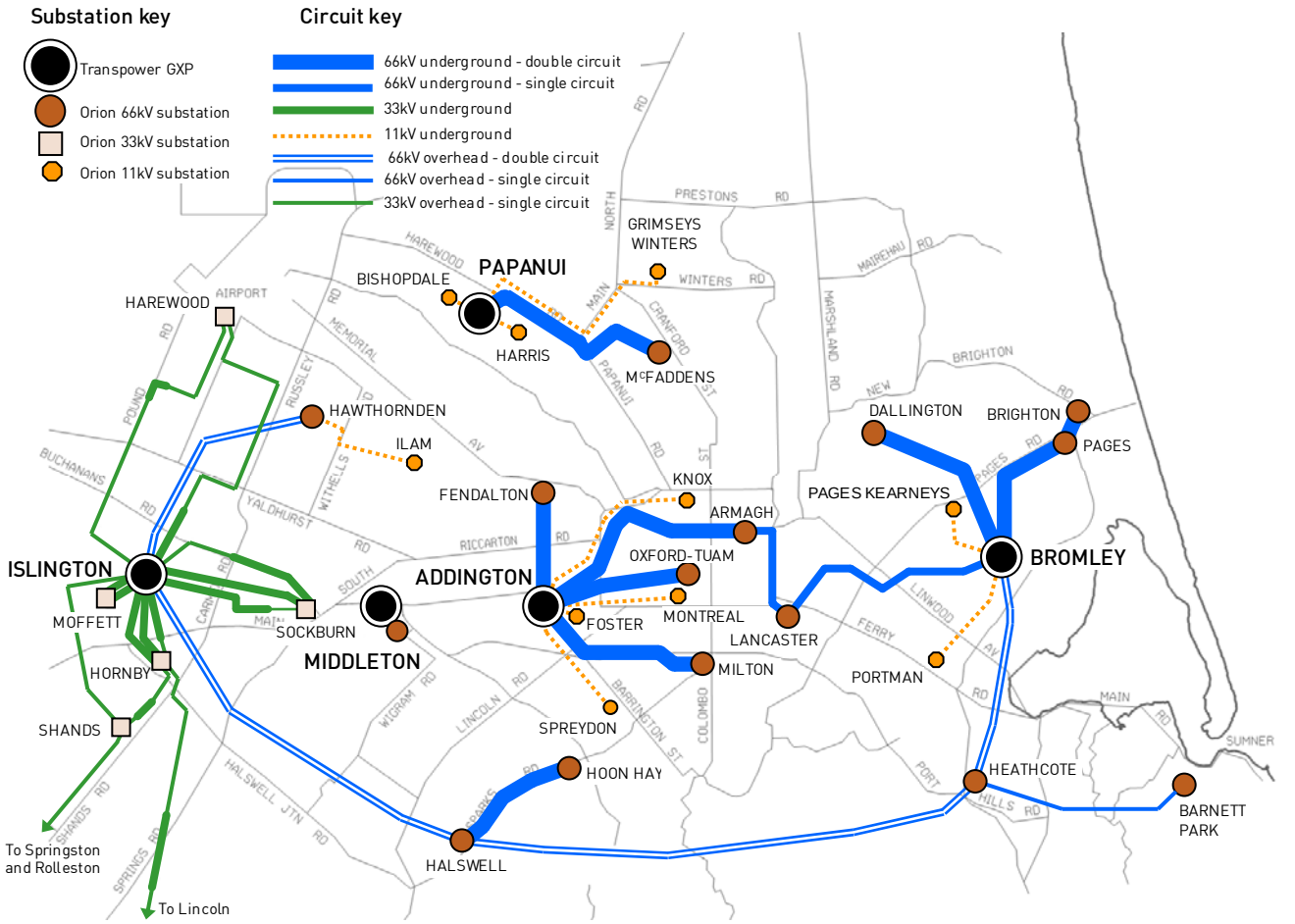
Each of these major consumers is charged on a 'major customer connection' delivery charge basis, and their security and reliability of supply requirements generally fit within our normal target levels of supply. Our operating regimes and asset management practices do not specifically provide enhanced levels of service for these consumers. Their connection asset configurations (transformers and switchgear) can vary slightly, and specific equipment charges apply for those assets.

One exception to the above categorisation is the new 3MW Synlait milk processing plant at Dunsandel. Livened in July 2008, its load is significant in the context of our rural network design, requiring a new 66/11kV district/zone substation at Dunsandel. We have created a new 'large capacity connection' category to accurately reflect the cost of supply to this connection. Stranding risk has been addressed by a connection charge for non-recoverable assets. The ongoing delivery charge has been adjusted to ensure an appropriate return on the assets needed to supply electricity to Synlait.

Network voltage level/asset relationships



66kV, 33kV and 11kV subtransmission network — Christchurch urban area



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 scattered 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. 66/11kV district/zone substations were then built to meet the increased demand. Those substations are the

backbone of the present urban system.

The original 11kV distribution system, supplied by a relatively 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 cross-section cables were provided to supply the distribution transformer substations and convert voltage to 230/400 volts for residential use. 66/11kV transformers were then introduced to allow even greater power density to be serviced, while fault levels could be controlled through suitable choice of transformer impedance.

This evolutionary process has resulted in a network of primary 'closed' rings of 11kV distribution cables which connect network substations to major district/zone substations.

From each network substation, radial 11kV cables provide an interconnected 11kV secondary distribution network which services ground-mounted distribution kiosk substations around the city.

This is a very secure system – most network substations have at least two sources of supply. Each section of the primary network is individually protected using a 'unit protection' system that automatically isolates a faulty section by operating circuit breakers located at both ends.

Network substations are strategically located at load centres, with typically 7MVA maximum loading, and at larger point loads, such as major customer connections. They usually contain four or more 11kV indoor circuit breakers, and may also include a local distribution (400 volt) substation. Therefore, faulty 11kV cables usually only cause interruptions to distribution substations connected to the secondary network, and so are limited to about seven times 300kVA of load, supplying approximately 400 consumer connections.

The interconnected nature of the secondary network means that supply can be switched, allowing us to rapidly restore 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.

Our urban system, although based on 66/11kV district/zone substations, does not have an extensive conventional high voltage subtransmission system, as is found in other New Zealand cities (for example, 110 and 33kV in Auckland and 33kV in Wellington and Dunedin). Instead, relatively short, duplicated 66kV oil-filled feeder cables directly connect to transformers without switching facilities. However, as described above, the primary 11kV network has a high degree of interconnection.

Secondary 11kV network cable sizes were increased during the 1990s. This has reduced the need for new network substations.

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 in the 1950s strained the 11kV systems, so 33kV subtransmission was introduced in the mid 1960s. The 33kV systems were used to convey bulk power to an increasing number of 'district' or 'zone' substations, usually consisting of a single 7.5MVA transformer with 11kV radial feeders interconnected to adjacent substations. Voltage of 33kV was always needed to get power to Duvauchelle in Banks Peninsula, because of the long distance from the grid connection point 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 20MVA firm capacity with two transformers per substation design, 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. A small number of larger 'closed' rings have been introduced in areas of high load concentration to provide improved reliability for major industrial consumers.

In recent years, very high growth in irrigation loads has meant the rural 33kV subtransmission system has approached its design capacity, especially at Hororata and Springston GXPs. We decided the most economical reinforcement method was to build additional 66/11kV district/zone substations equipped with 7.5/10MVA transformers within the existing 11kV distribution network, while retaining 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.

4.3 Format of asset sections

The following sections (4.5 to 4.24) describe Orion's existing assets by category.

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

Note: The definition of a fault as shown in the graphs of faults per 100km for each asset is "any interruption to supply other than that for programmed work". This is usually a mixture of third party and weather interference/damage and plant failures.

Asset condition

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

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). Any drawings held are also listed.

Maintenance plan

The ongoing day to day work plans required to keep the asset serviceable and prevent premature deterioration or failure. Three categories of maintenance are carried out:

- scheduled maintenance – work carried out to a predetermined schedule and allocated budget
- unscheduled maintenance – work that must be performed outside the predetermined schedule, but does not constitute an emergency
- emergency maintenance – work that must be done because a portion of the network requires an immediate repair.

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. Many assets are not maintained and instead are replaced at the end of their service life, while other assets are assessed for the benefits of maintenance versus replacement.

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.

All references to years, for example 2010, are to be taken as the financial year ending that year, for example 31 March 2010.

4.4 Substations

A 'substation' consists of some of the asset groups described in this section, for example switchgear, transformers and buildings, assembled at one site. Our network structure has three identified levels of substations – district/zone, network and distribution. The lifecycle asset management plans for substations are grouped under each asset type and therefore a substation is not described as an asset in its own right.

4.4.1 District/zone substations

A district/zone substations is a major building substation and/or associated switchyard high voltage structure that has been identified as such because of its importance in our network. Orion has 50 district/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 from a Transpower GXP are redistributed or a ripple injection plant is installed. District/zone substations are inspected every two months and given an infra-red scan every two years.

66/11kV district/zone substations

We have 20 district/zone 66/11kV substations. Fifteen of them are in the Christchurch city urban area. Seven of the urban substations have an exposed bus structure. The largest structure is at Heathcote and is a major 66kV switching point. The Armagh structure is unique as it is constructed inside a building. Construction dates for the urban structures are:

- Heathcote 1968
- Halswell 1974
- Barnett Park 1981
- Pages 1989
- Lancaster 2000
- Armagh 2001
- Hawthornden 2004

Most of the urban 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 district/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. More detail about ratings is shown in section 4.8.2. The transformers supply 11kV switchgear housed in two, three or four fire and explosion resistant switchgear rooms. This switchgear may feed up to twenty 11kV cables and can be sectioned using bus-couplers between the switchgear rooms.

The five rural 66/11kV substations at Killinchy, Te Pirita, Greendale, Brookside and Dunsandel are supplied by overhead lines and have 7.5/10MVA transformers. All have outdoor structures. The indoor 11kV switchgear feeds up to five 11kV feeder cables. Brookside substation also has a 33/11kV transformer bank with 11kV busbars coupled via a circuit breaker.

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

33/11kV district/zone substations

Orion has 20 33/11kV substations, mainly in the rural area and on the western fringe of the city. All have some form of outdoor structure and bus-work. 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 independent dual rated transformers. These have separate supplies, with each transformer and supply rated to carry the full substation load. The 11kV switchgear feeds up to eleven 11kV cables and is housed in two 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 district/zone substations (largely in rural areas) rely on back-up capacity from adjacent single transformer substations to provide firm capacity.

11kV district/zone substations

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

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

Weedons 33/11kV rural district/zone substation.

District/zone substation schedule

District/zone substation	Circuit breakers in service			Transformers in service		
	66kV	33kV	11kV	66kV	33kV	Rating (MVA)*
Annat		1	4		1	2.5
Armagh	5		33	2		20/40
Bankside		1	5		1	7.5/10
Barnett Park			12	1		11.5/23
Bishopdale			18	2		20/40
Brighton			21			
Brookside	1	1	10	1	1	7.5/10 and 7.5
Dallington			25	2		20/40
Darfield		1	6		1	7.5
Diamond Harbour		3	4		1	7.5
Dunsandel	4		9	2		7.5/10
Duvauchelle		5	9		2	7.5
Fendalton			20	2		20/40
Foster			20			
Grimseys Winters			18			
Greendale	1		6	1		7.5/10
Halswell	8		11	2		11.5/23
Harewood		2	9		2	7.5
Harris			18			
Hawthornden			28	4		20/40 x2 and 11.5/23 x2
Heathcote	7		29	2		20/40
Highfield	1		6		1	7.5
Hills Road		1	5		1	7.5
Hoon Hay			25	2		20/40
Hornby		10	11		2	10/20
Hororata		2	4		1	7.5
Ilam			13			
Knox			21			
Killinchy	2		6	1		7.5/10
Lancaster	3		24	2		20/40
Lincoln		2	8		2	7.5
Little River		3	3		1	2.5
McFaddens			24	2		20/40
Middleton	2		19	2		11.5/23
Milton			28	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	1					
Pages Kearneys			16			
Papanui	1					
Portman			18			
Rolleston		2	9		2	7.5
Shands Road		4	11		2	11.5/23
Sockburn		3	17		2	10/20
Spreydon			18			
Springston		4	6		1	7.5
Te Pirita	1		6	1		7.5/10
Teddington		1	3		1	2.5
Weedons		1	5		1	7.5
Total in service	**37**	**56**	**683**	**35**	**30**	

- * Dual rated transformers have been installed with a design nominal rating/emergency rating.
- This table only shows equipment in service.

4.4.2 Network substations

Orion has 271 network substations 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. They may also contain secondary 11kV switchgear, a distribution transformer(s) and an 800A or 1500A 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 district/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 district/zone substation, and it is more economical to do so, secondary cables may be laid from the district/zone substation to reinforce overloaded cables. This avoids the need for additional network substations.

A network substation design from the late 1930s.

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.

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 district/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.

Typical 'outdoor' distribution substation consisting of an outdoor style transformer and a half-kiosk.

The types of substation that make up the total 10,400 substations in this asset category are shown in the following table.

Distribution substations		
Type	**No.**	**Description**
Building	275	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 all insulated unit (AIU) 250MVA 11kV switchgear and a 400V distribution panel containing fuse assemblies using high rupturing current (HRC) links.
Kiosk	2,635	Full kiosks vary in size and construction but all usually contain a transformer, up to 500kVA, with AIU (all insulated unit) 250MVA 11kV switchgear and a 400V distribution panel containing fuse assemblies using HRC (high rupturing current) links.
Outdoor	505	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 1000kVA.
Pole	6,150	These are mainly single pole substations, usually with 11kV fusing and a transformer up to 200kVA maximum. Those substations on a 2-pole structure (approx 60) may have a transformer of up to 300kVA installed.
Pad transformer	535	These are transformer only, mounted on a concrete pad and supplied by high voltage cable from switchgear/fuse at another site. Transformers are uncovered except for approximately 34 that are enclosed in a polythene or fibreglass cover.

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. Urban areas have good bonding between earths, so we concentrate earthing maintenance on our rural network. Earthing in these rural areas is subject to deterioration because of highly resistive soils, stony sub-layers of earth and corroded earthing systems. Between 1,200 and 1,500 sites are tested in any year and those sites requiring repairs are scheduled for remedial work in the following year.

Greendale is a typical example of a 66kV rural district/zone substation (commissioned 2005).

4.5 Overhead lines – subtransmission 66kV (ODRC $6.5M)

4.5.1 Asset description

Christchurch urban area

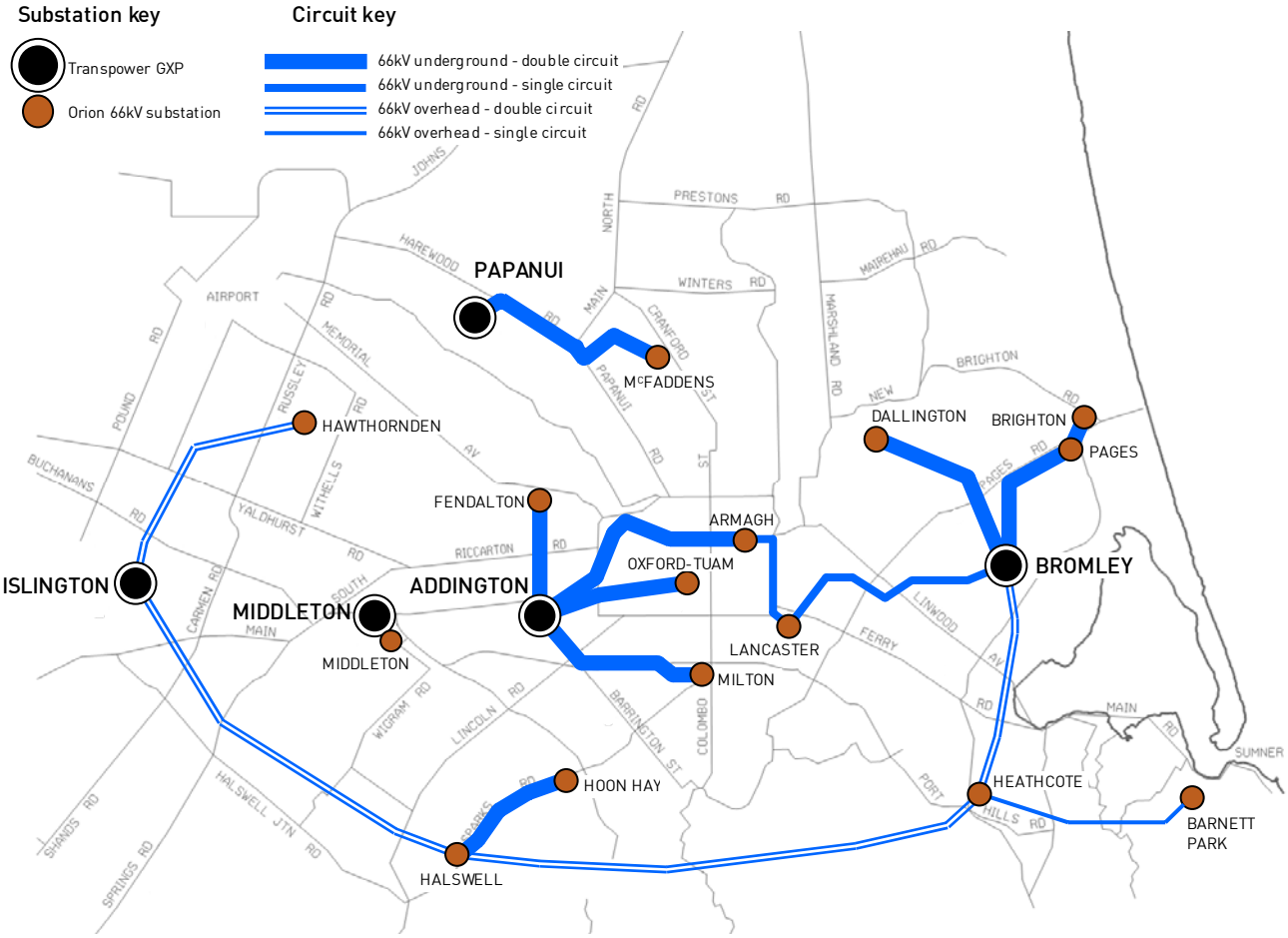
Our 66kV subtransmission overhead system in the Christchurch urban area consists of 59km circuit length of mainly double circuit tower line. The towers used to be owned by the NZED. It consists of the following sections:

- Islington to Hawthornden 31 towers
- Islington to Halswell 35 towers and six poles
- Halswell to Heathcote 34 towers
- Heathcote to Bromley 22 towers
- Heathcote to Barnett Park 19 towers

These lines provide important security to the Christchurch city subtransmission network by providing limited alternative connection between Transpower's Islington GXP and Bromley GXP.

Three towers (33,34,35) on the Islington-Halswell line were replaced with concrete poles in 2007 as the result of a subdivision.

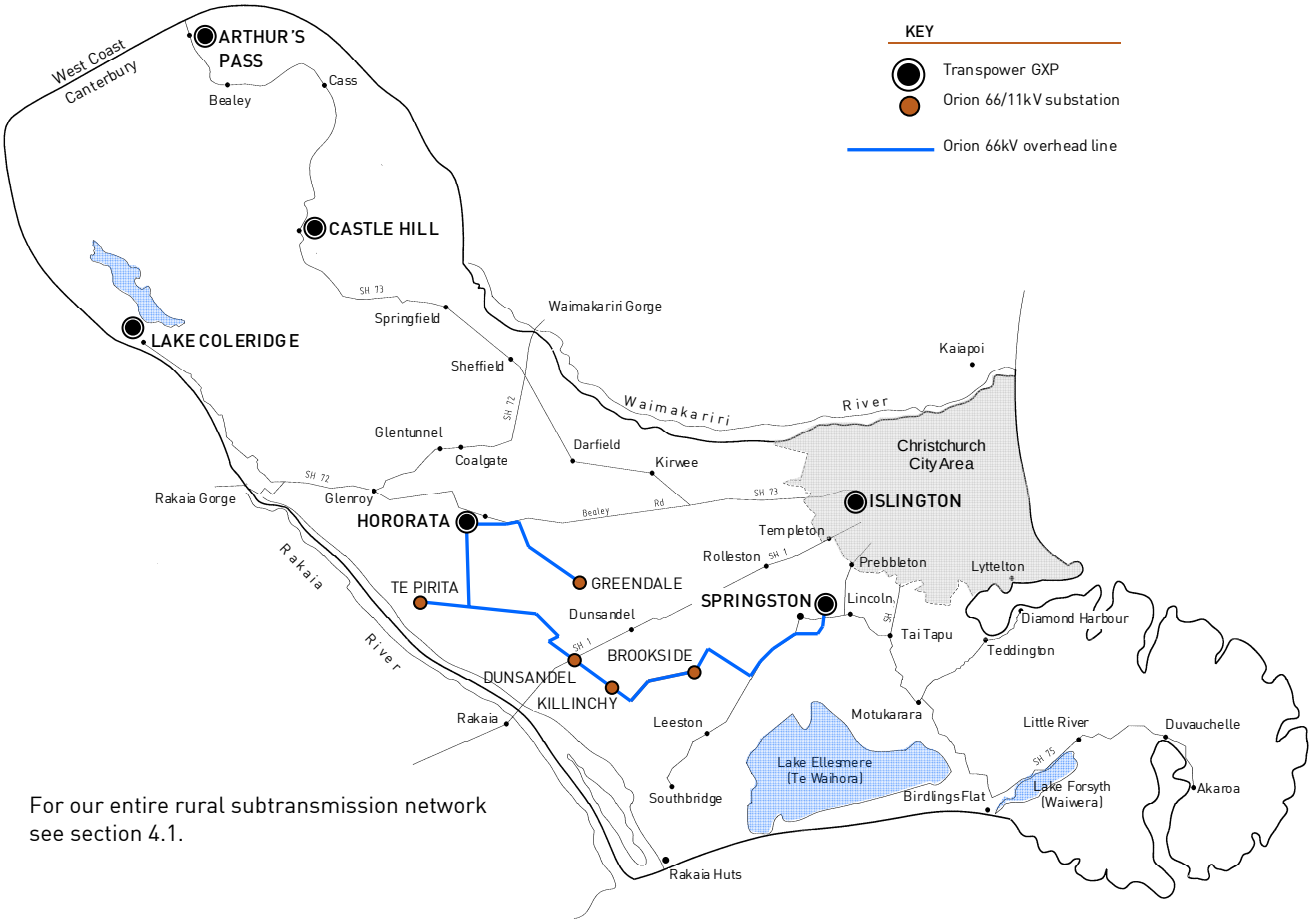
Subtransmission 66kV network – Christchurch urban area



Rural central Canterbury area

The 66kV subtransmission overhead system in the rural area consists of 85km of single circuit overhead pole lines. The lines run from Transpower's Hororata GXP to our 66/11kV substations at Te Pirita, Dunsandel, Killinchy, Greendale and Brookside. The section through to Transpower's Springston GXP was completed in 2008.

Subtransmission 66kV – central Canterbury rural area overhead lines



For our entire rural subtransmission network see section 4.1.

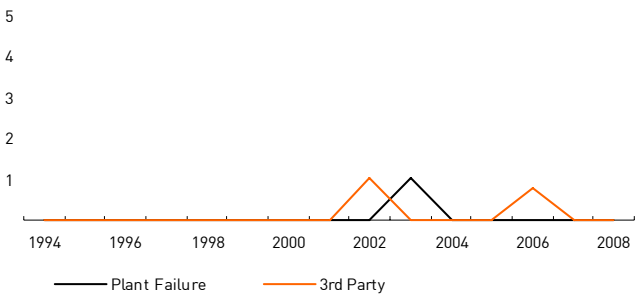
4.5.2 Asset capacity/performance

The conductor used for the urban circuits is 'Wolf'.

The dual circuit Islington to Bromley is rated at 525A per circuit @75^{0}C. The Islington-Hawthornden and Heathcote-Barnett Park circuits are rated at 400A @60^{0}C.

The conductor for the rural circuits is 'Dog'. The single circuit is rated at 300A @70^{0}C.

Overhead lines 66kV – faults/100km



4.5.3 Asset condition

The overall condition of the steel towers is good. Assessments of tower corrosion have been completed and a prioritised programme of tower painting has been implemented. Towers will now be inspected and painted as required. Tower signs and anti-climbing barriers were upgraded in 2006 to provide better security.

The tower line Wolf conductors have been analysed and determined to have a remaining service life of 10-15 years.

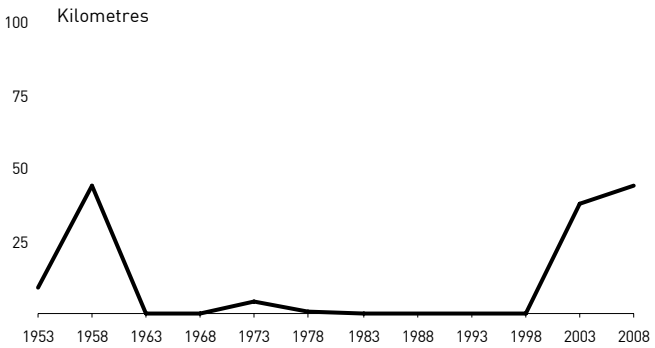
New Y ball clevises were installed, and disc insulators replaced, on the Islington to Heathcote line between 1990 and 1993.

Vibration dampers were installed to all sections of tower line between 1998 and 2000. These changes have improved security and reduced the risk of line failure from excessive vibration. Vibration recorders have been installed on the rural lines to determine vibration levels. Where this is found to be at an unacceptable level, vibration dampers will be installed to eliminate ongoing issues.

The earth wire on the Heathcote-Barnett Park line and a small section at Islington were replaced in 1998.

Of the 141 tower foundations, 47 have concrete footings and 94 are 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 89 of the grillage foundations completed. The remaining five sites have access issues and should be completed by 2010.

Overhead lines 66kV – age profile



4.5.4 Standards and asset data

Standards and specifications

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
- NW72.21.09 – Visual inspection of high voltage lines
- NW72.21.10 – Thermographic survey of high voltage lines
- NW72.21.18 – Standard construction drawing set – Overhead lines
- NW72.21.19 – Tower foundation inspection
- NW72.24.01 – Tree cutting adjacent to 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
- tower/pole age and type
- 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:

- annual 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.

The maintenance work planned is as follows:

- suspension hardware assemblies will be assessed for corrosion damage
- tower foundation refurbishment continues to 2010.

The budgeted maintenance costs are shown in section 3.4 – Service level targets – Works.

4.5.6 Replacement plan

There are no plans for any major replacement of conductor within the next 10 years.

Plans are underway to replace two spans of circuit (three towers) with a 66kV underground cable. This is the result of a subdivision. The budgeted costs have been included in the underground conversion costs detailed in section 3.4 – Service level targets – Works.

4.5.7 Creation/acquisition plan

For a list of projects containing this asset see section 5 – Network development.

4.5.8 Disposal plan

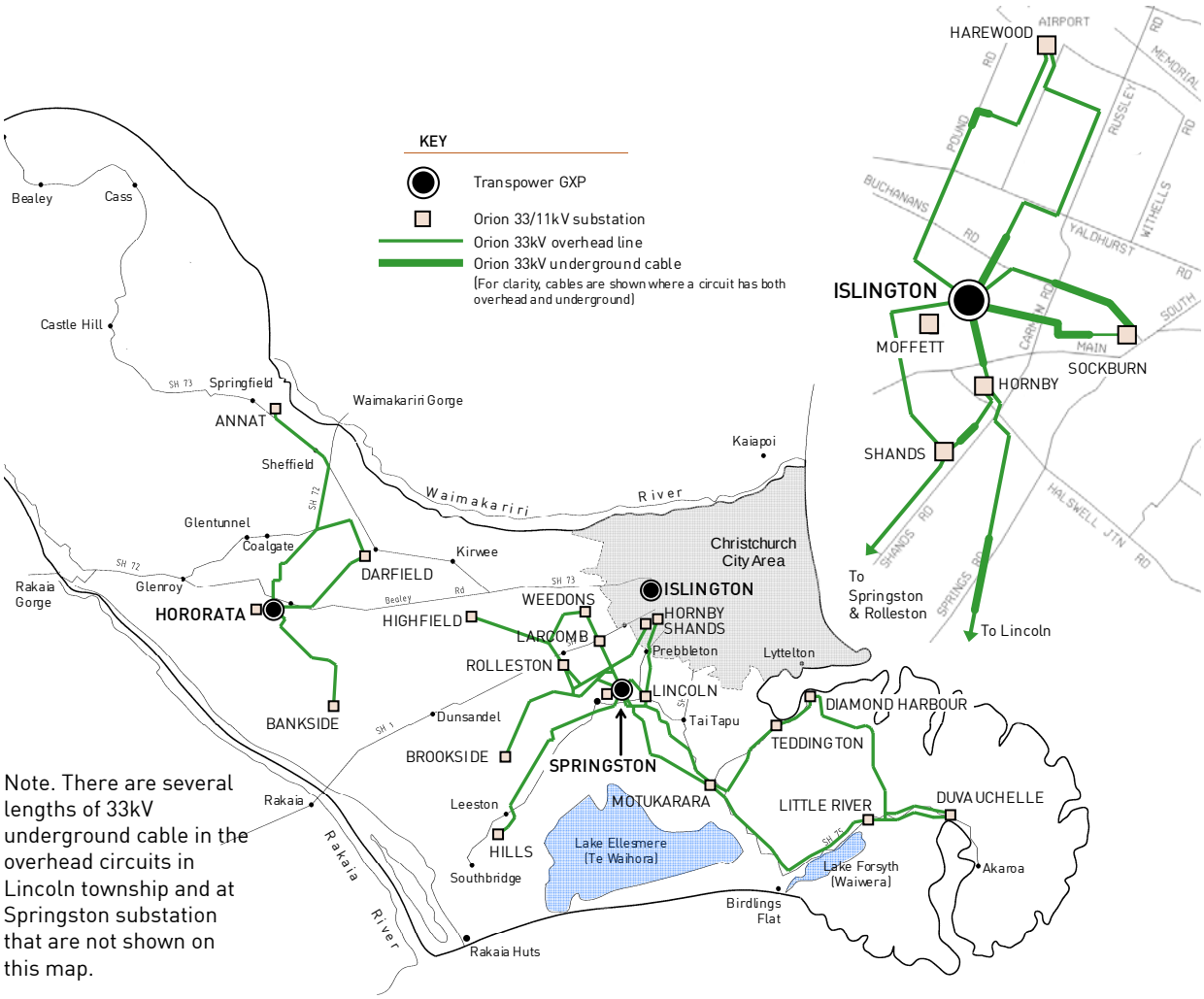
We have no plans to dispose of any of the 66kV overhead line asset.

4.6 Overhead lines – subtransmission 33kV (ODRC $7.9M)

4.6.1 Asset description

The 33kV subtransmission overhead system consists of 302km circuit length of lines that take supply from Transpower's Islington, Springston and Hororata substations and 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.

Subtransmission 33kV network



Note. There are several lengths of 33kV underground cable in the overhead circuits in Lincoln township and at Springston substation that are not shown on this map.

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.)

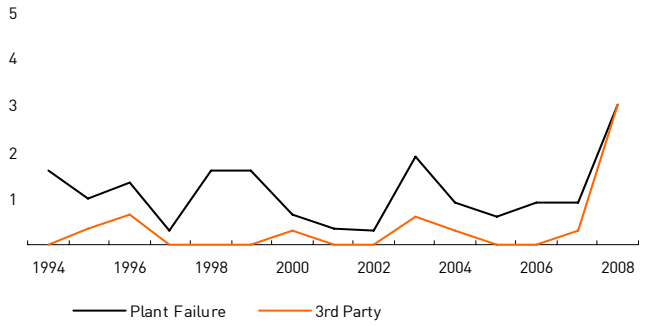
Standard 33kV conductors

Conductor (Aluminium)	Rating (Amps)	Conductor (Copper)	Rating (Amps)
Jaguar ACSR	412	19/0.083 HD	265
Dog ACSR	277		
Sparrow ACSR	140		

All 33/11kV district/zone substations have an alternative 33kV supply, except Hills Road, Bankside, Highfield and Annat.

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.

Overhead lines 33kV – faults/100km



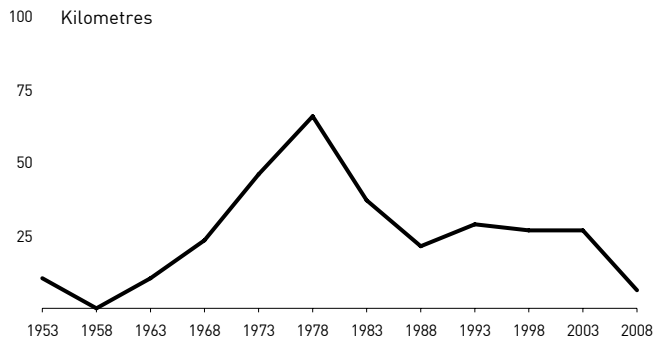
4.6.3 Asset condition

The 33kV lines are in good condition. A 10 year programme to replace the Motukarara-Little River-Duvauchelle line (started in 1995) was completed in 2004.

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. Indications suggest these insulators will need to be replaced by 2010.

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

Overhead lines 33kV – age profile



4.6.4 Standards and asset data

Standards and specifications

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
- NW72.21.09 – Visual inspection of high voltage lines
- NW72.21.10 – Thermographic survey of high voltage lines
- NW72.24.01 – Tree cutting adjacent to 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
- pole age and type
- 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.

The budgeted maintenance costs are shown in section 3.4 – Service level targets – Works.

4.6.6 Replacement plan

Due to reliability issues we plan to replace older concrete (non-type tested) and hardwood poles, along with green glass insulators, on the 33kV lines by 2010.

The budgeted replacement costs are shown in section 3.4 – Service level targets – Works.

4.6.7 Creation/acquisition plan

For planned projects containing this asset see section 5 – Network development.

4.6.8 Disposal plan

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

4.7 Overhead lines – distribution 11kV (ODRC $51.7M)

4.7.1 Asset description

Our 11kV distribution overhead system is 3,265km of circuit length of lines in the rural area of central Canterbury, Banks Peninsula and outer areas of Christchurch city. Supply is taken from district/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 carry 33kV subtransmission and 400V lines. The 11kV system includes 11kV lines on private property that serve individual consumers.

Five separate systems of single wire earth return (SWER) lines on Banks Peninsula total 86km circuit length. These lines supply power to remote areas, and at times are exposed to severe weather conditions.

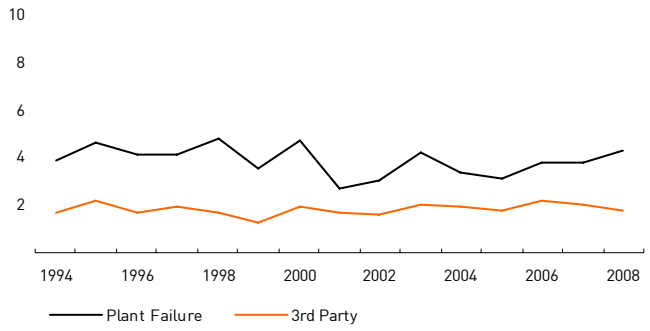
Our 11kV lines are supplied from the district/zone substations shown on the overhead lines – 33kV subtransmission network map in the previous section. Supply is also taken directly at 11kV from the GXPs at Coleridge, Castle Hill and Arthur's Pass.

4.7.2 Asset capacity/performance

The standard 11kV conductors are itemised in the table below. Ratings are based on 20^{0}C ambient and 30^{0}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 Flounder conductor reduces breakages in lines exposed to snow and high winds.

Overhead lines 11kV – faults/100km



Standard 11kV conductors

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

Bolted-clamp line connection failures have caused us to introduce the 'Ampact' wedge connection system. All high voltage connections since 1995 have been made with the wedge connectors. High voltage line connections in the Hornby area where fault currents are high were replaced with Ampact wedges in 1996.

In 1991 we decided to change to treated softwood poles to reduce the expenditure on old line replacement. These softwood poles proved very reliable in the August 1992 snow storm – nearly all broken poles were concrete.

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.

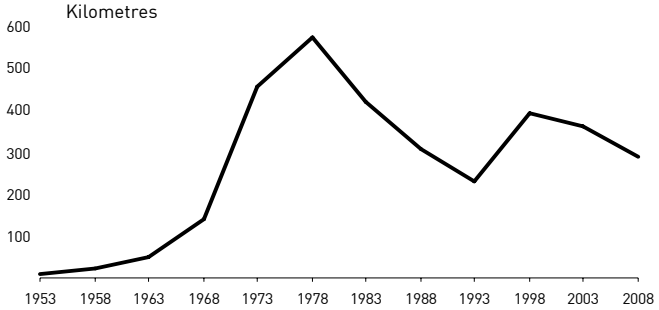
The 2003 tree regulations introduced a notice regime that defines responsibilities for problem trees. This has brought significant extra costs for us to meet, but gradual improvement in reliability statistics is expected.

The June 2006 snow storm (assessed as between a one-in-20 and one-in-50 year storm) cut power to approximately 15,000 consumers. All affected consumers had power reinstated within six days. As a result of the storm we independently reviewed our design standards. This led to some relatively minor changes. Changes include the programming of retrospective strengthening of some existing lines, additional snow loading criteria, and updating of design standards to the latest revision of codes and standards.

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. 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.

Overhead lines 11kV – age profile



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 aluminium.

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.

4.7.4 Standards and asset data

Standards and specifications

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
- NW72.21.09 – Visual inspection of high voltage lines
- NW72.21.10 – Thermographic survey of high voltage lines
- NW72.21.18 – Standard construction drawing set – overhead
- NW72.24.01 – Tree cutting adjacent to 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 and type
- 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
- a thermal imaging scan (selected areas as required)
- an inspection of poles within the Christchurch urban area, street-by-street
- an inspection of poles in the rural area, by survey district block.

Maintenance work planned is as follows:

- to cut trees (in conjunction with 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.

The budgeted maintenance costs are shown in section 3.4 – Service level targets – Works.

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 1,200 and 1,500 sites are tested in any one year and those sites 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.

The budgeted replacement costs are shown in section 3.4 – Service level targets – Works.

4.7.7 Creation/acquisition plan

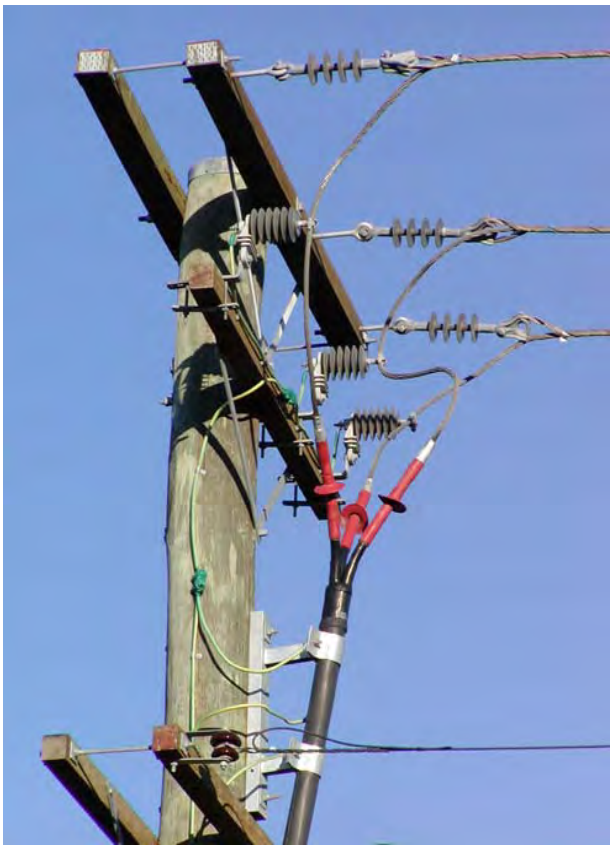
We now only create 11kV lines in our rural area as they are prohibited in urban areas by city/district plan requirements.

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

- reinforcement plans (refer to section 5 – Network development)
- 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.



11kV cable termination to an overhead line

4.8 Overhead lines – distribution 400V (ODRC $37.9M)

4.8.1 Asset description

Our 400V distribution overhead system is 3,078km circuit length of lines, mainly within the Christchurch urban area. This length includes 961km 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 400V between phases and 230V to earth. The network can be interconnected in the city 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.

Recent tree regulations introduce a notice regime that defines responsibilities for problem trees. This will result in significant extra costs for us to maintain trees.

Standard 400V conductors			
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.

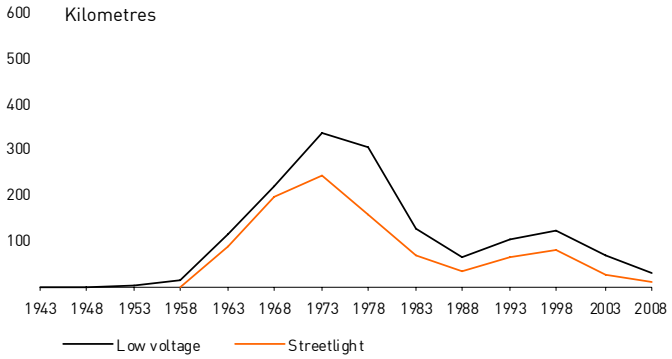
During 2001 and 2002 a telecommunications company installed a communications network in a large portion of the Christchurch urban area. This required a major pole inspection and assessment programme to determine if existing poles were capable of supporting a communication network. As a result of this analysis, we replaced approximately 4,300 poles. The foundation of a considerable number of other poles was also upgraded over the two year period. In conjunction with the assessment programme, all poles, including deeded poles from Telecom, streetlight poles with overhead reticulation and back-section service poles were inspected and assessed. A large number of the back-section poles were found to be nearing the end of their life expectancy.

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 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 lines is shown in the following graph.

Overhead lines 400V – age profile



4.8.4 Standards and asset data

Standards and specifications

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
- NW72.21.09 – Visual inspection of high voltage lines
- NW72.21.18 – Standard construction drawing set – overhead
- NW72.24.01 – Tree cutting adjacent to 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 and type
- 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.

Through to 2009 we are focusing 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.

The budgeted maintenance costs are shown in section 3.4 – Service level targets – Works.

4.8.6 Replacement plan

The condition of our overhead lines is generally good. Renewal of these lines will mainly consist of pole replacement up to 2010. Overhead lines in rural towns have now been surveyed and the bulk of renewal work is expected to occur between 2010 and 2015.

An increased number of back section service poles will be replaced through to 2011.

The budgeted replacement costs are shown in section 3.4 – Service level targets – Works.

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 in response to consumer connection requirements only.

4.8.8 Disposal plan

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

4.9 Underground cable – subtransmission 66kV (ODRC $33M)

4.9.1 Asset description

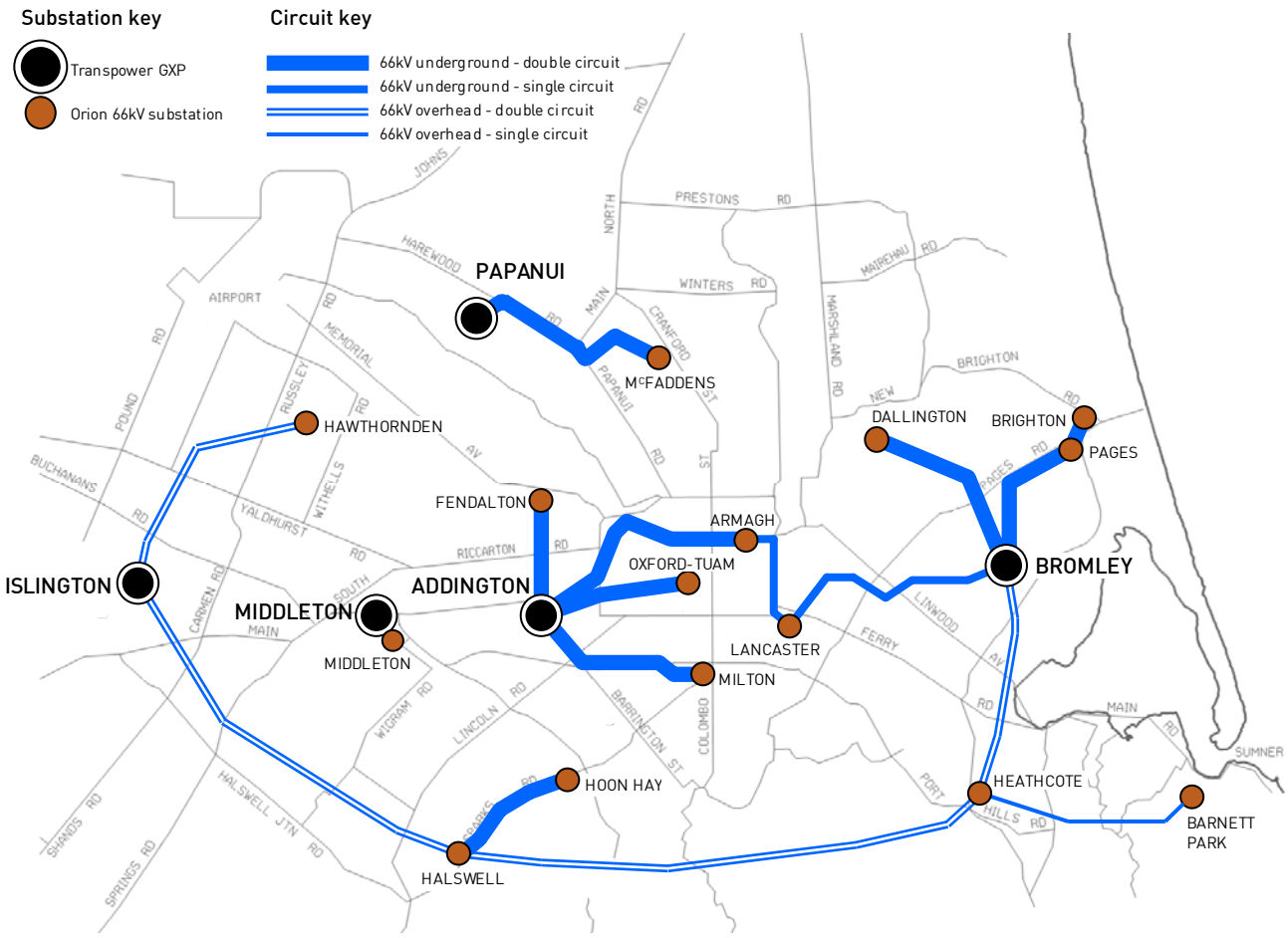
Traditionally, pairs of radial 66kV 3-core aluminum, oil filled, aluminum sheathed cables were installed to supply most of our 66/11kV district/zone substations. Recently, a 3x1core copper, XLPE cable was installed from the Bromley GXP to Lancaster and Armagh district/zone substations. This cable provides additional system security to the Christchurch CBD.

There is 58km of circuit length of aluminum cable in our network. Each cable has an emergency rating equivalent to the full load of the district/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 district/zone substation the two cables have been laid in a common trench spaced 300mm apart at a minimum depth of 750mm.

The recently installed 1,600mm^2 3x1core copper XLPE cable has a continuous rating of 160MVA. This rating allows for the contingency of a loss of supply at the Addington GXP, and enables the Christchurch CBD and surrounding areas to be supplied from the Bromley GXP. The single core cables have been installed in a weak mix of thermally stabilised concrete and capped with a 50mm layer of stronger concrete that has been 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 district/zone substations to link primary equipment. These cables are shown in the circuit listing, along with the main cables.

Subtransmission 66kV – Christchurch urban area



4.9.2 Asset capacity/performance

The 66kV underground cables are predominantly 300mm^{2}Al (paper insulated, oil filled and aluminum sheathed) with a nominal rating of 425A or 48.5MVA @85^{0}C. The recently installed cable, Bromley-Lancaster-Armagh, is a 1,600mm^2 Cu XLPE lead sheathed cable with a design rating of 1400A or 160MVA @90°C.

Failure modes have predominately 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.

The cable routes have been assessed to ascertain the vulnerability of the cables to a seismic event. As a result of this assessment the Armagh Street bridges and the Dallington footbridge have been reinforced.

The Dallington to Bromley 66kV cable has been identified as being subject to lateral movement during an earthquake in the area of the south side of the Avon River. The impact of the loss of this cable has been mitigated by the cable from Bromley via Lancaster to Armagh substations.

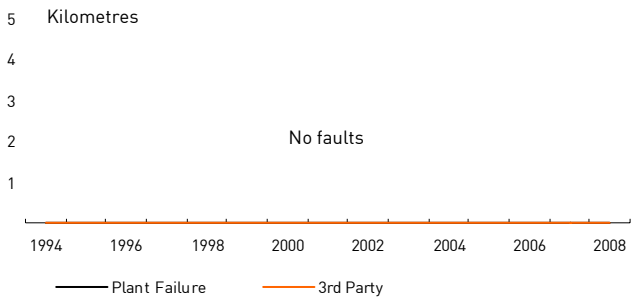
66kV cable circuit and underground joint listing

Cable circuit	Install year	Cable type/ manufacturer	Size	Rating (A)** summer/ winter	Length (m)	Original oil filled cable underground joints	New underground reinforced joints
Addington 66-Armagh No.1	1981	3c Oil (Pirelli)	300 Al	343/370	4280	0	12
Addington 126-Armagh No.2	1981	3c Oil (Pirelli)	300 Al	343/370	4416	0	13
Addington 66-Fendalton T1	1978	3c Oil (Hitachi)	300 Al	345/393	2464	0	9
Addington 176A-Fendalton T2	1978	3c Oil (Hitachi)	300 Al	345/393	2345	0	10
Addington 46-Milton T1	1979	3c Oil (Hitachi)	300 Al	330/384	3990	7	5
Addington 176B-Milton T2	1979	3c Oil (Hitachi)	300 Al	330/384	4089	6	6
Addington-Oxford Tuam T1	1975	3c Oil (Dianichi)	0.45 Al	330/350	2661	8	-
Addington-Oxford Tuam T2	1975	3c Oil (Dianichi)	0.45 Al	330/350	2562	8	-
Bromley 146-Pages (T1)	1975	3c Oil (Pirelli)	0.45 Al	335/383	1943		
	1986	3c Oil (Pirelli)	300 Al	335/383	896	0	6
Bromley 186-Pages (T2)	1975	3c Oil (Pirelli)	0.45 Al	335/383	1935		
	1986	3c Oil (Pirelli)	300 Al	335/383	862	0	6
Pages-Brighton T1	1976	3c Oil (Dianichi)	0.45 Al	335/383	407	1	-
Pages-Brighton T2	1976	3c Oil (Dianichi)	0.45 Al	335/383	386	1	-
Bromley 96-Dallington T1	1967	3c Oil (AEI)	0.45 Al	302/363	4172	1	13
Bromley 126-Dallington T2	1967	3c Oil (AEI)	0.45 Al	302/363	4126	1	11
Bromley-Lancaster	2000	3x1c XLPE (Olex)	1600 Cu	1400/1400	4884	N/a	N/a
Bromley-Portman (11kV)	1984	3c Oil (BICC)	300 Al	330/350*	2918	8	-
Halswell 196-Hoon Hay T1	1969	3c Oil (AEI)	0.45 Al	289/356	2644	0	5
Halswell 136-Hoon Hay T2	1969	3c Oil (AEI)	0.45 Al	289/356	2647	0	5
Papanui 136-McFaddens T1	1972	3c Oil (Dianichi)	0.45 Al	348/396	4163	10	-
Papanui 206-McFaddens T2	1972	3c Oil (Dianichi)	0.45 Al	348/396	4091	10	-
Barnett Park	1987	3 core Oil	300 Al	330/350*	120	N/a	N/a
Lancaster-Armagh	2002	3x1c XLPE (Olex)	1600 Cu	1400/1400	2363	N/a	N/a
Armagh (T1/T2)	2001	3x1c XLPE (Olex)	300 Cu		75	N/a	N/a

* Nominal rating - investigation to determine full rating to be completed.

** 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).

Underground cables 66kV – faults/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 have not been subject to electrical aging mechanisms. We have monitored the cables to ensure the integrity of the mechanical protection of the cables is maintained.

Inspections of the original 66kV British designed and Japanese Hitachi oil filled cable joints have indicated excessive movement of conductors within the joints.

We have also inspected samples of the Japanese-designed Dianichi oil filled cable joints. The Dianichi joints have so far shown no signs of damage or buckling. However because this movement within the joints has led to premature joint failure in other networks, we have commenced a programme to replace identified joints. This programme is scheduled for completion in 2014, but this timing will depend on the final outcome of the Dianichi joint assessment.

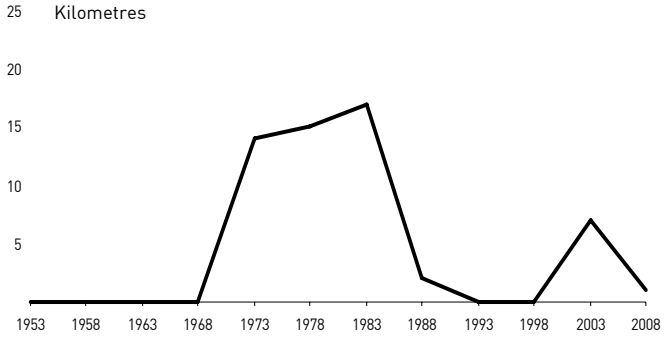
The reinforcement of joints on 66kV circuits to Brighton, Hoon Hay, Armagh and Fendalton District/zone substations have now been completed.

In the interim alarms will warn of low oil pressure and levels via the SCADA system and we will install pressure transducers at the cable ends. Cables with identified joint problems have been de-rated up to 25% as a further risk mitigation.

Summary of 66kV cable joints (includes straight-through and splitter types)

Make	Origin	Original number installed	Condition	Current status
Pirelli	UK	36	Weakest design. Signs of buckling observed at many joints.	Highest priority for replacement. All now replaced with a new reinforced design.
AEI	UK	34	Considered a weak design. Minor signs of buckling observed on a few.	12 joints already replaced. Balance to be replaced by March 2008.
BICC	UK	08	Considered a weak design. None inspected yet.	Only used on the Bromley–Portman single cable which is operated at 11kV and is backed up by four other 11kV cables. Low priority for replacement. Post 2011.
Hitachi	Japan	39	Less potential to buckle, but problems with glove design. Some damage to cores observed.	Highest priority for replacement after AEI joints . Programmed to be done by 2010.
Dianichi	Japan	36	Strong design not likely to buckle. Good condition.	Currently being assessed for overall strength and resistance to buckling by a UK based consultant. Lowest priority for replacement. Maybe able to leave in service.

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.

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 of cable routes
- route profile drawings.

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 in the following year
- alarms fitted to give early warning of low oil pressure and levels 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 around 66kV cables in areas where tests indicate that the cable's rating is compromised
- continue inspecting joints for signs of thermal-mechanical damage.

The budgeted maintenance costs are shown in section 3.4 – Service level targets – Works.

4.9.6 Replacement plan

A 10-year programme to replace joints in oil filled cables is to be completed by 2014.
See 4.9.3 and 6.7.1 for more detail.

The budgeted replacement costs are shown in section 3.4 – Service level targets – Works.

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 containing this asset see section 5 – Network development.

4.9.8 Disposal plan

We have no plans to dispose of any of this asset group.

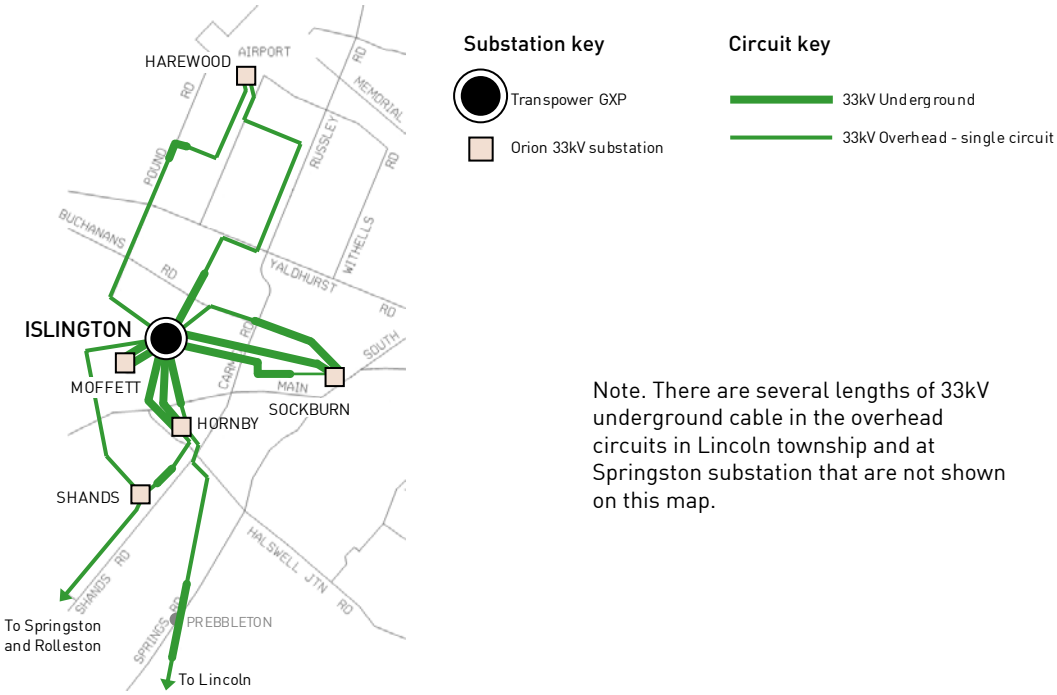
4.10 Underground cable – subtransmission 33kV (ODRC $5.6M)

4.10.1 Asset description

Our subtransmission 33kV cable asset is 27km 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 and Prebbleton, and is made up approximately as follows:

- Oil filled 4km installed 1967-1977
- PILCA 5km installed 1978-1988
- XLPE 19km installed 1992-2007

Subtransmission 33kV – Christchurch urban area



Note. There are several lengths of 33kV underground cable in the overhead circuits in Lincoln township and at Springston substation that are not shown on this map.

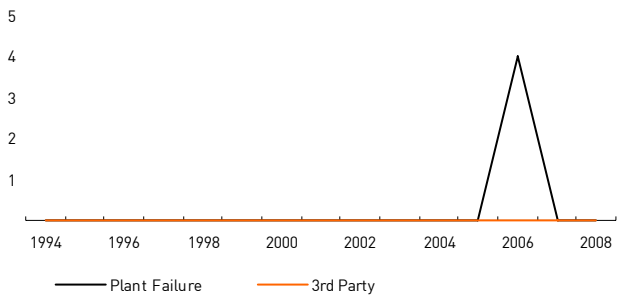
4.10.2 Asset capacity/performance

The cable sizes are as shown in the circuit listing (on the following page) and are oil filled or solid insulation with a nominal rating of 425A or 24MVA.

There is no real history of cable failure other than two outdoor termination failures in 1995 and 2006 and some incorrectly installed XLPE joints that have now been replaced. 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.

Underground cables 33kV – faults/100km



33kV cable circuit listing

Cable circuit	Length (m)	Type	Size	Winter rating (A)
Islington 2102-Harewood 234.	220	XLPE	300 Al	475*
Islington 1036-Moffett 334	172	Paper lead	.3 Cu	313
Islington 2092-Moffett 344	136	Paper lead /XLPE	300Al/.3 Cu	313
Islington-Sockburn T2				
Islington 2062-Sockburn T3	3,513	XLPE	300Al/630Cu	372
Islington 886-Harewood 224	2,186	PILCA /XLPE	300Al	319
Islington 966-Hornby 572-582	829	Oil filled/XLPE	300Al/.3 Cu	306*
Islington 2072-Hornby 532-542	2,183	Oil filled/XLPE	300Al/.3Cu/185Cu	338*
Springston 1206-Shands 434	67	PILCA	300Al	365*
Hornby 502-512- Shands 454	830	PILCA/XLPE	300Al	365*
Hororata 1206-Hororata 924	95	PILCA	.3Al	280*
Hororata 134-Hororata 1226/Annat 1114	65	PILCA	.3Al	280*
Springston 1206-Rolleston 3234	2,790	XLPE	300Al	475*
Springston 1146-Springston 3554	74	PILCA	.3Al	280*
Springston 1186-Springston 3544	80	PILCA	185Cu	355*
Springston 1176-Motukarara 3612/3622	1,921	XLPE	300Al	
Springston 1196-Weedons 3324	330	PILCA	185Cu	355*
Springston 3532-Motukarara 3614	975	PILCA/XLPE	300Al/185Cu	355*
Lincoln 3434-Hornby 562-572	2,696	XLPE	300Al	475*
Springston 1176-Lincoln 3444	936	XLPE	300Al	475*
Springston 1166-Brookside 3114	172	XLPE	300Al	475*
Islington 1026-Hornby 512-522	1,836	XLPE	300Al	
Islington 2082-Shands 444	20	XLPE	150Cu	
Hornby substation-Ripple plant	22	XLPE	300Al	
Hornby substation-Bus	44	XLPE	630Cu	
Hornby substation-T1	36	XLPE	300Al	
Hornby substation-T2	49	XLPE	300Al	
Shands substation-Bus	12	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.

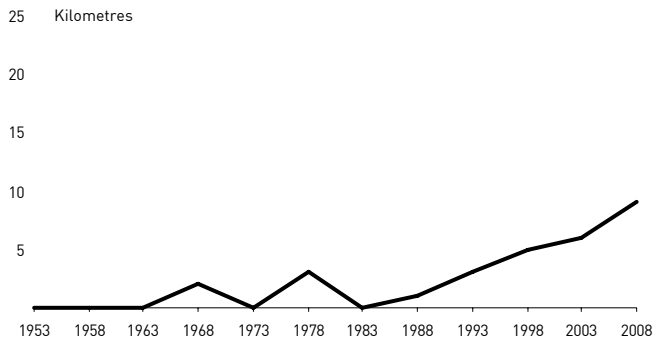
4.10.3 Asset condition

These cables are in good condition and, to date, no sheath faults have occurred.

Buried oil tanks connected with the older oil filled cables were excavated in 1998, treated for corrosion and placed inside sealed concrete housings. This was to extend their life and reduce the risk of oil leakage into the environment.

Joints and terminations of 33kV oil filled cables have similar a construction to the 66kV cables. We are investigating and assessing the risk of premature joint failure due to excessive movement, similar to that found in the 66kV cables. The fact that these conductors are copper means the risk should be less than that in the aluminium conductor 66kV cables.

Underground cables 33kV – age profile



4.10.4 Standards and asset data

We install 33kV cables to comply with manufacturers' specifications and industry standards to suit the ground conditions where they are located.

Standards and specifications

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.

The budgeted maintenance costs are shown in section 3.4 – Service level targets – Works.

4.10.6 Replacement plan

We plan to replace the 33kV oil filled cables due to issues with joints similar to the those on the 66kV oil filled cables. With 33kV cables it is more cost effective to replace the entire cable rather than upgrade the oil filled joints. This work is planned to take place in 2010 to 2012.

The budgeted replacement costs are shown in section 3.4 – Service level targets – Works.

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 – Network development.

4.10.8 Disposal plan

We do not plan to dispose of any of the 33kV cable assets.

4.11 Underground cable – 11kV (ODRC $212.6M)

4.11.1 Asset description

Our 11kV cable network is 2,157km of circuit length of underground cable and is largely concentrated in the urban area of Christchurch (99.6% of total length).

These cables are classed as subtransmission (feeder and primary) and distribution (secondary) cables as follows:

- feeder cables which supply the 11kV district/zone substations from Transpower GXPs (see the table on the following page)
- primary cables which supply the network substations from the district/zone substations
- secondary cables which supply the distribution substations from the network substations.

The reason for having these systems 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

11kV feeder system
These cables supply the 11kV district/zone substations from Transpower GXPs and are currently the subject of a study to determine the rating of each cable based on the thermal resistivity of the cable bedding material. The study results so far indicate that under normal conditions the capabilities of the cables are within the present loading requirements of the substations, but during single circuit outages the capacity of the remaining circuits falls short of the total substation load.

Primary 11kV system
This system is designed to be run in single or multiple closed rings. Each ring usually starts at a district/zone substation bus and includes one or more network substations before returning via a different route to the starting district/zone substation. To provide additional 11kV tie capacity, primary circuits may also be provided in some cases to alternative district/zone substations. A primary ring consists of dedicated runs of cable between a district/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 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 300mm^2 Al/0.25in^2 Cu PILC giving each circuit a rating of 365A or 7MVA.

Secondary 11kV system
This system consists of radial feeders, most of which are supplied from network substations. However, some secondary feeders are also supplied from a district/zone substation bus. Depending on the area and load supplied, secondary feeders have nominal ratings ranging between 1 and 6MVA. 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. Generally this would mean that, under normal circumstances, any individual feeder should not be loaded above 70% of cable rating.

The age of the cables making up this asset covers a wide range. The modes of faults on cables 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 causing premature failure
- failure of terminations.

To manage these issues the following actions are taken:

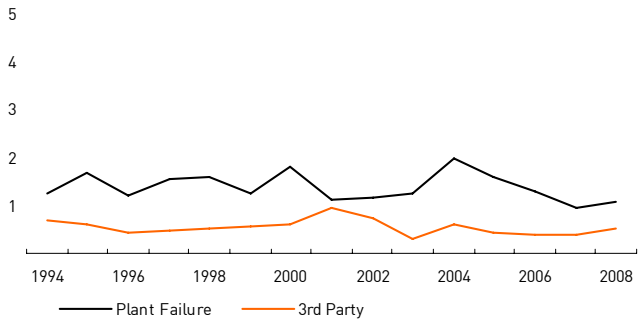
- proactive promotion to contractors of cable locating services
- inspection of contractors during the laying of cables
- ultrasonic and partial discharge monitoring of terminations in district/zone and network substations
- new cable is now required to be installed with an orange coloured sheath to allow easier identification.

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/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/400 Cu	306/334**	2,500
Addington 1/2822-Montreal 15	1963/2000	PILCA	0.5 Cu/400 Cu	306/334**	2,500
Addington 1/2642-Montreal 4	1963/94	PILCA	0.5 Cu	306/334**	2,500
Bromley 1-Portman 4	1987/99	PILCA	400 Cu/400 Al	320/360	2,750
Bromley 4-Portman 15	1957/85	PILCA	0.25 Cu/185 Cu/300 Al	233/273	3,035
Bromley 10-Portman 10	1984/99	PILCA	0.6 Cu/185 Cu/300 Al/400 Al	353/361	2,920
Bromley 15-Portman 14	1987/99	PILCA	400 Cu/400 Al	320/350	2,755
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
Bromley 11-Linwood A4	1962/91	PILCA	0.25 Cu/185 Cu	159/255	3,070
Bromley 12-Linwood A9	1962/96	PILCA	0.25 Cu/185 Cu	159/255	3,070
Bromley 13-Linwood B4	1964	PILCA	0.25 Cu	218/274	3,165
Bromley 14-Linwood B9	1961	PILCA	0.25 Cu	218/274	3,180
Papanui 2-Grimseys Winters 10	1964-96	PILCA	0.5 Cu	261/320**	3,770
Papanui 4-Grimseys Winters 9	1964/75	PILCA	0.5 Cu	261/320**	3,770
Papanui 6-Grimseys Winters 2 (2 cables)	1954	PILCA	2 x 0.25 Cu	410/524***	3,580
Papanui 8-Grimseys Winters 1 (2 cables)	1953/2000	PILCA	2 x 0.25 Cu/150 Cu	410/524***	3,565
Papanui 9-Bishopdale 15	1965	PILCA	0.5 Cu	355/455**	1,290
Papanui 11-Bishopdale 9	1965	PILCA	0.5 Cu	355/455**	1,290
Papanui 13-Bishopdale 3	1965	PILCA	0.5 Cu	355/455**	1,290
Papanui 10-Harris 3	1967	PILCA	0.5 Cu	312/405	145
Papanui 12-Harris 9	1967	PILCA	0.5 Cu	312/405	145
Papanui 14-Harris 15	1967	PILCA	0.5 Cu	312/405	145
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.

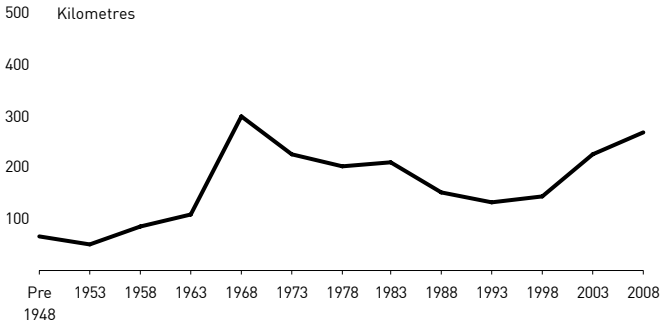
Underground cables 11kV – faults/100km



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.

Underground cables 11kV – age profile



4.11.4 Standards and asset data

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
- 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 replacement programme has been implemented.

The budgeted maintenance costs are shown in section 3.4 – Service level targets – Works.

4.11.6 Replacement plan

There are no plans to replace any of the 11kV cable assets.

The budgeted replacement costs are shown in section 3.4 – Service level targets – Works.

4.11.7 Creation/acquisition plan

Additional 11kV cables are installed as a result of the following:

- reinforcement plans (refer to section 5 – Network development)
- conversion of reticulation from overhead to underground as directed by the Christchurch city and 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.

4.12 Underground cable – distribution 400V (ODRC $232.7M)

4.12.1 Asset description

Our 400V cable network is 2,470km of circuit length of underground cable and is largely concentrated in the urban area of Christchurch. The earlier cables are paper lead. 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 5,500 link-boxes installed on our 400V cable network. Sufficient link-boxes 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. Link boxes are all above ground. Older ones are generally steel and the later ones are a PVC cover on a steel frame.

We have 26,000 boundary boxes installed on our 400V cable network. These are generally installed on alternate boundaries on both sides of the street to supply our consumers. Several types of boundary 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 and steel.

Street-lighting cables are also included in this asset group. The street-lighting cable network consists of 1,850km circuit length of underground cable and is largely concentrated in the urban area of Christchurch. Nearly 90% of this cable is included as a fifth core in the main distribution cables above.

4.12.2 Asset capacity/performance

Many system configurations are used for 400V cable distribution, depending on the area to be supplied, but generally this is a two-sided system with 400V cables on both sides of the street. These cables are fed from a kiosk distribution substation via multiple feeders, each with a rating of around 250A. The cable is buried directly in the ground.

Jointing methods have been changed to improve performance.

To date the majority of failure modes have included:

- third party damage
- damage of cable during installation or other disturbance causing premature failure.

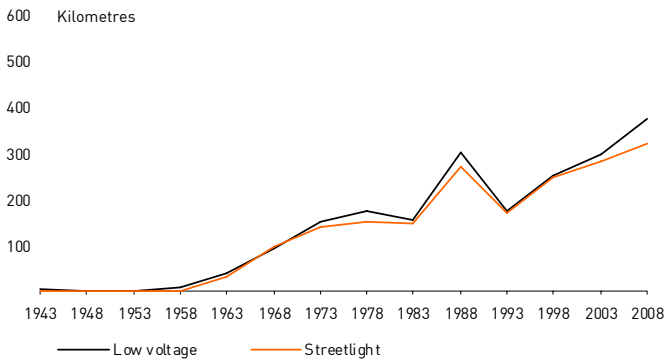
To manage these issues the following actions are taken:

- proactive promotion to contractors of cable locating services
- inspection of contractors during cable laying
- new cable is now required to have 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. The above-ground cable distribution boxes are in reasonable condition. We inspect them every five years, with any defects remedied in a subsequent contract.

Underground cables 400V – age profile



4.12.4 Standards and asset data

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
- NW71.12.03 – Cabling and network asset recording
- NW72.22.02 – Excavation, backfilling and restoration of surfaces
- NW72.21.12 – Network inspection.

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)
- 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
- old cast iron cable termination boxes with heat shrink are being replaced to remedy safety issues.

The budgeted maintenance costs are shown in section 3.4 – Service level targets – Works.

4.12.6 Replacement plan

We have no plans to replace any of the actual cable asset, but plans are underway to upgrade the existing link-boxes to a safer and more secure design, see section 6.2 – Risk management-Safety.

The budgeted replacement costs are shown in section 3.4 – Service level targets – Works.

4.12.7 Creation/acquisition plan

Additional 400V cables will be installed 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 disposal associated with changes and rearrangements in the network.

4.13 Communication cable (ODRC $6.1M)

4.13.1 Asset description

Our communication cables are predominantly located in Christchurch city where they form a 1045km circuit length of cables, most of which are armoured. They enter most building substations and are used for SCADA, telephone and data services to district/zone substations and depots, 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 11kV distribution 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.

Optical-fibre cables have been laid with the 66kV cable from Bromley to Lancaster and Armagh.

4.13.2 Asset capacity/performance

The standard cables laid are 0.9mm^2 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.

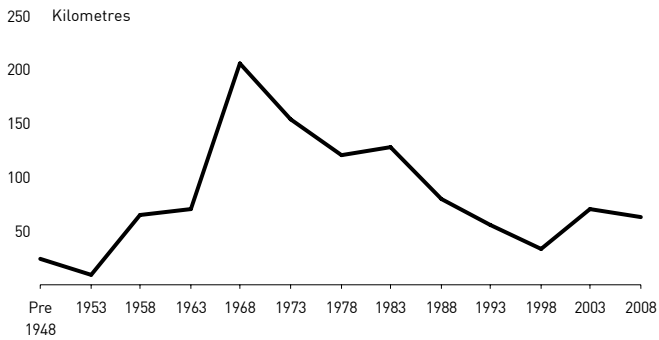
Two separate types of optical-fibre cable, each containing multiple fibres have been laid with the new CBD 66kV cables, multi-mode for cable temperature measurement and single mode for communications purposes. The protection equipment for the 66kV cables use single mode fibres.

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.

Communication cables 400V – age profile



4.13.4 Standards and asset data

Standards and specifications

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:

- NW74.23.20 – 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. Therefore we locate a duplicate copy of all control cable connection details at our mapping centre.

4.13.5 Maintenance plan

The condition of this asset is monitored by a test of the unit protection system every four years includes the most important of these cables, to ensure that they are available for service when required. 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.

The budgeted maintenance costs are shown in section 3.4 – Service level targets – Works.

4.13.6 Replacement plan

An allowance has been identified for pilot cable replacement where repair is shown to be costly.

The budgeted replacement costs are shown in section 3.4 – Service level targets – Works.

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 (ODRC $31.3M)

4.14.1 Asset description

Circuit breakers (CBs) 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.

Circuit breaker quantities			
Location	66kV	33kV	11kV
District/zone substation	31	49	665
Network substation			1,246
Distribution substation			70
Overhead line			57

66kV circuit breakers

66kV circuit breakers are installed at district/zone substations in outdoor switchyards. Armagh substation is the one exception where the 'outdoor' circuit breakers have been installed indoors in a specially designed building.

Circuit breakers purchased pre-circa 1974 are minimum-oil interruption, live tank units. The rest of the 66kV circuit breakers are a mixture of live tank and dead tank units using SF_6 gas as the interruption medium.

33kV circuit breakers

A mix of outdoor and indoor 33kV circuit breakers are installed in the 33kV district/zone substations. Those installed pre-circa 2001 are mainly minimum oil interruption type. The newer units at Duvauchelle, Hornby and Motukarara substations are an indoor vacuum interruption type.

Indoor 11kV circuit breakers

These circuit breakers are installed inside a building and are used for primary and distribution network protection. They have a breaking medium of oil or gas in the older units and vacuum in the later units installed since 1992.

Those shown are the vacuum type used in our 11kV switchgear replacement programme.

Pole mounted 11kV line circuit breakers

Overhead line circuit breakers are pole mounted with reclose capability, and installed in 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.

Circuit breaker ratings

Circuit breaker voltage	Current rating	Fault rating
66kV	1200A-2500A	21.9kA-31.5kA
33kV	400A-1600A	6kA-29kA
11kV	200A-2500A	2kA-26.5kA

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.

The overall performance of circuit breakers is satisfactory. Isolated cases of common mode faults have occurred in some of the older circuit breakers. These have been recorded in the faults register and have been targeted for replacement in the near future.

Pole mounted 11kV line circuit breakers

Although line circuit breakers are performing satisfactorily, we have begun to encounter problems with the electronic protection and control equipment on the older switches, primarily McGraw Edison KFEs. The control electronics on these switches were replaced in the early 1990s with early digital electronic protection relays. These are beginning to fail with no replacements available. Alternatives to these controllers are being investigated.

Line circuit breaker ratings

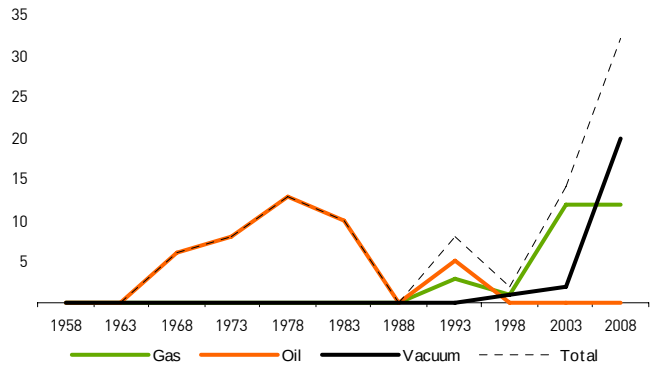
Type	Current rating	Fault rating
11kV older 3 phase	400A	6kA
11kV newer 3 phase	630A	12.5kA
11kV SWER single phase	200A	3kA

4.14.3 Asset condition

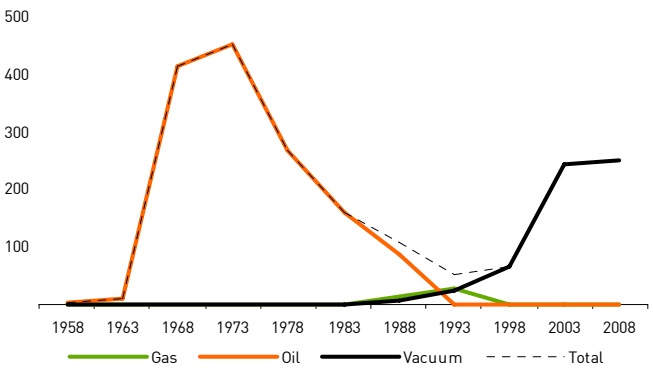
All circuit breakers at district/zone substations are maintained and are in satisfactory working condition. New methods of condition monitoring has enabled us to detect defects at an early stage. Older minimum oil type units are 40 years old and insulation levels are slowly deteriorating.

Some of the older models are becoming difficult to maintain due to their construction and the unavailability of new spares. However, these units are still maintained during the normal maintenance round. At this stage their operational capabilities have not been compromised and they are performing satisfactorily.

Circuit breakers 33 and 66kV - age profile



Circuit breakers 11kV - age profile



The 11kV indoor switchgear units are mounted on concrete floors and are securely fixed. The auxiliary and voltage transformers have been strapped to the switchgear frames and spare circuit breakers are also restrained to prevent movement during an earthquake.

Circuit breaker average age (years)			
Circuit breaker interruption type	66kV	33kV	11kV
Oil	38	33	38
Vacuum	n/a	5	8
Gas (SF_6)	7	n/a	20

4.14.4 Standards and asset data

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 – District/zone substation inspection
- NW72.23.07 – District/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 and model 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 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

The budgeted maintenance costs are shown in section 3.4 - Service level targets - Works.

All switchgear is visually inspected for oil leaks and general condition. Major invasive maintenance is carried out at regular intervals as shown in the table below.

Switchgear inspection and maintenance schedule

Switchgear location	Inspection frequency (months)	Major maintenance frequency (years)
District/zone substation	2	4
Network substation	6	8
Distribution substation	6	8
Outdoor ground 11kV	6	4
Pole mounted circuit breakers and sectionalisers	12	8
Load-break and motorised air break isolators	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 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:

District/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

The budgeted maintenance costs are shown in section 3.4 - Service level targets - Works.

All switchgear has been reviewed based on a number of factors - safety, performance, condition, maintenance, operation, logistical support, environment and age. Safety issues have been given priority to ensure protection of public, employees and contractors. Performance and condition are considered in each case and this has resulted in a scheduling of the replacement. The criticality or location of the equipment, i.e. district/zone substation or network substation, has also been considered under the factors above. While this results in a homogeneous replacement plan, the costs have been separated into the asset areas.

Through our monitoring and maintenance we have, on average, extended the life expectancy of circuit breakers beyond that indicated by the industry (ODV life).

In some network and distribution substations older circuit breakers are being replaced with new circuit breakers. In other cases they are replaced by less expensive switches. Circuit breaker replacement is reviewed regularly 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 cost per unit. 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 switchgear is generally driven by consumer demand.

For a list of projects containing this asset see section 5 - Network development.

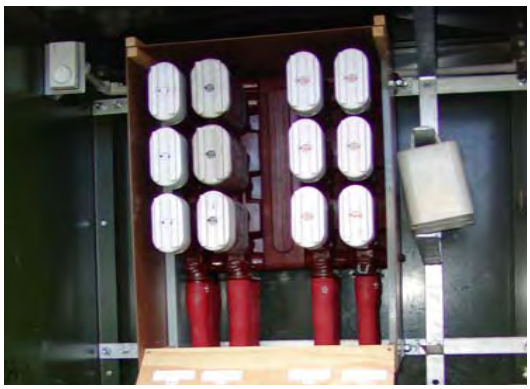
4.14.8 Disposal plan

Switchgear assets are disposed of as part of the replacement costs.

33kV indoor vacuum circuit breaker panel installed at Hornby district/zone substation in 2006. These indoor panels replaced outdoor units similar to those shown previously in section 4.14.1.

4.15 Switchgear high voltage and low voltage (ODRC $58.7M)

4.15.1 Asset description



All insulated unit (AIU)

These AIU switches, also known as Magnefix 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 in 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.

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 AIUs 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 AIUs.

Air break isolator (ABI)

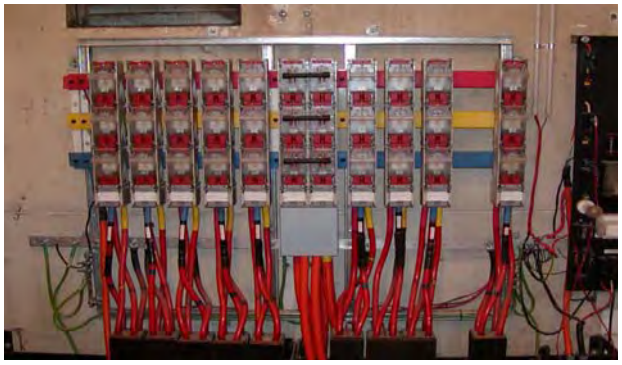
11kV and 33kV line ABIs are pole mounted in our rural overhead network. The substation 66kV and 33kV ABIs are used as isolation points in the substation structures and are mounted on support posts or hang from an overhead gantry.

A few 11kV ABIs in remote areas have been automated by a motorised actuator to allow remote operation for fault clearing. This speeds up the isolation of the faulty sections of the network.

Sectionaliser

11kV sectionalisers are pole mounted, oil filled and installed to perform a similar function to the remotely controlled ABIs. The operation is automated, with the sectionaliser opening after detecting a pre-set number of unsuccessful attempts to re-liven the line 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.

The majority of existing older panels (approximately 3000) are British exposed bus (skeleton) and V-type fuse design. These designs risk accidental contact, which modern designs have addressed.

Switchgear quantities

Device type	Quantity
66kV Substation air break isolator	80
33kV Substation air break isolator	99
33kV Line air break isolator	23
11kV All insulated unit	3668
11kV Oil switch	146
11kV Line air break isolator	1027
11kV Sectionaliser	4

4.15.2 Asset capacity/performance

All insulated unit (AIU)

An AIU 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.

Oil switch

Oil switches are manually operated. They have caused some problems over the years due to oil leaks and jammed operating mechanisms.

Air break isolator (ABI)

A standard existing ABI installed on our rural network (33 and 11kV) is rated at 400A. Load-break attachments 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 'skeleton' type panels and switches have good electrical performance, however, the exposed busbars create safety issues.

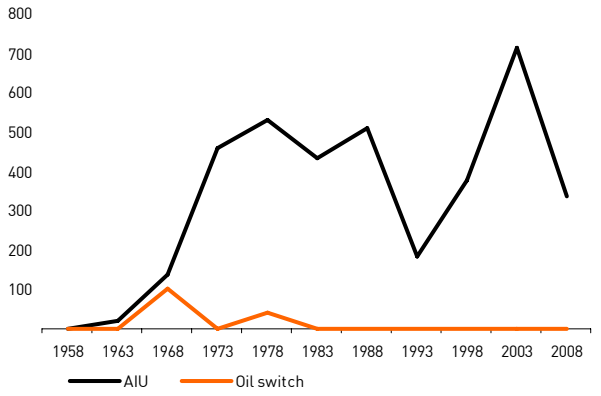
Some issues have surfaced with DIN type switches. These have generally related to overheating created by the quality of connection and installation. Overheating is a more significant issue for DIN switches than for other switches, due to their enclosed construction.

4.15.3 Asset condition

All insulated unit (AIU)
The condition of AIUs within the network is very good.

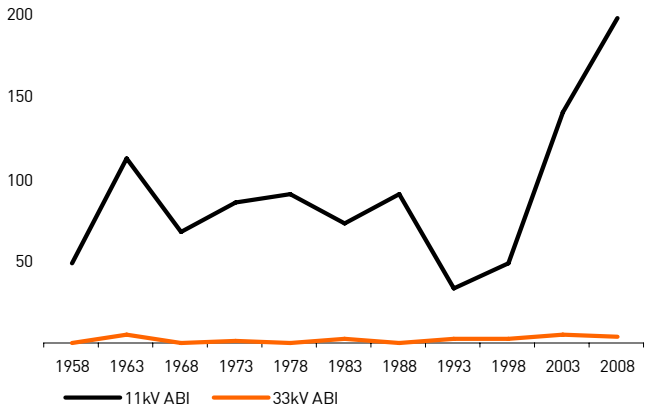
Oil switch
Oil switches are maintained in good operational condition. Any problematic operating mechanisms can be replaced with an AIU.

AIU and oil switches - age profile



Air break isolator (ABI)
The condition of our line ABIs on the network is generally good. However, the older Canterbury Engineering types are reaching the end of their economic life. Approximately one third of ABIs fall into this category.

Line ABIs 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.

4.15.4 Standards and asset data

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

The budgeted maintenance costs are shown in section 3.4 - Service level targets - Works.

All insulated unit (AIU)

11kV AIUs 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)

In 2001 we implemented a plan to operate and check ABIs fitted with load break devices at two yearly intervals. This plan also includes manual operation and checking of motorised units in remote areas.

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. A four-year programme to install safety screens over the open and live busbars and switches is underway.

4.15.6 Replacement plan

The budgeted replacement costs are shown in section 3.4 - Service level targets - Works.

All insulated unit (AIU)

There are no current programmes to replace these switches.

Oil switch

Most of these switches are nearing the end of their useful lives, and are progressively being replaced with AIU switches.

Air break isolator (ABI)

A programme to replace older ABIs commenced in 2006, and will run through to 2020. 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 telescopic 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 to be installed in place of sectionalisers. This programme started in 2003, and very few sectionalisers are 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 District/zone transformers and regulators (ODRC $26.5M)

4.16.1 Asset description

Transformer

District/zone transformers are installed at district/zone substations to transform subtransmission voltages of 66 and 33kV to our 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 may be integral with the main tank or stand-alone.

All our transformer mounting arrangements have been upgraded to current seismic standards, and all transformers have been bunded to contain any oil spill that could occur.

Transformer quantities (includes emergency spares)

Rating MVA	66kV	33kV
20/40	25	
11.5/23	5	7
10/20		4
7.5/10	6	1
7.5		17
2.5		4
Total	**36**	**33**

Regulator quantities (includes emergency spares)

Rating MVA	11kV
20	3
4	9
1	2
0.75	2
0.65	1
0.55	1
Total	**18**

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 district/zone substation
- provide automatic voltage regulation on fixed tap transformers.

We use a wide range of ratings, from 550kVA to 20MVA, to cater for different load densities within our network. All regulators are oil filled, with automatic voltage control by an on-load tap-changer or induction. The installation designs allow for quick removal and re-installation.

4.16.2 Asset capacity/performance

District/zone 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 due to heating and lighting.

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 district/zone transformers are in good condition and should achieve the industry nominal life expectancy.

Historically, tap-changer mal operation has created the most significant failures in transformers. As a result, a proactive tap-changer maintenance/refurbishment programme has been implemented.

Voltage regulators

The regulators at Heathcote are of an older design. They were refurbished before being put back into service and are working satisfactorily.

4.16.4 Standards and asset data

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:

- NW72.23.01 – Mineral insulating oil maintenance
- NW72.23.03 – District/zone substation inspection
- NW72.23.07 – District/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 (draft)
- 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
- age
- circuit diagrams

- 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

The budgeted maintenance costs are shown in section 3.4 - Service level targets - Works.

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 transformer on-load tap-changers is reconditioned annually. Invasive maintenance is carried out every four years as part of the district/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 district/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

The budgeted replacement costs are shown in section 3.4 - Service level targets - Works.

Transformers
Some 33/11kV transformers are to have older, unreliable tap-changers replaced with vacuum units. This project is underway and is planned for completion in 2009/2010.

Transformer control relays for 66/11kV transformers will be replaced by 2010.

4.16.7 Creation/acquisition plan

For projects containing this asset group see section 5 - Network development.

4.16.8 Disposal plan

There are no plans to dispose of any of this asset group at this stage.

4.17 Distribution transformers (ODRC $54.9M)

4.17.1 Asset description

Distribution transformers are installed at our distribution substations to transform voltage to a level for consumer connections across our network. They have a ratio of 11000/400V, and range in capacity from 5kVA to 1,500kVA.

Sizes up to 200kVA can be installed on a single pole. The larger sizes are only ground-mounted, either outdoors or inside a building.

Typical 300kVA transformer (Circa 1980).

Distribution transformer quantities (owned by Orion)															
Rating kVA	10	15	25	30	50	75	100	150	200	300	500	750	1000	1250	1500
Quantity	654	1403	416	1649	1097	134	660	122	1471	1529	660	259	125	2	4

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 38%.

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, with overall values in rural areas of around 30%.

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 is 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 approximately 23 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.

4.17.4 Standards and asset data

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 650 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 because of maintenance work. Their condition at that stage is 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 distribution transformers within building substations that require maintenance as identified during maintenance inspection programmes.

Remaining single-phase transformer banks are to receive minimal maintenance to extend their usable life until replaced.

The budgeted maintenance costs are shown in section 3.4 - Service level targets - Works.

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.

The budgeted replacement costs are shown in section 3.4 - Service level targets - Works.

4.17.7 Creation/acquisition plan

For a list of projects that contain this asset group see section 5 - Network development.

4.17.8 Disposal plan

We dispose of transformers when they reach the end of their economic life, as detailed in the maintenance plan.

A late 1960s building substation after refurbishment with a new roof and doors.

4.18 Generators

4.18.1 Asset description

One generator is permanently located within our network and three generators provide emergency backup for our operational control centre at Manchester Street. We also utilise two mobile generators.

The permanent generator is an 800kVA diesel generator installed at Lyttelton. We use it for peak load shedding and to provide a 'lifeline' electricity supply to the Lyttelton area in the event that the main feeder supplying the area fails. This generator can be shifted to another location in the event of an emergency.

The two truck-mounted (mobile) generators are used to restore power at a distribution substation during a fault or planned works.

Generator listing		
Location	Generator kVA	Generator kW
Simeon substation (Lyttelton)	800	640
Truck-mounted	440	352
Truck-mounted	350	280
Orion car park	110	88
Manchester Street car park (basement)	55	44
Armagh district/zone substation	30	24
Total generating capacity	**1,785**	**1,428**

4.18.2 Asset capacity/performance

All generators are operated within their nameplate ratings.

4.18.3 Asset condition

All generators are checked, tested and maintained in good operational condition.

4.18.4 Standards and asset data

Contingency plans developed and in use for this asset are:

- NW20.40.02 - Contingency plan for emergency generators.

Orion standards:

- NW21.03.04 - Emergency supply generator (criteria for use).

Operator instructions:

- NW72.13.210 - Standby generator - Simeon
- NW21.19.14 – Standby generator truck – 350kVA
- NW21.19.16 – Standby generator truck – 440kVA.

4.18.5 Maintenance plan

We contract several providers to service our generators. Employees regularly inspect and test each generator.

Maintenance includes:

- inspection before use
- monthly testing
- service checks every six months
- fully serviced at 200 hour intervals

The budgeted maintenance costs are shown in section 3.4 - Service level targets - Works.

4.18.6 Replacement plan

We assess our generators annually for age, serviceable condition, operational requirements and availability of parts.

The budgeted replacement costs are shown in section 3.4 - Service level targets - Works.

4.18.7 Creation/acquisition plan

We have gained resource consent to install a 10MW diesel generating set at Bromley and Belfast. Proceeding with either of these sites is subject to satisfactory negotiation of contractual arrangements with the Electricity Commission.

As the Commission has advised that it does not wish to contract for any additional capacity at this time, this project is now on hold.

4.18.8 Disposal plan

These assets are disposed of by auction when they become surplus to our requirements.

4.19 Protection systems (ODRC $11.2M)

4.19.1 Asset description

We install protection systems to protect the electrical network in the event of power system faults. These systems protect all levels of the electrical system, except the low voltage network where fuses are used. Traditionally electro-mechanical relays were used throughout the network for the protection systems, but over the last 20 years electronic relays have been introduced. These relays have the added benefit of greater protection functionality, storage of fault records and the ability to communicate via the SCADA network.

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.

Relay types in Orion network

Relay type	Number in network as % of total relays	Average age (years)
Electro-mechanical	70	31
Analogue electronic (first generation IED)	13	22
Digital electronic (second generation IED)	17	9

4.19.2 Asset capacity/performance

Electro-mechanical relays have performed adequately in the past, but with increasingly complex network control, they are no longer always suitable. Electronic relays offer better sensitivity, increased functionally, communication capability and less maintenance, Therefore we prefer them over the electro-mechanical equivalent. However, in areas where fault levels and clearance times are not onerous, reliability of electro-mechanical relays is proving satisfactory.

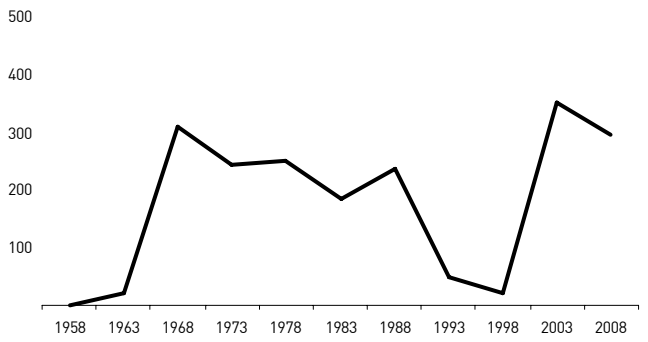
Some early models of electronic relays are problematic, due to failure of electronic components, nuisance tripping and difficulties sourcing spare parts. As a result we have initiated a programme to phase out relay types with a known failure mode.

4.19.3 Asset condition

The current average age of protection relays is approximately 24 years. Some electro-mechanical and first generation intelligent electronic device (IED) relays are no longer supported by their manufacturers. They are becoming difficult to maintain due to their intricate design and unavailability of spare parts. These relays are replaced with modern equivalents in new substations and as part of primary equipment/switchgear upgrades.

We continue to monitor performance of older relays not yet scheduled for replacement. If we determine they are no longer suitable for their purpose, we will initiate a replacement programme.

Protection systems - age profile



4.19.4 Standards and asset data

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
- circuit diagrams
- 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 settings in our network asset register. A specialised protection database to manage relay firmware and settings has recently been purchased.

Details of the onsite installations are shown on our schematic diagrams of the host circuit breaker.

4.19.5 Maintenance plan

Protection equipment is checked for calibration and operation. Results are recorded and minor adjustments made if necessary. Major errors result in the relay being removed from service.

The budgeted maintenance costs are shown in section 3.4 - Service level targets - Works.

4.19.6 Replacement plan

A programme to replace the older types of induction disc and attracted armature relays and early electronic relays is underway. These early electronic relays are on average 22 years old and components are starting to fail.

The budgeted replacement costs are shown in section 3.4 - Service level targets - Works.

4.19.7 Creation/acquisition plan

For projects containing this asset group see section 5 - Network development.

4.19.8 Disposal plan

We dispose of obsolete types of relays as the host circuit breakers are replaced.

4.20 Communications (ODRC $0.3M)

4.20.1 Asset description

A communication system is an essential component of our network. 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.

Our radio communication system is used for both SCADA remote terminal unit (RTU) links using ultra high frequency (UHF), and voice (radio telephone) using very high frequency (VHF) radio links.

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 district/zone and network substations (see section 4.13 - Communication cables for more information).

Voice communication also uses private and public telephone, cellular and paging networks.

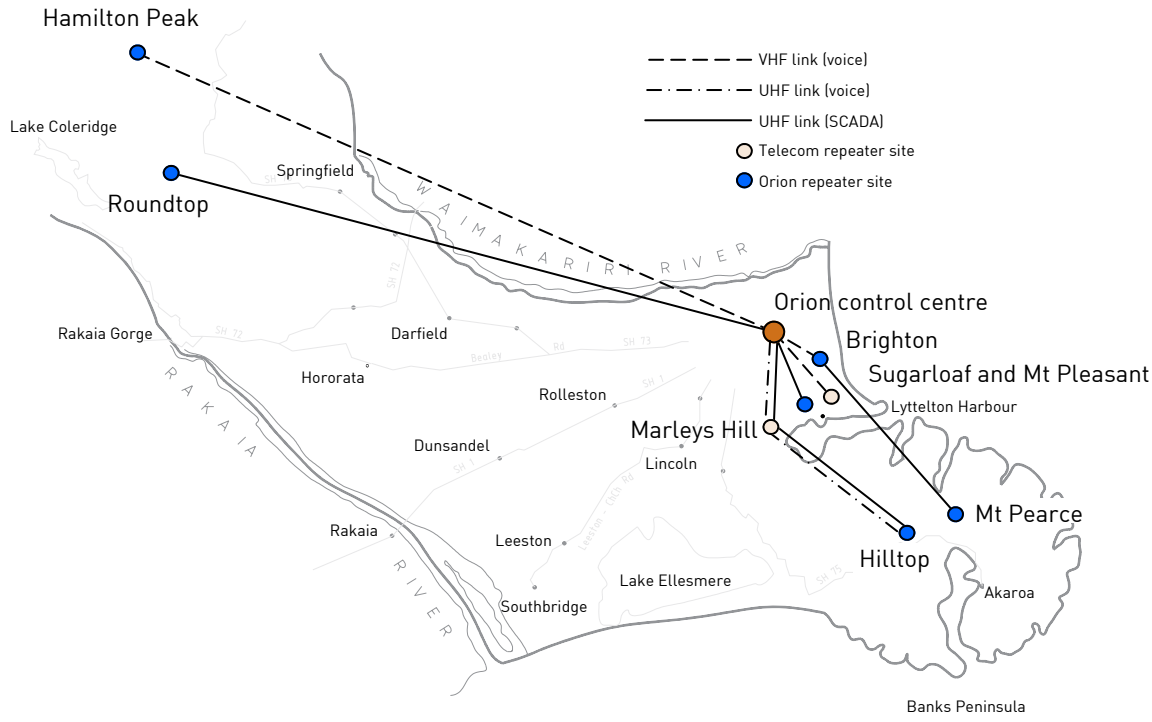
We have recently introduced UHF internet protocol (IP) radios in our rural area to provide low latency communications which enables us to use the latest generation of protection equipment.

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. The current network is being overlaid by a UHF IP network operating in both a point-to-point and point-to-multipoint configuration. This network will eventually replace the existing network. During the transition phase a number of substations will use cellular data modems and radio data communications provided by a commercial network.

Our current power quality monitoring units utilise cellular data modems.

Radio communication network



Voice radio link

Voice radio is provided by a number of linked and same-frequency VHF hilltop radio repeaters. Two linked, different frequency repeaters provide coverage to the greater Christchurch and surrounding rural areas. One same-frequency linked repeater provides coverage in the Akaroa and Peninsula Bays area and an unlinked same-frequency solar powered repeater provides coverage in the Arthur's Pass and upper Rakaia areas. A project is underway to replace the same-frequency repeaters on their own frequency, and all will be linked by UHF radio with the feature to link or unlink each repeater controlled from our control centre.

SCADA cable link

This is comprised of three communication cable technologies:

- audio frequency shift keying (AFSK) modem technology - this provides 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

Tait Electronics' model T346 and T347 repeaters, while still serviceable, are progressively being replaced by their T8000 equipment as servicing of the older equipment becomes more challenging.

Part of the migration of SCADA communications to modern modem and HDSL modems is driven by the condition of older modems.

Our business telephone switch is a hybrid TDM and IP system. It remains current with supported hardware and software releases.

4.20.4 Standards and asset data

All radio equipment is licensed and complies with the relevant regulations imposed by the Ministry of Economic Development's radio frequency service (RFS).

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 RFS regulations.

We have maintenance contracts with several service providers to provide ongoing support and fault resolution.

A maintenance contract for the telephone switch is in place. Preventative maintenance is carried out on a monthly basis.

The budgeted maintenance costs are shown in section 3.4 - Service level targets - Works.

4.20.6 Replacement plan

Our continually reviewed replacement programme takes into account the specific serviceability of equipment, and how appropriate the current deployed technologies are compared to the task they are required to perform. We are replacing older equipment and a programme of SCADA line communication modem replacement and conversion to IP technology is ongoing.

The budgeted replacement costs are shown in section 3.4 - Service level targets - Works.

4.20.7 Creation/acquisition plan

Voice radios

Our network operators' vehicles are now equipped with back-to-back radios. This allows the more powerful vehicle radio to be used when they leave their vehicle with only a low power hand-held radio for communication. Associated with this are 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.

SCADA radios

A high performance SCADA UHF IP radio system is about to be delivered. This is intended as a general purpose radio system which can be used in either point-to-point or point-to-multipoint mode.

In point-to-multipoint mode the system will provide high speed full duplex Ethernet communications for both SCADA and engineering access to substations. In point-to-point mode it will be possible to simultaneously use the communication channels for both protection signalling, and also Ethernet SCADA communications. The system will allow a new high speed, high reliability communication network to be developed for rural substations.

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 (ODRC $5.5M)

4.21.1 Asset description

Our main network load management system (ripple injection) is used to control loads on the network by deferring energy consumption and peak load, and therefore network investment. Its other main function is tariff switching. It works by injecting a signal into our network that is acted upon by relays installed at the consumers connection point. The relays are owned by the retail traders, with the exception of some 2,000 used for streetlight control.

The load management system is comprised of a master station and two ripple injection systems.

Load management master station

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 form RTUs located at the GXPs and district/zone substations. Sources of information and communication paths are duplicated where reasonably feasible.

Ripple injection system - Telenerg 175 Hz

This system operates within the urban 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 20 small injection plants connected via circuit breakers to the 11kV network at individual 66/11kV district/zone substations and Christchurch urban 33/11kV district/zone substations.

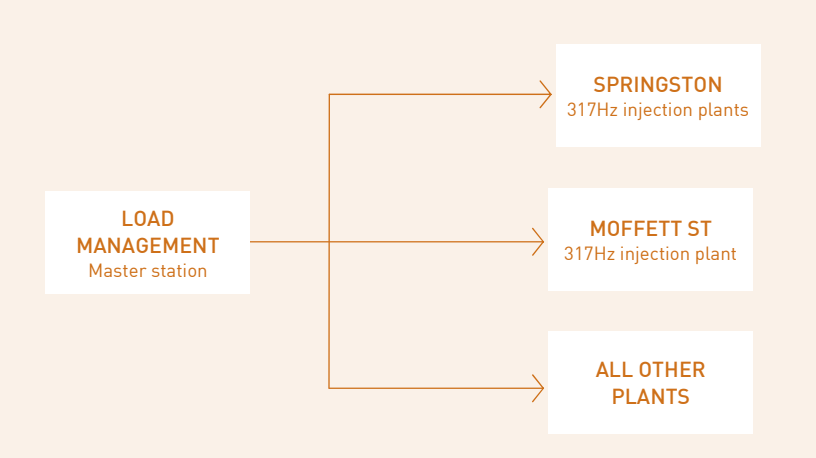
Four plants have recently been installed within the Islington GXP 33kV supply area. These 175Hz signals supplement the 317Hz signals and allow us to carry out reinforcements and shift load from the area previously supplied from the 66kV.

These plants can operate independently with all fixed-time signalling carried out from a timetable stored in the individual plant controller. All anytime signalling is controlled by the SCADA system via individual controllers in response to commands from the load management system running on the SCADA master station.

The plants are relatively small and, apart from the coupling cell itself, consist of 19 inch rack mounting equipment for which spares are held. A complete coupling cell is also kept as a spare. It is also possible in an emergency for a single plant to signal an adjacent area.

The controllers communicate individually with the load management master station and are controlled as an RTU by the master station.

Ripple injection system control diagram



Ripple injection system - Zellweger decabit

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 district/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.

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 and Middleton district/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 signalling 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. Back-up for the individual 33kV plant controllers is provided by the controller located in the control room which can be used to manually control the injection plants directly via dedicated communication paths.

Communications between the central controller and the injection plants is via cable pairs to Springston, Moffett and Hornby substations. In each case the anytime control is carried out by the SCADA system which uses separate cable pairs to each RTU. The Springston RTU also has a backup UHF channel.

There are no pilot cables available to Hororata, Killinchy, Brookside, Greendale, Te Pirita and Dunsandel plants and thus these are only controlled via the SCADA system using UHF radio.

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.

Ripple injection system - urban 175Hz

The 66kV injection system was completely replaced in 2002-2004 with small individual 11kV injection plants.

A larger number of smaller injection plants significantly reduces the risk from the effects of single plant failure as adjacent plants can cover a single plant failure. New 11kV plant capacity is matched to the capacity of the district/zone substation it is connected to. As load growth occurs, additional plants will need to be installed in conjunction with additional district/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.

The 11kV, 317Hz ripple plants have been installed at Killinchy, Brookside, Greendale, Te Pirita and Dunsandel substations because these substations are physically within the existing 317Hz injection area, but are supplied from the 66kV subtransmission system. These are of similar design and supplied under the same contract as those installed as replacements for the 175Hz ripple plants.

4.21.3 Asset condition

Load management master station

The hardware of the master station is suitable for current requirements. The hardware, and the latest version of the software, were installed in 2004/05. The master station software is modified to ensure modifications to the network are incorporated in the system configuration. It is anticipated that the system hardware and software will require updating in the next two to three years to maintain support and reliability.

Ripple injection system - urban 175Hz system

The majority of the 11kV injection plants on the 66kV system were installed from 2004, 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 2005 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.

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.

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 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.

4.21.5 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.

The budgeted maintenance costs are shown in section 3.4 - Service level targets - Works.

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.

The budgeted replacement costs are shown in section 3.4 - Service level targets - Works.

4.21.7 Creation/acquisition plan

New 11kV ripple injection plants are installed in conjunction with new district/zone substations.

4.21.8 Disposal plan

We plan to retire the 33kV ripple injection plants at Moffett and Hornby in 2017. This will provide spares for the remaining plants at Springston and Hororata.

11kV injection plant at a district/zone substation.

4.22 Network management systems (ODRC $3.5M)

4.22.1 Asset description

Our Supervisory Control And Data Acquisition (SCADA) system is a key tool for monitoring and operating our electricity network. It monitors network assets in real time and, through alarms, notifies of potential or actual equipment failure. The SCADA can be used to view the electrical state of devices and is invaluable in diagnosing faults and delivering solutions to network related problems. It is the primary source of control for our ripple control plants.

The SCADA system is a master station consisting of four networked redundant database servers, two communication line servers (CLS) and two dedicated operator stations. Each of the database servers can act as an operator station in its own right and can also support multiple remote operator sessions running on generic PCs via the corporate network. This equipment is located in the Manchester Street control centre and communicates with many remote terminal units (RTUs), located throughout the network, designed to respond to commands from the master station. The previous master station was replaced in 2001.

Communication between the master station and the RTUs is generally by pilot cable, with the rural RTUs by radio.

The RTUs are mainly a mixture of Foxboro (ex Leeds & Northrup (L&N)) and GPT (GEC Plessey Telecoms) equipment. The 175Hz 11kV ripple injection controllers include RTU functionality and are also connected to the master station to provide access to ripple channel status and control.

All original L&N C2020 RTUs installed in the late 1970s have now been replaced with modern Foxboro C50 RTUs. Several L&N C225 RTUs are still in service and are being replaced as part of an ongoing programme.

4.22.2 Asset capacity/performance

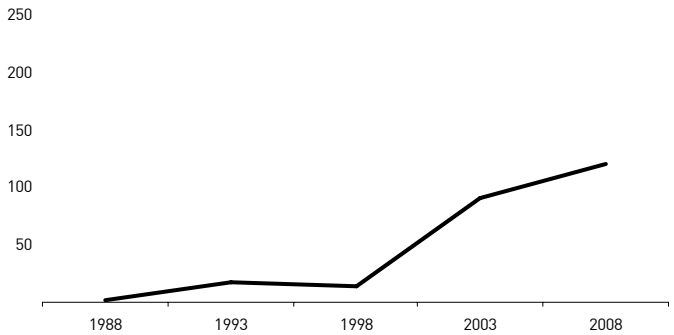
The SCADA master station meets the requirements of a modern functional system. However a review of requirements for managing the operation of the network and retailer and customer information has led to the decision to introduce a fully integrated network management system (NMS). This includes a new SCADA, fault/trouble call management and operational network management systems.

4.22.3 Asset condition

Master station
The master station database servers were replaced in 2004. In 2005 two additional database servers were installed and the original single database split into separate independent 'network' and 'load management' servers/databases. This was done to provide extra security and independence to the load management function. As part of the hardware upgrade the SCADA software was also upgraded to the latest version.

RTU
There are 13 GPT-made RTUs. These will be replaced during communication upgrades over the next three to four years. The manufacturer no longer supports this model, but we hold enough spares to cover maintenance, and the present maintenance programme of annual checks is expected to hold failures to a minimum. The type C225, and more recent C5 remotes from L&N are being treated in a similar manner to the above.

SCADA remote terminal units - age profile



4.22.4 Standards and asset data

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

Inspections we carry out include:

- a weekly general operational check of the equipment's software
- a yearly detailed check of hardware and software systems
- a yearly operational check of all RTU controls and indications.

In general the master station components are maintained on an as-required basis, with component availability the main criteria. The workstations are maintained under a component replacement contract with SUN New Zealand. A telephone support contract is also in place with Foxboro Australia.

The budgeted maintenance costs are shown in section 3.4 - Service level targets - Works.

4.22.6 Replacement plan

A maintenance contract with the SCADA master station software vendor includes upgrades of the core software 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 and hardware releases.

All computer hardware (except the CLSs) is covered by a maintenance contract with the hardware vendor (SUN New Zealand). It is expected that the master station server hardware will have a life of approximately five years, and the CLSs of at least 10 years. Replacement will depend on the availability and pricing of new equipment, the requirements of any core SCADA system software upgrades and the ramp up of maintenance contract costs.

RTUs are replaced as part of the substation or communication upgrades. The 18 GPT RTUs are expected to remain in use until 2010.

The type C225 Leeds & Northrop remotes have been superseded by type C50 units, but are still reasonably current technology. A replacement programme for these units has been established and they will be phased out.

The replacement programme for the Tait Electronics type T340 series equipment is progressing to plan. It will be reviewed each year to reflect the latest technological improvements.

The budgeted replacement costs are shown in section 3.4 - Service level targets - Works.

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.

Pole mounted line circuit breaker with SCADA control via UHF radio link.

4.23 Metering (ODRC $0.2M)

4.23.1 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 10 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. This is also the case for two supply transformers at Papanui GXP. 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 is usually reactive. We respond to consumer complaints (which generally stem from the consumer's own actions) while assuming that network performance is satisfactory. However, as we do not qualitatively know the underlying power quality performance of our network, we have begun a three-year project to install standards-compliant power quality measurement equipment at selected sites.

4.23.2 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's
- 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.

4.23.3 Asset condition

In 2008 we completed a programme to replace all of our GXP metering equipment. All metering equipment is in good condition.

4.23.4 Standards and asset data

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.

GXP drawing list:

Addington	A2 / 13493	Arthur's Pass	A2 / 12697
Bromley	A2 / 11634	Castle Hill	A2 / 12698
Coleridge	A2 / 12699	Hororata	A2 / 11663
Islington	A2 / 11678	Papanui	A2 / 11675
Springston	A2 / 11681		

4.23.5 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.

The budgeted maintenance costs are shown in section 3.4 - Service level targets - Works.

4.23.6 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.

4.23.7 Creation/acquisition plan

We have begun a three-year project to install standards-compliant power quality measurement equipment at selected sites throughout our network. We aim to survey power quality to determine present network performance and changes over time. Approximately 30 measurement sites will be chosen to give a representative sample of the average and worst performing parts of our network over a variety of consumer types.

4.23.8 Disposal plan

We have no specific plans to dispose of any of this asset group.

4.24 Property (ODRC $95.8M)

4.24.1 Asset description

This section on property covers all buildings, kiosks (ODRC $61.2M) and land assets (ODRC $34.6M) that form part of our network.

All of our 50 district/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 271 network and 275 distribution substation buildings vary in both construction and age. We own approx 70% of the network buildings and approx 25% of the distribution substation buildings. Some 200 of them are incorporated in a larger building that we do not own.

Full low kiosk.
(Access is by front doors and a hinged lid).

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 as shown above. The low style kiosk is also constructed in half and quarter versions for use where the transformer is mounted externally or at a remote location.

Distribution kiosk quantities (owned by Orion)

Kiosk type	Low (full) steel	Low (half) steel	Low (quarter) steel	High steel	Fibreglass	Berm steel	Total
Quantity	1,930	460	175	655	29	1	**3,250**

4.24.2 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 10 year programme of security and safety review 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 ongoing to achieve this outcome.

4.24.3 Asset condition

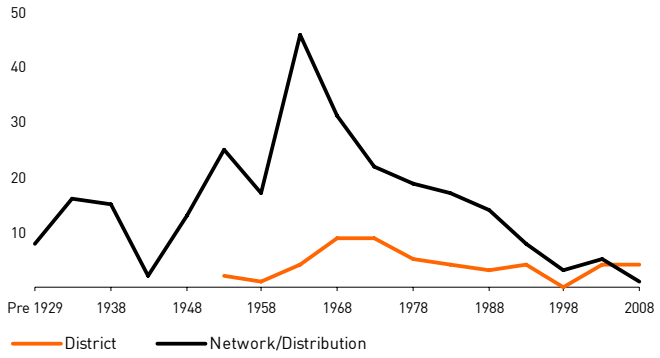
Our district/zone substation buildings are well designed and mostly constructed with reinforced and filled concrete blocks. The structural integrity of all the buildings has been inspected and remedial action taken to bring all district/zone substations up to the latest building code and related seismic strength code. We are underway mitigating known issues with our district/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 28 kiosks of a fibreglass/stone chip construction and these have been the subject of a detailed inspection to assess their condition and possible replacement.

We are currently over half way through a programme to seismic strengthen our dual pole and single pole substations with large heavy transformers.

Substation buildings (owned by Orion) - age profile



4.24.4 Standards and asset data

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.

4.24.5 Maintenance plan

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 substations will require seismic upgrading over time if they are retained.

Upgrading is underway on some of our rural district/zone substation buildings constructed in modular concrete sections with predominantly steel framed glass ends. The ends are being replaced with about two-thirds solid wall, with aluminium doors and windows. This will help with weather tightness and security.

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 ongoing.

A number of our substation buildings were constructed with a flat concrete roof with a tar-based membrane covering. These have been prone to leak, when cracks develop in the concrete. Over the past few years we have implemented a programme to upgrade these buildings by constructing a new pitched colorsteel roof over the top. We expect to have covered all of the original flat concrete roofs within the next two years.

Some of the older kiosk foundations have moved due to surrounding land movement. They need to be leveled to relieve stress on the attached cables. A small number of them are being attended to each year.

We plan to repaint all of our kiosks by 2014, at a rate of approximately 340 kiosks each year. Buildings are repainted approximately every 10 years.

Graffiti is an ongoing 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.

Consumer-owned network 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.

The budgeted maintenance costs are shown in section 3.4 - Service level targets - Works.

4.24.6 Replacement plan

Our seismic assessment programme has not identified any unnecessary substations, but it has identified 28 substations that could be replaced by kiosk substations. However, the cost of achieving this would exceed the cost of upgrading the existing buildings. Therefore, these buildings will be seismically strengthened and the existing switchgear replaced with cheaper AIU switchgear.

Kiosk shells will be replaced when inspection shows them to be beyond maintenance due to rust or structural damage/deterioration.

The budgeted replacement costs are shown in section 3.4 - Service level targets - Works.

4.24.7 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.

4.24.8 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.

A typical 1930s brick network substation showing some of the seismic strengthening works undertaken.

A typical modular concrete network substation.

The modular district/zone substation buildings are of a similar design.

Network development

5

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 customer demand for electricity and the number of new customer connections to our network. Other significant demands on capital include:

- meeting safety and environmental compliance requirements
- meeting and maintaining our security of supply standard
- meeting shareholder desires to place existing overhead wires underground
- meeting requirements for suitable metering, control and data acquisition technology for the competitive retail environment.

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 it is influenced by growth factors such as underlying population trends, growth in the commercial/industrial sector and changes in rural land use.

In the short-term Environment Canterbury's Clean Air Plan is driving higher demand growth as the plan encourages customers to install electric heat pumps.

Another factors that have influenced our network development plan are:

- concern that, in some areas, groundwater resources are not adequate for increased irrigation pumping – this may affect irrigation load growth
- in-fill housing in existing central suburbs and new housing estates in areas such as Belfast, Halswell, Burwood, Brighton, Cashmere, Huntsbury Hill, Redcliffs and Sumner – it is likely we will extend our urban network to meet these developments and, in particular, we will complete a strategic development plan for our 66kV subtransmission system.

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).

5.2 Network architecture

5.2.1 Transpower GXPs

Our network is supplied from ten GXP substations – five 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 the GXPs at Hororata and Springston, all the GXPs peak in winter.

Apart from the 33kV supply at Bromley and Islington , all other GXPs depend on the Islington 220/66kV interconnection made up of two 200/250MVA transformers and one 250/300MVA 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 and must plan the connection assets and 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).

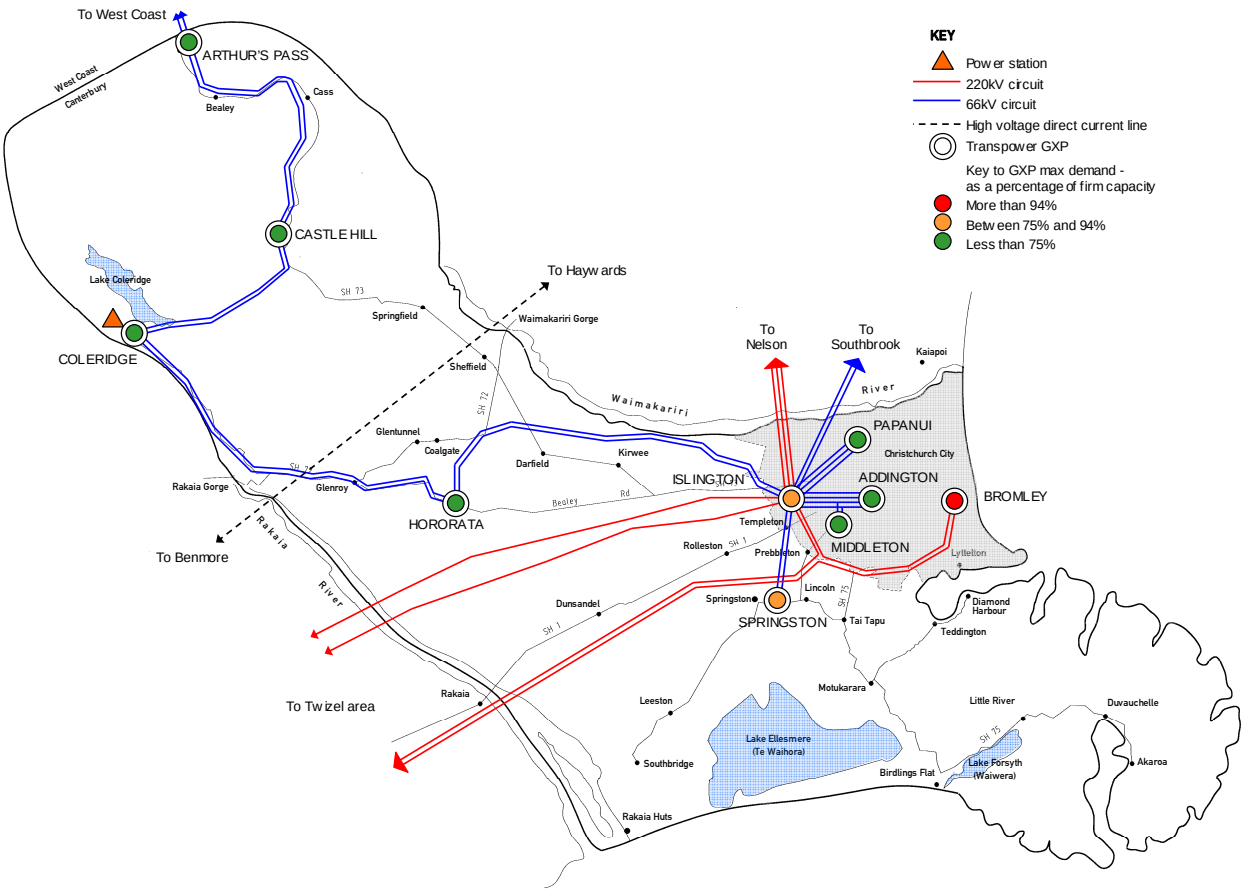
Urban GXPs

Urban GXPs are located at Islington, Papanui, Addington, Middleton and Bromley substations. Islington supplies a 66kV and 33kV grid connection. Papanui, Addington and Bromley supply both 66kV and 11kV grid connections and Middleton 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. Addington and Papanui GXPs are supplied by 66kV lines from the Islington 66kV bus.

The Addington 66kV busbar is operationally split into two bus sections to improve reliability for consumers. We have implemented a similar bus zone protection scheme at Bromley and are investigating options for Papanui. If appropriate those options will be implemented in 2012.

Transpower system



Rural GXPs

Orion takes connection from five rural GXPs; the two main ones are located at Springston and Hororata. Each GXP is supplied via a double 66kV line from the Islington 66kV bus. Hororata and Springston supply Orion at both 66kV and 33kV. Hororata is also connected to the 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

Orion has 15 urban 66/11kV district/zone substations, five urban 33/11kV district/zone substations and 10 11kV district/zone substations (with no transformer). This plan envisages up to four new district/zone substations in the period until 2017. 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.

Each increment of between 20 and 40MW of new load requires a new district/zone substation. District/zone substations supply an area close to them and free up capacity in adjacent substations. New district/zone substations require a suitable site, transformers, switchgear and subtransmission connected to Transpower's 66kV or 33kV GXPs.

5.2.3 Rural subtransmission

Orion has six rural 66/11kV district/zone substations and 16 rural 33/11kV district/zone substations. This plan envisages up to four new district/zone substations in the period until 2019. 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 10MW of new load requires a new district/zone substation. District/zone substations supply an area close to them and free up capacity in adjacent substations. New district/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 minimising cost. Most circuits are operated in a radial configuration, with duplicated transformers at some sites. Most transformers are 7.5MVA capacity. Substations feeding the rural townships are served by two alternative line routes. Rural subtransmission capacity is generally limited by voltage drop considerations. Subtransmission at 66kV is economically more attractive for new 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 capital return.

Sections 5.3.3 to 5.3.5 discuss some of the 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.

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 customer types exists.

Further information, including how you can comment on our network security standard, can be found on our website oriongroup.co.nz.

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 customer 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, public sports venues and more recently the Synlait milk processing plant at Dunsandel.

Distribution network supply security standard					
Class	Description	Load size (MW)	N-1 cable, line or transformer contingency	N-2 cable, line or transformer contingency	Bus fault or switchgear failure
Urban – Transpower GXPs					
A1	Lines, buses and supply banks	15-200	No interruption	Restore within 2hrs	No interruption for 50% and restore rest within 2 hrs
Rural – Transpower GXPs					
B1	Lines, buses and supply banks	15-60	No interruption	Restore within 4hrs (1)	No interruption for 50% and restore rest within 4 hrs (1)
B2	Supply banks	0-1	Restore in repair time	Restore in repair time	Restore in repair time
Urban – Orion network					
C1	District/zone substations with CBD or special industrial load	15-40	No interruption	Restore within 1hr	No interruption for 50% and restore rest within 2 hrs
C2	District/zone substations without CBD or special industrial load	15-40	No interruption	Restore within 2hrs	No interruption for 50% and restore rest within 2 hrs
C3	District/zone substations or 11kV ring with Christchurch CBD or inner urban load	2-15	Restore within 0.5 hr	Restore 75% within 2hrs and the rest in repair time	Restore within 2 hrs
C4	Outer, mainly residential district/zone substations	4-15	Restore within 2 hrs	Restore 75% within 2hrs and the rest in repair time	Restore within 2 hrs
C5	Inner 11kV distribution feeder	0.5-2	Restore within 1 hr	Restore in repair time	Restore 90% within 1 hr and the rest in 4 hrs (use generator)
C6	Outer, mainly residential 11kV distribution feeder	0.5-4	Restore within 1 hr	Restore in repair time	Restore 90% within 1 hr and the rest in 4 hrs (use generator)
C7	11kV distribution spurs	0-0.5	Use generator to restore within 4 hrs	Restore in repair time	Use generator to restore within 4 hrs
Rural – Orion network					
D1	Subtransmission feeders	15-60	No interruption	Restore within 4hrs (1)	No interruption for 50% and restore rest within 4 hrs (1)
D2	District/zone substations and subtransmission feeders	4-15	Restore within 4hrs (1)	Restore 50% within 4 hrs and the rest in repair time (1)	Restore within 4 hrs (1)
D3	Small district/zone substations and 11kV distribution feeders	1-4	Restore within 4hrs (1)	Restore in repair time	Restore 75% within 4 hrs and the rest in repair time (1)
D4	11kV distribution spurs	0-1	Restore in repair time	Restore in repair time	Restore in repair time
(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 district/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. District/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 district/zone substation supplying the area is near full capacity then it may be more cost effective to bring forward the new district/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 district/zone substation and 11kV feeders is generally fixed by the desire to standardise network equipment. The capacity of a district/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, high load densities and underground 11kV cables in urban areas facilitate large district/zone substations without the issues of excessive voltage drop and losses associated with equivalently sized rural district/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 cable capacities are exceeded, it is normally most effective to lay new cables. When line capacities are exceeded, replacement 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.

Further detail of our approach to increased capacity can be found in our document NW70.50.05 – Network design and overview. Please contact John Langham at john.langham@oriongroup.co.nz for access to that document.

The following table provides a summary of our standard network capacities:

Standard network capacities

Location/load density	Sub-transmission voltage (kV)	Sub-transmission capacity	District/ zone substation capacity (MW)	11kV feeder size (1) (2) (MW)	11kV tie or spur (1) (MW)	11/400kV substation capacity (MW)	400V feeders (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	4-6	0.2-1	Up to 0.3
Rural low density loads	66	30MW for radials and interconnected network	10	5	2	0.025-1	Up to 0.3
Rural low density loads	33	15MW radials and interconnected network	7.5	5	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 5MW 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.

Of the external factors, we deem coordination with Transit NZ and local authority projects as the most rigid. 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 in effect may cause us to bring forward, or even delay if possible, capital works projects to avoid any major future complications and unnecessary expenditure which may arise, for example coordination of planned cable reinforcement with any future road widening programmes to avoid the need to re-lay cables or excavate and then reinstate newly laid road seal.

More factors to be considered when prioritising projects, in order of significance, are:

1. Satisfying individual or collective consumer expectations:

   Above all else, 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.

2. 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.

3. 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.

4. 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 switchgear replacement.

5. Our asset maintenance programme:

   We seek to schedule any major substation works and upgrades to coincide with asset maintenance programmes, for example district substation transformer half-life maintenance.

5.3.5 Non-network solutions

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

- uneconomic connections
- demand side management
- distributed 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 connection contribution is treated as revenue and therefore eliminates the need to increase prices to existing consumers.

This policy ensures that the true cost of providing supply is passed on to the appropriate consumer and thereby allows the consumer to make the right financial trade-offs. If an economic non-network alternative is available then that option can be chosen.

Demand side management

When the network becomes constrained it is not always necessary to relieve that constraint by investing in new district/zone substations and 11kV feeders. Demand side management (DSM) provides an alternative to transmission and distribution network reinforcement.

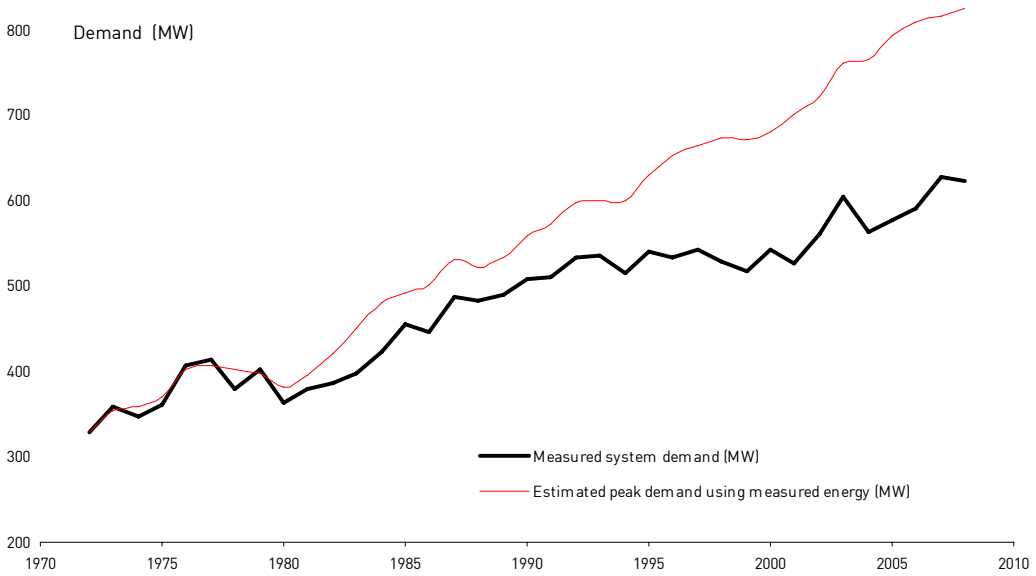
DSM can be defined as shaping the overall consumer load profile to obtain maximum mutual benefit to the consumer and the network operator.

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 and increased effective investment return
- improved utilisation of Transpower's transmission capacity
- consumers benefit by becoming more efficient in the utilisation of energy and network capacity

Peak demand capping



- consumer relations improve through less upward pressure on prices.

The following DSM strategies are applied or are being investigated by Orion:

- ripple system – anytime hot water cylinder control
- ripple system – night rate price options to spread load more evenly over the period
- ripple system – major customer price signalling
- ripple system – interruptible irrigation
- power factor correction rebate
- heat pump efficiency promotion

For further detail on the potential of consumer DSM initiatives to defer or avoid investment, see section 5.6.11.

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 20 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 graph on the previous page 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. Ripple control has facilitated the implementation of the following DSM strategies:

- hot water cylinder control – 40MW 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) – 40MW during contingencies.

To ensure that we can continue to achieve these results, three 66kV ripple injection 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 network and also reduce the 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. We have recently modified our Network Code to make it mandatory to install ripple receivers.

Interruptible load groups – irrigation

When an interruption to supply occurs on our network, there is a cost of lost production and inconvenience is experienced by 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 the 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 with irrigation consumers, we have extended the possible duration of interruptions for irrigators up to 48 hours under extreme conditions. The ability to do this has prevented the need to install Ardlui district/zone substation ($3m) and has delayed several other projects ($7m in total). This has significantly reduced pressure on price rises to our consumers.

Power factor correction rebate

If a consumer's load has a poor power factor then our network 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. We have recently introduced a penalty charge for consumers whose power factor falls short of the 0.95 minimum. In the Christchurch urban area where we have predominately high capacitance (which helps to correct power factor) underground 66kV and 11kV subtransmission, 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 5kW. The rebate provides an incentive for irrigators to correct their power factor beyond 0.95. The rebate is currently set at $25.20 per kVAr per annum. This is a level which recognises 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.

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.

Distributed/embedded generation

The purpose of our distribution network is to deliver bulk energy from Transpower's 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 oriongroup.co.nz/getting connected/distributed generation) for DG provides a different treatment for different sizes of distributed generation.

In particular our policy for DG above 750kW gives considers 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.

In order for DG to be effective we require a contract to ensure that peak lopping is reliably achieved. This is done at present through pricing structures that encourage users to control load at times of system peak. We will continue to encourage DG 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 DG 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 22MW of generation is available on control period demand signalling. A further 13MW of standby generation is owned by consumers for their own use during an interruption.

Our peak load forecast assumes that an additional 2MW of peak DG will be installed each year. For this to be effective in deferring network capacity, the generation capacity must be reliably available to support the network in the event of an interruption to supply. 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, solar, 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. Justification for installing generation at these sites will require either a dry year reserve contract from the Electricity Commission or suitable market arrangements to reward us for relieving transmission constraints between Twizel and Christchurch. Depending on the nature and duration of any Electricity Commission contract for dry year reserve and/or funding as a transmission alternative, this generation may also provide alternative investment options for our distribution network.

We are also investigating wind generation opportunities and have installed an 800kVA diesel generator at Lyttelton to provide supply security and peak lopping capacity. Our potential involvement in large scale generation projects is limited by regulations although this has relaxed slightly in recent times.

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 has shown a consistent trend. This trend provides a first estimate of load growth, both for the full network, and for areas within it. However any load forecasting is an approximation – load cannot be forecasted with 100% accuracy.

Energy and peak demand growth is a function of many different 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. 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 distribution network development project takes approximately three years to plan, design and build, while smaller 11kV projects take around 18 months. 400V solutions 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 historical trends in growth and adjust it to reflect significant inputs such as Environment Canterbury's Clean Air Plan and DSM initiatives.

The following sections summarise our key load forecasting inputs.

Impact of economic downturn

The potential impact of the recent economic downturn has not been factored into this AMP. We will monitor how this global situation affects growth and commodity prices, and adjust future development and financial plans accordingly.

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 district/zone substation load forecasts. Instead we encourage DG in constrained areas on our network by publishing the area specific network deferral value of DSM initiatives (see section 5.6.11).

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 residential 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 uptake of household 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.

5.4.1 Observed and extrapolated load growth

Energy throughput (GWh)

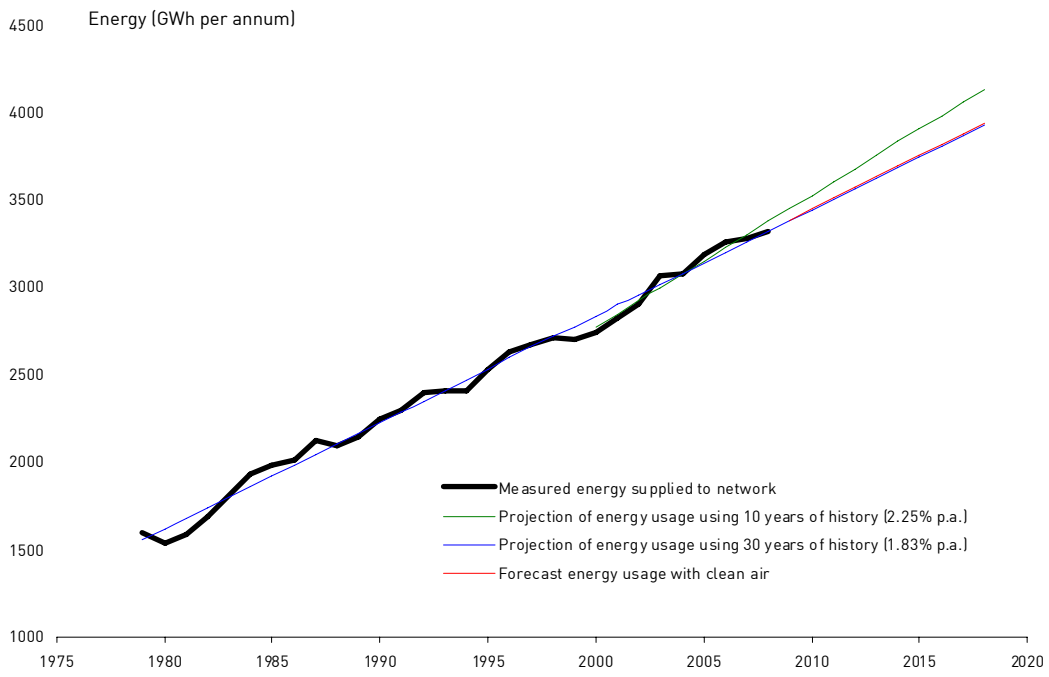
Network energy throughput for the year ending 31 March 2008 was 3,323 GWh (excluding embedded generation of about 5.3 GWh), up 1.3% on the previous year and up 2.1% on the 2006 year.

The 30-year history suggests an averaged steady growth rate of about 1.8% each year. For the five previous years, energy growth has been higher than the long term average at 2.0%. This has been influenced by the increase in summer irrigation load, but is expected to slow as ECAN constraints on ground water extraction reduce the number of dairy and cropping conversions.

Energy growth is therefore expected to continue at a rate similar to the long term trend. ECAN's clean air plan (CAP) is likely to have only a modest impact on energy use, as we consider the high conversion rates of solid fuel burners to heat pumps will be balanced in part by consumers switching from resistive heating to higher efficiency heat pumps.

The graph of historic and forecast energy consumption below shows this trend.

Orion network annual energy trends



Maximum demand

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.

Network maximum demand, including exports from DG, for the year ending 31 March 2008 was 623MW, down slightly by 9MW from the previous year due to a warmer 2007 winter. Although the maximum demand was lower than the previous year the demand was slightly above the long and short term trends. Long and short term trends suggest a demand growth rate of about 1-2% per annum.

The graph of historic network demand shown below also includes three forecasts:

- **Expected demand excluding CAP**

  This forecast is based on a continuation of medium term trends and excludes any impact from the CAP.

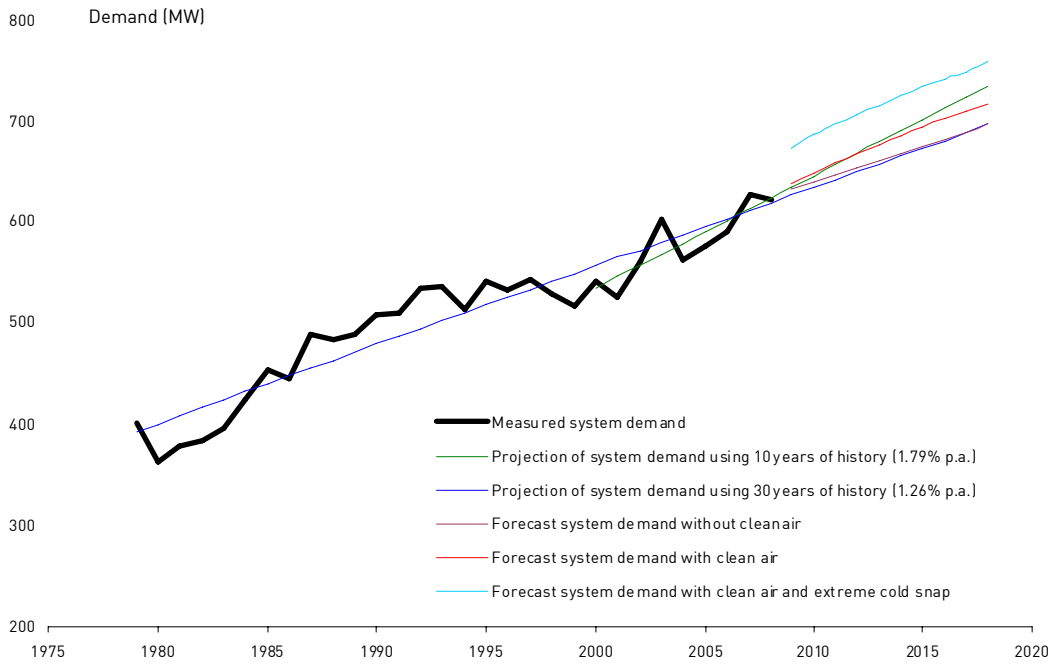
- **Expected demand including CAP**

  This forecast is based on a continuation of medium term trends and includes an estimate of 30MW of total clean air plan demand growth during the period from 2004 to 2016. About 14MW of clean air plan growth is estimated to have occurred so far. In general terms, this forecast is based on 6MW per annum (1% per annum) of nominal load growth and 1-5MW per annum (0.3%pa average) of growth associated with the CAP. 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.

- **Potential cold-snap peak**

  This forecast is based on events similar to those in 2002 when a severe cold-snap changed consumer behaviour. We experienced a loss of diversity between consumer types and, while the load in individual areas did not exceed normal levels, the overall peak was approximately 40MW higher than anticipated. When planning our network, it is not appropriate to install infrastructure to maintain security of supply during a peak that may occur for 2-3 hours once every 10 years. This forecast is therefore used to determine nominal capacity requirements of our network only.

Overall maximum demand trends on the Orion network (MW)



Load factor

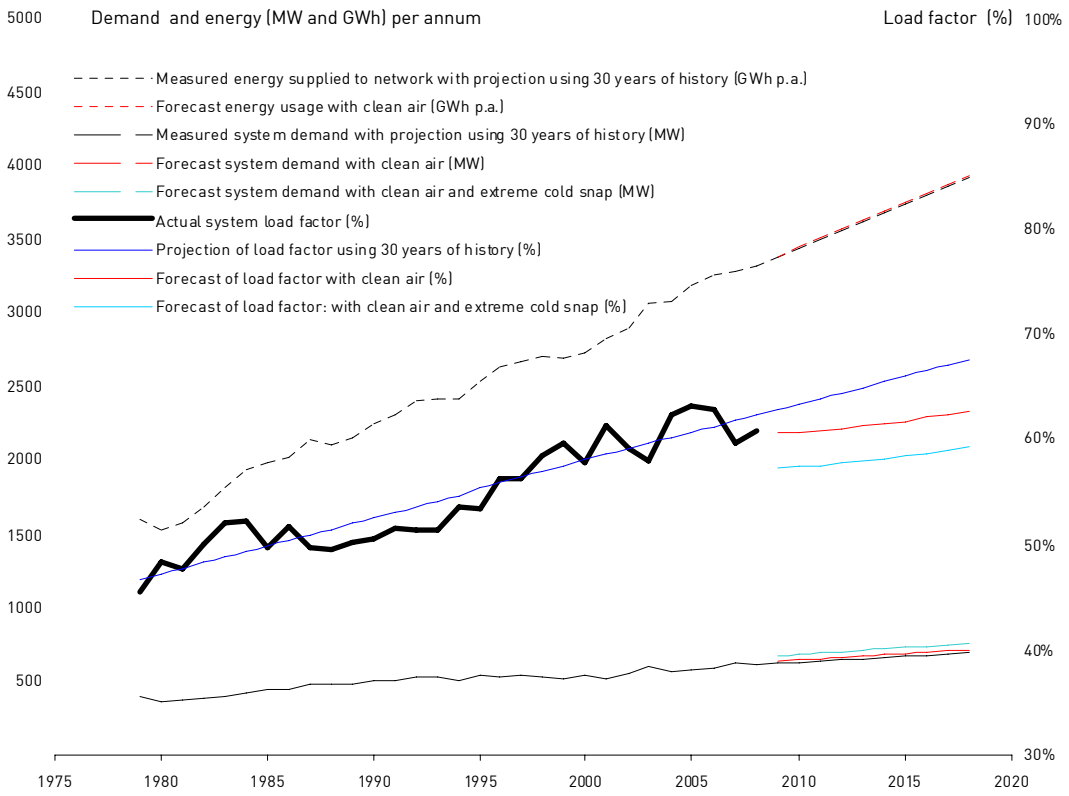
Overall system utilisation

Overall network utilisation is indicated by the system annual load factor (defined as the ratio of peak to average demand). Orion's annual system load factor has generally improved over the last few years, but can vary significantly as vagaries in our weather from year-to-year influence maximum demands. For the year ending 31 March 2008 the load factor was 60.1%, up slightly on the previous year, but still down on the long term trend.

Improvements (or increases) in load factor come from increased off-peak loads (irrigation and summer air conditioning), combined with effective control of winter peak loads through price signalling and encouraging other fuel use for on-peak heating. Winters without extreme cold weather often lead to higher load factors.

The present trends to reduced irrigation load growth, and increased electrical winter heating load suggest that load factor may plateau in the near future.

System load factor



Load duration

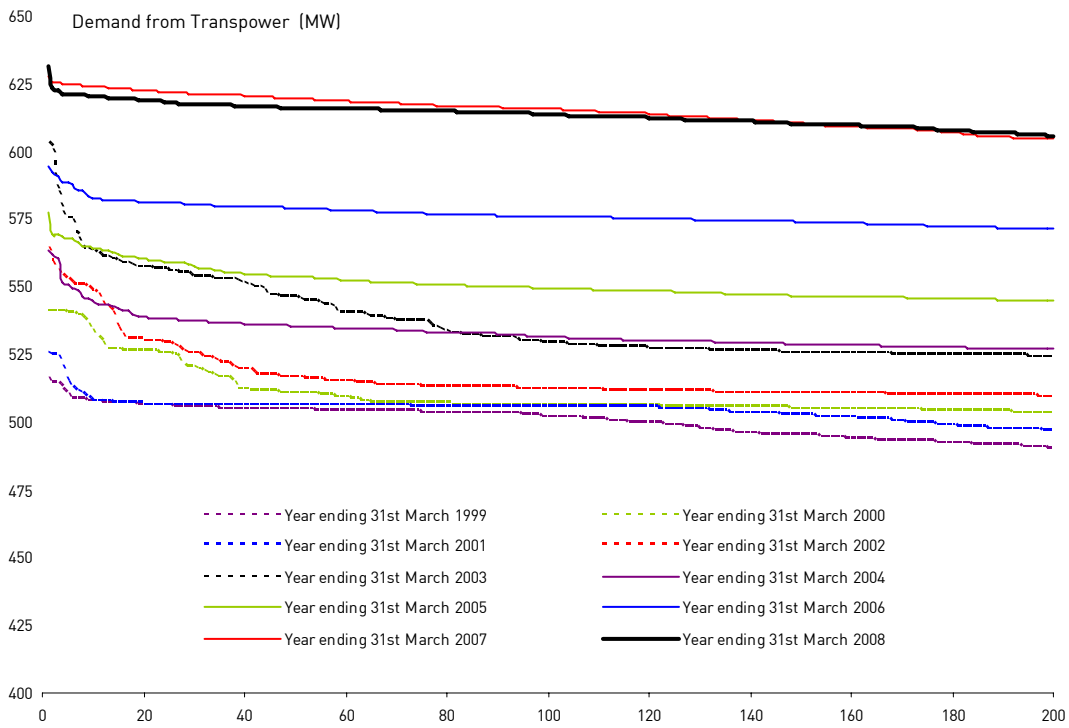
With the constantly changing load on our network, the peak demands that determine the network capacity required generally only occur for very short periods in the year. The following graph shows the load duration curves of our 200 peak half hour demands on the Transpower network over 10 years. The graph shows that in most years an increase in demand side management for 20 hours each year would reduce our network peak demand by 20-50MW. The relatively flat shape of the March 2008 year was a result of a milder than expected 2007 winter compared with 2006.

The Transpower grid requires sufficient capacity to meet load during extreme weather conditions (such as the 2002 snow storm) that may last for only a few hours. Peaking generation can help to delay the need for increases in Transpower network capacity. This generation may need to operate for only a few hours over the largest peak demand times, as required to avoid Transpower network constraints. In the 2002 winter, peaking generation of 30MW would only have needed to operate for about four hours to reduce our urban network maximum demand by about 30MW. In unusually prolonged cold conditions longer hours of operation might be needed.

Generation may also be used to reduce Transpower 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 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 ongoing installation and maintenance of ripple receivers.

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.

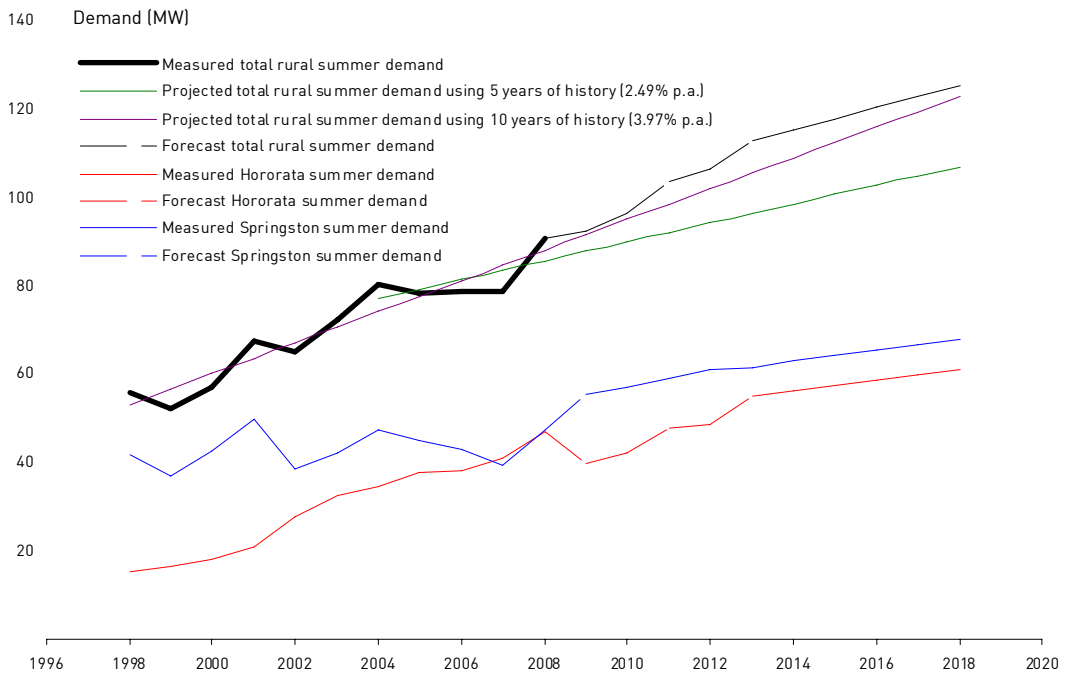
New applications for electrical capacity each year since 2002 have been reasonably consistent, although the summers of 2007/08 and 2003/04 were exceptional seasons with an increase of 12MW and 7MW respectively across Hororata and Springston GXPs. This demonstrates how variable peak loads can be, and how weather dependent they are – a dry summer in the Canterbury Plains causes an increase in peak demand as irrigation is required simultaneously across a large area.

Recently some irrigators with large ground-water irrigation schemes have installed surface river-take schemes in parallel with their existing schemes. These surface water schemes require a much smaller electric pump than the equivalent ground-water schemes, but are highly dependant on river flows and rain in the river catchment areas.

Steady irrigation load growth is expected in the next few years, but is expected to ease off due to restrictions in the number of new ground-water consents.

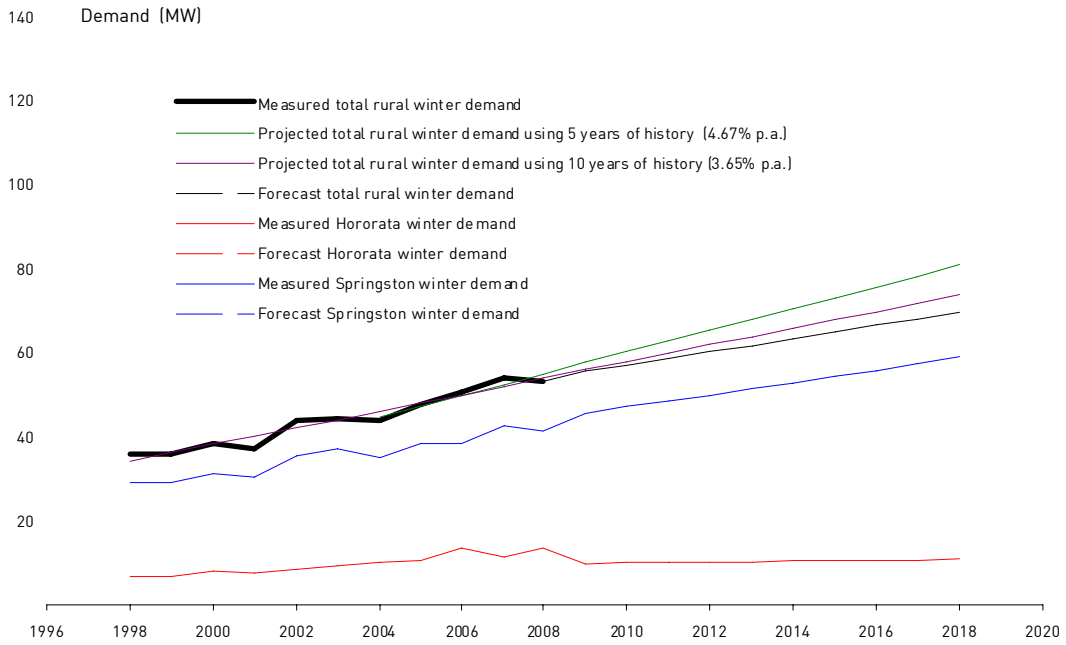
The following graph shows recent load growth in our rural area. Note the effects of load transfers from the Hororata GXP to the Springston GXP in 2007/08 and the forecast impact of the new Synlait milk processing plant near Dunsandel.

Rural summer maximum demand (MW)



Rural winter load growth has been steady at approximately 4% per annum over the last five years. The recently completed Urban Development Strategy (UDS) indicates that significant growth is expected to continue around Rolleston and Lincoln townships. We forecast 2.5% of winter load growth per year over the next 10 years.

Rural winter max demand (MW) graph



5.4.2 Methodology for determining GXP and district/zone substation load forecasts

As stated in section 5.4, we estimate that future demand will grow by an average of 1.3% per annum (8.0MW per annum) over the next ten 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 following sections describe some of the factors and methodologies used to estimate the quantity and location of load growth. We forecast growth at the district/zone substation level and translate this up to the Transpower GXPs and finally to a total network demand forecast. This total network forecast is compared with the linear projection forecast shown in section 3.4.1. If we exclude the impact of consumer behavioural changes (for example popularity of heat pumps) then the statistical approach to total network demand provides a good fit to the 'bottom up' process described below. We expect this result because local authority planning processes do not forecast major change in the underlying growth factors such as population and gross domestic product.

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. These forecasts are relatively high level and are in 10 and 15 year blocks. Further refinement of this data and industrial forecasting is described in the sections below.

Christchurch city

The Christchurch City Council (CCC) reports on vacant residential and industrial 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 district/zone substations in our model.

To forecast industrial growth we utilise the CCC industrial vacant land reports to identify areas developed and zoned for potential growth and then apply an average uptake rate of 23Ha per annum. We utilise historic uptake rates and market judgement to allocate the yearly 23Ha of growth to the different areas of available land. These allocations are mapped in our model to a district/zone substation with a forecast load density of 130kW per hectare.

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, the UDS proposal is anticipated in the medium term to deliver an increase in residential infill within the CBD and inner city areas around the shopping malls. In the short term, major subdivision growth is planned for Wigram, Halswell, Belfast and hill areas. Industrial development is expected to mainly continue in Hornby and Islington in the short term and in Belfast in the medium term.

Selwyn district

Most of our district/zone substations within the Selwyn district are required to meet irrigation load and are predominately summer peaking. However significant residential growth has occurred around Rolleston and Lincoln district/zone substations. These are winter peaking substations and, similarly to the CCC, we utilise the UDS/Selwyn household growth projections to forecast residential growth in the greater Selwyn region.

The Rolleston Izone industrial park has also experienced significant growth in recent times and we are working closely with Izone to ensure that our forecasts in this area are consistent with their expectations.

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 35MW (39%) in the next 10 years.

The following main issues need to be considered when managing growth:

- sufficient time to procure district/zone substation land and/or negotiate circuit routes (typically 1-2 years)
- sufficient time for detailed design (typically 1 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.

In the current environment, three factors may result in actual demand varying from forecasted demand:

1. Clean air plan

The ECAN Clean Air Plan (CAP) largely bans the use of open fires and non-complying solid fuel burners in developed areas. Assistance packages to encourage household insulation and conversion to 'clean' heating appliances are provided by ECAN. The CAP is being implemented in the context of a national air quality standard to be achieved by 2012.

Progress to date has involved more than 10,000 assisted conversions. Of these conversions, about 60% have used heat pumps. Other conversions have occurred outside the ECAN scheme, and statistics on these are difficult to obtain. To meet the national air quality standard it is estimated that 42,000 households will need to convert to clean air heating by 2012. ECAN intends to assist approximately 26,000 households by 2012. This requires a rate of about 3,000 to 4,000 conversions per year.

The CAP is anticipated to add 30MW to our peak demand between 2004 and 2016. This equates to

approximately one additional district/zone substation within the city area. The 30MW increase in demand is based on the trends established during the conversion of the first 4000 households to clean air heating and a number of assumptions about diversity and efficiency gains associated with household insulation improvements. Some of these assumptions were confirmed during a small Orion household monitoring project during the winter of 2008. Generally the additional CAP load is spread around the city, although it is slightly more concentrated in the older established suburbs. We use 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 noticed a measurable increase in peak demand on our distribution transformers. Overall network growth is within the range of forecast growth.

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 (although recent Environment Court consent cases have found in favour of the applicant, although with restrictions on the consents)
- land in some areas is approaching its full irrigation potential
- interruptible load arrangements to cover short term fault situations
- design and implementation of the Central Plains Water (CPW) scheme and/or other large irrigation schemes.

The proposed CPW irrigation scheme is likely to change irrigation in the affected area from ground water extraction to pumping from irrigation races. This gives rise to the medium term potential for stranded assets in the Darfield and Te Pirita regions.

We have developed peak demand forecasts for a number of rural irrigation scenarios. A balance of capacity, security and reliability is required while ensuring that our expectations, and those of our rural consumers, are met.

Irrigation and its associated industries (such as dairy sheds and factories) is anticipated to cause almost all of the forecasted 35MW of summer peak growth over the next ten years. The availability of water and the possibility of the CPW scheme proceeding causes significant uncertainty in this forecast. In the extreme scenario that all land becomes irrigated without the CPW scheme then growth could reach 50MW over the next ten years. This could be merged into the current plan without having a major impact to the 'managing growth' issues listed above. Conversely, it is also possible that only 10MW of summer peak growth will occur over the next 10 years. For this reason we have created a timely responsive development plan for the rural area.

3. Oil supply issues

Various sources predict that the world supply of oil is likely to peak in the next few decades. Estimates vary between now and 2037. When this peak occurs the supply of low cost transport fuels will begin to decline, and high prices will help to match usage to shrinking supply.

It is too early to estimate timing and how this will effect our network but the following effects may be contemplated as fuel availability declines:

- fuel substitution in favour of electricity for transport
- reduced electricity consumption as electricity prices increase to reflect increased cost of oil
- land use changes as people seek to reduce oil usage.

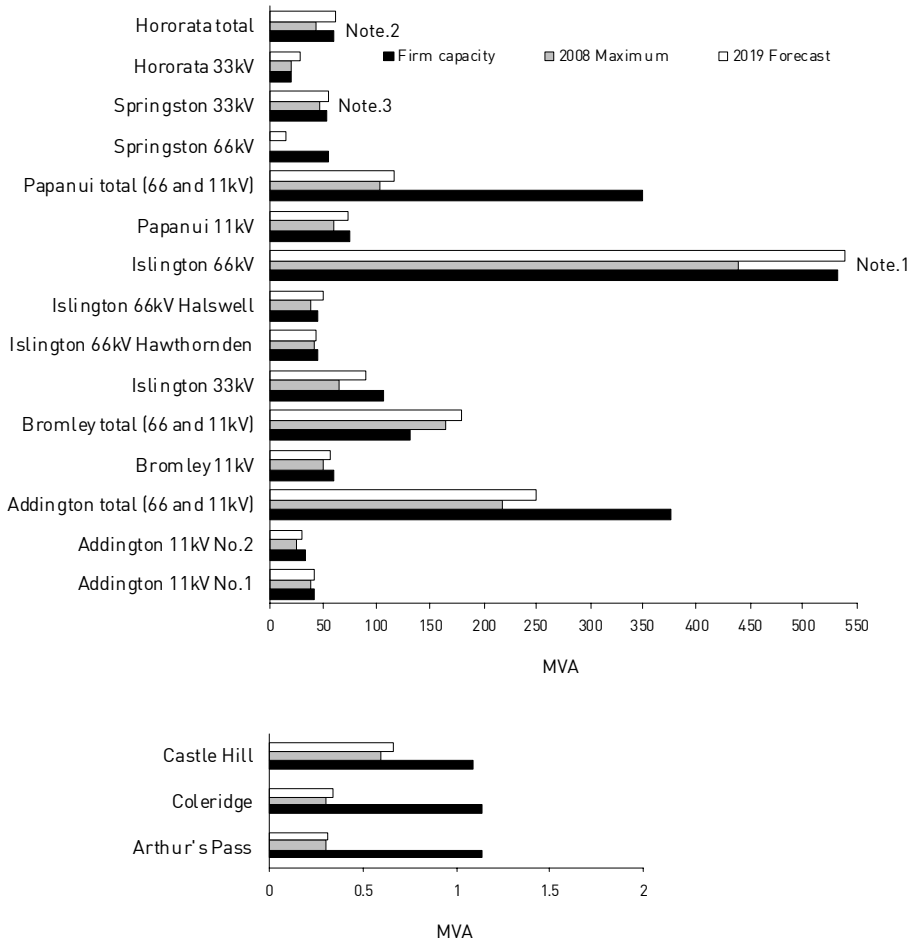
We will follow the development of oil related issues, and when appropriate, our peak demand forecast will incorporate oil related issues.

5.4.3 Transpower GXP load forecasts

The following graph indicates the capacity of each Transpower GXP that supplies our network. Present and expected 10 year maximum demands are also shown. 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.

GXPs – maximum demand versus firm capacity



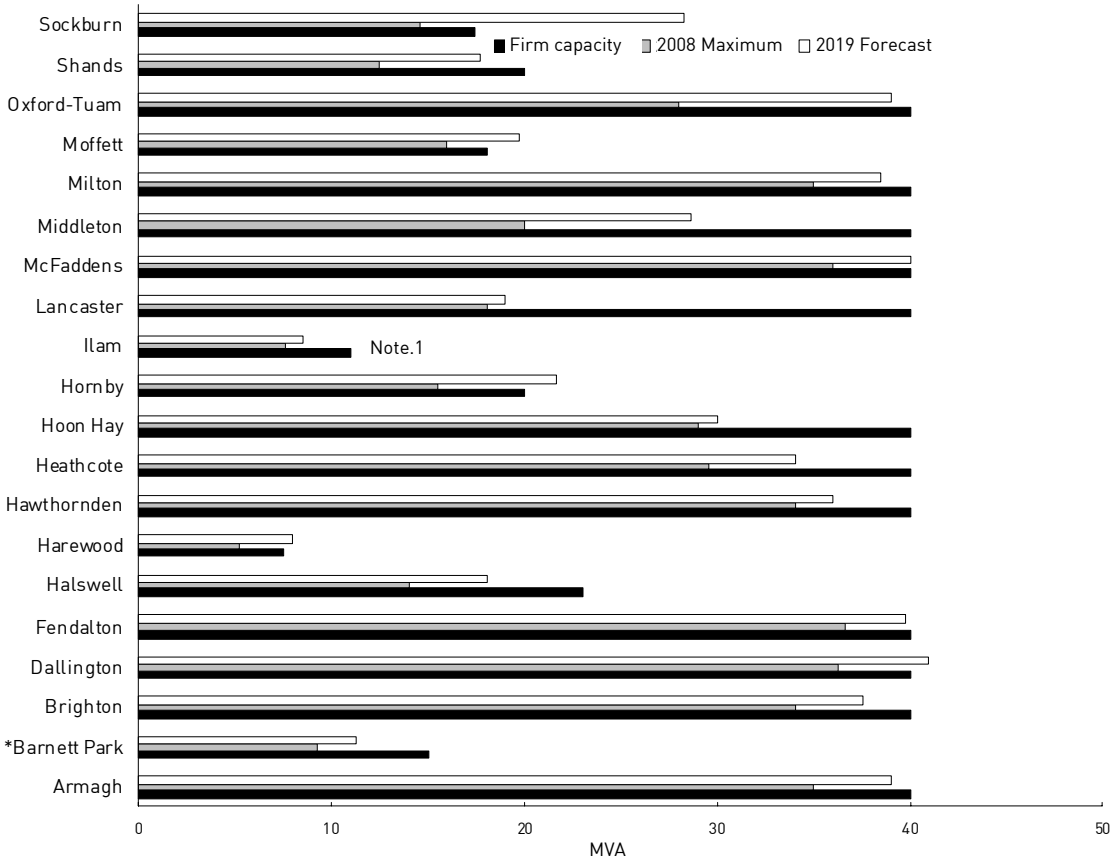
Notes:

1. Assumes only 32% of Mainpower load is fed from Islington post Islington T6 contingency.
2. Can be limited to 40MW when Coleridge is not generating or providing reactive support.
3. When Larcomb 66kV is in parallel with Springston the limit will increase to the 66/33kV transformer continuous rating of 59.4MVA.

5.4.4 Orion urban district/zone substation load forecasts

The following two graphs compare the firm capacity of each of our urban district/zone substations with present and predicted future loads.

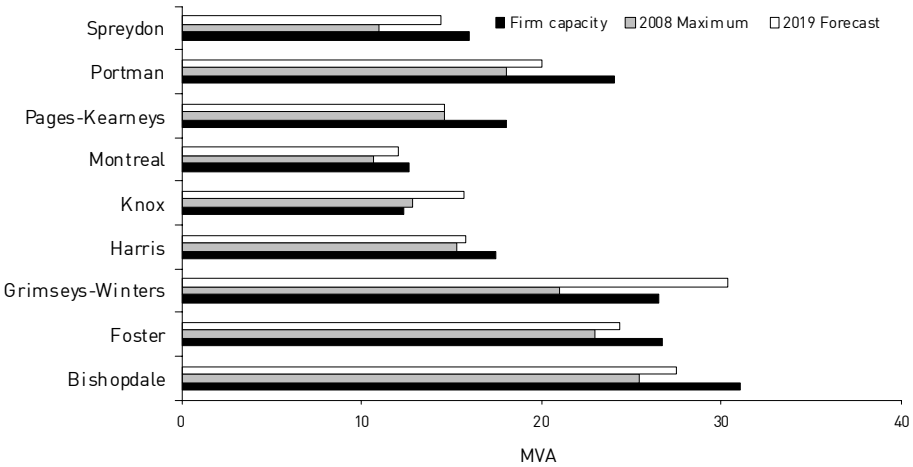
Urban 66 and 33kV district/zone substations – maximum demand versus firm capacity



* Denotes single transformer substation

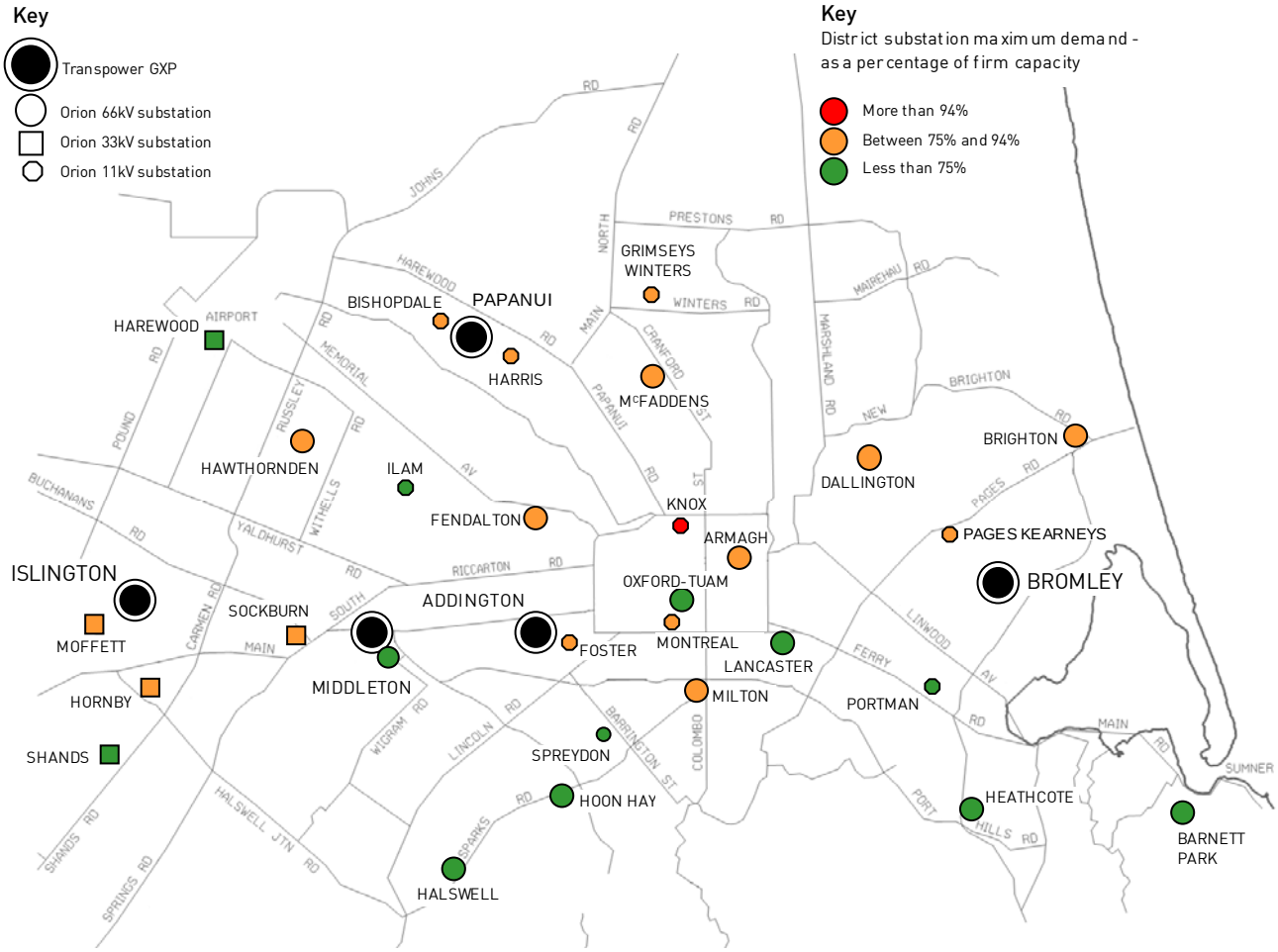
Note. 1
Ilam district substation is included with the 66 and 33kV substations although it is regarded as an 11kV substation elsewhere in this plan. This is because it has no transformers on site but has two dedicated 66/11kV transformers located at Hawthornden.

Urban 11kV district/zone substations – maximum demand versus firm capacity



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.

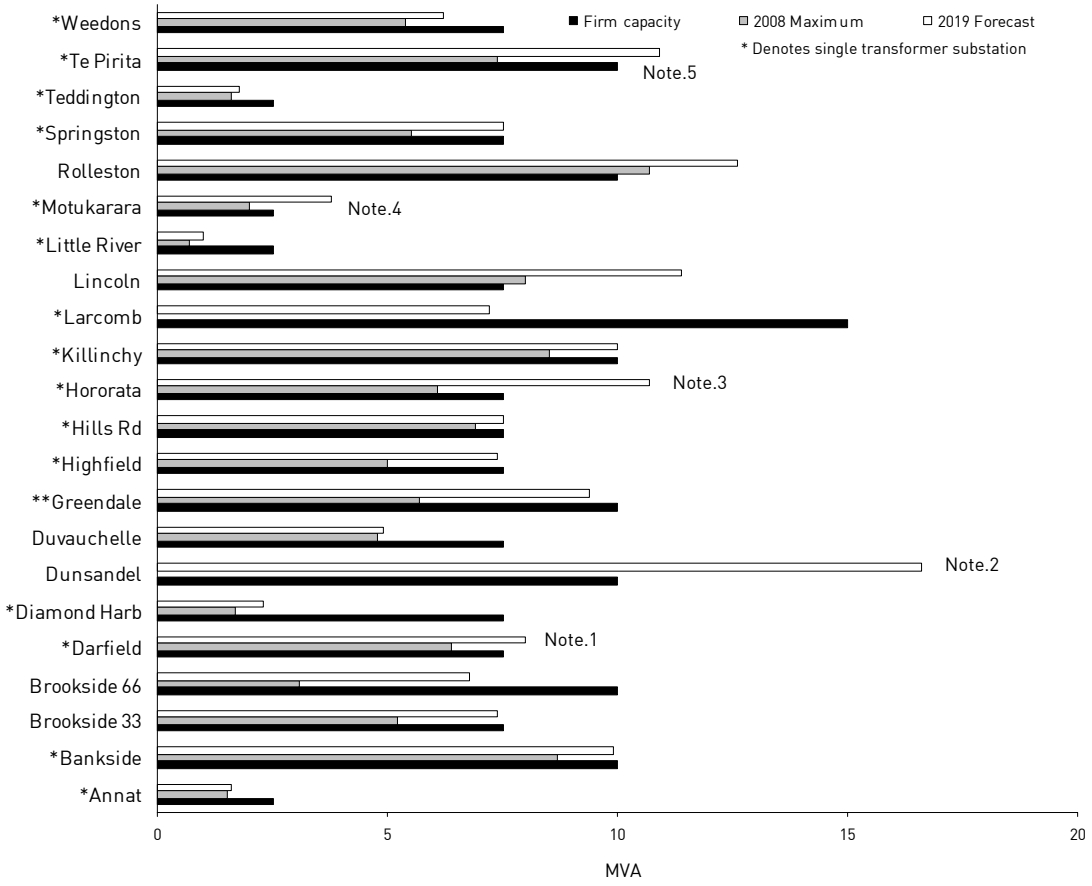
District/zone substations – urban (2008 maximum demand as a percentage of firm capacity)



5.4.5 Orion rural district/zone substation load forecasts

The following graph compares the firm capacity of each of our rural district/zone substations with present and predicted future loads.

Rural 66 and 33kV district/zone substations – maximum demand versus firm capacity

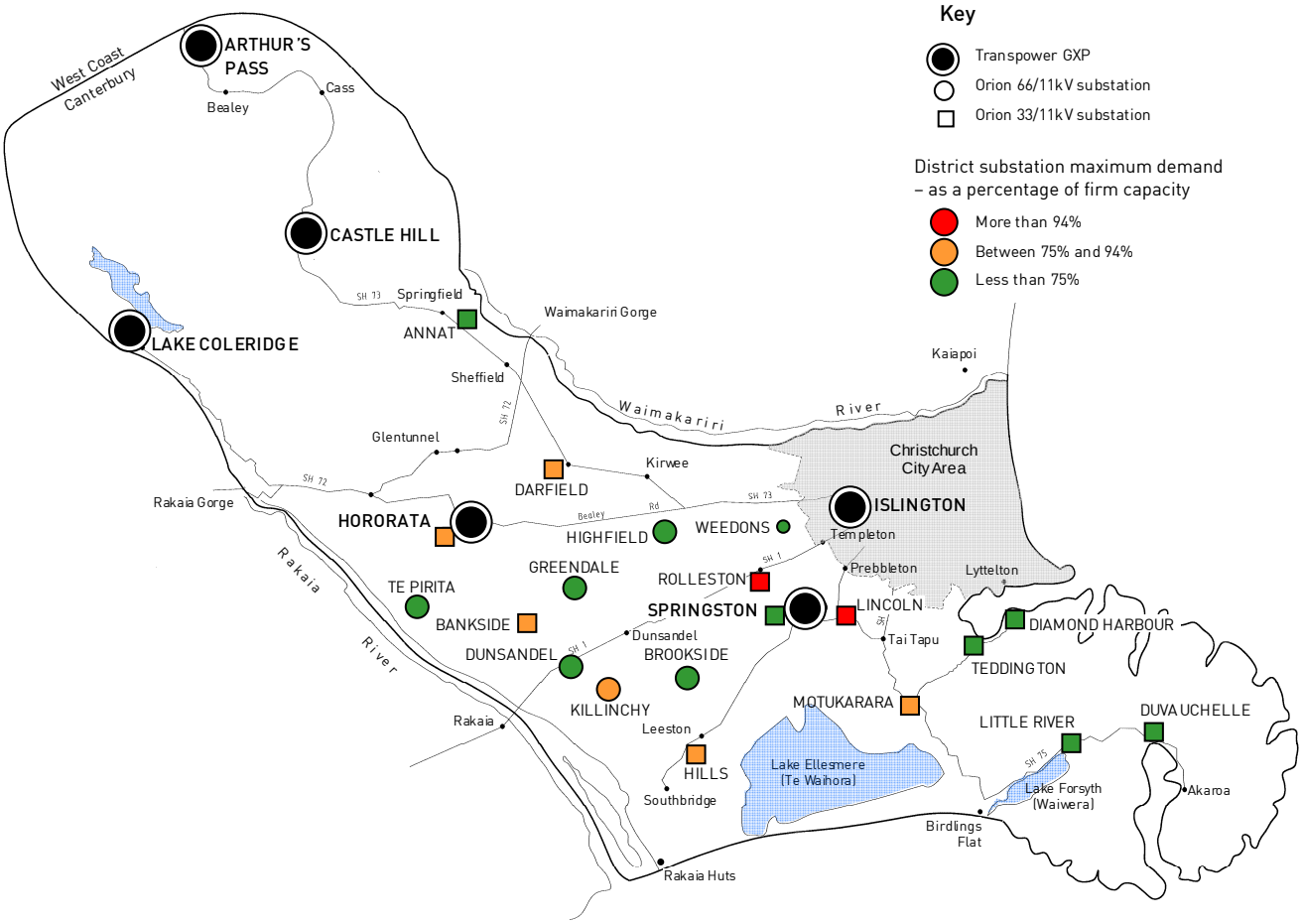


Notes:

1. Constraint to be resolved when Kirwee GXP is installed.
2. Depending on load growth associated with the Synlait milk processing plant at Dunsandel, transformers will be replaced with 23MVA units.
3. Constraint to be resolved by the installation of Windwhistle.
4. Constraint will be resolved by the installation of a spare 7.5MVA transformer from Springston.
5. Constraint to be resolved by the installation of Windwhistle.

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.

District/zone substations – rural (2008 maximum demand as a percentage of firm capacity)



Note:

A new substation (Larcomb) in 2009 will relieve Rolleston district/zone substation. Upgrade of transformers at Lincoln in 2009 and 2010 will provide enough new capacity to meet load growth over the next ten years.

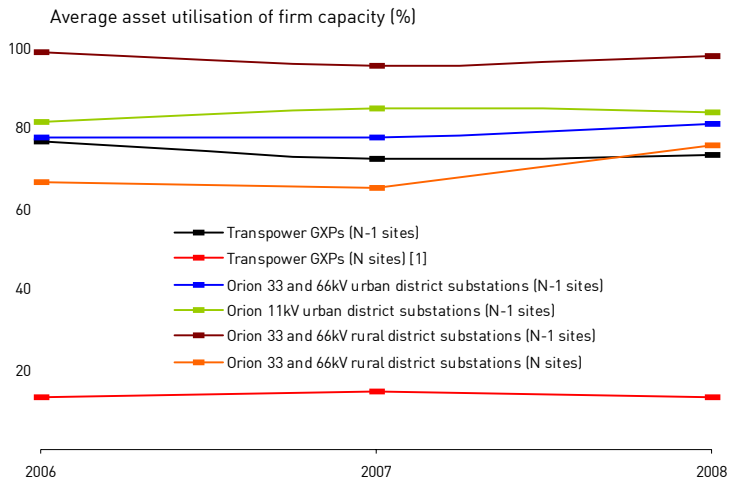
5.4.6 Utilisation of assets

GXP, 66kV, 33kV and 11kV district/zone substation utilisation

For N-1 sites with dual transformers or parallel 11kV incomers, we calculate percentage 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 reliability of supply will reduce.

For N security sites with single transformers and/or line or cable supplies, percentage 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 percentage utilisation of 70-80% is appropriate in this context.

GXP, 66kV, 33kV and 11kV district/zone substation utilisation

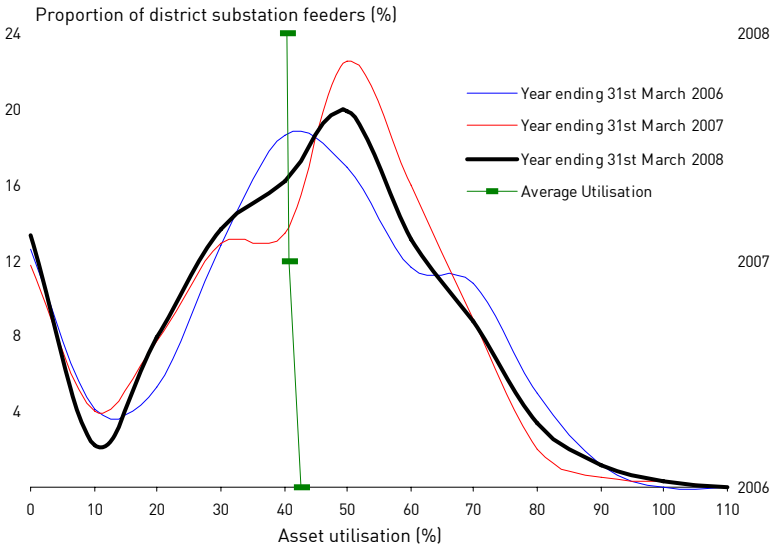


(1) Very small GXPs at Arthur's Pass, Castle Hill and Coleridge

11kV feeder cable utilisation

We have calculated cable utilisation for all urban district/zone substation 11kV network feeders from recorded SCADA values. It is based on the peak load under normal system conditions with respect to the nominal design capacity of the smallest capacity cable section between the district/zone substation circuit breaker and the first downstream load. A de-rating of 80% has been applied to the cable capacity to allow for the common thermal environment and where multiple cables are laid in parallel.

District/zone substation 11kV feeder cable utilisation graph

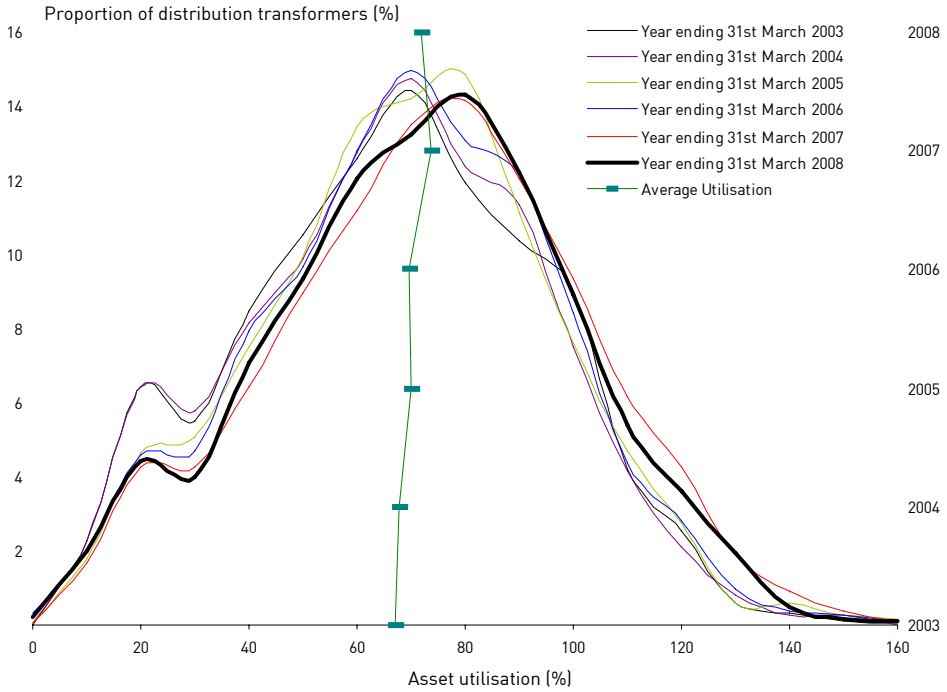


The graph on the previous page of district/zone substation 11kV network feeder cable utilisation shows average utilisation is around 40%. Ideally, with our N-2 urban architecture considered, the nominal average cable utilisation should be 50%. However, several cables carry zero loads under nominal operating 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.

Distribution transformer utilisation

The accompanying graph shows the distribution of utilisation factors for our 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.

Distribution transformer utilisation graph



The graph shows that distribution transformers commonly have peak loads in the range of 60 to 100% of their continuous rated load. It also illustrates that average utilisation over the last six years has increased from 67 to 72%.

While the graph also shows that around 18% of distribution transformers are above 100% loaded, the load factor for most distribution transformers is usually quite low. This is certainly true for the distribution transformers that supply mainly residential customers. Customers 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. 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.

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 eminent load growth are quickly eliminated 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 primary 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 high 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 eminent 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/EC 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 kWhr thereafter.

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 network development proposals which are required for load growth or asset replacement.

Because annualised VOLL figures can hide the high VOLL of a particular event it is important to consider the implications of rare but costly events if they were to occur.

Notes to the following tables:

The Electricity Commission has recently developed 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 core-grid, spur or GXP assets. Proposed projects for Transpower core grid assets will be subject to Electricity Commission approval.

The table includes current security standard gaps only. Additional projects listed in the ten year AMP provide solutions for future 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.

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 2hrs.	534	8.0	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	TP 26	3.7	2.18:1	2012
Bromley							
Single Bromley 11kV GXP busbar fault causing complete loss of supply to 54MW of load. Restoration achievable in 2hrs.	1,254	18.8	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	TP 27.6	3.9	4.88:1	2010
Bromley and Islington							
Bromley 220/66kV transformer failure causing cascade trip during high loads.	2,100	20	Upgrade Bromley interconnectors.	TP 8,000	242	1:12	Further engineering and commercial analysis required but tentatively scheduled for Transpower. Year ending 30 June 2010.
Partial loss of restoration for an Islington 220/66kV dual transformer failure.	8,200	30	Upgrade Bromley interconnectors.	TP 8,000	242	1:12	Further engineering and commercial analysis required but tentatively scheduled for Transpower. Year ending 30 June 2010.
Islington							
Partial loss of restoration for an Islington 220/33kV dual transformer failure.	2,200	4	Wigram and/or Templeton 66kV substation. (1)	Orion 4,000	480	1:109	Influenced by load growth at Wigram and Templeton.
Papanui							
Single Papanui No.1 11kV GXP busbar fault causing complete loss of supply to 25MW of load. Restoration achievable in 2hrs.	581	8.7	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	TP 27.6	3.9	2.26:1	2009
Single Papanui No.2 11kV GXP busbar fault causing complete loss of supply to 39MW of load. Restoration achievable in 2hrs.	906	13.6	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	TP 27.6	3.9	3.52:1	2009
Interruption to all Papanui GXP load for a 66kV bus fault (restorable).	1,300	30	Install 66kV bus coupler.	TP 930	80	1:2.6	2012, but depends on the outcome of the urban subtransmission review.
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	43	1:2.6	Uneconomic. No date proposed.
Partial loss of restoration for a Hororata 66/33kV dual transformer failure.	1,180	11	Kirwee GXP or convert Darfield to 66kV. (1)	TP & Orion 4,000	480	1:42	Influenced by load growth at Kirwee. Year ending 31 March 2017.
Interruption to all Hororata 33kV GXP load for a 33kV bus fault (restorable).	386	8,800	Install a 33kV bus coupler (will halve VOLL values).	TP 250	22	1:5	Uneconomic. No date proposed.
Springston							
Partial loss of restoration for a Springston 66kV dual line or 66/33kV transformer failure.	TBA	TBA	Weedons 66kV Larcomb 66kV.	TBA	TBA	TBA	Year ending 31 March 2012. Year ending 31 March 2014.
Interruption to all Springston 33kV GXP load for a 33kV bus fault (restorable).	907	21	Install a 33kV bus coupler (will halve VOLL values).	TP 250	22	1:2	33kV subtransmission changes are likely to make this economic in 2010.

Note.1 Shared mobile generation could provide an alternative solution.

Transpower GXP security gaps

Substation	Network gap	Solution	Cost $000	Proposed date
Brighton	Single 11kV network substation busbar fault on the Brighton 11kV 0905 primary ring causing complete loss of supply to 19MW of load. Restoration achievable in 1hr.	Ring is to be split up broken down to manageable sizes, with a three feeder ring and two radial feeders created as part of a combined reinforcement and switchgear replacement job.	NA	2010
Dallington	Single Dallington 11kV busbar fault causing complete loss of supply to 33MW of load. Restoration achievable in 2hrs.	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	27.5	2019
Halswell	Single Halswell 66kV busbar fault causing complete loss of supply to 42MW of load.	Operational options are currently being investigated.	TBA	TBA
Heathcote	Single Heathcote 66kV busbar fault causing complete loss of supply to 33MW of load.	Several options are being investigated to coincide with the planned 66kV switchgear replacement.	TBA	TBA
	Single Heathcote 11kV busbar fault causing complete loss of supply to 21MW of load. Restoration achievable in 2hrs.	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	25	2019
Hoon Hay	Single Hoon Hay 11kV busbar fault causing complete loss of supply to 28MW of load. Restoration achievable in 2hrs.	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	25	2026
McFaddens	Single McFaddens 11kV busbar fault causing complete loss of supply to 37MW of load. Restoration achievable in 2hrs.	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	25	2022
Milton	Single Milton 11kV busbar fault causing complete loss of supply to 33MW of load. Restoration achievable in 2hrs.	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	25	2014
Oxford-Tuam	Single Oxford-Tuam 11kV busbar fault causing complete loss of supply to 29MW of load. Restoration achievable in 2hrs.	Install bus zone scheme to create two bus zones as part of the protection upgrade.	50	2009
Hornby	Single Hornby 11kV busbar fault causing complete loss of supply to 15MW of load. Restoration achievable in 2hrs.	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	50	2019
Lancaster	Loss of 18MW of load for a single 66kV cable failure. Restoration achievable in 10min.	Complete a 66kV loop from Armagh to Dallington.	8,500	2015-2016
Moffett	Single Moffett 11kV busbar fault causing complete loss of supply to 18MW of load. Restoration achievable in 2hrs.	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	50	2030
Papanui	Single busbar fault at Northcote Road No.123 network substation on the Belfast 11kV ring causing a cascading loss of supply to 24MW of load. Restoration achievable in 2hrs.	Install an 11kV bus coupler at Northcote Road No.123. The impact will be reduced by the installation of Marshland district/zone substation (project 488) and then fully solved by reconfiguring Northcote 123.	TBA	TBA
Sockburn	Single Sockburn 11kV busbar fault causing complete loss of supply to 16MW of load. Restoration achievable in 2hrs.	Install bus zone protection to create three bus zones as part of the planned 11kV switchgear replacement.	75	2009
Bishopdale	Single Bishopdale 11kV busbar fault causing cascading loss of supply to 22MW of load. Restoration achievable in 2hrs.	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	25	2016
Harris	Single Harris 11kV busbar fault causing complete loss of supply to 16MW of load. Restoration achievable in 2hrs.	Bypass substation as part of the Papanui GXP 11kV switchgear replacement.	NA	2009

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 for purpose. The installation of 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 SF_6 switchgear. Ongoing 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 (2010)
- the next four years (2011-2014)
- the remainder of the period (2015-2019)

All 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 (2015 and beyond) are indicative only because of the uncertainties as to the nature and magnitude of future loads.

A summary of the options considered for the major projects has been provided. Because most of the projects beyond 2010 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 2010, the value per kW of deferral has been tabled later in this section (5.6.11) 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

In the last five years we have met growth within our urban network without the need to invest significantly in the urban subtransmission network. In the next three to four years we anticipate that new district/zone substation capacity will be required towards the north of Christchurch city. Our existing 66kV subtransmission network in the area is insufficient to supply this district/zone substation and we will need to invest significantly to meet the electrical needs of northern Christchurch consumers. Development decisions made over the next two-to-four 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. Our options analysis not only considers the impact of normal network contingencies but also considered 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 on 12 June 2007 which caused several hours of lost electricity supply to the majority of Auckland.

Over the last two years we have incorporated the results of the Urban Development Strategy (UDS) into our northern Christchurch load forecasting model and have analysed subtransmission options to resolve the forecasted network constraints.

To ensure that we can deliver these projects in a timely manner, detailed design will need to start within the next 12 months. Given the significant investment involved, we invite all interested parties to download a copy of our 'Urban Subtransmission Options Analysis' paper from our website oriongroup.co.nz and provide feedback accordingly.

Our preferred option for northern Christchurch would lead to the following projects in the next 10 years:

Subtransmission projects

Year	Project	Description	Estimated Cost $000
2012	487	McFaddens 66kV switchgear	3,350
2012	488	Marshland district/zone substation	4,400
2012	490	McFaddens to Marshland 66kV cable	10,400
2013	278	Dallington 66kV switchgear	850
2013	491	Dallington to Marshland 66kV cable	7,560
2018	492	Bromley to Dallington 66kV cable	7,050
2019	493	Armagh to McFaddens 66kV cable	7,420

5.6.4 Major GXP projects

Major GXP projects – $000, year ending 31 March											
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
498	Papanui 11kV switchgear	300									
499	Bromley 66kV bay upgrade	280									
305	Bromley 220/66kV transformer upgrade		8,000								
371	Islington 66kV bay for Weedons line		350								
325	Hororata 66kV bay for Windwhistle line		350								
328	Papanui 66kV Bus Zone			930							
370	Springston 66kV bay – 66/11kV local				500						
429	Springston 66kV bay – Larcomb					500					
391	Kirwee GXP								1,500		
326	Bromley 66kV bay – Dallington									500	
GXP total		**580**	**8,700**	**930**	**500**	**500**	**0**	**0**	**1,500**	**500**	**0**

Major project details – GXPs – current year 2010

2010 – PAPANUI 11KV SWITCHGEAR (PROJECT 498)

This project covers the cost of all incidental Transpower expenses required to move the necessary connections over to the new Papanui 11kV switchroom that we plan to build. An example is extending the existing incomers.

Options/comments

See project 486.

2010 – BROMLEY 66KV BAY UPGRADE (PROJECT 499)

Currently the 66kV bay where the Lancaster district/zone substation cable is terminated at Bromley GXP is limited to 800A due to the equipment ratings of the circuit breaker and disconnectors. This project will replace the equipment to ensure the full 160MVA rating of the 66kV cable can be utilised.

Major project details – GXPs – 2011-2014

2011 – BROMLEY 220/66KV TRANSFORMER UPGRADE (PROJECT 305)

Load at Bromley 66kV GXP already exceeds the emergency rating of the 220kV/66kV transformers during single fault transformer contingencies. The transformers are reaching the end of their lives and we propose to upgrade the capacity of Bromley 66kV GXP from 130MVA to approximately 300MVA. We are currently discussing with Transpower on the best way to achieve this capacity increase. Our urban subtransmission proposal would shift load from Islington GXP to Bromley GXP and therefore relieve constraints at Islington and make best use of new capacity at Bromley.

Options/comments

The most viable alternative to this approach would be to upgrade Islington 66kV GXP and transfer load on our network from Bromley to Islington. The cost to upgrade Islington GXP is estimated at $13m and this option would further increase the dependency of Christchurch city electricity supply on Islington.

2011 – ISLINGTON 66KV BAY FOR WEEDONS LINE (PROJECT 371)

To provide increased capacity in the greater Rolleston area and relieve constraints on Transpower's Springston GXP we propose to install a new 66kV line between Islington GXP and Weedons substation. This project provides for termination of the line at Islington.

Options/comments

See project 412 in section 5.6.6 – Major rural projects.

2011 – HORORATA 66KV BAY FOR WINDWHISTLE LINE (PROJECT 325)

This is a Transpower project to provide an extra bay with the costs recovered through our new investment agreement with Transpower.

Options/comments

As the line assets from Hororata to Windwhistle have already been installed and built to 66kV construction an alternative would be to install a new 33kV bay and operate Windwhistle as a 33/11kV substation. However, 33kV supply banks at Hororata GXP are already at their N-1 capacity so further growth off Hororata GXP should be connected to the 66kV bus.

2012 – PAPANUI 66KV BUS ZONE (PROJECT 328)

Pending the outcome of our urban subtransmission review and assessment of the load on Papanui GXP we propose to install a 66kV bus zone protection scheme to improve reliability of supply.

Options/comments

An alternative option is to operate the Papanui 66kV bus with a permanent split effectively creating two 66kV busbars. However, this would require the return to service of the 4th Islington to Papanui 66kV line and the re-commissioning of two 66kV bays.

2013 – SPRINGSTON 66KV BAY-SPRINGSTON 66/11KV LOCAL (PROJECT 370)

This is a Transpower project to provide an extra bay with the costs recovered through new investment agreement with Transpower. For more details see project 366 in section 5.6.6 – Major rural projects.

Options/comments

See project 366 in section 5.6.6 – Major rural projects.

2014 – SPRINGSTON 66KV BAY-LARCOMB (PROJECT 429)

To coincide with the conversion of Larcomb to 66kV, and complete the ring connection to Islington 66kV, a new 66kV bay will be installed at Springston GXP. This is a Transpower project to provide the extra bay, where the costs are recovered through a new investment agreement between us and Transpower.

Options/comments

See project 411 in section 5.6.6 – Major rural projects.

Major project details – GXPs – 2015-2019

2017 – KIRWEE GXP (PROJECT 391)

Growth in Kirwee has exceeded the capability and reach of Highfield and Darfield therefore a new GXP is needed at Kirwee. This new GXP will take supply from the Islington to Hororata lines.

Options/comments

See project 420 in section 5.6.6 – Major rural projects.

2018 – BROMLEY 66KV BAY – DALLINGTON (PROJECT 326)

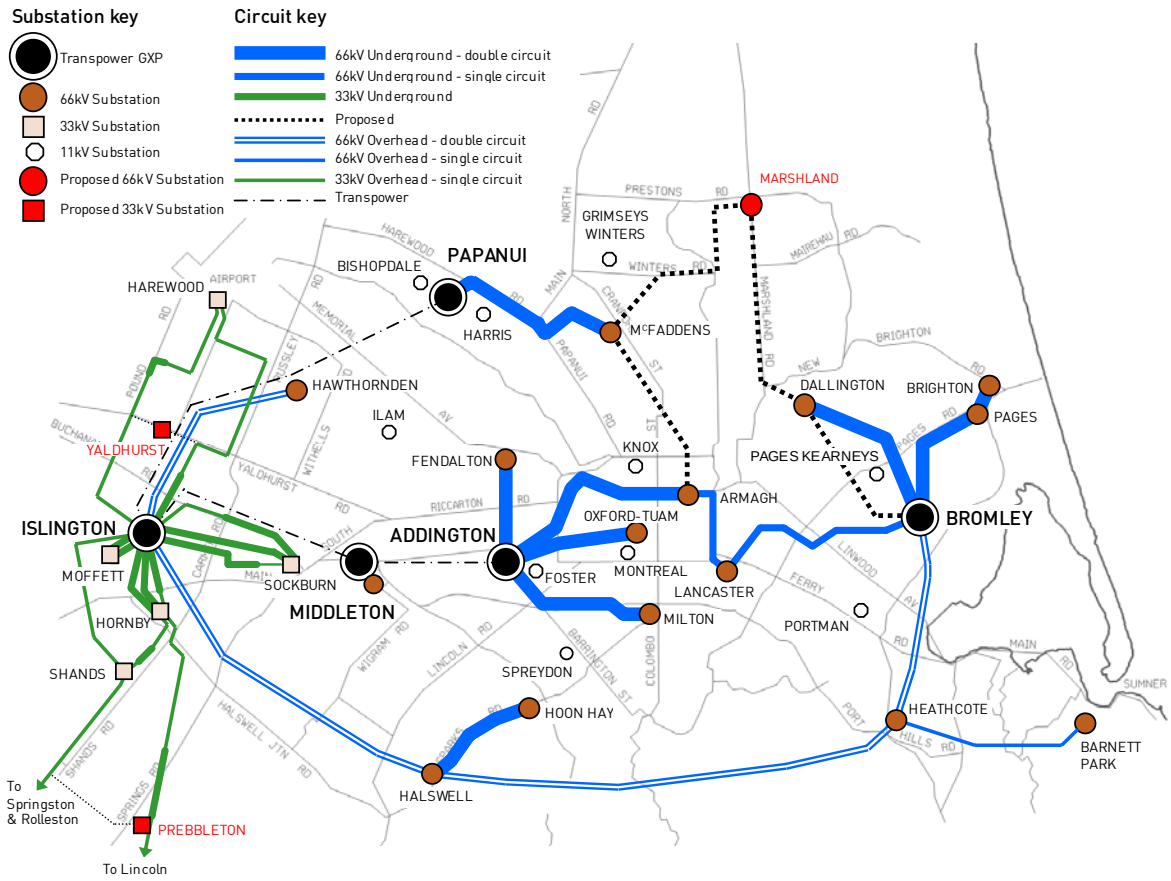
To provide additional capacity to the northern area of Christchurch city, a new 66kV bay will be required at Transpower's Bromley 66kV GXP. We propose to connect a 160MVA cable from Dallington district/zone substation. This project is part of our urban subtransmission options analysis. Further details are available on our website oriongroup.co.nz.

5.6.5 Major urban projects

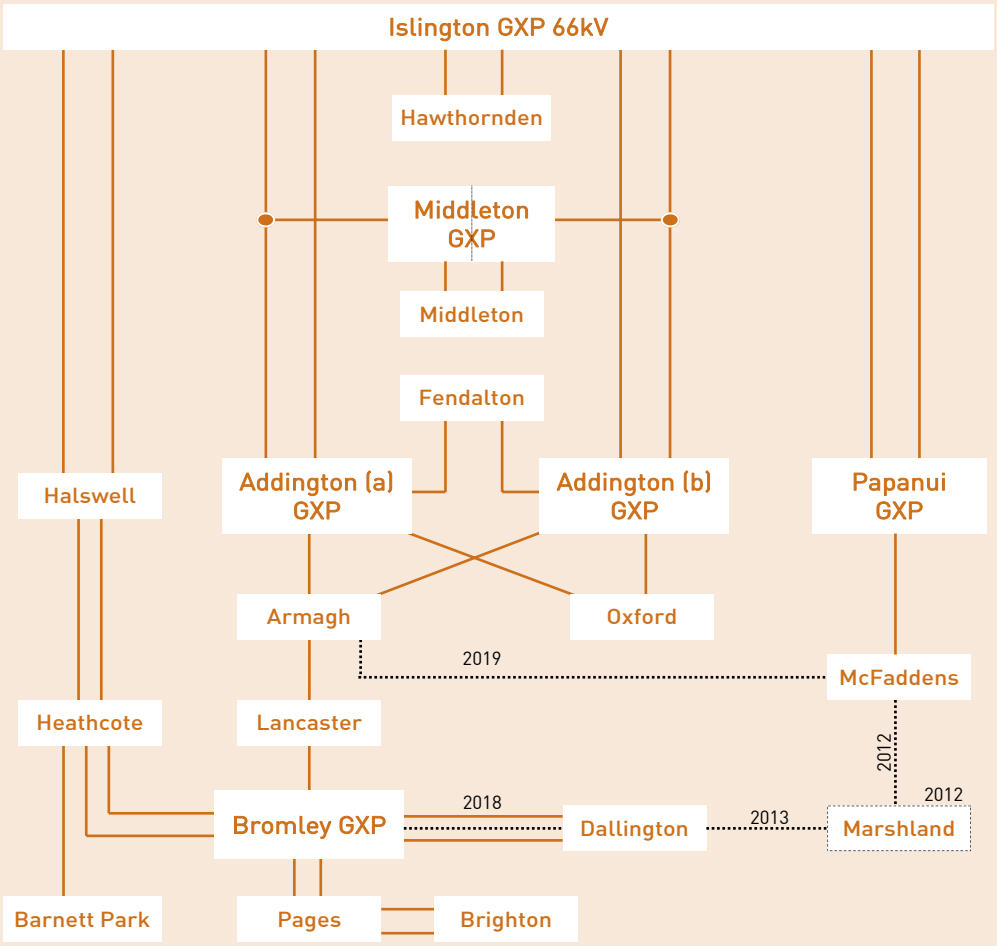
Major urban projects – $000, year ending 31 March

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
318	Hornby 33kV feeder upgrade	400									
401	Belfast substation site development	600									
451	Awatea land purchase	250									
486	Papanui 11kV swgr replacement stage 2	1,500									
282	Prebbleton substation		2,900								
487	McFaddens 66kV switchgear			3,350							
488	Marshland substation stage 1			4,400							
490	McFaddens to Marshland 66kV cable			10,400							
278	Dallington 66kV switchgear				850						
491	Dallington to Marshland 66kV cable				7,560						
496	Marshland substation stage 2				2,205						
118	Yaldhurst substation					4,500					
416	Prebbleton substation 2nd transformer							520			
417	Shands 33kV tee to Prebbleton							800			
233	Shands Road 33kV circuit reinforcement								250		
332	Moffett substation replace 33kV feeders								100		
492	Bromley to Dallington 66kV cable									7,050	
493	Armagh to McFaddens 66kV cable										7,420
144	Ilam 11kV switchgear										500
Urban subtotal		**2,750**	**2,900**	**18,150**	**10,615**	**4,500**	**0**	**1,320**	**350**	**7,050**	**7,920**

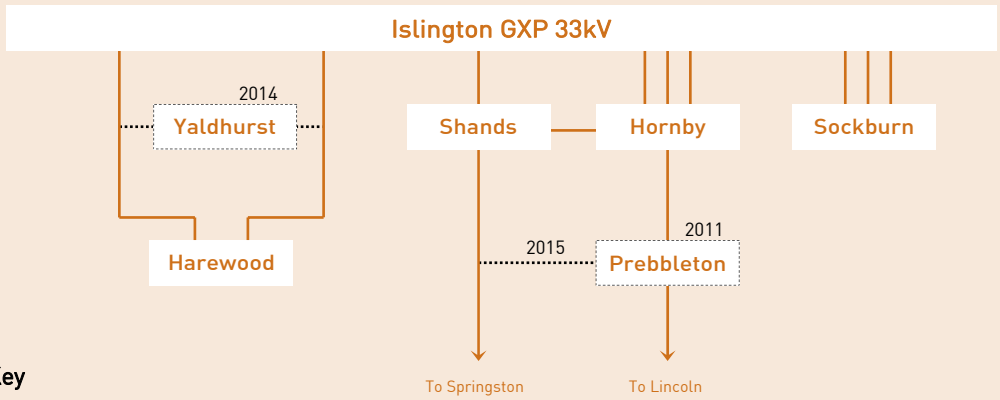
Urban subtransmission 66kV 33kV – existing and proposed



Urban subtransmission 66kV – existing and proposed



Urban subtransmission 33kV – existing and proposed



Key

2005 Proposed circuit/year

Existing circuit

Proposed substation | Existing substation

* Convert from 33kV to 66kV

These diagrams show only part of our total Christchurch urban network.

All of our substations are shown in the urban subtransmission map on the previous page.

Major project details – urban – current year 2010

2010 – HORNBY 33KV FEEDER UPGRADE (PROJECT 318)

Three 33kV feeders feed Hornby district/zone substation from Islington. Two of these feeders contain oil filled cable with an unacceptable risk of joint failure. One of the feeders also contains overhead line along Halswell Junction Road in the proposed path of the new southern motorway. The high impedance of the overhead line section limits capacity, as load is shared unequally between the three feeders. To rectify the situation, and provide additional capacity to feed a future Prebbleton district/zone substation, we propose to underground 1km of the overhead line between Foremans Road and Hornby district/zone substation. At the same time we will replace one of the existing Islington to Foremans Road 33kV oil filled cables to prevent the need to replace cable joints with costly 'oil to XLPE' joints.

Options/comments

The need to remove the overhead line to make way for the new southern motorway, together with the existing oil filled cable joint risk, led to the obvious solution above. A very costly alternative would be to abandon the 33kV feeder and increase 66kV capacity into the area.

2010 – BELFAST SUBSTATION – SITE DEVELOPMENT (PROJECT 401)

During 2008, we purchased land from meat processing company Silver Fern Farms for a future Belfast district/zone substation. We also hold a consent for 11.5MW of diesel generation at this site. To increase 11kV network capacity into the Belfast area we propose to undertake preliminary site works to enable our mobile generation to connect during emergencies. This project is the first stage of development and includes design, earthworks for noise bunding, perimeter fencing, exhaust stack and partial installation of an 11kV switchroom for temporary connection of our mobile generators.

Options/comments

The main alternative to this approach would be to construct the 66/11kV Belfast district/zone substation at an earlier date. Growth in residential subdivisions has slowed in recent times, and the incremental capacity approach provided by diesel generation offers a lower cost option in this economic environment. Diesel generation can also be used to assist with dry year reserve, upper South Island grid constraints and other contingencies on our summer peaking rural network.

2010 – AWATEA LAND PURCHASE (PROJECT 451)

Further residential and industrial land subdivision is proposed in Wigram and Awatea over the next 5-20 years. Transit and the Christchurch City Council (CCC) are currently designing the new southern motorway and spur road designs in Awatea. To ensure that land and cable corridors are available to develop a future 66/11kV substation, we propose to co-ordinate and purchase land in line with Transit and CCC proposals.

Options/comments

Alternative options include an upgrade of Halswell, Hornby and/or Shands district/zone substations. Depending on the load density of developments in the area, these options may prove to be viable in the longer term. We propose to purchase land in Awatea at this stage to ensure we have options in the future.

2010 – PAPANUI 11KV SWITCHGEAR REPLACEMENT – STAGE 2 (PROJECT 486)

The existing 11kV switchgear at Papanui GXP is owned by Transpower and was due to be replaced during 2009. Pending negotiations with Transpower and the most economic approach, Orion proposes to install and own the new 11kV switchgear. The new switchgear will facilitate options to remove Harris district/zone substation (scheduled for replacement in 2016) and provide an additional 4MVA of capacity to the Belfast 11kV network.

Options/comments

Continued load growth in close proximity to the Papanui 11kV switchgear provides no viable option but to replace the existing switchgear. The decision to extend the 11kV switchgear with additional 11kV circuit breakers was compared with the option to bring forward new 66/11kV district/zone substations at Belfast and Waimakariri. In the short term, the Papanui 11kV switchgear option provides a lower cost proposal without compromising reliability of supply.

Major project details – urban – years 2011-2014

2011 – PREBBLETON SUBSTATION (PROJECT 282)

Prebbleton township is currently supplied by two 11kV feeders from Shands district/zone substation. Limited contingent capacity is available from Lincoln and Springston district/zone substations but switching is made difficult by a phase shift between the rural substations and Shands Road. As the Prebbleton township grows, contingent capacity will be eroded and we propose to install a new 33/11kV district/zone substation at Prebbleton. Supply to Prebbleton district/zone substation will be provided by spare 33kV capacity at Hornby and through cutting into an existing 33kV overhead line between Hornby and Lincoln.

Options/comments

In the short term it is possible to continue to upgrade 11kV feeders with 11kV regulators from Shands district/zone substation to Prebbleton. The main limitation of this approach is higher losses and increasing dependency on Shands district/zone substation which has become increasingly difficult to support during N-2 events. Industrial development of land between Halswell Junction and Marshs Roads will also increase reliance on Shands district/zone substation. We will continue to monitor growth in this area, and if possible, will delay the installation of Prebbleton district/zone substation.

2012 – MCFADDENS 66KV SWITCHGEAR (PROJECT 487)

To provide a 66kV supply to the new substation at Marshland, we propose to install two 80MVA 66kV cables from McFaddens substation. A new 66kV switchroom will be required at McFaddens district/zone substation to rearrange the existing Papanui 66kV feeder cables and terminate the new Marshland cables. For further information on the background to this project please see our 'Urban Subtransmission Options Analysis' paper available on our website at oriongroup.co.nz.

Options/comments

We considered an option to lay two 40MVA cables from Papanui GXP to Marshland as this would reduce substation and switchgear costs. However, this option would increase cable costs and was rejected because it increased dependency on Papanui GXP and did not meet our security of supply objectives to create a 66kV interconnected network between Papanui and Bromley GXPs.

2012 – MARSHLAND SUBSTATION STAGE 1 (PROJECT 488)

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 draft Belfast Area Plan indicates significant industrial growth in the Belfast area is likely when the new northern motorway is installed. A local community group also proposes to request a change to the RPS which would allow an additional 2500 households in the Marshland area. To meet this growth in the short term we propose to install a new 66/11kV substation (23MVA) near the intersection of Marshland and Prestons Roads. Stage 1 would install the first of two 66/11kV 23MVA transformers. In the longer term, a 40MVA 66/11kV substation will be required in Belfast. Marshland substation provides a logical connection point for future 66kV supplies to the north (Belfast). Marshland district/zone substation will be supplied by 66kV cables from Dallington and McFaddens district/zone substation. For further information on the background to this project please see our 'Urban Subtransmission Options Analysis' paper available on our website at oriongroup.co.nz.

Options/comments

Substantial growth is expected to the north of Christchurch. To meet the demand for electricity, a 66/11kV substation/s will be required in the area. Where economically viable, a substation to the north of the city will be delayed by diesel generation at Belfast (see project 401 on the previous page). Belfast district/zone substation would delay the need for Marshland district/zone substation, but the remote Belfast site far from existing 66kV supplies would cause a lower level of security of supply at a similar cost. Marshland district/zone substation provides an opportunity to install a 66kV connection between Transpower's Papanui and Bromley GXPs. This significantly enhances the security of supply for our consumers in the northern half of Christchurch city.

2012 – MCFADDENS TO MARSHLAND 66KV CABLE (PROJECT 490)

To provide a 66kV supply to the new substation at Marshland, we propose to install two 80MVA 66kV cables from McFaddens substation. This project completes the first leg of a 66kV connection between Papanui and Bromley 66kV GXPs. For further information on the background to this project please see our 'Urban Subtransmission Options Analysis' paper, available on our website at oriongroup.co.nz.

Options/comments

Options to lay two 40MVA cables from either Bromley or Papanui GXPs to Marshland substation were not consistent with our objective to create a tie between Papanui and Bromley GXPs and were therefore not considered appropriate to meet our security of supply objectives. Over the next 12 months we will investigate whether one 120MVA cable from McFaddens to Marshland is sufficient. The decision to lay two 80MVA cables was based on the future need to have secure supply to Belfast district/zone substation. When more accurate pricing from cable suppliers is provided, we will assess the merits of delaying the second cable or perhaps providing an alternative feed from other locations within the network.

2013 – DALLINGTON 66KV SWITCHGEAR (PROJECT 278)

A small 66kV switchyard will be required at Dallington to terminate the Marshland-to-Dallington 66kV cable. For further information on the background to this project please see our 'Urban Subtransmission Options Analysis' paper available on our website at oriongroup.co.nz.

Options/comments

An alternative option was to bypass Dallington and take the Marshland cable directly to Bromley GXP. While this would reduce the need for Dallington 66kV switchgear, it would require us to bring forward the cost of the Bromley to Dallington 66kV cable. The net present value (cost) of this option is higher than our current proposal.

2013 – DALLINGTON TO MARSHLAND 66KV CABLE (PROJECT 491)

To relieve constraints on the Papanui to McFaddens 66kV cables, we propose to lay a new 160MVA cable between Dallington and Marshland substation. This will enable the Bromley to Dallington cables to provide back-up supply to Marshland substation during 66kV cable contingencies between Papanui and McFaddens. This project also completes the 66kV link between Papanui and Bromley GXPs, and therefore assists to restore supply quickly if a major plant failure should occur at Bromley or Papanui GXP.

Options/comments

For further information on the background to this project and alternative options please see our 'Urban Subtransmission Options Analysis' paper available on our website at oriongroup.co.nz.

2013 – MARSHLAND SUBSTATION STAGE 2 (PROJECT 496)

For detail about this project see project 488 (2012 – Marshland substation stage 1) on the previous page.

2014 – YALDHURST SUBSTATION (PROJECT 118)

Land development around Christchurch airport may mean our existing Harewood substation needs to be relocated. This project makes provision for a larger substation to be installed at Yaldhurst. In the longer term it may be more desirable to build a new substation (Waimakariri) to the north of the airport. The demand, timing and scale of land development around the airport is difficult to gauge and therefore this project is indicative only.

Options/comments

Several alternatives to this project exist, all of which are affected greatly by the timing and scale of development around Christchurch airport. We will continue to investigate options for this area to ensure our plans are flexible enough to deal with changes in demand and land use.

Major project details – urban – years 2015-2019

2016 – PREBBLETON SUBSTATION SECOND TRANSFORMER (PROJECT 416)

Depending on diversity of loads between Hornby, Shands and Prebbleton district/zone substations, load at Prebbleton district/zone substation may grow to a 15MVA without the need to increase the capacity of the 33kV subtransmission network. If this growth occurs, it would be appropriate to increase reliability and security of supply to Prebbleton by installing the old Larcomb 33/11kV 23MVA transformer at Prebbleton.

2016 – SHANDS 33KV TEE TO PREBBLETON (PROJECT 417)

Depending on diversity of loads between Hornby, Shands and Prebbleton district/zone substations, load at Prebbleton district/zone substation may grow to a 15MVA without the need to increase the capacity of the 33kV subtransmission network. If this growth occurs it would be appropriate to increase reliability and security of supply to Prebbleton by installing a closed ring 33kV supply. We propose to install a second 33kV incomer to Prebbleton by teeing onto the existing Shands to Rolleston tie feeder.

2017 – SHANDS ROAD 33KV CIRCUIT REINFORCEMENT (PROJECT 233)

Firm capacity at Shands district/zone substation is currently limited to 17MVA by a 33kV overhead line in Shands Road. Industrial load growth in the Hornby region will require an increase in capacity at Shands district/zone substation. We propose to increase Shands district/zone substation capacity to 23MVA by replacing the 33kV overhead line with a larger underground cable.

2017 – MOFFETT SUBSTATION REPLACE 33KV FEEDERS (PROJECT 332)

Depending on whether we install Yaldhurst district/zone substation in 2013, we may need to increase the capacity of Moffett district/zone substation to meet load in the Yaldhurst/Masham area. Moffett capacity is currently limited to 19MVA by the 33kV incomers. We propose to increase capacity to 23MVA by replacing the existing incomers.

2018 – BROMLEY TO DALLINGTON 66KV CABLE (PROJECT 492)

By 2019 the load on the Islington 66kV GXP is expected to exceed the contingency (N-1) capacity of the 220/66kV interconnecting transformers. We propose to avoid an upgrade at Islington GXP by transferring Armagh and McFaddens substations from Islington to Bromley GXP. To facilitate this approach requires a new cable between Bromley GXP and Dallington substation and also a cable between Armagh and McFaddens substations (see project 493 in 2019).

Options/comments

For further information on the background to this project and alternative options please see our 'Urban Subtransmission Options Analysis' paper, available on our website at oriongroup.co.nz.

2019 – ARMAGH TO MCFADDENS 66KV CABLE (PROJECT 493)

By 2019 load on the Islington 66kV GXP is expected to exceed the contingency (N-1) capacity of the 220/66kV interconnecting transformers. We propose to avoid an upgrade at Islington GXP by transferring Armagh and McFaddens substations from Islington to Bromley GXP. This approach requires a new cable between Armagh and McFaddens substations and also a cable between Bromley GXP and Dallington substation (see project 492 in 2018 above).

Options/comments

For further information on the background to this project and alternative options please see our 'Urban Subtransmission Options Analysis' paper, available on our website at oriongroup.co.nz.

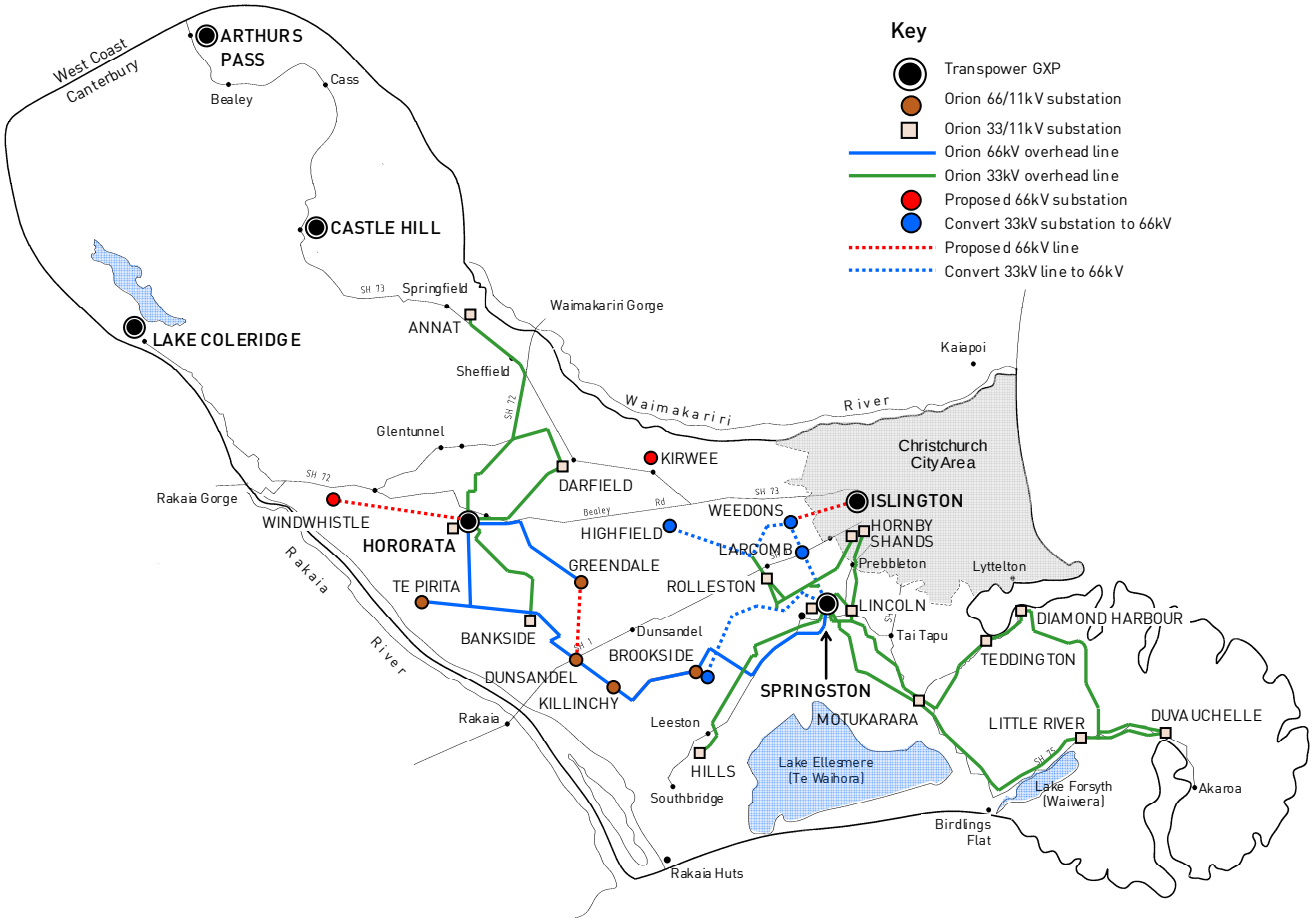
2019 – ILAM 11KV SWITCHGEAR (PROJECT 144)

The first stage of Ilam substation was completed during 2004. We anticipate that its capacity will be fully utilised by 2019.

5.6.6 Major rural projects

Major rural projects – $000, year ending 31 March											
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
218	Ground Fault Neutralisers	1,500									
411	Springston to Larcomb conductor upgrade	940									
452	Lincoln 33kV switchgear and transformer up-rating – stage 2	550									
470	Rolleston T1 protection upgrade	120									
484	Rural harmonic improvement	100									
192	Islington to Weedons 66kV line		2,500								
219	Ground Fault Neutralisers		1,185								
348	Windwhistle substation		2,800								
412	Weedons 66kV substation		1,730								
473	Dunsandel 66kV bay		380								
474	Greendale to Dunsandel 66kV line		2,300								
494	Rural power factor correction		120								
495	Rural power factor correction			120							
220	Ground Fault Neutralisers			880							
367	Darfield 33kV switchgear or second transformer			250							
221	Ground Fault Neutralisers				552						
306	Annat transformer upgrade				400						
361	Teddington transformer upgrade				350						
366	Convert Springston from 33/11kV to 66/11kV				1,140						
413	Larcomb to Weedons 66kV conversion					1,260					
414	Convert Larcomb to 66kV					2,915					
114	Highfield 66/11kV transformer						1,070				
415	Weedons to Highfield tee 66kV conversion						840				
369	Teddington 33kV line circuit breakers								600		
420	Kirwee 66kV substation								3,000		
365	Lincoln transformer upgrade									1,600	
418	Springston to Rolleston 33kV cable tee									1,250	
421	Springston to Brookside 66kV line conversion									2,660	
422	Brookside 66kV bay and transformer									2,000	
Rural subtotal		**3,210**	**11,015**	**1,250**	**2,442**	**4,175**	**1,910**	**0**	**3,600**	**7,510**	**0**

Rural subtransmission network 66 and 33kV – existing and future



Major project details – rural – current year 2010

2010 – GROUND FAULT NEUTRALISERS (PROJECT 218)

To minimise the risk of equipment damage and improve safety, Orion has historically installed neutral earthing resistors at district/zone substations which supply overhead 11kV networks. After a successful trial of an alternative earthing method using a Ground Fault Neutraliser (GFN) at Darfield district/zone substation in 2007/08, we now propose to fit a GFN to most rural substation transformers. This project is to purchase and install five additional units.

Options/comments

A GFN provides the same, or better, safety performance as traditional neutral earthing resistors while the reliability benefits are more economic than installing line circuit breakers and/or covered conductors.

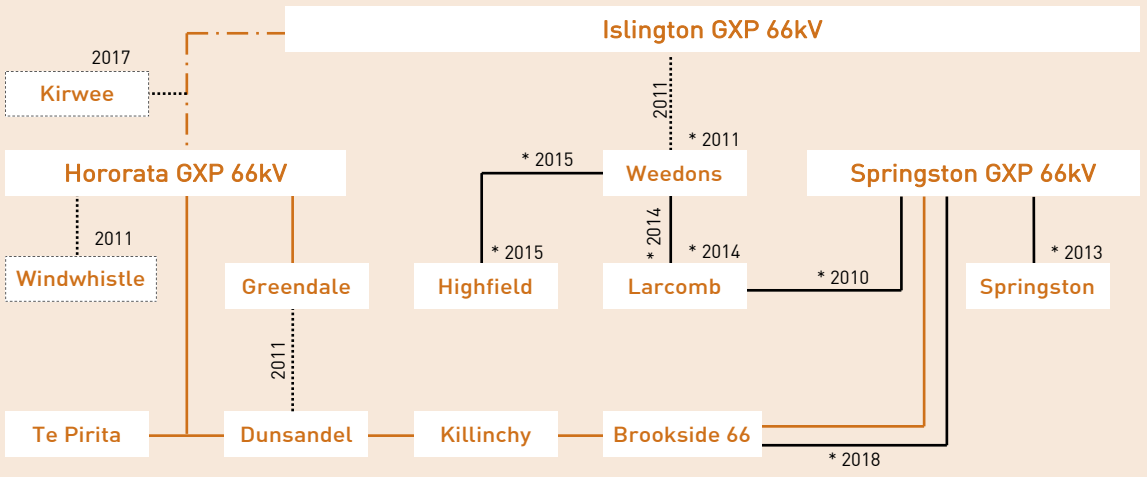
2010 – SPRINGSTON TO LARCOMB CONDUCTOR UPGRADE (PROJECT 411)

To provide increased capacity into the Rolleston 33kV loop, we propose to upgrade the Springston to Jones Road section of line to Jaguar conductor. To future proof the line for conversion to 66kV in 2014, we propose to use 66kV construction. This budget also covers the cost of design for the Islington to Weedons 66kV line conversion.

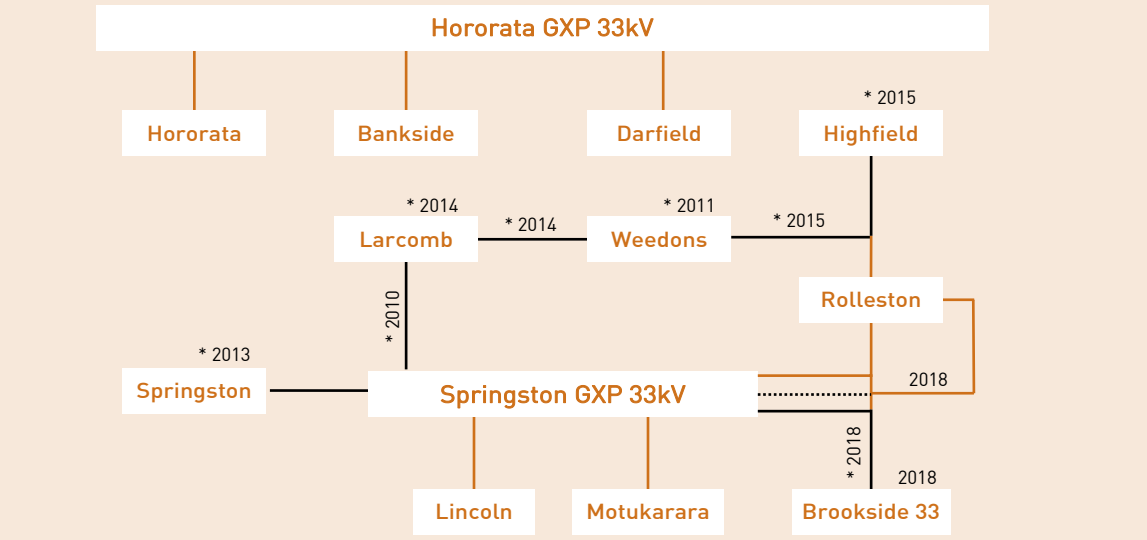
Options/comments

This project is part of a greater project to introduce further capacity into the close-to-constrained rural network by bringing a new 66kV line direct from Islington GXP to Springston GXP. It will increase the rural network capacity by 40MW and relieve the constrained Springston 33kV capacity. We also investigated an option to install a new 220/66kV point-of-supply at the existing Springston GXP site, but this was an expensive alternative and could only be justified if Islington capacity was stretched.

Rural subtransmission network 66kV – existing and proposed



Rural subtransmission network 33kV – existing and proposed



Key

- 2015 ..... Proposed line/year
- 2015 ——— Existing, convert to 66kV
- ——— Existing
- —·—·— Transpower

Proposed substation | Existing substation

* Convert to 66kV

These diagrams show only part of our total rural network.

All substations are shown in the rural subtransmission map on the previous page.

2010 – LINCOLN 33KV SWITCHGEAR AND TRANSFORMER UP-RATING – STAGE 2 (PROJECT 452)

To improve the reliability of supply for Lincoln township we propose to provide a closed ring 33kV supply by installing additional 33kV switchgear at Lincoln district/zone substation when we replace the existing outdoor structure. Also, we will attach cooling fans to the 7.5MVA transformers to improve the contingent transformer capacity. This project budget allows for additional costs above what it would normally cost to replace the Lincoln 33kV switchgear.

Options/comments

An alternative to the closed ring supply would be to install an additional 33kV cable from Lincoln back to Springston, creating two N-1 feeders. This would cost considerably more and would not provide a place to terminate the Hornby 33kV circuit.

2010 – ROLLESTON T1 PROTECTION UPGRADE (PROJECT 470)

To increase the reliability of supply to Rolleston we propose to switch the 33kV subtransmission to provide an alternative feed using the Brookside feeder. To enable this scheme to operate safely, reverse power flow protection must be installed on Rolleston T1.

Options/comments

This is a reliability improvement to Rolleston to provide uninterrupted N-1. The only other way to provide full N-1 would be to build another circuit from Springston GXP out to the Rolleston-tee at considerable extra cost. An operational solution could be to operate the Rolleston 11kV bus split, but half the Rolleston load would still lose power during a subtransmission fault.

2010 – RURAL HARMONIC IMPROVEMENT (PROJECT 484)

As the cost of variable speed drive (VSD) technology for irrigation pumps has decreased over the last five years, we have noticed an increasing number VSD pumps have been installed at new and existing sites. Although the VSDs give irrigators far greater flexibility, they also draw a non-sinusoidal current from the network and generate plenty of harmonics. These harmonics are approaching unacceptable levels so we are taking steps to reduce, and at best eliminate, the worst harmonic at 250Hz. We propose to change half of the VSD load supply transformers to ones with a 30 degree phase shift in a hope this will reduce the magnitude and propagation of harmonics into the upper network.

Options/comments

We investigated an option to install harmonic filters at each VSD site, but compared to the marginal increase in distribution transformer cost (due to the fact the existing ones can be reused), this was not economically viable.

Major project details – rural – years 2011-2014

2011 – ISLINGTON TO WEEDONS 66KV LINE (PROJECT 192)

Orion's rural network is currently fed by Transpower GXPs at Hororata and Springston. The combined capacity of Hororata and Springston GXPs is approximately 94MVA, and the existing peak rural load is approximately 80MVA. Depending on growth at Synlait dairy factory and the outcome of the proposed Central Plains Irrigation Scheme, we anticipate that further 66kV subtransmission capacity will be required in the area. This project is the start of a strategy to provide an extra 40-60MVA of capacity into the rural network and provide improved security and reliability to Hororata and Springston GXPs.

Options/comments

This project is part of a greater project to introduce further capacity into the close-to-constrained rural network by bringing in a new 66kV line direct from Islington GXP to link back to Springston GXP. It will increase the rural network capacity by 40MW and relieve the constrained Springston 33kV capacity. We also investigated an option to install a new 220/66kV point-of-supply at the existing Springston GXP, but this was an expensive alternative that could only be justified if Islington 66kV capacity was stretched.

2011 – GROUND FAULT NEUTRALISERS (PROJECT 219)

To minimise the risk of equipment damage and improve safety, Orion has historically installed neutral earthing resistors at district/zone substations which supply overhead 11kV networks. After a successful trial of an alternative earthing method using a Ground Fault Neutraliser (GFN) at Darfield district/zone substation in 2007/08, we now propose to fit a GFN to most rural substation transformers. This project is to install five units purchased in 2010 and purchase four additional units.

Options/comments

A GFN provides the same, or better, safety performance as traditional neutral earthing resistors while the reliability benefits are more economic than installing line circuit breakers and/or covered conductors.

2011 – WINDWHISTLE SUBSTATION (PROJECT 348)

The Windwhistle region is currently supplied from Hororata via an 11kV line. Peak load in this area is less than 1MVA. As a precursor to the Central Plains Irrigation Scheme, irrigating a large farm may require up to 3MW of new electrical capacity. Load in excess of 2MW would require new transformation capacity. This project proposes to install a new 66/11kV (or 33/11kV) district/zone substation at Windwhistle. The site location will be aligned with the long term requirements of the Central Plains Irrigation Scheme.

Options/comments

As the line assets from Hororata to Windwhistle have already been installed and built to 66kV construction, an alternative would be to install a new 33kV bay and operate Windwhistle as a 33/11kV substation. However, 33kV supply banks at Hororata GXP are already at their N-1 capacity, so further growth off Hororata GXP should be connected to the 66kV bus.

2011 – WEEDONS SUBSTATION CONVERT TO 66KV (PROJECT 412)

We propose to convert the existing Weedons 33kV substation to 66kV as part of the strategy to bring further 66kV capacity to the rural area and decrease dependence on the Springston GXP 33kV bus.

Options/comments

This project is part of a greater project to introduce further capacity into the close-to-constrained rural network by bringing in a new 66kV line direct from Islington GXP to link back to Springston GXP. It will increase the rural network capacity by 40MW and relieve the constrained Springston 33kV capacity. We also investigated an option to install a new 220/66kV point-of-supply at the existing Springston GXP, but this was an expensive alternative that could only be justified if Islington 66kV capacity was stretched.

2011 – DUNSANDEL SUBSTATION 66KV BAY (PROJECT 473)

Growth at Dunsandel has reached the point where an additional connection to the Hororata GXP is required. The Dunsandel district/zone substation has been designed to accommodate three line termination circuits. Therefore all that is required is to install an additional 66kV circuit breaker to establish the new bay.

Options/comments

An alternative to the additional circuit breaker to establish the new bay would be to share an existing bay with the Killinchy line. This would be operationally hard to manage and would require the installation of a complicated line protection scheme.

2011 – GREENDALE-DUNSANDEL 66KV LINE (PROJECT 474)

The exact timing of this project depends on the demand at Synlait dairy factory and the rate of future growth. At present the 66kV system is setup on a changeover between the Hororata to Springston GXPs if a fault occurs, but as load increases at Synlait the quality of supply post-contingency will degrade to a point where additional line capacity will be required. The chosen topology negates the need to build any additional circuit breaker bays at Greendale by having Greendale on a T-off.

Options/comments

We considered alternatives to reinforce the 66kV network out of Springston GXP or establish a new 220/66kV GXP at Killinchy due to its proximity to Transpower's Twizel-to-Islington 220kV tower line. However both these options

would cost more and a GXP at Killinchy would get low levels of use as the majority of the surrounding load is summer peaking irrigation. An alternative variation on our final design was to install new line section circuit breakers at Greendale to increase reliability, but detailed analysis showed this was not economically viable.

2011 – RURAL POWER FACTOR CORRECTION (PROJECT 494)

To reduce losses and help with voltage support during contingencies on the subtransmission network we propose to fit switchable capacitor banks to strategic 11kV buses on the rural network. This will cover the cost of installing capacitors at Killinchy and Dunsandel.

Options/comments

This project defers the need to bring forward major subtransmission reinforcement projects.

2012 – RURAL POWER FACTOR CORRECTION (PROJECT 495)

To reduce losses and help with voltage support during contingencies on the subtransmission network we propose to fit switchable capacitor banks to strategic 11kV buses on the rural network. This will cover the cost of installing capacitors at Te Pirita and Greendale.

Options/comments

This project defers the need to bring forward major subtransmission reinforcement projects.

2012 – GROUND FAULT NEUTRALISERS (PROJECT 220)

To minimise the risk of equipment damage and improve safety, Orion has historically installed neutral earthing resistors at district/zone substations which supply overhead 11kV networks. After a successful trial of an alternative earthing method using a Ground Fault Neutraliser (GFN) at Darfield district/zone substation in 2007/08, we now propose to fit a GFN to most rural substation transformers. This project is to purchase and install four additional units.

Options/comments

A GFN provides the same, or better, safety performance as traditional neutral earthing resistors while the reliability benefits are more economic than installing line circuit breakers and/or covered conductors.

2012 – DARFIELD 33KV SWITCHGEAR OR 2ND TRANSFORMER (PROJECT 367)

Darfield district/zone substation is currently fed via two 33kV radial supplies from Hororata GXP. The load is now at a point where full N-1 supply is required. The existing 33kV circuit breaker switchgear is due to be replaced so various options exist. To improve the reliability of supply to Darfield, we propose to install additional 33kV switchgear. This project includes installing additional 33kV breakers at Darfield district/zone substation during scheduled 33kV circuit breaker replacement.

Options/comments

An alternative to achieve an uninterrupted N-1 supply to Darfield would be to install a second transformer (which would possibly be the existing Weedons 7.5MVA) and remove the switchgear. A detailed analysis for costs and design will be done closer to the time.

2013 – GROUND FAULT NEUTRALISERS (PROJECT 221)

To minimise the risk of equipment damage and improve safety, Orion has historically installed neutral earthing resistors at district/zone substations which supply overhead 11kV networks. After a successful trial of an alternative earthing method using a Ground Fault Neutraliser (GFN) at Darfield district/zone substation in 2007/08, we now propose to fit a GFN to most rural substation transformers. This project is to install four additional units.

Options/comments

A GFN provides the same, or better, safety performance as traditional neutral earthing resistors while the reliability benefits are more economic than installing line circuit breakers and/or covered conductors.

2013 – ANNAT TRANSFORMER UPGRADE (PROJECT 306)

If the Central Plains Irrigation Scheme proceeds, an increase in capacity will probably be required at Annat to pump water from the Waimakariri River to Springfield and Sheffield. We propose to replace the existing 2.5MVA transformer with a 7.5MVA using a new or existing transformer depending on availability at the time.

Options/comments

The load on the Hororata 33kV GXP will be beyond the N-1 limit. Several options exist for this project. One option could be to convert Annat district/zone substation to 66kV, or if Annat stays at 33kV, the local transformer at Hororata district/zone substation could be removed and a new 66/11kV one installed at Hororata GXP. Detailed design will be done closer to the time.

2013 – TEDDINGTON TRANSFORMER UPGRADE (PROJECT 361)

Teddington district/zone substation provides contingent capacity for faults at Diamond Harbour district/zone substation and vice versa. Both Diamond Harbour and Teddington were 2.5MVA single transformer sites with peak loads of 1.6MVA. A fault at peak load (3.2MVA total) would overload the remaining transformer. The existing transformer at Diamond Harbour is a new 7.5MVA transformer installed in 2007. We now propose to relocate the new long reach 7.5MVA transformer from Motukarara to Teddington, and install the old Springston 7.5MVA transformer at Motukarara. This work would coincide with other major replacement and reinforcement work at the substation.

Options/comments

An alternative would be to install a second transformer at Diamond Harbour, but this option would require major civil works and a bigger substation yard.

2013 – CONVERT SPRINGSTON FROM 33/11KV TO 66/11KV (PROJECT 366)

Orion's 33kV switchgear at Springston district/zone substation will need to be replaced in 2013 and, although not required immediately, additional capacity at Springston will be required in the 5-10 year timeframe to support Lincoln district/zone substation during contingencies. Rather than replace the 33kV switchgear, we propose to install an additional 66kV bay on the Transpower bus and replace the existing 33/11kV 7.5MVA transformer with a new 10MVA 66/11kV transformer.

Options/comments

An alternative would be to replace the 33kV switchgear, but our current equipment standard for medium voltage switchgear requires us to use indoor vacuum circuit breakers. This would require a new building to be constructed at a combined cost far greater than that of a new 66kV bay and transformer.

2014 – LARCOMB TO WEEDONS 66KV LINE CONVERSION (PROJECT 413)

To make full use of the extra 66kV capacity gained from the new line from Islington GXP to Weedons district/zone substation, we need to convert the final section of line between Larcomb and Weedons to 66kV construction.

Options/comments

This project is part of a greater project to introduce further capacity into the close-to-constrained rural network by bringing in a new 66kV line direct from Islington GXP to link back to Springston GXP. It will increase the rural network capacity by 40MW and relieve the constrained Springston 33kV capacity. We also investigated an option to install a new 220/66kV point-of-supply at the existing Springston GXP, but this was an expensive alternative that could only be justified if Islington 66kV capacity was stretched.

2014 – CONVERT LARCOMB SUBSTATION TO 66KV (PROJECT 414)

We propose to replace the existing transformer at Larcomb district/zone substation with a new 66/11kV 23MVA transformer. This would enable the Larcomb-to-Springston line to operate at 66kV and improve reliability and security of supply to all Springston GXP consumers. To increase reliability at Larcomb and security of supply for Weedons, we propose to install a second 23MVA transformer at Larcomb.

Options/comments

See project 413 above.

Major project details – rural – years 2015-2019

2015 – HIGHFIELD 66/11KV TRANSFORMER (PROJECT 114)

Highfield district/zone substation is currently fed by 33kV line from Transpower's Springston GXP. This line also supplies Rolleston district/zone substation. During peak summer loads the Highfield transformer reaches its maximum tap range due to voltage drop in the 33kV line. Greendale substation installed in 2006 has relieved load on Highfield substation in the short term. During 2009 we propose to convert Highfield district/zone substation to 66kV. This project involves upgrading the existing 7.5MVA 33/11kV transformer at Highfield to a 10MVA 66/11kV transformer.

2015 – WEEDONS TO HIGHFIELD TEE 66KV CONVERSION (PROJECT 415)

To complete the conversion of Highfield to 66kV, the existing redundant 33kV line from Weedons to the Highfield tee-off will be converted to 66kV construction. This will be engineered to hold Jaguar conductor, but initially constructed with only Dog.

2017 – TEDDINGTON 33KV LINE CIRCUIT BREAKERS (PROJECT 369)

At present, a 33kV subtransmission fault anywhere on the line sections between Motukarara and Diamond Harbour will cause an outage to Teddington. We propose to install 33kV line breakers at Teddington to enable the Banks Peninsula 33kV subtransmission ring to be fully sectionalised. This will improve security of supply in the event of 33kV line faults.

2017 – KIRWEE 66KV SUBSTATION (PROJECT 420)

Kirwee is currently fed from Darfield at 11kV, however forecast growth at Kirwee and surrounding regions will cause excessive voltage constraints under normal operating conditions. We propose to develop a new 66/11kV substation in Kirwee taking supply from Kirwee GXP.

Options/comments

We could install an 11kV regulator to provide additional nominal capacity , but this would not provide the required security for major N-1 events.

2018 – LINCOLN TRANSFORMER UPGRADE (PROJECT 365)

The greater Christchurch urban development strategy proposes further residential zoning of land at Lincoln. The resulting increase in load could be supplied by Lincoln and/or Springston district/zone substation.

Options/comments

We propose to upgrade the existing Lincoln 10MVA transformers to 23MVA, or install a second transformer at Springston.

2018 – SPRINGSTON TO ROLLESTON 33KV CABLE TEE (PROJECT 418)

To improve subtransmission reliability and capacity to the Rolleston loop, we plan to lay a new 33kV cable from Springston to the Rolleston-tee. We also plan to swap feeders at Springston GXP between circuit breakers 1162 and 1202 to facilitate a future 33kV bus coupler. The aging Rolleston 33kV switchgear would also be removed.

Options/comments

Depending on load growth at Rolleston township and in the adjacent areas, options exist to convert the existing 33kV line to 66kV. We will investigate this project closer to the required date.

2018 – SPRINGSTON TO BROOKSIDE 66KV LINE CONVERSION (PROJECT 421)

To boost the load transfer capability between Springston and Hororata GXPs we propose to rebuild the existing 33kV line from Springston to Brookside using 66kV construction. This will run in parallel with the existing 66kV line to improve the reliability of supply.

2018 – BROOKSIDE 66KV BAY AND 66/11KV TRANSFORMER (PROJECT 422)

As part of the Springston to Brookside 66kV conversion, we will need to establish a new 66kV bay to replace the existing 33kV at Brookside. Also, as part of the conversion, the existing 33/11kV T2 transformer would be changed to a 66/11kV 7.5/10MVA to enable the existing T1 bank to run in parallel.

5.6.7 11kV urban reinforcement projects

11kV urban reinforcement – $000, year ending 31 March											
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
69	Montreal Street rearrangement	35									
226	Harewood Road reinforcement	847									
457	11kV primary ring protection – stage 2	90									
462	Power quality monitoring	150									
468	New Brighton reinforcement	480									
469	Sockburn-to-Moffett 11kV reinforcement	370									
471	Riccarton reinforcement	155									
475	Matipo Street reinforcement	91									
482	Parlane and Lincoln Road reinforcement	86									
497	Routed communication network	150									
50	Lyttelton subtransmission		1,034								
167	Bromley feeder rearrangement		250								
247	Dallington feeder		200								
252	Bishopdale-to-Roydvale upgrade		240								
255	Halswell 286 alterations		20								
316	Wickham Street reinforcement		300								
444	Templeton reinforcement		70								
459	11kV primary ring protection – stage 3		140								
463	McCormacks Bay Road		200								
479	Tower Street reinforcement		220								
480	Carmen Road reinforcement		150								
481	Waterloo Road reinforcement		100								
48	Lancaster-to-Milton tie			273							
315	Stanmore Road 119 upgrade			200							
476	Steadman Road			190							
478	Edmonton Road reinforcement			400							
485	Addington-Feilding Street secondary circuit			50							
483	Springs Road reinforcement				900						
Urban reinforcement subtotal		**2,454**	**2,924**	**1,113**	**900**	**0**	**0**	**0**	**0**	**0**	**0**

11kV reinforcement project details – urban – current year 2010

2010 – MONTREAL STREET REARRANGEMENT (PROJECT 69)

The secondary 11kV network between Hazeldean 198 and Wordsworth 49 has reached capacity during single fault contingencies. During switchgear replacement at Burke Street we propose to convert the existing primary 11kV feed to a secondary feed, which would provide tie support to the Hazeldean and Wordsworth secondary network.

Options/comments

As this utilises existing installed network capacity by re-routing , it is the cheapest option to gain further capacity.

2010 – HAREWOOD ROAD REINFORCEMENT (PROJECT 226)

Further load growth is anticipated north of Christchurch airport. To provide continued security of supply to the area in the short term, we propose to lay a new cable along Harewood Road to the north end of Orchard Road.

Options/comments

We investigated alternatives to introduce new generation or install a new district/zone substation. However as there is still plenty of undeveloped industrial land in the McLeans Island and Orchard Road areas a cable is seen as the most cost effective way to provide the necessary capacity in the short term as it utilises spare Papanui No.1 11kV capacity. It is also an incremental investment towards a district/zone substation as it forms routes for new 11kV feeders.

2010 – 11KV PRIMARY RING PROTECTION – STAGE 2 (PROJECT 457)

Orion's 11kV subtransmission utilises in some cases multi-parallel feed closed ring feeders for better asset utilisation and improved reliability for cable faults. However network substation bus faults on such architectures cannot be easily protected against and complete loss of all district/zone substation load may be imminent. Our chosen solution is the lowest cost, highest gain, solution that does not need complicated and expensive directional overcurrent elements on all network substations on the affected ring. This project will install new protection relays and associated current transformers at Milton.

Options/comments

An option would be to install directional overcurrent protection that was also capable of detecting circuit breaker trip failure on every circuit breaker at every network substation on an affected ring. However this would be a very expensive when compared to the chosen option.

2010 – POWER QUALITY MONITORING (PROJECT 462)

This will complete the third and final year in a three-year project to install a total of approximately 30 power quality monitors throughout our network. See section 7.8.4 for a description of this project.

2010 – NEW BRIGHTON REINFORCEMENT (PROJECT 468)

This project involves minor 11kV secondary reinforcement and was triggered by the Christchurch City Council's plans to rebuild the Palmers Road pump station site which also houses the Palmers Road 193 network substation. Also, the switchgear at Keyes Road N and Keyes Road S needs to be replaced. We therefore propose to bring additional capacity into the nearly fully-utilised New Brighton area to coincide with a local authority undergrounding project on Bower Avenue, decommissioning of Palmers Road network substation and downsizing of the North Brighton primary loop. No additional cables need to be laid from Brighton district/zone substation for this project. When we reduce the size of the existing primary ring system, the existing over-current protection at Brighton should be able to clear 11kV network substation bus faults. Under the existing configuration, those faults would cause cascade failure of the entire Brighton substation.

Options/comments

Other alternatives included rebuilding the Brighton primary loop like-for-like, but this would require three new 11kV circuit breaker switchboards, a new building and a new bus-fault protection system with no gains in capacity.

2010 – SOCKBURN-TO-MOFFETT 11KV REINFORCEMENT (PROJECT 469)

With Moffett district/zone substation approaching it's firm capacity, and Sockburn district/zone substation no longer constrained by subtransmission (after the third supply bank installation), an opportunity now exists to supply more load from Sockburn to relieve Moffett. This project proposes laying a new large capacity cable out of Sockburn substation into an area traditionally supplied by Moffett. Other minor alterations are also required to achieve the desired outcome.

Options/comments

As Moffett is on the fringe of the urban network we did not consider the option to increase Moffett's capacity. Problems would still exist for N-1 11kV feeder and N-2 faults at Moffett as load could not be carried from adjacent district/zone substations.

2010 – RICCARTON REINFORCEMENT (PROJECT 471)

Addington 11kV GXP #1 has reached full N-1 capacity and security of supply for Riccarton Mall has become difficult to manage due to load growth in the area. The upgrade of Middleton substation has relieved load on Fendalton substation and this provides an option to transfer load from Addington 11kV to Fendalton. This project reconfigures existing 11kV cabling in the Riccarton area to transfer load to Fendalton and improve security of supply for Riccarton Mall.

Options/comments

Alternative options were to increase the size of the transformer banks on Addington #1 to avoid the cascade effect, and increase capacity into the Riccarton Mall ring. However, these options would not fully address the N-2 tie capacity problems out of Riccarton and would be very expensive to implement.

2010 – MATIPO STREET REINFORCEMENT (PROJECT 475)

Commercial load in Blenheim Road has grown steadily over the past few years and has now reached the point where additional capacity is required. This project will use existing excess capacity and redirect it into Blenheim Road via tactical secondary cable reinforcement to restore network security in this area.

Options/comments

An alternative option to lay a new large-capacity cable down Blenheim Road from Addington GXP was considered, but were deemed unnecessary and expensive when compared to the option of using the spare capacity on feeders adjacent to the problem area.

2010 – PARLANE STREET AND LINCOLN ROAD REINFORCEMENT (PROJECT 482)

The Christchurch City Council plans to resurface Parlane Street therefore, an opportunity exists to lay a cable between Feilding Street and Lincoln Road 342 as stage one to establish a new connection across the historic Riccarton Borough and Christchurch MED system boundaries.

Options/comments

An alternative would be to install the cable when the rest of the circuit was established, but this would cost more due to Christchurch City Council rules requiring full reinstatement of newly installed footpath seal.

2010 – ROUTED COMMUNICATION NETWORK (PROJECT 497)

The Orion external IP communications network has grown very quickly and now connects more than 300 devices. It was originally a layer 2 network consisting of a single subnet. This configuration was suitable for a small network, but better security and reliability is now needed. Therefore we have converted most of the urban network to a fully routed network with firewall security at each substation. Further expenditure is needed to convert five more urban substations, integrate new Tait routed IP radios and purchase and install network monitoring tools.

11kV reinforcement project details – urban – years 2011-2014

2011 – LYTTELTON SUBTRANSMISSION (PROJECT 50)

The upgrade to Lyttelton port would require additional cable capacity from Heathcote district/zone substation, but new information indicates that load will not rise sharply and therefore this project may be further delayed. A key issue with Lyttelton is supply during N-2 contingencies at Heathcote. Contingent supply is currently provided by an existing Barnett Park 66kV line operating at 11kV. In the medium term, this 11kV line will be required at 66kV and alternative tie support for Lyttelton will be needed. The exact nature of this support will be best determined when location and timing of load growth becomes clear.

Options/comments

An alternative would be to move the 66kV to 11kV transformation point. We would need to reinsulate the existing line to 66kV level and find an appropriate Lyttelton site for a new transformer. Depending on growth at Lyttelton Port Company, different options will be investigated and this project may be further delayed.

2011 – BROMLEY FEEDER REARRANGEMENT (PROJECT 167)

Transpower's Bromley 11kV switchgear needs to be replaced and this provides an opportunity for Orion to reconfigure the Bromley 11kV layout to more adequately match present day requirements. This project would rearrange and terminate existing feeders to new 11kV switchgear at Bromley.

Options/comments

This rearrangement is part of a greater study of the Bromley and Portman supply area. We are investigating various options which include reinstalling a 66/11kV transformer into Portman to reduce the demand on the existing 11kV network between these two sites.

2011 – DALLINGTON FEEDER (PROJECT 247)

To relieve load on Armagh district/zone substation, 11kV open point changes were made between Dallington district/zone substation and Armagh prior to the winter of 2005. At the end of the 2005 winter, a review of the Dallington 11kV feeder loadings showed that an upgrade was not immediately required. If necessary at a later date, existing feeders will be rearranged to lift capacity between Dallington and Armagh.

Options/comments

Instead of addressing the imbalance issue on the ring, a new secondary circuit could be laid from Dallington to relieve the ring below its N-1 capacity, but this would lead to under-utilised assets.

2011 – BISHOPDALE-TO-ROYDVALE UPGRADE (PROJECT 252)

This project would convert 11kV overhead line to underground cable to increase capacity of the Orchard Road loop. We need to investigate it further as load develops in the area (particularly the airport). It may need to be co-ordinated with a Christchurch City Council proposal to underground the area.

Options/comments

Alternatives are to disestablish the current primary ring setup and lay a new large capacity secondary cable to provide the necessary reinforcement. Detailed analysis and design has yet to be done and will determine the most appropriate solution.

2011 – HALSWELL 286 ALTERATIONS (PROJECT 255)

At Halswell 286 substation, two of the primary cables from Lancewood and Halswell 131 will be removed from the substation and through-jointed. This work depends on the location of load growth and is intended to remove overloads on the Halswell 286 cable for Halswell district/zone substation. Halswell 381 contingencies would lead to accelerated aging and possible catastrophic failure of network plant.

Options/comments

An alternative would be to lay a new cable from Halswell district/zone substation out to Halswell 286 to prevent the overloading post-contingency, but this would install unnecessary capacity and would require new circuit breakers and an expensive cable installation.

2011 – WICKHAM STREET REINFORCEMENT (PROJECT 316)

Transpower's Bromley 11kV switchgear is due for replacement and this provides an opportunity to cost-effectively increase the number of 11kV circuit breakers. Depending on load growth, we may need to provide an additional 11kV secondary feeder into the Wickham Street region. This would reduce load on the Wickham Street/Taylors Place primary loop and enable this supply to run as a closed ring. Detailed design and timing will be determined over the next two years.

Options/comments

This rearrangement is part of a greater study of the Bromley and Portman supply area. We are investigating various options which include reinstalling a 66/11kV transformer into Portman to reduce the demand on the existing 11kV network between these two sites.

2011 – TEMPLETON REINFORCEMENT (PROJECT 444)

The planned Prebbleton district/zone substation will relieve feeders from Shands district/zone substation which previously fed Prebbleton township. This project will strengthen the network into Templeton to ensure sufficient capacity for future growth and contingent support. The network design for this job is yet to done.

Options/comments

An alternative would be to install a district/zone substation at Templeton. This would negate the need to reinforce, and free-up capacity from Shands, however it would cost more and is not justified due to slow load growth at Templeton.

2011 – 11KV PRIMARY RING PROTECTION – STAGE 3 (PROJECT 459)

Orion's 11kV subtransmission utilises in some cases multi-parallel feed closed ring feeders for better asset utilisation and improved reliability for cable faults. However network substation bus faults on such architectures cannot be easily protected against and complete loss of all district/zone substation load may be imminent. This project will install new protection relays and associated current transformers at Addington No.1 11kV GXP and Halswell.

Options/comments

An option would be to install directional overcurrent protection that was also capable of detecting circuit breaker trip failure on every circuit breaker at every network substation on an affected ring. However this would be a very expensive when compared to the chosen option.

2011 – MCCORMACKS BAY ROAD (PROJECT 463)

The primary cable between McCormacks Bay Road and Redcliffs Water Works network substations is prone to failure due to slumping of the ground on the causeway. We propose to replace the existing cable with a new cable. Detailed design is yet to be completed.

Options/comments

Possible options are to replace the cable with one on an alternative route, therefore maintaining the network electrically equivalent to the existing or decommission the connection to a secondary to provide reinforcement to the adjacent distribution network.

2011 – TOWER STREET REINFORCEMENT (PROJECT 479)

To ensure adequate network capacity is available to maintain the N-2 security standard for Sockburn, Hornby and Moffett, new radial ties are to be established by laying new 11kV cables down Tower Street to complete tie circuits that were partially formed as part of a large commercial network connection. This work depends on commercial development going ahead and will be delayed if planned construction is put on hold.

Options/comments

Most of the growth in the area is driven primarily by new connections and therefore has more influence on the load specific feeders carry rather than underlying district/zone substation growth. It is very difficult to justify non-network solutions unless specific customers install their own generation. However this is usually not economical as the capacity is only required in contingent situations or during operational maintenance. In the final design, full consideration was given to route diversity and avoiding routes where areas have been recently re-sealed.

2011 – CARMEN ROAD REINFORCEMENT (PROJECT 480)

Projected large loads in the Carmen Road area north of Waterloo Road will create a 'bottle neck' at a cable section in Carmen Road in a large capacity tie between Sockburn and Moffett. We propose to lay a new medium sized circuit to complement the existing cable in 2011 to coincide with Transit New Zealand's widening of Carmen Road.

Options/comments

An alternative would be to upgrade the existing cable to a larger capacity connection and decommission the old one, however we prefer to utilise existing assets. Our proposed option will also provide route diversification of electrical supply, allowing us to quickly restore power if a fault occurs in the area.

2011 – WATERLOO ROAD REINFORCEMENT (PROJECT 481)

To complete the radial tie connections between Moffett and Sockburn district/zone substations, minor alterations and reinforcement are required on Waterloo Road.

Options/comments

See project 469 in section 5.6.7 – 11kV urban reinforcement projects.

2012 – LANCASTER-TO-MILTON TIE (PROJECT 48)

Capacity to support Milton district/zone substation during double fault 66kV contingencies is constrained. This project provides an additional 6MVA of tie support from Lancaster district/zone substation. In the medium term, this capacity will also enable us to transfer load between Milton and Lancaster district/zone substations and thereby ensure N-1 security at Milton.

Options/comments

We investigated other minor reinforcement projects, but they did not offer the same level of benefits and would lead to further reinforcement on the upper network to solve the N-2 issue.

2012 – STANMORE ROAD 119 UPGRADE (PROJECT 315)

Infill housing and commercial developments are projected to increase demand in the Stanmore Road region. We anticipate additional capacity will be required in the area by 2010.

Options/comments

Detailed design has not been finalised at this stage but it may be possible to cut into an existing primary cable between Bromley and Tuam Street East. Alternatively, additional capacity could be provided from Lancaster district/zone substation.

2012 – STEADMAN ROAD (PROJECT 476)

To coincide with Transit New Zealand's plan to four lane the sections of roads linking Yaldhurst Road to Main South Road, we will remove the remaining 11kV overhead on Steadman Road. A new secondary connection will be made from Steadman to Fovant Street across the historic power board boundaries.

Options/comments

An alternative would be to replace the existing overhead line with an underground cable. However that replacement is not needed as there is adequate tie capacity on the existing network. Our chosen solution is a minimalist approach to provide supply points for the existing distribution substations.

2012 – EDMONTON ROAD REINFORCEMENT (PROJECT 478)

This project involves laying new 11kV circuits down Edmonton Road to strengthen the tie support between Hornby and Shands district/zone substations. We will also decommission the Edmonton Road network substation.

Options/comments

Multiple reinforcement options exist which depend on further industrial load growth in the area, so detailed design will be done when the load has reached a higher level. To improve reliability and safety we aim to remove the existing 11kV overhead conductor in the final design.

2012 – ADDINGTON-FIELDING STREET SECONDARY CIRCUIT (PROJECT 485)

We plan to lay a new section of 185Al cable from Fielding Street kiosk to join onto a redundant section of 0.2Cu, which in-turn will join onto the Trotting Grounds feeder which passes Lincoln 235 from Addington.

Options/comments

An alternative is to lay a completely new piece of cable all the way back to Addington. This would not utilise the existing redundant assets and would increase costs.

2013 – SPRINGS ROAD REINFORCEMENT (PROJECT 483)

This project will be primarily driven by increases in residential and industrial loads between Hornby and Sockburn and a desire to remove 11kV overhead line from the urban network. The timing of this project will be affected by the potential downgrading of Springs Road due to Wigram an Whincops Roads being the future preferred corridor between Lincoln and Christchurch city.

Options/comments

An alternative is to construct the Awatea district/zone substation so capacity between Hornby and Sockburn could be re-routed to the new substation. This would be a very expensive way to solve the tie support problem, and would not address the safety and reliability issues of the existing 11kV overhead on Springs Road which is one of the last remaining sections of overhead medium voltage circuit on our network.

5.6.8 11kV rural reinforcement projects

11kV rural reinforcement – $000, year ending 31 March											
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
376	Clintons Road and West Coast Road conductor upgrade	250									
385	Larcombs Road	222									
405	Breadings Road 11kV line and Terrace Road regulator	400									
431	SCADA at 11kV regulators – stage 3	100									
439	Brookside Irwell Rd	237									
467	Ardlui Road and Board Road 11kV lines	125									
381	Courtney Road conductor upgrade		275								
389	Charteris Bay 11kV regulator		240								
445	West Melton 11kV reinforcement – stage 2		174								
388	Rakaia Terrace Road			510							
392	Cordys Road and Milnes Road re-conductor			200							
464	Ridge Road 11kV regulator			20							
440	Teddington 11kV alteration				138						
Rural reinforcement subtotal		**1,334**	**689**	**730**	**138**	**0**	**0**	**0**	**0**	**0**	**0**

11kV reinforcement project details – rural – current year 2010

2010 – CLINTON AND WEST COAST ROAD CONDUCTOR UPGRADE (PROJECT 376)

Due to increased irrigation north of Darfield substation, and to provide Annat with increased contingency tie support, we propose to replace 3.7km of 11kV Raven conductor on Clintons Road and West Coast Road with Dog conductor.

Options/comments

We investigated an option to reinforce lines out of Annat to supply the irrigation load, but this substation has limited capacity and major works would be needed for this to be a viable option. Also, we would gain no tie capacity which would lead to longer outages if a major fault occurred.

2010 – LARCOMBS ROAD (PROJECT 385)

Excess capacity is available from the newly installed Larcomb district/zone substation and there is now sufficient district/zone substation capacity to fully restore from a Lincoln dual transformer contingency. We therefore plan to construct a new line in Larcombs Road to link the Lincoln supply area to Larcomb.

Options/comments

An alternative was to install a larger transformer at Springston and increase the 11kV tie capacity between the two sites. However this would require not only a new transformer, but also an additional 66kV bay at Springston GXP, as the 33kV capacity is already over N-1 security at peak load times. This option would also cost considerably more.

2010 – BREADINGS ROAD 11KV LINE AND TERRACE ROAD REGULATOR (PROJECT 405)

We plan to construct a new 2.5km 11kV Dog line down Breadings Road to supply the voltage constrained section of network south of Bankside on North Rakaia Road. This will take advantage of the additional capacity from the new Dunsandel district/zone substation. As part of this job we will install an 11kV regulator on Terrace Road to relieve Bankside, Te Pirita and Hororata.

Options/comments

Further 11kV reinforcement from Bankside and Te Pirita district/zone substations is limited as these two sites are near their capacity limit. Therefore, to cover for contingent situations without the new line and regulator, a new substation would be needed at Ardlui, which in-turn would require subtransmission upgrades.

2010 – SCADA AT 11KV REGULATORS – STAGE 3 (PROJECT 431)

This project is the final stage in a three-stage project to install remote control and indication at rural 11kV regulators.

2010 – BROOKSIDE AND IRWELL ROAD (PROJECT 439)

Continued growth in the Leeston and Rakaia Huts areas means contingent support for Hills district/zone substation has become increasingly difficult at peak times. The new 66kV line from Brookside to Springston in 2008 has left a redundant section of 33kV line down Brookside Irwell Road. An opportunity therefore exists to create an additional feeder into the Leeston township from Brookside. This project will re-liven the old 33kV line at 11kV and extend the circuit 850m with a new line or cable to the intersection of Leeston Road. Further alterations will be required at the intersection of Beethams, Drain and Leeston Roads.

Options/comments

An alternative solution to help Hills district/zone substation in contingent situations would be to install another 11kV regulator, but purchase/installation and maintenance/operational costs were well in excess of the minor reinforcement proposed above.

2010 – ARDLUI AND BOARD ROAD 11KV LINES (PROJECT 467)

Continued growth in dairy and irrigation load has caused voltage constraint in the area south-east of Hororata. To overcome this problem we will string new 11kV line sections under the existing 66kV line down Ardlui Road and Board Road to split the Substation Road Hororata feeder into two. We expect to complete this project in early 2010 for the following irrigation season.

Options/comments

All viable alternative solutions are also network reinforcement projects because distributed generation, for the size of load involved, would be uneconomical.

Of the available reinforcement options this project is the most cost-effective because it utilises the majority of existing pole assets and therefore only requires new crossarms and a conductor.

11kV reinforcement project details – rural – years 2011-2014

2011 – COURTNEY ROAD CONDUCTOR UPGRADE (PROJECT 381)

With the burgeoning growth in ground water irrigation it has become increasingly difficult to provide N-1 support in the area south of Highfield and east of Greendale. To increase tie support from Highfield in the event of a Greendale contingency, we will upgrade the Thrush conductor on 4.1km of 11kV line.

Options/comments

An alternative option would be to install another 11kV regulator but this could be used in one direction only and would be less cost-effective when combined with the cost of regular maintenance.

2011 – CHARTERIS BAY 11KV REGULATOR (PROJECT 389)

Growth at Diamond Harbour and Governors Bay has exceeded the N-1 capability of the 11kV network. Therefore we plan to install a new 11kV regulator on the 11kV line between Teddington and Diamond Harbour to cover transformer contingencies at either one of those sites.

Options/comments

An alternative would be to install standby generation or have it available. However, because of the load size involved, the cost would be substantial and considerable substation work would be required to connect the generation.

2011 – WEST MELTON 11KV REINFORCEMENT – STAGE 2 (PROJECT 445)

Subdivision developments in West Melton may require a cable from Weedons district/zone substation 1.2km up Weedons Ross Road to the intersection with Findlays Road. This would effectively create two distinct feeders into the area.

Options/comments

An alternative would be to install an 11kV regulator, but this would not have the reliability or security benefits of an additional circuit.

2012 – RAKAIA TERRACE ROAD (PROJECT 388)

The completed Windwhistle district/zone substation gives the potential for better 11kV support to Te Pirita district/zone substation in contingent situations. To make this possible, we will upgrade the existing Mink and Squirrel conductor from Te Pirita to Dog and complete the gap up to Windwhistle.

Options/comments

An alternative would be to build a new 66kV line between Windwhistle and Te Pirita district/zone substations. This would require major works at both sites and would only provide for line faults. It would also cost considerably more.

2012 – CORDYS AND MILNES ROAD RE-CONDUCTOR (PROJECT 392)

To strengthen the ties between Hororata and Te Pirita district/zone substations we will replace the existing Mink conductor with Dog on 3.5km of 11kV line down Cordys Road and Milnes Road.

Options/comments

This project depends on whether or not the Windwhistle substation job proceeds. It will not be required if Windwhistle proceeds.

2012 – RIDGE ROAD 11KV REGULATOR (PROJECT 464)

As the urban load at Lincoln has increased and all the load-shifts to Springston are exhausted, the need to off-load the outer rural fringes of these substations has become apparent. Increased capacity at Motukarara district/zone substation now gives us the ability to shift further load. This project will install our emergency spare 11kV regulator at Ridge Road allowing Motukarara to carry additional load south of Lincoln and Springston.

Options/comments

An alternative would be to upgrade the Lincoln transformers to larger capacity units, but this would cost considerably more.

2013 – TEDDINGTON 11KV ALTERATION (PROJECT 440)

As load grows at Teddington and Governors Bay our ability to provide 11kV tie support from Diamond Harbour and Motukarara becomes increasingly constrained. This project will rearrange the Teddington feeders so we can split load with more flexibility during a Teddington contingency. This reinforcement will coincide with major substation upgrade works.

Options/comments

An alternative would be to install a new supply point with either backup diesel generation, or re-insulate a line to Governors Bay to 33kV, and install a 33/11kV transformer. However our proposed solution is a low cost basic rearrangement in the medium term while we can still carry the load at Governors Bay via 11kV from Diamond Harbour and Motukarara.

5.6.9 Network connections and extensions

Overview

Network connections can range from a 60A 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 3000 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. On average 850 residential lots are developed annually within Christchurch city. 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.

5.6.10 Underground conversions

The local authority or Transit New Zealand 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.

5.6.11 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. If a DSM solution is presented, then further detailed analysis is undertaken to compare options.

For example:

The Lincoln district/zone substation transformer upgrade in 2010 has a capital cost of $550,000 and an annual funding cost of $77,000. It provides capacity and security of supply for 300kW 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 $257 ($77,000/300kW). If the DSM solution can provide three years of deferral (900kW at peak) then the DSM proposal cost must be lower than:

- $257 for 300kW in the first year
- $128 for 600kW in the second year, and
- $86 for 900kW in the third year.

The values in the table assume that the DSM solution is provided in the year required and therefore discounted values apply for DSM solutions implemented earlier than required.

Multiple projects are sometimes required to resolve network constraints – these have been grouped together by colours in the table (excluding black which are individual projects). The $/kW available for DSM solutions is the sum of all similarly coloured projects.

DSM value for network development alternatives

Year ending March 31	Project description	Budget capital ($K)	Growth per year (kW)	$ per kW available for DSM alternative			Comments
				Year 1	Year 2	Year 3	
2010-2013	Ground fault neutralisers	3,717					Reliability and safety initiative.
2010	Awatea land purchase	250					Strategic purchase.
2010	Lincoln switchgear and transformer upgrade	550	300	257	128	86	
2010	Hornby 33kV feeder upgrade	400	900	62	31	21	Coincides with oil filled cable replacement.
2010	Belfast substation site development	600	1000	84	42	28	
2010	Rolleston protection upgrade	120					Reliability initiative.
2010	Rural harmonic improvement	100					Power quality initiative.
2010	Papanui 11kV switchgear replacement	1,500					Project already started so committed.
2010	Springston to Larcomb conductor upgrade	940	1000	132	66	44	
2011	Islington to Weedons 66kV line	2,500	1000	350	175	117	
2011	Weedons 66kV substation	1,730	1000	242	121	81	
2011	Prebbleton substation	2,900	250	1,624	812	541	
2011	Windwhistle substation	2,880	2000	202	202	202	One-off load increase.
2011	66kV bay at Dunsandel	380					Mainly a reliability initiative for a single customer.
2011	Greendale-Dunsandel 66kV line	2,300					Mainly a reliability initiative for a single customer.
2011	Rural power factor correction	120					General rural capacity improvement and reduction in losses.
2012	Rural power factor correction	120					General rural capacity improvement and reduction in losses.
2012	Darfield 33kV switchgear or second transformer	250					Reliability initiative.
2012	M^c^Faddens 66kV switchgear	3,350					These projects are part of our urban subtransmission review. For further information about options and to view our consultation paper please see our website oriongroup.co.nz.
2012	Marshland substation-stage 1	4,400					
2012	M^c^Faddens to Marshland 66kV cable	10,400					
2013	Dallington 66kV switchgear	850					
2013	Dallington to Marshland 66kV cable	7,560					
2013	Marshland substation – stage 2	2,205					

Continued overleaf

Continued

DSM value for network development alternatives

Year ending March 31	Project description	Budget capital ($K)	Growth per year (kW)	$ per kW available for DSM alternative			Comments
				Year 1	Year 2	Year 3	
2013	Annat transformer upgrade	400	5,000				
2013	Teddington transformer upgrade	350	50				
2013	Convert Springston from 33/11kV to 66/11kV	1,140	150	1,064	532	355	Asset replacement implications.
2014	Yaldhurst substation	4,500	500	1,260	630	420	Dependent on airport requirements.
2014	Larcomb to Weedons 66kV conversion	1,260	1,000	176	88	59	
2014	Convert Larcomb to 66kV	2,915	1,000	408	204	136	
2015	Highfield 66/11kV transformer	1,070	800	187	94	62	
2015	Weedons to Highfield tee 66kV conversion	840	800	147	74	49	
2016	Prebbleton second transformer	520					Reliability initiative.
2016	Shands 33kV tee to Prebbleton	800					Reliability initiative.
2017	Shands 33kV circuit reinforcement	250	1,500	23	12	8	
2017	Replace Moffett 33kV feeders	100	300	47	23	16	
2017	Teddington 33kV line breakers	600					Reliability initiative.
2017	Kirwee 66kV substation	3,000	300	1,400	700	467	
2018	Lincoln transformer upgrade	1,600	150	1,493	747	498	
2018	Springston 33kV cable to Rolleston-tee	1,250	1,000	175	88	58	
2018	Springston to Brookside 66kV line conversion	2,660	1,000	372	186	124	Load growth uncertain.
2018	Brookside 66kV bay and 66/11kV transformer	2,000	1,000	280	140	93	Load growth uncertain.
2018	Bromley to Dallington 66kV cable	7,050					These projects are part of our urban subtransmission review. For further information about options and to view our consultation paper please see our website oriongroup.co.nz.
2019	Armagh to M^c^Faddens 66kV cable	7,420					
2019	Ilam 11kV switchgear	500					

Risk management

6

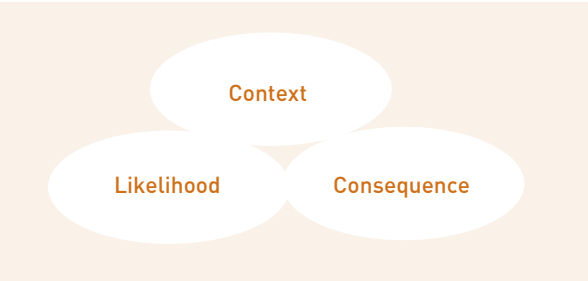
6.1 Introduction

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 controlled and mitigated within acceptable limits to achieve the most satisfactory outcome.

Risk is often measured or quantified as the product of a probability and a consequence, however a less obvious but important factor is context. While the severity of some risks may appear similar, their contexts may be quite different.

In this section we concentrate on the physical aspects of risk associated with managing network assets. The objective is to avoid catastrophe, reduce uncertainty and improve predictability.

The three components of risk



6.1.1 Risk management plans

Orion has 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 comply with the Civil Defence Emergency Management Act.

- **Asset risk management plan –** (NW70.60.02)

  The Civil Defence Emergency Management Act also requires us to plan for major events that affect the environment. In particular it requires us to:

  i. function to the fullest extent during and after an emergency

  ii. hold plans which show how we plan to function during and after an emergency

  iii. participate in civil defence emergency planning at national and regional level if requested

  iv. 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:

  i. exposure to natural disaster with details of specific hazards

  ii. establishing a rating system to easily identify those areas most at risk

  iii. mitigation measures and practical solutions to reduce risk or impact

  iv. the location, likely reasons for failure and contingency provisions for each asset group

  v. a schedule of the risk-based spares we hold.

  For further discussion on natural disaster and asset failure see sections 6.6 and 6.7.

- **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 3.2 and section 5.

- **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 reliable network and a safe and healthy work environment for all our employees, visitors and the public.

  The predominant focus of the plan is to restrict access by unauthorised personnel. However some of the consequences and dangers 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 children and opportunist intruders without specialised tools, and slow determined intruders. This is achieved by:

  i. reasonable measures to prevent access by members of the public to potentially fatal voltages

  ii. additional measures to deter, detect and slow determined intruders at higher risk sites.

  For further discussion on safety see section 6.2.

- **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 risk likelihood, consequence and mitigation-effectiveness based on 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.

  For our full environmental policy see section 3.6.

6.2 Safety

It is not possible to entirely eliminate all hazards as we operate and maintain our electrical network. However we are committed to providing a safe, reliable network and a healthy work environment – we take all practical steps to ensure that our staff, the community and the environment are not at risk. We control hazards through training, guidelines and standards. Potential hazards, in particular electrical hazards, must also be considered when new network installations are being designed and constructed.

A programme to become materially compliant with all relevant safety legislation is underway. We report our progress and key areas of non-compliance to our board every four months.

Legacy assets

Low voltage panels at our older substations are a key asset considered non-compliant. They pose a potential risk because an unsecure substation door can allow public access to live equipment. We have developed a new standard for substation low voltage panels and all new installations are touch safe and comply with the Electricity Regulations. Currently around 3,600 panels of the older open construction will need to be replaced or a barrier installed to ensure they are touch safe. As it will take more than 30 years to replace all of the older panels we intend to fit barriers to the existing panels to reduce risk to the public.

Legacy linkbox low voltage panels are similar to the substation panels and can be considered non-compliant. They pose a similar potential risk to the public. We have developed a new linkbox standard and all new installations are now touch safe and compliant. Currently around 5,500 open construction linkbox panels exist on our network. As the time frame to replace all of these linkbox panels is more than 30 years we intend to allocate $0.7M in each of the next four years to fit barriers to the existing panels to reduce risk to the public.

Staff

We are committed to consultation and co-operation between management and employees. Maintaining a safe 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 which may be present in their work areas.

Our systems 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 specific known hazards along with recommended actions to control hazards. Contractors are 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 managed if access to hazardous areas is restricted to competent personnel, and industry-recognised safe working practises are used.

Public

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

We recently engaged an independent consultant to undertake a risk analysis of security where access to our network could be considered a significant hazard to the public. This review accepted our present direction and standards for new installations. It also recommended a programme to review and upgrade existing legacy installations.

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.

6.3 Environmental management

We follow a policy of environmental sustainability, initiate energy efficiency programmes and work to minimise electrical losses on our network wherever possible.

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.

We instigated oil spill management systems several years ago and have successfully managed any significant spills.

6.4 Risk analysis

6.4.1 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 of impact on our network since both likelihood and consequence is high and with long equipment replacement times are a major constraint. The table below shows that earthquakes dominate asset exposure.

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 tapchanger	Earthquake
	Regulator	Earthquake
Ancillary equipment	Protection	Flooding

Possible causes of contaminant discharge and their relative risks

	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
Cause of discharge	District substn	Network 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.

6.5 Interdependence

6.5.1 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.

Interdependence of lifelines (one week after earthquake)

These are dependent on these → ↓	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

Since this chart 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.

In the past it was normal to have local in-ground fuel tanks available to be used in an emergency, thus minimising our reliance on external supply for at least a few days. This is not the case today largely due to compliance with the Resource Management Act and costs associated with holding fuel reserves. Restoration after a disaster, such as an earthquake, has a very high dependence on an adequate fuel supply.

6.5.2 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 three of 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.

Transpower is conducting a more detailed review of Papanui and Addington GXPs to determine the remedial work necessary to increase seismic security at these sites. As a result of this review, engineering measures are underway to reduce the likelihood of damage due to differential settlement.

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 would be to build diversity into future network development.

The following table is an attempt to quantify the relative risk between the four GXPs.

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			
Addington	Medium/High	Medium/High	Medium/High	Possible	Likely	150-200
Bromley	Low	Medium	Medium	Possible	Possible	20-40
Papanui	High	High	High	Possible	Likely	250-300
Islington	Low	Low	Low	Unlikely	Unlikely	

6.6 Natural disaster

Earthquakes and storms are our major natural event risks. We continue to invest significant time and money to ensure our network is protected against such events. 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.

Since this study, further detailed studies have been undertaken and we have minimised the overall risk to our network in a cost-effective manner.

We have addressed risk to communications at the two main communication sites – Sugarloaf and Marleys Hill.

Sugarloaf is operated by others and takes its primary power supply from our urban network. This site has generator back-up.

The adjacent site at Marleys Hill has many operators. Key operators at the site have a back-up power supply. 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.

Post event improvements

Lyttelton port is an important lifelines site. We have located an 800KVA generator in Lyttelton in an effort to mitigate loss of power to the port.

We have also installed a cable to allow the airport to be supplied by both Harewood and Hawthornden district substations. This dual feed improves security of supply to the airport, an important lifelines site.

6.6.1 Earthquake

Latest estimates identify a 65% chance of a major earthquake in Canterbury in the next 50 years. As part of an assessment of the vulnerability of the Christchurch electricity network in a seismic event, a structural assessment of substation buildings has been carried out. We have rated each building on a scale from minimum through to moderate risk. Each building will be examined in greater detail to identify where any improvements can be made.

Liquefaction hazard evaluation

Soils and Foundations (geotechnical consulting engineers) were engaged to evaluate the liquefaction hazard at key substation sites in 1998.

Based on knowledge of local ground conditions, the following sites were selected as potentially sitting on liquefiable material: Addington GXP, Bromley GXP and Armagh, Dallington, Heathcote, Milton, Portman, and Lancaster district substations.

The most severe form of damage due to liquefaction is a complete foundation failure of the substation buildings, towers and associated structures. A less severe, but more likely cause of damage, is post-earthquake settlement.

The potential for liquefaction and liquefaction-related damage is summarised in the following table.

Orion sites – Relative liquefaction potential and related damage

	Liquefaction susceptibility				
Substation	150 year	450 year	1000 year	Potential for foundation failure	Potential for settlement induced damage
Armagh	Medium	Medium	Medium	Unlikely	Unlikely
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
Portman	Medium/High	Medium/High	Medium/High	Unlikely	Unlikely

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.

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 substations to determine structural ability to withstand a moderate-to-severe earthquake. A seismic risk assessment report was prepared. The 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. All network substations were graded on their importance in the network and we used this grading to prioritise the strengthening work.

Kiosk substations are likely to satisfactorily 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

We expect that most underground cables to cope well with an earthquake, although damage can be expected where cables are stretched as a result of ground subsidence. Damage to the overhead reticulation system should be easily repaired.

6.6.2 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 Armagh site is not considered a flood risk.

6.6.3 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 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 programmed to install additional stays on these line sections over the next five years.

6.6.4 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.

6.6.5 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. We have investigated these and incorporated suitable actions into our natural event contingency plan to mitigate this risk.

6.7 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.

6.7.1 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 joints. We engaged an international consultancy to help quantify the risk across the various cable types and sizes.

We have instigated a joint replacement programme that has prioritised the joints most at risk. The joints are being 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. The programme should be completed in 2014

We have also instigated a comprehensive half-life maintenance programme for our major district/zone substation transformers. This is coordinated with our 66kV joint replacement programme to manage overall supply security risk.

6.7.2 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.

6.7.3 SCADA system

Our SCADA system 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. SCADA can be used to view the electrical state of devices and is invaluable in diagnosing faults and delivering solutions to network related problems. It is also the primary source of control for our ripple control plants.

The SCADA master station aggregates and interprets incoming data which is accessed from throughout our network using terminal emulation software. Loss of the master station could significantly reduce our ability to detect, diagnose and respond to important network events.

In addition to warranty and maintenance agreements that provide standby hardware, the SCADA master station is made fault tolerant through the use of redundant hardware. Identical servers are configured as master and slave with databases mirrored between them. In the event that either of these servers fails, the SCADA system will continue to operate. Both servers must be lost for the system to fail completely.

Maintenance service contracts for the current servers are increasingly expensive and after five years struggle to meet the demands of our expanding network. Both the Sun servers were replaced in 2005. The new machines will be mirrored as before but will have increased fault tolerance through internally raided disk sets.

The new servers also have greater physical separation. The servers are currently split between different buildings. Communications lines to remote field devices, which currently also all terminate in the same building will be split between buildings in the future.

6.8 Mitigation measures

6.8.1 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 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. Orion-owned generators
    v. Consumer-owned embedded generation
    vi. details of generator hire companies.

  - **Contingency plan – loss of supply to the CBD, district/zone substations and GXPs –** NW20.40.03

    This plan contains site specific information for the Christchurch CBD and each of our district/zone substations. It provides:

    i. a low, medium or high risk grading for each district/zone substation
    ii. details of major plant installed

iii. details of specific problems
iv. some restoration options.

- **Contingency plan – energy shortage (rolling power cuts)** – NW20.40.04

  The purpose of this plan is to identify the following:

  i. blocks of substations for load shedding
  ii. blocks of load for shedding
  iii. feeders with specific essential services for:
    a. communication
    b. hospitals
    c. emergency services (ambulance, fire, police)
    d. sewerage
    e. water supplies.

- **Disconnection of demand as required by the Electricity Commission 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 Commission Rules through:

  i. 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'
  ii. assisting Transpower with their automatic under frequency load shedding by providing a schedule of our preferred locations
  iii. assisting Transpower with automatic under voltage load shedding for upper South Island (Zone 3) transmission constraints by providing a schedule of Orion's preferred locations
  iv. Providing blocks of load to Transpower for emergency demand shedding.

6.8.2 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 have been implemented and 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 bunding at sites that hold oil in excess of 1500 litres. This limits the possibility of oil entering the environment. These sites are also inspected regularly. Other more appropriate methods exist to install bunding for sites with oil volumes below 1500 litres.

Excessive differential ground settlement during an earthquake could damage our 66kV cables. Bridges have been identified as the locations with the greatest risk of this settlement. We have investigated the bridges and reinforced them or taken alternative measures to reduce our dependency on the affected cables.

Installation of a new 11kV ripple system to replace the existing overloaded 66kV plants was completed in 2004.

We are committed to ongoing contracts to inspect, test and maintain key assets. These contracts are identified in section 4 – Lifecycle asset management.

6.8.3 Avoiding major supply failure

The plans and processes described 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 – the major-plant outage causing huge economic damage (MOCHED) event – 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 the failure of a major network asset.

The classic example in New Zealand is the failure in 1998 of the 110kV subtransmission cables that supply the Auckland CBD. In that case, a network with an apparent N-2 security standard sustained a complete failure of four main cables (i.e. N-4 failure), leaving the CBD with severely restricted power supply for many weeks.

To avoid this form of 'cascade plant failure' we need all the above elements of good asset rating and condition knowledge, clear operational and monitoring rules and an inventory of key emergency spares, along with good operational contingency and system security planning.

In our network, the main plant failures modes which we consider could lead to a MOCHED situation have been identified as:

(a) **Major subtransmission 66kV cable failures leading to loss of supply from two or more urban district 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 district substation using our existing interconnected 11kV primary 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 grid exit points 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 district substation transformer (typically 20–40MVA capacity) is not necessarily a major problem as all such substations have two transformers with dual emergency 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 from May to September. Transformer repair times can be weeks or many months.

The main reason for operating with less than two district substation transformers is to carry out planned maintenance. We have reached the point where half-life maintenance of major transformers is required to ensure that their full expected life can be 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 or multiple tripping of major transformers is therefore dependent on good

understanding of their capability and condition, as well as co-ordinating their extended maintenance programmes with other major plant outages. The mere act of removing transformers from service for extended periods of maintenance 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 grid exit points.

(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 the 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 MOCHED situation.

Earthquake damage to 66kV and 33kV outdoor switchgear and structures is also a potential common mode failure for both Orion and Transpower substations.

6.8.4 Mitigation of major supply failure

Our main mitigation strategies and initiatives to avoid a MOCHED situation from the three main plant failure modes described above are:

- We are replacing all at risk 66kV oil-filled cable joints with newly designed joints that will withstand thermo-mechanical buckling forces. We have completed 65% of our current 66kV joint replacement programme. If we decide to also replace another specific manufacturer's joint (Dianichi), then the programme will be extended. A decision on whether to replace these joints will be made in the next 12-24 months.
- In association with the joint renewal programme we are retrofitting cable joints and known hot spots with thermocouple thermometers connected to our SCADA system. This will enable cable temperature operating limits to be closely monitored especially in times of emergency.
- Careful co-ordination of work plans for 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 district/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 did 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 district/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 district 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 grid exit points. 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 district substation 11kV switchgear failure through assessing switchgear condition and the importance of each site to network security. On this basis, we have now replaced switchgear at Armagh, Fendalton, Grimseys Winters and Brighton district/zone substations.

6.8.5 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 district/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:

i. our network was built to meet an appropriate N-2 security standard
ii. we had completed asset capability modelling of the surrounding network and loaded the network capability ratings into our SCADA system
iii. 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:

i. our network built to meet an appropriate N-2 security standard
ii. 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
iii. pre-contingency load flow modelling was complete and N-2 contingency plans were pre-written.

6.8.6 Insurance

The following mitigation measures are in place:

- a material damage insurance policy has been arranged covering accidental physical loss or damage to buildings, plant, equipment, district and network substation buildings and contents based on assessed replacement values. This policy does not extend to include our overhead lines and underground cables. However our pole-mounted transformers and our substation equipment including our ground mounted transformers are insured. We also have a business interruption insurance policy which indemnifies us for a reduction in our electricity network delivery revenues and/or increased costs of working as a result of an insured loss to our assets as above.
- 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.

Evaluation of performance

7

7.1 Introduction

This section reviews our performance against the stated targets in our previous AMP. These targets may be actual target values as stated in section 3, or a declaration to carry out particular maintenance or reduce risk. We also discuss whether or not budgets were met and explain any variances.

It also includes a discussion on some current and future initiatives along with a reliability gap analysis.

Previous AMP

While we were pleased with the results of a Commerce Commission review of our 2007 AMP that ranked our plan number two in the country in terms of regulatory compliance and overall asset management planning best practice, the review did suggest some things we could do better.

In line with our focus on continual improvement, we have made the suggested changes as well as several further improvements in this version of our plan.

The main improvements are more information in the areas of:

- accountability and responsibility (section 2.4)
- use of out-sourced contractors (section 2.4)
- asset data accuracy and completeness (section 4)
- identification of large consumers (section 4.1.1)
- prioritisation of network developments (section 5.3.4)
- demand side management strategies (section 5.4)
- project options (section 5.6)

We have also aligned the plan more closely with the regulatory format.

7.2 Review of consumer service

7.2.1 Review of reliability

We completed the 2008 financial year well ahead of our targets. This excellent result was helped by reasonably settled weather and continued investment in technology to better understand, monitor and control the condition and capability of our network.

There was only one month in the 2008 financial year where the weather caused our network any real damage – October 2007 was an unsettled month with gale force winds causing a significant number of faults.

In the 2008 financial year 30% of consumers who experienced a fault had their power supply restored within one hour, and 72% were restored within three hours. In regular customer surveys of urban and rural consumers, approximately 95% of urban and 80% of rural consumers express satisfaction with the reliability of their power supply.

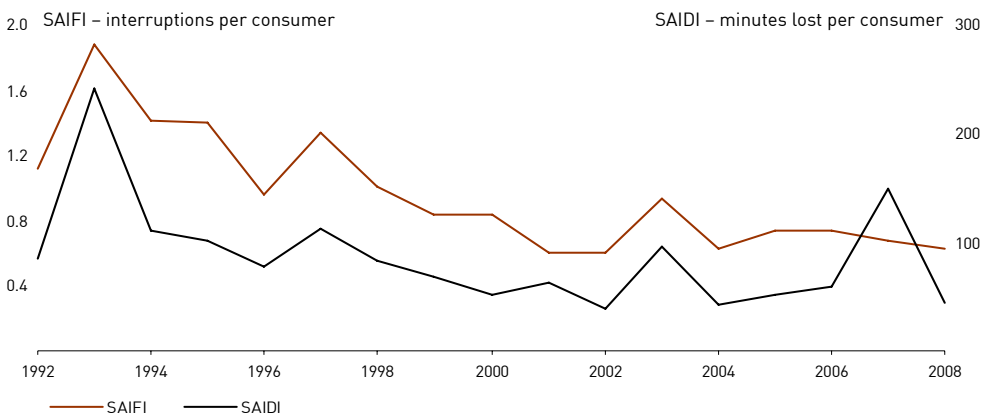
The duration of any interruption and the number of consumers affected are recorded in our control centre outage log. This information then provides all relevant statistical data needed to calculate our reliability statistics using the international measures of SAIDI, SAIFI and CAIDI (see the Glossary for a definition of these measures). More information on our network performance can be found in our network quality report on our website oriongroup.co.nz.

A summary of some of our 2008 performance statistics is outlined in the following table.

Orion network reliability results for 2008 and five year average 2004-2008

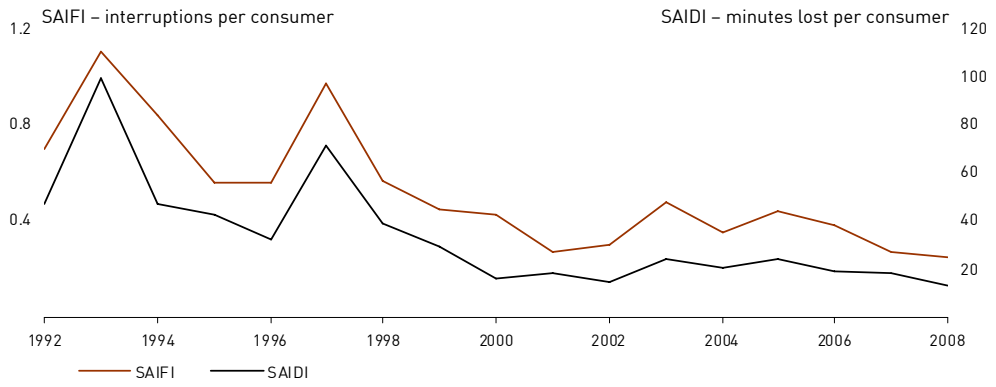
Category	Target	2008 actual	Five year average	NZ average (2007)
SAIDI	< 63	**45**	**70**	272
SAIFI	< 0.76	**0.63**	**0.68**	2.3
CAIDI	< 83	**72**	**103**	119
Faults/100 circuit-km all voltages	< 11.0	**7.3**	**7.9**	9.4
Faults/100 circuit-km 66kV	< 2.0	**1.0**	**1.0**	
Faults/100 circuit-km 33kV	< 4.0	**6.4**	**3.7**	
Faults/100 circuit-km 11kV	< 12.0	**7.6**	**8.5**	
Number of planned shutdowns (class B)	< 385	**318**	**296**	
Number of unplanned cuts (class C)	< 555	**449**	**466**	
Number of interruptions total (B and C)	< 940	**767**	**762**	

SAIDI and SAIFI – Orion network 1992-2008

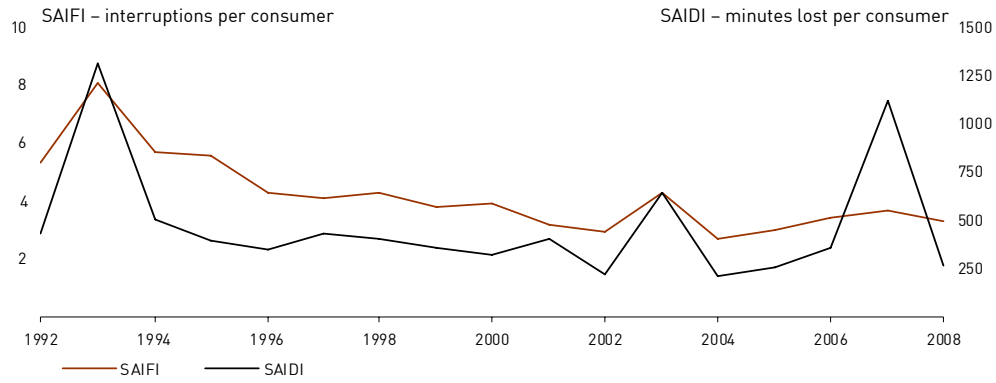


It is important to note that one-off factors such as weather can heavily influence the results in any one year. Therefore the long term average trend is more important and better reflects the reliability of long life assets. As can be seen in the following graphs, there were heavy snow storms in 1993, 2003 and 2007 financial years that caused major damage to our network. The most recent major storm in June 2006 caused the loss of some 19 million consumer minutes and accounted for 105 minutes of our final SAIDI total for the 2007 year of 150.

SAIDI and SAIFI – Orion urban network only 1992-2008



SAIDI and SAIFI – Orion rural network only 1992-2008

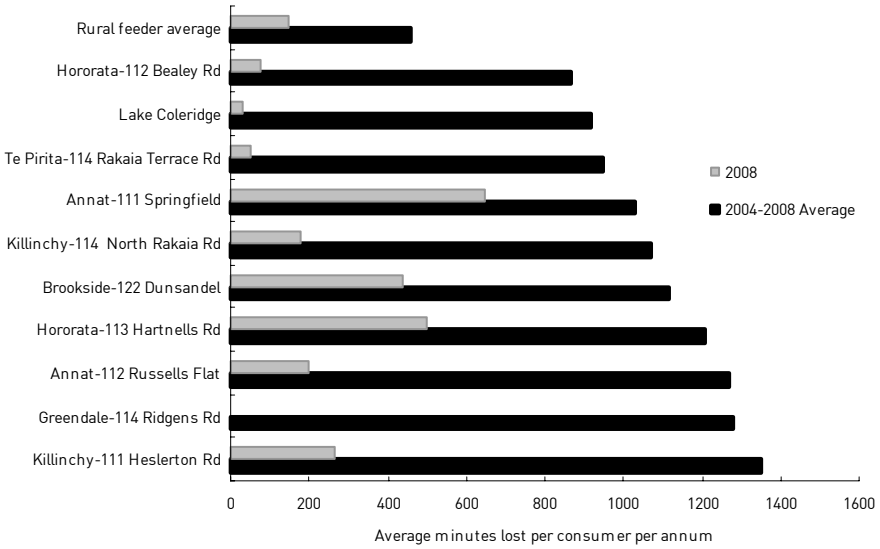


7.2.2 Least reliable feeders

Our network has 79 rural and 336 urban 11kV feeders that originate from district/zone substations.

The ten least reliable feeders on our rural network are shown below. All but two of the feeders were adversely affected by the June 2006 snow storm. The magnitude of the snow storm can be seen by comparing the five year average against a 'normal' year in 2008.

Orion's 10 least reliable rural feeders 2004-2008 (SAIDI) (unplanned interruptions only)

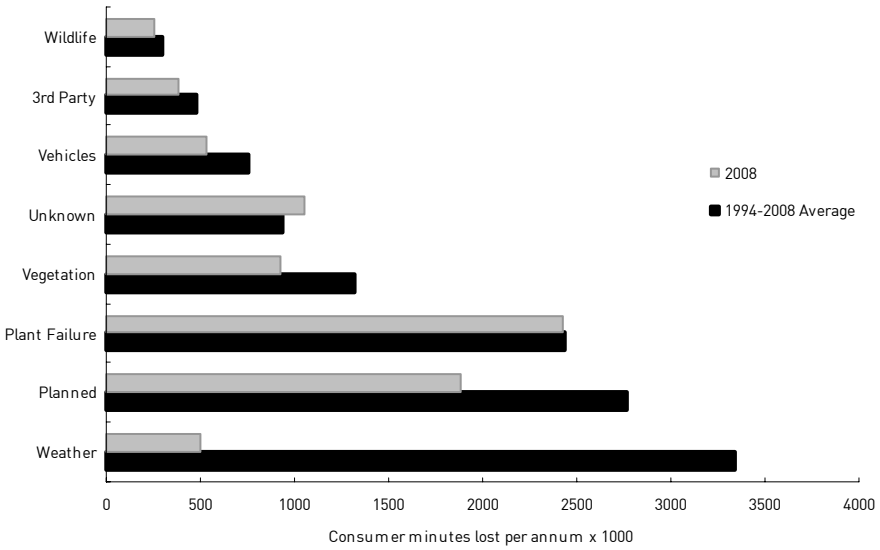


7.2.3 Cause of interruptions

The chart below compares the cause of consumer minutes lost per annum on our network over the fifteen year period 1994 to 2008 against the most recent year (2008).

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 'weather' category.

Cause of interruptions 1994-2008

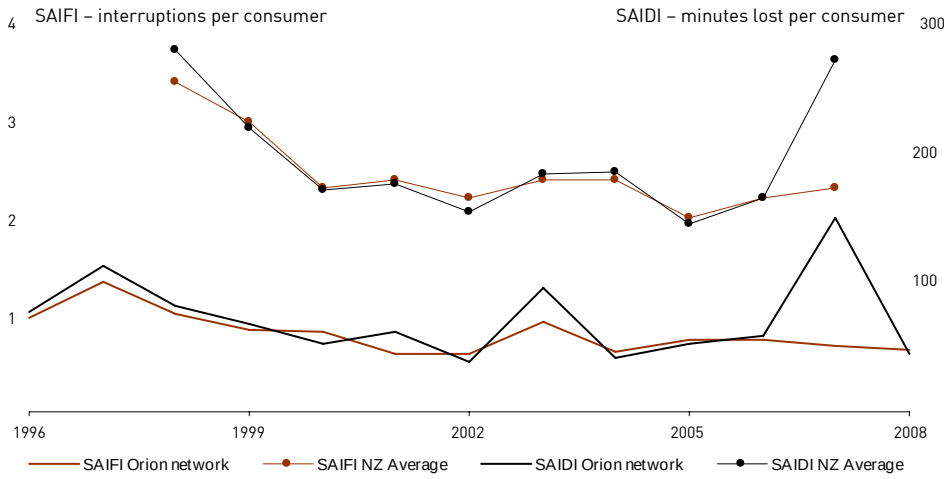


7.2.4 Reliability performance comparisons

The following graph compares our performance against other distribution networks across the two main reliability performance indices.

When compared with other New Zealand line companies, our urban network reliability appears to be above average, while our rural network is slightly below average. There is still scope to improve our performance and we discuss improvement initiatives later in this section.

Orion's position relative to average of NZ network companies – SAIDI and SAIFI



Central business district reliability

We also measure the reliability of our supply to Christchurch's central business district (CBD). A reliable electricity supply is critical to the CBD, given the economic impact of any interruption. Our network that supplies the CBD is very secure – several alternative sources can get power to the CBD if there is a fault somewhere on our network. The level of reliability in Christchurch's CBD is high compared with that of Australian cities. Unfortunately New Zealand CBD figures are not available for comparison – to the best of our knowledge, Orion is the only New Zealand distribution company that publicly discloses CBD reliability statistics.

Christchurch's CBD position relative to Australia – SAIDI and SAIFI

Location	SAIDI*	SAIFI*
Christchurch CBD	2	0.07
Brisbane CBD	0	0.00
Hobart CBD	36	0.62
Melbourne CBD	21	0.30
Sydney CBD	13	0.17

*Based on latest available figures.

*Excludes transmission outages and adjusted for extreme events in accordance with Australian reporting standards.

7.2.5 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 New Zealand Electricity Regulations 1997. 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.

Service level targets and results – network power quality

Category	Measure	Target	Achieved 2008	Performance indicator	Measurement procedure
Power quality	Voltage complaints (proven)	<70	17	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

7.3 Efficiency

7.3.1 Capacity utilisation

This ratio 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.

Capacity utilisation results for 2008 and five year average 2004-2008			
Category	Target	Achieved 2008	Achieved five year average
Capacity utilisation (%)	No target set*	37.5	36.8

* See section 3.3.1 for reasoning why no specific target is set for capacity utilisation.

7.3.2 Load factor

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. Load factor has trended upwards over the last 15 years by just over 0.7% per annum.

Load factor results for 2008 and five year average 2004-2008			
Category	Target	Achieved 2008	Achieved five year average
Load factor (%)	No target set*	60.1	61.6

* See section 5.4.1 for our load factor forecasts.

7.3.3 Losses

Measurement of losses

Loss results for 2008 and five year average 2004-2008			
Category	Target	Achieved 2008	Achieved five year average
Losses (%)	No target set*	<5 estimated	<5 estimated

* See the following paragraph for reasoning why no specific target is set for losses.

Historically, electrical losses were derived from the difference between volumes entering our network at GXPs and the energy volumes leaving our network, as measured (and billed) at consumer connections. Prior to the separation of distribution from retailing, losses on our network were measured at 4.9%. The separation of retailing from distribution has lead to inaccuracies and deficiencies in the billing system, and apparent losses have been measured as high as 10-15% in recent years. Due to these inaccuracies we continue to disclose a loss factor of 4.9%.

There is some uncertainty in the metered volumes because:

- metering errors occur at the GXPs (approximately ± 0.2%)
- metering errors occur at consumer connections (approximately ± 2.5%)
- timing of meter reading is precise at GXPs (meters are read every half hour) but is imprecise at consumers' meters, which are read every one or two months
- the volume lost is the small difference between two large numbers that have uncertainties – approximately 150 in 3,000 ±30 (±1%)
- metering data is subject to gaps and distortions due to incorrect multipliers being applied and omissions and errors when metering information is captured.

Consequently, our overall network loss ratio has to be considered as 4.9 ± 1%. Significant deviations from this value exist in some parts of the network, for example, when we compare urban areas against rural areas.

Source of losses

Our assessment of main contributors to the loss ratio is as follows:

NETWORK

Network loss contributors			
Asset	Urban	Rural	Average
Subtransmission lines and cables	0.4%	1.0%	
District (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%	4.9%

OTHER SOURCES

Internal usage by Orion – All our major facilities, such as our head 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 – For substantial volumes, such as supply to street and traffic lights, volumes 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 volumes are unknown. Electricity retailers are responsible for the integrity of metering at connections and for reading meters. It is in their interest to minimise theft.

Transformer purchases

Any new distribution transformers that we purchase must comply with the Minimum Energy Performance Standards (MEPS) as prescribed in Australian Standard 2374.1. In addition to MEPS, our equipment specification NW74.23.05 – Distribution Transformers 200 to 1000kVA, includes a 'no-load load loss' multiplier and a 'load loss multiplier' that are used for the capitalisation of loss costs when comparing offers of distribution transformers for purchase. As a result we purchase even lower loss transformers than MEPS requires.

Our equipment specifications for power transformers NW74.23.07 – Transformer 66/11kV, 7.5/10MVA, also have these loss multipliers for use when we evaluation of tenders.

Transformer 'no load loss' values		
Transformer size	Present value of 'no load loss' ($/kW)	Present value of 'load loss' ($/kW)
Up to 150kVA	$8,691	$273
200-1000kVA	$8,744	$820
20MVA	$8,041	$1,754

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 transformer costs and the future costs 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 8.5c/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 1000kVA.

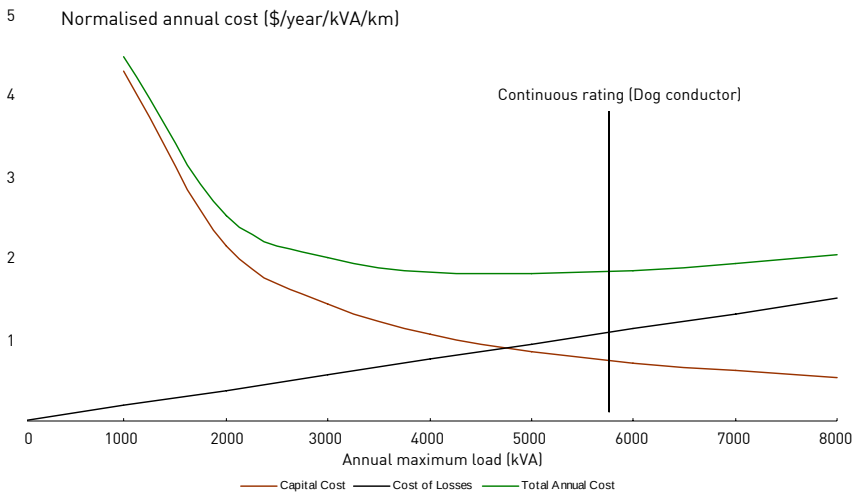
Selecting conductor size

Most electrical losses in our network occur in lines and cables, i.e., 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

Economic optimum operating conditions for overhead lines exist when delivering electricity to the reasonably substantial loads that typically occur on urban fringes. 'Kelvin's Law' of economics applies. It states that the minimum annual operating cost occurs when the annual cost of losses equals the annual capital cost. This optimum operation typically occurs when the maximum load is 75 to 85% of the conductor's rating. The characteristic is illustrated in the diagram below for the 11kV 'Dog' conductor which we commonly use in higher-density loading areas.

Annual cost versus loading – 11kV (dog) overhead line



We endeavour to design and operate our overhead lines within the optimum range in higher-density loading areas. However, we note that the annual operating cost does not vary much over the wider range of 50 to 100% of rating.

The conductor size needed for the longer overhead lines in rural areas is principally determined by the limits on voltage drop. Conductors with excess capacity are used as these have lower resistance which reduces voltage drop along the line. The economic optimum is not achieved, and lines typically operate with annual maximum loads of 5 to 50% of rating. Consequently, losses are lower than the economic optimum.

We need this extra capacity during fault contingencies and maintenance work to transfer load to alternative sources of supply.

Underground cables

For a given rating, cables cost more and have lower resistance per unit length. A comparative example is shown in the table below:

Underground cable versus overhead line comparison

Conductor	Rating (amps)	Installed cost ($/km)	Resistance (ohms/km)
Dog overhead line	300	$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 cable 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 size. We proved this justification when we reviewed our security standard in 2006. Analysis showed it was economic to install an 11kV network capable of restoring power

for N-2 faults at district/zone substations. Two thirds of the additional capital 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 discreet 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 preference's.

Summary

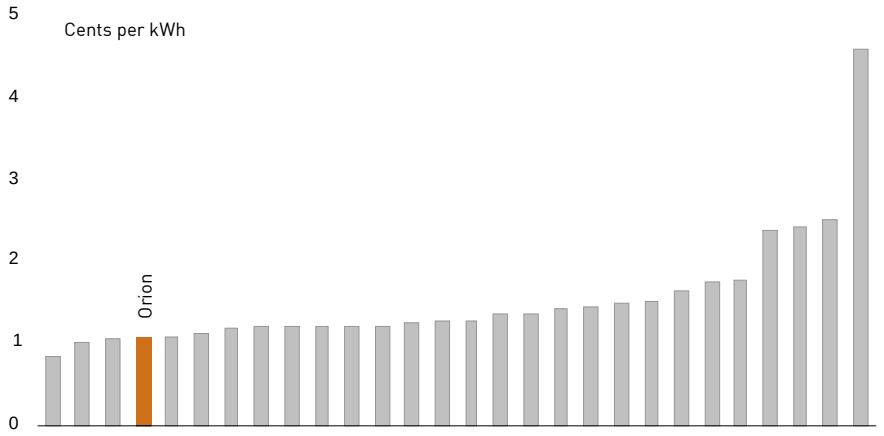
Overall, losses do not impact significantly on how we design and operate our network – other factors tend to dominate. Losses are significant in some aspects of network design though, and require policies for optimisation. Significant points are:

- it is difficult to determine electrical losses
- losses occur mostly in lines and cables (3.3%) and transformers (1.7%)
- 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 and operate overhead lines in areas with high loading density; elsewhere, other factors determine how we select conductor size
- for any major network development, we consider the cost of losses
- some other minor contributors towards losses – internal use, unmetered supplies and theft – have little impact on our overall network losses.

7.3.4 Economic performance comparison

Considering the excellent reliability of our network, our costs compare favorably with other New Zealand network companies.

Orion's position relative to other New Zealand network companies
Costs per unit (kWh) 2007



7.4 Works

7.4.1 Expenditure in 2008

The previous AMP figures shown here are from our AMP for the period from 1 April 2007 to 31 March 2017.

Maintenance

Our maintenance costs for 2008 were $17.8m, compared with our previous AMP forecast of $18.6m. The under-expenditure was due to lower than expected insurance/leasing costs, lower SCADA costs due to resources utilised on capital projects and better than average weather conditions during the year. Other works identified for 2008 were substantially completed.

Capex

- Consumer connections

  Our consumer connection costs for 2008 were $4.4m, compared with our previous AMP forecast of $4.2m. There has been consistent strong demand in both the residential and commercial markets.

- Network extensions

  Our network extension costs for 2008 were $3.2m, compared with our previous AMP forecast of $2.6m.

  Demand associated with network extensions and subdivisions has been high due to large and small residential subdivisions.

- Reinforcement

  Our reinforcement costs for 2008 were $4.5m, compared with our previous AMP forecast of $4.6m.

  All works identified to be completed in 2008 were substantially completed.

- Underground conversion

  Our underground conversion costs for 2008 were $1.5m, compared with our previous AMP forecast of $1.7m.

  This under-expenditure was largely due to project timing associated with roading authority needs and works undertaken by the Christchurch City Council.

- Major projects

  Major project costs for 2008 were $14.4m, compared with our previous AMP forecast of $16.5m.

  This under-expenditure was largely due to delay in installing Dunsandel substation. The completion date for this project was driven by the consumer's timetable. Other projects were substantially completed.

- Replacement

  Our replacement costs for 2008 were $8.4m, compared with our previous AMP forecast of $10.3m.

  Resource constraints due to major projects and works in neighbouring networks had significant impact on our works schedule. This under-expenditure will not impact on network performance when we achieve current expected completion times.

7.4.2 Project completion status

Project completion status			
Project number	Description	Completion date	Comments (if applicable)
Grid exit points			
323	Springston 66kV bus	Apr 08	Completed by Transpower, but final costs are still to be announced.
304	Middleton GXP	Mar 08	Completed by Transpower, but final costs are still to be announced.
Major projects – rural			
407	Killinchy line circuit breaker	Aug 08	
287	Neutral earthing resistors	Aug 08	
194	Larcomb substation – stage 1	n/a	Stage 2 ongoing.
271	Little River transformer upgrade	Mar 08	
427	Pound Road to Hasketts Road 66kV line	Apr 08	
275	Dunsandel 66/11kV substation – stage 1	July 08	
347	Brookside to Springston 66kV line – stage 2	June 08	
362	Motukarara 33kV switchgear and transformer upgrade	Apr 08	
Major projects – urban			
280	Middleton 33kV to 66kV conversion – stage 2	Apr 08	
356	Belfast land purchase	Mar 08	Purchase agreement is signed, but title will not be transferred until August 2009, as subdivision and CCC approval are required.
301	11kV ripple plant for Islington 33kV – final stage	Oct 07	
283	Sockburn third transformer – stage 1	n/a	Stage 2 ongoing.
Reinforcement – rural			
435	Rolleston transformer upgrade – stage 2	Apr 07	
404	Lincoln to James Street feeder upgrade	Aug 07	
399	Rakaia Terrace Road conductor upgrade		
379	Old South Road		
395	West Coast Road	Sep 07	
393	Roberts Road	Jan 08	
380	Highfield Road and Hoskyns Road new line	June 08	
Reinforcement – urban			
437	Belfast, Marshland and Walters Roads reinforcement	Mar 08	
430	Power quality monitoring	Mar 08	
428	Brooklands to Kainga tie	-	Postponed. Designed September 2008, to be completed by March 2009
406	Therese Street alterations	June 07	
403	Middleton to Sockburn tie	Mar 08	
402	Blenheim Road feeder	Mar 08	
374	Brooklands regulator and spare	Feb 08	
398	Sutherlands Road feeder upgrade	June 07	
375	Curletts Road reinforcement	Nov 07	
400	Kilmarnock Street No.44 substation upgrade	Aug 07	

7.5 Safety

Historically we have reported all employee injury incidents in our incident management database. This database now collects all incident types from our employees. 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 leading indicators of potential harm.

Personal safety – performance results

Key asset management driver	Measure	Target	Achieved 2008	Performance indicator	Measurement procedure
Personal safety	Injuries to staff	Zero	Zero	Number of 'serious- harm' injury accidents	Accident/incident reports
	Injuries to our contractors	Zero	Note.1		
	Injuries to public	Zero	Note.1		

Note.1 These statistics will be available for our 1 April 2010 AMP.

See section 6.2 – Risk management – Safety for details of our risk mitigation initiatives.

7.6 Environment

No significant environmental incidents occurred on our network in 2008.

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.

Environmental responsibility – performance results

Key asset management driver	Measure	Target	Achieved 2008	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)	Zero	Zero		

7.7 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, including the Electricity Governance Rules
- 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 three times each year.

7.8 Improvement initiatives

Our initiatives to lower risk to our network 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.

7.8.1 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

- carry out thermal engineering checks to determine/confirm the current rating of cables
- specify trench backfill to provide the required thermal and mechanical support
- replace 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

- replace insulators and install vibration dampers
- re-rate conductor for 75^{0}C operating temperature
- apply dynamic ratings
- assess condition of tower foundations and repair.

Transpower GXP

- increase reliability at Addington GXP by splitting the 66kV bus
- major alterations at Islington GXP to increase capacity and alter vector grouping along with replacing half of the 33kV outdoor switchgear with indoor equipment
- rearrange existing 11kV supplies at Addington GXP to increase security
- install a 66kV bus zone scheme at Bromley 66kV GXP.
- construct a 66kV bus at Springston (underway by Transpower).

7.8.2 Distribution overhead lines

Historical performance

Over the past 17 years our rural reliability performance has improved by a factor of approximately two. During this period the overhead line fault rate has decreased from approximately 25 faults per 100km per year to about 10-15 faults per 100km per year.

These improvements are primarily attributed to some major maintenance projects and better tree control. In addition, live-line work practices have significantly reduced planned outages. More line circuit breakers and shortened feeders as new district/zone substations are installed have also improved performance.

Our major initiatives are:

- complete 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 the high voltage lines
- increase use of smooth body conductors in areas exposed to snow and high winds
- removal of 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.

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 effects of line faults.

In the five years (from 2000-2004) we installed 29 additional line circuit breakers in our rural network – 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.

Ranking of reliability initiatives

Reliability improvement initiative	Cost per kWh ($)
Ground fault neutraliser (Average cost per kWh if installed at every rural substation)	8
Line circuit breakers	14-30
Tree trimming	15-30
Shorten feeder lengths	25
Covered conductor (80% of network)	78
Underground (80% of network)	695
Selective covered conductor for trees	Unknown
These costs to be compared with the cost of unsupplied energy to rural consumers of $15 per kWh.	

We supplied 3,85GWh of energy to 21,500 rural consumers during the year ended March 31, 2006. This equates to an average consumer usage of approximately 2kW per hour, so the cost of an outage to the average rural consumer is $30 per hour (2kW x $15 per kWh). Therefore the annual cost of network enhancement must not exceed the $30 per hour ($15 per kWh) of consumer reliability improvement. The annual cost of network enhancement is approximately 14% of the capital cost. In this scenario 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 2000-2004 installation programme was installed in a feeder from Lincoln district/ zone substation. This saw a reduction of approximately 2,200 consumer hours (132,000 minutes which was nearly 2% of overall system SAIDI at the time) for an annual cost of approximately $7,000 (only $1.60 per kWh). This is well below the $15 per kWh and was therefore a successful reliability enhancement. The 750 consumers affected now experience approximately half the number of interruptions and time without power. The 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. The best sites currently identified provide reliability improvements of approximately 250 consumer hours at an annual cost of $7,000 ($14 per kWh), which is marginal.

Current available options to improve rural network reliability come at considerably increased cost. 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 therefore 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 provide a performance improvement/cost benefit analysis for this option.

2. Continue to install additional line circuit breakers – as noted above, 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 district/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 district/zone substation typically costs about $3m, giving an annualised cost of $25 per kWh. This clearly exceeds the $15 per kWh 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 4.3million 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 $15 per kWh 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 customer minutes by approximately 6 million (100,000 hours) at an annualised cost of approximately $870 per kWh.

6. Installing ground fault neutralisers (GFN) at rural district/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 plan to eventually install this technology at all of our rural district/zone substations.

A GFN can reduce the residual earth fault current 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 $250,000.

Initial 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 district/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, which currently does not feed any overhead network) is shown in the table on the following page.

Installation of GFN – reliability savings

Substation	Anticipated savings for long term	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 Harbour	5,923	4,255	10,178	0.27
Little River	6,083	3,699	9,781	0.26
Castle Hill	4,223	1,830	6,053	0.16
Coleridge	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 10 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.

Underground conversion of selected rural consumers is underway to establish a basis on which to compare life cycle costs of rural underground with the life cycle costs of rural overhead lines.

7.8.3 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 33/11 kV district/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 district/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 Darfield substation to reduce earth fault levels and are in the process of installing GFNs at other rural district/zone substations including Rolleston.

7.8.4 Power quality

Although the power quality attributes discussed in section 3 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 or actions, and assume that fundamental network performance is satisfactory. We currently do not know qualitatively the existing underlying power quality performance of our network.

We have therefore begun a three year project to install power quality measurement equipment 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 expect to measure approximately 30 sites.

As a result of the survey we will develop and calculate power quality indices to define the power quality performance of our distribution network.

Power quality project

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

We also purchased the 'PQView power quality analysis package' to archive and analyse the data. Our preliminary analysis of data collected to date shows very high harmonic levels on the network supplied from Hororata GXP. This data has assisted Transpower to analyse the effect of transposing the 220kV lines as part of a project to reduce voltage imbalance. The data has also been used to discover and monitor the increasing harmonic distortion caused by everyday domestic consumer electronic equipment.

7.8.5 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 one-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.

7.9 Gap analysis

7.9.1 Reliability

Our network improved over the 17 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 now total 55 in our rural network.

7.9.2 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

Appendix A1 - Expenditure forecasts and reconciliations

For initial forecast year ending (year 1) 2010

A) Ten yearly forecasts of expenditure $000

	Actual for current Financial Year	Previous forecast for current Financial Year	Forecast year									
	Year -1	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
For year ended	2008	2008	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Capital expenditure; Customer connection			3,600	3,800	4,200	5,000	5,400	5,400	5,400	5,400	5,400	5,400
Capital expenditure; System growth			10,588	20,790	27,120	20,905	16,475	9,310	8,720	11,350	21,960	15,320
Capital expenditure; Asset replacement and renewal			10,513	11,565	11,149	11,780	15,638	17,825	17,077	17,642	17,434	18,151
Capital expenditure; Reliability, safety and environment			3,886	3,645	3,125	3,192	3,145	3,195	3,100	3,095	3,100	3,095
Capital expenditure; Asset relocations			2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
Subtotal - Capital expenditure on asset management	36,400	39,973	30,687	41,900	47,694	42,977	42,758	37,830	36,397	39,587	49,994	44,066
Operational expenditure; Routine and preventive maintenance			17,316	18,997	19,085	18,984	17,386	17,426	17,313	17,270	17,371	17,775
Operational expenditure; Refurbishment and renewal maintenance			2,890	2,890	2,890	2,905	2,905	2,905	2,105	2,105	2,105	2,105
Operational expenditure; Fault and emergency maintenance			3,170	3,170	3,170	3,170	3,170	3,170	3,170	3,170	3,170	3,170
Subtotal - Operational expenditure on asset management	17,800	18,607	23,376	25,057	25,145	25,059	23,461	23,501	22,588	22,545	22,646	23,050
Total direct expenditure on distribution network	54,200	58,580	54,063	66,957	72,839	68,036	66,219	61,331	58,985	62,132	72,640	67,116
Overhead to underground conversion expenditure			2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100

Explanatory notes: All overhead to underground conversion expenditure is attributed to Capital expenditure; Asset relocations.

B) Variance between actual expenditure and previous year forecasts $000

	Actual for current Financial Year	Previous forecast for most recent Financial Year	% Variance
	Year -1	Year -1	
	(a)	(b)	(a)/(b)-1
Capital expenditure; Customer connection			
Capital expenditure; System growth			
Capital expenditure; Asset replacement and renewal			
Capital expenditure; Reliability, safety and environment			
Capital expenditure; Asset relocations			
Subtotal - Capital expenditure on asset management	36,400	39,973	8.9
Operational expenditure; Routine and preventive maintenance			
Operational expenditure; Refurbishment and renewal maintenance			
Operational expenditure; Fault and emergency maintenance			
Subtotal - Operational expenditure on asset management	17,800	18,607	4.3
Total direct expenditure on distribution network	54,200	58,580	7.5

Explanation of variance more than 10% Explanatory notes

Appendix A2 - Requirement 7(2) - Assumptions

Electricity Distribution (Information Disclosure) Requirements 2008 – Requirement 7(2)

The Electricity Distribution (Information Disclosure) Requirements 2008, gazetted in October 2008 introduced a new requirement in relation to AMP information. In addition to the information to be included in the AMP, as prescribed in the Electricity Information Disclosure Handbook, dated 31 March 2004 and amended 31 October 2008, Orion is required to disclose the following information. This statement comprises Orion's disclosure in accordance with this Requirement.

(a) all significant assumptions, clearly identified in a manner that makes their significance understandable to electricity consumers, and quantified where possible;

- Climate - Orion is exposed to normal climatic variation over the planning period including temperature, wind, snow and rain patterns consistent with its experiences since 1993
- Corporate Vision, Objectives and Targets – see section 2
- Customer preferences for quality and price – section 3.2
- Demand projections – see section 5.4
- Embedded generation – see section 5.3.5
- Regulations, legislation and industry standards and codes of practice – see section 2.5.2
- Individual large loads – see section 4.1.1
- Land zoning – see section 5.4.2
- Load characteristics – see section 5.4
- Major disasters – see section 6.6
- Ownership – see section 2.3
- Relative input costs and exchange rates and the cost of borrowing
- Resource availability
- Transpower's obligations and commitments

(b) a description of changes proposed where the information is not based on the Distribution Business's existing business;

No changes are proposed to the existing business of Orion, and thus all prospective information has been prepared consistent with the existing Orion business ownership and structure.

(c) the basis on which significant assumptions have been prepared, including the principal sources of information from which they have been derived;

The basis on which the assumptions have been prepared is described in detail in Sections 3 and 5 (Service level targets and Network Development) of the AMP. The principal sources of information from which they have been derived are:

- Customer surveys
- Economic activity forecasts
- Exchange rates, interest rates
- Historical demand and connections
- Local interaction with customers
- Population data and forecasts
- Risk Management Plans such as Business Continuity Plans
- Strategic Planning documents such as Statement of Corporate Intent, Annual Business Plan

(d) the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures;

Factors which may lead to a material difference between the AMP and future actual outcomes include:

- Customers could change their demands for reliability or their willingness to pay for different levels of service.
- Demand growth and economic activity
- Embedded generation
- Input costs and exchange rates
- Land zoning
- Large customers
- Load patterns
- Major equipment failure
- Major natural disaster
- More detailed asset management planning
- New loads
- Ownership
- Regulatory requirements

(e) the assumptions made in relation to these sources of uncertainty and the potential effect of the uncertainty on the prospective information.

The assumptions made in relation to these sources of uncertainty are listed in (a) above. The potential effect of each on the prospective information is generally discussed in section 5. Presenting this information here to an acceptable depth and in a suitable format is being investigated and will be available in our next AMP.

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 Schedule 2 of the Electricity Information Disclosure Requirements. We have prepared the cross reference table below to help you find specific sections.

Sections as per the Electricity Information Disclosure Requirements	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 level targets
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	7. Evaluation of performance

Appendix C - Glossary of terms

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.

CAIDI: an international index which measures the average duration of an interruption to supply for consumers that have experienced an interruption. Usually calculated on a per annum basis.

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.

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 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 effecting it 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.

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: 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 4.24).

District/zone substation: a major building substation and/or switchyard with associated high voltage structure where either; voltage is transformed from 66 or 33kV to 11kV, two or more incoming 11kV feeders from a grid exit point are redistributed or a ripple injection plant is installed.

Dog: an aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of 103mm^2.

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 district/zone substation circuit breaker.

Flashover: a disruptive discharge around or over the surface of an insulator.

Flounder: a aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of 20mm^2. 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: voltage exceeding 1,000 volts (1kV), in Orion's case generally 11kV, 33kV or 66kV.

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 207mm^2.

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: 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 62mm^2.

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 25mm^2.

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 bioaccumulate 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 50mm^2.

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.

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 34mm^2.

Squirrel: an aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of 20mm^2.

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 100mm^2.

Wolf: an aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of 155mm^2.

XLPE cable: cross linked polyethylene insulated cable.

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