



AURORA ENERGY LTD

Asset Management Plan Number 18

April 2011 – March 2021

Prepared for Aurora Energy Ltd
by *DELTA* Utility Services Ltd



Date approved by Aurora Board: 30 March 2011

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F O R E W O R D

This is the eighteenth network Asset Management Plan for the distribution networks owned by Aurora Energy Ltd, and covers the 10 year period from 1 April 2011.

It documents existing and projected network asset conditions, and the likely or intended asset management strategies, policies, plans, and thinking, based on the present understanding of customer and regulatory requirements, and regulatory demands. It is not an approved programme for specific work; rather, the programmes and projects are indicative. In some cases plans will be subject to user discussion and/or funding, while in all cases they are subject to financial approvals.

D I S C L A I M E R

As this document is indicative, Aurora Energy Ltd will not accept responsibility for decisions, by others, which are based upon information contained herein. Any person proposing to use information contained in this document for decision making purposes should consult with Aurora Energy Ltd before doing so.

1 Summary

1.1 Purpose

The purpose of this summary is to provide brief overview information that Aurora Energy Limited (Aurora) considers significant.

1.2 Background and Objectives

This Asset Management Plan describes the asset management objectives, strategies, policies, plans and systems adopted by Aurora for its electricity distribution networks. It has been prepared in this format to meet the Electricity Distribution (Information Disclosure) Requirements 2008.

1.3 Assets Covered

The network assets consist of two geographically separate networks. The Dunedin network supplies 53,561 consumers in, and adjacent to, the urban area of Dunedin. The network in Central Otago, which stretches from Raes Junction to Lakes Wakatipu and Wanaka and north to St Bathans and Makarora, supplies 28,611 consumers.

The network assets comprise the types and quantities summarised in Table 1-1, located generally as shown in Figure 3.1. Their general condition is detailed in Section 3. The asset value and age data originates from the 2010 ODV data which is detailed below.

Asset Category	Quantity	RC	% by \$
Subtransmission	591km	\$49,901,590	9%
Zone substations	36	\$107,620,602	19%
HV cables	829 km	\$90,184,231	16%
HV lines	2346 km	\$75,163,603	13%
Distribution transformers	6,585	\$64,508,596	12%
Distribution switchgear		\$38,528,109	7%
Distribution substations	6,482	\$14,714,718	3%
LV distribution	1,827 km	\$93,263,487	17%
Service connections ¹	95,469	\$16,824,683	3%
Street lighting distribution	204 km	\$6,744,607	1%
System control		\$2,007,272	< 1%
Sundry		\$562,593	< 1%
Total		\$560,024,091	100%

Table 1-1 – Types and Quantities of Assets

1.4 Service Levels

Service level objectives are summarised in Table 1-2. Details appear in Section 4.

Function	Objective
General Network Performance	Average of no more than 86 minutes without supply per customer per year. (SAIDI)
Response Time - Dunedin Network Area Restore supply following general network failure.	Within 4 hours of notification.
Response Time - Central Network Area* Restore supply following general network failure.	Within 4 hours of notification in urban areas, and within 6 hours of notification in rural areas.

Table 1-2 – Service Level Objectives

Aurora's primary service level focus is the System Average Interruption Duration Index (SAIDI); other indicators are considered to be secondary. However, in the consumer survey described in Section 4.1.1, consumers wish to have fewer interruptions, therefore Aurora believes that making small improvements to SAIDI minutes is appropriate with specific emphasis on reducing the number of interruptions, as measured by the System Average Interruption Frequency Index (SAIFI).

1.5 Network Development Plans

New capital works are driven by demand growth in existing connections, new connections, replacement of equipment where it is economic to do so, and the community desire to underground overhead distribution for aesthetic reasons.

Probabilistic analysis is used to determine when equipment replacement and new capital works are economic. Planned capital expenditure, as detailed in Table 5-1, is summarised in Table 1-3 below:

Financial Year	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Total	23,600	18,800	26,380	27,280	30,490	21,700	21,950	27,110	28,310	27,600

Table 1-3 – Capital Expenditure (\$000)

1.6 Lifecycle Asset Management Planning

Aurora's maintenance strategy is based on continual monitoring of asset condition and performance.

Asset management policy is to evaluate and balance the cost of maintenance against the prospective cost of failure, refurbishment/renewal costs and the cost of non-supply. Asset renewal is determined when the cost of maintenance is greater than the cost of replacement.

* For Retailers using the standard Use-of-System Agreement dated July 2005.

As a result of continual refurbishment work, the network is in reasonably good condition. Improved knowledge and analysis of maintenance trends continues to result in inspection and test intervals being extended in some instances, and reduced in others. Maintenance requirements are continually monitored, and are subject to change as optimum levels evolve. The maintenance expenditure from Table 6-2 is summarised in Table 1-4 below:

Financial Year	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Total	9,120	9,350	9,580	9,810	10,050	10,300	10,550	10,820	11,070	11,360

Table 1-4 – Total Maintenance Expenditure (\$000)

1.7 Risk Management

Risk assessment and risk management strategies focus on four principal areas:

- (1) health and safety;
- (2) responsibilities dictated by the Resource Management Act;
- (3) network capacity (new capital investment for load growth);
- (4) network reliability (maintenance and/or restoration of supply).

Procedures contained in *DELTA's* Asset Management Quality System detail operational and planning policies and guidelines for dealing with each of these risk management areas.

The risk of insufficient competent human resource to complete capital works in a timely manner remains as a potential industry wide concern.

1.8 Evaluation of Performance

The diagram below compares the performance achieved by Aurora's network with that achieved by other large Electricity Lines Businesses (ELBs) in the year to 31 March 2010.

When judged on the combination of low price (average distribution charge/kWh delivered) and high quality (low SAIDI)¹, the Aurora network, shown as the shaded triangle in Figure 1.1 below, was in the 'best-performer quartile' of New Zealand's 29 large ELBs.

This analysis provides a great degree of confidence that Aurora's performance is satisfactory.

¹ SAIDI = System Average Interruption Duration Index (minutes).

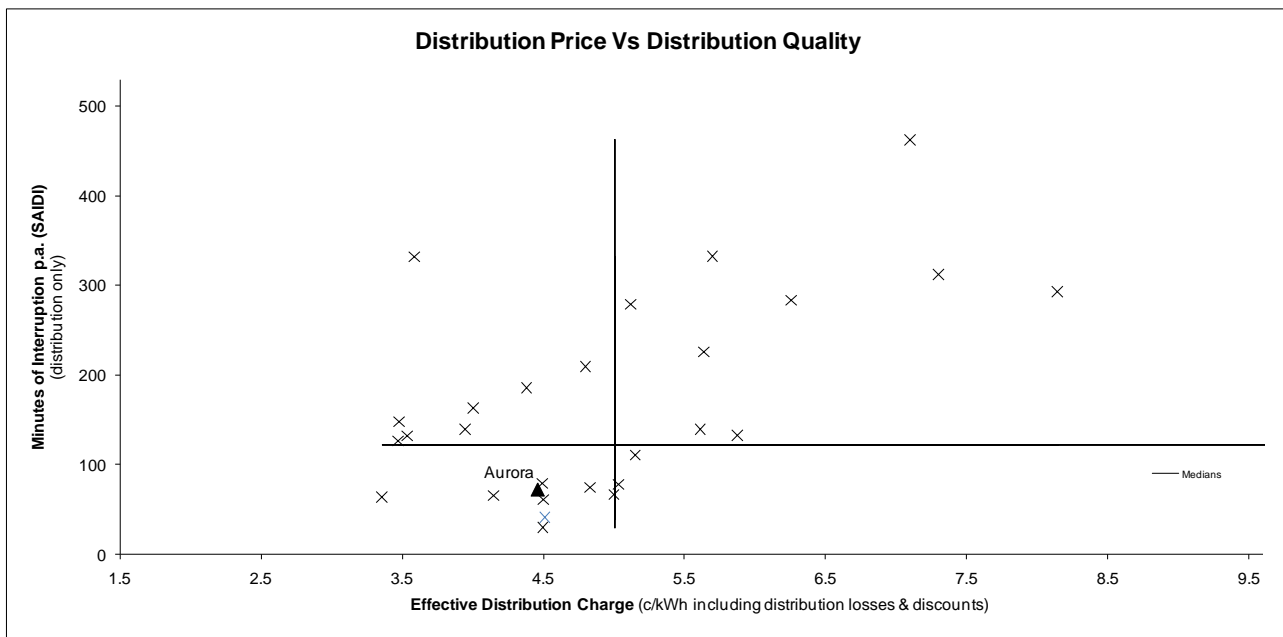


Figure 1.1 – Price-Quality Matrix

1.9 Stakeholder Consultation

Aurora's process for continual improvement will remain focussed on optimising the trade-off between price and quality. To this end, Aurora invites questions, comments, and suggestions for improvement of this Asset Management Plan at any time.

These can be lodged through <http://www.auroraenergy.co.nz/contactus.php> or by writing to:

Aurora Energy Ltd
P O Box 1404
DUNEDIN

This plan concentrates on asset management principles and overall indicators of asset condition and performance. Existing or potential users of network assets may request more details regarding the specific assets that affect them.

For some years, Aurora has actively sought comment on its Asset Management Plan, including through newspaper advertisements and direct approaches. There was one instance of feedback regarding demand growth on the 2006 Asset Management Plan and this was taken into account in the preparation of the 2007 Asset Management Plan. No other comment had been received in response, other than from the Commerce Commission and its agents. Separately, Aurora has also sought feedback from consumers on the level of reliability received and the price paid to assist with assessing whether consumers receive value for service.

In order to improve on this generally low level of public feedback, Aurora uses external consultants to assist in the ongoing development of the Asset Management Plan, policies and processes.

2 Background and Objectives

2.1 Purpose

The purpose of this document is to summarise Aurora's asset management methodology and practices to provide a systematic representation, ownership, governance and management framework that ensures that Aurora:

- sets service levels for Aurora's electricity networks that will meet consumer, community and regulatory requirements;
- understands what network capacity, reliability and security of supply is required, both now and in the future, and what issues drive these requirements;
- has robust and transparent processes in place for managing all phases of the network life cycle;
- has adequately considered the classes of risk Aurora's network business faces, and that Aurora has systematic processes in place to mitigate identified risks;
- has an ever-increasing knowledge of Aurora's asset locations, ages, conditions, and likely future behaviour;
- makes all decisions within systematic frameworks and guidelines.

Preparation of the Asset Management Plan in this format also assists in meeting the requirements of Section 7 of the Electricity Distribution (Information Disclosure) Requirements 2008.

2.2 Interaction between Plan Objectives and Other Corporate Goals, Business Processes and Plans

Aurora's corporate strategic asset management drivers reflect the company's corporate mission statement:

"TO BE THE BEST PERFORMING INFRASTRUCTURAL BUSINESS IN NEW ZEALAND"

Aurora has four levels of corporate planning: a Strategic Plan, this 10-year Asset Management Plan, an internal Development Plan, and an annual budget. Interaction between business processes and plans are detailed in Figure 2.1 overleaf.

Aurora's Strategic Plan sets out the vision of the Company and the key objectives that must be achieved if that vision is to be realised. The plan takes into account aspects such as regulatory, customer, staff and shareholder constraints and expectations, and defines and shapes the AMP.

Aurora's Development Plan, details potential developments to provide for anticipated load growth, improved security and reliability, and appropriate asset renewal. It is confidential to Aurora. This is approved by the Board prior to setting annual budgets. It contains more detail regarding capital works than the AMP, and is used as the basis of the proposed capital works programme contained herein. The AMP is, in effect, the summary document that encompasses both maintenance and capital projects.

This Asset Management Plan covers the period from 1 April 2011 to 31 March 2021, and represents an evolution of the annual Asset Management Plans published for the Dunedin network since 1993.

The Board approved this (2011 – 2021) Asset Management Plan on 30 March 2011.

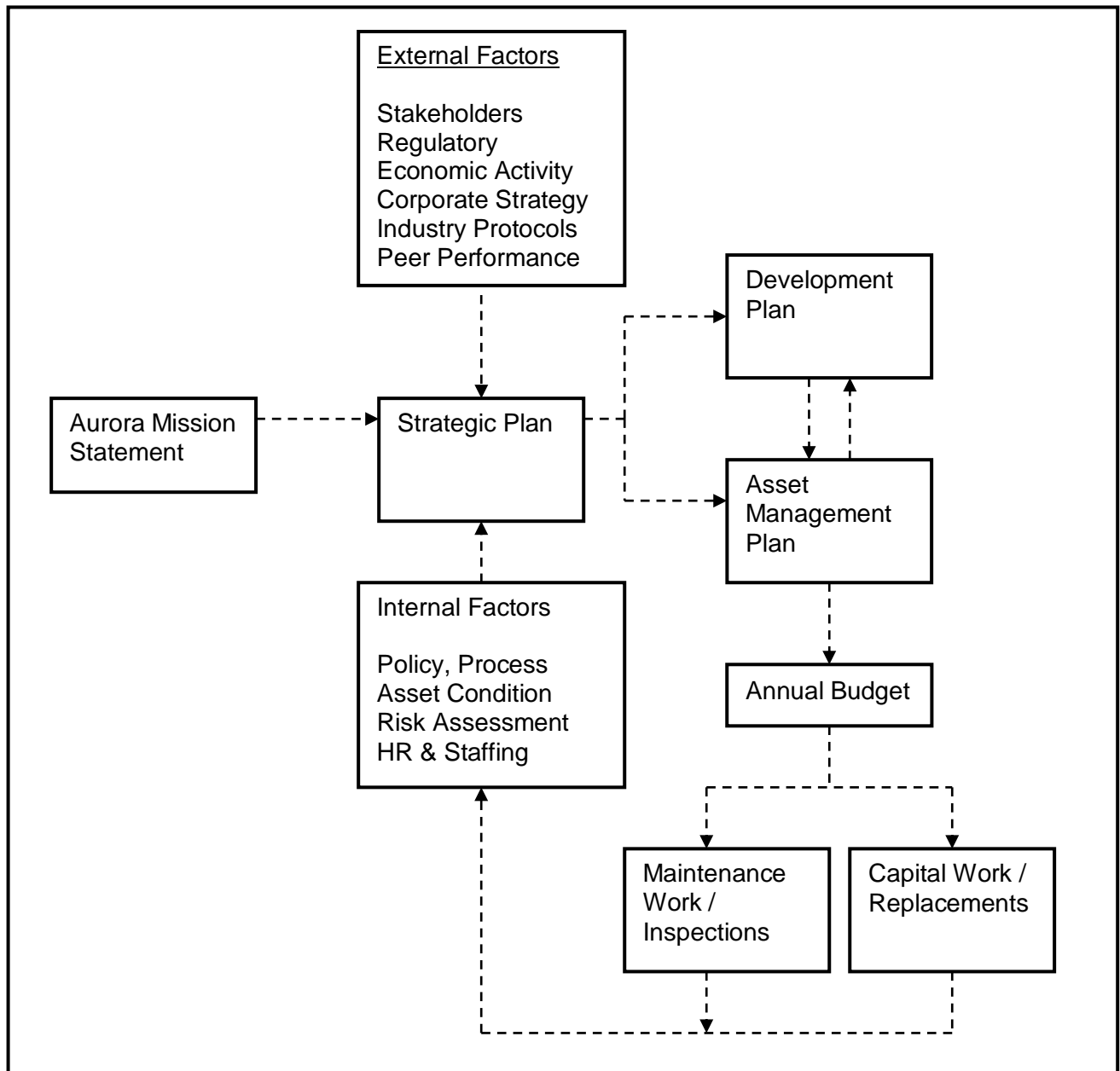


Figure 2.1 – Interaction Between Other Business Processes and Plans

2.3 Period to Which Plan Relates

This plan relates to the 2011 - 2021 period.

The plan is subject to change without notice in the event of significant unanticipated equipment failures, storm or disaster, or material changes in local loadings.

There is an obvious degree of uncertainty in any predictions of the future and, accordingly, the AMP is uncertain.

Following the continuation of the falling off of customer initiated works in the Central area coupled with a slump in international economic activity, Aurora has attached the following certainties to the timeframes of the AMP.

Timeframe	Residential and Commercial	Large Commercial and Industrial	Intending Generators
Year 1	Certain	Reasonably certain	Reasonably certain
Years 2 and 3	Some Certainty	Some certainty	Some certainty
Years 4 to 10	Little if any certainty	Little if any certainty	Little if any certainty

Table 2-1 – Loading Certainties

2.4 Stakeholder Interests

2.4.1 Stakeholders

Stakeholders are those parties with a direct interest in Aurora's network asset management policies and practices. The exact nature of stakeholder interests are identified by customer surveys, open requests for feedback, safety reviews, industry forums and other means. The principal stakeholders and the nature of their interests are as summarised follows:

Stakeholder	Interest	How Stakeholder Interests are Identified
Contractors who provide services to Aurora	Contractual relationship Safe working environment Continuity of work	Contractual requirements
Electrical Contractors who work for consumers and developers	New-connection policies Maintenance and upgrade policies	Contractual requirements Quality documentation feedback
Electricity Consumers	Line charges Network reliability/service quality Optimisation of electrical losses New-connection policies	Consumer satisfaction surveys Direct liaison re issues such as no power, trees etc. Safety advertising
Electricity Retailers, and distributed generators	Line charges Network reliability/service quality Contractual arrangements Optimisation of electrical losses	Use-of-System Agreements

Stakeholder	Interest	How Stakeholder Interests are Identified
Employees of DELTA (main Contractor)	Health and safety Creative work environment Career opportunities	Internal communications
Government	Economic efficiency Compliance with statutory requirements	Submissions Relationship meetings
Landowners with network facilities on their land	Safety Easement conditions Access for maintenance/repair Compensation for significant interference	Direct communication and consultation
Property developers	New-connection policies Timely network expansion	Direct communication
Shareholder	Adequate, stable, and secure return on investment Good corporate citizenship	Board Meetings
Territorial authority	Minimising of environmental impacts (RMA) Local economic development Control of assets in road reserve Conversion of overhead to under-ground	Direct communication Submissions RMA Applications
NZ Transport Agency	Control of assets in road reserve Safety issues such as hedges on Aurora-owned land	Direct communication
Transpower	Reliability of supply Investment for growth	Direct communication re planning System operator communication
Media	News, background information	Direct communication

Table 2-2 – Stakeholder Interests

This list is illustrative of the issues Aurora takes into account, but is not exhaustive.

Stakeholder interests are accommodated by considering the following aspects of asset management:

- Safety: safety is given the top priority – Aurora will not compromise the safety of contractors' staff or the public.
- Reliability/cost trade off: the network reliability targets are set as a reflection of Aurora's understanding of customer needs.
- Economic growth: Aurora will facilitate economic growth in the areas it serves by providing an electrical distribution network, on an economic basis, to meet consumers' needs.

- Environmental responsibility: where practicable, Aurora will enhance the environment it serves. Examples include:
 - undertaking under-grounding projects in partnership with local authorities;
 - paying particular attention to new zone substation designs;
 - liaising with potentially affected parties associated with new works with the aim of providing economic but visually inoffensive solutions that aim to meet the needs of all parties.
- Legislative compliance: Aurora will comply with New Zealand legislation.

In consideration and management of stakeholder conflict, Aurora will apply the criteria explained above, in order of priority, with safety being the primary concern. The Aurora Board will decide upon any issue of conflict between stakeholder interests.

2.4.2 Continuanace of Supply

Under the provisions of Section 62 (Continuance of Supply) of the Electricity Act 1992, Aurora's obligation to provide lines services (subject to Section 62.3) to all points of supply expires after 31 March 2013.

While Aurora recognises that some points of connection are, or may become, uneconomic, it intends to continue maintaining supply to them beyond 2013 via cross-subsidisation, conditional on an acceptable overall return on investment in the network and while 'cherry-picking' by other network owners is not evident.

However, line businesses will be required to continue to supply electricity beyond 31 March 2013 if the Electricity (Continuance of Supply) Amendment Bill 296-1 (2008), Government Bill is adopted.

2.5 Accountabilities and Responsibilities

Aurora has contracted asset management to *DELTA* under a performance-related contract that was renewed for a further 10 years on 1 July 2007. Under this contract *DELTA* is required to:

- deliver annually specified network performance and customer service, subject to significant financial penalty for non-performance;
- deliver detailed development plans covering periods during and beyond the contract period.

Figure 2.2 details the accountabilities and responsibilities for asset management within the Aurora / *DELTA* contract.

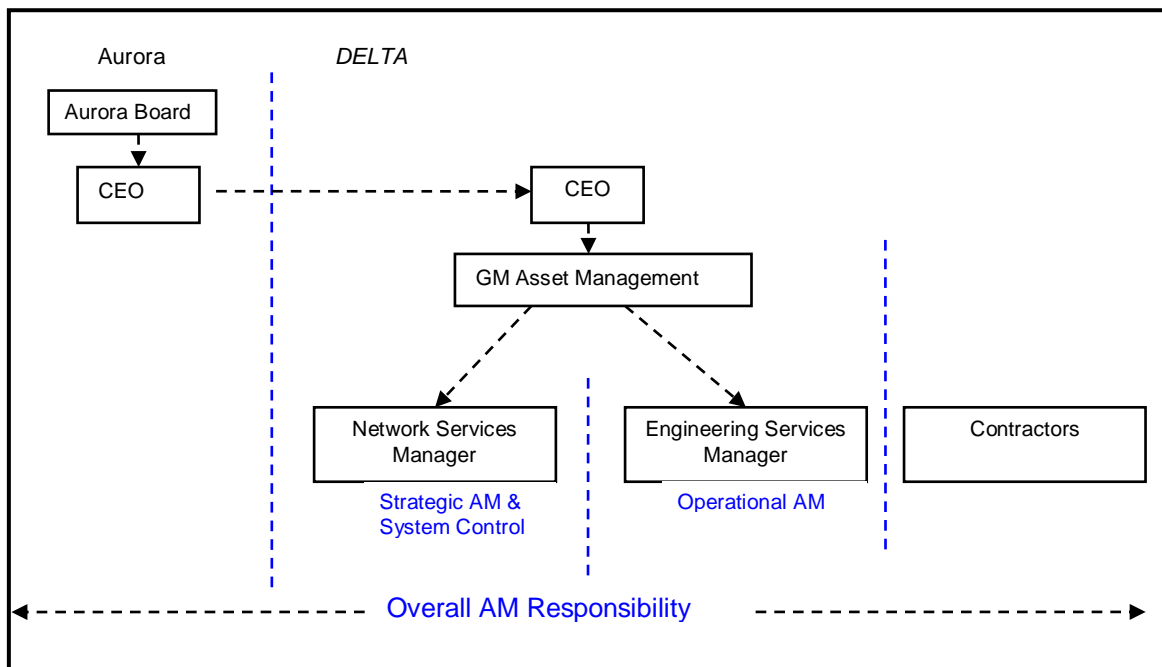


Figure 2.2 – Asset Management Accountabilities and Responsibilities

Under the asset management contract with *DELTA*, the responsibility for the management of the network is primarily through *DELTA*'s Chief Executive, the General Manager Asset Management, and the day-to-day operational management is delegated to *DELTA*'s Engineering Services and Network Services Managers, who together with the Aurora Commercial Manager, form the network management group within *DELTA*.

The Engineering Services Manager's responsibilities include asset planning, asset management including contractor and records management, and the capital expenditure programme.

The Network Services Manager's responsibilities include managing Aurora's contracts with energy retailers and directly connected consumers, Transpower, distributed generators, embedded network owners, use-of-system pricing policies, regulatory matters, the billing of line charges and outage management.

DELTA has made use of external contractors and consultants for works associated with the annual operational, maintenance, capital replacement and network development programmes.

The Aurora Board receives both regular and special reports from *DELTA*, and meets monthly to review a range of operational indicators and to consider strategic issues. Regular reports include financial reporting, capital expenditure, energy and system demands, outage summaries, and specific reports of all outages over 0.5 SAIDI minutes.

The capital programme is approved by the Board during the annual budgeting process. Specific risk issues are considered by the Board's Audit Committee.

DELTA advises that its Information Systems Strategic Plan was reviewed in 2007 and that it has a broad range of strategic objectives in hand to ensure its continued excellence in asset management.

While the information systems hardware and software belong to *DELTA*, the information they contain belongs to Aurora and must be provided to any new asset manager retained by Aurora when the current contract ends.

2.6 Details of Asset Management Systems and Processes

The asset management information systems are built around an ESRI geographic information system, which interfaces with the corporate Oracle database and the following suite of asset management tools:

- Application-for-supply Management System: the process of negotiating and constructing new connections is electronically managed from application to livening. The information is fed into the Gentrack database which is audited annually by external auditors.
- Maintenance Management System: storage and analysis of maintenance histories for specific plant items and for asset classes allows optimisation of maintenance and replacement at both class and item levels.
- Work Order Management System: The issue of work to and inspection of work by, contractors is managed electronically within the SAP accounting software.
- Production of ODV summaries and analysis is integrated with the core records of plant items.
- Outage Management System: planning and notification of outages and production of interruption statistics. This is audited annually by external auditors.
- Load Data: load data, (demand and total energy), is collected and analysed for growth trend information.

In June 1995, Aurora's (then named Dunedin Electricity Limited) Asset Management Quality System achieved ISO certification. Successive audits by the Telarc registration authority have seen that ISO certification maintained by *DELTA*. The data stored in these systems is regularly analysed to determine economic ways of maintaining system reliability (SAIDI) at the least cost to the consumer.

Section 3 details deficiencies in asset information (mainly dates) for each of the asset categories described. These deficiencies are being incrementally addressed as this becomes the economic course of action. Date data is not considered to be as important as condition data. Missing date data relates to old equipment with corresponding low residual value. As such, the benefits to be gained by improving date data for its own sake are minimal and are not actively pursued unless there is a perceived economic case to do so. Efforts to improve the quality of condition data, particularly for poles (which remains the highest priority project); continue to take a higher priority rather than the improvement of date data of all asset classes.

Data anomalies within the GIS, such as wrong transformer configurations, are being identified and rectified on an ongoing basis. This will improve the speed of ODV preparation. This process is expected to take several years to complete.

Figure 2.3 below summarises the asset management processes as described above.

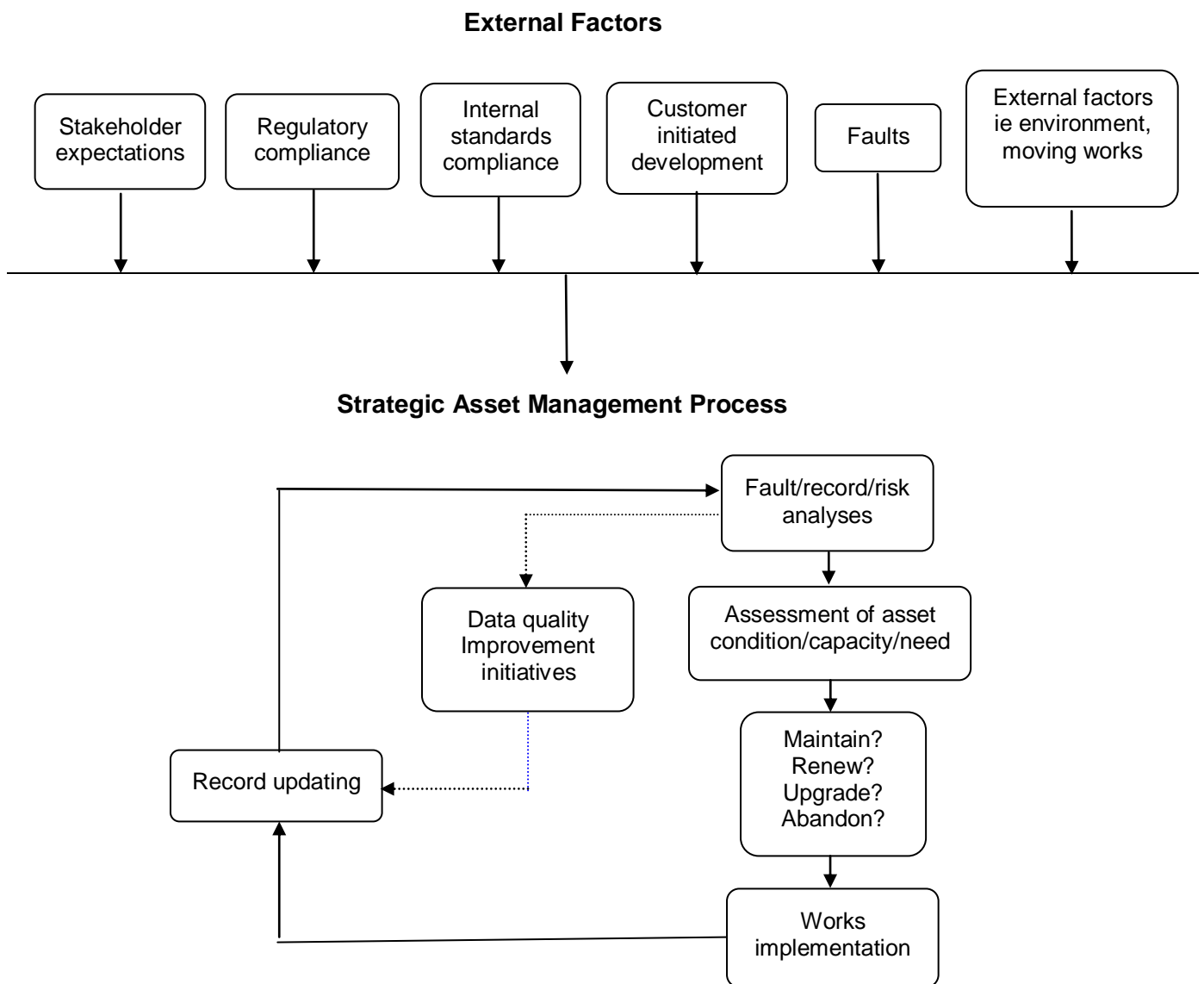


Figure 2.3 – Asset Management Processes

3 Assets Covered

3.1 High Level Description

3.1.1 Areas Covered

The network assets consist of two geographically separate networks in Dunedin and Central Otago, as shown in Figure 3.1 below.

- The geographically smaller network is the electricity network that supplies 53,407 ICPs, as at March 2010, in the urban areas of Dunedin, Mosgiel, and the inner reaches of the Taieri Plains. The Dunedin area is supplied from two Grid Exit Points (GXPs), between which Aurora has significant interconnection at 6.6 kV and 11 kV.
- The network in Central Otago, which stretches from Raes Junction in the south to Lakes Wakatipu and Wanaka in the north-west, and St Bathans and Makarora in the north-east, supplies 28,108 ICPs. The Central region is characterised by its separate river valley areas, mandating a radial network supplied from three transmission GXPs. Aurora has no high voltage interconnections between the Central GXPs.

A small embedded network, connected to The Power Company network, was installed in Te Anau in 2005.



Figure 3.1 – Aurora Network

3.1.2 Large Consumers

The largest consumer within the Dunedin network that has a significant impact on network operations is the University of Otago with a peak load of 5 MW. In Central Otago, the consumers that have the most significant effects on the networks are the ski fields (ie Coronet 4.4 MW).

3.1.3 Load Characteristics

The load in all areas is dominated by residential and commercial load. All GXP areas have their peak demand in winter. The daily peak loads for 2009, for each GXP are shown in Figure 3.2 (2009 loads are shown as they are higher in the winter than 2010 loads due to the fact that the 2010 winter was milder than average).

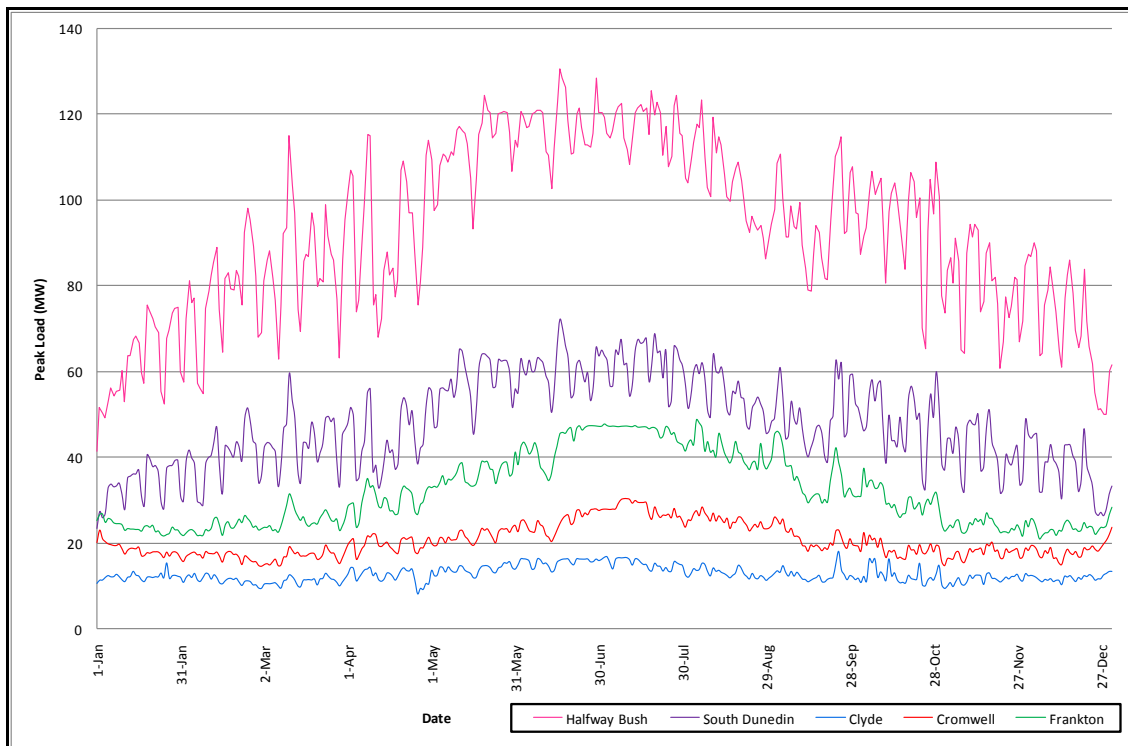


Figure 3.2 – Graph of Grid Exit Point Daily Load Peaks (2009)

The Frankton and Cromwell GXP peak loads usually occur during the July school holidays, due to the influx of skiers into the area, which drives three components of demand – ski field load, normally vacant holiday houses are occupied, and hotels, motels and café's experience higher occupancy. There has been significant growth in summer irrigation load on the Cromwell GXP where the Queensberry zone substation has a summer peak; however, the Cromwell GXP peak is not expected to shift from winter within the planning period.

The Clyde GXP serves Alexandra, Roxburgh, and surrounding areas, with load also peaking in winter. In some areas supplied from Clyde (such as Omakau, Roxburgh and Ettrick), frost-fighting pumps put a large demand on the system for a short time during September and October.

Dunedin peak loads are very weather dependent and, generally, occur during a snowfall event in the city which can be anytime from May to September. A peak load event is unlikely to occur during school holidays or at a weekend. The Dunedin load has a larger variation between weekend and week day loads than that observed in Central – due to a higher proportion of industrial and commercial load.

3.1.4 2010 Load Data

The key load and distributed generation statistics for the 2010 calendar year are presented in Table 3-1.

GXP	Clyde	Cromwell	Frankton	Halfway Bush	South Dunedin	Total
2010 peak MW including distributed generation	16.4	31.4	50.1	121.3	71.7	
2010 energy transported GWh	83.4	137.4	218.4	571.5	311.9	1322.6
Total number of ICPs	6,660	10,365	11,586	36,778	16,783	82,172
Off take n-1 capacity (24 hour winter post contingency) MVA	27	40.9	80	112	81	

Table 3-1 – GXP Load and Capacity Summary

3.2 Distributed Generation

Aurora has a total of 91.7 MW of distributed generation connected to its networks; 81.2 MW is generation stations dedicated to exporting energy, as shown in Table 3-2. Further increases to the wind generation capacity will occur in 2011 – 12.

10.5 MW is associated with consumer installations and is connected behind load. Most is diesel powered with the primary purpose of providing a standby supply, but can be operated in parallel with the Aurora network to reduce congestion period demand. Aurora owns a mobile 500 kW diesel generator which has been used for capital deferment in the Cardrona Valley. There is a small quantity of consumer photovoltaic (PV) generation and a single small wind generator. See Table 3-3 for summarised data on this generation.

Generator Name	GXP	Owner	Energy Source	Rated kW
Fraser	Clyde	Pioneer	Hydro	2,400
Michelle	Clyde	Pioneer	Hydro	1,600
Teviot Bridge # 4	Clyde	Pioneer	Hydro	1,125
George	Clyde	Pioneer	Hydro	800
Ellis # 5	Clyde	Pioneer	Hydro	3,400
Ellis # 6	Clyde	Pioneer	Hydro	3,400
Horseshoe Bend Hydro	Clyde	Pioneer	Hydro	4,100
Horseshoe Bend WT1	Clyde	Pioneer	Wind	750
Horseshoe Bend WT2	Clyde	Pioneer	Wind	750
Horseshoe Bend WT3	Clyde	Pioneer	Wind	750
Kowhai	Clyde	Pioneer	Hydro	2,000
Talla Burn	Clyde	Talla Burn	Hydro	2,150
Upper Meg # 2	Cromwell	Pioneer	Hydro	750
Lower Meg # 3	Cromwell	Pioneer	Hydro	2,000
Lower Meg # 4	Cromwell	Pioneer	Hydro	800
Glenorchy Oxburn	Frankton	Pioneer	Hydro	408
Wye Creek	Frankton	Pioneer	Hydro	800
Waipori 2A No.2	Halfway Bush	TrustPower	Hydro	18,000
Waipori 2A No.3	Halfway Bush	TrustPower	Hydro	18,000

Generator Name	GXP	Owner	Energy Source	Rated kW
Waipori 1A	Halfway Bush	TrustPower	Hydro	11,000
Deep Stream 1	Halfway Bush	TrustPower	Hydro	3,100
Deep Stream 2	Halfway Bush	TrustPower	Hydro	3,100

Table 3-2 – Schedule of Distributed Generation Dedicated to Export

Energy Source	Count	Total kW
Diesel	16	8,405
PV	8	25.5
Wind	1	2.4
Process Heat	1	2,240

Table 3-3 – Summary of Distributed Generation Behind Consumer Load

3.3 Subtransmission (66 kV and 33 kV)

3.3.1 Dunedin Area

The Dunedin network area is supplied from the Halfway Bush and South Dunedin GXPs. There are 19 33 kV feeder outlets at Halfway Bush and 11 at South Dunedin (one spare). The main Dunedin urban area is supplied by transformer-feeder zone substations, with each substation having two 33/6.6 kV transformers. The North East Valley zone substation is teed off the Port Chalmers zone substation 33 kV circuits. The Taieri Plain area, including Mosgiel, is served by four zone substations which are supplied from the three parallel 33 kV lines between the Halfway Bush GXP and TrustPower's Waipori power scheme. An overview of the network is shown in Figure 3.3 and zone substation details are in Table 3-4.

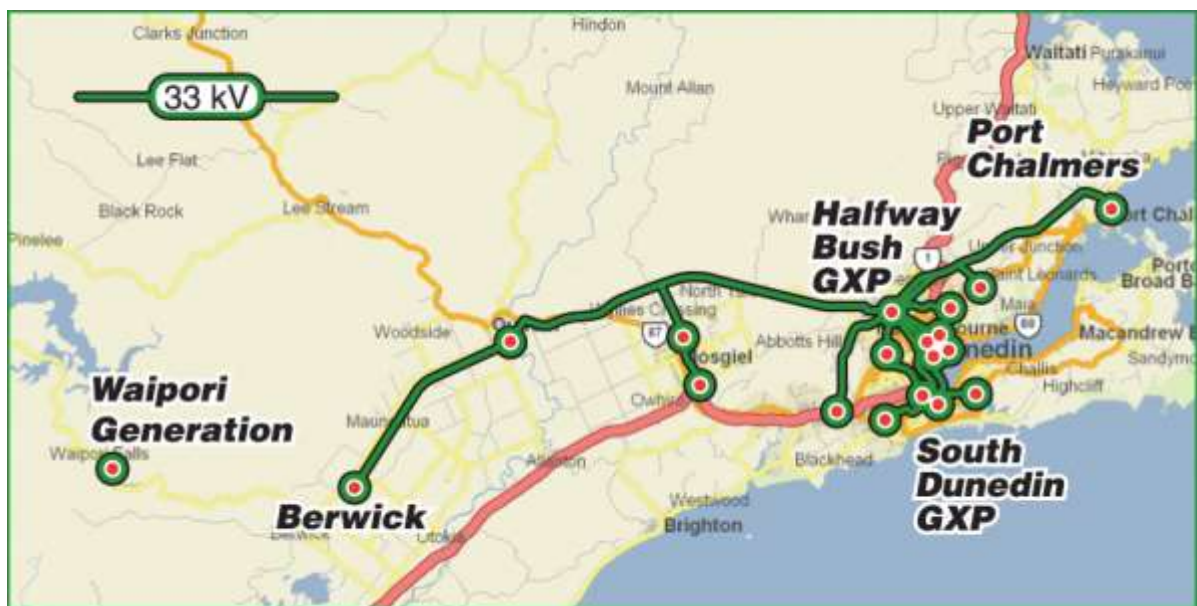


Figure 3.3 – Dunedin Subtransmission Network

Grid Exit Point	Zone Substation	Transformer Capacity MVA	Subtransmission	n-1 Security
Halfway Bush	Berwick	3	Selectable to any of the three Taieri 33 kV subtransmission lines	N
	East Taieri	12/24 + 12/24	Two 33 kV oil cables via Mosgiel and Taieri subtransmission circuits	Y
	Green Island	15 +15	Two 33 kV lines from HWB GXP	Y
	Halfway Bush	15 +15	Two PLYS cables from HWB GXP	Y
	Kaikorai Valley	24 +24	Two PLYS cables from HWB GXP	Y
	Mosgiel	10 +10	Selectable to any of the three Taieri 33 kV subtransmission lines	Y
	Neville Street	15 +15	Two gas cable from HWB GXP plus a tie cable to Ward Street	Y
	North East Valley	9/18 + 12/18	Two 33 kV line and cable circuits teed off Port Chalmers lines	Y
	Outram	3 +3	Selectable to any of the three Taieri 33 kV subtransmission lines	Y
	Port Chalmers	7.5 +7.5	Two 33 kV lines from HWB GXP	Y
	Smith Street	15 +15	Two 33 kV gas cables from HWB GXP	Y
	Ward Street	15 + 15	Two 33 kV gas cables from HWB GXP plus a tie cable to Neville Street	Y
	Willowbank	15 +15	Two 33 kV gas cables from HWB GXP	Y
	Andersons Bay	15 +15	Two 33 kV gas cables from Sth Dn GXP	Y
South Dunedin	Corstorphine	12/24 +12/24	Two 33 kV oil cables from Sth Dn GXP	Y
	North City	14/28 + 14/28	Two 33 kV oil cables from Sth Dn GXP	Y
	South City	9/18 + 9/18	Two 33 kV oil cables from Sth Dn GXP	Y
	St Kilda	12/24 +12/24	Two 33 kV oil cables form Sth Dn GXP	Y

Table 3-4 – Zone Substations in the Dunedin Area

3.3.2 Frankton Area

The Frankton area is supplied via seven 33 kV feeder outlets from the Frankton GXP. Two circuits supply the Wakatipu Basin via a ring, and there are three parallel lines from Frankton to Queenstown. A further two circuits supply the Frankton zone substation. A tee off the Wakatipu Basin ring supplies the Remarkables ski field and the Wye Creek generating station. An overview of the network is shown in Figure 3.4 and zone substation details are in Table 3-5.

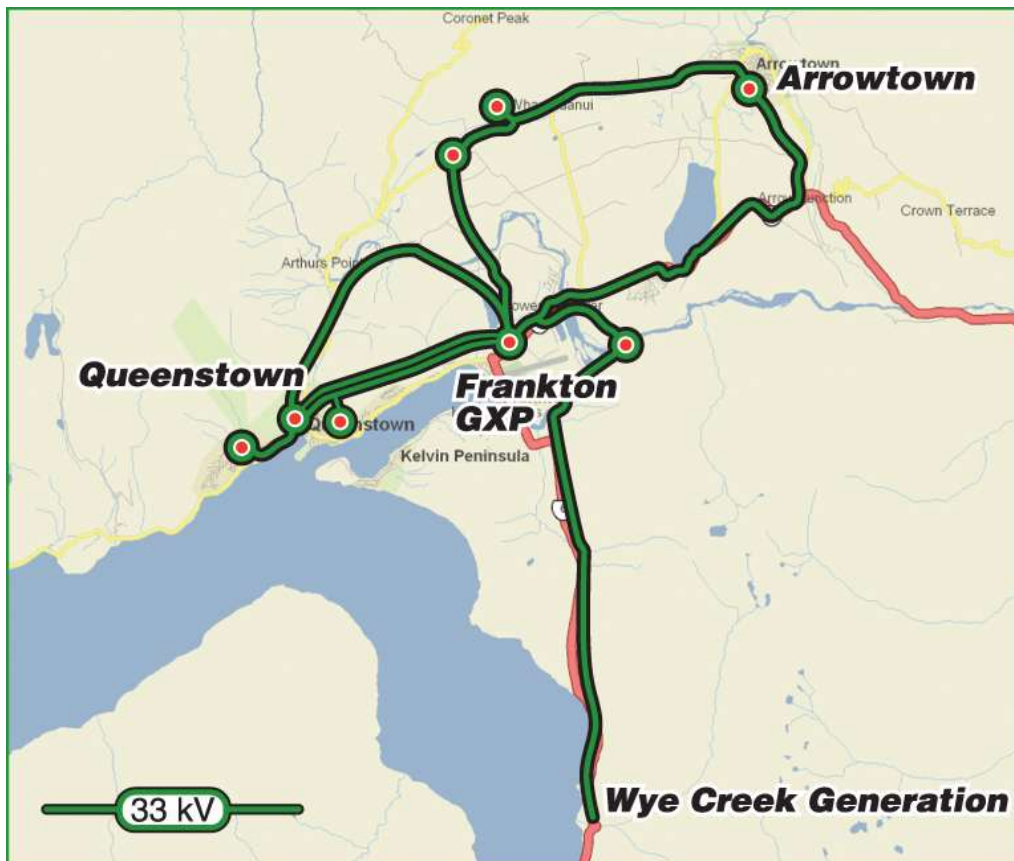


Figure 3.4 – Frankton Subtransmission Network

Substation	Transformer MVA	Subtransmission Configuration	n-1 Security
Arrowtown	5 + 5	Supplied from Wakatipu Basin 33 kV ring	Y
Dalefield	3	Supplied from Wakatipu Basin 33 kV ring	N
Queenstown	10/20 + 10/20	Three 33 kV lines from Frankton GXP	Y
Commonage	15/17 + 15/17	Two 33 kV lines from Frankton GXP	Y
Fernhill	10 + 10	Two 33 kV cables from Queenstown	Y
Frankton	7.5/10+7.5/15	One 33 kV cable and one 33 kV line from Frankton GXP	Y
Remarkables	1	Tee off from Wakatipu Basin 33 kV ring	N
Coronet Peak	5	Tee off from Wakatipu Basin 33 kV ring	N

Table 3-5 – Zone Substations in the Frankton Area

3.3.3 Cromwell Area

The Cromwell area is supplied via four 33 kV feeder outlets at the Cromwell GXP. Two of the circuits supply two Aurora-owned, 33/66 kV, 30 MVA, auto transformers, adjacent to the GXP, which supply the Wanaka area via two parallel 66 kV transmission lines. The other two circuits supply the Cromwell zone substation, and provide a connection to the Roaring Meg generation. The transformers at Wanaka are three winding, 66/33/11 kV units, with the 33 kV windings supplying the Maungawera zone substation. An overview of the network is shown in Figure 3.5 and zone substation details are in Table 3-6.



Figure 3.5 – Cromwell Subtransmission Network

Substation	Transformer MVA	Subtransmission Configuration	n-1 Security
Cromwell	7.5 + 5/10	One 33 kV line and one cable from Cromwell GXP	Y
Queensberry	3	Tee from either Wanaka to Cromwell 66 kV lines	N
Wanaka	30 + 30	Two 66 kV lines from Cromwell GXP with isolated sections of 66 kV cable	Y
Maungawera	3	Single 33 kV line from Wanaka	N

Table 3-6 – Zone Substations in the Cromwell Area

3.3.4 Clyde Area

The Clyde area is supplied via two 33 kV feeder outlets at the Clyde GXP. These circuits supply Alexandra via a parallel pair of overhead lines. A significant amount of the Clyde area load is supplied from the Teviot, Horseshoe Bend and Fraser generation stations. There are two parallel 33 kV lines between Alexandra and Roxburgh that deliver generation output to Alexandra from the south. Omakau, to the north-east of Alexandra, and Ettrick, to the south of Roxburgh, are each supplied by a single 33 kV line. An overview of the network is shown in Figure 3.6 and zone substation details are in Table 3-7.

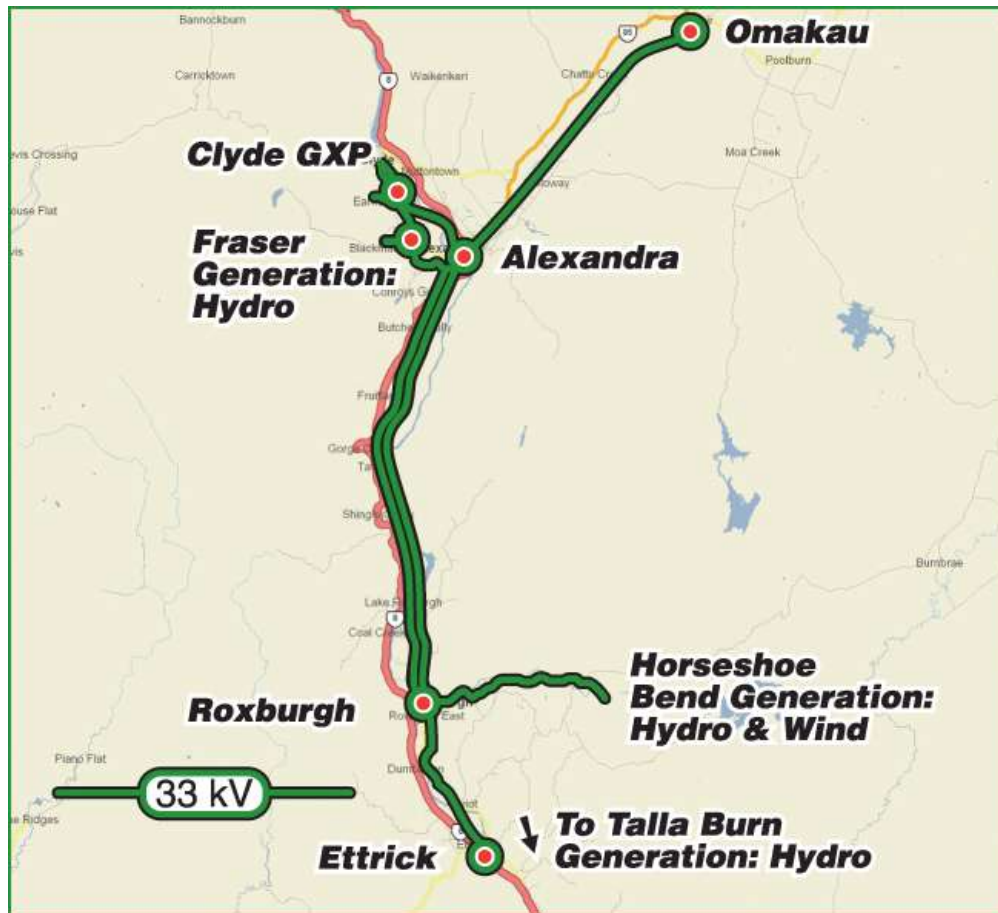


Figure 3.6 – Clyde Area Subtransmission

Zone Substation	Transformer MVA	Subtransmission Configuration	n-1 Security
Ettrick	3	Single 33 kV line from Roxburgh	N
Roxburgh	1.5 + 1.5	Via two 33 kV lines from Alexandra	Y
Alexandra	15 + 15	Two 33 kV lines to Clyde GXP	Y
Omakau	3	Single 33 kV line from Alexandra	N
Earnsclough	2	Tee off Alexandra to Clyde No. 1 33 kV line	N
Clyde/Earnsclough	2 + 4	Tee off Alexandra to Clyde No. 2 33 kV line	N

Table 3-7 – Zone Substations in the Clyde Area

3.4 HV Distribution (11 kV and 6.6 kV)

All HV mains are owned by Aurora, except where consumers specifically retain ownership.

3.4.1 Dunedin Area

HV distribution in the Dunedin area is via 182 HV feeders. Four zone substations; Berwick, Mosgiel, East Taieri, and Outram, have 11 kV feeders and the remaining fourteen have 6.6 kV feeders. The HV distribution voltage by location is shown in Figure 3.7 and the quantities by voltage are shown in Table 3-8. All new transformers installed are dual ratio 11/6.6 kV to facilitate eventual conversion to 11 kV. All feeders are radial with a high degree of meshing in the metro areas, except for the supplies to Otago University and the Hillside Workshops which have dedicated paralleled feeders. HV cable insulation in the Dunedin area is predominately PILC (87%) with the remainder being either XLPE (6%) or unknown (7%). For many years, all new cable has been rated for 11 kV operations even when it operates at 6.6 kV. Note that for this, and other assets described below, there is no plan to resolve unknown data as there is no economic case to do so.

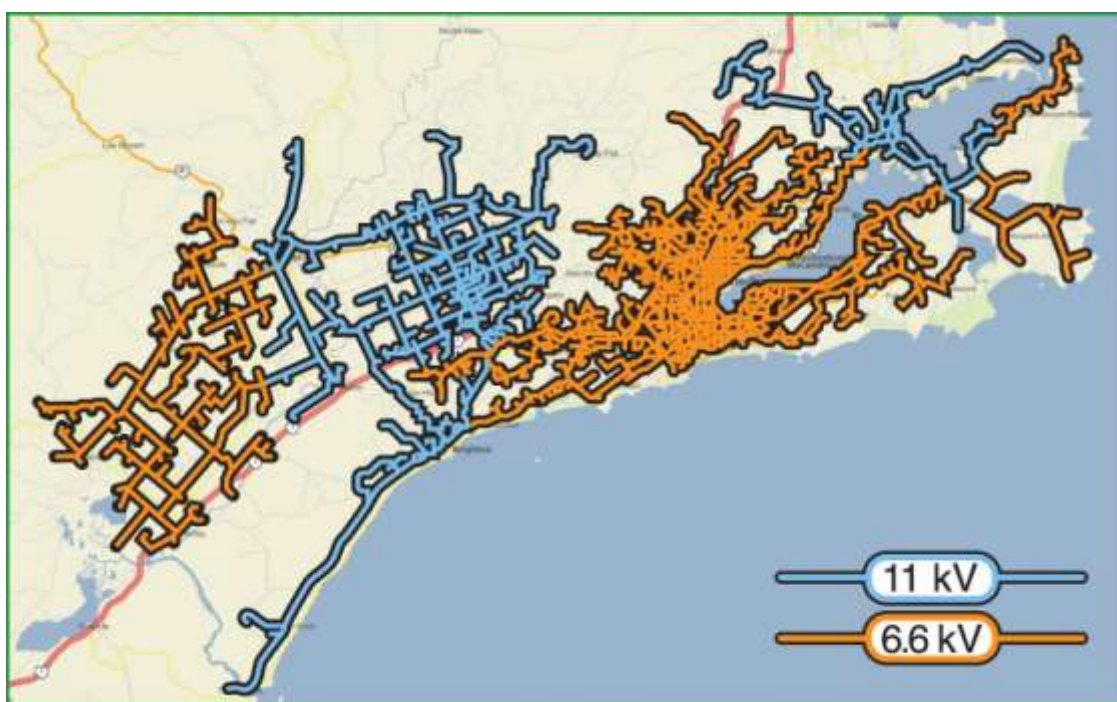


Figure 3.7 - Dunedin HV Distribution by Voltage

Voltage	Km	% Overhead	% Underground
11 kV	336	83%	17%
6.6 kV	702	66%	34%
Total	1,038	72%	28%

Table 3-8 - Dunedin HV Distribution Quantities

There is an additional 9 km of 11 kV SWER that supplies the north western extremity of the Dunedin HV network.

3.4.2 Central Area

HV distribution in the Central area is via 59 feeders. All HV feeders are 11 kV except for those in the Clyde area which are 6.6 kV. All feeders are radial with limited interties to other feeders. The HV distribution voltage by location is shown in Figure 3.8 and the quantities by voltage are shown in Table 3-9. HV cable insulation in the Central area is a mix of PILC (27%), XLPE (66%) and unknown (7%). In Central, there is a significant quantity of rural HV cable, due to local authority requirements and the high number of rural lifestyle subdivisions.

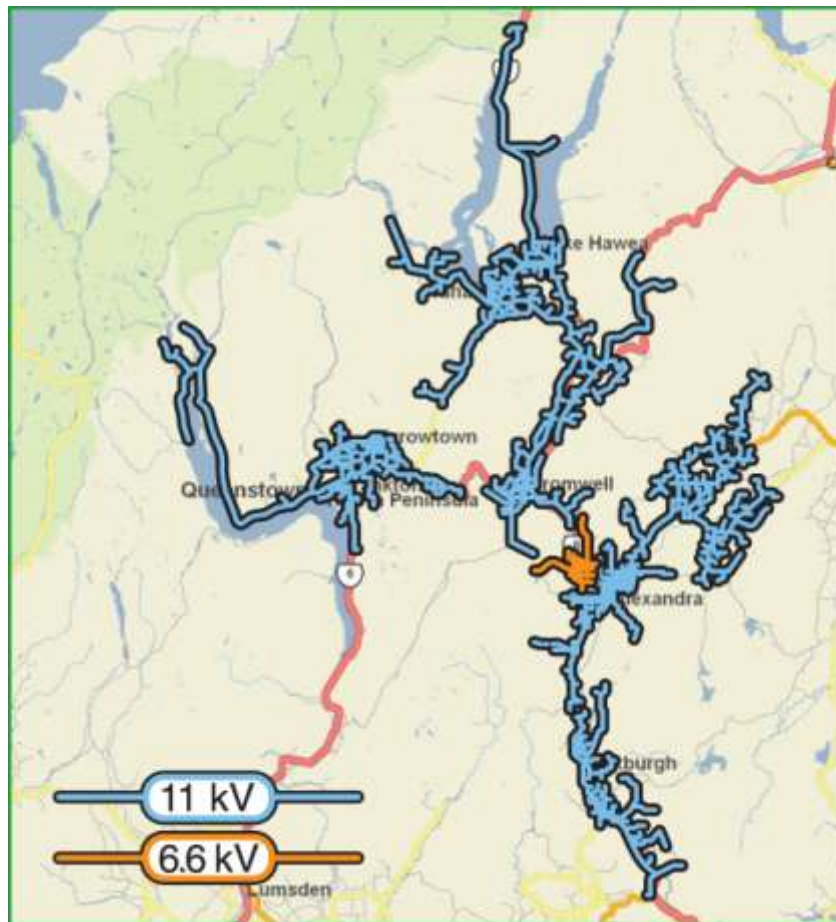


Figure 3.8 – Central HV Distribution by Voltage

Voltage	Km	% Overhead	% Underground
11 kV	2,051	75%	25%
6.6 kV	86	82%	18%
Total	2,116	75%	25%

Table 3-9 – Central HV Distribution Quantities

3.5 Distribution Substations (11/0.4 kV and 6.6/0.4 kV)

The quantities of each type of substation owned by Aurora are detailed in Table 3-10.

Substation Type	Count
Pole mounted	4,192
Ground mounted	2,271
Underground	19
Total	6,482

Table 3-10 – Substation Count

3.5.1 Pole Mounted

Pole mounted transformers range in size from 5 to 400 kVA. Transformers up to 100 kVA are accommodated on a single pole but larger sizes require a two pole support structure.

3.5.2 Ground Mounted

Ground mounted transformers range in size from 15 to 1500 kVA and fall into the following categories:

- **Cable Box/Cable Box (standard)** - this configuration is generally used when the transformer is dedicated to one consumer, with the consumer's LV mains directly connected to the LV terminals of the transformer.
- **Package** - this configuration consists of a specially configured transformer accommodated in a fibreglass enclosure, with associated HV switchgear and LV distribution board. This configuration is no longer used for new substations.
- **Mini (standard)** - these substations are proprietary units that include an LV distribution board and can include HV switchgear. They range in size from 100 to 1000 kVA.
- **Micro (standard)** - these substations are used for low visibility. They range in size from 15 to 100 kVA, have limited space for LV distribution facilities and do not accommodate any HV protection.
- **Underground** - these substations are only used in the Dunedin CBD area and consist of an underground vault that contains a transformer and associated HV and LV switchgear. They were constructed in the 1960s and 1970s, generally have a 1000 kVA capacity, and are not a modern standard option.
- **Cubicle** - these substations consist of a standard, pole mounting, bushing/bushing transformer, mounted on the ground with cable connections to the bushings and fitted with a metal cover. They range in size from 15 to 50 kVA. This configuration is no longer used for new substations.

3.6 LV Distribution (0.4 kV)

LV distribution is via radial feeders. In central business districts, LV intertie capability is provided by link boxes. In urban residential areas, there is limited LV intertie capability. The quantities by area are given in Table 3-11.

Area	Km	% Overhead	% Underground
Dunedin	1,033	79%	21%
Central	794	30%	70%
Te Anau	5.6	0%	100%
Total	1,833	57%	43%

Table 3-11 – LV Distribution Quantities

The reason that the Central area has a greater proportion of underground LV compared to Dunedin is due to the growth experienced in Central since it became mandatory to underground in new subdivisions. This continued growth is steadily reducing the relative proportion of overhead LV.

3.7 Secondary Assets

3.7.1 SCADA

Aurora has two SCADA systems; a Foxboro system, dating from 1998, for the control of the Dunedin area, and a Lester Abbey system dating from 2000, for the control of the Central network.

3.7.2 Telecommunication Systems

In the Dunedin area, a pilot cable network, installed with 33 kV cables, provides communication with twelve of the eighteen zone substations. Telecom facilities are used for the six zone substations not covered by the pilot network. In the Central area, data communication is via a combination of the Aurora owned VHF and UHF systems.

A limited UHF radio network exists in the Central area, principally providing for information transfer between Aurora and Pioneer Generation Ltd for operational and load management functions.

A VHF land mobile network is provided in Dunedin and Central and provides an extensive system for operational communications, and phase identification.

3.7.3 Load Management Systems

Dunedin Load Management

Load management in the Dunedin area is via 18 K22/Decabit 1050 Hz 11 kV/6.6 kV ripple injection plants at each zone substation. The injection plants are controlled via the Dunedin SCADA master station. All ripple receiver relays are owned by DELTA or Electricity Retailers, except for street lighting control relays in distribution substations, which are owned by Aurora. There are approximately 45,000 receiver relays on the Dunedin network. A new 317 Hz injection system has been installed and the relay receivers will be progressively changed from 1050 Hz to 317 Hz.

Central Load Management

The majority of load management in the Central area is via Decabit 317 Hz ripple injection plants; one in each GXP area. There are approximately 25,000 Decabit relays on the network, which are mainly owned by Electricity Retailers. The Central injection plants are controlled by a custom made system dating from 1996.

There is also a pilot wire system, controlled by interfacing Decabit relays installed at distribution substations, which supply approximately 2,000 consumers. This system is being replaced upon failure as there is no financial incentive to do otherwise.

3.7.4 Metering Systems

In the Dunedin area, Aurora receives meter pulses from the Transpower GXP metering. Check meters are installed at each GXP, and at the Waipori generating station. The data from these meters is processed by data loggers and monitored by the Dunedin SCADA. All load monitoring at Dunedin zone substations is done via the SCADA system.

In the Central area, Aurora receives meter pulses from the Transpower GXP metering and also has check meters at the Cromwell and Clyde GXPs only. Aurora does not have check meters at Pioneer Generation sites but receives load meter pulses from these sites via a UHF network. Central metering data is processed and stored via a load control PLC and associated load control computer at Alexandra.

3.7.5 Mobile Substations/Generation

Aurora owns three 11 kV/6.6 kV/400V mobile substations. One 500 kVA unit is based at Cromwell, with 300 kVA and 500 kVA units based at Dunedin.

A 5 MVA 66 kV/33 kV/11 kV/6.6 kV mobile substation was commissioned in 2009 and is based at Cromwell.

Aurora owns a mobile 500 kW generator, which is presently based at the future Cardrona zone substation site.

3.7.6 Power Factor Correction Equipment

Some consumers have installed power factor correction equipment in order to comply with Aurora policy to maintain a power factor of at least 0.95.

3.8 Asset Details by Category

The value of Aurora's assets by category, as derived from the 2010 ODV valuation of the network, (using 2004 Handbook values times CPI²), is presented in Table 3-12, and each category is detailed below. The age profiles are also based on the March 2010 disclosure. Significant changes since then are described.

² This method understates the replacement value since actual replacement costs are much greater than the 2004 ODV Handbook values times CPI.

Asset Category	Quantity	RC	% by \$
Subtransmission	591 km	\$49,901,590	9%
Zone substations	36	\$107,620,602	19%
HV cables	829 km	\$90,184,231	16%
HV lines	2346 km	\$75,163,603	13%
Distribution transformers	6,585	\$64,508,596	12%
Distribution switchgear		\$38,528,109	7%
Distribution substations	6,482	\$14,714,718	3%
LV distribution	1,827 km	\$93,263,487	17%
Service connections ¹	95,469	\$16,824,683	3%
Street lighting distribution	204 km	\$6,744,607	1%
System control		\$2,007,272	< 1%
Sundry		\$562,593	< 1%
Total		\$560,024,091	100%

Note 1 Includes street light circuit connection points

Table 3-12 – RC Value of the Aurora Network

The general condition of Aurora's assets is "fit for purpose". The underlying SAIDI (Section 8) is less than 90 minutes which compares very favourably with the performance of other like networks. Critical assets that have the potential to give concern, such as the oil and gas insulated 33 kV cables, are closely monitored.

3.8.1 Subtransmission Lines

The age profile of subtransmission lines (66 and 33 kV) is shown in Figure 3.9 based on conductor age.

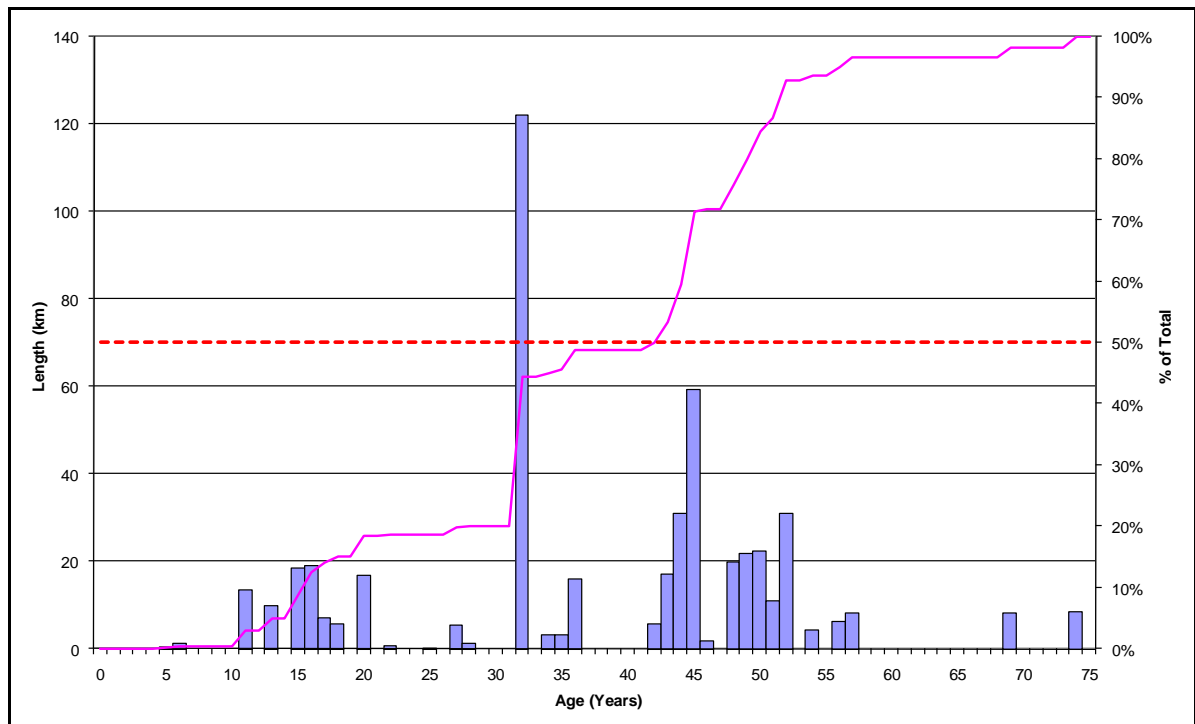


Figure 3.9 – 66 & 33 kV Lines Age Profile (Total = 494.6 km)

The lines shown at 74 years are the Roaring Meg subtransmission circuits and those at 69 years are the Wye Creek line.

All lines are in good condition and no significant expenditure is expected within the planning period, based on existing loadings. The present condition of any line is a factor of its age, the environmental impacts of the locations it traverses, and its maintenance history. A line located on the coastal areas near Dunedin may have a life of about 30 years, limited by salt corrosion; however, the same line located in Central will often be in excellent condition after 70 years. Generally, in coastal areas insulators will last about 30 years, conductors 40 years and poles over 45 years.

3.8.2 Subtransmission Cables

The age profile of 33 kV cables is shown in Figure 3.10.

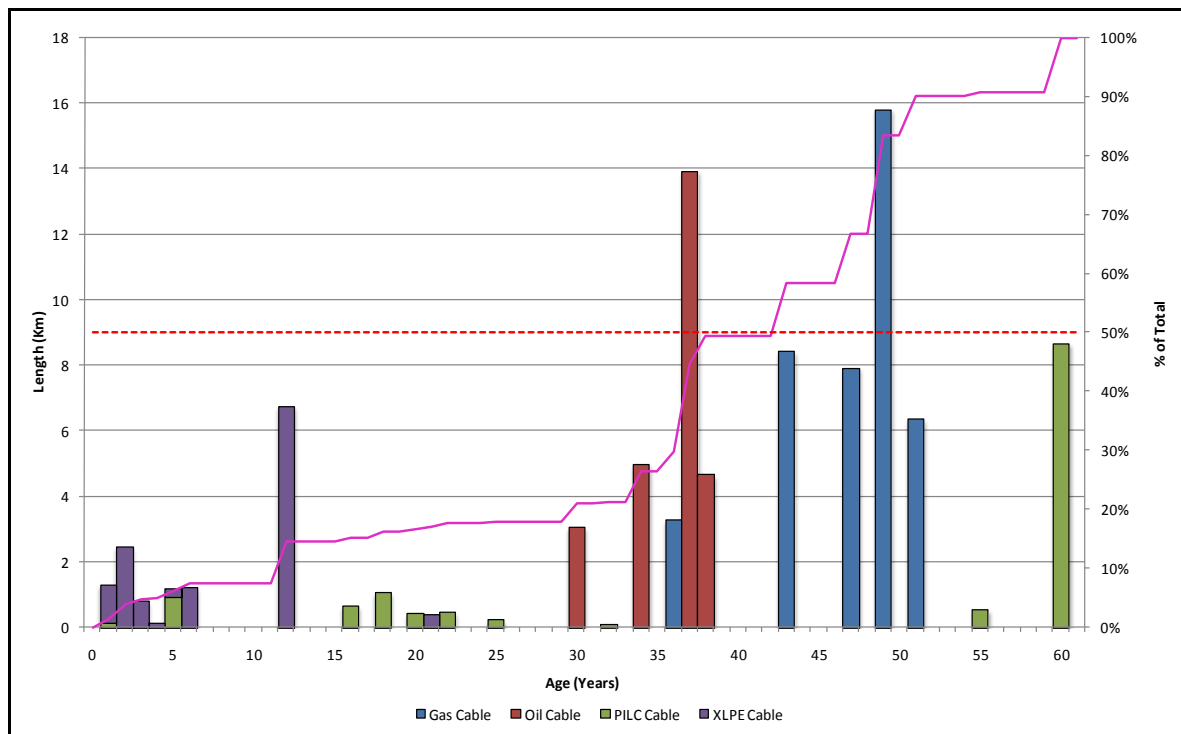


Figure 3.10 – 33 kV Cables Age Profile (Total 96 km)

Thermal resistivity is an issue in Central Otago so site specific requirements are set for new subtransmission cables.

The 33 kV gas insulated cables, in particular the cables from the Halfway Bush GXP to Neville Street zone substation, have experienced leaks. Following a review by external consultants, it is proposed to replace this type of cable within the planning period.

The Queenstown subtransmission cables were replaced in 2008 to meet ongoing growth.

3.8.3 Zone Substation Power Transformers

The age profile of zone substation transformers is shown in Figure 3.11. Transformers that are subject to moderate loading, minimal through faults, prudent monitoring and maintenance practices should last for at least 60 years. All power transformers have performed well to date and monitoring has not detected any latent concerns, with the exception of one transformer at Halfway Bush which had water ingress in November 2006, another where Dissolved Gas Analysis (DGA) indicated that planned maintenance was necessary in 2007 and the other transformer at Halfway Bush which had a tap changer failure. The new Ward Street transformers that are now in operation are not shown as they were replaced after March 2010.

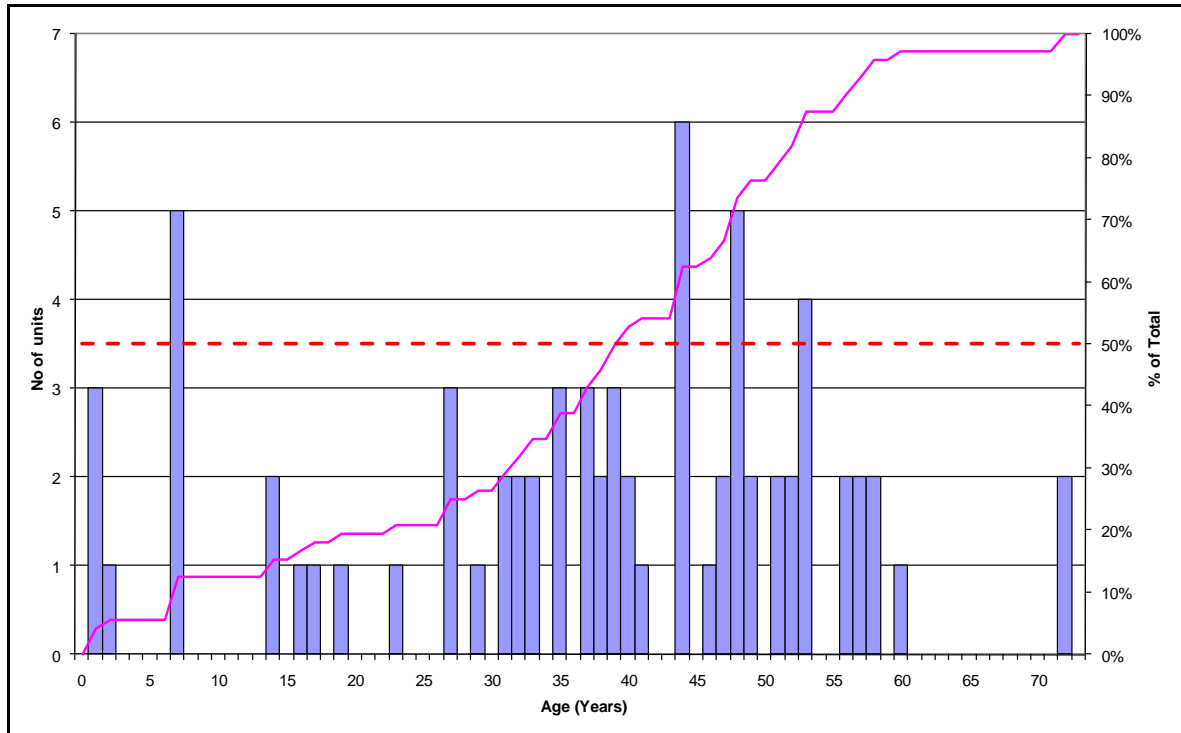


Figure 3.11 – 66 and 33 kV Zone Substation Transformers Age Profile (Total = 72)

3.8.4 Zone Substation 66 kV and 33 kV Circuit Breakers

The age profile of 66 and 33 kV circuit breakers is shown in Figure 3.12. The 33 kV circuit breakers at five zone substations are more than 40 years old but are performing very well. Their replacement strategy is shown in Section 6.5.6.

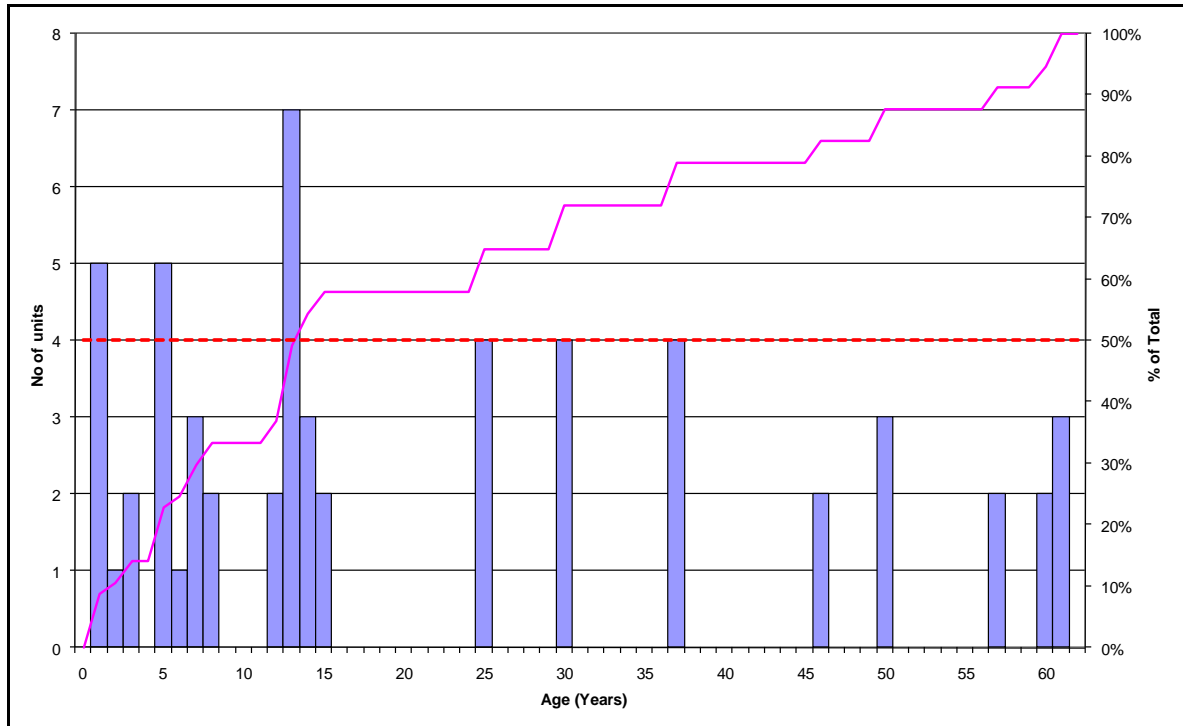


Figure 3.12 – 66 and 33 kV Zone Circuit Breakers Age Profile (Total = 57)

3.8.5 Zone Substation 11 kV and 6.6 kV Circuit Breakers

The age profile of 11 kV and 6.6 kV circuit breakers is shown in Figure 3.13. Half of the circuit breakers are older than 40 years. Their replacement strategy is shown in Section 6.5.8. The 73 year old breakers were located at Ward Street and have been replaced since March 2010.

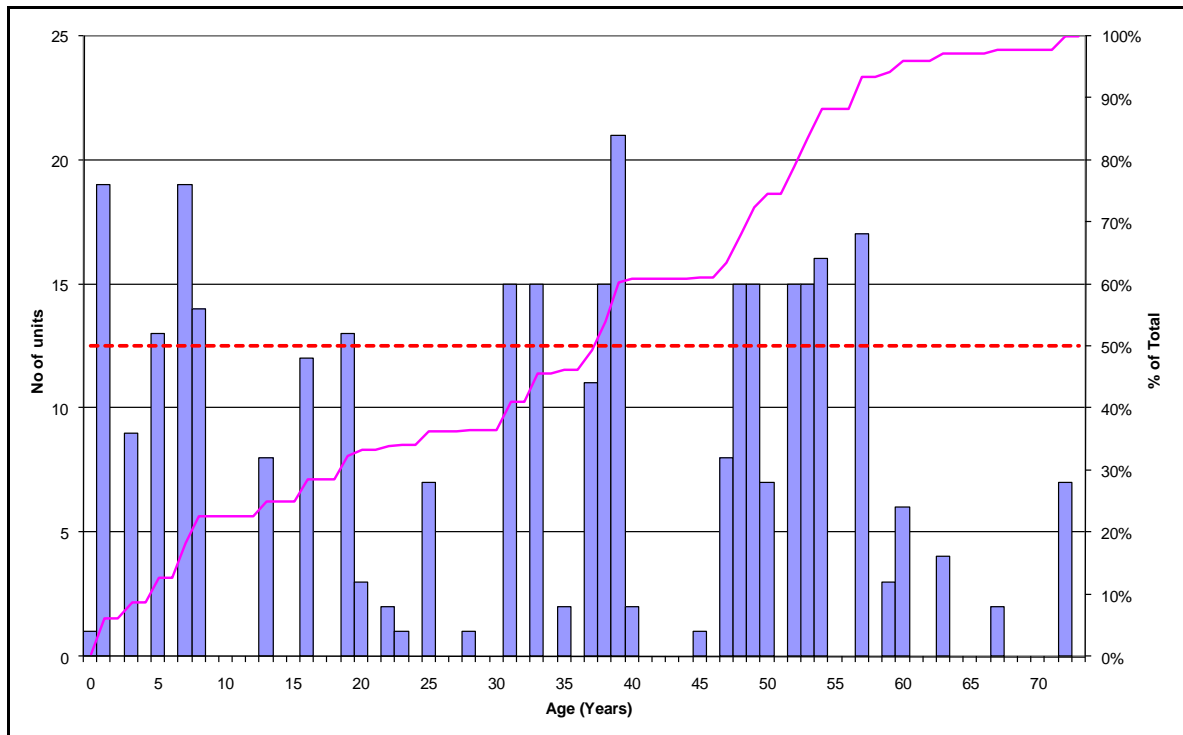


Figure 3.13 – 11 and 6.6 kV Circuit Breakers Age Profile (Total = 334)

3.8.6 Load Control Equipment

In the Dunedin network area, load management ripple injection is at 11 kV and 6.6 kV at each zone substation and dates from 1958. These plants inject at 1050 Hz and are all motor generator sets except for the North East Valley substation which is a solid state injector. Their replacement strategy is detailed in Section 6.5.12.

In Central Otago, there is one 317 Hz injector associated with each GXP. These injectors are all solid state units with a nominal life of 20 years. The Frankton injector has just been replaced, the Clyde injector which is at Alexandra is 23 years old and the Cromwell injection plant was replaced in 2009. The Cromwell unit was replaced because the additional transformer capacity installed by Transpower at the Cromwell GXP resulted in the plant injection capacity being exceeded.

The age profile of load management equipment is shown in Figure 3.14.

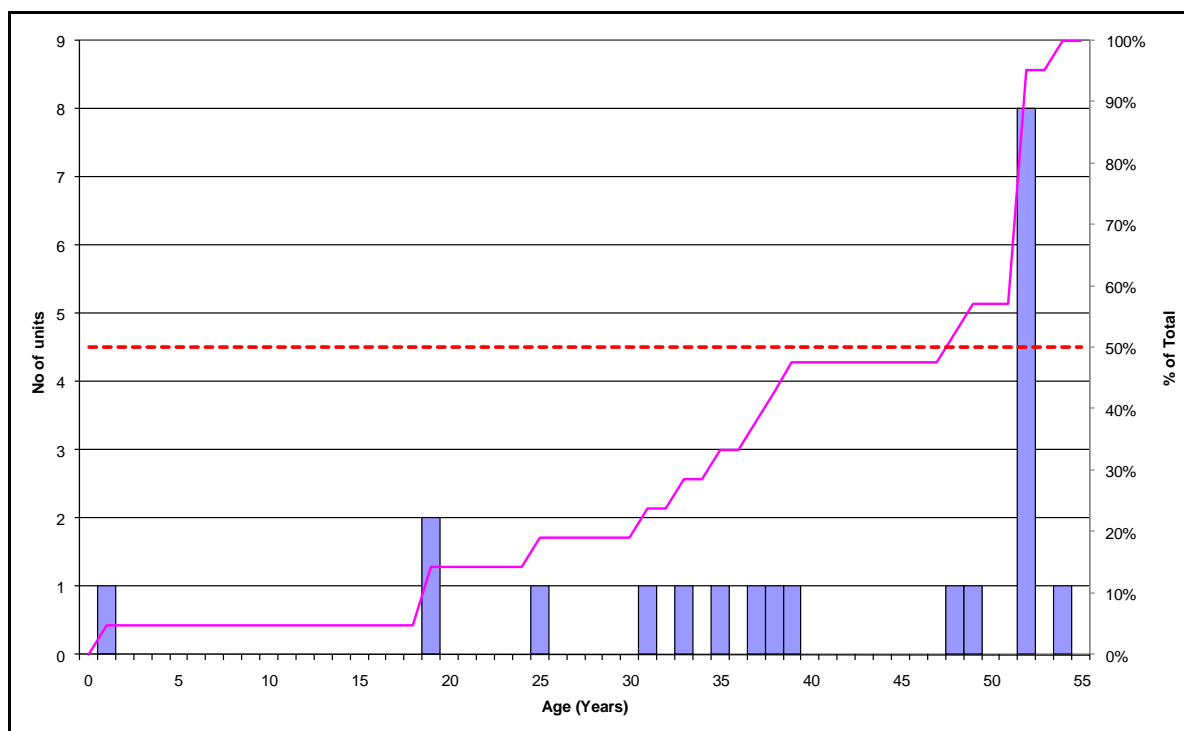


Figure 3.14 – Load Control Equipment Age Profile (Total = 21)

3.8.7 Zone Substation Protection Relays

Aurora does not have specific age profile data for the protection relays; however the age of the relays is generally the same as the associated switchgear. Protection relays are generally upgraded to modern IED relays when the associated switchgear is replaced.

Relays are performing well operationally (no evidence of mal-operation) and under test, so Aurora sees no reason to intensively manage relays as a separate asset class.

3.8.8 SCADA Remote Terminal Units

The SCADA RTUs in Central date from 2000. In Dunedin the majority of the RTUs were installed in 1988. Dunedin RTUs have been very reliable, but face technical obsolescence due to their inability to use modern master station communication protocols, and to communicate with intelligent electronic devices such as modern protection relays. When substation switchgear and protection is upgraded, the station RTU is also upgraded.

3.8.9 Other Zone Substation Equipment

Battery banks at substations include flooded and sealed lead acid cells with various life expectancies. Replacement and new banks will consist of sealed recombination lead acid cells which have low maintenance requirements, lower initial cost, and a 10 year rated life.

Portable earthing equipment is kept at all zone substations and is maintained to a high standard to ensure safety of maintenance personnel. Only routine maintenance is necessary.

3.8.10 Buildings, Grounds and Fences

There is regular maintenance of zone substation buildings, grounds and fences.

3.8.11 HV Lines

Figure 3.15 details the age profile of HV lines by conductor age and pole age. Aurora has 2,346km of HV lines and the age of 54.4 km (2.3%) has yet to be confirmed. As a result of growth in the Dunedin network area in the 1960s, and in the Central network area in the 1980s and 1990s, the age profile is relatively even up to 55 years old. 25% of conductor is aged more than 50 years. It is expected that maintenance expenditure on HV lines (pole replacements) will rise over the planning period.

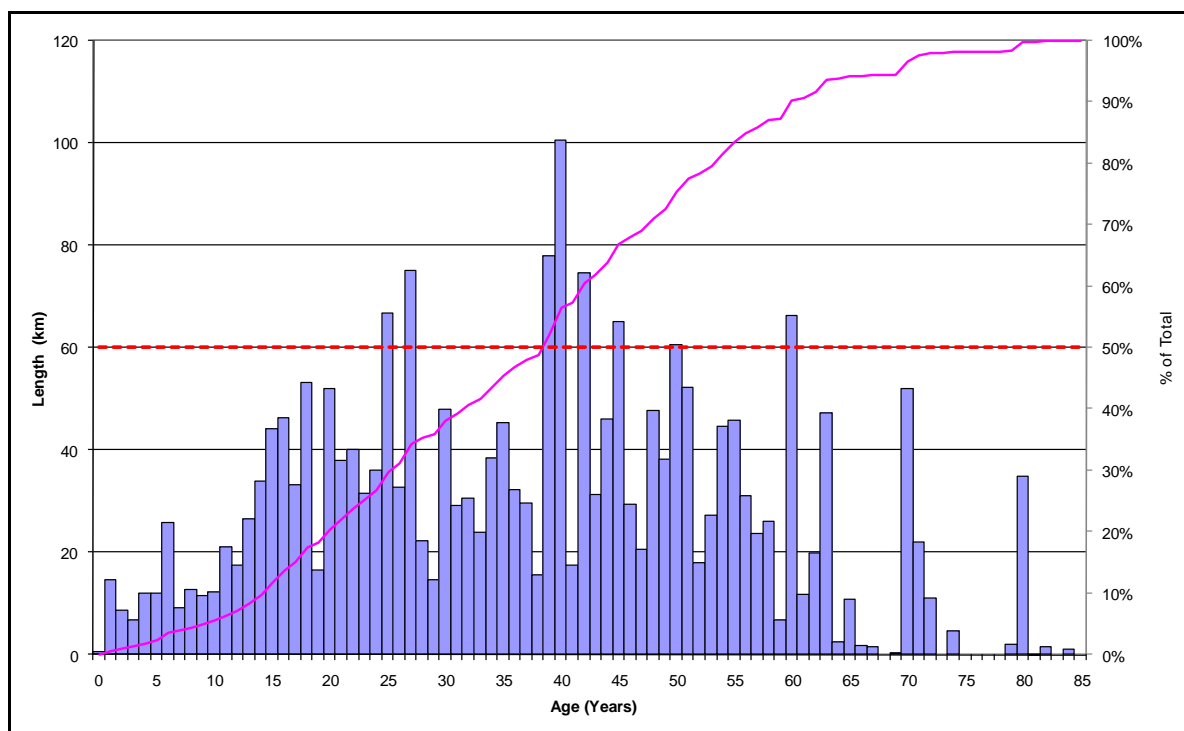


Figure 3.15 – 11 kV & 6.6 kV Lines Age Profile (Total = 2346 km)

3.8.12 HV Cables

The age profile of HV cables is shown in Figure 3.16. Aurora has 831km of HV cable, of which the age of 30.4 km (3.7%) has yet to be confirmed. Deterioration of HV cable has not been a particular problem, apart from several kilometres of aluminium sheath paper insulated cable installed in 1954, where sections of this cable have been replaced as the need arose due to corrosion of the aluminium sheath. Most repairs are due to either faults at joints or terminations, or due to third party damage.

No major replacements are proposed within the planning period.

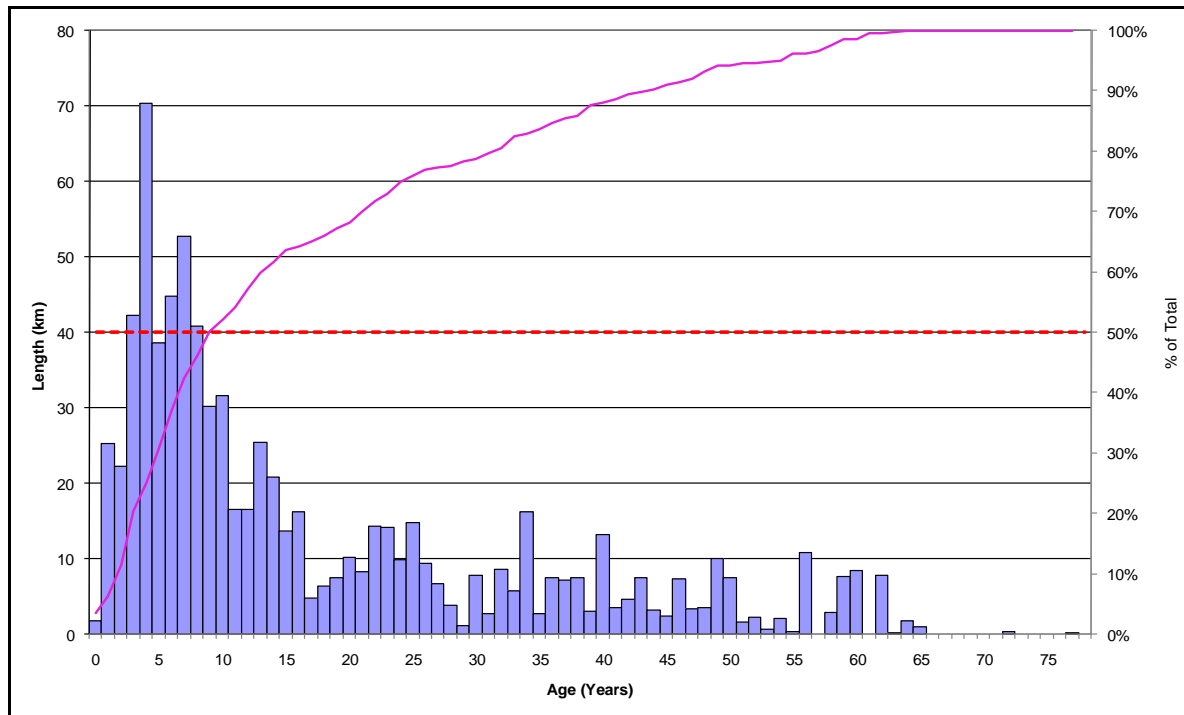


Figure 3.16 – 11 & 6.6 kV Cables Age Profile (Total = 829.3 km)

3.8.13 Distribution Substations

Distribution substations comprise the transformer (sub-categorised in section 3.8.14, below), transformer pad, HV and LV fusing, and an earth mat. At 1 April 2010, there were 6,482 distribution substations on the Aurora network.

In a historically abnormal flash-flood in February 2005, five underground distribution substations in Dunedin were flooded, and had to be off-loaded, with the subsequent failure of one transformer after the event. A programme is underway to seal and mechanically ventilate underground substations vulnerable to surface flooding or replace them with ground mounted substations if practicable.

3.8.14 Distribution Transformers

Figure 3.17, below, details the age profile of in-service distribution transformers. The age of only 84 units (1.28%) is unknown; however installation date data exists for all but 7 units. Approximately 5% of the transformer population is older than 55 years.

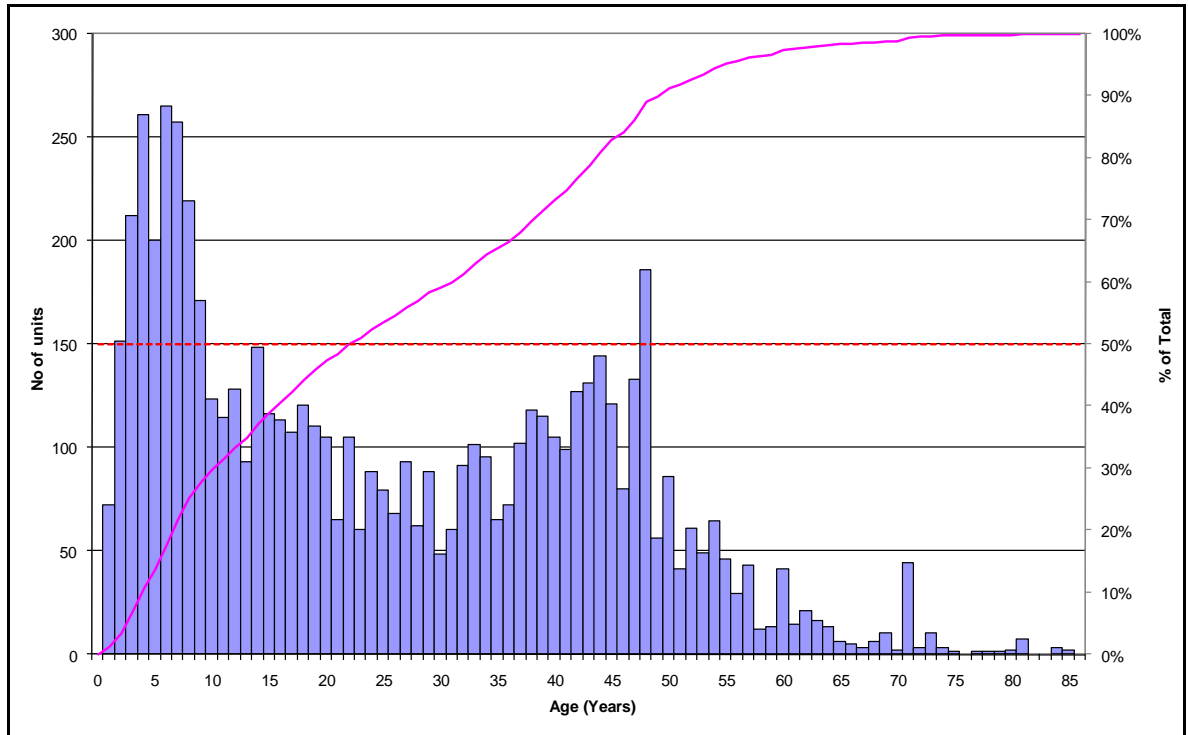


Figure 3.17 – Installed Distribution Transformers Age Profile (Total = 6585)

3.8.15 HV Regulators

Figure 3.18, below, details the age profile of regulators. The age profile is by regulator site; ie a site with three single phase regulators is treated as one unit.

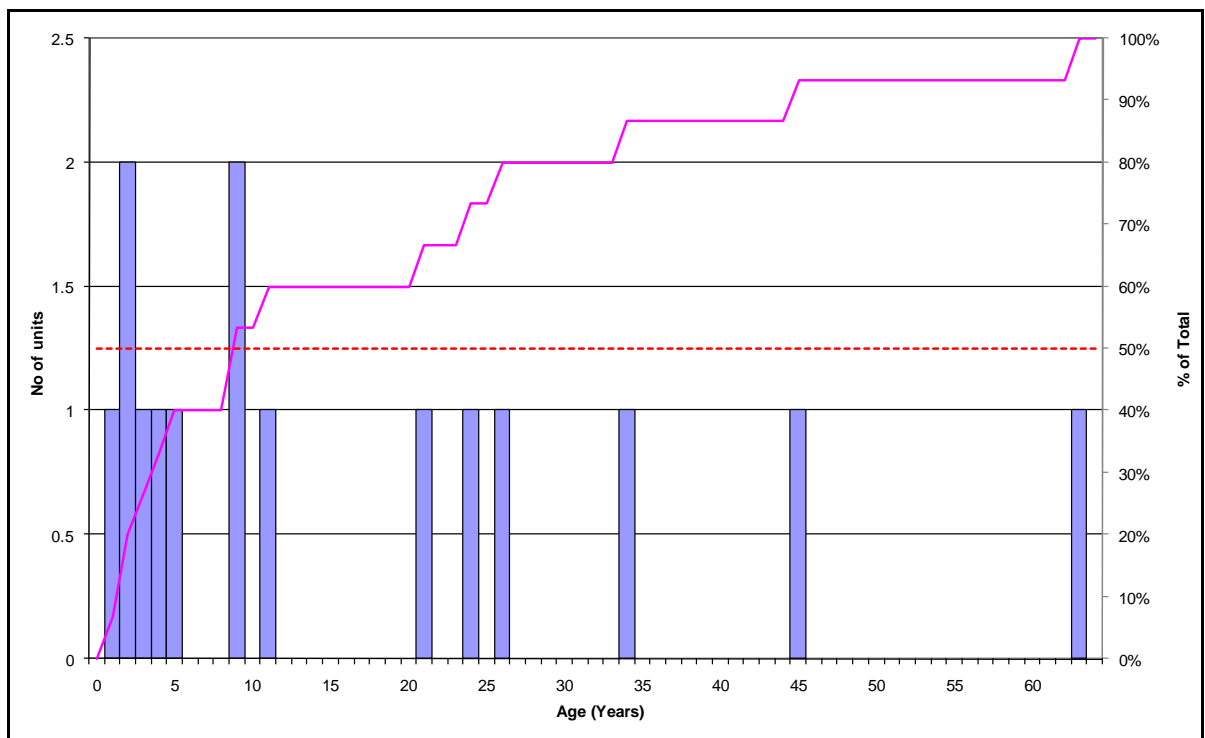


Figure 3.18 – HV Regulators Age Profile (12 Sites)

3.8.16 HV Auto-Transformers

Figure 3.19, below, details the age profile of auto-transformers. Nine auto-transformers (with a spare unit available) are used for the interconnection of 11 kV and 6.6 kV sections of the network. While these units have an average age greater than 38 years, they have been reliable and require only minimal maintenance.

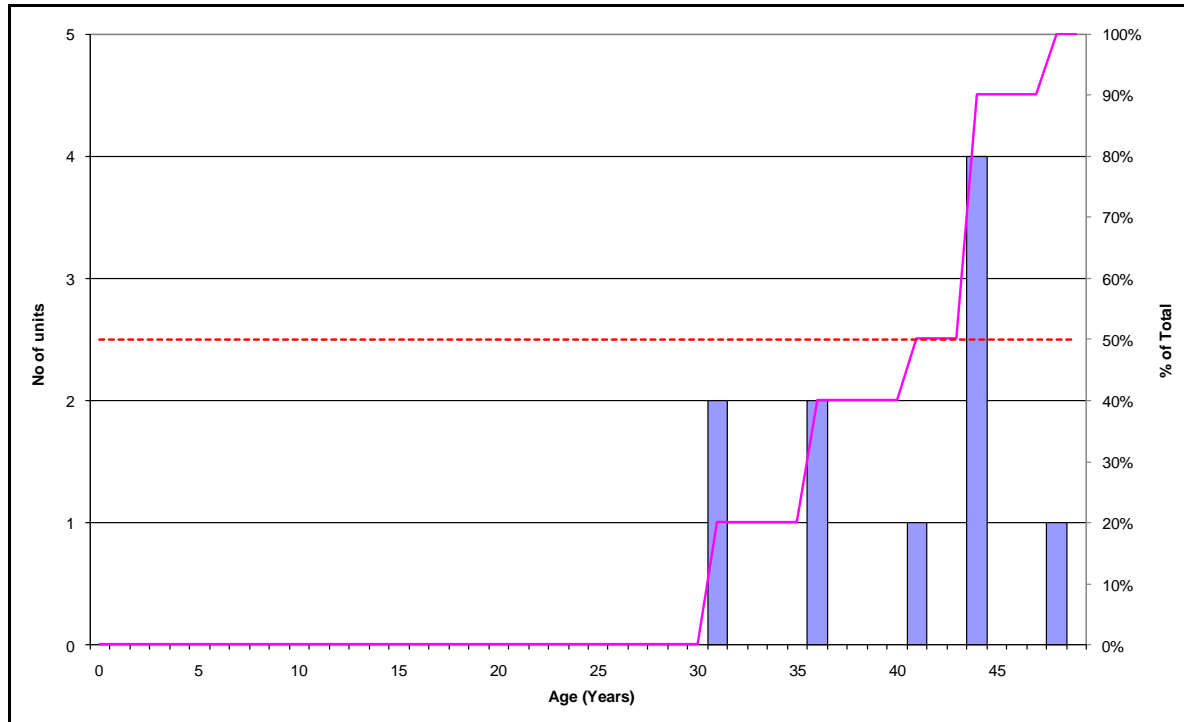


Figure 3.19 – HV Autotransformers Age Profile (10 Units)

3.8.17 HV Ground Mounted Distribution Switchgear

Ground mounted distribution switchgear consists of six different types, and the quantity by type is detailed in Table 3-13, below.

The age profile of ground mounted distribution switchgear is shown in Figure 3.20. Age data is not available for 10.0% of the units.

Switchgear Type	No of Units
Ground mounted 3 phase air fuse unit	114
HV oil ring main unit	527
HV oil fuse switch	302
Oil circuit breaker	32
Single HV oil switch	379
Vacuum circuit breaker	7
Total	1361

Table 3-13 – Ground Mounted Switchgear by Type

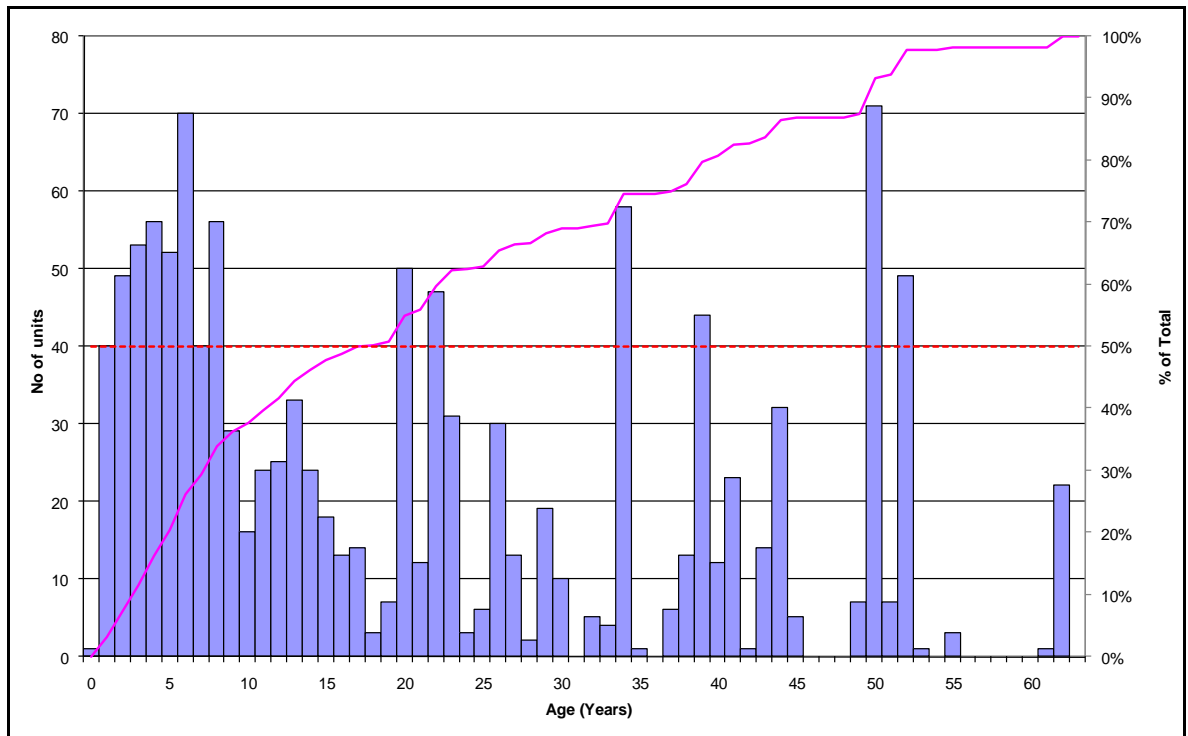


Figure 3.20 – HV Ground Mounted Switchgear Age Profile

3.8.18 LV Overhead Conductor

Figure 3.21 shows the age profile of overhead LV lines. Aurora has 1051 km of LV line, and the construction date of 252.54 km (24.0%) has yet to be confirmed. There are two types of LV overhead on the network, being predominantly open wire with only a few kilometres of Aerial Bundled Cable (ABC).

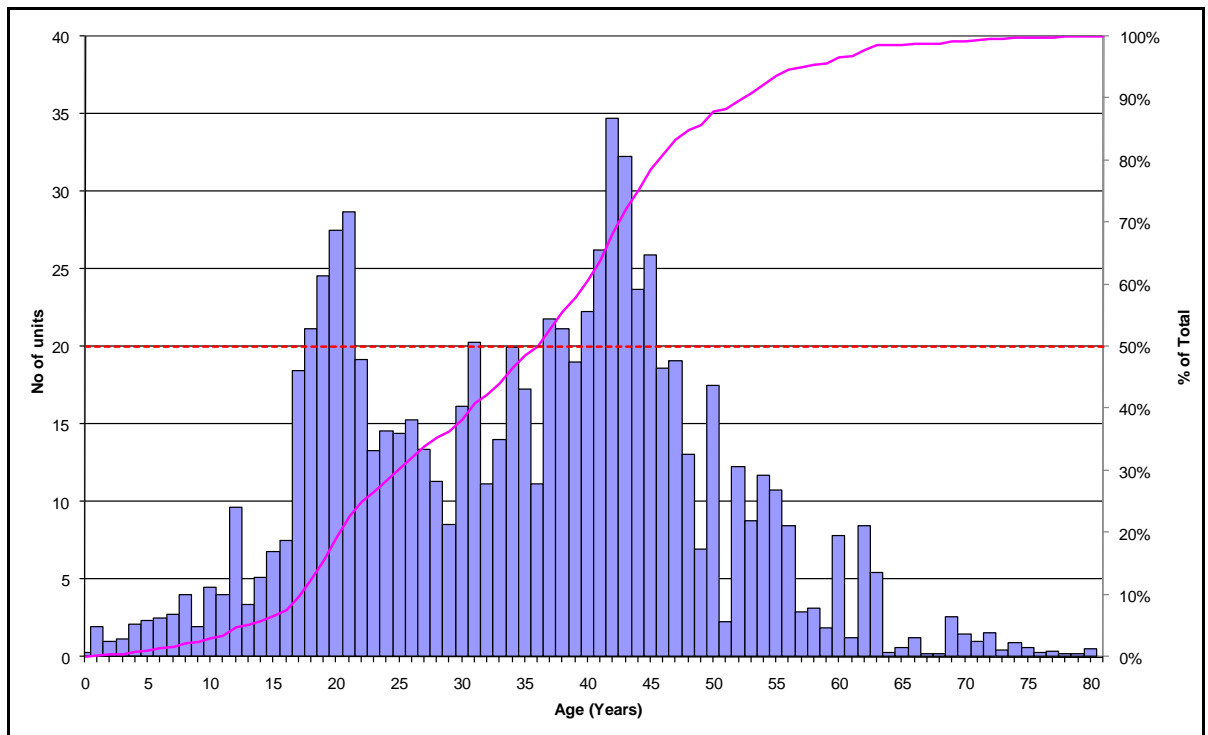


Figure 3.21 – LV Distribution Line Age Profile

While significant renewal of conductor might become necessary beyond the current planning period, when the lines installed from 1965 approach 50 years of age, no significant condition based expenditure increase is expected in the current planning period.

Part of the grouping at the 15- 20 year age group is due to default date data, which is to be corrected when resources are available. Note that this is not a high priority.

3.8.19 LV Underground

Figure 3.22 shows the age profile of the underground cables. Aurora has 776 km of LV cable, of which the age of 74 km (9.5%) has yet to be confirmed as dating from original construction. Most LV cable is cross-linked polyethylene (XLPE). However, in the Dunedin CBD, paper-insulated lead covered (PILC) cable has been the norm.

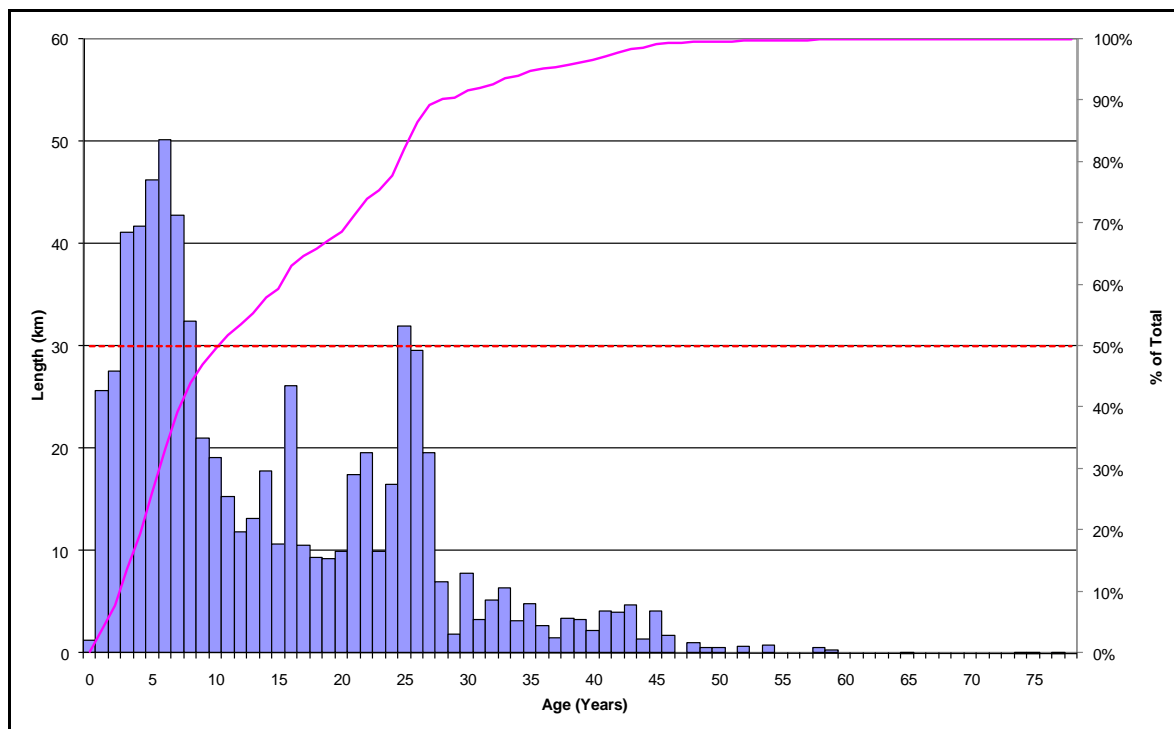


Figure 3.22 – LV Distribution Cable Age Profile

The recent boom in residential subdivision is evident.

The oldest LV cables show no sign of reaching the end of their economic lives.

3.8.20 Poles

Aurora has approximately 50,774 poles, of which only 230 (0.45%) poles do not have installation dates allocated.

Figure 3.23, below, details the age profile for EHV, HV and LV poles.

A condition-based inspection regime is in place, which indicates that the rate of renewal will double, at least, by the end of the planning period. Since 1990, softwood poles have been used as replacements for both concrete and hardwood poles, but questions arose as to their longevity in the Central Otago environment due to excessive twisting. In light of communication with other network operators; it is likely that softwoods may be limited in the situations that they may be used.

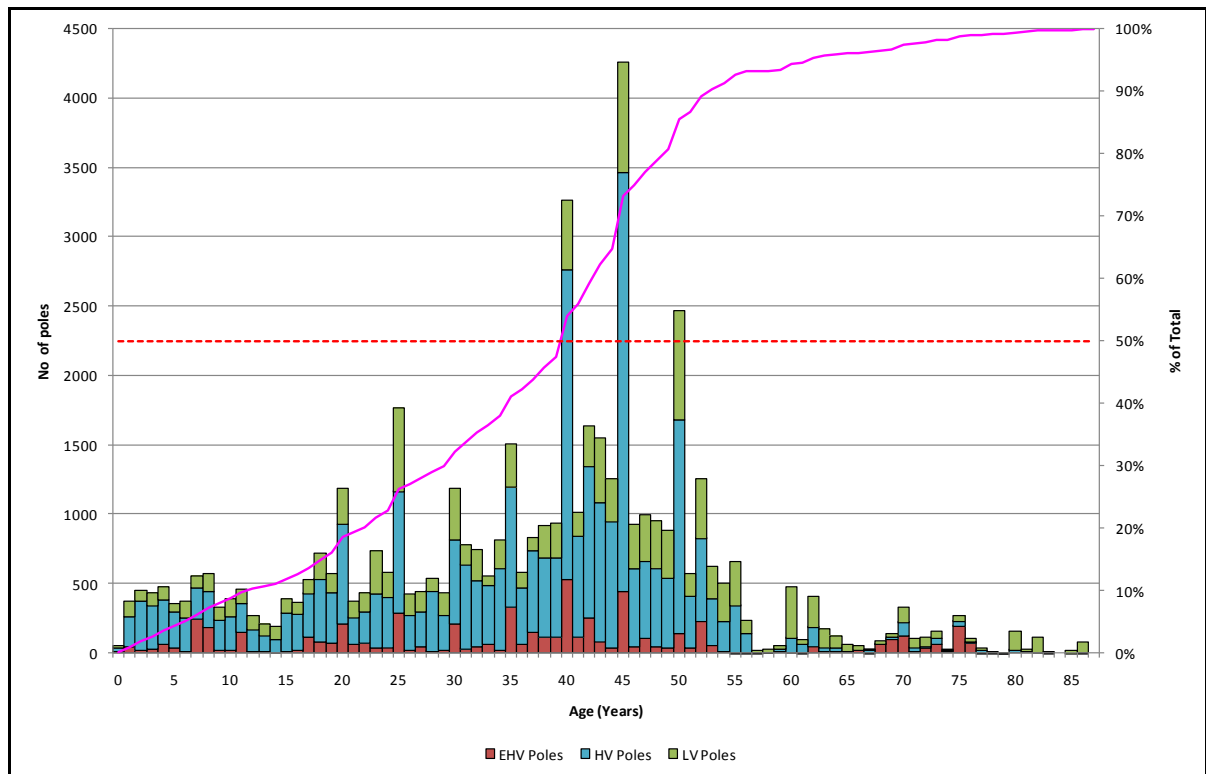


Figure 3.23 – HV and LV Poles Age Profiles

3.8.21 System Control Equipment

The Central region SCADA master station is a Lester Abbey system installed in 2000 with RTUs being installed from that time. The Dunedin master station is a Foxboro system for which a hardware and software upgrade was completed in March 2006. The Dunedin RTUs date from 1989.

3.9 Justification for Assets

All assets are justified by present or anticipated requirements, except for approximately 1.6% of assets by ODRC value which have been “optimised” out for ODV purposes. Although such assets have been optimised out, many are still required to meet existing network standards; for example, fault limiting reactors. These, normally older than average, assets require on-going monitoring and maintenance and, as such, represent a cost to the network. Until the cost of maintaining the status quo becomes higher than the cost to replace with the optimal network, these present network assets will remain in service.

Looking to the future, matching the level of investment in assets to expected growth and service levels requires the following issues to be considered:

- The need to accommodate future demand growth (noting that the ODV Handbook prescribed the number of years ahead that such growth can be accommodated).
- How asset ratings and configurations create service levels such as capacity, security, reliability and voltage stability.

- The asymmetric nature of under-investment and over-investment to be clearly understood; that is, over-investing creates service levels before they are needed, but under-investing can lead to service interruptions. This is illustrated in the disclosure reports which show that the average distribution transformer capacity utilisation has fallen from 33.2% in 2007, to 31.9% in 2009, and then up to 32.8% in the year ending March 2010.(we predict that the utilisation for the year ending March 2011 will be less due to the relatively mild winter in 2010). This shows that, during a time of economic growth, that investment will lead equipment utilisation.
- The discrete “sizes” of many classes of components to be recognised; for example, a 220 kVA load will require a 300 kVA transformer that would be only 73% loaded. In some cases capacity can be staged through use of modular components.

In theory, an asset would be justified if the service level it creates is equal to the service level required. In a practical world of asymmetric risks, discrete component ratings, non-linear behaviour of materials, and uncertain future growth rates, Aurora considers an asset to be justified if its resulting service level is not significantly greater than that required, subject to allowing for demand growth and discrete component ratings.

4 Service Levels

Aurora's business is the delivery of electricity to more than 82,000 consumers. To ensure that it is providing a cost effective service and one that is in line with consumer expectations, Aurora surveys consumers regarding their expectations, consults with stakeholders, and benchmarks itself against industry standards.

Aurora sets a broad range of service levels for all stakeholders; ranging from capacity, continuity of supply, and restoration of supply following faults, to ground clearances, earthing, absence of interference, compliance with District Plans, and submission of regulatory disclosures. This chapter describes the service levels that Aurora delivers to its stakeholders, explains why it sets particular service levels in preference to others, and discusses how it sets the quantum of those preferred service levels.

It also specifically describes the service levels that Aurora is required to uphold for various regulatory bodies, and to contribute to the well being of the community at large.

The service levels defined in this section will be used to:

- (a) inform stakeholders, especially customers, of proposed levels of service;
- (b) focus Asset Management Plan strategies to deliver the required service levels;
- (c) enable customers to assess whether their service levels are appropriate, given the nature of the assets that provide the delivery service;
- (d) over time, provide a measure of the effectiveness of the actions taken in accordance with the AMP.

4.1 Customer Oriented Performance Levels

4.1.1 Consumer Surveys

User opinion on quality of supply issues is continuously surveyed by Aurora. The survey was commenced in 1999 and is continuous so that results are:

- (1) less affected by long periods without supply interruption, or by significant interruption, at the time the survey is conducted with a given consumer, and
- (2) that results evolve with changes in network performance.

The survey is conducted directly with consumers because retailers appear to have little focus on quality issues at present, and because retailers may prove unable to reflect local preferences in the long term.

Table 4-1, below, summarises the survey results to-date. (2011 results are based on 11 months of data.)

Aurora's Continuous Price Versus Quality Survey								
Results to 31 March	2004	2005	2006	2007	2008	2009	2010	2011
Consumers surveyed	4,554	4,641	4,603	4,752	4,800	4,790	4,800	4,240
Response rate	18%	18%	18%	16%	17%	17%	16%	13%
Responses								
Prefer higher quality	7.4%	6.7%	5.3%	5.9%	4.8%	5.8%	4.2%	4.0%
Prefer lower price	92.6%	93.3%	94.7%	94.1%	95.2%	94.2%	95.8%	96.0%

Table 4-1 – Price Versus Quality Survey

Additionally, Aurora commenced telephone interviews of approximately 400 consumers in 2006, with the intention of increasing the frequency to yearly intervals. The results from the surveys are shown below. The telephone survey involved 200 consumers in the Dunedin area and 200 in the Central Otago area, selected at random, and questions covered a range of price – quality and service related issues. The main results of the survey are set out below:

Aurora's Customer Telephone Survey 2008, 2009 and 2010										
No	Question	Dunedin			Central			Total		
		2008	2009	2010	2008	2009	2010	2008	2009	2010
1	Price more important than quality	Yes 65% Unsure 11% No 24%	53% 25% 22%	62% 24% 14%	Yes 59% Unsure 16% No 25%	51% 26% 23%	56% 26% 18%	Yes 62% Unsure 14% No 24%	52% 25% 23%	59% 25% 16%
2	Single most important issue relating to quality	No of interruptions 40%	50%	13%	No of interruptions 46%	100%	28%	No of interruptions 43%	73%	50%
3	Accept 10% increase in line charges for 10% improvement in quality	No 100% Unsure 0%	0% 100%	73% 7%	No 46% Unsure 0%	100% 0%	71% 29%	No 70% Unsure 0%	45% 55%	72% 18%
4	Acceptance of rebate should increased supply not be achieved	Yes 60% Unsure 10%	33% 67%	47% 6%	Yes 92% Unsure 0%	80% 0%	71% 15%	Yes 78% Unsure 5%	55% 36%	59% 10%
5	Accept 10% decrease in line charges for say 10% more interruptions	No 81% Unsure 4%	29% 23%	51% 14%	No 77% Unsure 7%	29% 23%	44% 13%	No 79% Unsure 6%	35% 23%	48% 13%
6	Acceptable timeframe for restoration of supply (weighted average)	2.2 hrs	3.1 hrs	5.1 hrs	2.6 hrs	3.1 hrs	3.8 hrs	2.4 hrs	3.1 hrs	4.5 hrs

Table 4-2 – Price Versus Quality Survey

Key points to emerge from the surveys are that:

- consumers generally do not wish to pay more for much improved reliability;
- the number of interruptions rates as the most important issue although in 2010 voltage fluctuations has been raised as an issue which does not correlate with an increase in voltage complaints;

These results validate Aurora's approach of analysing worst performing feeders, as described in Section 4.4.2 and that this AMP should focus on improvements to the 10 worst performing feeders, relative to their peers.

4.1.2 Feedback from Electricity Retailers

From time to time, Aurora receives feedback from individual consumers, via their electricity retailer, on aspects of the Aurora delivery service. Based upon this feedback, Aurora is not aware of any systemic concerns with the level of reliability.

4.1.3 Consultation with Large Consumers

Aurora has a demand management program which targets large capacity connections and provides an opportunity for these consumers to offer feedback on a large number of issues, including service levels.

4.1.4 Consultation with Other Stakeholders

Aurora regularly consults with local councils and business groups on major projects; including discussion of the costs and benefits of various projects.

4.2 Network Reliability

Network reliability performance is influenced by many factors; including network design, customer density (connections per km of line), exposure to environment, and extreme weather events.

Extensive data is collected by System Control, for both planned and unplanned interruptions to supply; including the duration of the outage, number of consumers affected, and cause. This information provides all the input data necessary for calculating Aurora's reliability statistics. It is important to note that one-off events can unduly influence the results for any one year and that the long-term trend is more important and reflects the overall reliability of the assets.

Set out in Figures 4.1 and 4.2 below, are graphs of past performance for the Dunedin and Central Otago networks, using the SAIDI measure. The graphs show the average minutes without supply per customer for planned events, the largest unplanned event, and all other unplanned events.

Note: The graph for the Central Otago area includes the period from 1994 to 1999 when Central Electric owned this network area.

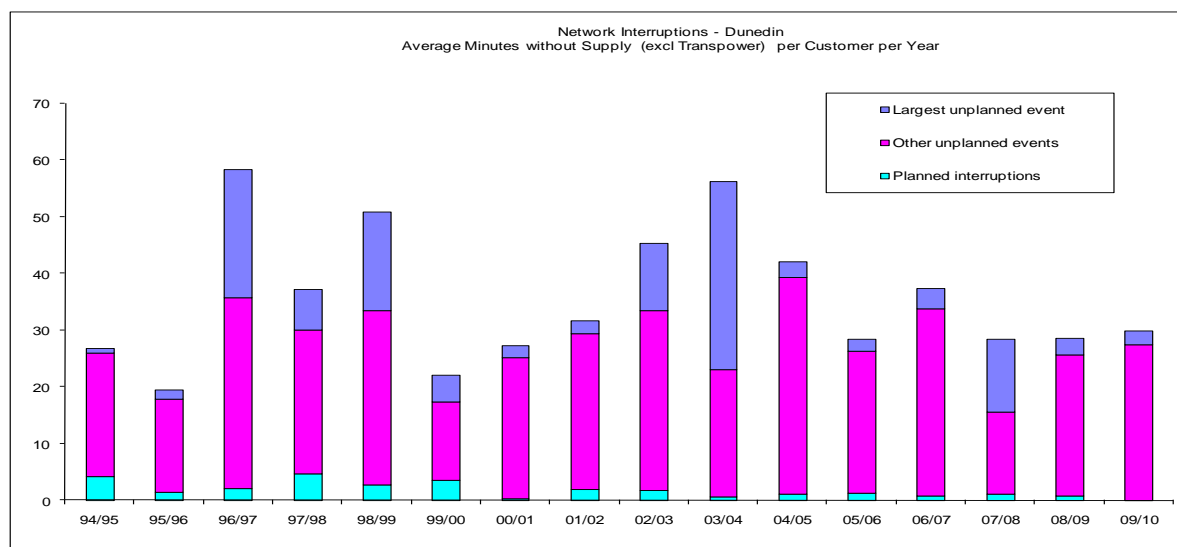


Figure 4.1 – Network Interruptions - Dunedin

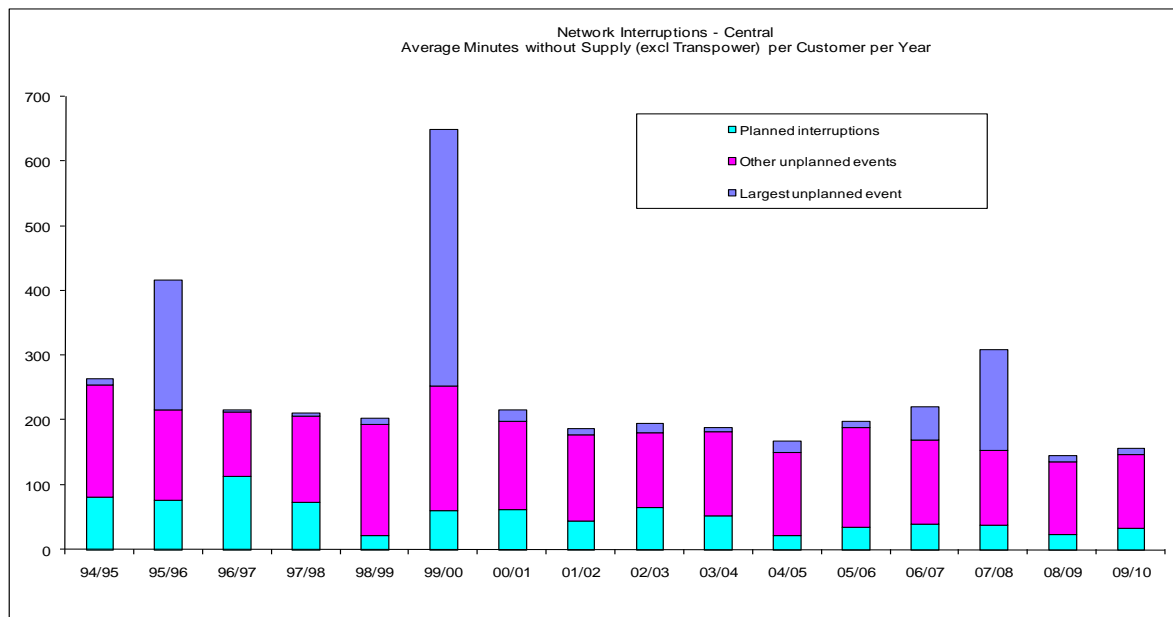


Figure 4.2 – Network Interruptions - Central

In 1999/2000, an extreme weather event consisting of very high winds, combined with heavy snow falls, resulted in widespread outages. In 2007/2008, gale force winds in Central Otago resulted in multiple outages, with both Cromwell to Wanaka 66 kV circuits affected for 10 hours.

4.3 Primary Customer Service Level Targets

From the above surveys and consultation, Aurora has confirmed that providing a reliable and secure network for electricity delivery is the primary requirement, and that consumers do not wish to have any reduction in service from that currently provided.

- consumers want service continuity (“keeping the lights on”);
- consumers want fewer interruptions especially in rural areas.

In summary, Aurora believes it has a strong community mandate to focus on supply continuity.

Aurora uses the internationally accepted supply reliability measures of SAIDI and SAIFI; the 10-year target levels of which are set out in Table 4-3 and Table 4-4 below. SAIDI is the primary measure chosen to monitor overall asset, since it combines both interruption frequency and interruption duration. This AMP provides for incremental improvement of SAIDI by reducing SAIFI, especially for those consumers that experience high levels of interruption.

	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Unplanned	71	70	69	68	68	67	66	65	65	65
Planned	14	14	14	14	13	13	13	13	13	13
Total	85	84	83	82	81	80	79	78	78	78

Table 4-3 – Network Performance Target (SAIDI) (minutes)

Within this strategy, analysis will continue to focus on improving the worst components of performance, and to mitigate the occurrence and impact of significant events. This includes analysis at the HV feeder level in order to identify economic opportunities to improve the worst performing feeders.

Another important service level is unplanned SAIFI, which is chosen due to the expressed consumer preference for fewer faults. The 10-year target for unplanned SAIFI is shown in Table 4-4, below.

	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Unplanned	1.27	1.26	1.25	1.24	1.24	1.22	1.20	1.19	1.19	1.19

Table 4-4 – Network Performance Target (SAIFI)

Aurora also recognises that these measures are somewhat academic and meaningless to individual stakeholders, so, in practical terms, individual consumers can expect the supply reliability levels stated in Table 4-5, below.

These levels of service are, in most cases, the results of previous system designs based upon deterministic forms of security guidelines. This is a useful rule-of-thumb approach to network design, but it is dependent on engineers' perceptions of consumers' needs (for example - larger load groups and "urban" feeders are generally assigned higher standards, without the basis of the choice being explicit) and has historically led to over-investment. Such a deterministic approach was used in the past by Aurora for the Dunedin City area, but future decisions on asset replacement and upgrade are being made using a demand-side driven, probabilistic, approach. This approach is more sophisticated, is facilitated by technology available today and, in Aurora's view, will lead to better asset utilisation and, thus, lower costs while meeting consumer expectations.

General Location	Target for Sustained Outages	Actual 2009/10 (No of feeders exceeding performance criteria) (No of feeders in that category)
Otago University, Hillside Workshops	No more than 1 outage of less than 4 hours every 5 years	0 of 7
Dunedin urban CBD	No more than 1 outage of less than 4 hours every 5 years	4 of 40
Dunedin urban suburbs	No more than 2 outages of less than 4 hours each year	8 of 104
Taieri Plains, Otago Peninsula	No more than 4 outages of less than 4 hours each year	13 of 30
Major urban areas in Central (Alexandra, Queenstown, Cromwell, Wanaka)	No more than 2 outages of less than 4 hours each year	6 of 22
Smaller towns in Central (Arrowtown, Roxburgh, Clyde, Ettrick, Omakau, Lake Hawea, etc)	No more than 4 outages of less than 6 hours each year	4 of 13
Rural areas in Central	No more than 10 outages of less than 6 hours each year	14 of 50
Remote rural areas in Central	No more than 20 outages each year	0 of 4

Table 4-5 – Fundamental Reliability Targets by Consumer Location

In the year ended 31 December 2010, 4,891 (6%) urban consumers experienced more than four interruptions and 1,229 (11%) rural consumers experienced more than 10 interruptions. Most rural consumers experiencing high numbers of interruptions are supplied from reclosers and, hence, many of the interruptions will be for relatively short periods. From recent customer surveys, Aurora is aware that, for many consumers, frequent interruption with fast restoration is more annoying than fewer interruptions but slower restoration. This is a factor that Aurora now takes into account when positioning reclosers in HV feeders.

4.4 Secondary Customer Service Level Targets

Aurora has a number of service level targets which it regards as secondary to the primary service levels.

4.4.1 Faults per 100 km of HV Circuit

Physical asset performance targets, such as faults per 100 km of HV circuit, are supply-side measures, and are secondary to SAIDI and SAIFI; however, they do provide segmented information to assist Aurora when making asset management decisions. Table 4-6, below, describes the target level of faults per 100 km of HV circuit, and the actual performance achieved for the 2009/10 year.

Measure	Indicator	Target Level	Actual 2009/10
Faults per 100 km HV	No of incidents per year	11.4	9.11
Faults per 100 km HV UG	No of incidents per year	2.5	1.7
Faults per 100 km HV OH	No of incidents per year	13.5	13.0

Table 4-6 – Targeted and Actual Performance - Faults per 100 km of HV Circuit

4.4.2 Improve the Performance of the 10 Worst HV Feeders

From consumer surveys, many rural consumers expressed a strong preference for fewer interruptions. Over the last 10 years, Aurora has focused upon installing SCADA systems into the Central Otago network and installing remote controlled switches into the many long rural HV feeders, in an effort to reduce the number of consumers interrupted when an unplanned interruption occurs, and then to restore supply as soon as possible. Whilst these efforts have reduced the average restoration time, the number of interruptions for some feeders is now becoming the main issue of concern.

In order to address these concerns, Aurora has selected the following feeders (refer Table 4-8) for attention over the next two years.

Area	Improve Reliability	Measure	Target Level
Ladies Mile, Lake Hayes Estate	FK704	Reduce SAIDI and number of interruptions	20% improvement
Closeburn	QT5202	Reduce SAIDI and number of interruptions	15% improvement
Brighton, Taieri Mouth	ET3	Reduce SAIDI minutes	15% improvement
Saddle Hill, Chain Hill	ET2	Reduce SAIDI minutes	10% improvement
Luggate	WK2752	Reduce SAIDI minutes	10% improvement
Hawea	MA260	Reduce SAIDI and number of interruptions	10% improvement
Mosgiel East	ET8	Reduce SAIDI minutes	10% improvement
Waldronville	GI11	Reduce SAIDI minutes	10% improvement
Glenorchy	QT910	Reduce SAIDI and number of interruptions	10% improvement
Lower Peninsula	PC3	Reduce SAIDI minutes	10% improvement

Table 4-7 – Targeted Improvement in the 10 Worst Performing Feeders

These feeders include three of those identified in last year's list as listed in Table 4-7 below (QT5202, PC3 and WK2752). Performance improvements were seen to the remaining seven feeders.

Last year, the following feeders were identified for attention; their actual performance is detailed below.

Area	Improve Reliability	Measure	Actual
St Bathans	OM634	20% reduction in SAIDI and number of interruptions	14% reduction in SAIDI minutes and 36% Reduction in number of interruptions
Bannockburn	CM821	10% reduction in SAIDI and number of interruptions	73% reduction in SAIDI minutes and 14% reduction in number of interruptions
Glenorchy	QT5202	20% reduction in SAIDI minutes	96% Increase
Lower Peninsula	PC3	20% reduction in SAIDI minutes	No change
Lake Hayes	AT7632	20% reduction in SAIDI minutes	26% Increase in SAIDI minutes and 29% Increase in number of interruptions
Springvale	AX168	10% reduction in SAIDI minutes	68% reduction
Hawea Flat	MA244	10% reduction in SAIDI minutes	31% reduction
Poolburn	OM679	10% reduction in number of interruptions	46% reduction
Aramoana	PC5	10% reduction in SAIDI minutes	24% reduction
Luggate	WK2752	10% reduction in SAIDI minutes	15% increase

Table 4-8 – Targeted Improvement in the 10 Worst Performing Feeders

4.4.3 Energy Delivery Efficiency Targets

Aurora's projected energy delivery efficiency measures are shown in Table 4-9, below:

Service Criteria	Service Definition	Target	Actual 2009/10
Load factor	Energy into network/peak kW hours per year	52%	54%
Loss ratio	Energy into network less energy delivered / energy into network	6.0%	5.0%
Capacity utilisation	Peak network kW / installed distribution transformer capacity kVA	30%	32.8%

Table 4-9 – Energy Delivery Efficiency Measures

Aurora encourages improvement in the above ratios through its congestion period demand pricing policies, which strongly incentivise the use of electricity during off-peak periods. The congestion period is approximately 150 to 250 hours per year, during May to August. Despite this pricing signal, the limited use of gas for heating purposes coupled with the location of several ski-fields in the Central Otago area, results in high loads occurring during winter. Thus, it is not appropriate to compare Aurora with, say, a North Island network which will have a flatter load profile and a corresponding higher load factor. Pricing signal efficacy notwithstanding, Aurora continues to promote the use of electricity during off peak periods through strongly signalling the high cost of delivery during peak periods compared to off-peak periods.

4.4.4 Restoration of Electricity Delivery Following a General Network Failure

If, as a result of a general network failure, supply has not been restored within four hours (urban areas) or six hours (rural areas) of notification of the failure, then Aurora will pay the Electricity Retailer:

- (i) \$50 (including GST) for 8 kVA and 15 kVA standard domestic connections;
- (ii) one month's use-of-system charges for other connections.

Payments are not made if the fault is due to extraordinary climatic conditions, civil emergencies, Transpower initiated, or certain third party events.

These payments apply to the standard Use-of-System Agreement with retailers, and other arrangements can be negotiated. To date, no party has sought any alternative compensation arrangement.

The actual spend on service failure payments (effectively a line charge reduction for reduced service) over recent years is detailed in Table 4-10, below:

Year to 30 June	Events	Consumers Affected	Total Paid	Percent of Line Revenue
2003	11	1148	\$63,336	0.119%
2004	16	415	\$25,410	0.048%
2005	24	896	\$51,553	0.091%
2006	14	324	\$21,435	0.036%
2007	15	246	\$13,210	0.021%
2008	16	1171	\$61,717	0.092%
2009	14	671	\$36,094	0.044%
2010	24	794	\$48,653	0.068%

Table 4-10 – Historic Service Failure Payments

As a result of the modest level of such payments, and the excellent delivery service provided, the quantum of compensation paid is insufficient to materially affect network design, and applies only modest pressure to operational decisions. Of far greater significance in changing behaviour is the cost-of-interruption charge Aurora applies to approved construction and maintenance contractors for planned outages, which is designed to maximise the use of live line techniques, and other innovative work practices.

4.5 Tertiary Customer Service Levels

4.5.1 Fault Calls

Since the separation of the line and energy businesses, Aurora has not operated a call centre capable of answering multiple fault calls. It does provide a 24 hour service for direct fault calls and emergency contact; however, this service has a limited capability and consumers are encouraged to call their retailer for up-to-date information on fault restoration.

4.5.2 Power Quality or Service Interruption Investigations

Aurora will respond to enquiries regarding power quality or service interruption investigations within 7 working days. If the investigation cannot be completed within 7 working days, then Aurora will provide, within that period, an estimate of the time it will take to complete the investigation. Aurora will remedy any problems under its control in a timely manner, in accordance with good industry practice.

4.5.3 Voltage Range

Minimum and maximum voltage is set by regulation for the protection of consumer appliances, but excludes "momentary" fluctuations. Voltage excursions outside of the statutory range will occur because of equipment failure, environmental effects (for example - lightning), or unexpected loads, and all can require solutions that take time. Voltage excursions will normally be reported by consumers for low voltage, due to rising loads or failing conductor joints, and occurs during winter when loads are highest. Often the problem has abated, until the following winter, before Aurora can confirm the cause or make additional investment, where this is necessary. Accordingly, Aurora sets a target for the maximum number of outstanding voltage complaints of ten per ten thousand consumers per annum; ie, 80 voltage complaints per year. Table 4-11, below, details the actual frequency of voltage complaints against target.

Aurora actively monitors progress to resolve complaints. If there are delays to remedying the issue, the usual impediment to meeting them is gaining Local Authority agreement to the location of equipment; for example, transformer placement on road reserve.

Measure	Service Level	Target	Actual 2009/10
Voltage complaints	No of valid voltage complaints per year	Less than 10 per 10,000 connections	3 per 10,000 connections

Table 4-11 – Reported Voltage Complaints

4.5.4 Customer Service

Because Aurora has contracted out management of its assets, Aurora monitors *DELTA*'s performance to ensure appropriate customer service levels are maintained for such matters as answering telephones and correspondence. Aurora is a founding member in the Electricity and Gas Complaints Commission scheme and is committed to resolving consumer issues in a responsible manner. Table 4-12, below, details Aurora's general customer service levels.

Measure	Service Level	Service Guarantee	Valid Claims 2009/10
Response to customer enquiries	Within 7 days Aurora will investigate and respond in detail or advise when a final response can be expected due to the nature of the problem	\$50 for exceeding the time-frame	Nil
Response to power quality or voltage	Within 7 days Aurora will investigate and respond in detail or advise when a final response can be expected due to the nature of the problem	\$50 for exceeding the time-frame	Nil
Notification of planned service interruption	Missing notification of planned interruption	\$20 per ICP per missed communication	Nil

Table 4-12 – Customer Service Levels

4.6 Regulatory Service Levels

Various Acts and Regulations require Aurora to deliver a range of outcomes within specified timeframes, such as:

- restraining prices during each financial year to that prescribed by the price path;
- ensuring that SAIDI and SAIFI do not materially decline from the 5-year average to 31 March 2009;
- publicly disclose an AMP each year;
- publicly disclose prescribed performance measures each year.

The complete derivation of these measures will be included in the Financial and Information Disclosures and the Price Quality Path Disclosures published on Aurora's website www.auroraenergy.co.nz.

4.7 Service Levels for Other Stakeholders

Aurora also creates a number of service levels that benefit other stakeholders such as safety, amenity value and absence of electrical interference.

4.7.1 Safety

There are various legal requirements for assets (and consumers' plant) to adhere to certain safety standards, which include earthing exposed metal and maintaining specified line clearances from trees and from the ground. These requirements include:

- Health & Safety In Employment Act 1992;
- the amended Electricity Act 1992 setting out the requirements for safety management systems;
- Electricity (Hazards from Trees) Regulations 2003;
- maintaining Safe Clearances From Live Conductors (NZECP34:2001); (we note that this can be a vexed issue with Territorial Authorities issuing Building Permits without taking due regard to safety clearances);
- power system earthing (NZECP35:1993).

The need to protect both the workforce involved with the operation and maintenance of Aurora's assets, and the general public, requires management of the inherent hazards of electrical equipment. Industry safety rules establish the principles for safe work and Aurora's operating and maintenance standards detail the procedures for meeting these principles in various situations.

The replacement programme for plant and equipment ensures that unsafe items are replaced at the earliest opportunity, if defects cannot be eliminated. To protect the public, Aurora takes care of its subtransmission and distribution lines, through its maintenance programmes, by ensuring that vegetation is maintained clear from lines. Similarly, zone substation fences and gates, distribution substations, LV pillars, and other equipment enclosures are maintained in good order.

Aurora's key safety measures are detailed in Table 4-13, below:

Measure	Indicator	Target Level	Actual 2009/10
Safety of public	No of incidents per year	Zero incidents per year	2*
Safety of personnel	No of incidents per year	Zero incidents per year	0
Safety of network assets	Compliance with standards	All significant site hazards removed or mitigated if practicable	0

Table 4-13 – Network Safety Levels

*One instance each of a cable flash and a pole falling with a worker attached occurred.

4.7.2 Environmental Management

There are a number of requirements that limit where and how overhead power lines are built:

- the Resource Management Act 1991;
- the operative Dunedin City, Central Otago and Queenstown Lakes District Plans;
- relevant parts of the operative Otago Regional Plan;
- Land Transport requirements.

In general, new assets will be required to be installed underground, in many areas, which is significantly more expensive than overhead construction.

Many of Aurora's assets are in environmentally sensitive areas. Maintenance programmes include; the repair and maintenance of oil filled equipment (such as transformers and circuit breakers) to prevent leakages, the upkeep of noise-reducing components, and appropriate landscaping and/or revision of land use.

In addition, some of Aurora's assets are in ecologically sensitive areas where design of the asset needs to take into account the local environment. The District Plans of local authorities also set out minimum standards, and in many cases assets are required to be located underground.

A specific instruction covers the handling of sulphur hexafluoride (SF6) gas used as an insulating medium in some equipment. Polychlorinated biphenyls (PCBs) have been eliminated from Aurora's equipment. No breaches of the RMA have occurred.

Table 4-14, below, describes Aurora's principal environmental performance measures.

Measure	Indication	Target Level	Actual 2009/10
SF6	No of incidents per year	Zero incidents per year	0
PCBs	No of incidents per year	Zero incidents per year	0
Oil spills	No of incidents per year	Zero incidents per year	0

Table 4-14 – Environmental Performance Measures

4.7.3 Electrical Interference

Under certain operational conditions, assets can interfere with other utilities, such as telephone wires and railway signals, or even with the correct operation of Aurora's own equipment or customers' plant. The following two codes impose service levels:

- harmonic levels (NZECP36:1993);
- SWER load limitation to 8A (NZECP41:1993).

4.8 **Justifying Service Levels**

Aurora justifies its service levels in several ways:

- on the basis that the majority of consumers have expressed a preference for maintaining similar levels of continuity and restoration, in return for paying similar line charges;
- by what is achievable within Aurora's constrained revenue;
- by the physical characteristics and configuration of the network, that embody an implicit level of reliability which is expensive to significantly alter (but which can be altered if a consumer or group of consumers agrees to pay for the alteration);
- because of the diminishing returns of each dollar spent on reliability improvements;
- by a customer's specific request (and agreement to pay for) a particular service level;
- when an external agency imposes a service level, or in some cases, an unrelated condition or restriction that manifests as a service level; such as a requirement to place all new lines underground, or a requirement to maintain clearances.

Consumer surveys over the past 4 years have indicated that consumer preferences for price and service levels are reasonably static – there is certainly no obvious widespread call for major increases in service levels other than a reduction in the number of interruptions. This is the aspect of service on which Aurora intends to focus in the immediate future.

It is important to note that the new sections of the Electricity Act 1992 setting out the Safety Management System requirements may require a step increase in the level of public safety, and, therefore, a step increase in activities like inspections. Once the new clauses in the Act become operative in 2012 Aurora will need to ensure that its program of inspections will meet the requirements, which may need to be reflected under the heading of public safety, above.

5 Network Development

5.1 Introduction

Capital expenditure on the Aurora network is driven by the following factors:

- growth in demand by existing consumers;
- connection of new consumers;
- enhancement of network reliability
- replacement of aging equipment to meet safety and reliability standards;
- community requirement to convert overhead distribution to underground.

In the Central area Aurora expects strong growth in electrical demand to continue which is the main driver for capital expenditure in this area. Minimal population growth is expected in Dunedin over the next 20 years where growth in electrical demand is expected to average between 0% and 1%, but there will be localised areas where growth will exceed this. Capital expenditure in the Dunedin area will mainly be driven by the replacement of ageing assets, the conversion of overhead distribution to underground, and reliability improvements.

Aurora's projected capital expenditure is presented in Table 5-1 the definition of capital expenditure categories is given in Table 5-2- and the timing of major projects is presented in Table 5-3

	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Customer connections	5,600	6,000	6,400	6,800	7,200	7,600	8,200	8,200	8,200	8,200
System growth	7,090	2,680	10,130	14,180	11,080	4,880	5,180	10,680	8,680	9,880
Reliability, safety environment	2,020	1,480	1,130	1,070	1,680	1,260	1,800	1,500	1,600	1,700
Asset replacement and renewal	8,490	8,140	8,120	4,730	10,030	7,460	6,270	6,330	7,430	5,420
Asset relocations	400	500	600	500	500	500	500	400	400	400
Total	23,600	18,800	26,380	27,280	30,490	21,700	21,950	27,110	28,310	27,600

Table 5-1 – Capital Expenditure Forecast (\$000)

Capital Expenditure Category	Definition
Customer connections	New or upgraded connections including subdivisions
Asset replacement and renewal	Replacement of technically obsolete or deteriorated assets
Reliability, safety environment	Works required for safety reliability or environmental
System growth	Works associated with growth in network loads
Asset relocations	Conversion of reticulation from overhead to underground and moving works for roading authorities and 3 rd parties

Table 5-2 – Capital Expenditure Category Definitions

Short Description	Section Ref	Estimated Costs \$000									
		2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
		(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)
Growth Projects											
Install HV tie between WK2752 and WK2756	5.12.3	500									
Install two new 5 MVA 66/11 kV substation in Maori Point Rd	5.11.10		7,000								
Establish Wanaka HV feeder 2751 into Dungarvon St	5.12.4			450							
66 kV line for Hawea Generation	5.10.3			3,500							
66 kV cable from Riverbank Rd substation to Wanaka substation	5.10.3				3,500						
New zone substation at Hawea	5.10.3				3,500						
Install new HV feeder in Cromwell to Leitrum St	5.12.5				500						
Construct Riverbank Rd 66 kV switching station	5.11.13				4,000						
Install two 12/24 MVA transformers at Cromwell substation	5.11.12					2,500					
Upgrade Remarkables transformer to 5 MVA	5.11.17					2,500					
Install 10 MVA transformers and switchgear at Arrowtown zone sub	5.11.8							4,000			
Install 3rd 33/66 kV auto tx at Cromwell GXP	5.10.3							2,000			
Install 66/11 kV transformer and switchgear at Riverbank Rd substation	5.10.3								2,500		
Install 3rd 33 kV circuit into Arrowtown	5.10.1								5,000		
Jacks Point zone substation	5.11.15									3,000	
Create 66 kV switching station at Queensberry	5.10.3										3,000
Renewal Projects											
Port Chalmers 5 renewal	6.5.16	350									
Roxburgh substation upgrade	6.5.5	500									
Replace Halfway Bush transformers	6.5.17		3,000								
Undergrounding of OH from Frankton substation for NZTA	5.12.2		500	500							
Replace Andersons Bay 33 kV gas cables	6.5.2			3,000							
Rebuild Neville St zone substation on new site	6.5.4					6,000					
Replace Kaikorai Valley 33 kV cables	6.5.3						2,900				
Replace Willowbank 33 kV gas cables	6.5.2							4,300			
Replace Smith St 33kV gas cables	6.5.2									3,500	
Upgrade Smith St substation	5.11.6									4,500	
Upgrade Andersons Bay substation	6.5.7										4,500
Replace Ward Street gas cables	6.5.2										4,700

Table 5-3 – Time Line of Major Capital Projects

5.2 Distributed Generation Policy

Aurora encourages the connection of distributed generation to its network, and examines each proposal with regard to strategic network development. Aurora currently has 92 MW of distributed generation; there is one project underway to connect an additional 36 MW of wind generation and a proposal for the future connection of 16 MW of hydro generation.

Distributed generation schemes have the potential to make a significant contribution to future network development, in terms of security, efficiency and economy of network operation. Aurora has guidelines and application information for the connection of distributed generation published on its website at www.auroraenergy.co.nz.

Aurora's Congestion Period Demand (CPD) pricing methodology financially rewards the operation of standby generation plant during network congestion periods. Aurora otherwise applies the pricing principals as set out in Part 6 of the Electricity Industry Participation Code 2010.

Several consumers have installed facilities that allow the parallel operation of diesel powered standby generation plant with the Aurora network. There are two consumers who operate diesel generation in parallel with the Aurora network due to network capacity constraints.

In autumn 2008, a generator was installed at the future Cardrona substation site to defer subtransmission upgrades. The generator ran for approximately 100 hours over times of winter peak demand during the winters of 2008 and 2010 and for a lesser time during the 2009 winter due to further optimisation of the generator start up and shut down set points. The generator is also being used to supply Cardrona Valley consumers while the transmission into the area is being upgraded.

5.3 Non-Network Solutions

Demand Side Management (DSM) provides an alternative to investing in network assets. The primary mechanism for better utilisation of distribution assets is via Aurora's delivery pricing structure.

Ripple signal injection is used to signal congestion periods, and to offer an appliance-switching service that is voluntary but financially attractive. The switching service is predominately used for water heating, space heating, and pumping loads, and results in peak demand being reduced by approximately 45 MW (16%) across the Dunedin and Central networks, requiring that much less investment in network capacity.

Distributed generation is encouraged to operate during congestion periods and this is facilitated by the CPD ripple signal. Over the last three years, a number of consumers completed alterations to their diesel generation plant to allow it to operate during congestion periods.

Aurora offers a demand management program to consumers with a capacity greater than 150 KVA who have the potential to manage their CPD. Over 70 consumers have signed up to this program. Further information on this program is available on the Aurora website www.auroraenergy.co.nz. Also on the website, is the current status of the CPD demand ripple channel and predicted CPD periods for the following week and month.

The application of smart meters that provide half hourly metering for all consumers could encourage the moving of further load away from peak periods. This process is under the control of Electricity Retailers and Metering Service Providers. Aurora will monitor this technology with a view to assessing if it can be used to encourage consumers to reduce their demand during faults on the Aurora network which could enable Aurora to defer some network upgrades.

5.4 Planning Process

An annual development plan is prepared that details the expansion and upgrading of the Aurora Network and GXP connections, considered necessary during the following 10 years, to accommodate predicted future network loading. The plan also proposes works to improve network reliability and renew aging assets. An outline of proposed projects with estimated costs and construction dates is included.

For complex proposals separate detailed development reports are prepared. These reports describe the proposed development, consider alternatives, and provide detailed cost estimates and economic analysis.

A key input to the planning process is half hourly load data that is analysed after each winter for all grid exit points, zone substations and HV feeders.

There are usually multiple options to resolve network capacity constraints and reliability issues which include:

- Operational activities, in particular switching the distribution network to shift load from heavily-loaded to lightly-loaded feeders, to avoid new investment.
- Influence consumers to alter their consumption patterns so that network loads are reduced. Examples might be to shift demand to different time zones, negotiate interruptible tariffs with certain consumers so that overloaded assets can be relieved, or assist a consumer to adopt a substitute energy source to avoid new capacity.
- Construct distributed generation. Distributed generation would be particularly useful where additional capacity could eventually be stranded, or where primary energy is going to waste; eg, water being released from a dam that could be used in a hydro generator.
- Modify an asset to increase its capacity; for example, by adding forced cooling to a transformer.
- Installation of automated or remote controlled switching to minimise the impact of faults and speed up supply restoration.
- Install new assets, with greater capacity.
- Do nothing and simply accept that some consumers may face a reduction in service levels. In reality, the do nothing option would only be adopted if the benefit-cost ratio of all other reasonable options were unacceptably low and if analysis was provided to the Chief Executive and Directors that the do nothing option did not represent an unacceptable increase in risk to the business.

Aurora generally selects the option with the lowest life-cycle cost, by determining the NPV of the following costs associated with a project: A discount rate of 9.8% is used.

- initial construction;
- on-going maintenance;
- consumer outage costs associated with construction;
- cost of losses (presently valued at \$0.07 per kWh);
- on-going consumer outages (as per Table 5-4).

Following a review by external consultants in 2010; the following Values of Lost Load were adopted:

Type of Interruption	Value of kWh Unserved
Unplanned – residential	\$10
Unplanned – other	\$50
Planned – residential	\$ 5
Planned – other	\$25

Table 5-4 – Cost Allocated to Energy not Supplied

Other factors that may be taken into consideration during project selection are environmental impact, community feedback, and future development options.

5.5 Planning Criteria

Planning decisions within the electrical distribution industry have historically been deterministic and sometimes overly conservative. In the past the “n-1” criterion was applied almost universally at a zone substation and sub transmission level. Aurora uses the n-1 criteria as a screening tool, as described in Appendix C, to identify which parts of its subtransmission and zone substation network require the application of probabilistic analysis to determine the most economic time to upgrade assets. Probabilistic analysis calculates an annual cost of energy not supplied for the selected network configuration. Upgrades will proceed when the net present value of the energy not supplied is greater than the cost of the upgrade. The value used for energy not supplied is detailed in Table 5-4.

Probabilistic analysis is also applied at the HV feeder level. The trigger for analysis is when it is not possible to fully off-load a feeder onto adjacent feeders at peak load times or the feeder has reached 85% of its thermal rating. On rural feeders it is normally be voltage drop that will determine the maximum capacity of a feeder and not its thermal capacity. Typically 5% is the maximum volt drop tolerable in the HV network; however, this can be exceeded on some rural feeders where consumers typically have their own transformer and there is minimal LV distribution.

The cost of and outage using probabilistic analysis is determined by multiplying all the parameters below

- value of energy not supplied;
- quantity of load not supplied;
- probability of an outage;
- probability of outage occurring during an at risk time;
- likely outage duration.

Each of these parameters is discussed below.

Value of Energy not Supplied

The value of energy not supplied, (also known as Value of Lost Load), is detailed in Table 5-4 above.

Quantity of Load Lost

Load duration data is used to determine the annual hours at risk and determine the mean load not supplied during an outage. Growth factors are applied when applicable.

Probability of an Outage

The probability of failure is assessed by using engineering judgement in considering past and likely future failure rates. Judgement is required as pure consideration of past failure rates tends to under predict the future. Typical default values are shown in **Table 5-5** below.

Equipment	Annual Fault Probability	Units
66 or 33 kV overhead line	0.06	per kilometre
HV overhead line	0.1	per kilometre
HV underground cable	0.05	per kilometre
Power transformer	0.005	per unit
Circuit breakers	0.005	per unit

Table 5-5 – Equipment Outage Probabilities

Probability of Outage During “At Risk” Time

The “at risk” time is when the load on a system exceeds the n-1 capacity of the system plus the shoulder period just outside such times but within anticipated repair times. Load duration data is used to determine the annual hours at risk. Growth factors are applied when applicable.

Outage Duration

The duration of the outage will depend on the equipment that has failed its location and the nature of the failure. Typical outage times are given in Table 5-6 below:

Equipment	Outage Time	Notes
Overhead line	1 to 6 hours	Required to locate gas leak
33 kV oil cable	Up to 2 weeks	
33 kV gas cable	1 to 2 weeks	
PILC and XLPE cables	12 to 24 hours	Time to deploy mobile sub Faults can range from minor tap-changer issues to total transformer failure
Power transformer <= 5 MVA	6 to 12 hrs	
Power transformer > 5 MVA	1 week to one year	

Table 5-6 – Typical Equipment Outage Times

5.6 Demand Forecasting Methodology

Demand predictions are undertaken annually. Half hourly loading data is collected from GXP's and zone substations including HV feeders. At the GXP and zone substation level predictions are primarily based on past growth rates with adjustments for known large load increases or distributed generation connections. An Excel spreadsheet is used to predict the future loads using both the Growth (exponential) and Linear prediction functions. The value used for planning is usually midway between the growth and linear predictions unless engineering judgement and local knowledge suggests otherwise.

Consideration has been given to correlating load to weather conditions such as degree-day data and then producing separate predictions for a normal, cold or warm winter. But other factors that influence load such as the day or the week, school and public holidays, and ski field operations make the correlation difficult. In Dunedin once every 5 to 10 years, there is an extreme cold weather event; typically, a three-day snowfall that occurs during the week, and outside of the school holiday period. These events can add an additional 10% to the Dunedin peak demand. In Central very cold weather during the July school holidays, with the ski fields operating, can cause a large increase in demand in the Wanaka and Queenstown areas. Aurora has determined that it is not economic to install additional assets to maintain normal supply security levels during these infrequent events.

At the HV feeder level, the ability to off-load each feeder is checked. Detailed predictions of feeder loads are only done on at risk feeders ie near their maximum rating or cannot be fully off-loaded. Long rural feeders at risk of being voltage constrained have UTL data loggers installed at selected consumers premises that telemeter the consumers voltage to Aurora for analysis. Remedial works are considered if the consumer's voltage is outside the regulated limits for more than 5% of the year.

Aurora maintains a project database in its GIS system that identifies the location and expected electrical demand of proposed developments such as sub divisions. This information is used to assist with HV feeder load predictions.

5.7 Project Prioritisation Methodology

In general, the priority for the completion of capital projects is determined in accordance with Table 5-7, below:

Priority	Project Category
1	Projects to eliminate significant health and safety issues.
2	Projects to resolve consumer voltage outside statutory limits.
3	Consumer driven projects such as new connections and subdivisions.
4	Projects to provide for load growth.
5	Projects to improve reliability that are not related to load growth. Projects in this group with the highest expected benefit to cost ratio are implemented first.
6	Overhead to underground conversion projects.
7	Renewal projects where there is no immediate threat to network reliability or health and safety issues.

Table 5-7 – Project Priority List

5.8 Equipment Ratings

Equipment ratings are assigned in accordance with Table 5-8 to 5-9 below:

Equipment	Rating Allocation
Zone substation transformers ONAN	Winter peaking transformers are operated to 120% of nominal rating by taking advantage of low ambient temperature during high load periods and cyclic load profile as per AS 2374.7 "Loading guide for oil immersed transformers".
Transformers ONAN/OFAF	Manufacturer assigned emergency rating.
Overhead lines	Winter night and summer day ratings assigned in accordance with IEEE Std 738 -1993.
Switchgear	Manufacturer's assigned rating, no overload permitted.
Current transformers	120% of nominal rating unless rated for extended thermal range.
Cables	Some 33 kV cables have had ratings assigned by consultants after investigation of specific installation conditions. For all other cables the manufacturer's standard data sheet ratings are used including ambient temperature, soil thermal resistivity and cable proximity.
Distribution transformers	Transformers with a normal residential area load profile can be loaded to 150% of nominal rating. For other loads 130% of nominal rating.

Table 5-8 – Assignment of Equipment Ratings

Parameter	Summer Day	Winter Night
Ambient temperature	30°C	10°C
Wind direction	60° to the conductor	60° to the conductor
Wind speed	1 m/s	1 m/s
Max conductor temperature	50°C	50°C
Latitude	45°	45°
Sun time	mid-day, 1 kW/m ²	None
Emissivity	0.5	0.5
Absorptivity	0.5	0.5

Table 5-9 – Parameters Used to Determine Overhead ACSR Conductor Ratings

Conductor	Ratings (Amps)		Volt Drop %/MVA/km		
	Winter	Summer	33 kV	11 kV	6.6 kV
Wolf	542	385	0.026	0.228	0.631
Dog	374	226	0.035	0.31	0.859
Mink	300	213	0.051	0.455	1.256
Ferret	231	164	0.071	0.634	1.742
Squirrel	148	105	0.131	1.168	3.179

Table 5-10 – Ratings of Standard ACSR Conductors

5.9 Grid Exit Points

5.9.1 Demands and Growth Predictions

The historic and projected peak demands (in MW) for the *network areas associated with each GXP* are shown in Table 5-11; the demands are equal to the demand on the GXP plus distributed generation.

Calendar Year			Clyde	Cromwell	Frankton*	Halfway Bush	South Dunedin		
2003	Actual	GXP Off take + Distributed Generation (MW)	15.2	20.3	38.3	116.4	61.3		
2004			15.6	21.5	41.4	126.0	67.0		
2005			17.2	24.4	41.8	126.0	66.1		
2006			16.3	25.1	45.1	125.1	70.2		
2007			18.2	30.6	49.7	130.6	71.0		
2008			16.4	28.0	48.0	124.0	70.6		
2009			16.8	30.5	47.7	130.6	72.2		
2010			16.4	31.4	50.1	121.3	71.7		
2011	Predicted		17.0	33.2	51.7	126.1	73.4		
2012			17.1	34.2	52.7	126.8	74.1		
2013			17.1	35.2	53.7	127.4	74.9		
2014			17.2	36.2	54.8	128.0	75.6		
2015			17.3	37.2	55.8	113.6	91.3		
2016			17.4	38.3	56.9	114.2	92.2		
2017			17.5	39.3	57.9	114.8	93.0		
2018			17.6	40.4	59.0	115.4	93.8		
2019			17.6	41.5	60.1	116.0	94.6		
2020			17.7	42.6	61.2	116.6	95.5		
Past Growth Rate (Trend 2004 to 2010)			0.4%	6.21%	3.13%	-0.20%	1.38%		
2010 off take peak (MW excluding distributed generation)			8.1	27.9	49.4	109.0	71.7		
Off take n-1 Capacity (Continuous) MVA			27	40.9 ³	66	100	81		
Off take n-1 Capacity (24 hr Winter Post Contingency MVA)			27	40.9	80	112	81		
Distributed Generation (2010 MW at time of load peak)			12.5	3.4	0.7	31.9	0		

Table 5-11 – GXP Area Peak Demands

4 MW of Ward Street load was transferred in the winter of 2010 from the Halfway Bush GXP to the South Dunedin GXP whilst the Ward Street upgrade was underway. This load has now been transferred back to the Halfway Bush GXP.

³ This is Aurora off take only - ESL off take is approximately 1.5 MW additional

The Energy use normalised in 2002 GWh for each GXP is shown in Figure 5.1 and the load factor⁴ by GXP is shown in Figure 5.2. The reduction in Dunedin load factors is attributed to the loss of high load factor industrial load which has been replaced by low load factor weather dependent residential and commercial load.

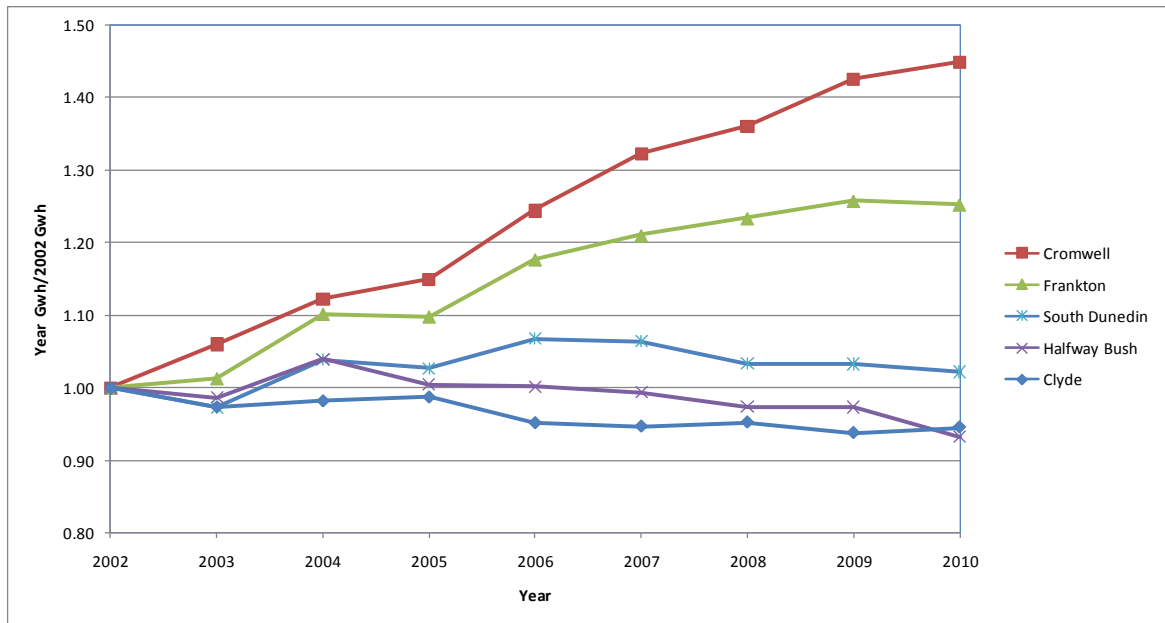


Figure 5.1 – Comparative Growth in GXP Energy (GWh 2002 Normalised)

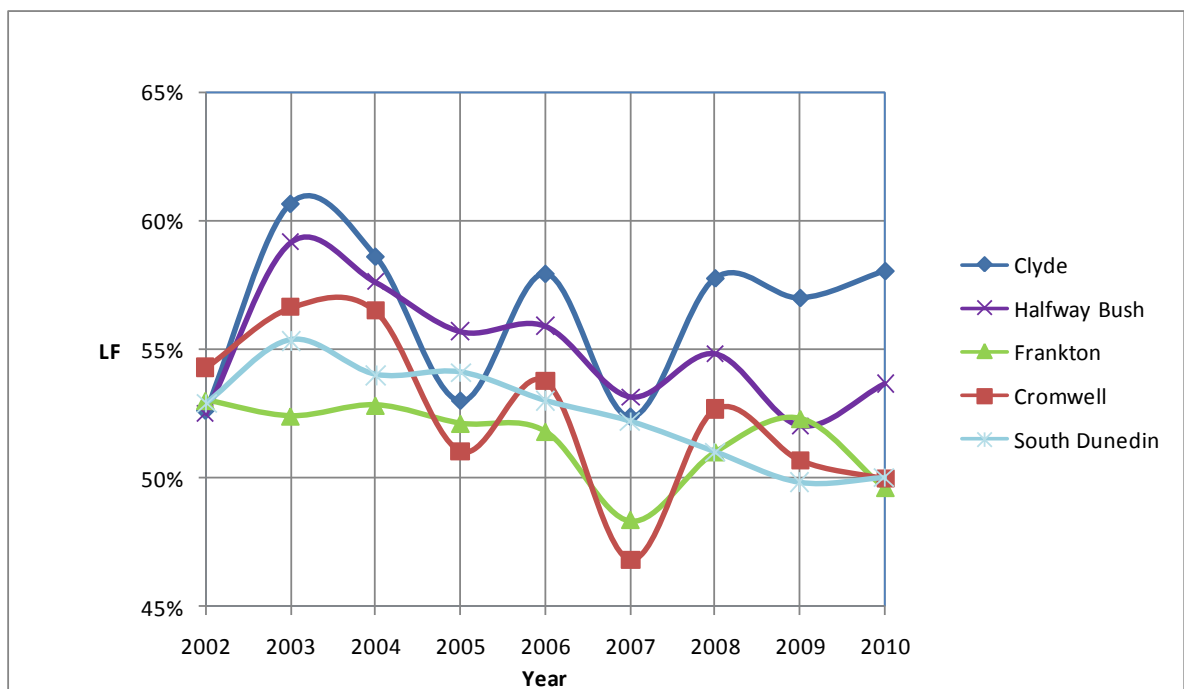


Figure 5.2 – Load factor by GXP

⁴ Load Factor is the annual energy used if actual annual energy use was divided by constant peak demand

The demands in Central during the 2010 winter were lower than predicted in the 2010 plan for all GXP's reflecting the mild weather in 2010. See Table 5-12 below.

GXP	2010 MVA Predicted	2010 MVA Actual	Difference
Clyde	17.6	16.4	-7.1%
Cromwell	33.3	31.4	-6.1%
Frankton	52.3	49.4	-5.8%
HWB	130.3	121.3	-7.4%
Sth Dn	74.9	71.7	-4.5%

Table 5-12 – Comparison of 2010 Actual and Predicted Loads

5.9.2 Frankton GXP

The Frankton GXP is supplied by a Transpower double circuit 110 kV line via two 220/110/33 transformers at the Transpower Cromwell substation as described in Section 5.9.3.

The GXP has a continuous n-1 rating of 66 MVA and a 24 hour winter post contingency rating of 80 MVA. The 110 kV lines have a winter rating of 76 MVA. It is predicted the 66 MVA continuous n-1 rating of the T2A/T2B transformers will not be exceeded during the planning period.

Electricity Southland Ltd (ESL) now takes supply from this GXP as well as Aurora. The load predictions include the ESL load.

There is space in the switch room for two additional 33kV feeder circuit breakers. Installing an additional feeder will be easy while it is possible to obtain the existing switchgear model. Transpower is to advise Aurora before production of the current model ceases to facilitate advance purchase of a breaker if necessary.

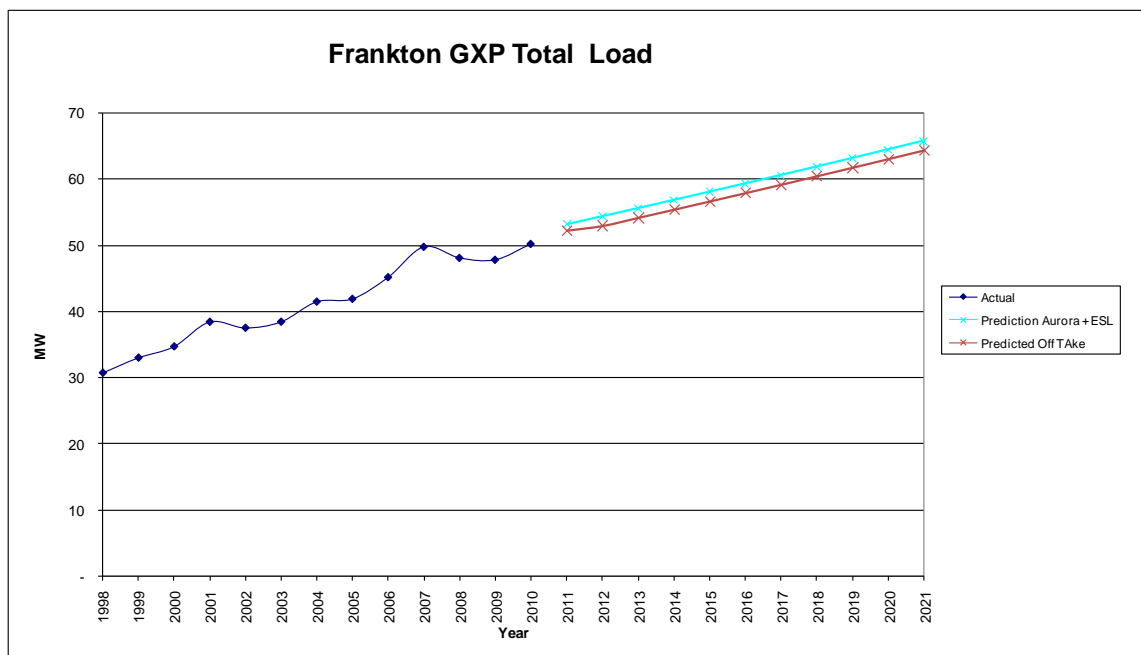


Figure 5.3 – Frankton GXP Load Prediction

5.9.3 Cromwell GXP

The Cromwell GXP “tees off” the Transpower 220 kV lines that run between Twizel and Clyde. Two three-winding transformers supply both the 33 kV to the Cromwell GXP and the 110 kV supply to the Frankton GXP. The Cromwell transformers were upgraded in 2009 resulting in the n-1 ratings listed in Table 5-13. The 33 kV rating of the T8 transformer is constrained to 40.9 MVA by a protection limitation and to 45.7 MVA by incoming circuit breaker rating otherwise it would be 50 MVA. The off take load is predicted to exceed 40.9 MVA during the winter of 2019. The works required to remove the protection constraint have yet to be determined.

Voltage	Continuous n-1 MVA	Winter 24-Hour Contingency MVA
220 kV	150	202
110 kV	97.2	108.8
33 kV	40.9	40.9

Table 5-13 – Cromwell GXP Transformer n-1 ratings

The predicted load on the 33 kV windings of the Cromwell transformers is shown in Figure 5.4. The reduction in off-take demand in 2014 is due to the proposed commissioning of the Hawea generation, which is predicted to reduce the off-take demand by 2 MW. See Section 5.10.3 for additional information on the Hawea generation proposal.

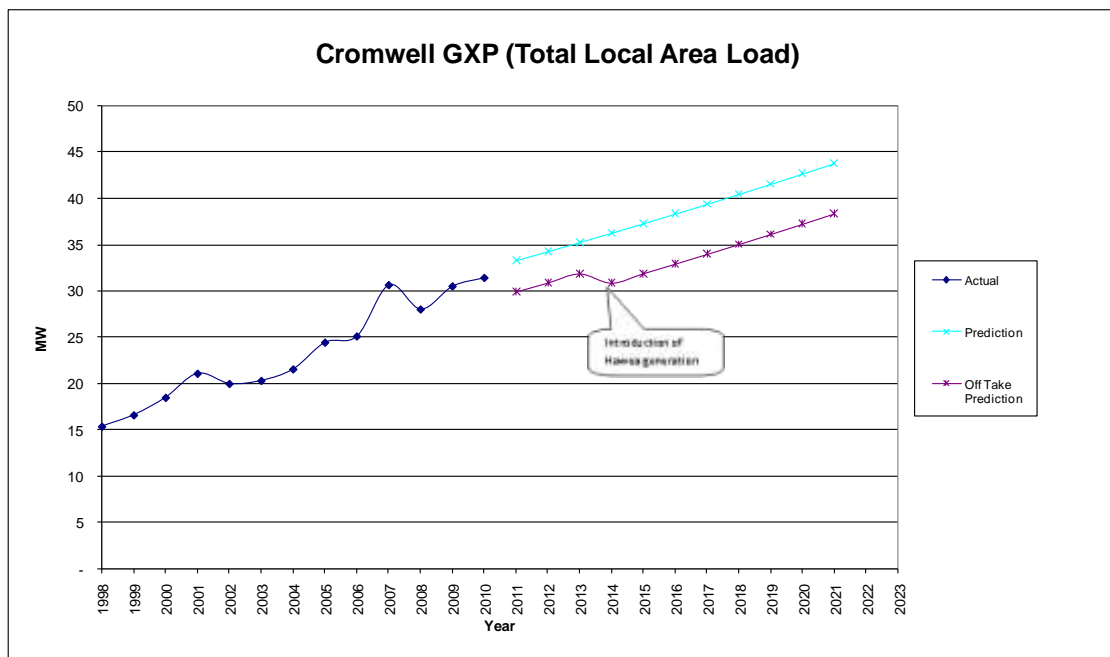


Figure 5.4 - Cromwell GXP 33 kV Load

5.9.4 Clyde GXP

The Clyde GXP has two 27 MVA transformers. The distributed generation on this GXP almost meets the total demand on the GXP. Should the distributed generation fail, the maximum demand on the GXP would be approximately 18 MVA. There is adequate GXP capacity at Clyde for the foreseeable future. Growth has averaged 1% per year since 2003, and is not expected to accelerate during the planning period. Pioneer Generation Ltd commissioned 2.2 MW of wind generation during 2009 adjacent to its Horseshoe Bend hydro station. The connection in late 2010 of the 2.1 MW Talla Burn generation and the 2 MW Kowhai generation in 2010 will continue to keep the off-take low.

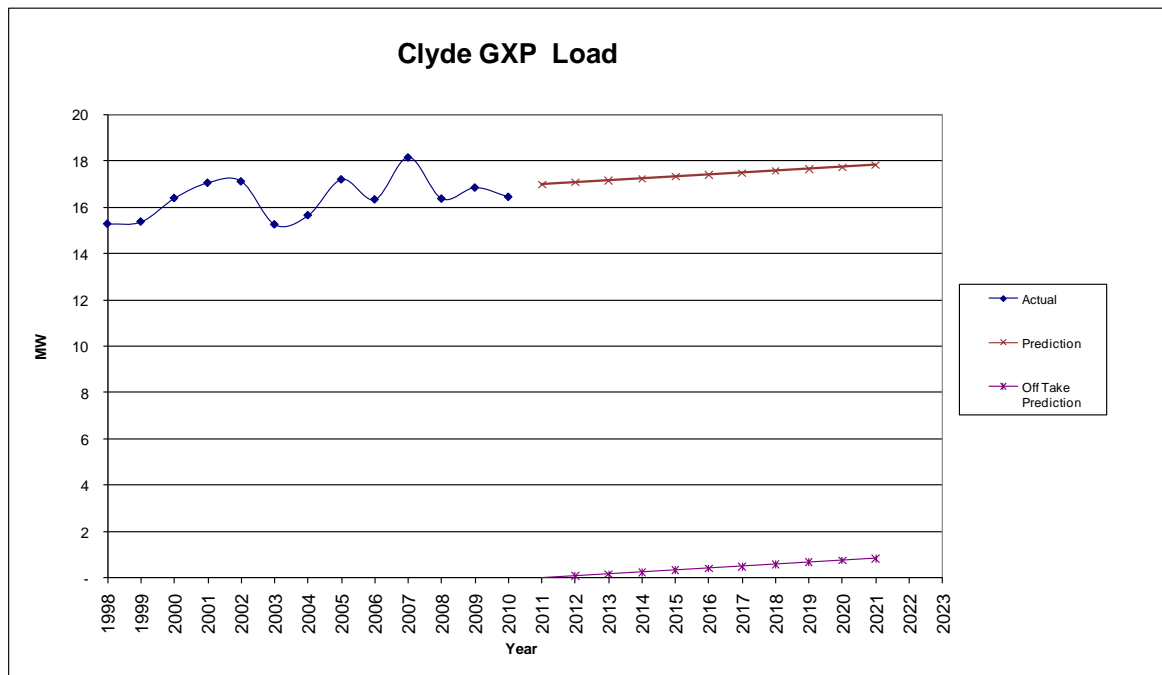


Figure 5.5 – Clyde GXP Load

5.9.5 Halfway Bush GXP

The off-take peak at Halfway Bush exceeds the 112 MVA post contingency rating. This is not of concern as, in the event of a failure of the Transpower 100 MVA transformer, TrustPower would be asked to increase its Waipori 33 kV generation, up to 44 MW, during peak periods. Also, up to 5 MW can be transferred to the South Dunedin GXP via the 6.6 kV network. A contingency plan has been prepared for this situation.

It is planned to move the Neville Street substation load to the South Dunedin GXP by May 2015, when the Neville Street gas cables are replaced. See Section 6.5.2. This would reduce the demand on Halfway Bush by approximately 15 MVA. See Figure 5.6 below.

The proposed connection of the 36 MW TrustPower Mahinerangi wind farm in 2011 is expected to assist in reducing the off-take on the Halfway Bush GXP.

Transpower plans to convert the remaining outdoor 33kV circuit breakers to indoor units in 2012. At this time, it may be desirable to have Transpower fit 33kV VTs to the Waipori lines which will eliminate the need for the outdoor VTs in the takeoff area.

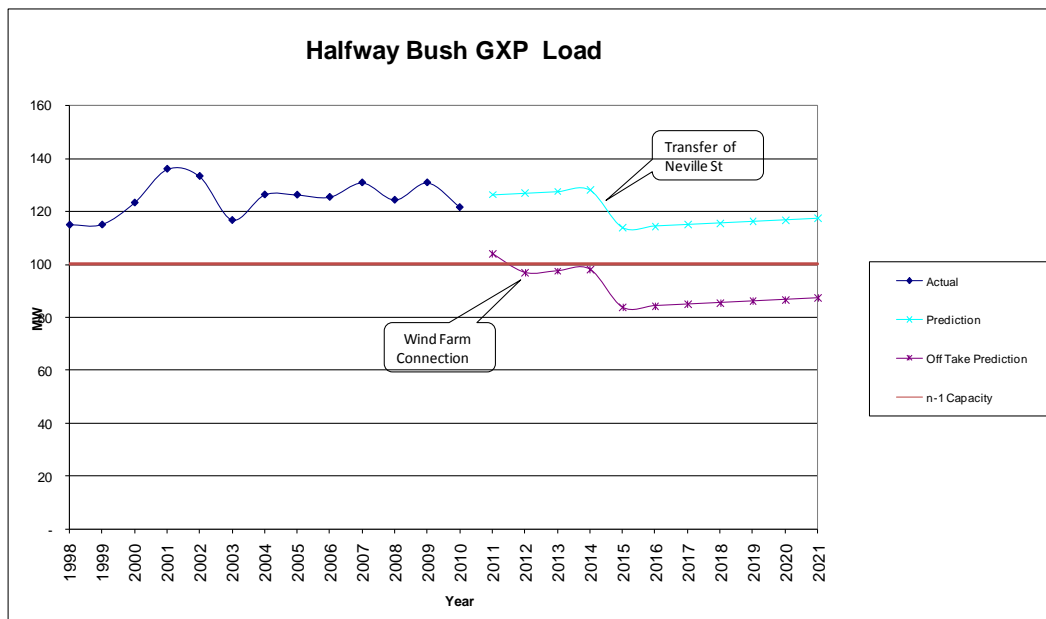


Figure 5.6 – Halfway Bush GXP Predicted Loads

5.9.6 South Dunedin GXP

The load prediction for the South Dunedin GXP is shown in Figure 5.7. The South Dunedin GXP has two 100 MVA transformers which have been assigned an 81 MVA limit by Transpower, due to metering accuracy limitations. The maximum peak demand on South Dunedin is 72 MVA (2009) and well under the 81 MVA limit but, when the Neville Street substation load is transferred to South Dunedin, as proposed in Section 6.5.4, the load will exceed 81 MVA. The work required to eliminate the constraint is to change the metering CT ratio from 1200/1 to 2400/1 and recalibrate the meters. Transpower has a metering upgrade planned, but the timing is uncertain; it is proposed to combine the CT ratio change with this project. Further upgrading work is not anticipated during the planning period.

Estimated Cost (Transpower)

Completion: TBA

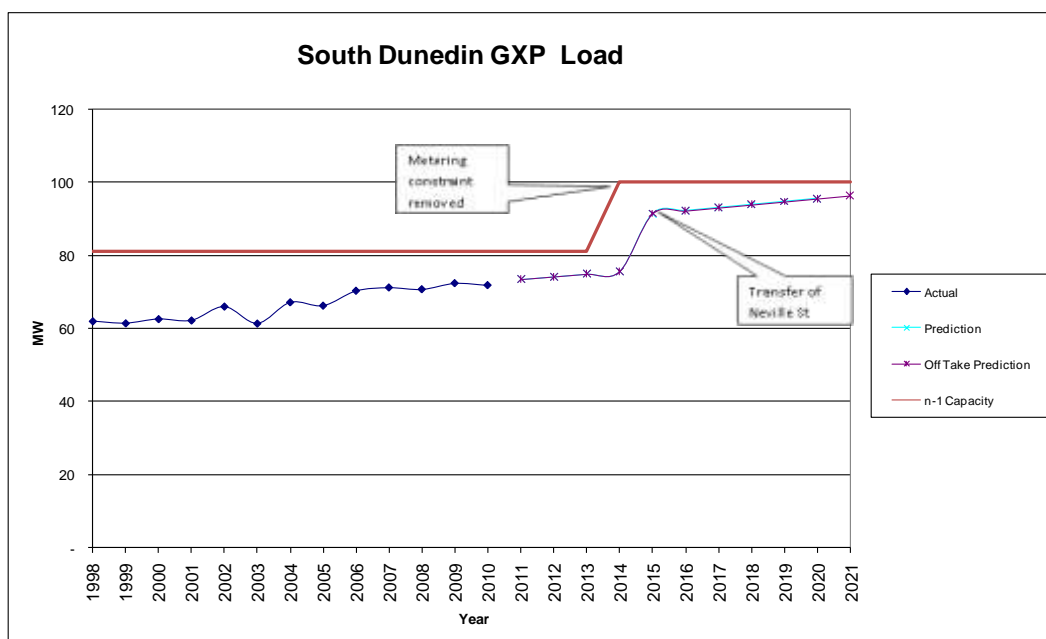


Figure 5.7 – South Dunedin GXP Predicted Loads

5.10 Subtransmission

This section provides details and discussion on subtransmission facilities that are expected to become constrained during the planning period and new anticipated subtransmission required for load growth or generation connections.

5.10.1 Wakatipu Basin 33 kV Ring

The Wakatipu Basin 33 kV ring supplies the Dalefield, Arrowtown, Coronet Peak and Remarkables substations and is run open at Arrowtown. The ring consists of Ferret and Mink conductor and short sections of cable. See Figure 5.8 for the configuration of the ring.

The Arrowtown peak load is predicted to reach the rating of the 70mm² cable (170 A 9.7 MVA) in 2017 and it is proposed that the cable is upgraded during the 2016/17 summer.

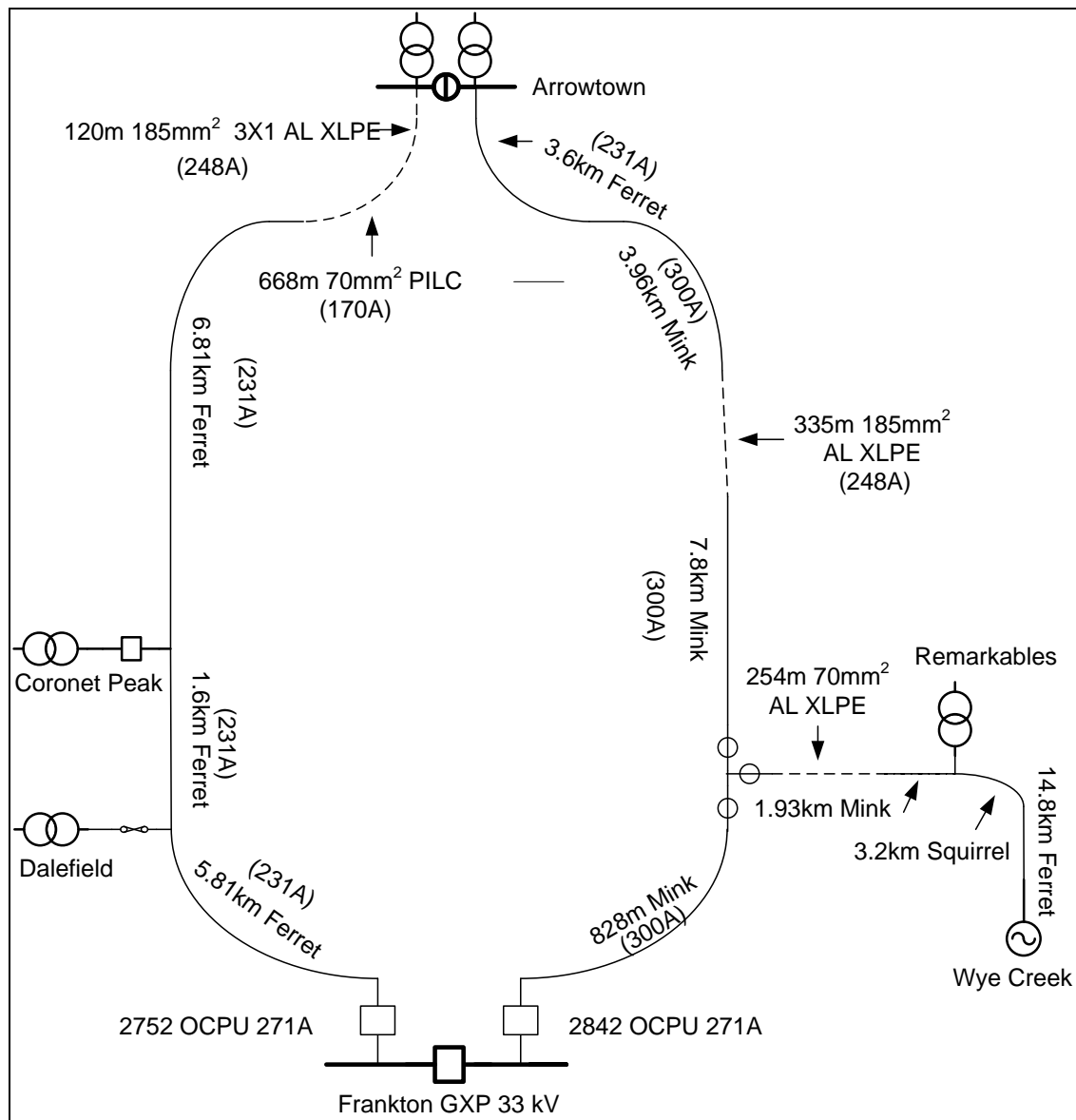


Figure 5.8 – Wakatipu Basin 33 kV Ring

The ring has a capacity of 22 MVA with all circuits in service. The present n-1 capacity of the ring is 13 MVA with the constraint being the winter rating of Ferret conductor. If the Ferret was upgraded, the constraint then becomes the rating of the 185mm² cable ⁵ (14.1 MVA). The ring load is predicted to exceed its n-1 capacity during the winter of 2011 for very short periods of time see Figure 5.14 for loading predictions

To improve the n-1 capacity of the ring requires either upgrading of the existing line conductors and cables or the installation of a third circuit into the area. Upgrading all the Ferret conductor to Mink only results in a 1.1 MVA increase in n-1 capacity. If the 185mm² cable was upgraded to the capacity of Mink conductor (17.1 MVA) then the n-1 capacity increases to 17.1 MVA. An upgrade of existing lines to Dog conductor increases the n-1 capacity to approximately 19 MVA. The introduction of a third 33 kV circuit increases the n-1 capacity to the present n capacity of 22 MVA. A third circuit and the upgrade to Dog conductor would increase the n-1 capacity to 31 MVA.

It will be economic, in terms of probabilities of loss of supply and the value of lost load, to augment the Arrow Ring once the peak load reaches a peak load of 15.6 MVA, which is predicted to be in the winter of 2019. The load would then be over the “n-1” rating of 13 MVA for 2.2% (193 hours) of the year. Predicted growth on the ring is less than historical growth due to the economic downturn and that a significant proportion of the recent growth has been due to additional snow making at Coronet Peak.

The chosen augmentation option should be designed and be ready to be constructed in the summer immediately following the reaching of this peak load.

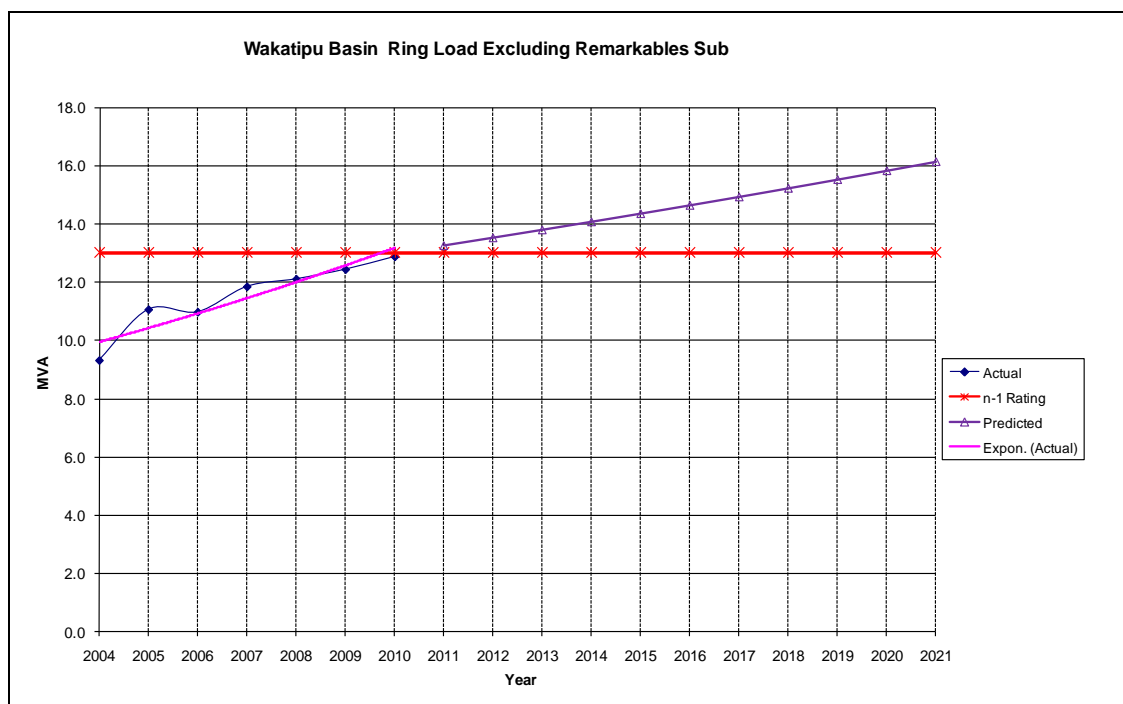


Figure 5.9 – Wakatipu Basin 33 kV Ring – Predicted Loading

Two options are considered for the installation of a third circuit. Both of these options require the installation of an additional 33kV feeder outlet from the Frankton GXP. This outlet will also serve the Jacks Point substation when it is commissioned, which is projected for 2019 as detailed in Section 5.10.2.

⁵ The winter rating of the 185mm cable was confirmed to be 248 Amps in Maunsell report of 25 Aug 2008.

Option 1 is to install an additional 33 kV circuit from the north bank of the Shotover River to Arrowtown. See Figure 5.10 for the proposed circuit route and Figure 5.11 for a single line diagram. The circuit would have 800m of cable at the Arrowtown end, 700m of cable at the Shotover end and 10 km of 33 kV overhead line. The line route is in the road reserve and mainly involves converting 11 kV line to 33/11 kV line.

Option 2 is to install a 33 kV circuit from the same source as option 1 but to run it to a new substation in the vicinity of the Coronet substation. See Figure 5.11 for the circuit route and Figure 5.13 for a single line diagram. The cable requirements for this option are similar to option 1, but only require 6 km of 33 kV line. The line route is also in the road reserve and mainly involves converting 11 kV line to 33/11 kV line.

Option 1 is preferred at present, but if the load on Dalefield or Coronet substations grows significantly, such that a new dual transformer substation is required in that area, then Option 2 could be the more economic solution.

A schedule of the projects associated with the Arrowtown ring is listed in the table below. If the third 33 kV circuit proposal is done before the 70mm² cable upgrade, then the cable upgrade could be deferred as the Arrowtown load will then be split over two circuits during an n-1 situation.

The third circuit project requires the installation of the additional Frankton GXP outlet for the Jacks Point, which is scheduled for completion in 2019 as detailed in Section 5.10.2.

Project Description	Estimated Cost \$000	Completion
Replace 668m of 70mm ² cable	\$300	May 2017
Install third 33 kV circuit	\$5,000	May 2019

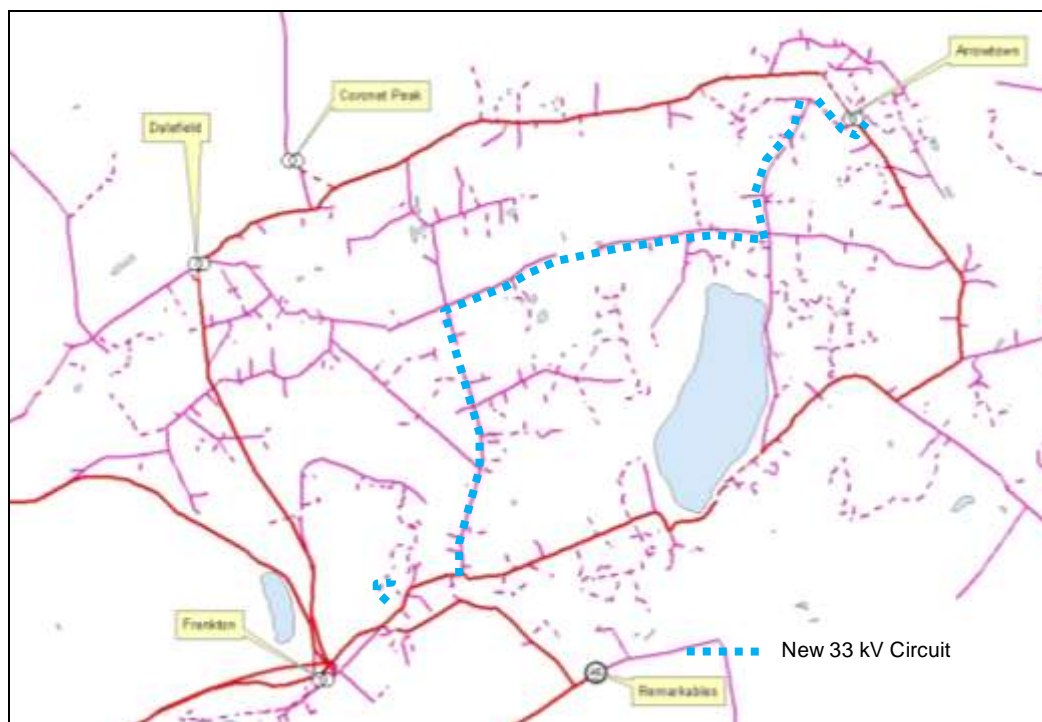


Figure 5.10 Wakatipu Ring Upgrade – Option 1 3rd Line to Arrowtown

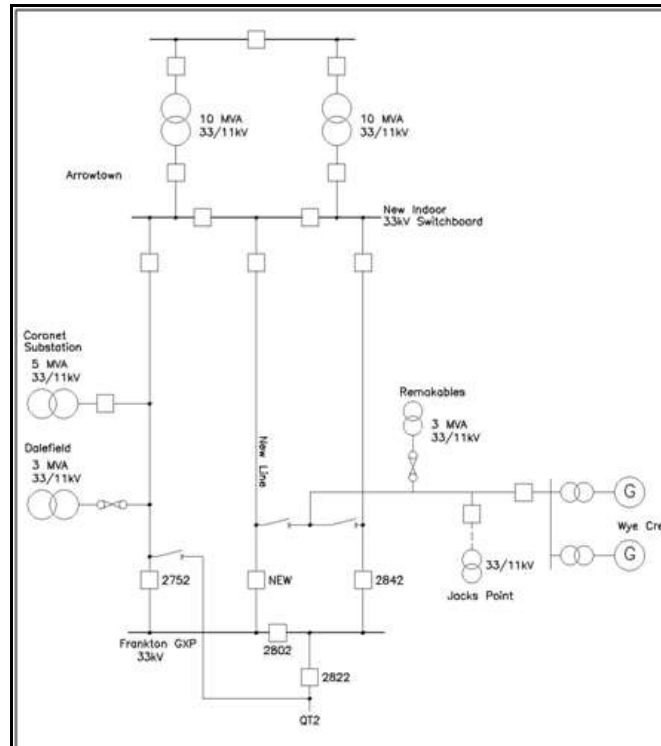


Figure 5.11 – Wakatipu 33 kV Ring upgrade – SLD Option 1

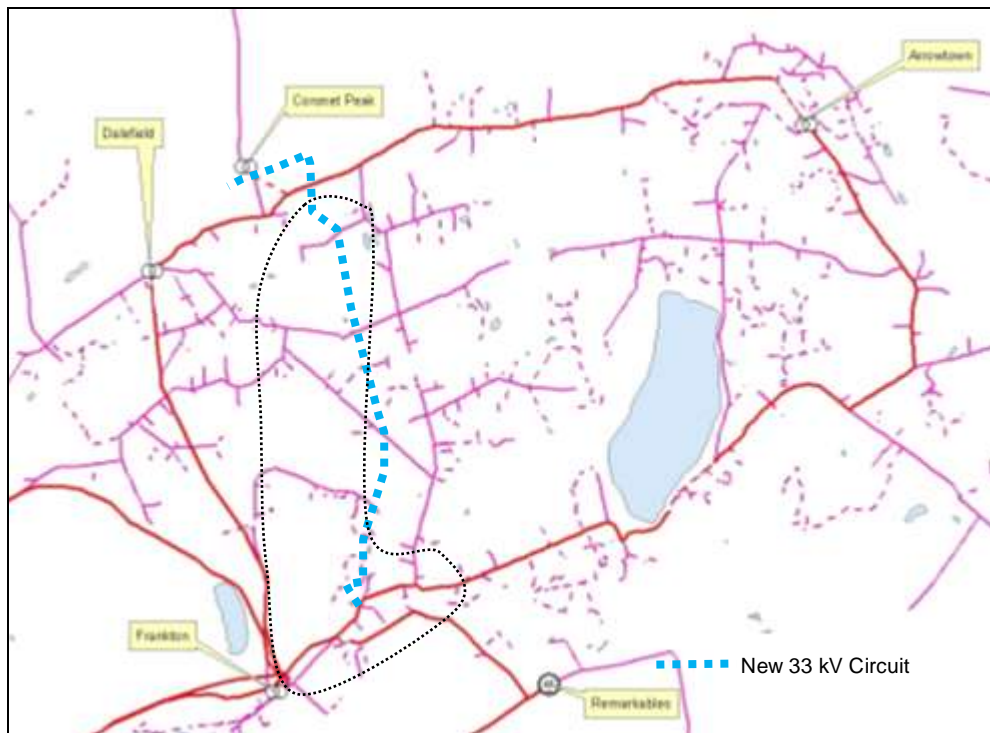


Figure 5.12 – Wakatipu Ring Upgrade – Option 2 Line to Coronet Peak

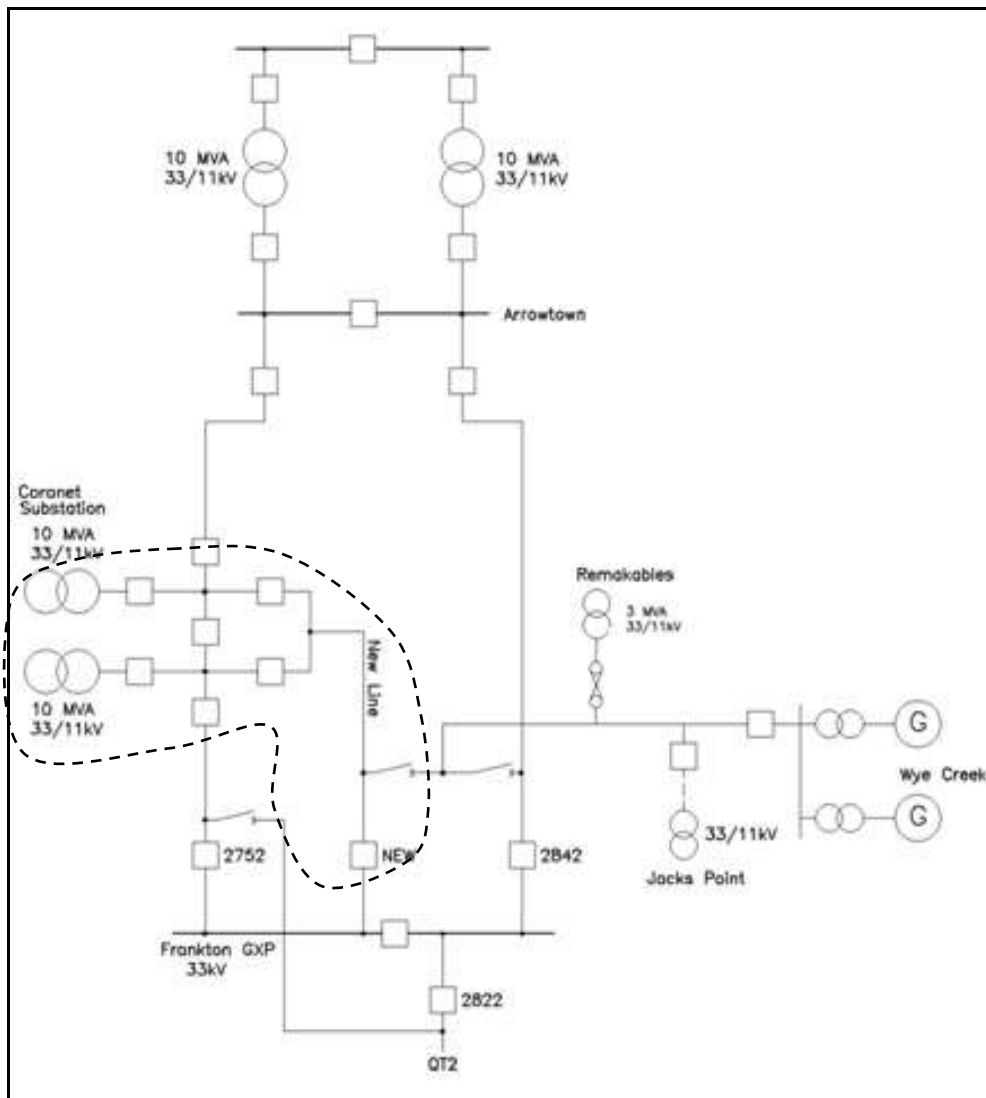


Figure 5.13 – Wakatipu 33 kV Ring Upgrade – SLD Option 2

5.10.2 New 33 kV Feeder to Supply Jacks Point and Remarkables

To meet load growth, it is proposed to install an additional 33 kV outlet from the Frankton GXP to supply the Remarkables and Jacks Point zone substations. See Figure 5.14 for the proposed configuration. The work required is:

- install an additional 33 kV circuit breaker at the Frankton GXP;
- install 33 kV cable from the GXP to Glenda Drive 1 km;
- install a 33 kV cable along Old School Road;
- install two 33 kV air break switches.

Estimated Cost included in Section 5.10.1

Completion: May 2019

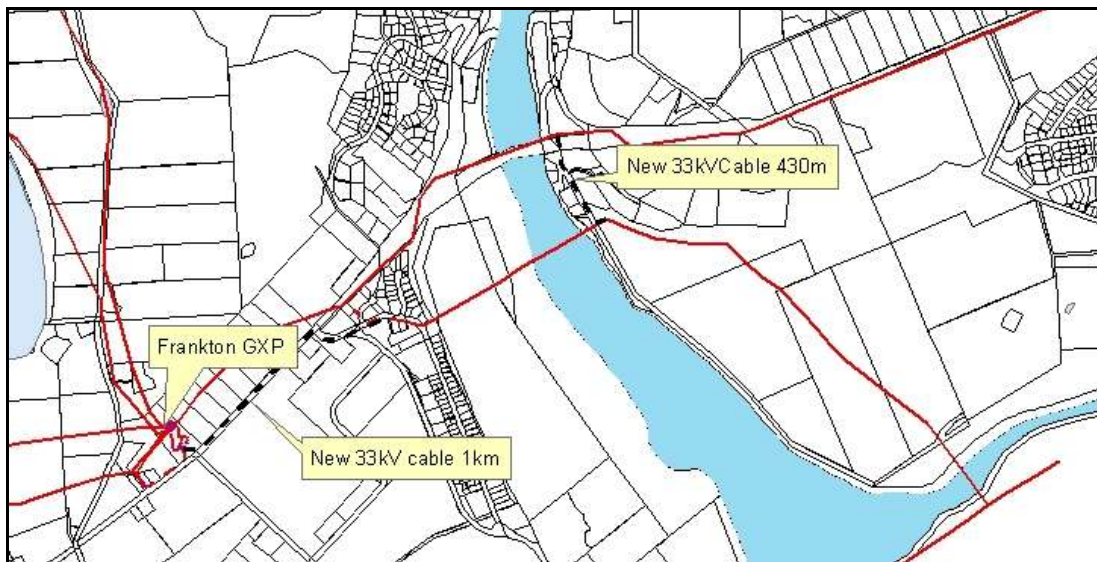


Figure 5.14 – Configuration of Network for new Jack's Point + Remarkables Feeder

5.10.3 Upper Clutha 66 kV

The Upper Clutha area is supplied from the Transpower Cromwell GXP at 66 kV. See Figure 5.15 for a single line diagram of the existing subtransmission system. The 66 kV is derived from two 30 MVA 33/66 kV auto-transformers adjacent to the Transpower Cromwell 33 kV switchyard. The Wanaka transformers are three winding units 66/33/11 kV rated at 30/10/24 MVA. Maungawera is supplied at 33 kV from Wanaka. The Queensberry transformer is connected to either of the 66 kV lines and the Queensberry 66 kV bus is only closed while transferring the transformer from one line to the other. The 66 kV lines from Cromwell to Wanaka have Dog conductor with summer/winter ratings of 266/374 Amps.

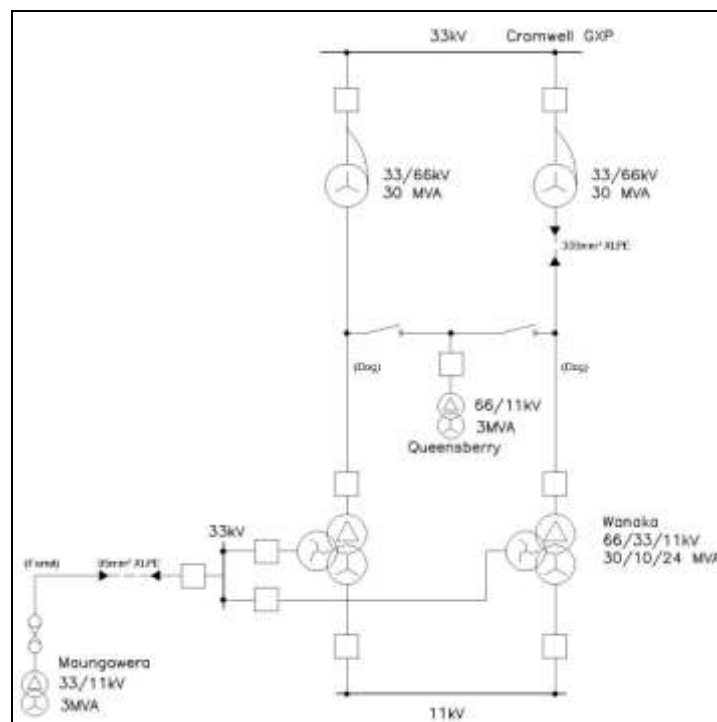


Figure 5.15 – Single Line Diagram of Existing Upper Clutha Subtransmission

A single line diagram of the proposed long term configuration is shown in Figure 5.17 and a geographic layout in Figure 5.16. Progress towards this configuration will depend on load growth rates and the installation of generation.

It is planned to establish a 66 kV substation in Riverbank Road and a 66 kV ring circuit from Queensberry to Riverbank Road via Hawea. The Cardrona substation is scheduled to be commissioned in April 2011 and will initially be supplied at 33 kV and be converted to 66 kV when the Riverbank Road substation is commissioned.

The need to upgrade the supply to Hawea is driven by three factors which are: the loading on the Maungawera substation, the conversion of the Maungawera 33 kV line to 66 kV to accommodate a future North Wanaka substation and the provision of a 66 kV connection for the proposed Hawea generation. Each of these drivers is discussed below. At present, the main driver is the connection of the Hawea generation.

Previous predictions were for the Maungawera substation to be fully loaded in 2012, but reconfiguration of the 11 kV network in late 2007, resulted in a larger load transfer than expected and it is now predicted Maungawera will not be fully loaded until beyond 2021. See Section 5.11.14 for Maungawera loading details.

The Hawea generation is currently on hold by Contact, but for planning purposes, it is assumed it will be commissioned in 2014. See Section 5.10.7 for details on proposed connection arrangement.

The future North Wanaka substation is not likely to proceed during the planning period. It is proposed that loading on the Wanaka zone substation be relieved by the installation of transformers at the proposed Riverbank Road substation, see Section 5.11.13. It is recommended land for the substation be purchased well in advance of being required if offered by a willing seller.

Continued load growth will cause the capacity of the existing Upper Clutha 66 kV network to face the following constraints:

- ability to maintain 11 kV target volts in the Wanaka area;
- rating of Cromwell 33/66 kV auto transformers;
- rating of the 66 kV Dog conductor;
- firm 33 kV capacity at the Cromwell GXP.

Works that would reduce these anticipated future constraints are:

- installation of 66kV bus at Riverbank Road that enables the Wanaka transformers to operate in parallel when one 66kV line is out of service which reduces volt drop;
- installation of a 66 kV bus and extra auto transformer at Cromwell that will prevent overloading an auto transformer when one line is out of service;
- installation of 66 kV bus at Queensberry which will reduce the volt drop when one line is out of service;
- establishment of GXP at Queensberry and the completion of the Riverbank Road to Queensberry line via Hawea.

An upgrade plan has been prepared, as detailed in Table 5-14, assuming no support from the Hawea generation. Water flow ramp rate restrictions on the generation means there is no guarantee of significant generation being available during an Upper Clutha 66 kV line outage or even for normal network peak demands. In Table 5-14, the predicted Upper Clutha load is presented and the available capacity of the Upper Clutha network at each upgrade stage. It is current practice for Aurora to take some risk and allow loads to exceed the n-1 capacity for a short time before upgrades are completed. The Upper Clutha load has a relatively low load factor with the highest peaks only occurring for the few hours each year. A schedule of the required upgrade projects with estimated costs is presented Table 5-15. The long term proposal to establish a GXP at Queensberry would be very expensive and is expected to exceed \$30M. This would be installed by Transpower and funded by Aurora via a new investment agreement. The application of demand side management could be an acceptable solution to Wanaka consumers to assist in the deferment of this large capital investment and the consequential impact on line charges. The future development of either of the proposed Luggate or Queensberry hydro generation would allow the cost of transmission upgrades in the area to be shared with other parties. An alternative is to establish a 110kV bus at Cromwell and construct a double circuit 110kV line from Cromwell to Queensberry along the East side of the valley to supply two 110/66kV transformers

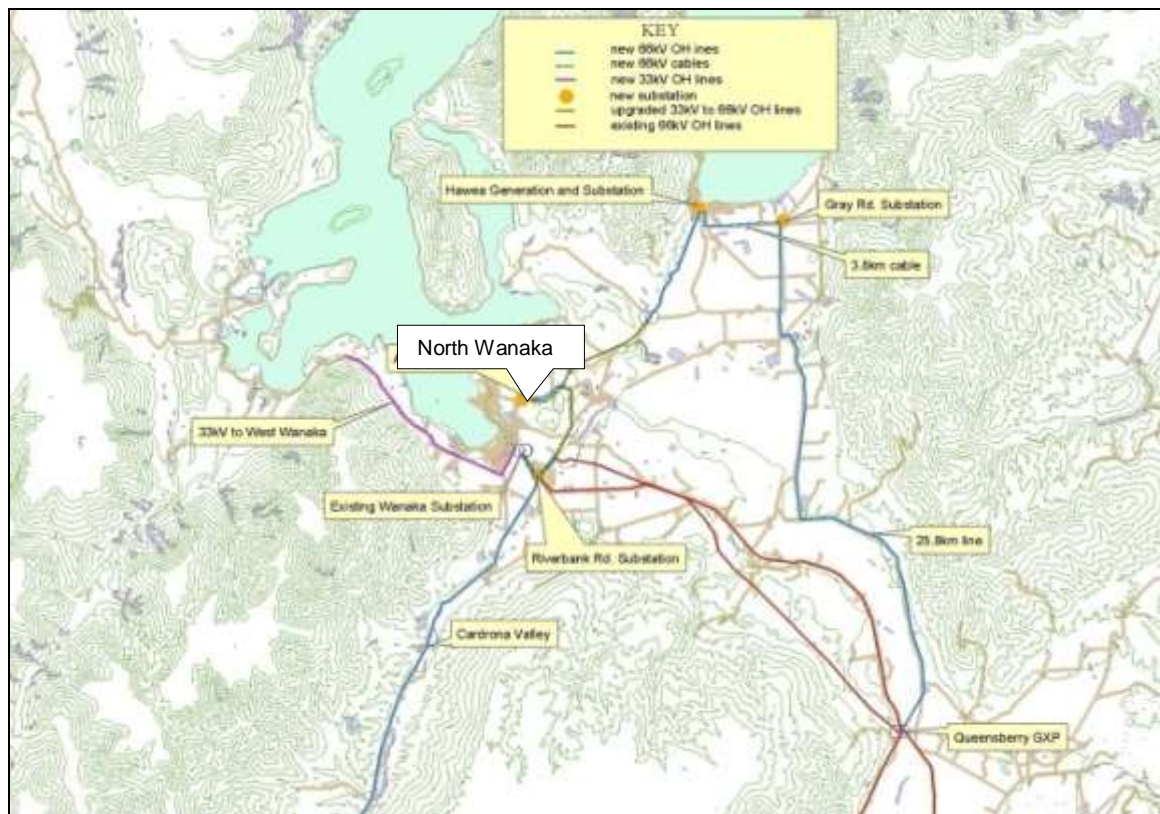


Figure 5.16 – Geographic Layout of Upper Clutha Long Term Subtransmission

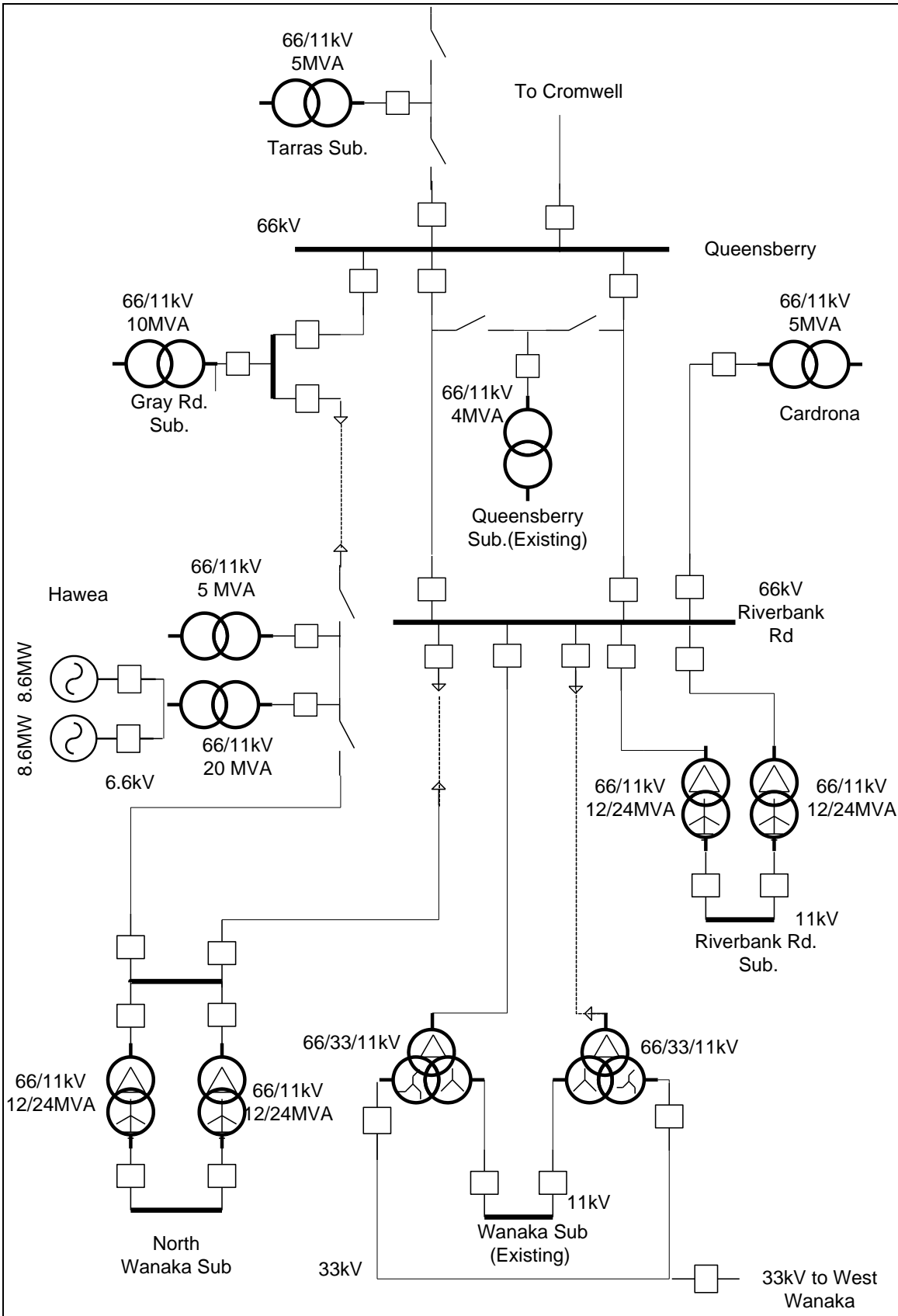


Figure 5.17 — Single Line Diagram of Long Term Upper Clutha Subtransmission

Year	Predicted UC Load MVA	Description of Works	UC Network n-1 Capacity MVA	n-1 Capacity Minus Predicted Load
2011	25.7		25	-0.7
2012	26.8		25	-1.8
2013	28.0		25	-3.0
2014	29.1	Riverbank Road switching station installed	29	-0.1
2015	30.3		29	-1.3
2016	31.5		29	-2.5
2017	32.7		29	-3.7
2018	34.0	Establish 66kV bus at Cromwell	33	-1.0
2019	35.3		33	-2.3
2020	36.9		33	-3.9
2021	38.6	Establish 66kV bus at Queensberry	36	-2.6

Table 5-14 – Schedule of Works to Maintain Upper Clutha Transmission Capacity

Project Details	Project No	Estimated \$000	Completion
Obtain land and designation for Riverbank Road switching station	2969	175	Dec 2011
66 kV transmission to Hawea	2514	3,500	March 2014
Construct Hawea substation with generation connection	2798	3,500	May 2014
Construct Riverbank Road switching station	3022	4,000	May 2014
Install 66 kV cables Riverbank Road to Wanaka and Riverbank Road to UC1	3216	2,500	May 2014
Establish 66 kV bus at Cromwell + third auto transformer	3021	2,000	May 2018
Install transformer and 11kV switchgear at Riverbank Road substation	3437	2,500	May 2019
Create 66 kV bus at Queensberry	3438	3,000	March 2021

Table 5-15 – Upper Clutha 66 kV Subtransmission Project Schedule

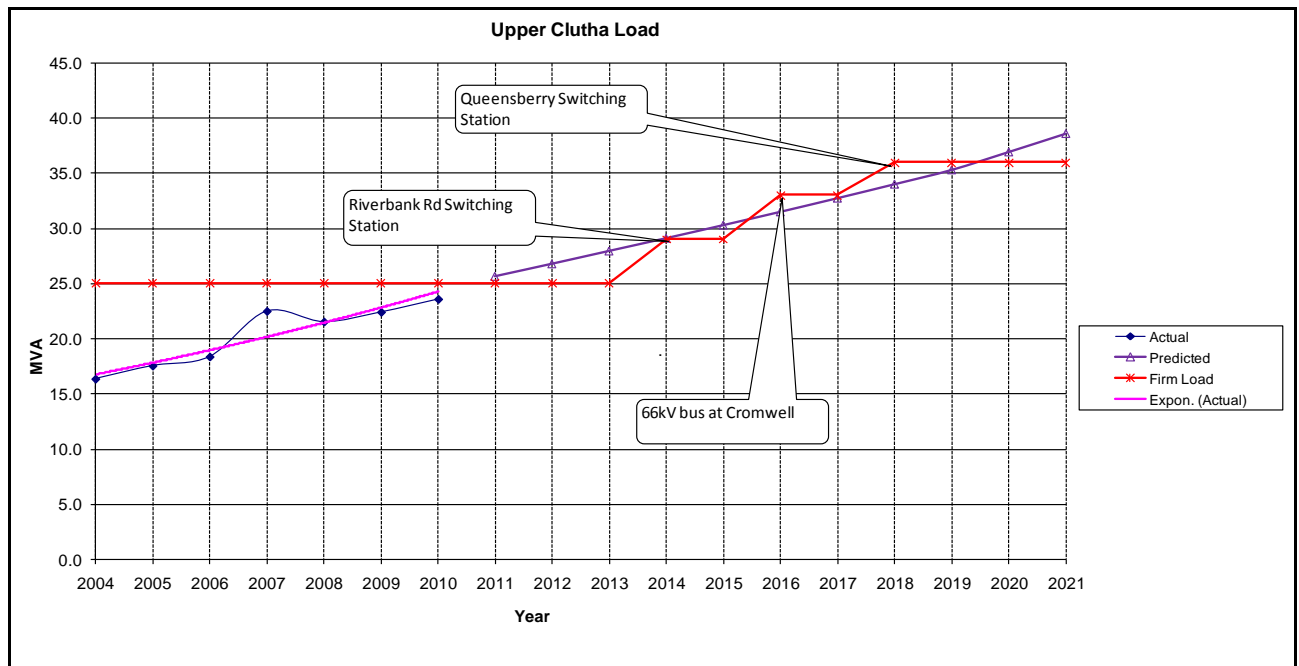


Figure 5.18 – Upper Clutha Load Projection

5.10.4 Alexandra to Roxburgh

There are two 33 kV lines between Roxburgh and Alexandra. These lines consist of both Dog and Jaguar conductor. The maximum load on these lines is driven by generation. With the commissioning of the Pioneer wind turbines at Horseshoe Bend (1.2MW), the Talla Burn (1.9 MW) and Kowhai (2 MW) generation there may be times when the total load being carried on these lines will exceed the summer rating of a single circuit Dog line (226A, 12.9 MVA). It is proposed to manage this constraint by requesting a reduction in generation output, if necessary, when one line is out of service.

There is now no capacity for additional generation to be connected to the Roxburgh 33kV bus due to the operating voltage being at the maximum Aurora's zone substations in the area can tolerate.

5.10.5 Taieri Subtransmission

The "A" and "B" lines are rated at 300 Amps (17 MVA) while the "C" line is rated at 440 Amps (25 MVA). The recent loss of major industrial load means that now under an 'n-2' contingency situation resulting in the loss of "C" line and no generation available from Waipori, the Taieri load can still be supplied via "A" and "B" lines.

The Mosgiel No 3 lateral is only rated at 360 Amps (20 MVA). The other laterals are rated in excess of 500 Amps. The 360 Amp rating means that should the lateral be required to carry the combined Mosgiel and East Taieri loads, its rating could be exceeded. At present, the Lateral 3 constraint could be avoided by dedicating Lateral 3 to supply East Taieri, Lateral 2 to supply Mosgiel thus making Lateral 1 the standby lateral. This project would require some strung bus modifications at Mosgiel plus protection and control modifications. Further investigation is required to determine if this project is economic.

TrustPower is connecting 36 MW of wind generation to the Waipori 2A 33 kV bus. The generators are expected to progressively come on line during 2011. TrustPower will manage the mix of wind and hydro generation to keep the loading on the Taieri subtransmission within the limits of the conductors. Facilities are being provided to automatically reduce generation if a line should trip when the system is highly loaded.

To accommodate the wind generation, TrustPower is installing 15KVAR of 33kV capacitors at the Aurora substation to improve load sharing between the A, B and C lines and to ensure the power factor at the Halfway Bush GXP is not made worse by the introduction of the generation.

5.10.6 Cardrona Valley

A project has been approved by the Aurora Board to install 66 kV subtransmission up the Cardrona Valley to a new zone substation. The project was scheduled for construction during the 2009/10 summer but delays in obtaining resource consent have delayed the project until the 2010/11 summer.

Estimated Cost \$ 3.5 million

Completion: April 2011

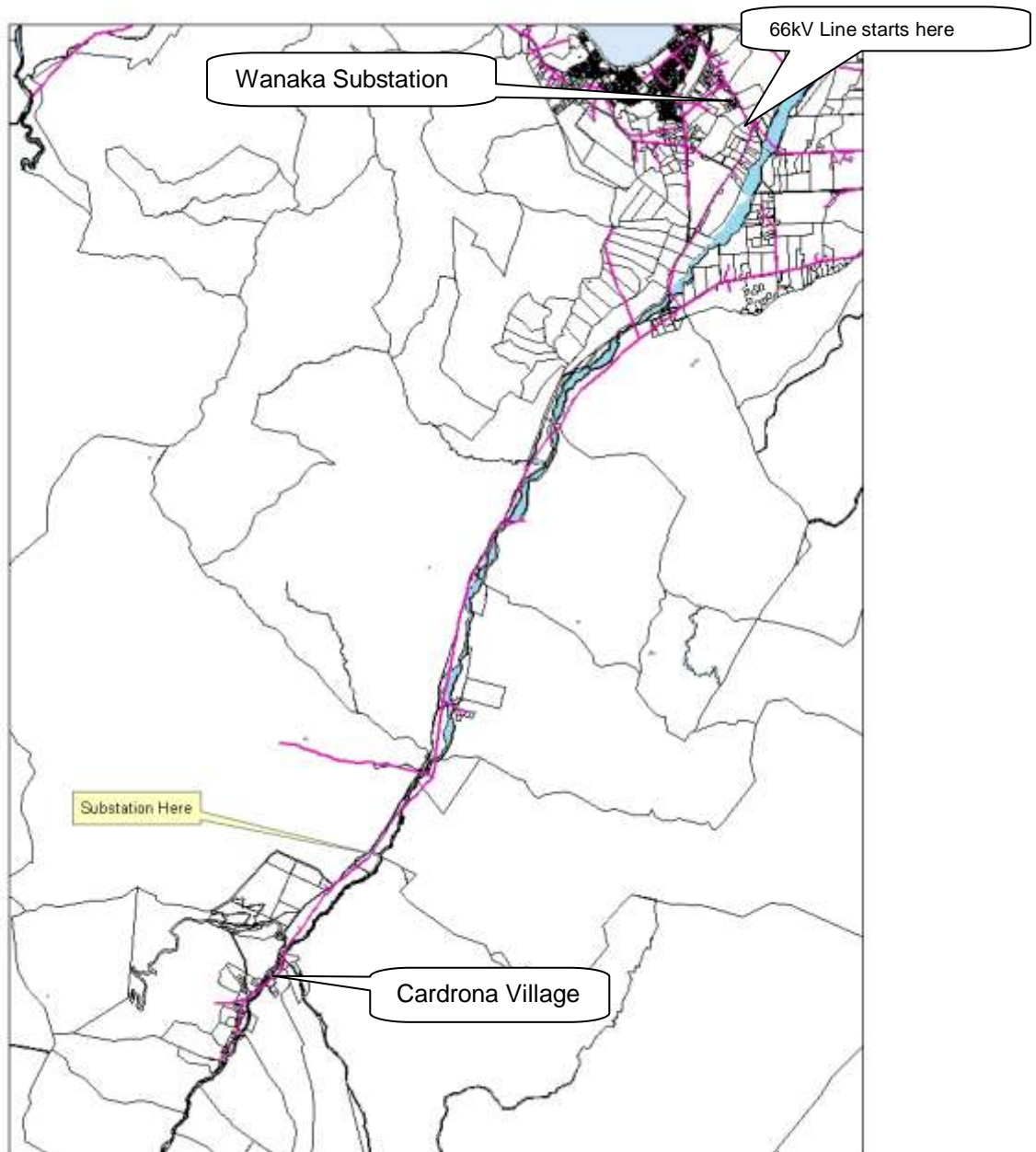


Figure 5.19 – Location of Cardrona 66/11 kV Line

5.10.8 **West Wanaka and Treble Cone**

The Treble Cone ski field have proposed to install a gondola that would require an all-year capacity of 1 MW. This project is in abeyance but other development proposals in the area could increase the load on the Wanaka 11 kV feeder 2754 beyond its ability to maintain statutory voltage limits. When this occurs it is proposed to extend the 33 kV subtransmission towards Treble Cone and install the appropriate 33/11 kV zone substations.

This project has not been scheduled due to the uncertain nature of the load growth in the area.

Estimated cost \$6.93 million

Completion: on hold

5.10.9 **Nevis Power Scheme**

Pioneer Generation Ltd is investigating installing a 40 MW hydro generation station on the Nevis River and has enquired about options for connecting this generation to the Aurora network. The Aurora network cannot accommodate the generation without significant upgrading. Indicative costs have been given to Pioneer which also has the option of connecting to the nearby Transpower 110 kV lines. This project is the subject of appeal.

This issue needs to be resolved before the project can proceed. No expenditure provision has been made for the connection of this generation and its output is not considered in load predictions.

5.10.10 **Dairy Creek Irrigation Project**

There is a proposal to establish an irrigation scheme that will pump water from Lake Dunstan at Dairy Creek just above the Clyde Dam. The scope of this project has expanded and could require up to 9 MW of primary pumping plus additional on-farm load.

A preliminary proposal is for the load to be supplied via two new zone substations one close to Clyde (2 X 10 MVA) and the other close to the north end of Springvale road (5 MVA). The Clyde substation can be supplied from the existing Clyde to Alexandra 33 kV lines and the Springvale Road Substation from the Omakau line. It is expected significant upgrades would be required to the HV distribution network in the area including upgrading 6.6 kV circuits to 11 kV.

No expenditure provision has been to accommodate this load and it is not included in network load predictions due to the uncertain nature of the project but if it proceeds between \$10 million and \$15 million could be required.

Estimated cost \$10 to \$15 million

Completion: on hold

5.11 **Zone Substations**

In this section demand projections for all zone substations are presented and this is followed by details of projects anticipated during the planning period to resolve zone substation capacity constraints.

5.11.1 **Demand Projections**

The historical and predicted demands for all zone substations are shown on Table 5-16. The following notes relate to the interpretation of this information.

The n-1 capacity is the maximum load a substation can supply in the event of the failure of any one item of substation equipment without the need to transfer any load from the substation. The firm capacity is the maximum load a substation can carry with the largest transformer out of service and up to 6 MVA of load transfer to adjacent substations. It would generally take at least an hour to transfer load from the zone substation. During this hour the in service transformer and associated equipment must be capable of carrying the allocated firm capacity. Where the load limitation is HV switchgear that has no overload capability the firm load can be restricted to the same as the n-1 load.

Predicted future demands are shown with a shaded background when they exceed the firm capacity of the substation and these act as a “flag” for closer study. Zone substations with a capacity of 5 MVA or less are not designed with n-1 security. The mobile substation or spare transformers provide cover.

When new substations are commissioned there will be a reduction in load of the substation that is presently supplying the load. This is taken into account in future demand predictions.

Table 5-16 – Zone Substation Historical and Predicted Demands

Zone Substation	Transformer MVA	Firm Load MVA	n-1	Historical Loads MVA							Previous Growth (Exp) %/yr	Predictions		Predicted Demands Between Exp and Linear MVA												
				2004	2005	2006	2007	2008	2009	2010		Exponential Growth %/yr	Linear Growth MVA/yr	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		
Alexandra	7.5/15+7.5/15	15	15	10.4	10.8	10.9	12.4	11.4	11.9	11.6	2.00%	1.5%	0.17	12.2	12.4	12.5	12.7	12.9	13.1	13.3	13.5	13.6	13.8	14.0		
Anderson's Bay	15 + 15	18	18	15.3	14.6	14.9	16.6	15.7	17.1	15.3	1.32%	1.0%	0.15	16.4	16.6	16.7	16.9	17.1	17.2	17.4	17.5	17.7	17.9	18.0		
Arrowtown	5 + 5	7.5	6	6.3	6.4	7.2	7.7	7.3	7.6	7.9	3.81%	3.5%	0.28	8.3	8.6	8.9	9.2	9.5	9.8	10.1	10.4	10.7	11.1	11.4		
Berwick	3	3.6	0	1.1	1.1	1.1	1.2	1.3	1.2	1.3	3.00%	1.0%	0.01	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4		
Clyde/Earnsclough	4 +2	4.8	4	3.6	3.6	3.7	4.0	4.1	4.1	4.1	2.82%	1.0%	0.04	4.3	4.3	4.3	4.4	4.4	4.5	4.5	4.6	4.6	4.6	4.7		
Coronet Peak	5	6	0	3.0	4.4	3.6	3.6	4.5	4.6	4.6	13.20%	0.0%	0.00	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6		
Corstorphine	12/24 + 12/24	23	23	13.1	12.5	12.8	13.8	12.5	14.3	13.2	1.82%	1.0%	0.13	13.8	13.9	14.0	14.2	14.3	14.4	14.6	14.7	14.9	15.0	15.1		
Cromwell	5/10 + 7.5	9.0	9.0	7.1	6.8	7.9	9.2	9.2	9.8	10.0	7.06%	3.7%	0.36	10.7	11.1	11.5	11.9	12.3	12.7	13.1	13.5	14.0	14.4	14.9		
Dalefield	3	3.6	0	1.4	1.9	1.8	2.3	2.1	2.1	2.3	3.79%	3.0%	0.06	2.3	2.4	2.5	2.5	2.6	2.7	2.7	2.8	2.9	3.0	3.0		
Earnsclough	2	Used to increase Clyde/Earnsclough firm capacity to 4.8MVA													0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
East Taieri	12/24 + 12/24	See Text	18.5	14.2	14.9	15.7	15.7	15.5	16.7	15.8	1.96%	2.0%	0.29	16.7	17.0	17.3	17.6	18.0	18.3	18.6	18.9	19.3	19.6	20.0		
Etrick	3	3.6	0	1.8	2	1.5	2.0	1.8	2.1	2.0	2.28%	0.5%	0.00	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1		
Frankton	7.5/15 +7.5/10	12	10	8.0	9.0	10.4	12.0	13.2	13.9	12.1	8.76%	3.0%	0.36	12.5	12.8	13.2	13.6	14.0	14.4	14.8	15.2	13.6	14.0	14.4		
Fernhill	7.5/10+7.5/10	10	10	5.2	5.4	5.6	6.1	6.2	5.9	5.8	2.25%	1.5%	0.09	6.2	6.3	6.4	6.5	6.6	6.7	6.8	6.9	7.0	7.1	7.2		
Green Island	15 + 15	18	18	13.6	13.8	14.0	14.2	13.8	13.7	13.4	-0.27%	0.0%	0.00	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7		
Halfway Bush	15 + 15	18	18	12.3	13.1	13.6	14.2	13.8	14.5	14.6	2.66%	1.0%	0.15	15.0	15.1	15.3	15.4	15.6	15.7	15.9	16.0	16.2	16.3	16.5		
Kaikorai Val.	12/24 + 12/24	23	22	10.0	11.9	10.3	10.4	9.9	10.2	9.2	-2.05%	2.0%	-0.22	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6		
Maungawera/Hawea	3	3.6	0	2.2	2.3	2.5	3.2	2.1	2.2	2.3	2.69%	3.0%	0.07	2.4	2.4	2.5	2.6	2.7	2.7	2.8	2.9	3.0	3.0	3.1		
Mosgiel	10 + 10	14	12	11.6	11.8	12.2	12.0	12.0	9.3	7.6	-6.02%	0.8%	0.06	8.6	8.7	8.7	8.8	8.9	8.9	9.0	9.0	9.1	9.2	9.2		
Neville St	15 + 15	18	18	13.6	13.9	14.4	14.9	13.3	14.8	13.4	-0.04%	0.0%	0.00	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0		
North City	14/28 +14/28	28	28	20.4	19.8	20.2	20.7	20.3	19.7	19.0	-0.82%	0.5%	0.10	19.6	19.7	19.8	19.9	20.0	20.1	20.2	20.3	20.4	20.5	20.6		
North East Val.	9/18 +12/18	23	18	11.4	10.8	10.8	11.0	10.9	11.8	11.2	0.44%	0.5%	0.05	11.3	11.4	11.4	11.5	11.5	11.6	11.6	11.7	11.8	11.8	11.9		
Omakau	3	3.6	0	1.5	1.6	1.6	1.8	1.8	2.0	2.1	5.79%	4.0%	0.08	2.2	2.2	2.3	2.4	2.5	2.6	2.7	2.8	2.9	3.0	3.1		
Outram	3 + 3	5.6	3.6	2.6	2.6	2.9	2.8	2.7	2.8	2.9	1.38%	1.0%	0.03	2.9	2.9	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.2	3.2		
Port Chalmers	7.5 +7.5	10	9	7.9	8.1	7.9	8.3	7.5	7.9	7.5	-0.96%	0.0%	0.00	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6		
Queensberry	3	3.3	0	1.4	1.6	1.9	1.7	1.8	1.4	2.4	4.83%	3.0%	0.06	2.5	2.6	2.6	2.7	2.8	2.8	2.9	3.0	3.1	3.1	3.2		
Queenstown	10/20 +10/20	22	20	20.4	18.3	20.2	22.8	22.1	21.3	14.7	No	2.0%	0.29	15.0	15.3	15.6	15.9	16.2	16.5	16.8	17.1	17.5	17.8	18.1		
Remarkables	3	3.6	0	0.8	0.7	0.8	0.8	0.8	0.8	0.8	1.48%	Manual Prediction		0.8	2.6	3.4	3.5	3.5	4.8	4.8	4.8	4.8	4.8	4.8		
Roxburgh	1.5 +1.5	3.6	1.8	1.7	2.3	2.5	2.5	2.2	2.8	2.8	6.34%	0.5%	0.01	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0		
Smith St	15 + 15	18	18	18.1	18.1	16.5	16.9	16.1	16.8	15.8	-2.07%	1.0%	0.15	16.0	16.1	16.3	16.5	16.6	16.8	16.9	17.1	17.3	17.4	17.6		
South City	9/18 +9/18	18	18	13.6	14.3	15.4	15.7	15.3	15.8	15.0	1.73%	1.0%	0.20	15.9	16.1	16.3	16.5	16.7	16.9	17.0	17.2	17.4	17.6	17.8		
St Kilda	12/24 + 12/24	23	23	15.1	15.2	15.4	16.3	15.6	15.7	15.3	0.37%	0.4%	0.06	15.7	15.8	15.9	15.9	16.0	16.0	16.1	16.1	16.2	16.3	16.3		
Wanaka	12/24 +12/24	24	24	13.6	14.6	15.1	18.6	18.7	19.6	20.3	7.43%	4.6%	0.93	20.3	21.3	22.2	23.2	24.2	25.2	26.3	27.4	20.5	21.5	22.4		
Ward St	12/24 +12/24	18	24	10.9	10.6	11.6	11.3	11.4	12.5	11.9	2.07%	2.0%	0.25	12.4	12.7	12.9	13.2	13.4	13.7	13.9	14.2	14.5	14.7	15.0		
Willowbank	15 + 15	18	18	13.7	13.7	12.8	12.7	12.5	13.7	12.2	-1.31%	0.0%	0.00	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5		
Commonage	14/17 +14/17	23	17							9.8		2.0%	0.20	10.0	10.2	10.4	10.6	10.8	11.0	11.2	11.4	11.6	11.9	12.1		
Cardrona	5	5										5.0%	0.10	2.0	2.1	2.2	2.3	2.3	2.4	2.5	2.6	2.6	2.7	2.8		
Jacks Point *	7.5/10	10	0			0.54	0.56	0.62	0.68	0.69	3.41%	10.0%	0.20							0.0	0.0	2.0	2.2	2.4		
Riverbank Rd	12/24 +12/24	24	24									4.6%	0.38							0.0	0.0	8.0	8.4	8.8		
MG + ET (Merged 1/2hr data)			30.8	30.8	25.05	26	27.25	26.5	26.46	23.52	23.1	0.00%	2%	0.5	24.1	24.5	25.0	25.5	26.0	26.5	27.0	27.5	28.0	28.5	29.0	
* Jacks Point actual load is included in Frankton																										
Subtransmission																										
	Diversity																									
QT Sub TX	0.98	40		25.1	23.2	25.3	28.3	27.7	26.7	29.7				30.6	31.2	31.7	32.3	32.9	33.5	34.1	34.7	35.3	36.0	36.6		
Arrowtown Ring (EX RM Sub)	0.87	13		9.3	11.0	11.0	11.8	12.1	12.4	12.9				13.3	13.6	13.9	14.2	14.5	14.9	15.2	15.5	15.9	16.2	16.6		
Upper Clutha		25		16.4	17.5	18.4	22.5	21.5	22.4	23.6				25.7	26.8	28.0	29.1	30.3	31.5	32.8	34.0	35.3	36.8	38.4		
Port Chalmers	0.9	27		17.4	17.0	16.8	17.4	16.6	17.7	16.8				17.1	17.1	17.2	17.2	17.3	17.3	17.4	17.4	17.5	17.5	17.6		

5.11.2 Mobile Substation Parking Bays

Aurora took delivery of a 5 MVA 66-33/11-6.6 kV mobile substation in October 2009. The mobile substation will provide replacement transformer capacity at substations that only have a single transformer. It will also be used to provide temporary additional capacity at the Cromwell zone substation until the transformer capacity there is increased, see Section 5.11.12.

To deploy the mobile substation requires the establishment of a suitable parking area, earthing facilities and connection points at each site where it will be used. The Queensberry site has been completed and put in service; and facilities are proposed for Ettrick and Berwick substations at a cost of \$50,000 each.

5.11.3 Alexandra Substation

The Alexandra zone substation is predicted to exceed its firm load rating beyond the planning period, see Figure 5.21 for load prediction.

Options to eliminate this constraint are to either upgrade the Alexandra transformers to 12/24 MVA units or establish a new zone substation. At this stage the establishment of a new zone substation is preferred with a proposed site in Dunstan Road adjacent to the Omakau 33 kV line as indicated in Figure 5.22. The advantage of establishing a new substation is that it will help eliminate future HV feeder off-loading constraints, especially AX168, and a second zone substation will provide a more secure supply to the Alexandra area. It is proposed that, initially, the substation consists of a single transformer supplied from the Omakau line. As load grows, a second 33 kV supply from Alexandra will be justified along with another transformer.

Estimated Cost \$4.5 million

Completion: On Hold

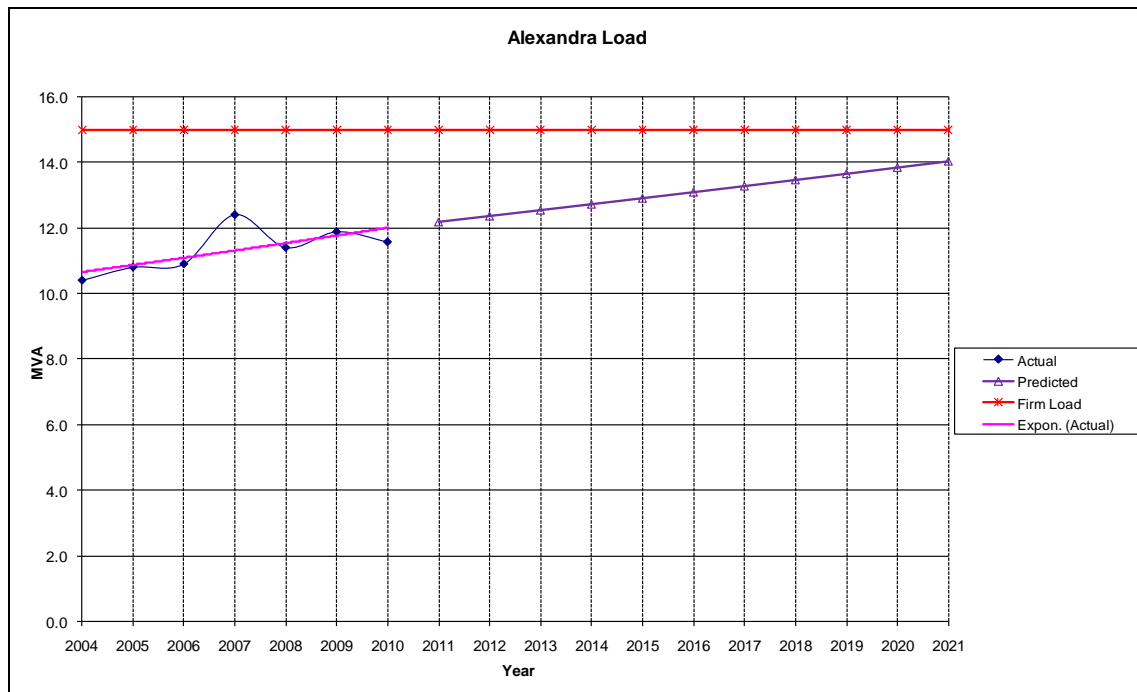


Figure 5.21 - Alexandra Load Prediction



Figure 5.22 – Location of Proposed New Alexandra Zone Substation

5.11.4 Andersons Bay Substation

Load growth on the Andersons Bay substation has been steady and has exceeded previous load predictions. See Figure 5.23 for the current prediction. Some load could be transferred to St Kilda but it is expected that most of the equipment at Andersons Bay will be at the end of its economic life in 2021, so it is proposed the substation be upgraded with new transformers and switchgear at this time.

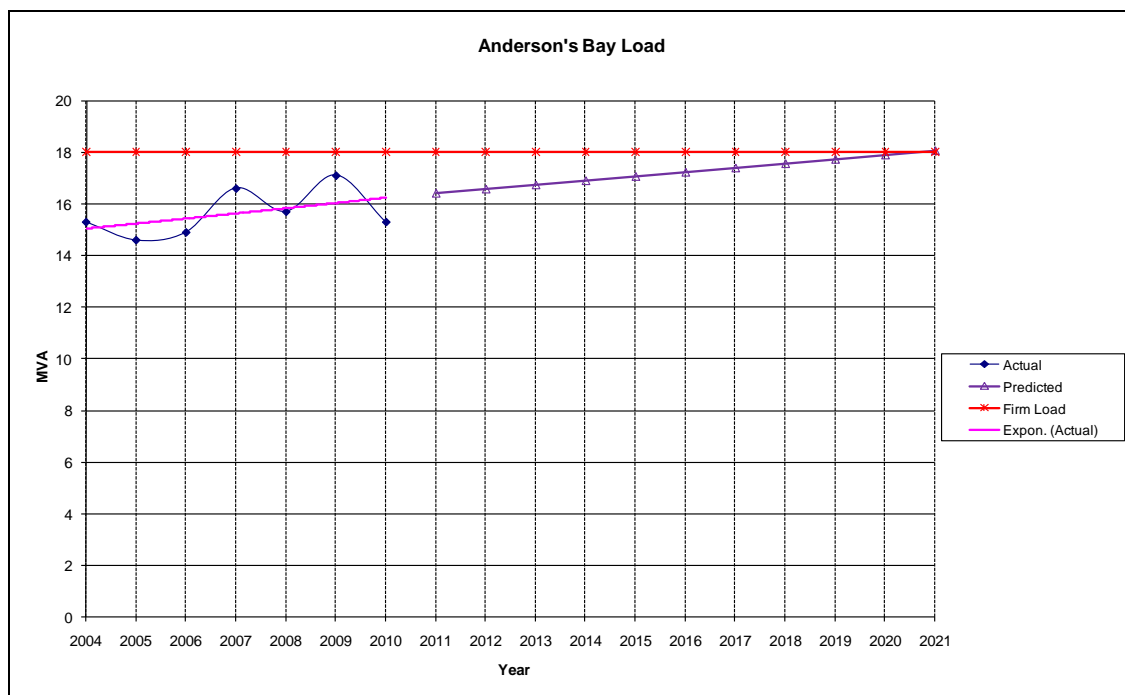


Figure 5.23 – Andersons Bay Load Prediction

5.11.5 Macandrew Bay Substation

Slow steady load growth on the Otago Peninsula is expected to result in feeder off-loading issues with feeder A7 being the first to be affected. One option to resolve this constraint is to establish a zone substation at Macandrew Bay. Aurora already owns the land for the substation and there is a 33 kV line, currently operating at 6.6 kV, from Darnell Street to the Macandrew Bay substation site, see Figure 5.24. It is proposed that the 33 kV supply be derived from the Andersons Bay zone substation, which would require the installation of approximately 1.2 km of 33 kV cable from the substation to Darnell Street and 33 kV switchgear at Andersons Bay. It is envisaged the substation would be a single 5 MVA dual ratio 33/11-6.6 kV transformer. The installation of this substation would provide additional off-load capacity for the Port Chalmers and Andersons Bay substations. The timing of the project is driven by three factors: the Andersons Bay and Port Chalmers zone substation loads and the Peninsula feeder loads. The project is provisionally scheduled at the end of the planning period and will be reviewed annually. An option to resolve the feeder off-loading issue is to move some load from the Andersons Bay end of AB7 onto a new feeder using the spare breaker at Andersons Bay

Estimated Cost \$4 million

Completion: On Hold

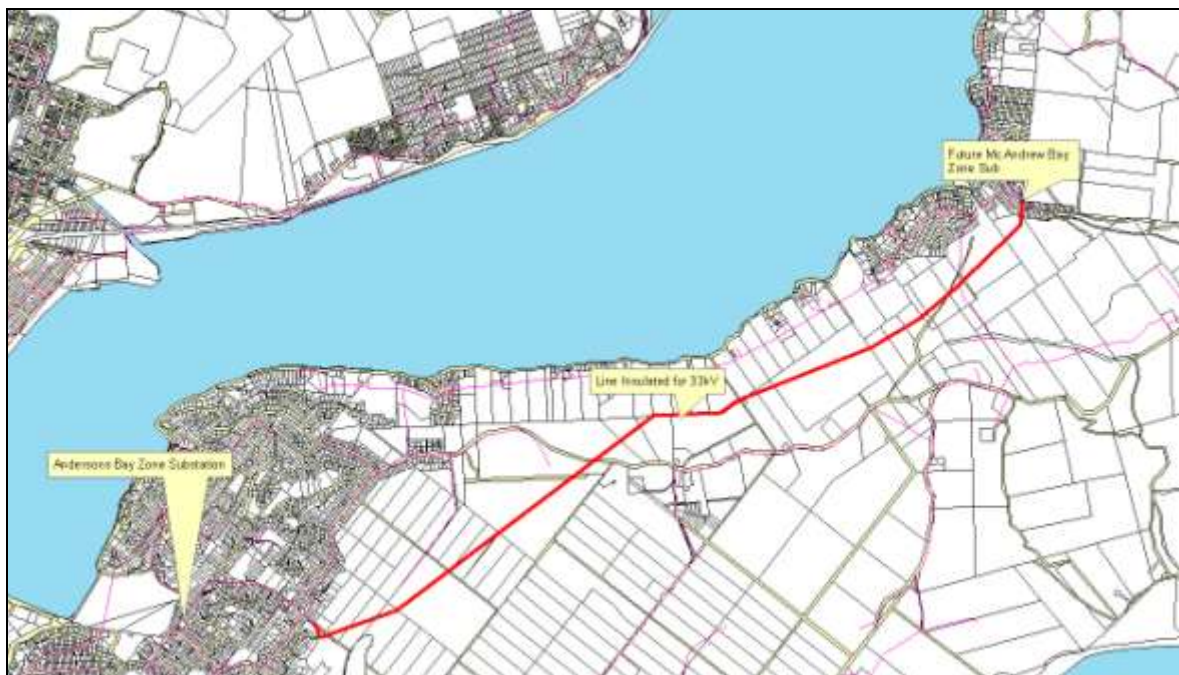


Figure 5.24 – Proposed Macandrew Bay Zone Sub Transmission

5.11.6 Smith Street Substation

Load was transferred from Smith Street to South City in 2005, to keep the demand on Smith Street below its firm rating which is determined by the capacity of the incoming circuit breakers. Smith Street is predicted to exceed its firm rating during the winter of 2018. It is proposed that Smith Street be upgraded to 12/24 MVA transformers and the HV switchgear be replaced prior to the winter of 2020. The existing transformers and switchgear that were purchased in 1957 will be 62 years old by then and replacement would be justified on reliability grounds. It may be advantageous to replace subtransmission cables at the same time.

Estimated Cost \$4.5 million

Completion: March 2020

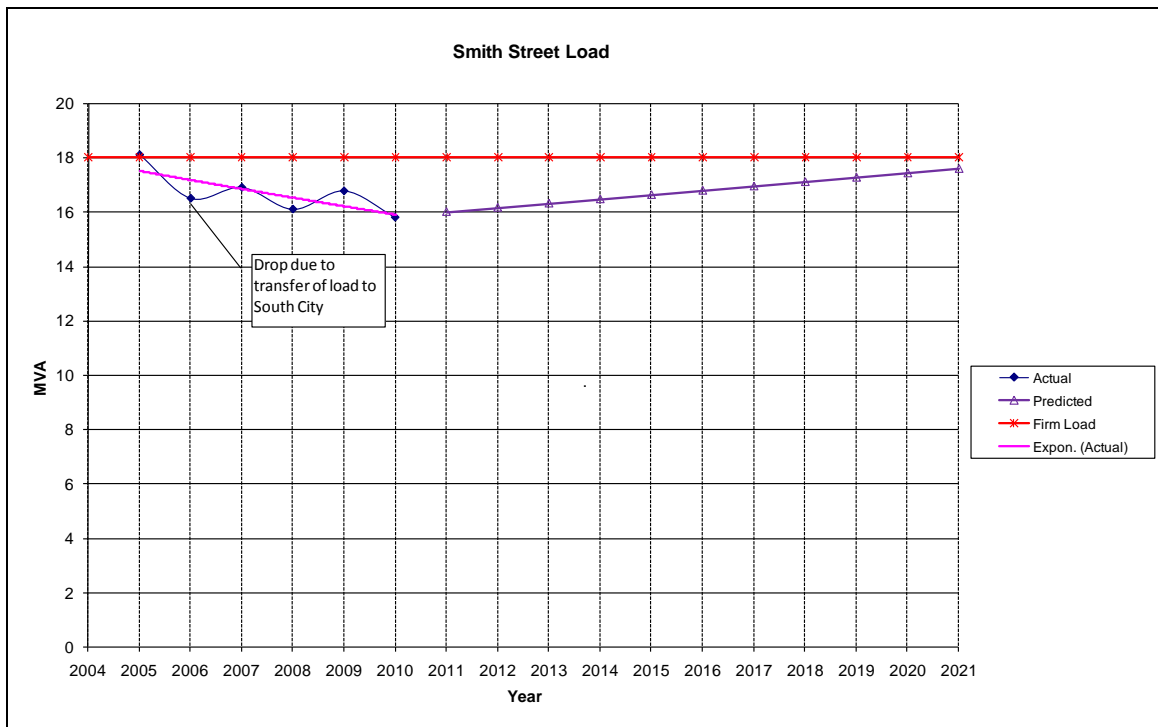


Figure 5.25 – Smith Street Predicted Loads

5.11.7 South City Substation

The South City substation is predicted to stay within its firm rating until the end of the planning period as shown in Figure 5.26. If Smith Street is upgraded in 2020 the load that was transferred from Smith Street to South City in 2005 can be transferred back again, thus deferring the need to upgrade South City to beyond the planning period.

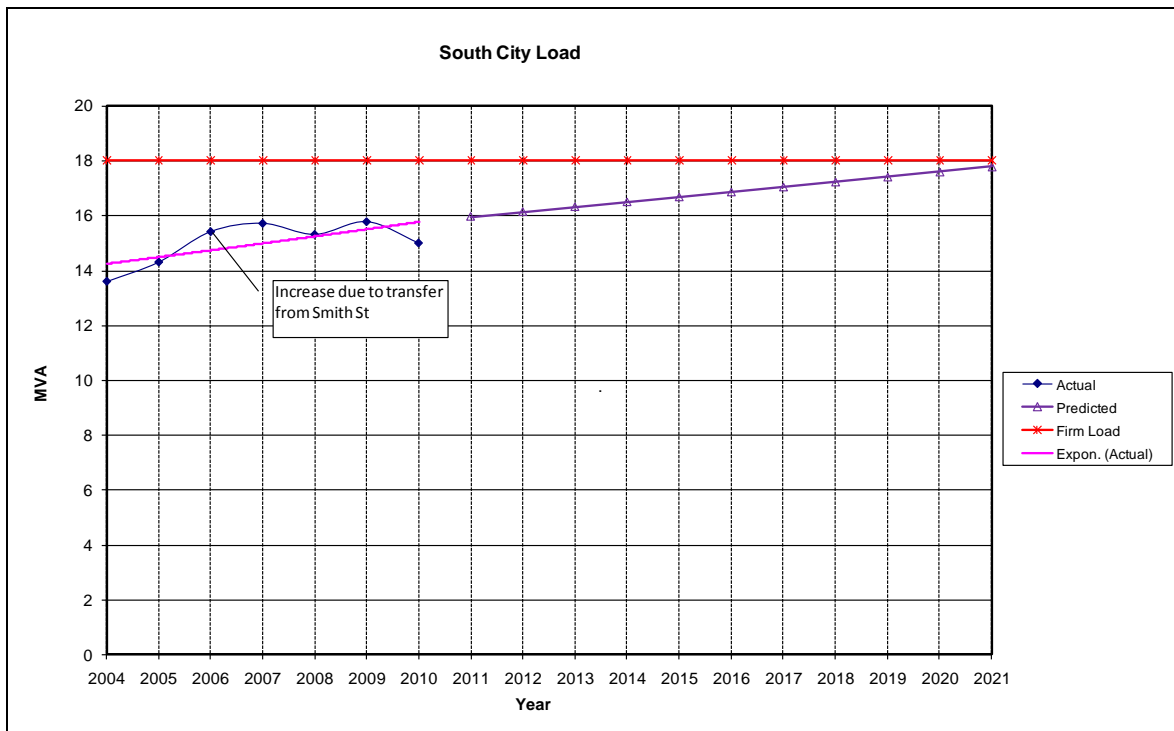


Figure 5.26 – South City Predicted Load

5.11.8 Arrowtown Substation

The Arrowtown substation demand during the 2010 winter was 7.94 MVA which exceeded its firm rating of 7.5 MVA. See Figure 5.27 for predicted loads on the Arrowtown substation.

The load is predicted to reach 10 MVA during the winter of 2017. It is proposed to install the 5/10 MVA transformer from the Cromwell substation and the 7.5/10 MVA transformer from the Frankton substation at Arrowtown during the 2016/17 summer which will increase the firm capacity to 11.5 MVA. Associated with this upgrade it is proposed install indoor 11 kV and 33 kV switchgear and supply the transformers from 33 kV circuit breakers rather than fuses as at present.

It is proposed to install the 5/10 MVA transformer from the Cromwell substation and the 7.5/10 MVA transformer from the Frankton substation at Arrowtown during the 2012/13 summer which will increase the firm capacity to 12 MVA. Associated with this upgrade, it is proposed to install indoor 11 kV and 33 kV switchgear and supply the transformers from 33 kV circuit breakers, rather than fuses as at present.

To provide cover until the 10 MVA transformers are installed, the 5 MVA mobile substation will be used.

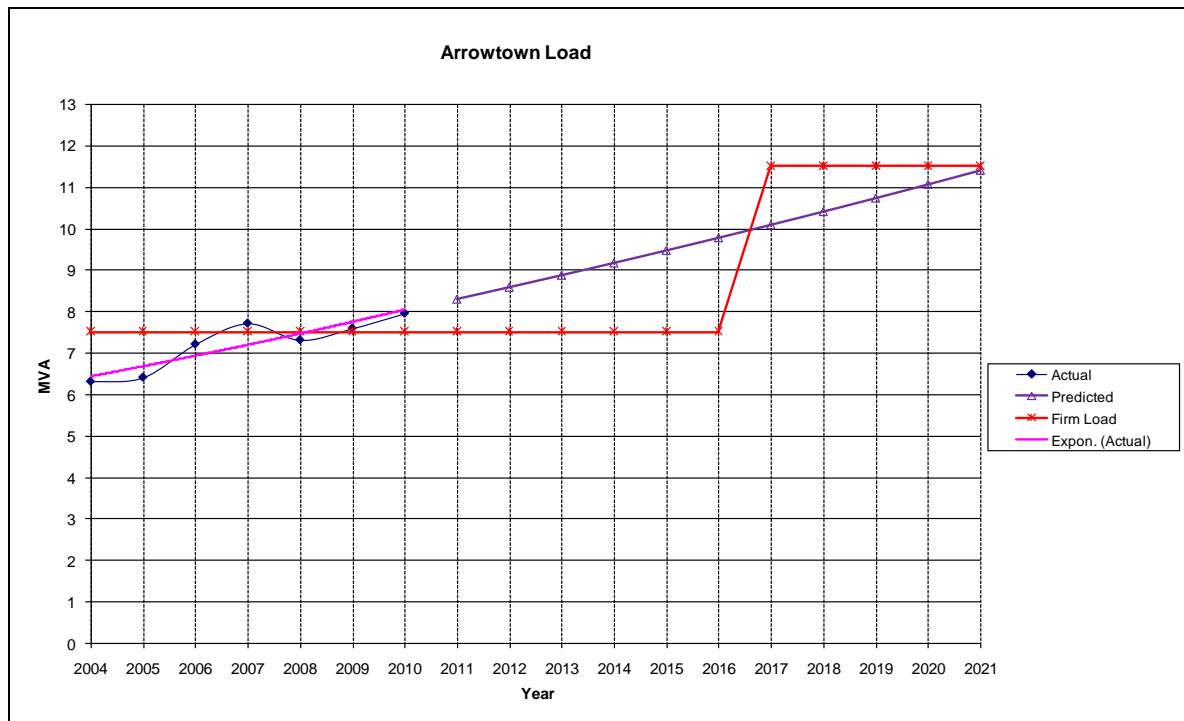


Figure 5.27 – Arrowtown Predicted Loads

The existing 5 MVA transformers have 11 kV incoming circuit breakers mounted on them. The 7.5/10 MVA unit from Frankton has an 11 kV transformer mounted breaker but this facility is not provided on the Cromwell 5/10 MVA unit. This is one of the drivers for the installation of 11 kV indoor switchgear. The existing 11 kV feeder breakers are reclosers that can be redeployed elsewhere on the network. The 33 kV switchgear configuration would be designed to accommodate the third 33 kV circuit, as proposed in Section 5.10.1 and detailed in Figure 5.11.

Estimated Cost \$4 million

Completion: May 2017

5.11.9 East Taieri Substation

In the 2010 plan, it was proposed that the East Taieri transformers be moved to the Cromwell substation where additional capacity is required, but the 9.2% maximum boost voltage will not be a limitation. Recent load trends, (loss of industrial load), now makes this proposal redundant. No works are planned within the 10-year time frame.

5.11.10 Substations for Tarras Irrigation Project

There is an irrigation proposal being considered by the Tarras community that could require up to 8 MW of pumping. If this project proceeds, it is envisaged that two 66/11 kV 5 MVA substations will be required, one at each end of Maori Point Road. Initial estimates are that these would cost in the order of \$3 million each plus \$1 million for associated overhead lines. The substations would be connected to the Cromwell to Wanaka 66 kV subtransmission which runs along Maori Point Road. This load, being predominantly a summer load, would not constrain the capacity of the Upper Clutha 66 kV subtransmission.

Estimated Cost \$7 million

Completion: Jan 2013

5.11.11 Frankton Substation

Frankton substation has a 7.5/15 MVA and 7.5/10 MVA transformer and has been allocated a firm load of 12 MVA which has been exceeded. A project is underway to rebuild the Frankton substation. See Figure 5.28 for load predictions. Further upgrading is not expected during the planning period because, when the Jack's Point substation is commissioned, load will be lost to Jack's Point and the firm capacity will increase due to the ability to transfer Frankton load to Jack's Point.

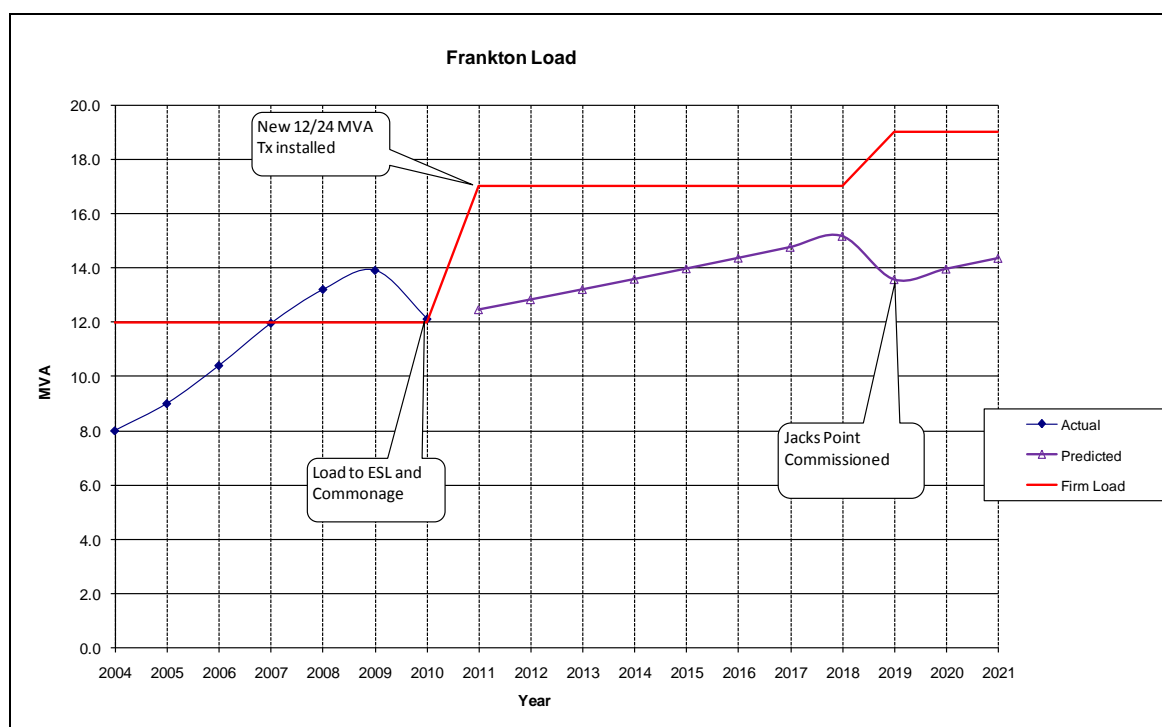


Figure 5.28 – Frankton Predicted Loads

Estimated Cost \$4.96 million

Completion: May 2011

5.11.12 Cromwell Substation

The load on Cromwell is growing strongly and the peak demand now exceeds its 9 MVA firm capacity for a very short period of time. It is proposed that the 5 MVA mobile substation be used to provide n-1 cover until the peak load reaches 12 MVA which is predicted to occur during the winter of 2015. It is then proposed that two new 12/24 MVA transformers be installed. The reason for the 12 MVA limit is that if the 5/10MVA unit fails the load will be carried on the 7.5 MVA transformer plus the 5 MVA mobile, total 12.5 MVA. It will not be possible to share the load between the transformers in proportion to their rating so to avoid excessive transformer over loading the 12 MVA limit is recommended.

From May 2011 the 7.5/10 MVA transformer to be removed from Frankton will be available to be installed at Cromwell in the event of a Cromwell transformer failure.

The 7.5 MVA transformer from Cromwell would be available for future installation at Jack's Point and the 5/10 MVA unit installed at Arrowtown.

Estimated Cost \$2.5 million

Completion: May 2015

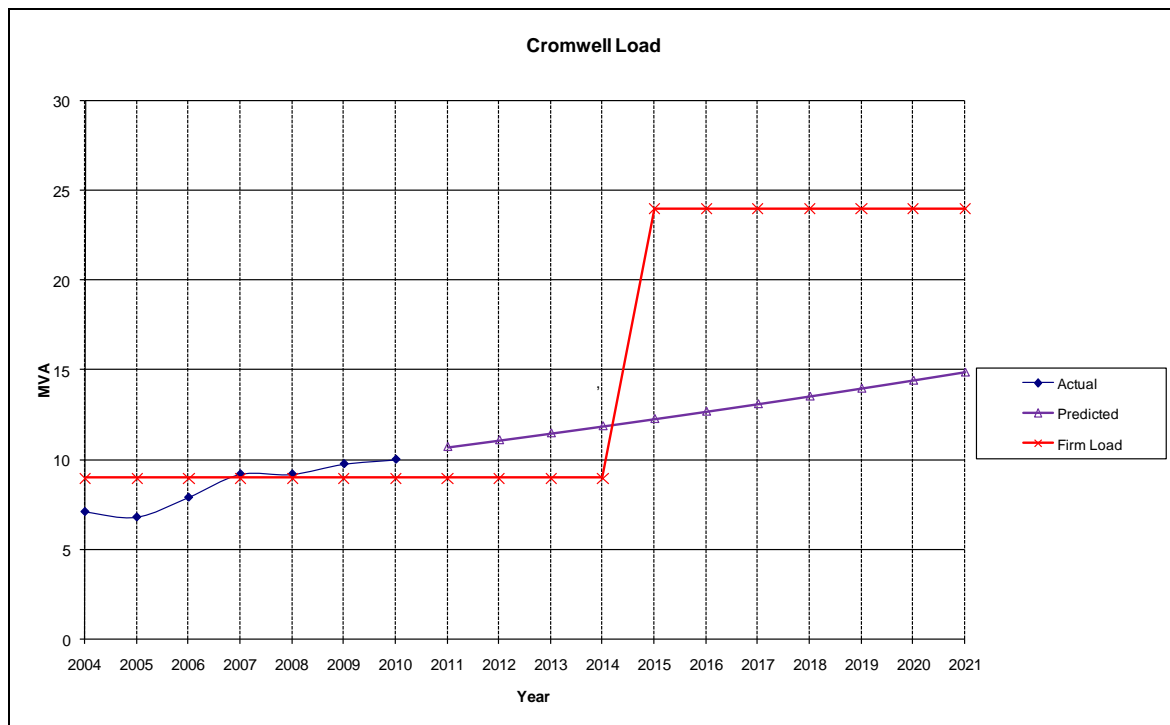


Figure 5.29 – Cromwell Zone Substation Loading Projections

5.11.13 New Wanaka Area Switching/Substation (Riverbank Road)

Load growth on the Wanaka zone substation has been exceptional (9.3% annually since 2003 to 2009). See Figure 5.30 for load projections. The Wanaka 11 kV n-1 capacity is 24 MVA and this is predicted to be exceeded in 2013.

In the 2009-2019 Plan, it was proposed that Wanaka be off-loaded by the construction of a new substation in North Wanaka. It is now considered the most economic solution is to install a 12/24 MVA transformer at the Riverbank Road switching station prior to the winter of 2016. Up to 8 MVA of load could be transferred from Wanaka to Riverbank Road by connecting to the existing HV feeders adjacent to the Riverbank Road site. This is the same load transfer that would be expected from the establishment of a substation in North Wanaka.

The advantages of Riverbank Road over North Wanaka are:

- Riverbank Road would be supplied by duplicate 66 kV circuits where as North Wanaka would have been on a 66 kV spur;
- the cost of installing a transformer at Riverbank Road will be significantly less than setting up a new substation in an alternative location.

It is assumed that the Riverbank Road switching station is commissioned in 2014. The installation of a second transformer at Riverbank Road is proposed when it becomes no longer possible to completely off-load Riverbank Road onto adjacent substations.

Estimated Cost \$4.0 million

Completion: May 2015

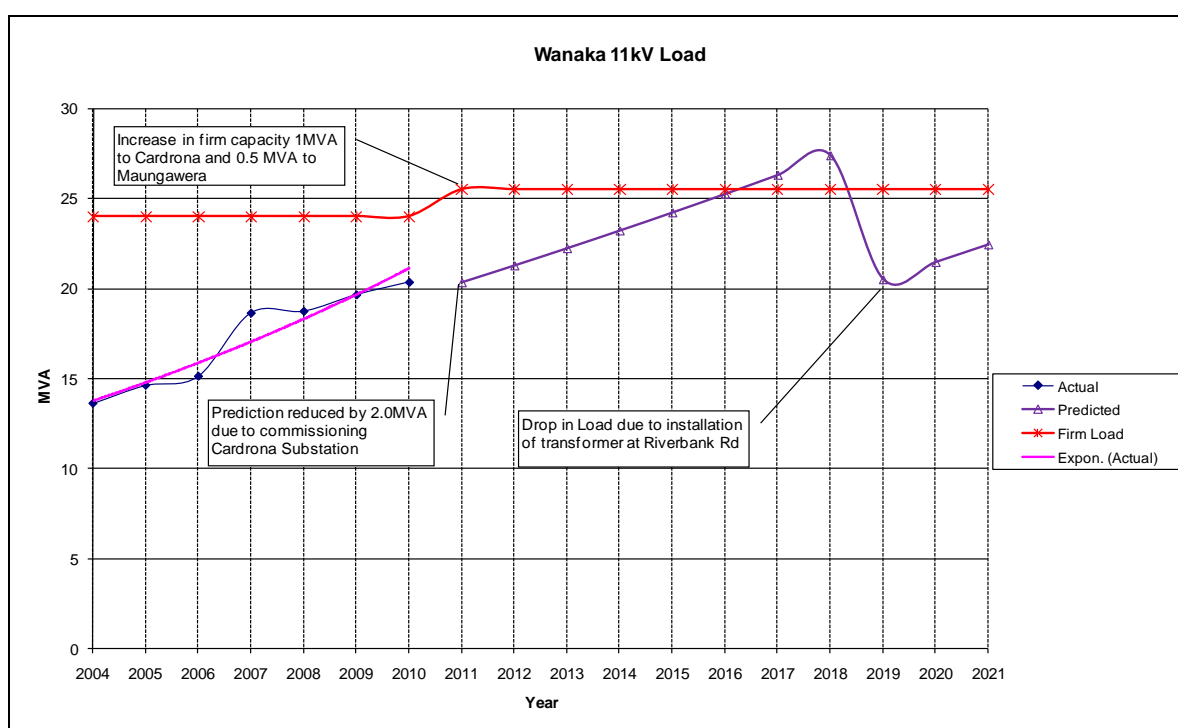


Figure 5.30 – Wanaka 11 kV Predicted Loads

5.11.14 Maungawera Substation

There was a significant increase in the load on the Maungawera substation during the winter of 2007. This has been attributed to the cold weather and the increase in development in the Hawea and Albert Town areas. Relief has been provided by shifting an 11 kV open point to transfer Albert Town load onto the Wanaka substation and it is now predicted the substation will not exceed its firm rating during the planning period. See Figure 5.31 for load predictions.

If the Hawea generation project proceeds; the extension of the subtransmission to Hawea and an upgrade from 33 kV to 66 kV would be required. At this time, it is proposed to remove the Maungawera substation and supply the area from a new 66/11 kV transformer at Hawea at an Aurora-owned site. See Section 5.10.7 for details on the Hawea generation connection proposal.

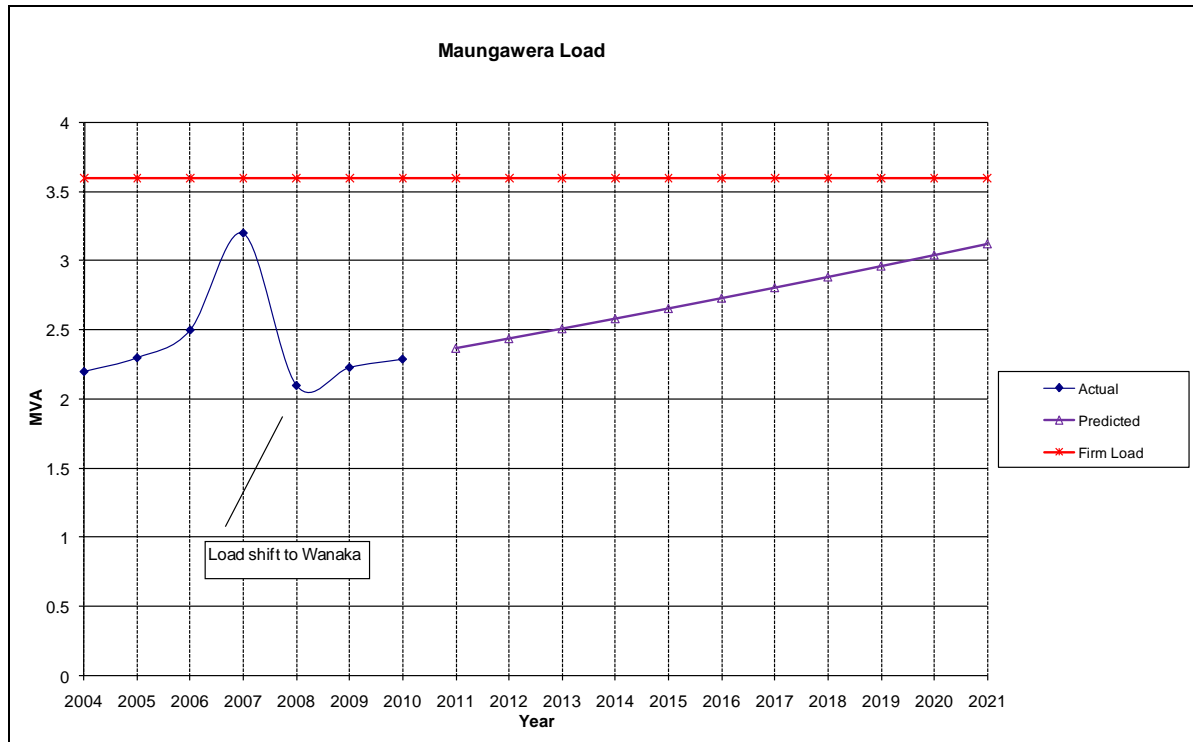


Figure 5.31 – Maungawera Substation Predicted Load

5.11.15 Jack's Point Substation

The Jack's Point development has an ultimate capacity of 2,700 lots that will require in the order of 8 to 10 MW of electricity. Jack's Point will initially be supplied from Frankton feeder 723 up to a load of approximately 2 MVA. When this load limit is reached, it is intended to install a 33/11 kV substation in the development that will be supplied from the 33 kV line to Wye Creek. The substation will be designed to eventually accommodate two 5/10 MVA transformers. A substation site has been provided by the Developer and a 33 kV cable has been installed from the Wye Creek line to the site.

The timing depends on the uptake of lots which has been slow to date. An initial growth rate of 100 kVA per year is assumed, which is equivalent to approximately 30 houses, with the rate increasing to 200 kVA a year by 2016. This will require a substation by the winter of 2019.

Estimated Cost \$3 million

Completion: May 2019

5.11.16 Cardrona Substation

A substation is under construction consisting of a single 5 MVA dual ratio 33/66 kV to 11 kV transformer with provision to accommodate the 5 MVA mobile substation. The substation will initially be operated at 33 kV and then upgraded to 66 kV when the Riverbank Road switching station is established.

Estimated Cost \$2.65 million

Completion: April 2011

5.11.17 Remarkables Substation

The Remarkables ski field have requested a capacity increase of 1.7 MVA for the winter of 2012 with further increases in 2015 and 2016 to a projected total demand of 4.75 MVA. The 1 MVA unit at the site was scheduled to be swapped for a refurbished 1 MVA unit in Dec 2010 but instead the spare 3 MVA transformer was installed when we were advised of the ski field development plans. The predicted loads for the substation are shown

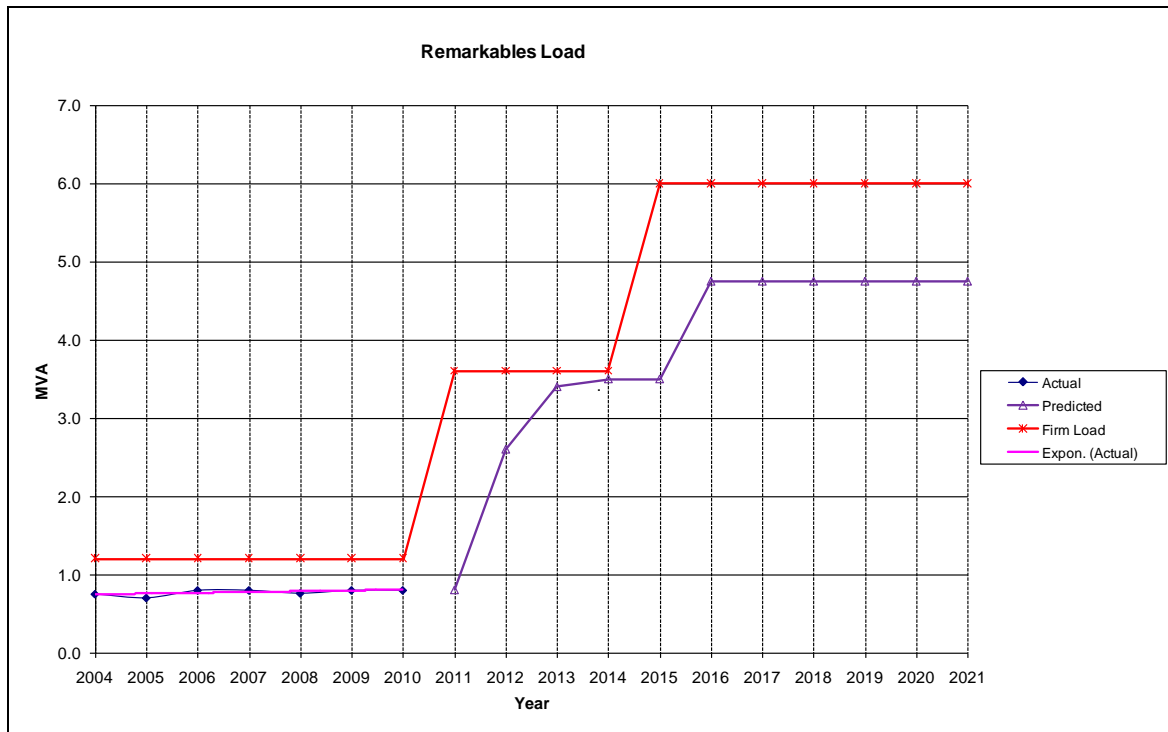


Figure 5.32 – Remarkables Substation Predicted Load

The spare 3 MVA transformer, which was at Arrowtown, was installed at the Remarkables site just before Christmas 2010. When ski field requirements exceed the capacity of the 3 MVA transformer, it is proposed to install a 5 MVA transformer at the site.

Estimated Cost \$2.5 million

Completion: April 2015

5.12 HV Feeders

A feeder rating is the minimum of its circuit breaker rating, outgoing cable rating, or 120% of its nominal CT rating. Some feeders have constraints beyond the outgoing cable. Feeders are not permitted to exceed their rating.

It is desirable to be able to transfer the entire load on a feeder to adjacent feeders in the event of a fault on the outgoing cable. Generally, there are several options to off-load most feeders. The ability to off-load a feeder is also calculated by the “Feeder Loading” database. When it becomes impossible to completely off-load a feeder, analysis is carried out to assess if the cost of eliminating the off-loading constraint is economic.

Major HV feeder projects (>\$300,000 or those reflecting recent strategic initiatives) that required within the planning period to eliminate known feeder loading constraints are detailed below.

5.12.1 Conversion of 6.6 kV Feeders to 11 kV

Aurora has an extensive 6.6 kV distribution network in the Dunedin area and small amount in the Clyde/Earnsclough areas. 6.6 kV is an obsolete distribution voltage and all modern HV distribution equipment has a minimum rating of 11 kV. A circuit operating at 11 kV can deliver 1.67 times the power it can deliver at 6.6 kV. If a circuit is voltage constrained, it can deliver 2.7 times the maximum 6.6 kV power if operated at 11 kV.

Aurora has adopted a long-term strategy of converting its entire 6.6 kV networks to 11 kV. This could take 25 to 40 years to complete. This requires new distribution transformers installed on the Aurora 6.6 kV network be dual ratio units. For consumer initiated projects Aurora fully funds the additional cost of dual ratio transformers. An allowance of \$80,000 per year has been made for this. When 6.6 kV zone substations are upgraded, replacement transformers will have both 6.6 kV and 11 kV capability. See Table 5-17 for a progress report on the conversion program.

Transformer Voltage	Clyde Earnsclough				Dunedin 6.6kV Area			
	2009		2010		2009		2010	
	Count	%	Count	%	Count	%	Count	%
6.6kV	102	49%	103	49%	1,492	83%	1,469	83%
11/6.6kV	106	51%	107	51%	295	17%	305	17%
Total	208		210		1,787		1,774	

Table 5-17 – Dual Ratio Transformer Conversion Progress

5.12.2 Undergrounding in SH6

NZTA is considering roading modifications in SH6 between Glenda Drive and Frankton that will require overhead lines in the area to be moved. The details and timing of this project is in the hands of NZTA which has yet to commit to design of the proposed Glenda Drive round-about. Our information is that the funding of this would be from NZTA, QLDC, and several property developers. Also, the proposed round-about at Grants Road is not planned to be funded by NZTA as it was intended to be funded by a former (now bankrupt), property developer. Given these facts and that NZTA funds are committed for the next 18 months; it is unlikely that there will be any tangible developments in the next two years. NZTA is thinking about, but has yet to decide when, having a workshop involving all affected parties. The timing of the project has, therefore, been moved out by two years.

Estimated Cost \$1 million (over 2 years)

Completion: March 2014

5.12.3 Tie from WK2752 to WK2756 and WK2758

WK 2758, which supplies northern Wanaka, cannot be fully off-loaded at peak times. It is proposed to alleviate this constraint by installing a cable from the junction of Plantation Road and Andersons Road (950 metres of 300 mm² PILC) along SH84 to connect to an existing spur line on WK 2752. A three-way switch would be installed to allow either WK 2756 or WK 2758 to be connected to the new cable. The spur line (1.2 km) would be upgraded from Squirrel to Dog. When the Cardrona substation is commissioned, the load on WK 2752 is expected to reduce by approximately 100 Amps which will provide WK 2752 with at least 200 Amps of spare capacity.

When the Riverbank Road substation is established, this upgraded circuit will be extended to Riverbank Road substation by installing an 11 kV cable along Riverbank Road with the 66 kV cable required to supply Riverbank Road. It would then become a separate Riverbank Road feeder. This project is economic and, as such, is planned for the next financial year.

Estimated Cost \$500,000

Completion: March 2012

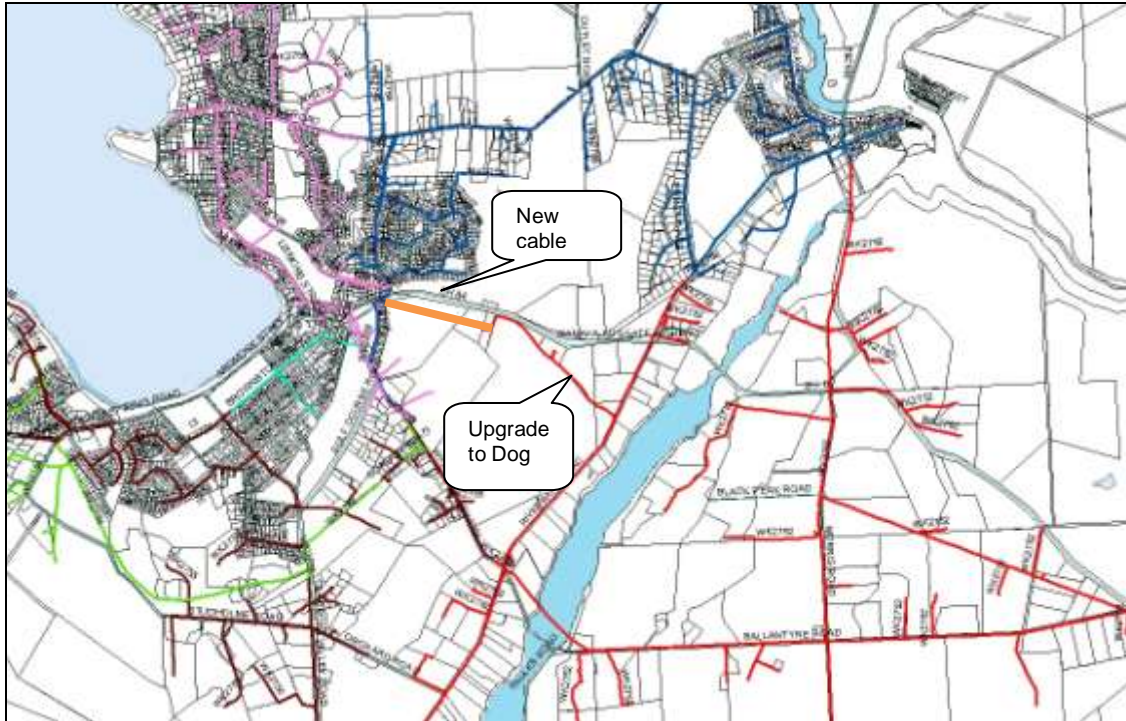


Figure 5.33 – Location of Tie Cable Between WK2756 and WK2752

5.12.4 Establish New Wanaka Feeder 2751

Feeder WK 2753 cannot be readily offloaded at peak times. To alleviate this constraint, it is proposed to install a new HV feeder intertie to WK 2753. Wanaka zone substation has a spare 11 kV feeder outlet, CB 2751, with live end capped cable in Ballantyne Road. It is proposed this cable be extended to create an intertie with WK 2753. The proposed route of this new feeder cable (1.1 km) is along Golf Course road and across the golf course as, shown in Figure 5.34, to connect to the overhead in Dungarvon Street. The overhead conductor in Dungarvon Street (480 m) would be upgraded to Dog.

Estimated Cost \$450,000

Completion: May 2013



Figure 5.34 – Proposed Route of New Wanaka Feeder 2751

5.12.5 New Cromwell Feeder

It is now not possible to fully offload CM831 at peak load times. Project 3205 (CFR5367), which was the installation of a switch, was completed in November 2010. This was a pre-requisite for future works. A new feeder will be required in the future to facilitate the off-loading of CM823 and CM831. It is now not possible to fully offload CM831 at peak load times. It is considered a new feeder will be required in the future to facilitate the off-loading of CM823 and CM831. This new feeder would be run along Barry Avenue to Leitrum Street (1.8 km) as shown in Figure 5.35. A new circuit breaker would be required to be installed at the Cromwell zone substation.

Estimated Cost \$500,000

Completion: May 2014

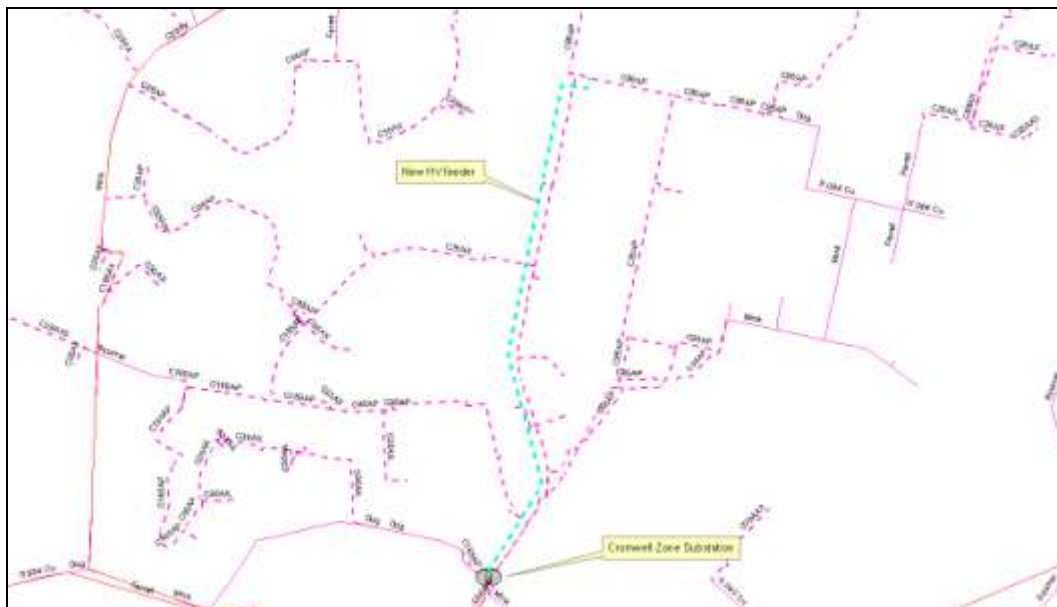


Figure 5.35 – Proposed Route of New Cromwell HV Feeder

5.13 Distribution Substations

Distribution substation projects are not itemised in the Asset Management Plan as they are usually driven by new customer connections and an appropriate response is made at the time.

5.13.1 Distribution Substation Utilisation

The loading of all distribution transformers greater than 200kVA (which represents 78% of installed transformer capacity) is monitored by Maximum Demand Indicators (MDIs). The MDIs in “at risk” substations are read at least annually; for other substations, the interval is longer. Overloading of smaller substations is normally brought to attention by LV fuses failing or voltage complaints. Utilisation data is shown in Table 5-18 and is for all transformers connected to the Aurora network, including those not owned by Aurora.

Year	2005	2006	2007	2008	2009	2010
Utilisation	34.2%	33.6%	33.2%	33.7%	31.9	32.8%

Table 5-18 – Distribution Transformer Utilisation

Overall, utilisation is above the 30% ODV optimisation threshold. However, we expect the year ending 31 March 2011 utilisation to be less than the 2010 figure above, due to the fact that the winter of 2010 was milder than the winter of 2009.

5.14 Reliability and Risk Mitigation Projects

Reliability initiated projects that will economically reduce the number or duration of consumer outages are detailed in this section.

5.14.1 HV Feeder Performance

Set out in Figure 5.36 is data on outages over the 2008 -2010 calendar years per circuit plotted against circuit length. All things being equal, feeders of similar length in similar physical environments would be expected to suffer similar numbers of faults. The worst performing feeders have been investigated and, where economic, projects to improve feeder reliability are initiated. Note that outages upstream of the feeder breaker are included but the length of the upstream feeders is not. This graph shows the average of the last three years performance to reduce the anomalies cause by extreme events.

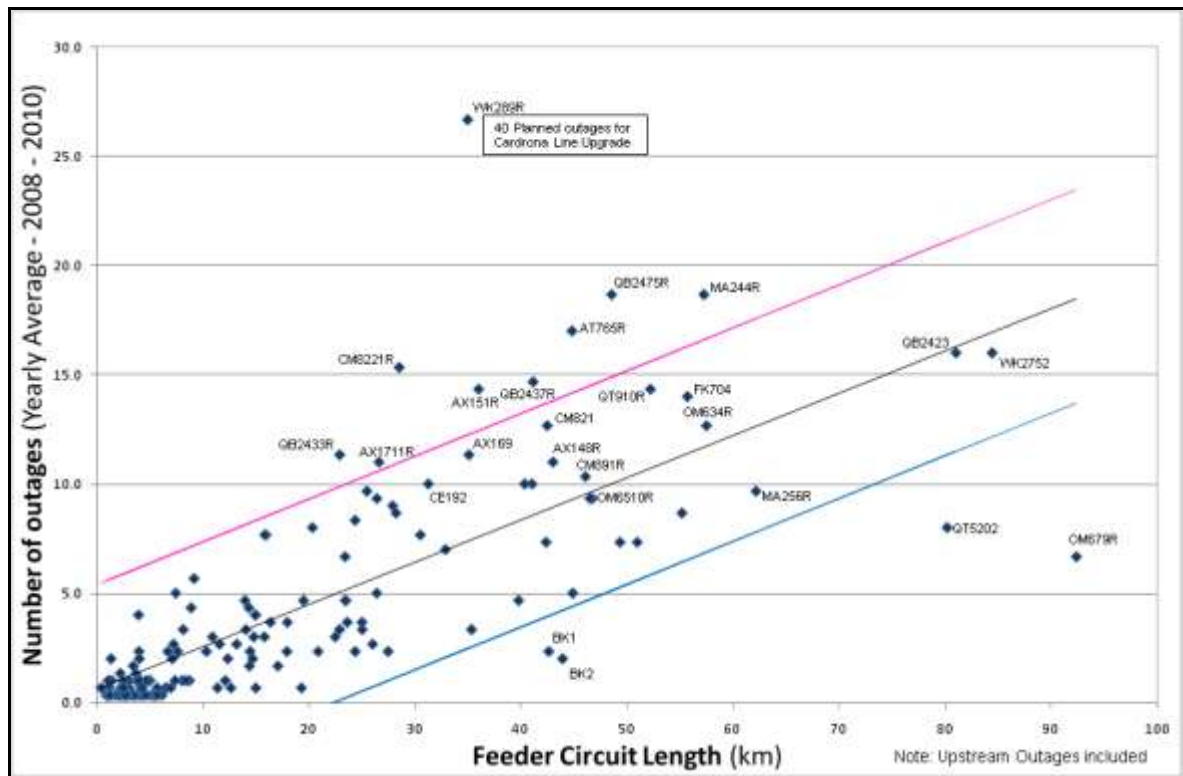


Figure 5.36 – HV Feeder Outages as a Function of Feeder Length

Another reliability indicator is the system customer outage minutes per HV feeder which is detailed in Figure 5.37 below.

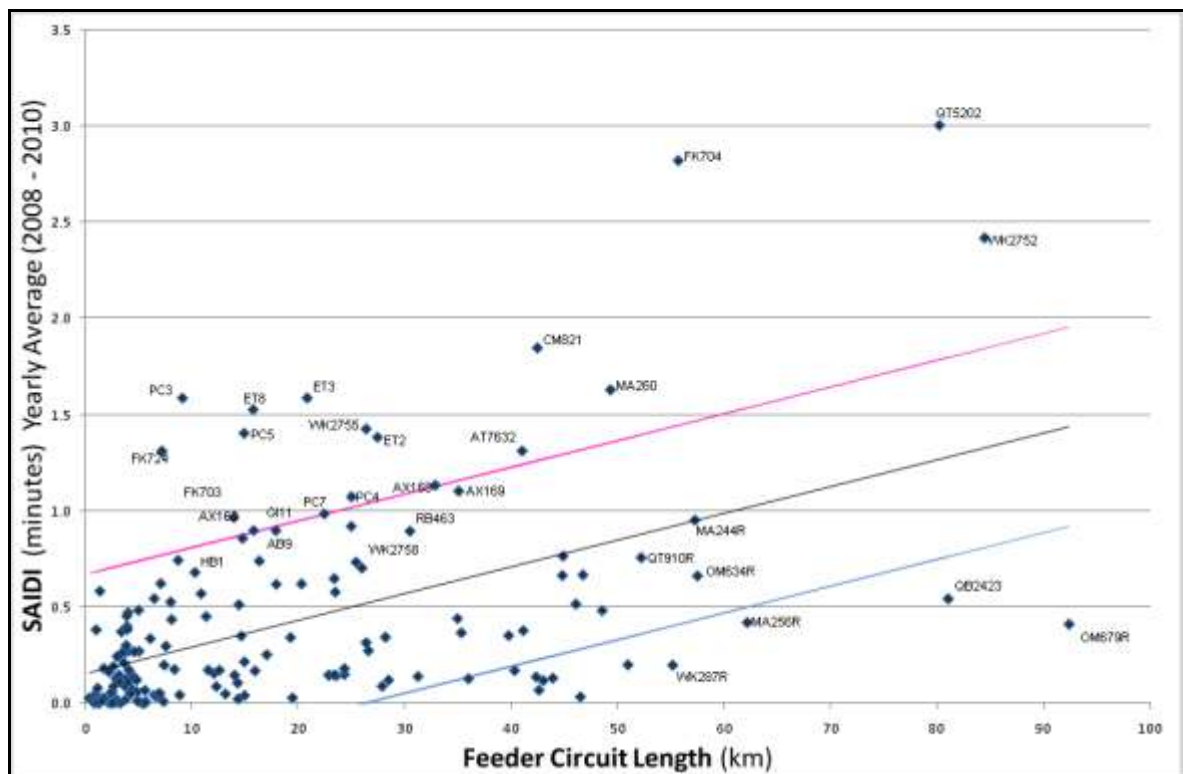


Figure 5.37 – HV Customer Outage Minutes by HV Feeder Length (2008 - 2010)

Analysis of this data results in the identification of feeders to be targeted for performance improvements as shown in Section 4.4.2.

5.14.2 Dunedin Recloser Projects

An investigation was carried out to identify sites where the installation of auto reclosers may be economic. Typical locations are at the rural/urban boundary of feeders. Two projects have been completed and one is underway. See Table 5-19 for a list of remaining projects.

Recloser Location	Cost	Completion
Feeder OT3 at SW1581	\$48,000	June 2010
Feeder PC 5 Deborah Bay	\$48,000	June 2011
Feeder AB9 at SW889	\$48,000	June 2011

Table 5-19 – Dunedin Area Proposed Recloser Projects

5.15 Overhead to Underground Conversion Projects

Aurora has a policy of assisting local authorities to have overhead lines placed underground.

The projected expenditure by Aurora Energy Ltd along with the Territorial Authority is detailed in Table 5-19 below.

Year	DCC	CODC	QLDC
	\$000	\$000	\$000
2011/12	600	310	500
2012/13	600	320	510
2013/14	600	330	530
2014/15	600	340	550
2015/16	600	350	570
2016/17	600	360	590
2017/18	600	370	600
2018/19	600	380	610
2019/20	600	390	620
2020/21	600	400	630

Table 5-20 – Overhead to Underground Conversion Budget

Expenditure in the CODC and QLDC areas is subject to the respective territorial authorities contributing on a 50:50 basis. If this does not occur, then the undergrounding budgets will not be spent.

5.16 New Customer Connections

New customer connections cover the cost of extensions to the Aurora network to facilitate the connection of customers to the network. Customers make a contribution toward the cost of this work in accordance with the Aurora capital investment policy. The expenditure in these categories is entirely customer driven and subject to regional economic activity. The budgeted annual expenditure is presented in Table 5-21.

Year	Dunedin \$000	Central \$000	Total \$000
2011/12	1,200	4,400	5,600
2012/13	1,200	4,800	6,000
2013/14	1,200	5,200	6,400
2014/15	1,200	5,600	6,800
2015/16	1,200	6,000	7,200
2016/17	1,200	6,400	7,600
2017/18	1,200	7,000	8,200
2018/19	1,200	7,000	8,200
2019/20	1,200	7,000	8,200
2020/21	1,200	7,000	8,200

Table 5-21 – Annual Cost of New Customer Connections (\$000)

6 Lifecycle Asset Management Planning for Maintenance and Renewal

6.1 Maintenance Planning Criteria and Assumptions

The prime asset management considerations are customer service (particularly reliability of supply), longevity, and economic efficiency, which act against the background of safety and environmental responsibility. Aurora network maintenance is conducted in line with the risk management policy described in Section 7.1 and is reflective of customer, community, and legislative requirements, in addition to fulfilling Aurora's business objectives.

Maintenance expenditure is now split into three categories, as per the Electricity Distribution (Information Disclosure) Requirements 2008. These are summarised below:

- Routine and Preventative Maintenance: Programmed maintenance, including post fault inspections and repairs.
- Refurbishment and Renewal Maintenance: Replacement or refurbishment of components of an asset class, as described in the ODV Handbook.
- Fault and Emergency Maintenance: Response to unplanned events.

Table 6-1 summarises the forecast maintenance expenditure in the above categories.

Maintenance Expenditure (\$000)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Fault and Emergency	4,270	4,370	4,470	4,570	4,670	4,780	4,890	5,010	5,120	5,240
Refurbishment & Renewal	1,310	1,340	1,370	1,390	1,430	1,460	1,490	1,520	1,550	1,590
Routine and preventative	3,540	3,640	3,740	3,850	3,950	4,060	4,170	4,290	4,400	4,530
Total	9,120	9,350	9,580	9,810	10,050	10,300	10,550	10,820	11,070	11,360

Table 6-1 – Routine and Preventative Maintenance Costs Summary, by Disclosure Requirements Category

A third party damage allowance of \$750,000 per annum is now included in the above table, in the fault category.

The proportion of overhead to underground conversion works that would be expensed, such as removal of overhead lines, is now included in refurbishment and renewal estimate above.

Effective maintenance management involves balancing the cost of maintenance against the cost of replacement, after including the consequences of failure in both scenarios. Age-based maintenance and renewal, while conservative in engineering terms, tends to lead to unnecessarily high maintenance (replacement) costs. Aurora's maintenance strategy is based on careful monitoring of asset condition to balance the risks. Aurora continues to refine its maintenance management systems by reviewing practices and policies regularly.

All defects reported are recorded in a defects register until the required remedial work is undertaken. Once a defect has been identified, remedial work is programmed before the risk and consequences of failure become unacceptable. Assets are not renewed based on age or other generic criteria; they are kept in service until such time as their continued refurbishment is uneconomic, or until they pose a safety or reliability risk.

6.2 Routine and Preventative Inspection and Maintenance

Around 40% of Aurora's budgeted maintenance expenditure is for periodic inspections, servicing and tests, and associated maintenance to ensure that defects or emerging risks are identified and mitigated. Servicing can also involve minor component replacements (for example - seals, bushings etc), but does not involve any significant repairs.

DELTA has developed routine procedures for this type of work, specific to each asset type, which define the frequency of servicing/inspection, and the scope of work that must be covered. They are based on a combination of manufacturers' recommendations, industry practice, and *DELTA*'s own experience; which, in turn, is based on the incidence of faults and defects for each asset design, type, make or model, and factors such as its operating environment (salt-laden atmosphere, wind, etc).

Subtransmission lines undergo detailed inspection every five years and are patrolled regularly in the interval.

For circuit breakers, intervals for minor and major services, and the type of work to be carried out, are defined for each type, make and model, with the interval monitored against failure rates. These services vary from annual servicing, costing in the order of a few hundred dollars per breaker, to infrequent major overhauls, costing up to several thousand dollars. Greater emphasis is being placed on in-service diagnostic testing, as techniques for this become better developed. This can be a cost-effective means of identifying defects and items that are at risk of failure. It includes (for example) chemical analysis of transformer oil, and use of thermographic cameras to identify "hot spots".

Objective defect criteria are defined for all items, and vary between asset types. For some, the key aspect is safety (for example - risk of explosion, fire or electrocution); for others, it is maintaining a reliable supply, while still others are driven by the economic consequences of allowing components to deteriorate past the point where corrective action is desirable (for example - distribution transformer corrosion and power transformer insulation embrittlement).

6.2.1 Subtransmission

Cables

The 33 kV underground cables are a mixture of gas filled, oil filled, and Mass Impregnated Non-Draining (MIND) and XLPE types. Pressure alarms are installed on the former two, and these are tested at six-monthly intervals, and the outer sheath electrical integrity on most cables is tested annually. Occasionally, leaks develop in these cables, usually at joints. Faults are expensive to repair, being very labour intensive. MIND cables are virtually maintenance free but faults occasionally occur due to insulation migration on hill sections, or if they have been damaged by third parties (for example - road openings etc).

An above-ground visual inspection programme is in place, which involves inspecting the route of each cable for ground disturbance or ground movement, providing suspect areas for further detailed investigation.

Overhead Lines

Annual drive-by patrols are carried out on the overhead 66 kV and 33 kV lines to provide a visual check on such aspects as tree growth, leaning poles, or broken insulators, etc. All overhead lines and poles are closely inspected on a regular basis, and condition assessments made and recorded for maintenance planning.

Patrols are also carried out, on request, if a line trips out on earth or over current fault of unknown source.

Protection Pilots

Most of the pilot circuits are underground cables, generally run with 33 kV cables. They are tested biannually for continuity, insulation resistance, and attenuation.

6.2.2 Zone Substations

33 kV Transformers and Tapchangers

The transformers are relatively trouble free, apart from occasional oil leaks from bushings or radiators. The exception to this was in late 2006 when one transformer required repairs following ingress of water. All transformers have their insulating oil tested annually for acid level, breakdown resistance, and moisture content. DGA testing is completed on an annual cycle.

Buchholz relay operation tests are conducted, along with tests of winding and oil temperature alarms, from source. These occur at four-year intervals, and are carried out in conjunction with associated circuit breaker maintenance.

Painting of outdoor 33 kV transformers is undertaken on a rolling basis, with major repaints at 10-year intervals.

Tapchangers are routinely overhauled after a set number of operations, dependent on type. Routine scheduled work on transformers and tapchangers is undertaken on a contract basis.

Buildings and Grounds

A 10-year building maintenance plan, produced by external consultants, details requirements for yards, roofs, external walls, doors, windows, plumbing, electrical services, and the interior. Buildings are serviced by contract cleaning staff at fortnightly intervals. Grounds maintenance is also outsourced.

Corstorphine, South City and Ward Street substations have asbestos materials installed in some areas. Tests are carried out at 5-year intervals to monitor air-borne fibres.

Circuit Breakers and Isolators

Oil circuit breakers are given an overhaul at 4-year intervals or after operation under severe fault conditions. Painting of outdoor circuit breakers is undertaken on a rolling basis with, major repaints at 10-year intervals.

Isolators are checked for operation and condition in conjunction with the 4-year routine overhaul for the circuit breakers.

Ripple Injection Plant

Routine maintenance of the 1050 Hz ripple injection plant in the Dunedin network area consists mainly of contactor checks, and the dressing or replacement of contacts. The solid state coupling cells at North East Valley zone substation and in the Central network, are virtually maintenance free. The North East Valley zone substation ripple injection plant and the 33 kV injection equipment in the Central network area, are covered by an outsourced maintenance contract which involves annual ripple signal checks, carrying of strategic spares stock, replacement units for rental and a fault callout service.

Miscellaneous

All batteries are, at present, in reasonably good condition, with larger units monitored by discharge tests.

Above ground earth connections, for all equipment, are inspected and maintained at six-yearly intervals. The main earth grid connection resistances to above ground attachment points, have been measured to a common datum at each substation, and these measurements are checked at six-yearly intervals for changes in value. Sample underground connections to the main earth grid are also checked at six-yearly intervals for physical deterioration.

At twelve-monthly intervals, all SCADA transmit and receive levels are checked, recorded, and adjusted if necessary, and power supplies are checked at the master station and all remote terminals. All alarms are tested at four-yearly-intervals, from the local alarm panel and from source, and confirmed at System Control on the SCADA screen, and by print-out. The work is carried out in conjunction with minor circuit breaker servicing work.

CO₂ flood systems in load control coupling cell cubicles are inspected annually. Pressure cylinders are tested at regulated intervals dependent upon age. Inspection is carried out internally, with repairs and pressure testing conducted by external contract.

6.2.3 HV and LV Lines and Cables

At present, lines are inspected approximately every three years, and the procedures in the Electricity (Hazards from Trees) Regulations 2003 are followed. A précis of the regulations is published on Aurora's website.

HV and LV Lines

A rolling inspection of approximately 600 km of overhead lines occurs each year (covering LV, HV, and combinations of both), to establish priorities for the maintenance programme. Two towers are planned to be repainted in the next financial year after 51 years of service.

HV and LV Cables

Apart from a five-yearly inspection of underground 400 Amp LV link boxes in the Dunedin central business district, no routine inspections of cables or associated equipment are made.

Earths

General distribution system earths are tested at six-yearly intervals; however earths on the single wire earth return systems are inspected at three-yearly intervals, and tested at six-yearly intervals.

6.2.4 Distribution Substations

Substations

Ground-mounted substations that have HV circuit breaker equipment installed, have their tripping batteries checked three monthly and, where applicable, alarms are tested six monthly. All ground mounted substations are inspected at three yearly intervals.

Pole substations greater than 100 kVA are also inspected annually in conjunction with the scheduled MDI reading round. Smaller sized pole substations are inspected as required.

Buildings and Grounds

Distribution substation buildings (75) are inspected at six-monthly intervals for safety, security, and miscellaneous repairs.

Switchgear

Ring-main switchgear is relatively maintenance free, and checks on oil levels and general condition are included in the substation inspection round. The HV oil circuit breakers installed in some substations are overhauled at five-year intervals, or following operation for over-current fault.

6.2.5 System Control

SCADA

At twelve-monthly intervals, all transmit and receive levels on the communications panels are checked, recorded, and adjusted if necessary, and power supplies are checked at the master station and all remote terminals.

UHF and VHF Systems

At twelve-monthly intervals, all sites are visited; operational levels are checked, recorded and adjusted, if necessary. All aerials and power supplies, along with site security and accessibility, are also checked and rectified as necessary. At four-yearly intervals, a more detailed inspection of aerials and equipment is undertaken, and major operational adjustments made if necessary. Central zone substation remote alarms are self diagnostic with monitoring setup accordingly.

Miscellaneous

All ladders, portable earthing equipment, and safety gear used in zone substations are inspected or tested at six-monthly intervals.

6.2.6 Expenditure Projections

It is expected that the routine and preventative maintenance costs to meet agreed service targets over the next 10 years will be generally in line with the figures shown in Table 6-2.

Financial Year	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Subtransmission	371	381	392	402	413	425	436	448	457	471
Zone substations	905	930	955	981	1,008	1,036	1,065	1,094	1,115	1,148
System control	160	165	169	174	178	183	188	194	198	20421
HV and LV	1,725	1,773	1,882	1,872	1,923	1,976	2,030	2,086	2,128	2,192
Distribution substations	360	369	380	390	401	412	423	435	444	457
Total	3,521	3,617	3,717	3,819	3,924	4,032	4,143	4,257	4,342	4,472

Table 6-2 – Routine and Preventative Maintenance Costs Summary, by Asset Category

6.3 Asset Renewal and Refurbishment Policies

6.3.1 Planned Renewal and Refurbishment

Around 12% of maintenance expenditure that is expensed is for planned renewals, and refurbishment of unserviceable assets. About half of this involves asset renewal, or refurbishment programmes, to a class or model of asset or component based on evidence of a "type failure" or design weakness. The major works at the end of this section are capitalised.

These programmes of work are identified and planned before the beginning of each financial year. The remainder comprises a large number of, typically minor, component refurbishments; for example, individual insulators, many of which arise out of specific defects found within the year.

6.3.2 Fault Refurbishment

Fault refurbishments are carried out directly following an equipment failure, in order to restore service, and are budgeted to account for around 44% of maintenance expenditure. This work may, or may not, involve permanent refurbishment of the faulted equipment, as the objective is to restore service as quickly as possible by the most economical method. If the fault involves major refurbishment work, it may be that the faulted unit is renewed by a serviceable unit; for example, a spare transformer unit. The faulted unit can then be refurbished later, or disposed of if refurbishment cannot be justified.

6.3.3 Overhead Line Repairs and Refurbishment

Future maintenance workloads are projected using an analytical model. The assessed condition of each major component of each line is coded against condition criteria which are used to set maintenance priorities.

6.3.4 Circuit Breaker Renewal

Analysis has also been undertaken for programming circuit breaker renewals, based on data for individual circuit breaker types, make and model, together with an assessment of the expected economic service life of each circuit breaker, and its current rating.

Servicing expenditure for circuit breakers is also produced by the same model. Individual circuit breaker servicing frequencies, together with average costs per service, enables the model to calculate the annual servicing cost based on the population of circuit breakers in each year.

6.3.5 Power Transformer and Distribution Transformer Renewals and Refurbishment

Similar modelling to that used for circuit breakers is utilised for assessing renewal or refurbishment of transformers.

Where proactive refurbishment is required, the analysis has been conducted based on the total number of units in service, and an assessment of when and how many of the transformers may be removed from service for refurbishment each year. This analysis includes winding, core, and internal connection repairs, oil refurbishment, painting and radiator renewal.

6.4 Maintenance and Refurbishment Programmes

6.4.1 Subtransmission

Cables

The 33 kV underground cables do not have a planned refurbishment programme. Capital replacement will occur when the cost of repairs become uneconomic. Leaks occasionally develop on the gas and oil filled cables, usually at joints. Faults refurbishment is expensive, being very labour intensive. The MIND cables are virtually maintenance free but faults occasionally occur due to insulation migration on hill sections or if they have been damaged by third parties (for example - road openings, etc).

Overhead Lines

No 66 kV or 33 kV overhead lines have been identified as requiring major renewal or refurbishment although pole replacements continue as required.

Protection Pilots

No protection pilots have been identified as requiring renewal or refurbishment.

6.4.2 Zone Substations

33 kV Transformers and Tapchangers

Although the age profile is getting high, most of these transformers have not been heavily loaded during their life.

Tapchangers are refurbished at intervals based on a predetermined number of operations. The usual work required is the dressing or replacement of contacts, and filtering of oil, but springs and driving mechanisms are also checked.

All transformers have had their insulating oil refurbished in the last few years, and most transformers now have less than 0.1 mg KOH/g acid level, good breakdown resistance, and low moisture content. Some transformers have higher than optimum moisture content and this is being rectified by using mobile "Trojan" plant to dry the oil out.

Buildings and Grounds

As part of the works identified in the ten year building maintenance plan, a number of buildings will have exterior paint work carried out within the planning period.

Circuit Breakers, Isolators and Structures

Twelve 33 kV circuit breakers are now over 40 years old, and some will require renewal within the next 10 years. (See Section 6.5.6.)

One hundred and thirty three 6.6 and 11 kV circuit breakers are now over 40 years old, and some will require renewal within the next 10 years. (See section 6.5.7.)

Ripple Injection Plant

As part of the routine contactor checks in Dunedin, contacts will be renewed. Motor-generator sets are being monitored and routine maintenance will be carried out where identified as necessary.

The Alexandra 33 kV injection equipment in the Central network area has been identified as now having reached the end of its expected service life with no critical spares available.

While North East Valley 33 kV injection equipment is still within its expected service life there are no critical spares available.

Through the outsourced maintenance contract for the 33 kV injection equipment, rental units are available and would be hired while new units were acquired.

Cromwell upgrades are now complete in association with a recent Transpower GXP upgrade.

There are approximately 65 distribution substations in the Central Otago network which had pilot wire control circuits installed between 1970 and 1988. These have been suffering from decreased reliability, and it has been standard practice, after failure of these circuits, for the retailer to renew the pilot wire relay on the consumer's switchboard with a modern ripple receiver.

6.4.3 HV and LV Lines and Cables

HV and LV Lines

Hardwood poles are presently being renewed at the rate of about 1.5% per year. The pole age profile implies that the renewal rate will gradually increase over the next 20 years, and then decline again.

Approximately 5 kilometres of HV conductor and cross-arm renewal is programmed each year, in both the Dunedin and Central areas, and it is expected that this level of renewal will be sufficient for the next 10 years.

Approximately 2 to 5 kilometres of LV conductor and cross-arm renewal is programmed each year, depending on condition assessments. As well as condition based renewal work, renewal is frequently necessary due to the installation of new substations and/or local load growth and voltage complaints.

HV and LV Cables

Renewal work has been carried out, over recent years, on the LV distribution system in the Queenstown and Alexandra CBDs, where many obsolete link pillars have been renewed with modern units that provide a safer and more flexible system. Queenstown CBD is now complete with Alexandra CBD ongoing. This work has now been extended to the Wanaka and Cromwell areas.

Earths

Earths identified during routine inspection as requiring attention will be refurbished as required.

6.4.4 Distribution Substations

Transformers

Transformers identified as requiring refurbishment during the annual inspection round will be refurbished as required

Substations

Substations identified as requiring refurbishment during the annual inspection will be refurbished as required.

Buildings and Grounds

Buildings and grounds identified as requiring refurbishment during the six monthly inspections will be refurbished as required.

Switchgear

The HV oil circuit breakers installed in some substations supply critical circuits, and are reaching the end of their physical life. These will be renewed within the planning period, and expenditure on these will gradually reduce over the duration of the plan. (See section 6.5.8.)

6.4.5 System Control

SCADA

A service contract for the maintenance of the SCADA software commenced in July 2005, which covers a helpdesk service for faults and future software upgrades.

UHF and VHF Systems

No UHF or VHF systems have been identified as requiring renewal or refurbishment.

Miscellaneous

Ladders, earthing equipment, and safety gear at zone substations identified as requiring refurbishment during the six monthly inspections will be refurbished as required.

6.4.6 Expenditure Projections

It is expected that the expensed refurbishment and renewal costs, (excluding fault repairs and third party damage), to meet agreed service targets over the next 10 years, will be generally in line with the figures shown in Table 6-3.

Financial Year	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Subtransmission	57	58	60	62	63	65	67	69	72	74
Zone substations										
System control										
HV and LV	724	744	764	785	807	829	852	875	918	946
Distribution substations	229	235	241	248	255	262	269	277	288	296
Total	1,009	1,037	1,066	1,095	1,125	1,156	1,188	1,220	1,278	1,316

Table 6-3 – Refurbishment and Renewals Costs Summary by Asset Category (\$000)

Renewals within zone substations are usually major items; for example, 11 kV switchgear replacements, and as such are part of the capital renewals schedule. Subtransmission renewals are also capitalised.

6.5 Capital Replacement Projects

Replacement of equipment is scheduled when the annual cost to own, operate and maintain existing equipment plus the average annual cost of consequential failure exceeds the annual cost to own, operate, and maintain new equipment. Replacements are also scheduled when the design or condition of equipment is a significant hazard to operating staff or the public. Projects over \$300,000 or those of strategic significance are described below.

6.5.1 Ward Street Substation

The Ward Street substation was renewed in the 2010/11 year.

6.5.2 33 kV Gas Cables

Five Dunedin zone substations are supplied by gas insulated 33 kV cables as shown in Table 6-4 below. These cables have been prone to gas leaks. For six months in 2004-05 the failure rate reached 20 failures per 100 kilometres per year, which was unacceptably high. Since then, the failure rate has reduced.

Linetech Ltd, which reviewed the 2009 Aurora development plan, recommends that Aurora should schedule the replacement of all its gas cables. They are prone to leaking gas at joints after a shock load event. A shock load will occur when one cable of a pair trips causing the doubling of the load on the cable left in service. This increases the chance of having a complete loss of 33 kV supply to a zone substation. Cable replacement is scheduled in the 10 year planning period.

A recent gas leak on the Willowbank 2 cable in September 2010 was due to corrosion of the bronze tapes. There was evidence that the cable rubber sheath had deteriorated significantly. It appears that the deteriorated rubber sheath allowed moisture to enter the cable resulting in corrosion of the bronze tapes. Refer to Figure 6.1 and to Figure 6.2 below.



Figure 6.1 - Willowbank No2 Cable – Failed Bronze Tape September 2010



Figure 6.2 - Willowbank No 2 Cable – Degraded Rubber Sheath September 2010

A replacement schedule is outlined in Table 6-4 below. This is an initial program and performance of the cables could alter priorities.

The Andersons Bay cable is considered to be the top priority as Andersons Bay cables are the unreliable bronze tape type and it is not possible to fully off-load Andersons Bay. Two excavations of the Andersons Bay cable were carried out in November 2010 and samples of the rubber sheath were removed for inspection. The sheath sections removed were in relatively good condition but at one site there was evidence of moisture on the bronze tapes. Due to this favourable result the replacement of the Andersons Bay cables has been deferred one year from the date proposed in the 2010 plan.

The Neville Street and Smith Street cable upgrades are scheduled to be replaced in conjunction with the upgrade of the associated substation. See Sections 6.5.4 and 5.11.6.

The Ward Street cable is last on the list as it is the youngest cable and has an aluminium sheath which is more reliable than the bronze tape cable.

Willowbank has a moderate priority as it will be possible to fully off-load Willowbank but the cable is the unreliable bronze tape type.

Cable	Year Installed	Route Length (km)	Replacement Year	Estimated Cost \$000
Sth Dn – Andersons Bay	1961	2.7	2012/13	3,000
HWB – Neville Street	1961	6.82	2014/15	1,600
HWB – Willowbank	1963	3.95	2017/18	4,300
HWB – Smith Street	1959	3.2	2019/20	3,500
HWB – Ward Street	1967	4.21	2020/21	4,700

Table 6-4 –33 kV Gas Cable Replacement Schedule

6.5.3 Kaikorai Valley 33 kV Cables

There are two parallel 33 kV cables from the Halfway Bush GXP to the Kaikorai Valley zone substation with a route length of 2.9 km. These cables were originally installed in 1950 to supply the Neville Street substation and were subsequently diverted to the Kaikorai Valley substation in 1978. The original cables were paper insulated with a lead sheath. There have been failures of the cable on the steeper sections of the route due to the cable paper drying out due to the oil used to impregnate the cable migrating down the cable.

In the 2009 plan, it was proposed to replace the first 250m out from the substation in Stone Street. It is now considered it would be more appropriate to replace the whole cable at once rather than piece meal replacement program. This has been scheduled for 2015/16 unless the failure rate accelerates before then.

Estimated Cost \$2.9 million

Completion: May 2016

6.5.4 Neville Street Substation Upgrade

The majority of the primary equipment at the Neville Street substation was installed in 1948 and is nearing the end of its economic life. It is believed the most economic upgrade option is to completely rebuild the substation on land adjacent to the existing site. The substation is adjacent to the Carisbrook sports ground which has been purchased by Dunedin City Council. It is believed there will be mutual benefit to both Council and Aurora to have the substation relocated.

The Neville Street substation is very large by today's standards and would impose significant constraints on the redevelopment of the land. It is proposed the replacement of the Neville Street 33 kV gas cables be carried out at the same time and their connection be moved from the HWB GXP to the South Dunedin GXP. See Section 6.5.2.

Estimated Cost \$6.0 million

Completion: May 2015

6.5.5 Roxburgh Substation Upgrade

There are several items that need attention at the Roxburgh substation:

- two of the 11 kV circuit breakers are scheduled for replacement;
- the incoming circuit breakers are near the end of their economic life;
- SCADA enhancements are proposed;
- protection relays need to be moved out of the Teviot Power Station;
- new control room required;
- space and connection facilities required for the mobile substation;
- lightning arresters upgrade required.

Rather than addressing each item separately, a one-off upgrade is proposed to address all the issues at Roxburgh.

Estimated Cost \$500,000

Completion: May 2012

6.5.6 Zone Substation 33 kV Switchgear Replacements

Several zone substation 33 kV breakers are older than 40 years and are scheduled for replacement. The scheduled replacements, subject to confirmation by economic analysis, are detailed in Table 6-5 below.

Substation	Notes	Year of Manufacture	No of Breakers	Year	Cost (\$000)
Neville Street	Replacement or removal will be done in conjunction with sub-station rebuild	1948	3	2014/15	
Alexandra	Scheduled	1960	3	2013/14	200
North East Valley	Scheduled	1963	2	2011/12	160
Queenstown	RV		2	2011/12	160

Table 6-5 – Zone Substation 33 kV Switchgear Replacement Schedule

6.5.7 Zone Substation 6.6/11 kV Switchgear Replacement

The zone substation 6.6/11 kV switchgear older than 40 years is listed in Table 6-6 below and scheduled replacements are identified.

The Andersons Bay 6.6 kV switchgear had a low bus bar insulation test in December 2009 and as a precaution was scheduled for replacement during the 2011/12 summer. Further testing completed in November 2010 indicates that the insulation resistance is not deteriorating further and as such an upgrade could be delayed until nearer the end of the 10 year planning period when it can be carried out in conjunction with a transformer replacement. The Willowbank 6.6 kV switchgear, which is the same type and the Anderson Bay switchgear, was also tested and is not deteriorating either.

In 2009, the ASEA minimum oil circuit breaker mounted on the Frankton T2 Transformer failed to clear a fault and was totally destroyed. This type of breaker is also installed on transformers at Arrowtown, Dalefield, Omakau, Clyde Earnsclough, Maungawera and the spare 3 MVA unit. They have installation dates between 1960 and 1970. Replacement of the Ettrick, Dalefield, Omakau and spare transformer breakers has been scheduled. Replacement of the Maungawera, Clyde-Earnsclough and Earnsclough has been deferred due to other pending area upgrades eliminating the need.

Substation	Manufacture Year	Status	Number CBs	Year	Cost (\$000)
Roxburgh feeders	1950	Planned	2	2010/11	35 Note 1
Ward Street	1938	Underway	14	2009/10	Note 2
Frankton	1950	Underway	8	2011/12	Note 3
Neville Street	1948 & 1953	Planned	14	2014/15	Note 4
Halfway Bush	1956	Monitor	16	-	
Green Island	1957	Monitor	15	-	
Smith Street	1958	Planned	15	2018/19-	Note 5
Earnsclough	1960	Monitor	1	-	
Dalefield	1960	Planned	1	2011/12	80
Roxburgh T1 & T2	1960	Planned	2		
Ettrick	1960	Planned	1	2010/11	80
Clyde-Earnsclough T1 & T2	1960	Monitor	2		
Andersons Bay	1961	Monitor	15	2020/21	1,800
Willowbank	1962	Monitor	15		
Outram	1963	Monitor	8		
Maungawera	1965	Rebuild at Hawea?	1		
Arrowtown T1 & T2	1970	Planned	2	2016/17	Note 6

Table 6-6 - Zone Substation 6.6/11 kV Switchgear Replacement Schedule

Note 1: Use Nova CB704 and 723 when removed from Frankton.

Note 2: Switchgear replacement part of major sub upgrade see Section 6.5.1.

Note 3: Switchgear replacement part of major sub upgrade see Section 5.11.11

Note 4: Switchgear replacement part of substation rebuild project see Section 6.5.4.

Note 5: Switchgear replacement part of substation upgrade project see Section 5.11.6.

Note 6: Switchgear replacement part of substation upgrade project see Section 5.11.8.

6.5.8 Distribution Circuit Breaker Replacements

A number of distribution substations have oil circuit breakers. The Reyrolle Type C switchgear is that is now over 60 years old is obsolete and expensive to maintain. It is proposed this switchgear be replaced with ABB SD switchgear in accordance with the schedule in Table 6-7.

Site	Make	Date of Manufacture	Replacement Date	Cost (\$000)
Andersons Bay rectifier	Reyrolle	1948	2011 Underway	148
Tyne St rectifier	Reyrolle	1948	2011	120
Tennyson St rectifier	Reyrolle	1948	2012	120
Great King St rectifier	Reyrolle	1948	2013	120
Shacklocks	Statter AC2	1960	Monitor	
High Street	Statter AC2	1960	Monitor	
Ravensdown Fertilizer	J&P	1962	Monitor	
Hillside Workshops	J&P	1956	Monitor	

Table 6-7 – Distribution Substation HV Switchgear Replacement Schedule

6.5.9 Replacement of Potentially Hazardous Central Ground Mounted Substations

In Central, there were some ground mounted substations that consist of BU-BU or CB-BU transformers in a Central Electric designed enclosure. These substations were potential hazards due to HV terminals being accessible ventilation mesh and there are also safety issues with the LV distribution boards. In the last year four have been completed with one remaining.

Sub Name	Size kVA	Completion Date	Estimated Cost
WK37	150	2011/12	\$50,000

6.5.10 Replacement of Pacific Fuses

In the Central area, many distribution pole top substations are fused with glass tube "Pacific" fuses. These fuses have limited fault rating. In Dunedin, a decision was taken in 1979 to progressively replace all these fuses after a technician narrowly escaped serious injury when livening a transformer using a Pacific fuse. These fuses are still used on the Central Network. It is recommended that these fuses be progressively replaced over the next 8 years.

Estimated Cost \$60,000 per year to 2018

6.5.11 Underground Substations, Distribution Board Replacements

The LV distribution boards in the London Street underground substations need to be replaced due to excessive rusting. It is proposed to relocate the substation above ground which will also eliminate flooding problem. Acquiring a suitable site is taking longer than planned.

Estimated Cost \$90,000

Completion: December 2011

6.5.12 Replacement of Dunedin Ripple Injection Equipment

The Dunedin ripple injection system presently a 1050 Hz mixed K22/decabit system with 18 injectors, one at each zone substation. All of the injectors are motor-generator sets except one. Several of the MG sets are now over 50 years old and there have been three failures in recent years. There are problems with 1050 Hz injection being harmonic interference, absorption by capacitors and poor signal propagation.

A project is underway to upgrade the Dunedin ripple injection system to 317Hz injection at the 33 kV grid exit points. This only requires three injectors rather than 18 if injection was maintained at zone substations. The 1050 Hz system will be required to operate in parallel with the 317 Hz system for several years until all the 1050 Hz receivers on the network have been replaced or re-tuned. The receivers are owned by Electricity Retailers and DELTA Utility Services. It is proposed to initially target the replacement of relays on the Taieri which will enable the motor generator sets at Outram, Berwick, East Taieri and Mosgiel substations to be removed which will then be available as spares for the remaining sets.

An alternative solution of using a low frequency radio network was investigated but was determined to be more expensive than the 317Hz injection option.

Estimated Cost \$2.658 million

Completion: March 2011

6.5.13 Replacement of Frankton Ripple Injection

A project is underway to renew the Frankton ripple injection equipment and re-locate it to the Transpower Frankton GXP. When this upgrade is complete the new injectors will cope with up to 100 MW of connected load.

6.5.14 Replace Central Load Control Master Station

Load control in Central is controlled by a PLC interfaced to a PC in Alexandra. This system was designed and programmed by Central Electric. The maintenance of this system is dependent on the knowledge of the original designer. It is recommended the system be upgraded to a proprietary system and control and monitoring be integrated with the Central SCADA master station.

Estimated Cost \$200,000

Completion: May 2012

6.5.15 Refurbishment of the Port Chalmers to Peninsula Towers

These towers were installed in 1960 and have been relatively maintenance free until now. External consultants have recommended that the towers should be cleaned and repainted. These are strategically important as they provide a robust 11 kV feeder to the Otago Peninsula. (There is also a submarine cable across the harbour that has been trouble free since the early 1990's; however a single cable repair would be of the order of \$300,000 - \$500,000.)

Estimated Cost \$250,000
(one tower)

Completion: March 2012

6.5.16 Renewal of Section of PC5 Involving a Conversion to Underground

A section of PC5 adjacent to Port Otago is has reached the end of its economic life. This section of line is constructed very close to a Port Otago warehouse and safety clearances are inadequate. It is not possible to reconstruct the line and maintain NZECP28 safety clearances. In conjunction with the project it is proposed to remove the short overhead spur that provides a tie to PC4. This spur line requires maintenance and tree control work.

There is another tie with PC4 further along PC5 making this tie unnecessary. It is proposed the 100KVA Macandrew Road substation be removed and the customers connected to it be supplied via new LV underground cable from the Mount Street substation. The project requires the installation of a 3 way ground mounted HV switch.



Estimated Cost \$350,000

Project No 3722

Completion: Dec 2011

6.5.17 Replacement of Halfway Bush Transformer T1

Transformer T1 had a tapchanger fault in October 2010. Investigations showed that the insulation paper has reached its end of economic life and as such is to be replaced along with Transformer T2 (same age, repaired winding fault in 2006).

Estimated Cost \$3.0 million

Completion: April 2012

7 Risk Policies, Assessment, and Mitigation

7.1 Methods, Details and Conclusions of Risk Analysis

Aurora manages risks imposed by technological change, economic alternatives, load changes, distributed generation, and the environment.

7.1.1 Risk Management

DELTA has developed and implemented a risk management policy that defines the approach taken to manage risks associated with the management of Aurora's electricity line business. The primary strategy of this policy is to document all significant risks as they are identified, together with the policies and procedures for eliminating, or reducing and managing the consequences of each risk event. This risk management policy specifies the risk areas for which formal policies will be maintained, as set out in Table 7-1.

Generic Risk Area	Sub-Category	Policy Reference
Asset protection	Safe-keeping	<ul style="list-style-type: none"> Electricity Distribution Quality System Risk Management for Electricity Networks Policy (QM20)
	Maintenance of service potential	<ul style="list-style-type: none"> Network Planning Policy
	Replacement planning	
Customer service	Product/service quality	<ul style="list-style-type: none"> Quality System Coverage Scope and Definitions Policy
	Complaints	<ul style="list-style-type: none"> Handling of Complaints Policy
Disaster – fire, flood, earthquake, tsunami, chemical spill, etc		<ul style="list-style-type: none"> Contracting Hazard Register Index Network Risk Management Policy Pandemic Planning Policy
Employment	Employee relations	<ul style="list-style-type: none"> Standard Conditions of Employment Policy Individual Employment Agreement Template
	Health and safety	<ul style="list-style-type: none"> Health and Safety Policy
	Maintenance of work skill capability	<ul style="list-style-type: none"> Training and Staff Competence Pandemic Planning Policy
Environmental protection		<ul style="list-style-type: none"> Environmental Policy
Financial management	Interest rate exposure	
	Liquidity	
	Re-financing	
	Defalcation	
	Fraud	<ul style="list-style-type: none"> Fraud and Other Similar Irregularities Policy Protected Disclosures Policy Delegations Policy

Generic Risk Area	Sub-Category	Policy Reference
Information systems	Financial systems	• Delegations Authorities Policy
	Archives	• Company Filing Policy
	Filing system	
Legal compliance	Health and Safety in Employment Act	▪ Health and Safety Policy
	Electricity Act and associated Regulations	▪ Network Policy
	Resource Management Act	▪ Environmental Policy
	Human Rights Act	▪ Human Rights in Employment Policy
	Local Government Official Information and Meetings Act	▪ Handling of Complaints Policy
	Ombudsmen Act	▪ Handling of Complaints Policy
	Privacy Act	▪ Security of Personal Information Policy
	Protected Disclosures Act	▪ Protected Disclosures Policy

Table 7-1 – Risk Categories and Related Policies

The Asset Management Plan addresses asset related risks only. The scope of other risks that may affect Aurora and its contractors are included above for completeness. We note that the Pandemic Plan was tested in the autumn and winter of 2009 with strategic hygiene related materials being issued, regular staff updates being made, along with the monitoring of staff health and absences following the outbreak of swine flu in Mexico. The main risks associated with Aurora's assets are described below:

7.1.2 Injection Performance (Risk of non-supply from Transpower)

Supply availability and reliability to zone substations is dependent upon both the security of supply from the five GXPs within the network areas, and the security and level of distributed generation connected into those GXP systems.

	n-1 Transpower Capacity MVA	Distributed Generation MW	n-1 Security
Halfway Bush	107	58	No
South Dunedin	81	2	Yes
Clyde	27	23	Yes
Frankton	66	3	Yes
Cromwell	50	5	Yes

Table 7-2 – Injection Security

Section 5.9.5 refers to the fact that Waipori generation would be able to maintain supply to the Halfway Bush GXP. The risk of non-supply from Transpower is, therefore, assessed to be very low – even though when this happens the effects are likely to be major.

7.1.3 **Network Capacity** (ie adequacy of service)

Aurora's policy is to provide sufficient capacity to meet customers' requirements, subject to satisfactory financial arrangements. For asset management planning, projected demands determine capacity criteria, for which additions and modifications to the network are designed.

Capacity increases to cater for existing and predicted growth are step like in nature. For example, the provision of the new Commonage substation increased the capacity of the Queenstown CBD and surrounding area by 15 MVA, or 75%. Similarly, the upgrading of the Frankton substation will increase the n-1 capacity in this area by 50%.

There is a risk that growth could slow, or stagnate, and lead to a short term view that there has been over-investment in this region. However, given the lead times required under the RMA and the time required for equipment to be sourced from overseas; the risk of non-supply and the resulting consequential effects is greater than that of over-investment and, as such, is the predominate risk to be managed.

Over-capacity due to consumers no longer needing a power supply, or a high capacity power supply is an ongoing second order risk compared to the above paragraph. Equipment is relocated if it is economic to do so.

7.1.4 **Network Reliability** (ie continuity of service)

Reliability is a function of:

- equipment duplication, which either avoids an interruption or shortens restoration times (ie security of supply);
- asset condition, which affects the likelihood of failure of a component;
- operational practices, which reduce restoration time.

A "deterministic filter" to highlight areas of the network that require further economic analysis is shown in Appendix C - Table of Guidelines for Security of Supply.

While, ultimately, it is customers' requirements and financial commitments which drive work that might alter system reliability, expenditure is presently planned to achieve the supply reliability targets set out in Section 4.3.

Where problems are identified in relation to short-term voltage variations, Aurora works with individual network users to identify and implement the optimum solution.

Probabilistic analysis, as described in Section 5.5, is used for major plant items to determine the likelihood of equipment failure and the consequential effects of lost load.

The probability of failure is assessed by using engineering judgement in considering past and likely future failure rates. Judgement is required, as blind consideration of past failure rates tends to under-predict the future.

Probabilistic analysis is also used to justify small scale projects, such the installation of reclosers to improve SAIDI.

7.1.5 Works Implementation

In reviewing the progress of capital works, in particular over the three years, the ability of the supply industry to meet what have been historically reasonable deadlines has declined. Consulting staff are not as available as they have been in the past, and equipment procurement, particularly power transformers, requires long lead times as mentioned in recent AMPs.

The risk of not obtaining adequate competent human resources for timely design and construction is an industry-wide risk. Longer lead times are, therefore, required to minimise the possibility of industry peak workloads causing unacceptable pricing of works. This situation, compounded with the need to design and order items such as power transformers before finishing detailed design such as substation layouts required for resource consent, with its own possibility of objector delays is creating further uncertainty of being able to complete projects on time.

In the 2009/10 AMP, reference was made to a project being put on hold following the appeal by a member of the public regarding the issuing of a Resource Consent. This took approximately eight months to resolve using the mediation provisions of the Environment Court. This delayed the project for a year. In a different project, it took five months to designate land “for substation purposes”. The land already had a zone substation on it for several decades. Such delays do nothing to facilitate the economic provision of a reliable power supply.

A potential risk to works implementation is the recent (December 2010) proposal to remove the ability of Lines Companies to designate land for works as well as the possibility of removing access to the Public Works Act. Submissions have been made to Central Government regarding these issues.

7.1.6 Safety

Customer, employee, and public safety are assured by a combination of adequate design, safe operation, and appropriate maintenance of assets.

The Health and Safety in Employment (HSE) Act is a key item of safety legislation impacting on Aurora’s contractors. While not overriding safety requirements found in the Electricity Act and Regulations, the HSE Act has far reaching impact; requiring all hazards associated with assets to be identified, assessed, and controlled, if found to be significant. This is achieved by duties set on all parties associated with design, construction, maintenance and operation of Aurora assets.

As an owner and principal, Aurora is required to take all practicable steps to ensure no harm befalls contractors, contractor employees, and others. This is achieved through good design, plant security, safe systems for work access, and contractor selection and monitoring. Contractors are responsible under the HSE Act for safety and competency of their employees working on Aurora assets.

All operation and maintenance work performed on Aurora network assets must be performed in accordance with “Safety Manual, Electricity Industry”, which is a set of safety rules for the New Zealand Electricity Generation, Transmission and Distribution Industry. This publication is an industry-accepted standard, and provides a means of complying with the safety requirements of the HSE Act, the Electricity Act, Electricity Regulations, and subsequent amendments. A Public Safety Management System is being developed as per the Electricity Safety Regulations 2010.

The “Southern Power Companies’ HV Safety Procedures” complement the Safety Manual by specifically detailing and standardising methods of compliance with those rules.

The Building Act 1991 impacts on various Aurora facilities, requiring that buildings are safe, sanitary, and offer adequate means of escape from fire.

7.1.7 Environmental Responsibility

Aurora's policy is to act in an environmentally responsible manner, and as required under legislation.

The Resource Management Act is the major legal driver. The provisions relating to the discharge of contaminants into the environment, the duty to avoid unreasonable noise, and the duty to avoid, remedy or mitigate any adverse effect on the environment are of particular relevance.

The Act requires appropriate consents for new work, and requires management systems (mainly for environmental and public safety issues) in relationship to existing works. Aurora develops practices on the basis of being a reasonable and prudent operator, to ensure that both environmental and public safety issues have been addressed.

The main environmental risk from Aurora operations is the accidental discharge of insulating oil into waterways. Oil spill kits are provided at all zone substations, and contractors are required to carry oil spill kits in vehicles used to transport oil filled equipment. Where practicable, zone substations have adequate bunding to contain potential oils spills.

Aurora is complying with the tree trimming regulations, (Electricity (Hazards from Trees) Regulations 2003) and is managed by quality policy QP1511.

The use of equipment with SF6 is actively discouraged, where economic alternatives exist, due to its potential to act as an ozone depleting agent if it is accidentally released into the atmosphere. We note that SF6 is likely to become the insulation medium of choice within New Zealand due to most line companies no longer using oil based switch-gear and as such *DELTA* staff have been investigating likely suppliers.

7.1.8 External Reviews

External reviews of selected aspects of asset management practices are undertaken to ensure that internal mindsets do not occur. Recent external reviews include:

- May 2005. All ground-mounted transformers were assessed for risk of vehicle impact and subsequent oil leak into a water way.
- March 2007. Analysis and review of circuit breaker monitoring and maintenance procedures was initiated, and completed in August 2008, following a study of peer practices. This has resulted in an increased frequency of circuit breaker inspections.
- June 2008. Analysis and review of pole inspection records, monitoring, and data capture procedures. This has identified data deficiencies. Improvements to condition data records continue.
- Year ending March 2010. A review of structural adequacy of selected zone substation buildings was initiated.

- Also in the year ending March 2010, a review of the Value of Lost Load was initiated which resulted in adoption of the values in this AMP.
- Year ending March 2011. Reviews of maintenance practices, engineering approach to risk and security of supply issues were completed. The conclusion is that the gas insulated subtransmission cables in Dunedin are fast approaching the end of their economic life has been reinforced by further site investigations. Structural checks have shown that one substation requires further earthquake strengthening.

7.2 Details of Emergency Response and Contingency Plans

7.2.1 General

Aurora's Emergency Response Plans consist of a series of quality documents and procedures. They provide both general guidelines and specific instructions for response to abnormal conditions, created by either a civil defence emergency or plant and system failure, and are directed towards minimising the effect of the emergency, and the prioritisation of restoration of electricity supplies.

7.2.2 Civil Defence

DELTA has a comprehensive plan for response to emergency situations and for liaison with local Civil Defence organisations for the effective use and co-ordination of resources within Aurora's electrical supply area in emergencies. The details are in documents QP2001 Civil Defence and QP2002 Emergency Preparedness Plan. These documents are updated every two years.

The *DELTA* Engineering Services Manager is the lead Civil Defence Engineering Manager in Dunedin. Other *DELTA* staff have roles within the Civil Defence structures in Otago. *DELTA* staff take part in Civil Defence exercises as required. Several *DELTA* staff assisted in damage assessment activities immediately after the September 2010 Christchurch (Darfield) earthquake and have passed on lessons learned to key staff.

Aurora has installed a generator at the Cromwell base to enable this hub, like Dunedin, to be fully operational during an emergency. Satellite phones are kept at these hubs and Queenstown for emergency use.

7.2.3 Routine Emergency Response

DELTA responds regularly to routine emergencies, such as network system outages. Restoration of supply is co-ordinated via the System Control Centres, which are staffed during normal business hours. After hours, standby rosters are in place with the on-duty Controller attending the Control Centre as necessary. Standard Operating Procedures are covered by quality control documents QP1601, QP1602, QP1603, QP1604, QP1605, QP1606, QP1607 and QP1609.

7.2.4 Contingency Plans

DELTA has developed general contingency plans to assist in the timely restoration of supply following an outage to a major distribution feeder or zone substation. These are recorded in QP 1602/21 which is updated every two years. It should be noted that it is not possible to offload peak loads at most substations for potentially rare “n-2” events; ie transfer a complete substation’s load for a combined failure, such as both subtransmission circuits or both transformers at the larger substations. Some of these substations serve CBD areas so external consultants have been engaged to confirm whether this situation remains appropriate.

Reviews of how well the plans worked during major events are completed with the most recent being the off-loading of the Willowbank zone substation due to a dual subtransmission fault (third party damage) in August 2009.

In 2009, Aurora was one of the first two distributors to have its Participant Outage Plan approved by the Electricity Commission. This plan is required to be produced under the Electricity Governance (Security of Supply) Regulations 2008. It details how Aurora would manage severe energy shortages if the Electricity Commission declared that savings are required.

8 Performance Measurement, Evaluation and Improvement

8.1 Review of Network Service Level Performance

These are summarised in Appendix A.

8.1.1 Reliability

The System Average Interruption Duration Index (SAIDI) provides an overall measure of asset performance for the year. This is shown in Table 8.1 below along with unplanned System Average Interruption Frequency Index (SAIFI).

Category	09-10 Target	09-10 Actual
SAIDI	Minutes	Minutes
Unplanned		
Underlying	62	56.8
Significant events	10	4.5
Planned	15	11.2
Aurora Subtotal	87	72.5
Transpower	0	10.2
SAIDI Grand Total	87	82.7
SAIFI	Interruptions	Interruptions
Unplanned by Aurora	1.31	1.48

Figure 8.1 – Target v Actual SAIDI and SAIFI 2009-2010

System performance is categorised to eliminate causes outside Aurora's normal span of control; specifically the results of Transpower initiated outages, or significant storm events. The resultant underlying system performance is the area that is closely monitored to identify areas for improvement. Significant or storm events are also analysed to identify areas for improvement that may produce a cost effective means of minimising disruption from those events.

For unplanned interruptions, the "underlying" pattern was 5.2 minutes below target. There was a significant, (significant being defined as over 300,000 customer minutes), weather event in Central Otago on 18 December 2009. Also there was a major Transpower initiated event on 16 March 2010.

Planned interruptions were 3.8 minutes below the 2009-10 target figures, which was assisted by a drop off in new network connections. Wherever economic, contractors use live line techniques to connect new extensions to the network.

8.1.2 Faults per 100 km HV Circuit

The number of faults per 100 km of line for the year 1 April 2009 to 31 March 2010 was 9.1, which is a small reduction from 9.2 the previous year. Note that the forecast for 2010 – 2011 year is 10.6.

8.1.3 Low Voltage Complaints

Twenty four valid voltage complaints were received for the year 1 April 2009 to 31 March 2010. This is well below the target of 10 per 10,000 connections.

8.1.4 Environmental Performance

There were no reported environmental incidents for the year 1 April 2009 to 31 March 2010.

8.2 Review of Financial Performance

8.2.1 Maintenance Expenditure

For the year in review, planned maintenance activities have generally been completed in line with maintenance standards.

A comparison of Aurora's maintenance expenditure against budget is shown in Table 8-1, below:

Category	2009/10 Actual \$000	2009/10 Budget \$000	Variance	
			\$000	%
Routine and Preventative Maintenance	3,147	3,410	-263	-7.7
Refurbishment and Renewal Maintenance	1,417	956	461	48.2
Fault and Emergency Maintenance	4,527	4,154	373	9.0
	9,091	8,520	571	6.7

Table 8-1 – Maintenance Expenditure Budget Compared to Actual

Variances from budget are discussed below:

- Routine and preventative maintenance was held back due to the over-expenditure in faults.
- Underground conversion costs were not included in the original renewal budget.
- Third party damage was slightly higher than budgeted so adding to the faults over-spend compared to budget.

8.2.2 Capital Expenditure

A comparison of Aurora's capital expenditure budget is shown in Table 8-2.

Category	2009/10 Actual	2009/10 Budget	Variance	
	(\$000)	(\$000)	(\$000)	%
Customer Connection	7,725	5,000	2,725	54.5
System Growth	9,157	3,650	5,507	150.9
Asset Replacement and Renewal	2,528	5,460	-2,932	-53.7
Reliability, Safety and Environment	2,102	500	1,602	320.4
Asset Relocations	186	400	-214	-53.5
Total	21,698	15,010	6,688	44.6

Table 8-2 – Comparison of Actual Capital Expenditure with Plan

The causes of variances are:

Capital expenditure - asset relocations - mainly driven by local authorities.

Operating expenditure - refurbishment and maintenance - mainly above budget due to higher expensed costs associated with the overhead to underground programme.

- Customer connections work, which is consumer initiated, remained higher than the budget which was reduced compared to previous years. Note that the actual quantum was less than previous years.
- System growth was above forecast due to the late commissioning of the Commonage zone substation (\$2.9 million) plus more accurate coding has transferred expenditure from the asset replacement and renewals capital expenditure.
- Asset replacement and renewal – as above plus there was \$1.1 million of overhead to underground expenditure in “Assets under Construction” which was expected to be capitalised by 31 March 2010.
- Reliability, safety and environment was above forecast due to the late arrival of 5 MVA mobile transformer

Asset relocations timing and quantum is mainly dictated by local authority projects and, as such, the planning of this work is largely outside Aurora's control.

As at 31 March 2010, Aurora had \$8,369 million of works under construction; major Aurora initiated items are detailed in Table 8-3.

Item	Value (\$000)	Status
Ward Street substation	1,890	Construction underway but major plant delivery delays
Cardrona lines and substation	1,132	Construction underway but RMA and material supply delays
Undergrounding projects	1,320	Projects underway but not complete (Kaikorai Valley Road, Dunedin)

Table 8-3 – Projects Under Construction

Looking forward to the year ending March 2011, we note that the earthquake in Christchurch on 22 February 2011 disrupted material supply, such as switchgear, to several capital projects.

8.3 **Gap Analysis and Identification of Improvement Initiatives**

Both planned and unplanned maintenance activities are analysed to monitor performance trends, and to evolve both maintenance practices and replacement policies. No changes to current practices have been made in the last year; however, some policies are being externally reviewed to confirm that they still meet best practice.

All unplanned interruptions exceeding 0.5 SAIDI minutes are subjected to an engineering investigation, and a summary report provided to the Aurora Board. These reports specifically identify improvements to material selection, items of plant, design, configuration, and operation. No systemic equipment failures were identified within these reports in the last year.

Recently identified improvements have included:

- SCADA improvements to the Central network;
- data quality improvements to GIS records, when economic to do so (ongoing);
- renewal of the Ward Street zone substation (completed during the winter of 2010).
- upgrading of the Frankton zone substation (approved, transformers ordered, construction underway, expected completion by the winter of 2011);
- construction of the Cardrona zone substation and a new subtransmission circuit to it from Wanaka (approved and underway but parts of the project were on hold as at 1 April 2010 due to an appeal to the Environment Court). This matter was resolved using the Environment Court mediation procedures and the project got underway again in spring 2010;
- installation of new 317 HZ load management injection equipment at the Frankton, South Dunedin and Halfway Bush GXPs;
- upgrading of the Remarkables Zone substation from 1 MVA to 3MVA.

The use of RCC Ground Fault Neutralisers continues to be monitored and is still not yet considered to be economic. This continues to be reviewed annually by liaising with other networks who are installing them.

Further studies regarding potential projects to maintain/improve reliability are underway. These may result in new projects being identified and described in future AMPs.

8.4 Smart Grids and New Technologies

During the last ten years, Aurora has concentrated on improving network reliability performance by:

- installing more remote control of switches in the network;
- installing more intelligence in protection devices at zone substations;
- improved thermal monitoring of equipment to allow some key assets to be operated closer to their limits;
- extending the functionality of the SCADA system to all substations;
- improving zone substation earths;
- upgrading load management injection units;
- replacement of selected copper communications circuits between system control and zone substations with fibre communications circuits.

The above additions have been linked to Aurora's SCADA system at System Control which has provided additional information to controllers and allowed improved performance during faults or reduced the risk of a trip occurring.

For the 10-year planning period to 2021, Aurora expects that the following will impact on network operation and investment.

- significantly more distributed generation connected to the low voltage network;
- the charging of electric vehicles will begin to impact on network operation and design;
- installation of smart meters with links to home area networks and in-home displays which will provide consumers with incentives to modify the times at which certain loads or appliances are used;
- real 'smart' meters will also provide Aurora with more information regarding the quality of supply at individual network connection points;
- more distributed intelligence within the network as networks become more 'active' with multiple sources of energy - for example the present design and operation of a general radial network will change as increasing amounts of energy are injected at load connections during part of the day or year.
- RCC ground fault neutralisers will become economic to use in selected rural situations.

These changes are predicted to impact on the growth rates across the network, and will present many challenges for Aurora to manage from both an operational and investment viewpoint. However, Aurora is ready and willing to tackle these challenges as they arise.

The effects of these potential future initiatives have not been allowed for in the growth forecasts within this AMP as they are unknown. However, Aurora will continue to take an active involvement in monitoring future developments with the intention of continuing to reward activities that reduce network peak demand.

Glossary of Terms

ABS	Air break switch
ACSR	Aluminium conductor steel reinforced
ADMD	After diversity maximum demand
AMP	Asset Management Plan
AUFLS	Automatic Under Frequency load shedding
CAIDI	Customer average interruption duration index
CB	Circuit breaker
CIGRE	Conference Internationale des Grands Reseaux Electriques (International council for large electric systems)
CPD	Congestion Period Demand
CAIDI	Consumer average interruption duration index
CODC	Central Otago District Council
DC	Direct current
DCC	Dunedin City Council
DGA	Dissolved gas analysis
DRC	Depreciated replacement cost
DSM	Demand side management
GIS	Geographical Information System
GPD	Group Peak Demand
GWh	Gigawatt hour
GXP	Grid exit point
HV	High voltage
HWB	Halfway Bush
Hz	Hertz
ICP	Installation control point
IEDs	Intelligent electronic devices
IEEE	Institute of Electrical and Electronic Engineers
km	Kilometre
kV	Kilovolt
kVA	Kilovolt ampere
kVAr	Kilovolt ampere reactive
kW	Kilowatt
LV	Low voltage
MDIs	Maximum demand indicators
MVA	Mega volt-ampere
MVAr	Mega volt-ampere reactive
MW	Megawatt (one million watts)
ODV	Optimised deprival value/valuation
ORC	Otago Regional Council
PILC	Paper insulated lead cable
pf	Power factor
PV	Photo voltaic
QLDC	Queenstown-Lakes District Council
RC	Replacement cost
SAIDI	System average interruption duration index (minutes) (= sum of number of interrupted customers x interruption duration) / total number of customers
SAIFI	System average interruption frequency index
SCADA	Supervisory Control and Data Acquisition System
SF6	Sulphur hexafluoride
SWER	Single wire earth return. The Aurora network has one SWER line that supplies the Pigeon Flat area of Dunedin.
V	Volt
XLPE	Cross linked polyethylene cable

Appendix A – Service Level Targets

Service Criteria	Performance Indicator	Target 2009/10 to 2018/19	Actual 2009/10
Supply quality	No of proven voltage complaints per 10,000 consumers	10	3
Operating efficiency	Losses	6%	5%
Operating efficiency	Faults per 100 km line	10.5	9.11
Operating efficiency	Distribution transformer utilisation - kVA capacity per peak demand kW	30%	32.8%
Operating efficiency	Load factor - network input GWh / peak MW * hours per year	52%	54%
Environmental effectiveness	Incidents of contaminant spill from network	0	0
Safety*	Staff and contractors serious harm incidents	0	2
Safety	Public injury incidents	0	0

*one instance each of a cable flash and a pole falling with a worker attached occurred.

SAIDI		Network Planned	Network Unplanned	Network Total	Transpower Planned	Transpower Unplanned	Transpower Total	Overall SAIDI
Actual	2001/02	13.8	61.5	75.3	-	13.4	13.4	88.7
	2002/03	20.5	68.6	89.1	-	12.1	12.1	101.2
	2003/04	16.3	80.0	96.3	-	1.0	1.0	97.3
	2004/05	7.3	73.2	80.5	-	-	-	80.5
	2005/06	11.7	70.8	82.5	-	14.0	14.0	96.5
	2006/07	13.2	83.5	96.7	-	4.7	4.7	101.4
	2007/08	13.3	116.0	129.3	-	11.0	11.0	140.3
	2008/09	8.8	59.2	68.0	-	-	-	68.0
	2009/10	11.2	61.3	72.5	-	10.2	10.2	82.7
Target	2010/11	15.0	71.0	86.0	-	-	-	86.0
	2011/12	14.0	71.0	85.0	-	-	-	85.0
	2012/13	14.0	70.0	84.0	-	-	-	84.0
	2013/14	14.0	69.0	83.0	-	-	-	83.0
	2014/15	14.0	68.0	82.0	-	-	-	82.0
	2015/16	13.0	68.0	81.0	-	-	-	81.0
	2016/17	13.0	67.0	80.0	-	-	-	80.0
	2017/18	13.0	66.0	79.0	-	-	-	79.0
	2018/19	13.0	66.0	79.0	-	-	-	79.0
	2019/20	13.0	66.0	79.0				79.0

SAIFI		Network Planned	Network Unplanned	Network Total	Transpower Planned	Transpower Unplanned	Transpower Total	Overall SAIFI
Actual	2001/02	0.17	1.39	1.56	-	0.23	0.23	1.79
	2002/03	0.15	1.36	1.51	-	0.57	0.57	2.08
	2003/04	0.14	1.47	1.61	-	0.11	0.11	1.72
	2004/05	0.07	1.39	1.46	-	-	-	1.46
	2005/06	0.09	1.40	1.49	-	0.23	0.23	1.72
	2006/07	0.10	1.59	1.69	-	0.13	0.13	1.82
	2007/08	0.10	1.37	1.47	-	0.35	0.35	1.82
	2008/09	0.05	1.17	1.23	-	-	-	1.23
	2009/10	0.05	1.17	1.34	-	0.14	0.14	1.48
Target	2010/11	0.13	1.29	1.42	-	-	-	1.42
	2011/12	0.12	1.27	1.39	-	-	-	1.39
	2012/13	0.12	1.26	1.38	-	-	-	1.38
	2013/14	0.12	1.25	1.37	-	-	-	1.37
	2014/15	0.12	1.24	1.36	-	-	-	1.36
	2015/16	0.11	1.24	1.35	-	-	-	1.35
	2016/17	0.11	1.22	1.33	-	-	-	1.33
	2017/18	0.11	1.20	1.31	-	-	-	1.31
	2018/19	0.11	1.20	1.31	-	-	-	1.31
	2019/20	0.11	1.20	1.31				1.31

CAIDI		Network Planned	Network Unplanned	Network Total	Transpower Planned	Transpower Unplanned	Transpower Total	Overall CAIDI
Actual	2001/02	81.7	42.2	48.3	-	59.0	58.3	49.6
	2002/03	134.9	50.6	59.0	-	21.3	21.2	48.7
	2003/04	119.9	54.5	59.8	-	8.8	9.1	56.6
	2004/05	100.2	52.8	55.1	-	-	-	55.1
	2005/06	135.7	50.5	55.4	-	60.0	60.9	56.1
	2006/07	127.0	52.6	57.2	-	35.6	36.2	55.7
	2007/08	129.5	84.6	88.0	-	31.4	31.4	77.1
	2008/09	160.5	50.5	55.4	-	-	-	55.4
	2009/10	129.4	49.0	54.2	-	71.0	71.0	55.8
Target	2010/11	120.0	55.0	60.0	-	-	-	60.0
	2011/12	120.0	55.0	60.0	-	-	-	60.0
	2012/13	120.0	55.0	60.0	-	-	-	60.0
	2013/14	120.0	55.0	60.0	-	-	-	60.0
	2014/15	120.0	55.0	60.0	-	-	-	60.0
	2015/16	120.0	55.0	60.0	-	-	-	60.0
	2016/17	120.0	55.0	60.0	-	-	-	60.0
	2017/18	120.0	55.0	60.0	-	-	-	60.0
	2018/19	120.0	55.0	60.0	-	-	-	60.0
	2019/20	120.0	55.0	60.0				60.0

Appendix B – Compliance Matrix

Revised Information Disclosure Requirements October 2008

	Requirement	AMP Location
4.5.1	Summary of the Asset Management Plan	1
4.5.2	Background and Objectives <ul style="list-style-type: none"> (a) Purpose of the plan. (b) Interaction of objectives with other corporate goals, business planning processes and plans. (c) Period to which the plan relates and date approved by board of directors. (d) Stakeholder interests. (e) Accountabilities and responsibilities for asset management. (f) Details of asset management systems and processes including asset management systems/software and information flows. 	2.1 2.2 2.2 / 2.3 2.4 2.5 2.6
4.5.3	Assets Covered <ul style="list-style-type: none"> (a) High level description of the distribution area. (b) Description of network configuration. (c) Description of network assets by category including age profiles and condition assessment. (d) Justification for the assets. 	3.1 3.2-3.3 3.5-3.8 3.9
4.5.4	Service Levels <ul style="list-style-type: none"> (a) Consumer oriented performance targets. (b) Other targets, eg – asset performance, asset efficiency and effectiveness, the efficiency of the lines business activity. (c) Justification for target levels of service based on consumer, legislative, stakeholder and other considerations. 	4.1 4.2-4.5 4.6-4.8
4.5.5	Network Development Planning <ul style="list-style-type: none"> (a) Description of the planning criteria and assumptions. (b) Description of the prioritisation methodology adopted for development projects. (c) Details of demand forecasts, the basis on which they are derived and the specific network locations where constraints are expected due to forecast load increases. (d) Distributed generation policy. (e) Non-network solution policy. (f) Analysis of network development options available and details of the decisions made to satisfy and meet target levels of service. (g) Description and identification of the network development programme and actions to be taken, including associated expenditure. 	5.4 / 5.8 5.5 / 5.7 5.1 / 5.6 5.9 5.2 5.3 5.1 / 5.0 / 5.14/ 5.15 5.1 / 5.10 – 5.16

	Requirement	AMP Location
4.5.6	Lifecycle Asset Management Planning (Maintenance and Renewal) (a) Description of maintenance planning criteria and assumptions. (b) Description and identification of routine and preventative inspection and maintenance policies, programmes, and actions to be taken for each asset category, including expenditure projections. (c) Description of asset renewal and refurbishment policies. (d) Description and identification of renewal or refurbishment programmes or actions to be taken for each asset category, including associated expenditure projections. (e) Asset replacement and renewal expenditure.	6.1 6.2 6.3 6.3 6.4/6.5 6.4/6.5
4.5.7	Risk Management (a) Methods, details and conclusions of risk analysis. (b) Details of emergency response and contingency plans.	7.1 7.2
4.5.8	Evaluation of Performance (a) Review of progress against plan, both physical and financial. (b) Evaluation and comparison of actual performance against targeted performance objectives. (c) A gap analysis and identification of improvement initiatives.	8.1 / 8.2 8.1/ /4.1/Ap A 8.3

Appendix C - Table of Guidelines for Security of Supply (Note 1)

Class of Supply	Range of Group Peak Demand (GPD) in MVA	Examples	Minimum Demand to be met after:		
			First Outage (Circuit or Transformer)	Second Outage (Circuit or Transformer)	Bus-bar Fault
URBAN					
U1	0 to 1.0	LV circuits, transformers on HV spur feeds	Initially - nil Within repair time 100% GPD (notes 2, 4)	Initially - nil Within repair time 100% GPD (notes 2, 4)	Not applicable
U2	1.0 to 3MVA (6.6kV) or to 5MVA (11kV)	HV feeders	Initially - nil Within switching time 100% GPD	Initially - nil Within repair time 100% GPD (notes 2, 4)	Not applicable
U3	Up to 10 MVA	Small/medium zone substations	Initially - nil Within switching time 100% GPD (note 5)	Initially - nil Within repair time 100% GPD (notes 2, 4)	Initially - nil In within switching time 100% GPD (note 7)
U4	Over 10MVA	Larger zone sub-stations	Defined firm capacity	Initially - nil Within repair time 100% GPD (notes 2, 4)	Initially - nil In within switching time 100% GPD (note 7)

Class of Supply	Range of Group Peak Demand (GPD) in MVA	Examples	Minimum Demand to be met after:
			First Outage (Circuit or Transformer)
RURAL			
R1	All	Rural customers (eg fed by a single transformer)	Initially - nil Within repair time 100% GPD (notes 3, 4)
R2	0 to 3 MVA (6.6 kV) or to 5 MVA (11 kV)	Rural radial feeder	Initially - nil Within repair time 100% GPD (notes 3, 4)
R3	0 to 5 MVA	Rural zone substation	Initially nil Within switching time 100% GPD (notes 3, 4)

NOTES:

- 1) This table provides the basic guidelines for supply security; however, in all cases, if the GPD exceeds the given range, any reinforcement expenditure must be justified by economic analysis.
- 2) A target restoration time has been set of 4 hours from notification in urban areas – except under disaster conditions (eg extreme weather).
- 3) A target restoration time has been set of 6 hours from notification in rural areas – except under disaster conditions (eg extreme weather).
- 4) A mobile generator or temporary reticulation may be used to achieve restoration within the target restoration times if time to repair the failed asset is expected to exceed the target time.
- 5) In recognition of the long repair times associated with repairing transformer failures, it is normal practice to install two transformers in all locations where the load exceeds 5 MVA. In the event of a single transformer failure, part of the load will remain on supply - and thus can be regarded as having a full (N-1) security. The remaining load would normally be restored by switching and, thus, is classified as (N-1) switched.
- 6) A mobile substation may be relocated if appropriate to achieve restoration.
- 7) Substations with loads exceeding 5.0 MVA are built with the HV bus-bars split by a bus-coupler and have two transformers (see note 5). If the bus-coupler fails, it is regarded as a double fault situation.