



AURORA ENERGY LTD

Asset Management Plan Number 19

April 2012 – March 2022

Prepared for Aurora Energy Ltd
by Delta Utility Services Ltd



ISO 9001

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F O R E W O R D

This is the nineteenth network Asset Management Plan for the distribution networks owned by Aurora Energy Ltd, and covers the 10-year period from 1 April 2012.

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

This section provides a summary of the information contained within the Asset Management Plan (AMP) for Aurora Energy Limited (Aurora) and specifically highlights the information that Aurora considers significant.

1.2 Background and Objectives

The key objectives of Aurora's activity is to ensure that the supply and distribution of electricity is secure, reliable and affordable, service levels are met and maintained, service delivery is safe and investment is financially sustainable over the short, medium and long-term.

Aurora has contracted asset management to Delta under a performance-related contract. Under this contract Delta is required to meet the above objectives by delivering on specific targets for network performance and customer service, as well as the provision of detailed development plans covering periods during and beyond the contract period.

This AMP describes the asset management policies, objectives, strategies, plans and systems adopted by Aurora for its electricity distribution networks; and has been prepared in accordance with industry rules and regulations.

Overall, the AMP demonstrates an integrated framework for asset management which ensures that Aurora's asset management needs are addressed through ensuring a robust approach to asset management processes, practices and subsequent service delivery.

1.3 Assets Covered

Aurora's network assets consist of two geographically separate networks - Dunedin and Central Otago, with electricity being delivered to over 82,000 consumers. The Dunedin network is supplied from two Grid Exit Points (GXP's), being South Dunedin and Halfway Bush. The Central network is supplied from three GXP's being Frankton, Clyde and Cromwell.

The network assets comprise the types and quantities summarised in Table 1-1, located generally as shown in Figure 3-1. The value of Aurora's assets by category (based on the information provided for the Electricity Distribution (Information Disclosure) Requirements) is presented below. Information on quantities and their general condition is detailed further in Section 3.

Asset Category	RC	% by \$
Subtransmission	\$55,453,878	9%
Zone substations	\$98,596,582	16%
Distribution and LV lines	\$135,762,972	22%
Distribution and LV cables	\$186,159,307	30%
Distribution substations and transformers	\$94,270,474	8%
Distribution switchgear	\$52,184,629	8%
Other	\$5,624,154	1%
Total (rounded)	\$628,052,000	100%

Table 1-1 – Types and Quantities of Assets

1.4 Service Levels

Service level objectives are summarised in Table 1-2 below. 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 have identified they 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).

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

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 is summarised in Table 1-3 below.

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

Financial Year	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
Total	27,890	22,479	25,426	22,074	19,290	18,030	22,635	21,290	27,445	17,361

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

This expenditure is based on financial year 1 July - 30 June (and does not include carry-overs from 2011/12 for the 2012/13 total).

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.

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 Section 6 is summarised in Table 1-4 below:

Financial Year	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
Total	9,350	9,580	9,810	10,050	10,300	10,550	10,911	11,070	11,360	11,660

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

1.7 Risk Management and Business Continuity

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).

The main risks currently associated with Aurora's assets are asset protection, customer service, natural disaster, employment, environmental protection, financial management, information systems, and legal compliance. The risk of insufficient competent human resource to complete capital works in a timely manner remains as a potential industry wide concern.

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.

In 2010, new safety regulations came into force which introduced new standards for public safety management systems to prevent harm to people and property from electricity and gas supply systems. In response to this Delta, on behalf of Aurora, has developed and implemented a Public Safety Management System. Further detail regarding this is provided in Section 7.

Delta has recently undertaken a review of its risk management philosophy, framework and approach as part of a Risk and Business Continuity Project based on the AS/NZ ISO 31000:2009 Risk Management Standard. The adoption of a new Risk Management Framework and Guidelines for Delta is a priority outcome from this. In 2012, more focus will be placed on considering and understanding Aurora's asset risk profiles under the framework and guidelines. Section 7 of the AMP provides further detail.

1.8 Evaluation of Performance

Price-Quality

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 2011.

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.



Figure 1-1 – Price-Quality Matrix

Process

In terms of overall performance regarding the approach and framework for asset management, a high-level assessment carried out in November 2011 identified six key priority areas of focus, which are currently being worked on. The priority areas were identified through a gap analysis based on the PAS55 standard as well as the IIMM guidelines for asset management. During 2012, focus will be placed on further review and assessment of Delta's asset management processes and procedures against these standards and guidelines to ensure that Delta continues to move closer towards establishing advanced asset management practices.

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

1.9 Stakeholder Consultation

Aurora's main stakeholders and their key interests are outlined in Section 2 of this AMP. Consultation with stakeholders has been undertaken through customer surveys, open requests for feedback, safety reviews, industry forums and other means. Stakeholder interests are subsequently validated or identified through these means.

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 addition to this, Aurora has actively sought comment on its Asset Management Plan, including through newspaper advertisements and direct approaches.

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

If stakeholders or other interested parties require further detail than outlined within this AMP, they are welcome to request more details regarding the specific issues or assets that affect them.

2 Background and Objectives

Aurora's key business activity is the management and delivery of electricity to more than 82,000 consumers within Dunedin and Central Otago. The Aurora-owned electricity network begins downstream of Transpower's transmission Grid Exit Points (GXPs), delivering electricity to the property boundaries of residential, industrial and commercial customers.

The key objectives of Aurora's activity is to ensure that the supply/distribution of electricity is secure, reliable and affordable, service levels are met and maintained, service delivery is safe and investment is financially sustainable over the short, medium and long-term.

This Asset Management Plan (AMP) sets out the overall framework for how Aurora addresses these needs through ensuring a robust approach to asset management and subsequent service delivery.

2.1 Purpose

Aurora undertakes asset management to ensure that service levels, stakeholder interests and regulatory requirements are met for its electricity distribution networks over the short, medium and long term, in the most cost effective manner.

This calls for Aurora to clearly define and understand requirements in order to develop meaningful asset lifecycle strategies to address the risks associated with not meeting key activity objectives.

The AMP illustrates how Aurora achieves this by outlining the asset management policies, objectives, strategies, plans and systems adopted by Aurora for the efficient management of its electricity distribution networks.

The AMP demonstrates an integrated framework for asset management which 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.
- maintains a culture of continuous improvement in asset management.

2.2 Relevance of AMP to Corporate Goals, Business Processes and Plans

Figure 2-1 illustrates the cascade from Aurora's mission statement through to the AMP and provides context for associated business process with other external drivers such as the regulatory environment. The services provided by Aurora are regulated by two main bodies: the Commerce Commission and the Electricity Authority.

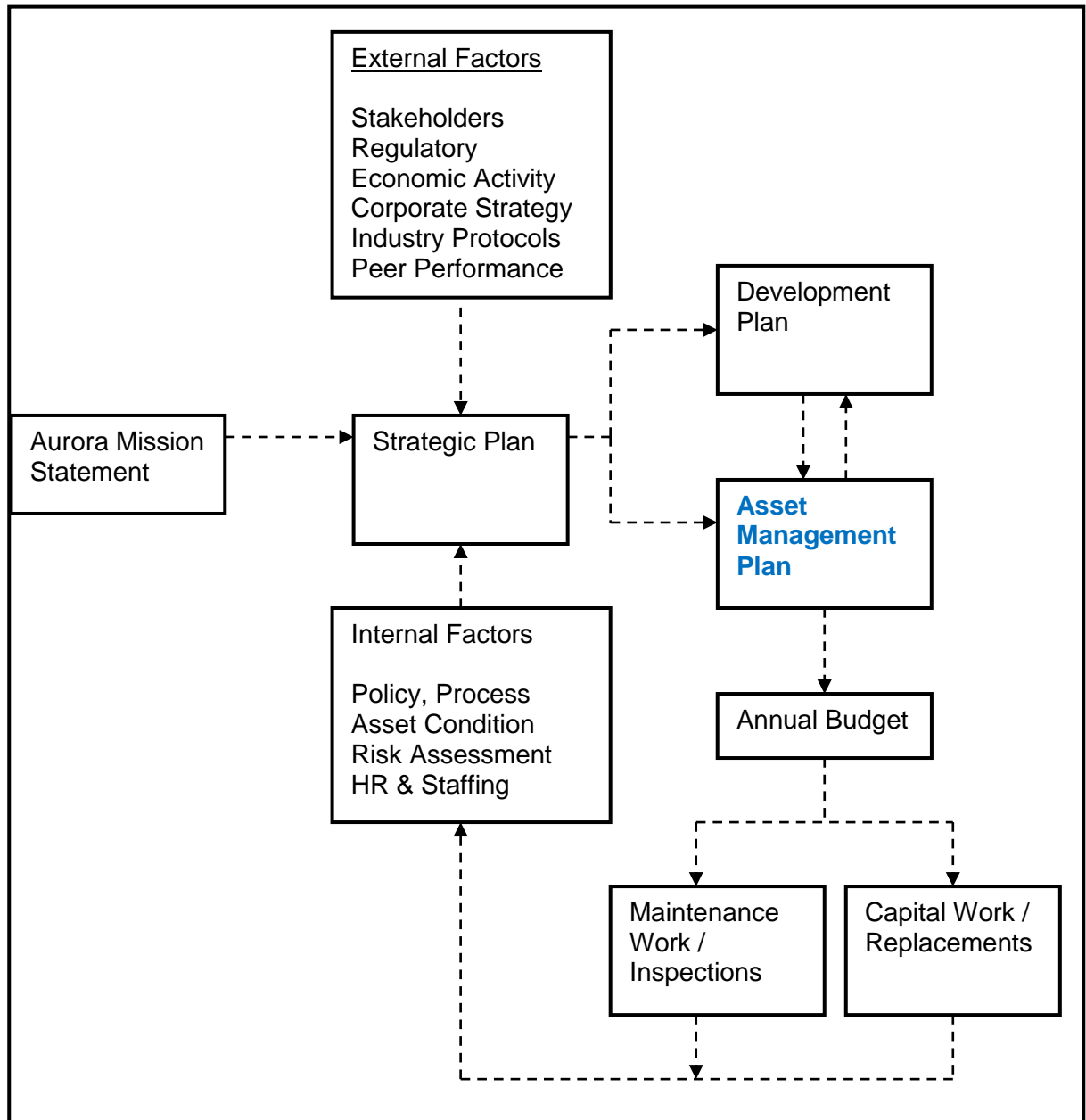


Figure 2-1 – Interaction Between Other Business Processes and Plans

Aurora's Strategic Plan has identified asset management as a fundamental component for achieving the company's strategic objectives.

The Strategic Plan takes into account aspects such as regulatory, customer and shareholder interests, constraints and expectations which, along with the physical assets themselves, cascade into the requirements and drivers for asset management; and subsequently capital, operational and maintenance investment needs.

2.3 Plan Assumptions and Uncertainties

This plan relates to the 2012 - 2022 period.

As a consequence of the long-term planning period, there is a degree of uncertainty associated with any future forecasts or predictions.

Table 2-1 indicates the degree of uncertainty associated with the timeframe of this AMP. This has been derived through an analysis of recent declining trends in customer-initiated works (particularly in the Central area) as well as a down-turn in economic activity as influenced by the international economic environment.

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

It is acknowledged that unanticipated equipment failures, storms or other natural disasters, or material changes in local loadings may require a change to the planned investment programme outlined in this AMP.

The planning and forecasting assumptions and uncertainties relating to the Aurora electricity distribution networks will be undergoing a comprehensive review in 2012 to ensure that decisions remain aligned with the most recently available and reliable information. Future AMPs will, therefore, contain more transparency on:

- significant assumptions considered to have a material impact on forecast expenditure;
- the source and impacts of significant assumptions; and
- assumptions that have been made in relation to sources of uncertainty.

These were also among the main items identified by the Commerce Commission through its review of Aurora's AMP in August 2011.

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
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

Stakeholder	Interest	How Stakeholder Interests are Identified
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.

Where stakeholder conflict arises, Aurora will apply the criteria (above) in order of priority, with safety being the primary concern. The Aurora Board will decide upon the most appropriate way to resolve any issue of conflict between stakeholder interests.

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.

Up until the latter part of 2011, asset management was carried out by the Engineering Services and Network Services Managers who, together with the Aurora Commercial Manager, formed the Network Management group within Delta.

Recent changes to this structure have seen the establishment of a specific Asset Management group, consisting of five core teams: Asset Management, Infrastructure Performance, Asset Systems, Delivery and Commercial; reporting to the General Manager for Asset Management.

Figure 2-2 details the accountabilities and responsibilities for asset management within the Aurora/Delta contract.

Under this contract, the responsibility for the management of the network is primarily through Delta's Chief Executive, the General Manager Asset Management, and Managers within the Asset Management group. Table 2-3 provides more detail on actual responsibilities.

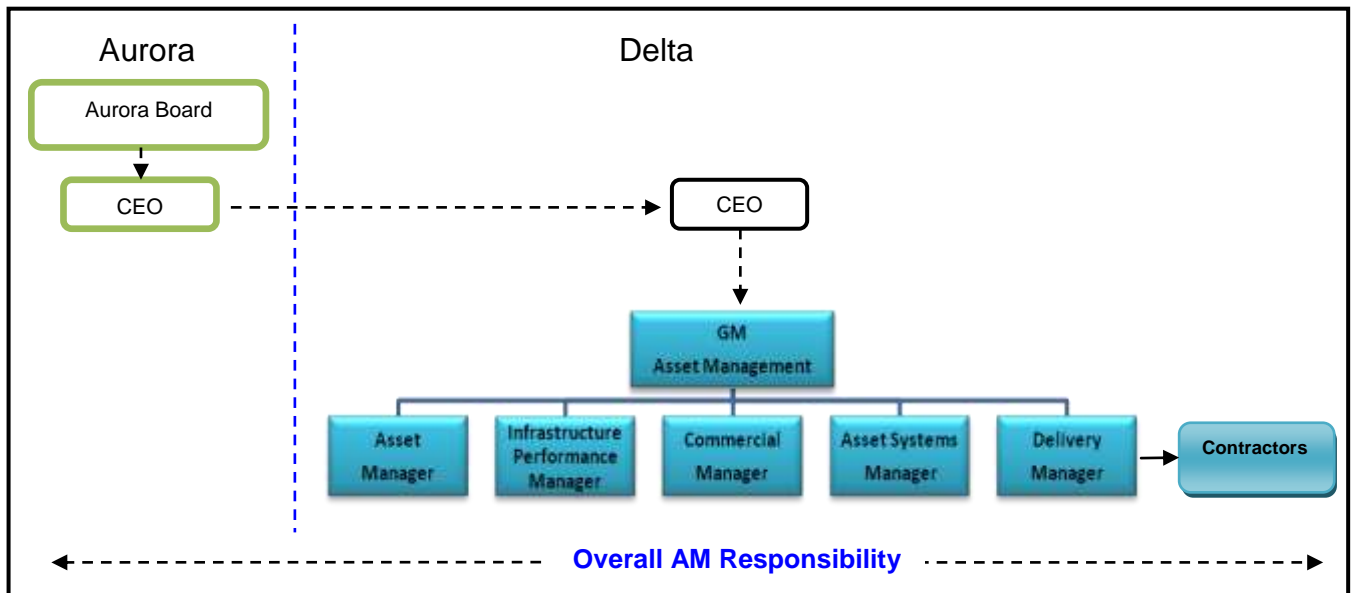


Figure 2-2 – Asset Management Accountabilities and Responsibilities

Title	Responsibilities
Aurora Board	Overall governance and decision-making for Aurora. Receives and reviews regular and special reports from Delta, and meets monthly to review a range of operational indicators and to consider strategic issues. Capital programme approval. Consideration of business risks.
CEO & GM Asset Management	Primary responsibility for management of the network. Preparation of regular and special reports to the Aurora Board, including the AMP and detailed development plans. Reports to the Board include financial reporting, capital expenditure, energy and system demands, outage summaries, and specific reports of all outages over 0.5 SAIDI minutes.
Asset Manager	Ensuring a high quality Asset Management Plan is prepared and completed in line with industry best practice and meets necessary disclosure requirements. Development, documentation and improvement of the policy and processes of Delta's asset management methods. Development of the capital, operational and renewal expenditure programme; and implementation of strategies that extract optimal value, and mitigates risk exposure, over the lifetime of the portfolio of assets under ownership or management.
Infrastructure Performance Manager	Manage forecasting, analysis and design to ensure that security and reliability levels are maintained over the lifetime of managed assets. Carry out network investigations and risk assessment to inform planning and investment requirements and strategies. Develop concept and detailed designs for capital, operational and renewal expenditure programmes. Public Safety and Risk Management.
Delivery Manager	Responsible for efficient project and contract management to deliver the annual works programme - including new capital, renewals and maintenance projects. Accountable to ensure delivery of projects within approved budget, time and quality constraints – ensuring co-ordination and timely communication with contracting and operations, as well as relationship management and development of contractor standards.
Asset Systems Manager	To enable and support integrated asset management through the development and implementation of an integrated asset management system including system control operations, ensuring quality data capture systems, information and data accuracy and management; in order to support strategic asset decision making and work management systems. Adding value to processes, systems and thinking through the creation of knowledge and intelligence.
Commercial Manager	Manages 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. Maintains overview on regulatory requirements.
Internal Contracting Team	To deliver works associated with the annual operational, maintenance, capital replacement and network development programmes as required by the Delivery Manager.
External Contractors and Consultants	Delta has made use of external contractors and consultants for works associated with the annual operational, maintenance, capital replacement and network development programmes.

Table 2-3 – Delta's Accountabilities and Responsibilities for Asset Management

2.6 Asset Management Systems

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.

Proposed Changes

As part of the Asset Management System's project, Delta has recently undertaken a review of existing asset management information systems with the aim to improve current asset management capabilities, processes and the technological tools that support these. An evaluation of the appropriate software to enable the above has resulted in the short-listing of two options: SAP and Maximo.

The overall outcome from this project is to ensure cost-effective asset management is attained and maintained, with an appropriate balance between performance, risk and cost; including efficient customer services, effective contractor and works management, as well as more efficient data management and analysis.

2.7 Asset Information and Data Confidence

Current amount of knowledge of asset existence, location, material type and capacity and performance is sound. However, there are some known improvements required in the asset information for each of the asset categories. Poles have been identified as a priority area to focus on and Delta is currently undertaking a project to improve the quality of condition data for poles via the development of more meaningful assessment criteria, the outputs of which will feed into a framework for risk assessment and prioritisation. This will enable better prioritisation of at-risk areas in the network so that renewals and maintenance programmes are more effective at attaining a balance between, performance, risk and cost against budget allocations.

Data anomalies within the GIS, such as wrong transformer configurations, are being identified and rectified on an ongoing basis. Refer to Section 3 for further detail on asset information.

Next Steps

The status of asset information and data confidence will be reviewed in 2012 to ensure that focus is being placed in the right area. From this, a more structured approach to addressing any issues will be developed and implemented where it is considered economic to do so. Overall, the asset management information systems project will assist with this and provide a co-ordinated focus on acquiring, compiling and integrating relevant asset information.

2.8 Asset Management Framework and Processes

This AMP draws on information from various sources and systems as outlined in Section 2.6. Development of asset management processes and implementation of the proposed 'asset management system' will assist Delta to achieve a more systematic approach to asset management that links information together according to the process flow diagram illustrated in Figure 2-3. Progress towards attaining advanced asset management continues with improvements in alignment with best practice standards and guidelines, such as PAS55 and the International Infrastructure Management Manual.

Figure 2-3 provides an overall picture of Delta's approach and framework for integrated asset management. Having an integrated approach is fundamental to delivering Aurora's asset management objectives.

Delta's Asset Management team carried out an initial gap analysis in November 2011 with reference to the PAS 55 standard as well as the IIMM guidelines. This provided an initial high-level identification of 6 key priority areas of focus, which are currently being worked on.

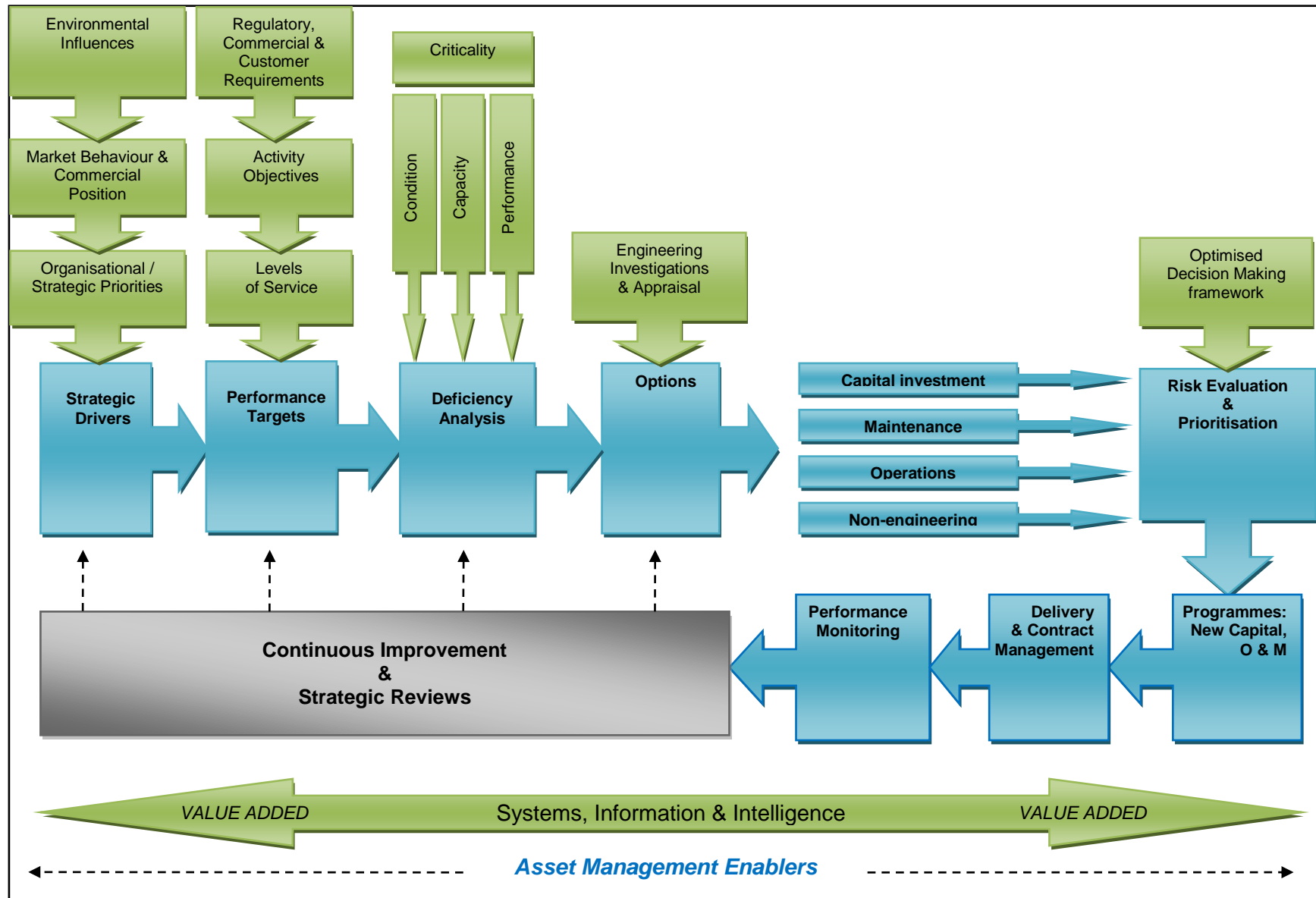


Figure 2-3 – Integrated Asset Management Framework

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.

- In the Dunedin that includes the urban areas of Dunedin, Mosgiel, and the inner reaches of the Taieri Plains has 53,646 customer connections. 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 has 28,878 customer connections. 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 network are the ski fields (e.g. 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 2011, for each GXP are shown in Figure 3-2

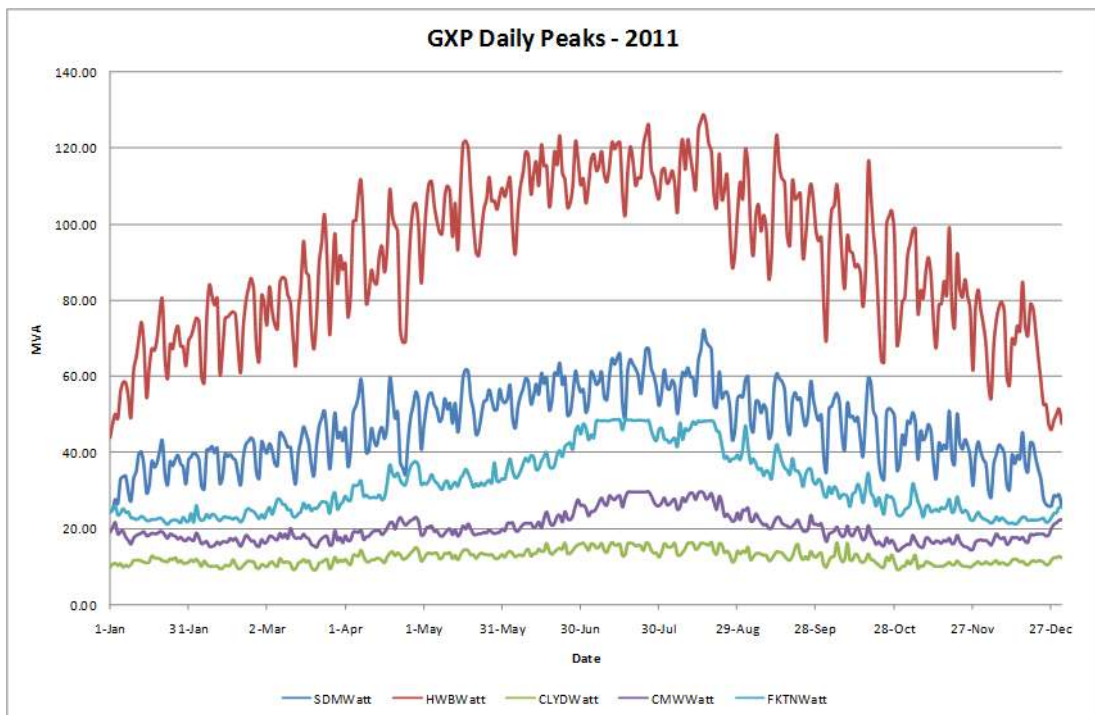


Figure 3-2 – Graph of Grid Exit Point Daily Load Peaks (2011)

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), orchard 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 2011 Load Data

The key load and distributed generation statistics for the 2011 calendar year are presented in Table 3-1.

GXP	Clyde	Cromwell	Frankton	Halfway Bush	South Dunedin	Total
2011 peak MW including distributed generation	17.4	29.9	48.7	128.7	72.2	
2011 energy transported GWh	81	132	214	587	308	1323
Total number of ICPs	6,629	10,508	11,741	36,861	16,785	82,524
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 129.7 MW of distributed generation connected to its networks; this is a significant increase on the 2010 capacity due to the commissioning of the TrustPower Mahinerangi 36MW wind farm. 118 MW is associated with generation dedicated to export and 11.6MW is associated with consumer installations connected behind load. See Table 3-2 for a schedule of distributed generation by GXP and owner and Table 3-3 for a summary by energy source.

Most consumer generation 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. There is a small quantity of consumer photovoltaic (PV) generation a single small wind generator and two micro hydro connections. See Table 1 3 for summarised data on this generation. In the last year there has been a marked increase in applications to install small domestic PV units.

GXP	Generation Owner	KW
Clyde	Consumer	4
	Pioneer Generation Ltd	21,125
	Talla Burn Generation Ltd	2,150
Clyde Total		23,279
Cromwell	Consumer	1,951
	Pioneer Generation Ltd	3,550
Cromwell Total		5,501
Frankton	Consumer	1,800
	Pioneer Generation Ltd	2,131
Frankton Total		3,931
Halfway Bush	Consumer	5,654
	TrustPower	89,200
Halfway Bush Total		94,854
South Dunedin	Consumer	2,168
Grand Total		129,732

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

Energy Source	Count	Rated kW
Hydro	19	79,856
Wind	5	38,302
Diesel	15	7,905
Process heat	1	2,240
PV	8	45
Total		128,349

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 GXP's at 33 kV. There are 19 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 the 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.

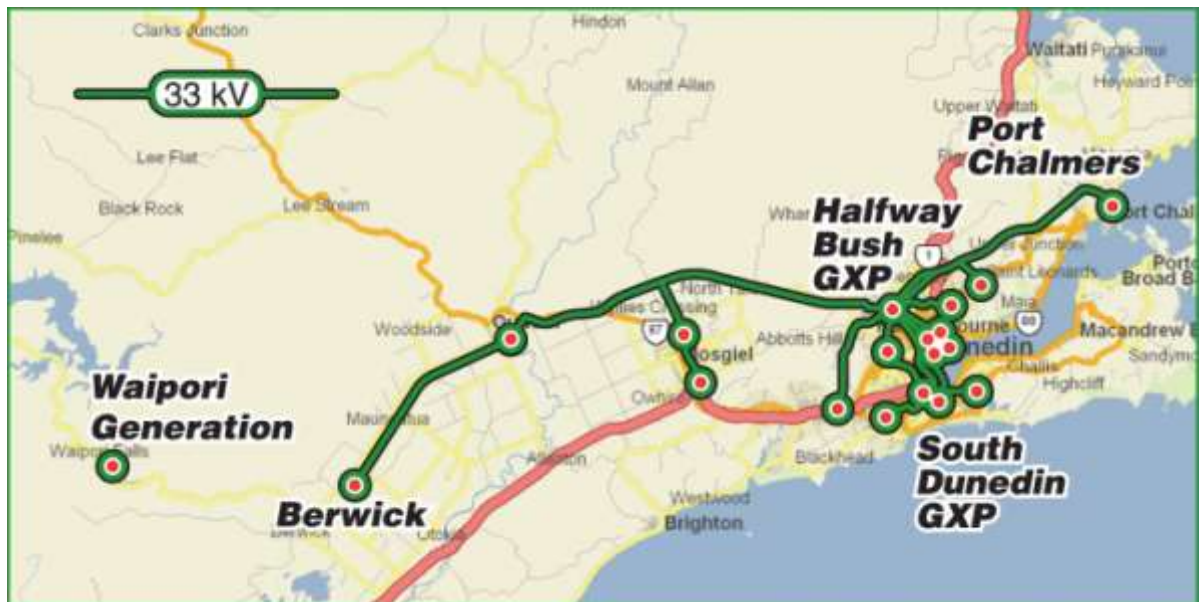


Figure 3-3 – Dunedin Subtransmission Network

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 PILC cables from HWB GXP	Y
	Kaikorai Valley	24 +24	Two PILC 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 cables from HWB GXP plus a PILC tie cable to Ward Street	Y
	North East Valley	9/18 + 12/18	Two 33 kV lines and PILC 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
South Dunedin	Andersons Bay	15 +15	Two 33 kV gas cables from Sth Dn GXP	Y
	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.

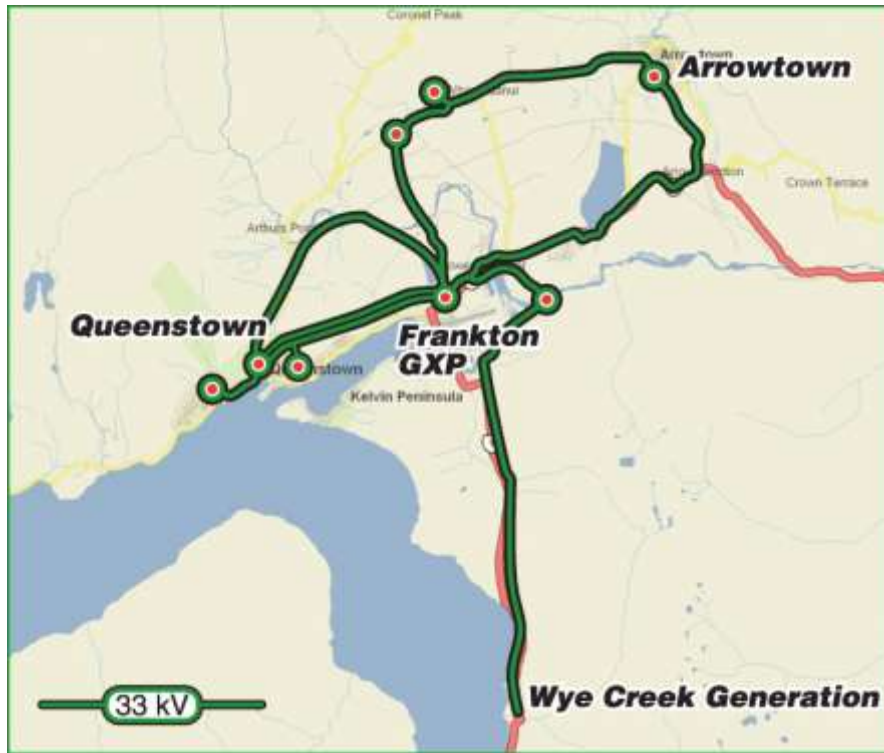


Figure 3-4 – Frankton Subtransmission Network

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 XLPE cables from Queenstown	Y
Frankton	12/24 + 7.5/15	One 33 kV XLPE cable and one 33 kV line from Frankton GXP	Y
Remarkables	3	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 and Cardrona zone substations. 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.

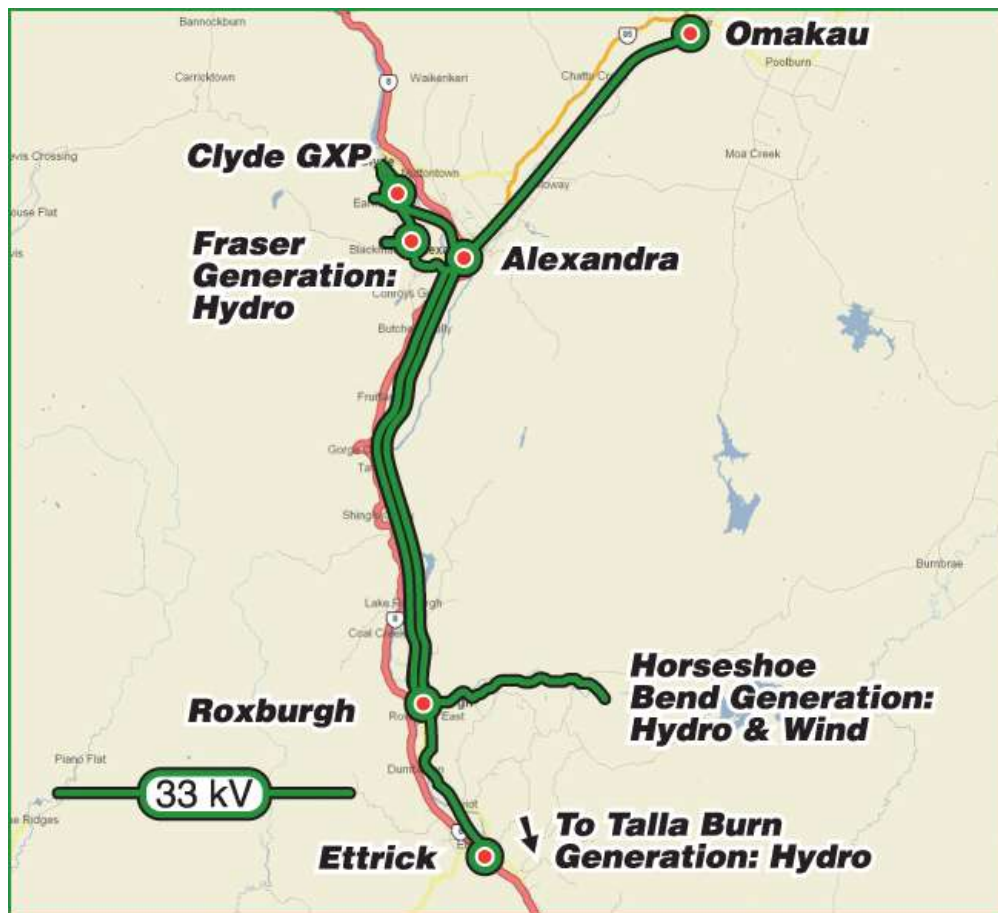


Figure 3-6 – Clyde Area Subtransmission

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 (85%) with the remainder being either XLPE (9%) or unknown (6%). For many years, all new cable has been rated for 11 kV operations even when it operates at 6.6 kV.

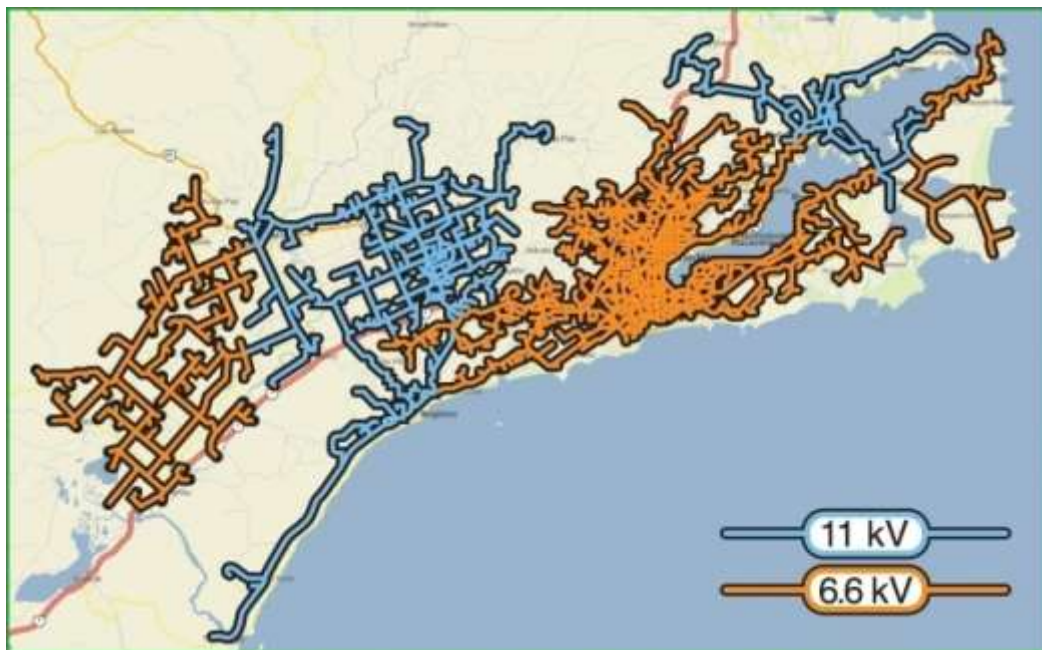


Figure 3-7 - Dunedin HV Distribution by Voltage

Voltage	Km	% Overhead	% Underground
11 kV	336.	65	35
6.6 kV	710	83	17
Total	1047	29	71

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 (71%) and unknown (3%). In Central, there is a significant quantity of rural HV cable, due to local authority requirements and the high number of rural lifestyle subdivisions.

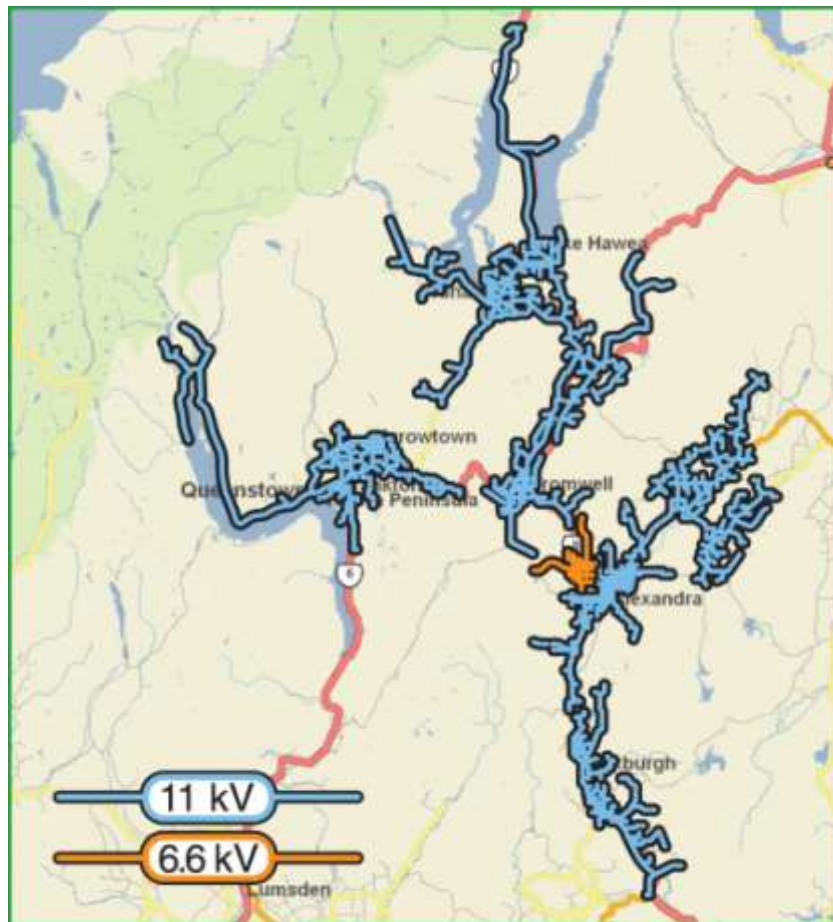


Figure 3-8 – Central HV Distribution by Voltage

Voltage	Km	% Overhead	% Underground
11 kV	2081.	26	74
6.6 kV	78.9	15	85
Total	2,160	26	74

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	4212
Ground mounted	2363
Underground	19
Total	6594

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 1000 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	1024	78	22
Central	805	29	71
Te Anau	5.6	0	100
Total	1836	56	44

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 33kV injection system was installed in 2011 adjacent to the South Dunedin and Halfway Bush GXPs and operates in parallel with the 1050Hz system. Ripple receivers will be progressively changed from 1050 Hz to 317 Hz and 1050Hz injectors progressively removed. The 1050Hz system will be converted to pure decabit by the end of 2013 when the last of the electromechanical K22 relays are removed from the network.

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.

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 11/6.6 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 66/33/11/6.6 kVA mobile substation is based at Cromwell.

Aurora owns a containerised 500 kW generator. This generator is not currently in service.

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.

TrustPower has connected 15MVAR of capacitors at the Mosgiel substation to mitigate the adverse effect on the power factor at the Halfway Bush GXP due to the installation of the 36 MW Mahinerangi wind farm.

3.8 Asset Details by Category

The value of Aurora's assets by category (based on the information provided for the Electricity Distribution (Information Disclosure) Requirements) is presented in Table 3-12. Information on quantities and their general condition is detailed further in this section.

Asset Category	RC	% by \$
Subtransmission	\$55,453,878	9%
Zone substations	\$98,596,582	16%
Distribution and LV lines	\$135,762,972	22%
Distribution and LV cables	\$186,159,307	30%
Distribution substations and transformers	\$94,270,474	15%
Distribution switchgear	\$52,184,629	8%
Other	\$5,624,154	1%
Total	\$628,051,996	100%
Total (rounded)	\$628,052,000	

Table 3-12 – Value of the Aurora Network

The general condition of Aurora's assets is "fit for purpose". The underlying SAIDI 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 and will be subject to further investigation and risk assessment in 2012/13.

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.

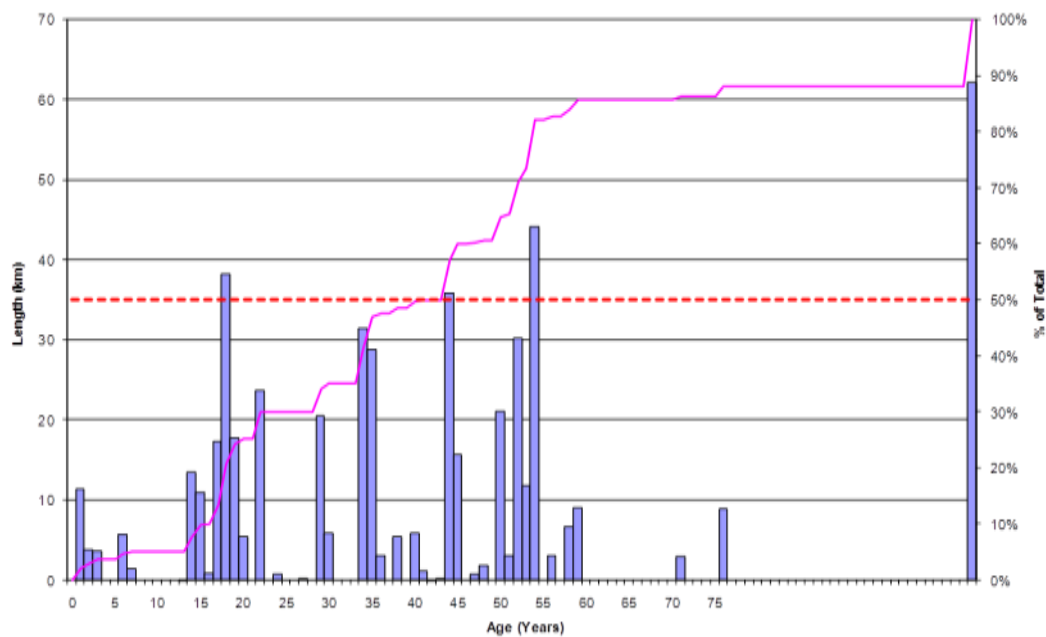


Figure 3-9 – 66 and 33 kV Lines Age Profile (Total = 494.6 km)

The 105 years old lines are the Halfway Bush to Berwick "A" and "B" lines. The lines have solid copper conductor and the short spans have contributed to its long life

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.

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 Dunedin have experienced leaks. It is proposed to replace this type of cable within the planning period.

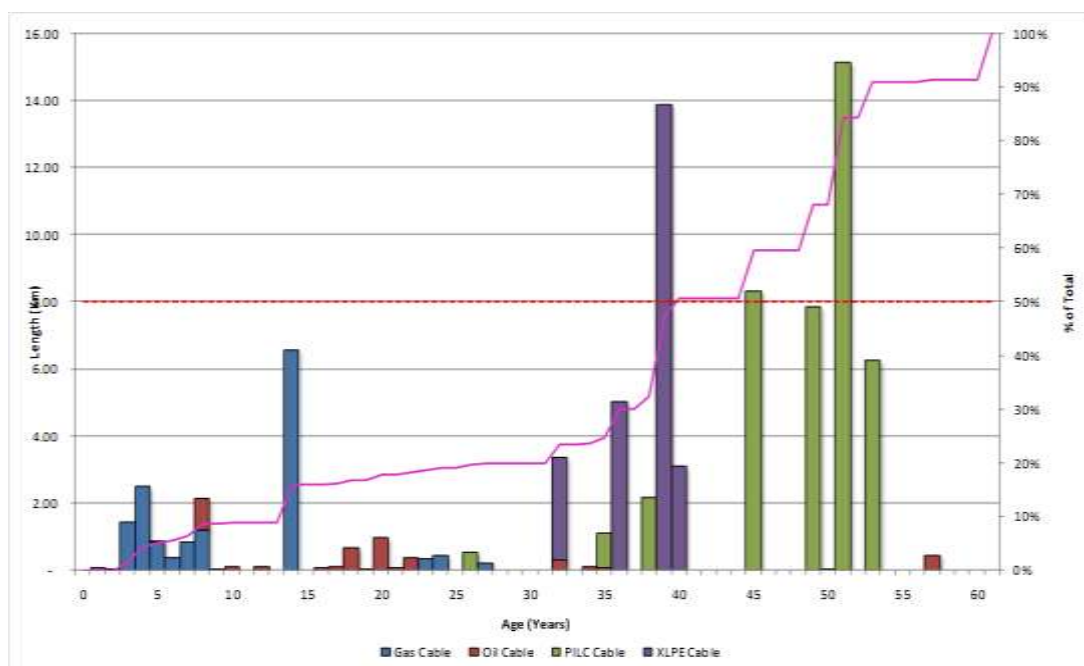


Figure 3-10 – 33 kV Cables Age Profile (Total 96 km)

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. The oldest four transformers are at the Neville St and Outram substations and are scheduled for replacement. In recent years there have been three transformer failures resulting in the scraping of these transformers. A more intensive monitoring and maintenance program is being implemented to mitigate the possibility of further failures.

A program is underway to fit de-hydrating breathers to older transformers. A project to eliminate mercury switches from transformer Buchholz relays is underway to prevent these relays operating during earthquakes.

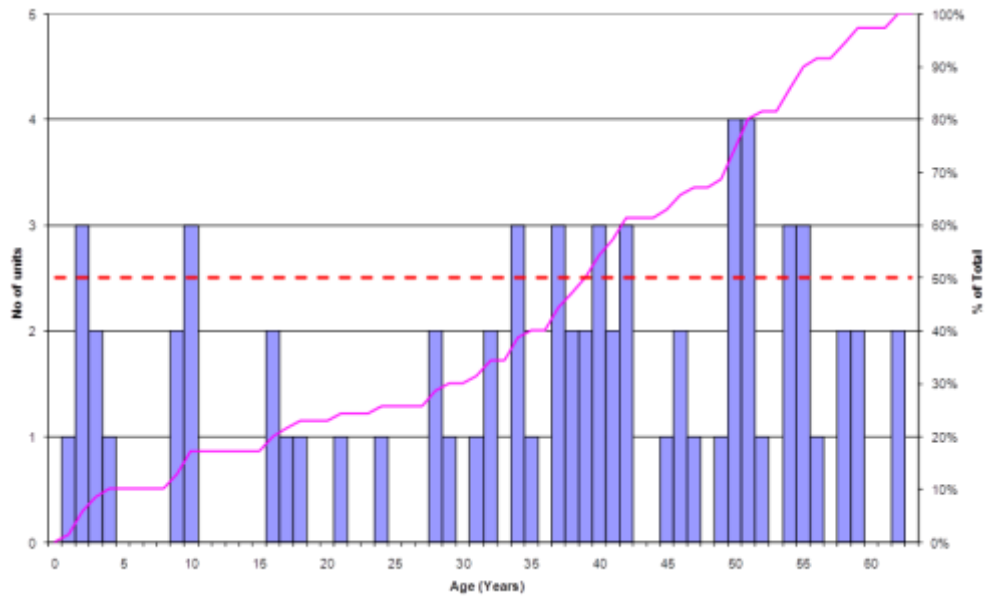


Figure 3-11 – 66 and 33 kV Zone Substation Transformers Age Profile (Total = 70)

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 Table 3-12. The 33 kV circuit breakers at three zone substations, Neville Street, North East Valley and Alexandra are more than 40 years old and they are all scheduled for replacement. Their replacement strategy is shown in Section 6.5. There have been problems with water ingress into copper VWVE circuit breakers that have been fitted with CT bushing extensions; remedial options are under investigation.

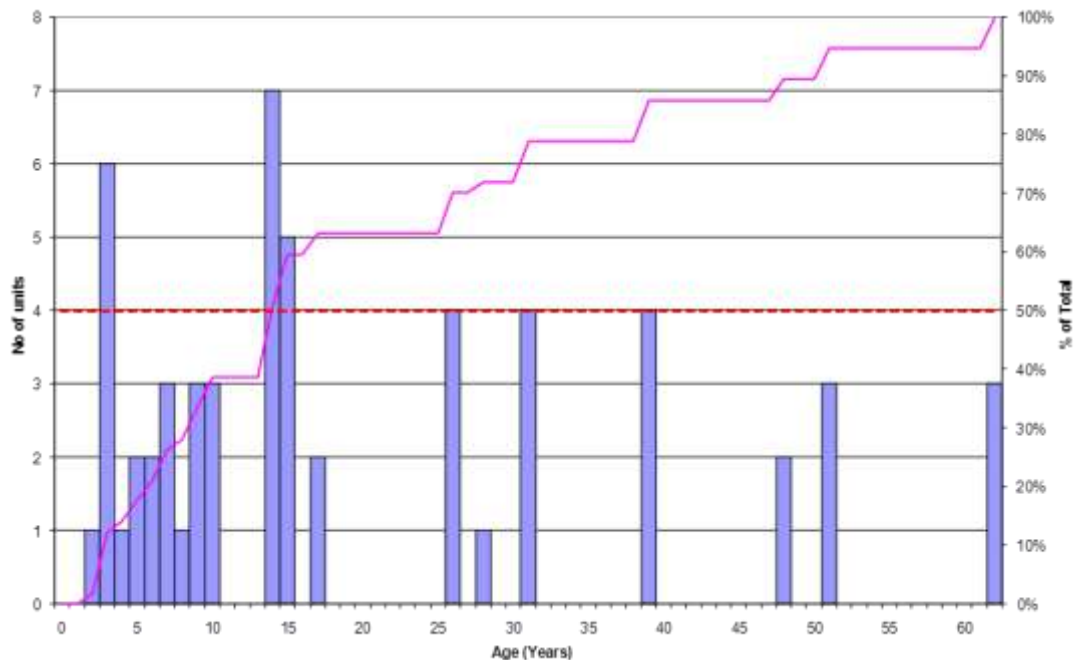


Figure 3-12 – 66 and 33 kV Zone Circuit Breakers Age Profile (Total = 57)

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 1.13. 40% of the circuit breakers are older than 40 years. Their replacement strategy is shown in Section 6.5.

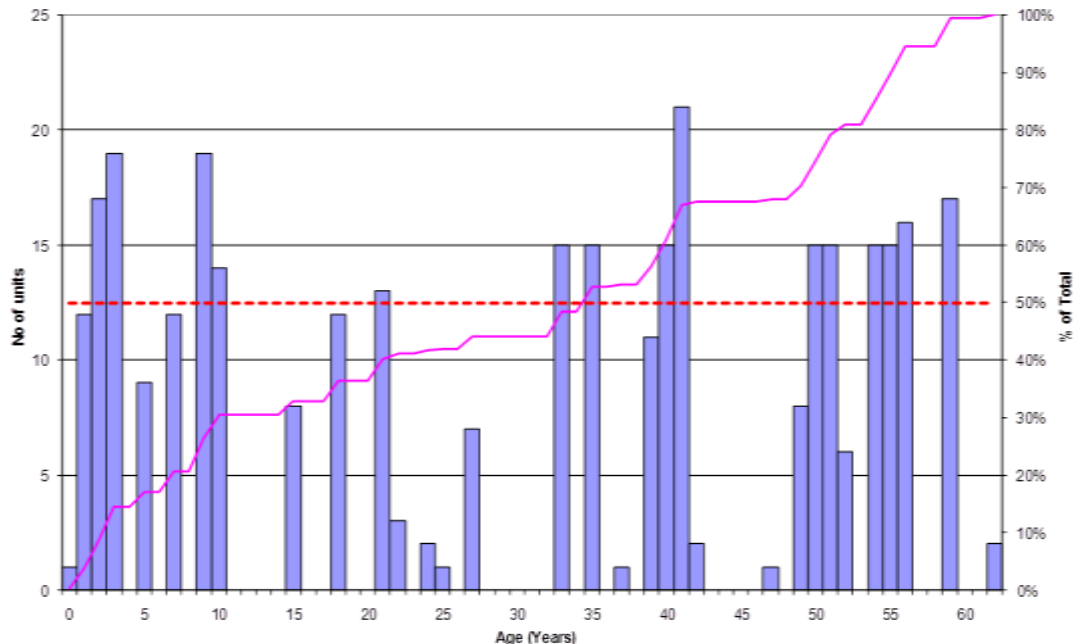


Figure 3-13 – 11 and 6.6 kV Circuit Breakers Age Profile (Total = 339)

3.8.6 Load Control Equipment

Until April 2011, the Dunedin network area, load management ripple injection was exclusively 1050 Hz injection at 11 kV and 6.6 kV at each zone substation with equipment dating from 1958. In April 2011 317Hz 33kV injection equipment was installed at the Halfway Bush and South Dunedin GXPs that will facilitate the phasing out of 1050 Hz injection. All new ripple receivers being installed operate at 317 Hz and relay owners have a program of progressively replacing 1050 Hz units.

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 and Cromwell injectors have recently been replaced. The Clyde injector which is at Alexandra was installed in 1985 (27 years old) and is now programmed for replacement.

The age profile of load management equipment is shown in Figure 3-14.

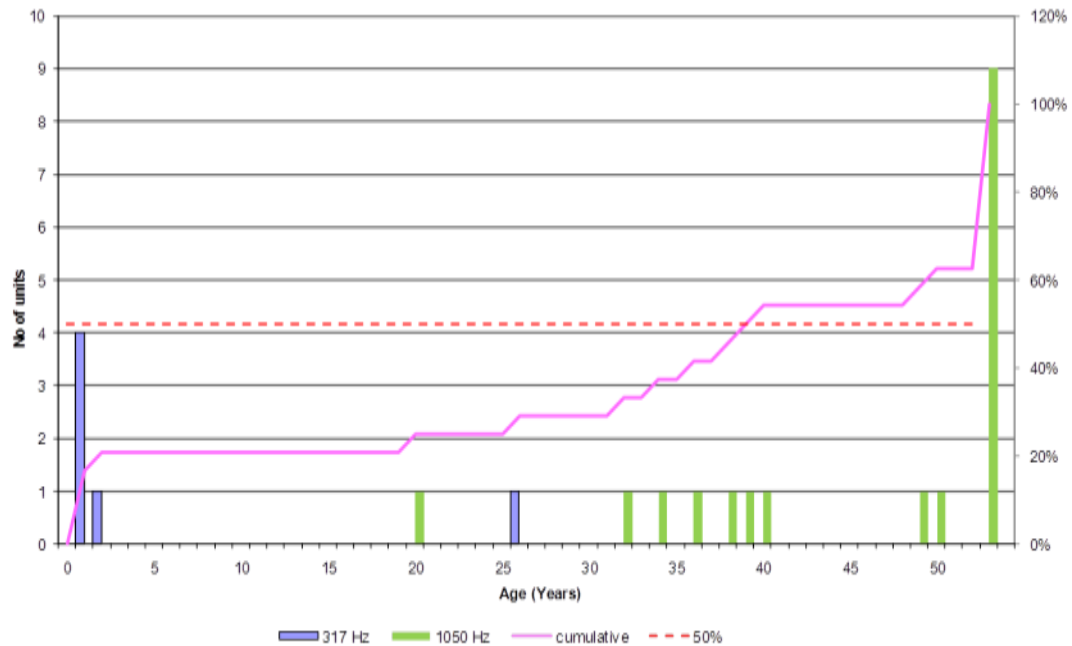


Figure 3-14 – Load Control Equipment Age Profile (Total = 21)

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.

Electromechanical relays generally have a life equivalent to the associated switchgear but electronic relays are not expected to last as long. There has been a failure of one early model electronic relay and as a result the replacement of the HV feeder protection relays at the Alexandra zone substation is scheduled. It is proposed that protection relays be more intensively managed in the future 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. A program is underway to progressively upgrade the RTUs at Dunedin zone substations at five sites per year.

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. Some earthquake strengthening of the Mosgiel zone substation has recently been completed.

3.8.11 HV Lines

Figure 3-15 details the age profile of HV lines by conductor age and pole age. Aurora has 2,342km of HV lines and the age of only 0.4km has yet to be confirmed. 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.

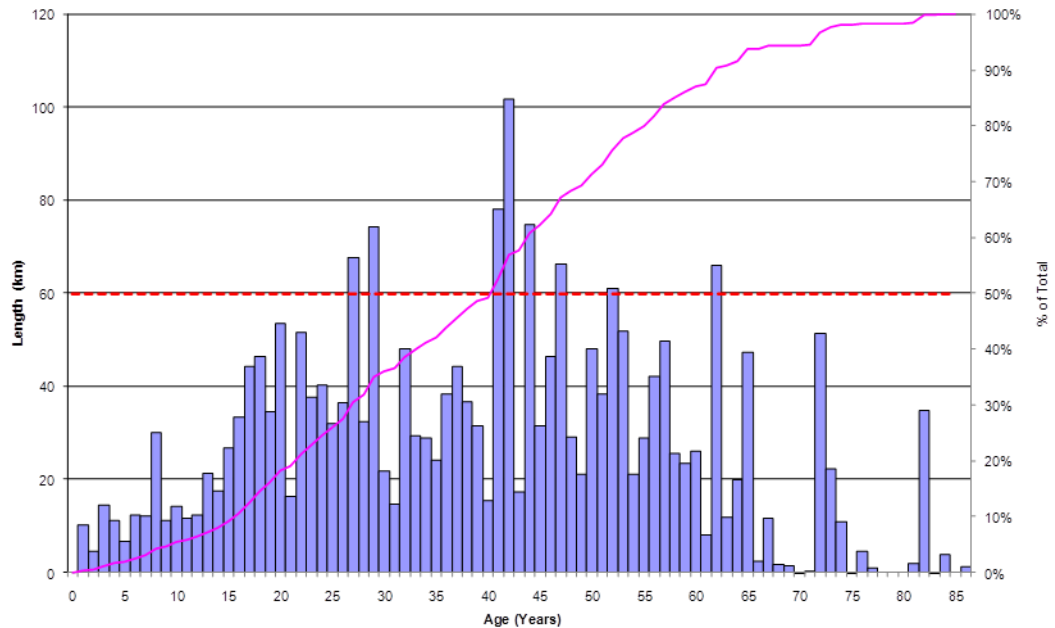


Figure 3-15 – 11 kV and 6.6 kV Lines Age Profile (Total = 2342 km)

3.8.12 HV Cables

The age profile of HV cables is shown in Figure 3-16. Aurora has 864km of HV cable, of which the age of 22 km (2.5%) 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. In recent years there have been failures of paper lead cables at bridge abutments believed to be caused by bridge movement when heavy vehicles cross the bridge. No major replacements are proposed within the planning period.

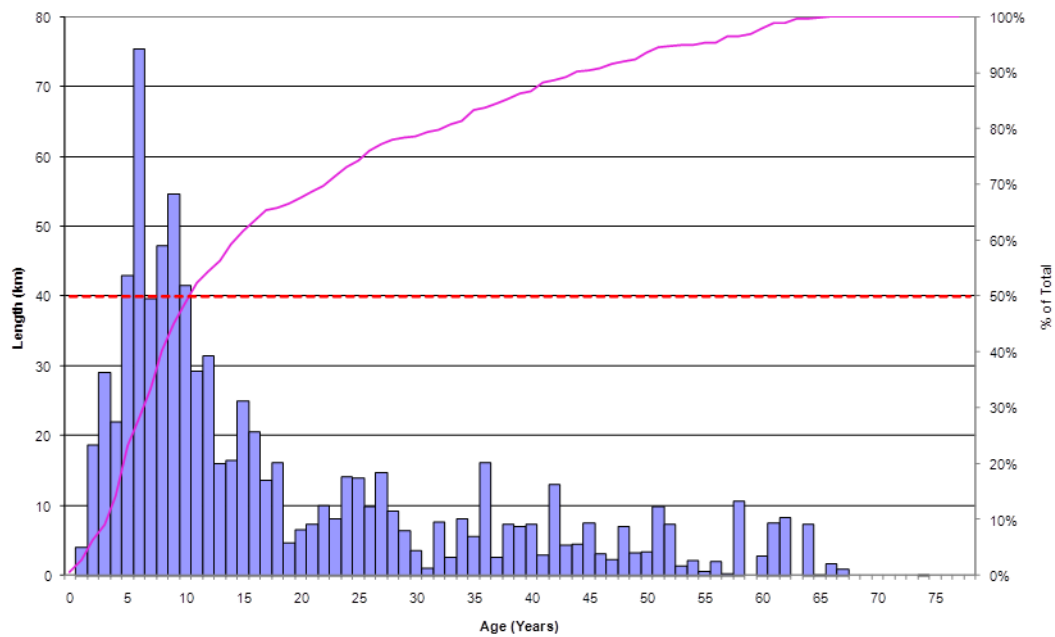


Figure 3-16 – 11 and 6.6 kV Cables Age Profile (Total = 829.3 km)

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 March 2012, there were 6,594 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 Aurora-owned distribution transformers. The age of only 27 units (0.4%) is unknown. Approximately 6% of the transformer population is older than 55 years.

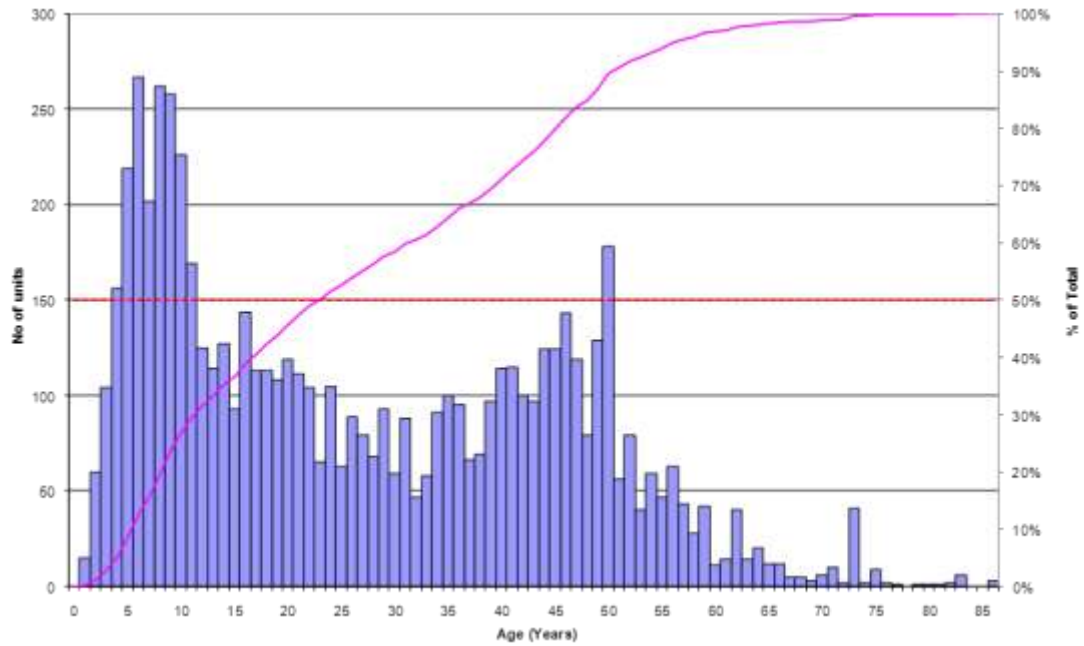


Figure 3-17 – Installed Distribution Transformers Age Profile (Total =6545)

3.8.15 HV Regulators

Figure 3-18, below, details the age profile of regulators. The age profile is by individual regulator; ie a site with three single phase regulators is treated as three units.

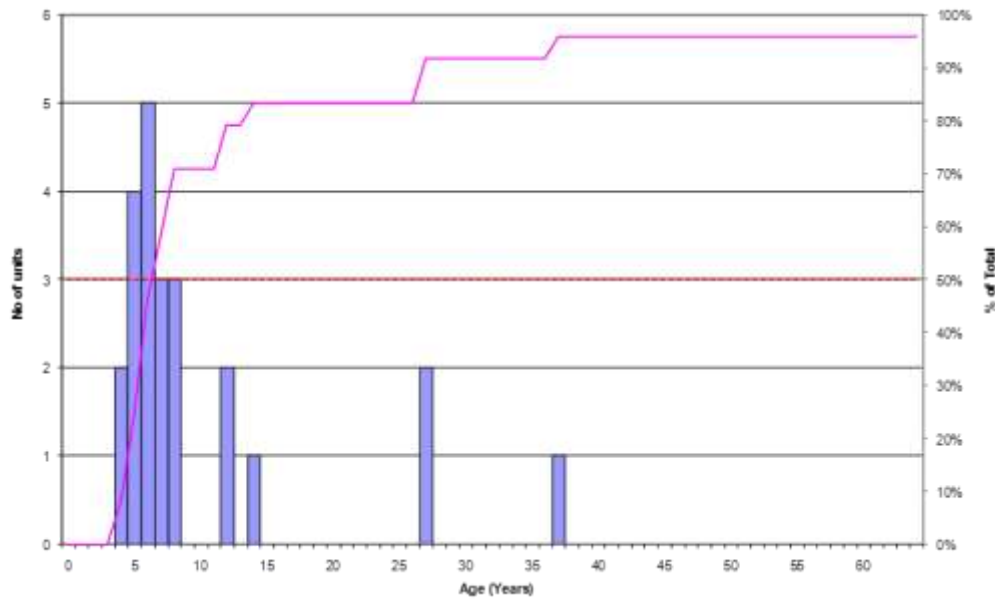


Figure 3-18 – HV Regulators Age Profile (24 units)

3.8.16 HV Auto-Transformers

Figure 3-19 below details the age profile of auto-transformers used for the interconnection of 11 kV and 6.6 kV sections of the network.

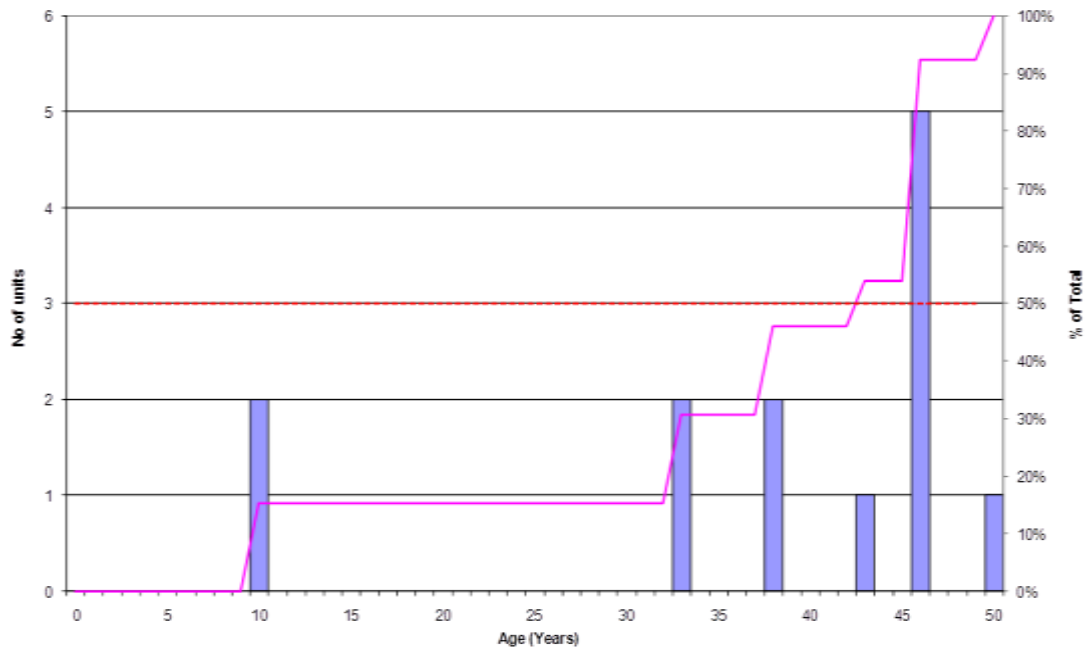


Figure 3-19 – HV Autotransformers Age Profile (13 Units)

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 ring main unit	501
HV fuse switch	383
Circuit breaker	25
Single HV oil switch	413
Total	1436

Table 3-13 – Ground Mounted Switchgear by Type

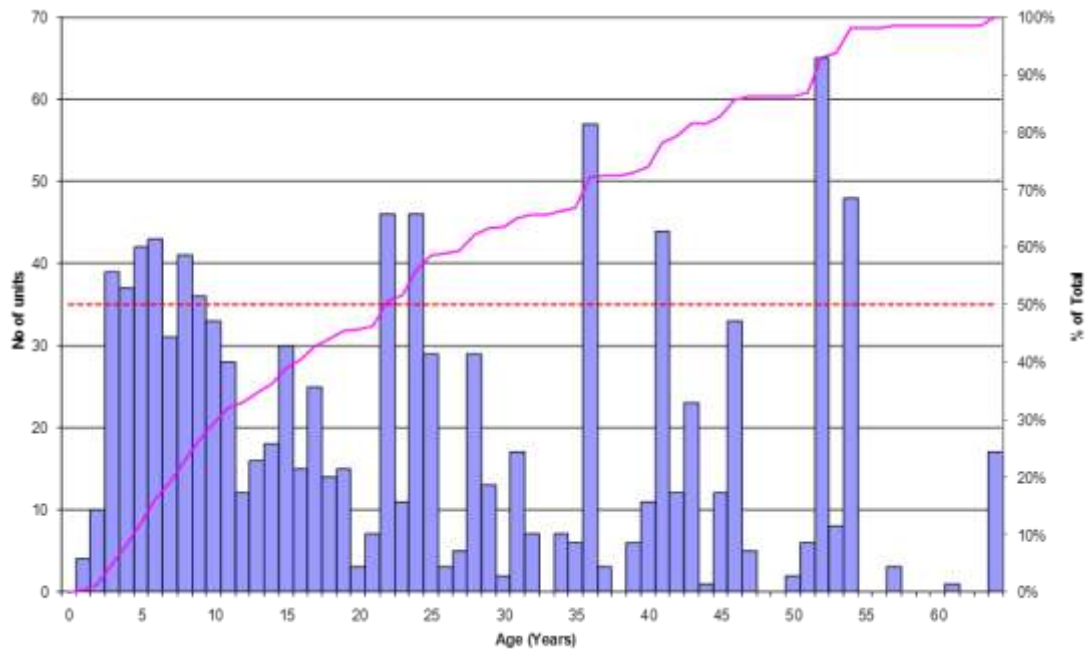


Figure 3-20 – HV Ground Mounted Switchgear Age Profile

3.8.18 LV Overhead Conductor

Figure 3-21 shows the age profile of overhead LV lines. Aurora has 1035 km of LV line, and the construction date of 217 km (21.9%) 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).

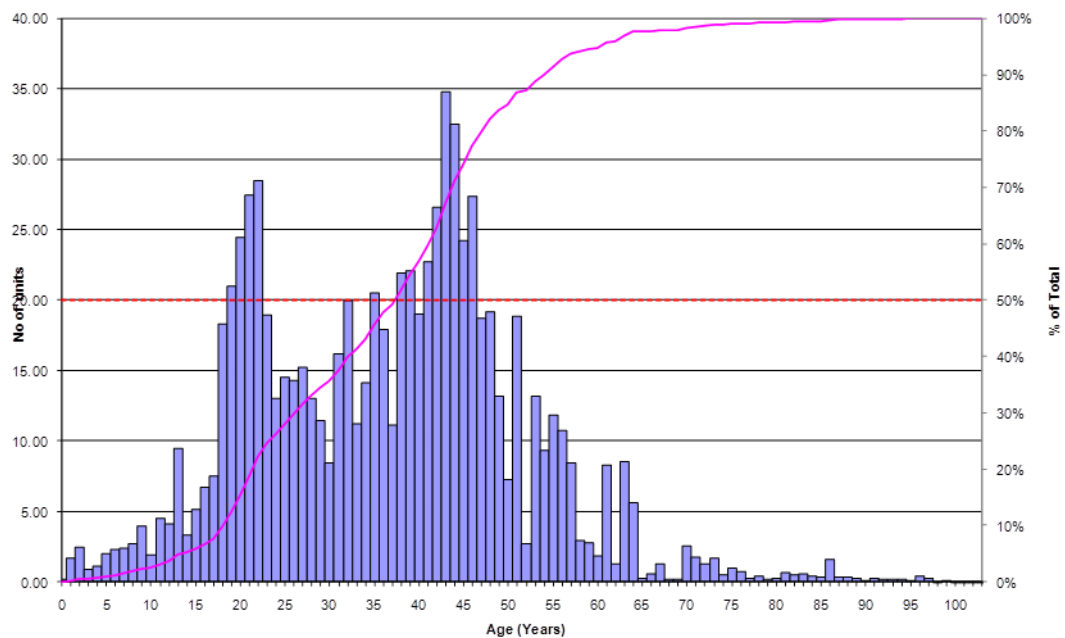


Figure 3-21 – LV Distribution Line Age Profile

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 801 km of LV cable, of which the age of 78 km (9.7%) 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.

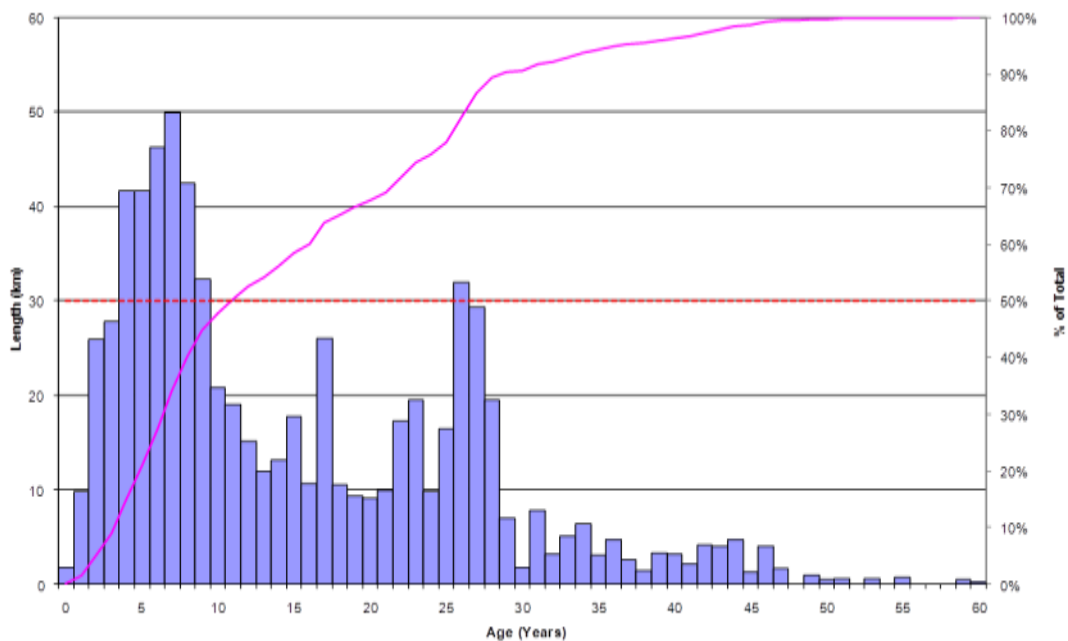


Figure 3-22 – LV Distribution Cable Age Profile

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 53,716 poles, of which only 327 (0.6%) 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. See section 6.5 regarding the replacement programme for poles.

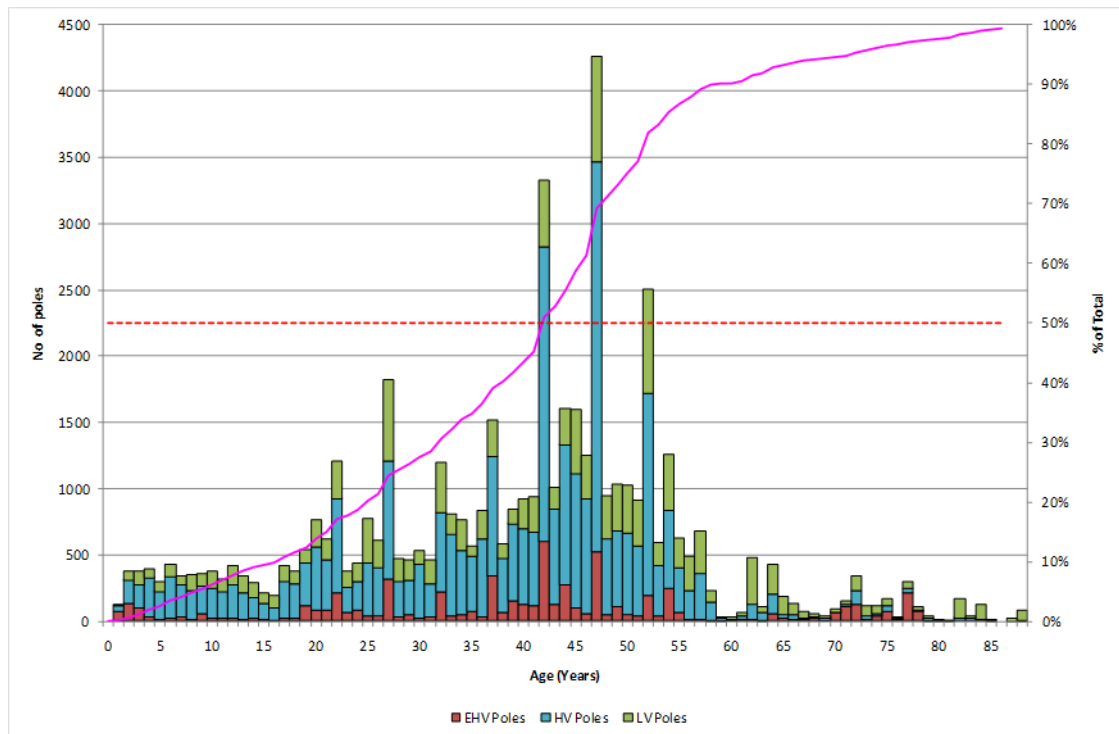


Figure 3-23 – HV and LV Poles Age Profiles

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 master station CPUs are in the process of being replaced and the display and graphics software is being upgraded.

The Dunedin master station is a Foxboro system for which a hardware and software upgrade was completed in March 2006. The master station CPU computers are nearing the end of their economic life but it is not possible to replace them and retain the existing operating system and SCADA software. An upgrade of hardware and software is scheduled for the end of 2013 but the exact nature of this upgrade has yet to be determined.

3.9 Justification for Assets

All assets are justified by present or anticipated requirements, except for approximately 1.6% of assets by ODR value which have previously 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. 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 (2012 results are based on 8 months of data).

Aurora's Continuous Price Versus Quality Survey									
Results to 31 March	2004	2005	2006	2007	2008	2009	2010	2011	2012
Consumers surveyed	4,554	4,641	4,603	4,752	4,800	4790	4,800	4,640	3198
Response rate	18%	18%	18%	16%	17%	17%	16%	13%	11%
Responses									
Prefer higher quality	7.4%	6.7%	5.3%	5.9%	4.8%	5.8%	4.2%	4.0%	4.7%
Prefer lower price	92.6%	93.3%	94.7%	94.1%	95.2%	94.2%	95.8%	96.0%	95.3%

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 2009, 2010 and 2011										
No	Question	Dunedin			Central			Total		
		2009	2010	2011	2009	2010	2011	2009	2010	2011
1	Price more important than quality	Yes 53%	62%	54%	Yes 51%	56%	44%	Yes 52%	59%	49%
		Unsure 25%	24%	28%	Unsure 26%	26%	30%	Unsure 25%	25%	29%
		No 22%	22%	18%	No 23%	18%	26%	No 23%	16%	22%
2	Single most important issue relating to quality	No of interruptions 50%	13%	60%	No of interruptions 100%	28%	21%	No of interruptions 73%	50%	32%
3	Accept 10% increase in line charges for 10% improvement in quality	No 0%	73%	80%	No 100%	71%	86%	No 45%	72%	84%
		Unsure 100%	7%	20%	Unsure 0%	29%	7%	Unsure 55%	18%	11%
4	Acceptance of rebate should increased supply not be achieved	Yes 33%	47%	100%	Yes 80%	71%	36%	Yes 55%	59%	53%
		Unsure 67%	6%	0%	Unsure 0%	15%	21%	Unsure 36%	10%	15%
5	Accept 10% decrease in line charges for say 10% more interruptions	No 29%	51%	58%	No 29%	44%	54%	No 35%	48%	56%
		Unsure 23%	14%	13%	Unsure 23%	13%	10%	Unsure 23%	13%	11%
6	Acceptable timeframe for restoration of supply (weighted average)	3.1 hrs	5.1 hrs	5.9 hrs	3.1 hrs	3.8 hrs	4.5 hrs	3.1 hrs	4.5 hrs	5.3 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 overall; however Central Otago respondents rate voltage fluctuations as the most significant issue. This does not correlate with the reported number of voltage complaints, however.

These results validate Aurora's approach of analysing worst performing feeders, as described in Section 4.4.2.

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 Figure 4-1 and Figure 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.

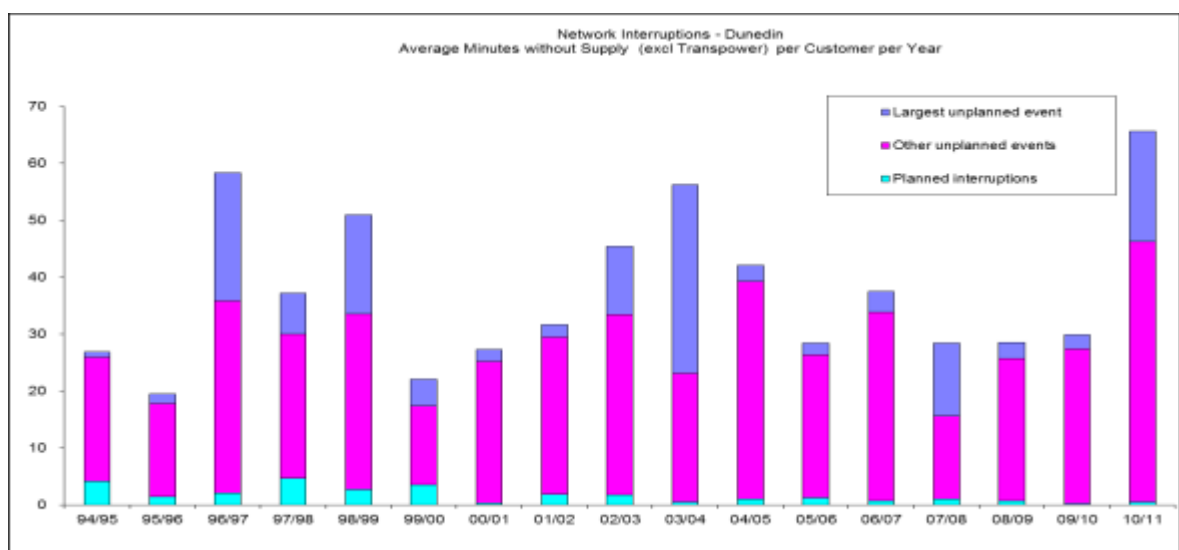


Figure 4-1 – Network Interruptions - Dunedin

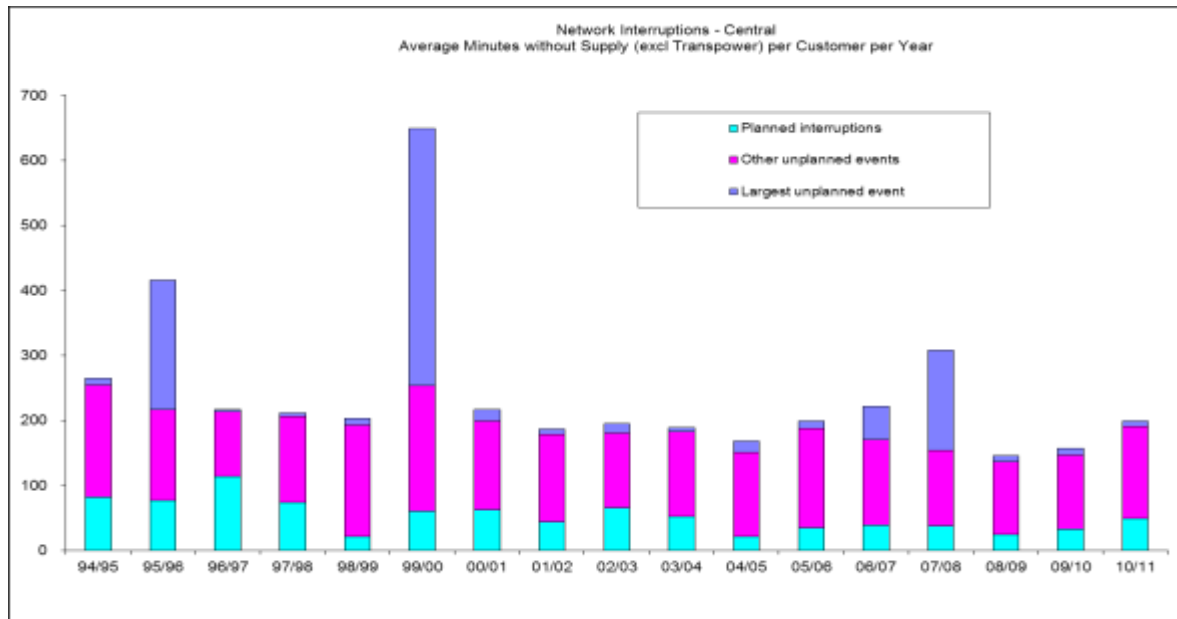


Figure 4-2 – Network Interruptions - Central

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.

	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
Unplanned	70	69	68	68	67	66	65	65	65	65
Planned	14	14	14	13	13	13	13	13	13	13
Total	84	83	82	81	80	79	78	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.

	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
Unplanned	1.26	1.25	1.24	1.24	1.22	1.20	1.19	1.19	1.19	1.19

Table 4-4 - Network Performance Target (SAIFI)

For individual consumers, the above targets and measures can be translated the supply reliability levels stated in Table 4-5 below, providing a more practical explanation of service level delivery.

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 2010/11 (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 49
Dunedin urban suburbs	No more than 2 outages of less than 4 hours each year	4 of 107
Taieri Plains, Otago Peninsula	No more than 4 outages of less than 4 hours each year	14 of 30
Major urban areas in Central (Alexandra, Queenstown, Cromwell, Wanaka)	No more than 2 outages of less than 4 hours each year	1 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 19
Rural areas in Central	No more than 10 outages of less than 6 hours each year	21 of 48
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 2011, 4,816 (6.6%) urban consumers experienced more than four interruptions and 1,791 (16.4%) rural consumers experienced more than 10 interruptions. These results were both higher compared to 2010 results. Some of this can be attributed to weather-related events and/or from tree contact. Delta have completed a survey of the overhead network (in 2011) to assess the impact of vegetation and this information will be used this to update maintenance programmes to ensure that vegetation is maintained clear from lines.

It should also be noted that 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 20010/11 year.

Measure	Indicator	Target Level	Actual 2010/11
Faults per 100 km HV	No. of incidents per year	11.4	11.9
Faults per 100 km HV UG	No. of incidents per year	2.5	2.3
Faults per 100 km HV OH	No. of incidents per year	13.5	15.3

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.

The graphs on the following page show feeder outage and customer outage minutes by feeder length (Figure 4-3 and Figure 4-4). The worst performing feeders are identified and assessed on an annual basis (Table 4-9 and Table 4-9) and, where economic, projects to improve feeder reliability are initiated (see Sections 5.13 and 6.2 for more detail).

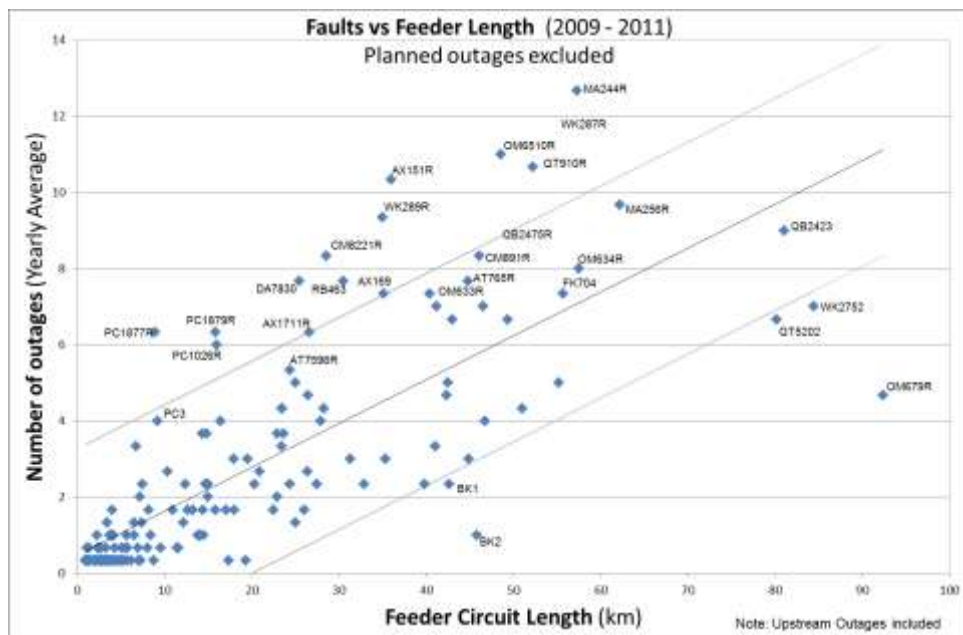


Figure 4-3 - HV Feeder Outages as a Function of Feeder Length

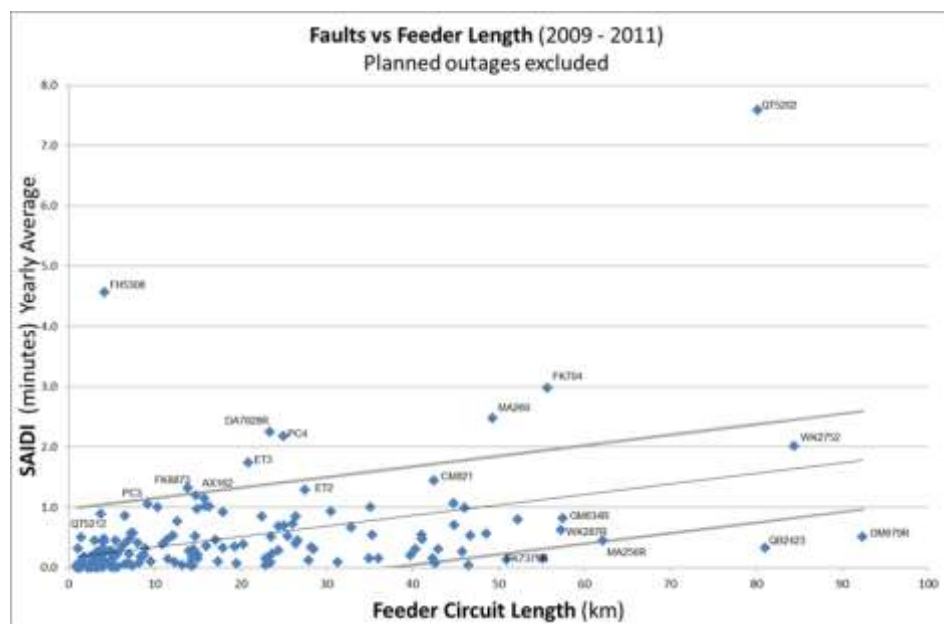


Figure 4-4 - HV Customer Outage Minutes by HV Feeder Length

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

Area	Improve Reliability	Measure	Actual
Ladies Mile, Lake Hayes Estate	FK704	20% reduction in SAIDI and number of interruptions	70% reduction in SAIDI minutes and 73% reduction in number of interruptions
Closeburn	QT5202	15% reduction in SAIDI and number of interruptions	242% increase in SAIDI minutes and 56% increase in number of interruptions
Brighton, Taieri Mouth	ET3	15% reduction in SAIDI minutes	73% reduction
Saddle Hill, Chain Hill	ET2	10% reduction in SAIDI minutes	95% increase
Luggate	WK2752	10% reduction in SAIDI minutes	15% reduction in SAIDI minutes
Hawea	MA260	10% reduction in SAIDI and number of interruptions	7% increase in SAIDI minutes and 44% reduction in number of interruptions
Mosgiel East	ET8	10% reduction in SAIDI minutes	100% reduction
Waldronville	GI11	10% reduction in SAIDI minutes	85% reduction
Glenorchy	QT910	10% reduction in SAIDI and number of interruptions	58% reduction in SAIDI minutes and 44% reduction in number of interruptions
Lower Peninsula	PC3	10% reduction in SAIDI minutes	54% reduction

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

Aurora has selected the following feeders (refer Table 4-8) for attention over the next two years. These feeders include three of those identified in last year's list as listed in Table 4-7 above (QT5202, MA260 and WK2752). Performance improvements were seen to the remaining seven of these feeders.

Area	Improve Reliability	Measure	Target Level
Closeburn	QT5202	Reduce SAIDI and number of interruptions	25% improvement
Fernhill	FH5308	Reduce SAIDI minutes	15% improvement
Dalefield	DA7828	Reduce SAIDI minutes	15% improvement
Remarkables park	FK7783	Reduce SAIDI minutes	10% improvement
Sawyers Bay	PC4	Reduce SAIDI minutes	10% improvement
Hawea	MA260	Reduce SAIDI and number of interruptions	10% improvement
Luggate	WK2752	Reduce SAIDI and number of interruptions	10% improvement
Pisa Moorings	CM891	Reduce SAIDI and number of interruptions	10% improvement
Gibbston Valley	AT765	Reduce SAIDI and number of interruptions	10% improvement
Omakau west	OM679	Reduce SAIDI and number of interruptions	10% improvement

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 2010/11
Load factor	Energy into network/peak kW hours per year	52%	55%
Loss ratio	Energy into network less energy delivered / energy into network	6.0%	6.2%
Capacity utilisation	Peak network kW / installed distribution transformer capacity kVA	30%	31.2%

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 4-12, 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%
2011	33	1897	\$143,366	0.195%

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 4-13, 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 2010/11
Voltage complaints	No of valid voltage complaints per year	Less than 10 per 10,000 connections	4 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 2010/11
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	1

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. More recently, a Public Safety Management System has been developed and implemented in response to new safety regulations introduced under the Electricity (Safety) Regulations in 2010 (See Section 7 'Risk Management' for more detail).

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 2010/11
Safety of public	No of incidents per year	Zero incidents per year	0
Safety of personnel	No of incidents per year	Zero incidents per year	1
Safety of network assets	Compliance with standards	All significant site hazards removed or mitigated if practicable	compliant

Table 4-13 – Network Safety Levels

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 2010/11
SF6	No of incidents per year	0	0
PCBs	No of incidents per year	0	0
Oil spills	No of incidents per year	0	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 four 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.

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 forecast capital expenditure is presented in Table 5-1. This projection is based on a financial year of 1 July to 30 June (the 2012/13 year does not include carry-overs from 2011/12). The definition of capital expenditure categories is given in Table 5-2 and the timing of major projects is presented in Table 5-3.

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)
Central										
Customer Connections	4,850	5,200	5,600	6,000	6,400	7,000	7,000	7,000	7,000	7,000
System Growth	9,447	5,190	5,120	7,590	5,250	1,000	3,500	1,000	6,300	5,200
Reliability Safety and Environment	3,058	1,380	280	500	1,060	660	600	540	600	700
Asset Replacement and Renewal	2,649	3,719	2,495	465	1,565	935	900	910	910	605
Asset Relocations	300	400	500	400	400	400	400	300	300	300
	20,300	15,889	13,995	14,955	14,675	9,995	12,400	9,750	15,110	13,805
Dunedin										
Customer Connections	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
System Growth	150	180	180	180	1,080	580	680	4,680	4,680	100
Reliability Safety and Environment	420	1,150	1,466	1,404	600	500	1,200	900	1,000	1,000
Asset Replacement and Renewal	5,720	3,960	8,485	4,235	1,635	5,655	7,055	4,660	5,355	1,156
Asset Relocations	100	100	100	100	100	100	100	100	100	100
	7,590	6,590	11,431	7,119	4,615	8,035	10,235	11,540	12,335	3,556
Grand Total	27,890	22,479	25,426	22,074	19,290	18,030	22,635	21,290	27,445	17,361

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

Table 5-3 – Time Line of Major Capital Projects

ProjectNumber	Description	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Growth Projects											
3023	2 X20MVA zone substation in Maori Point Rd for Tarras irrigation scheme	5,300									
4183	HV Distribution and substations associated with Tarras Irrigation Scheme	3,800									
4135	Upgrade Maungawera Substation from 3 to 5 MVA		3,300								
3165	New Wanaka Feeder 2751.		600								
3428	Install new HV feeder in Cromwell to Leitrum St		500								
3024	Install two new 24 MVA transformers at Cromwell substation			2,500							
4182	Upgrade Glenorcy supply to 33 kV			1,200							
4161	Upgrade HV lines Maungawera Zoe Sub to Devon Dairy 4.6km.			420							
3022	Construct Riverbank Rd 66kV switching station.				4,000						
3216	Install 66kV cables from Riverbank Rd substation to Wanaka Sub and to UC2 line.				2,500						
3019	Install 10 MVA transformers and new switchgear at Arrowtown Zone Sub.					4,000					
3437	Install 24 MVA 66/11kV transformer and 11kV switchgear at Riverbank Rd substation.							2,500			
3414	Upgrade Smith St Substation - new 24MVA transformers and HV switchgear								4,500		
3038	Upgrade Andersons Bay substation. New Xfms and switchgear.									4,500	
3438	Create 66kV Switching Station at Queensberry									3,000	
3021	Install 3rd 33/66kV auto transformer at Cromwell GXP and create 66kV bus									2,000	
3046	Upgrade 33kV 70mmsq cable (668m) into Arrowtown Substation									300	
2611	Jacks Point zone substation										3,000
Renewal Projects											
3472	Repalce Andersons Bay 33kV gas cables	2,700									
2130	Roxburgh Substation Upgrade	2,108									
4205	Pole replacements 2012/13 Central Area	2,000	2,000	2,000							
4204	Pole replacements 2012/13 Dunedin Area	1,000	1,000	1,000							
2567	Upgrade Central ripple control master station and associated communications.	300									
4210	Allowance for Communication Upgrades		1,000	1,000	1,000						
4038	Replace Lower Shotover River 33 kV Crossing Old School Road with cable across bridge.		1,000								
4212	Submarine cable crossing Port Chalmers to Portobello.		800								
3272	Undergrounding of OH from Frankton Sub to Glenda drive for LTSA roading work.		500								
3669	Dunedin SCADA master station upgrade.		300								
2324	Rebuild Neville St zone substation on new site + replace gas cables.			6,000							
4179	Upgrade Outram Zone Substation				3,000						
3470	Replace Willowbank 33kV gass cables						3,900				
3171	Replace Kaikorai Valley 33kV cables							2,900			
3471	Replace Smith St 33kV gas cables								3,500		
3469	Replace Ward Street gas cables									4,200	

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 and there are several proposals for additional generation connections.

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.

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 an 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.

5.5.1 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.

5.5.2 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.

5.5.3 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

5.5.4 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.

5.5.5 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

As part of the review of the planning and forecasting assumptions and uncertainties relating to the Aurora electricity distribution networks in 2012, further review and consideration will be given to the current decision-making criteria and prioritisation methodology in order to provide more transparency for the reasons selected options have been chosen, particularly for network development projects.

5.8 Equipment Ratings

Equipment ratings are assigned in accordance with Table 5-8 and Table 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

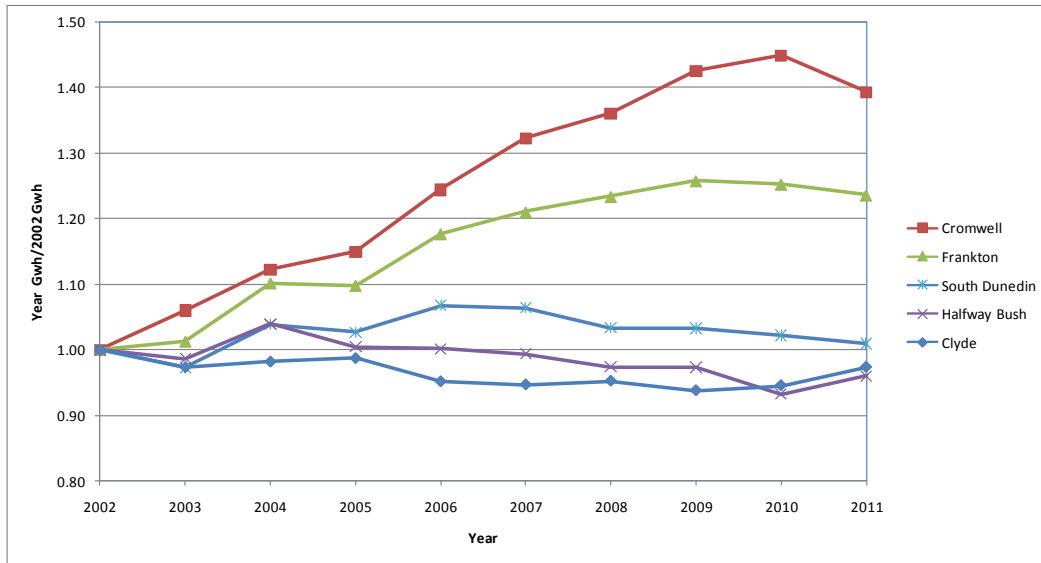
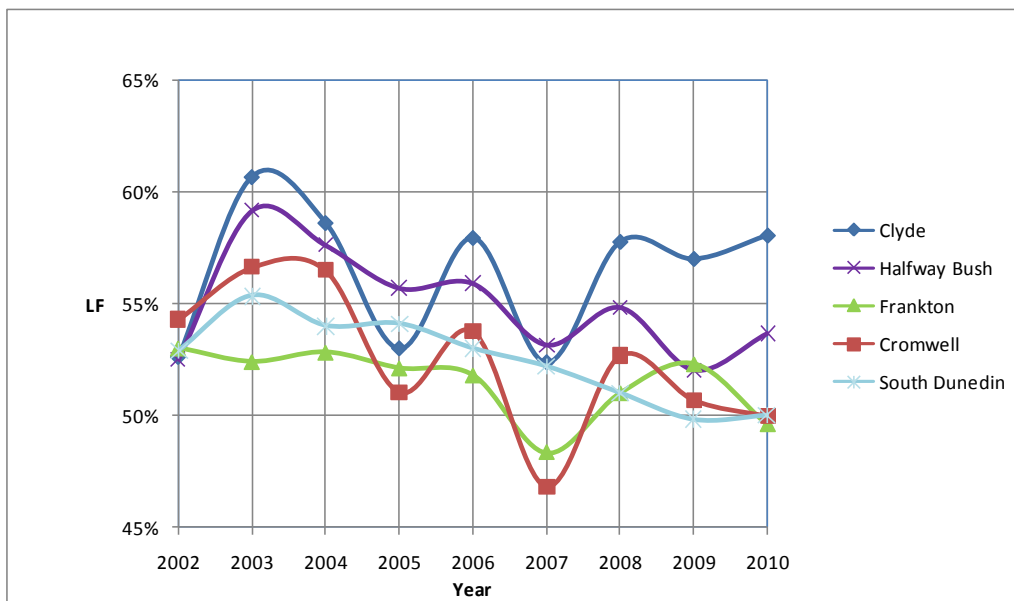
Table 5-10 – Ratings of Standard ACSR Conductors**5.9 Grid Exit Points****5.9.1 Demands and Growth Predictions**

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

The Energy use normalised in 2002 GWh for each GXP is shown in Figure 5-1 and the load factor 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.

Calendar Year			Clyde	Cromwell	Frankton	Halfway Bush	South Dunedin	
2004	Actual	GXP Off take + Embedded Generation (MW)	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			16.4	29.9	48.7	128.7	72.2	
2012	Predicted		16.6	31.8	51.2	127.3	73.7	
2013			16.7	32.7	52.2	127.9	74.5	
2014			16.8	33.7	53.2	128.5	75.2	
2015			16.8	34.6	54.3	115.2	90.0	
2016			16.9	35.6	55.3	115.8	90.8	
2017			17.0	36.6	56.4	116.4	91.6	
2018			17.1	37.7	57.4	117.0	92.4	
2019			17.2	38.7	58.5	117.6	93.2	
2020			17.3	39.8	59.6	118.2	94.1	
2021			17.4	40.8	60.7	118.8	94.9	
2022			17.4	41.9	61.8	119.4	95.8	
Past Growth Rate (Trend 2005 to 2011)			-0.6%	3.85%	2.19%	0.01%	1.17%	
2011 off take peak (MW excluding embedded generation)			7.6	26.7	47.5	115.4	72.2	
Off take n-1 Capacity (Continuous) MVA			27	40.9 ²	66	100	81	
Off take n-1 Capacity (24 hr Winter Post Contingency MVA)			27	40.9	80	112	81	
Embedded Generation (2011 MW at time of load peak)			20.5	3.2	1.2	29	0	
Embedded Generation (2011 MW at time of off take peak)			3.5	3.3	1.0	4.9	0	

² This is Aurora off take only ESL off take approximately 1.5 MW

Table 5-11 – GXP area peak demands**Figure 5-1 – Comparative growth in GXP energy (GWh 2002 normalised)****Figure 5-2 – Load factor by GXP**

The demands at all GXPs during the 2011 winter except for Halfway Bush were lower than predicted in the 2011 plan. This has been attributed to the mild winter and the impact of the economic down turn. See Table 5-12 below.

GXP	2011 MVA Predicted	2011 MVA Actual	Difference
Clyde	17.0	16.6	-2.7%
Cromwell	33.2	29.9	-11.1%
Frankton	51.7	48.7	-6.1%
HWB	126.1	128.7	2.1%
Sth Dn	73.4	72.2	-1.6%

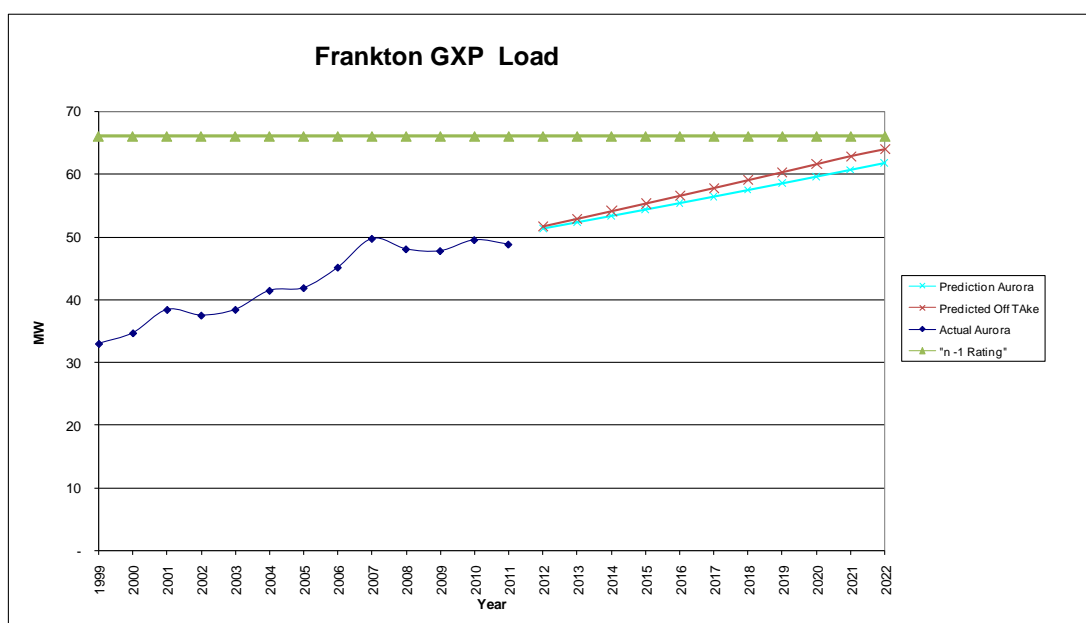
Table 5-12 – Comparison of 2011 actual and predicted loads**5.9.2 Frankton GXP**

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 which is determined by the T2A/T2B transformers. The 110 kV lines have a winter rating of 76 MVA. It is predicted the 66 MVA continuous n-1 rating will not be exceeded during the planning period as shown in Figure 5-3.

Electricity Southland Ltd (ESL) takes supply from this GXP as well as Aurora. The load predictions include an estimated allowance for ESL load.

There is space in the switch room for two additional 33 kV feeder circuit breakers. Installing an additional feeder will be easy while it is possible to obtain the existing switch-gear 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****5.9.2.1 Frankton Ripple Injection**

The Frankton ripple injection plant was upgraded in 2010 the new injectors will cope with up to 100 MW of connected load.

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 2022. The protection constraint is the over-current setting on the 33 kV incoming circuit breakers which cannot be increased due to the need

to detect 33 kV feeder line end faults. One solution is to install duplicate protection on affected feeders.

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 on Figure 5-4. The impact of the Hawea Generation has not been included in the load prediction due to the uncertain nature of this project.

Transpower plans to convert the outdoor switchyard to indoors by 2025 but this work has yet to be scheduled.

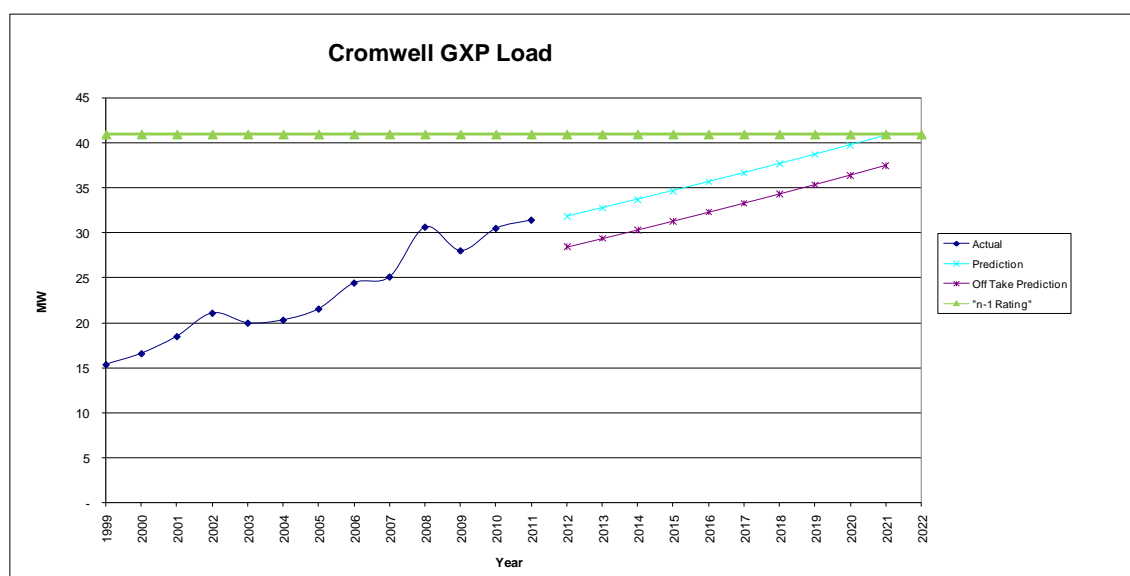


Figure 5-4 – Cromwell GXP 33 kV Load

5.9.3.1 Cromwell Ripple Injection

The Cromwell ripple injection was upgraded in 2009 and is rated to cope with a connected load in excess of the current 50 MVA firm capacity as well as the future Hawea generation.

5.9.4 Clyde GXP

The Clyde GXP has two 27 MVA transformers. The embedded generation on this GXP almost meets the total demand on the GXP. Should the embedded generation fail the maximum demand on the GXP would be approximately 17 MVA. There is adequate GXP capacity at Clyde for the foreseeable future. Growth has averaged less than 1% per year since 2004 and is not expected to accelerate during the planning period unless the Dairy Creek irrigation project proceeds. Pioneer Generation Ltd commissioned 1.2 MW of wind generation during 2009 adjacent to their Horseshoe Bend hydro station. The connection of the 1.9 MW Talla Burn generation and the 2 MW Kowhai generation in 2010 plus the possibility of additional generation will continue to keep the off-take low.

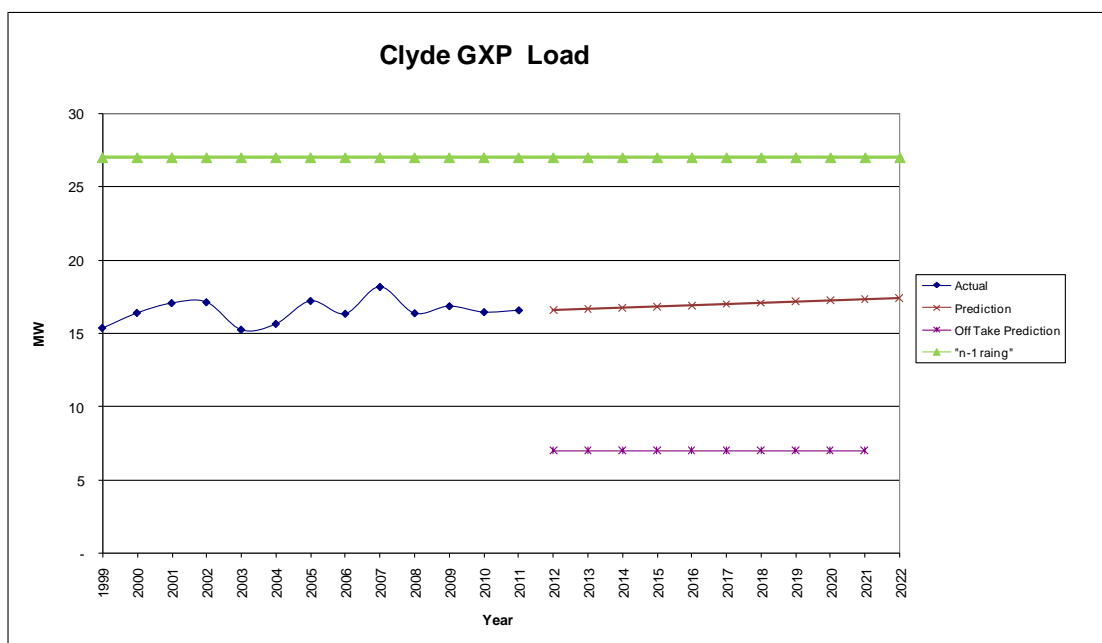


Figure 5-5 – Clyde GXP load

5.9.4.1 Clyde Ripple Injection

The ripple injection for the Clyde GXP area is located at Alexandra and was installed in 1985 (26 years old) and is past its nominal 20 year life. The injection unit ex Frankton is available as a spare but this unit is also older than 20 years. Spare parts are no longer available for either unit.

A capacity check indicates the existing injector has capacity to cope with many years of load growth.

Development report DR123 investigates the future options for the Alexandra injection units and recommends that the injection unit be replaced with a new 200kW unit that is the same model as used at all other sites.

Estimated Cost \$120,000

Completion: May 2013

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 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 (see development report DR24).

It is planned to move the Neville Street substation load to the South Dunedin GXP by May 2015 when the Neville Street substation and gas cables are upgraded, see Section 6.5.1. This would reduce the demand on Halfway Bush by approximately 14 MVA; see Figure 5-6 below for load projections.

The connection of the 36 MW TrustPower Mahinerangi wind farm during 2011 will assist in reducing the off take on the Halfway Bush GXP.

Transpower plans to convert the remaining outdoor 33 kV circuit breakers to indoor units in 2106. At this time, it may be desirable to have Transpower fit 33 kV VTs to the Waipori lines which will eliminate the need for the outdoor VTs in the takeoff area.

Transpower plans to remove the two 110/33 kV transformers and replace them with a single 120MVA 220/33 kV transformer operating in parallel with the existing T5 transformer in 2017. This will enable the present separate 33 kV buses at Halfway Bush to be operated as one solid bus which will have some operational advantages for Aurora. When the new transformer is installed, it is assumed it will be fitted with an NER. It is proposed that Transpower be requested to install an NER on the existing T5 transformer at the same time. This will allow the use of light duty cable screens when 33 kV cables from Halfway Bush are renewed which reduces the cable cost by up to 30%

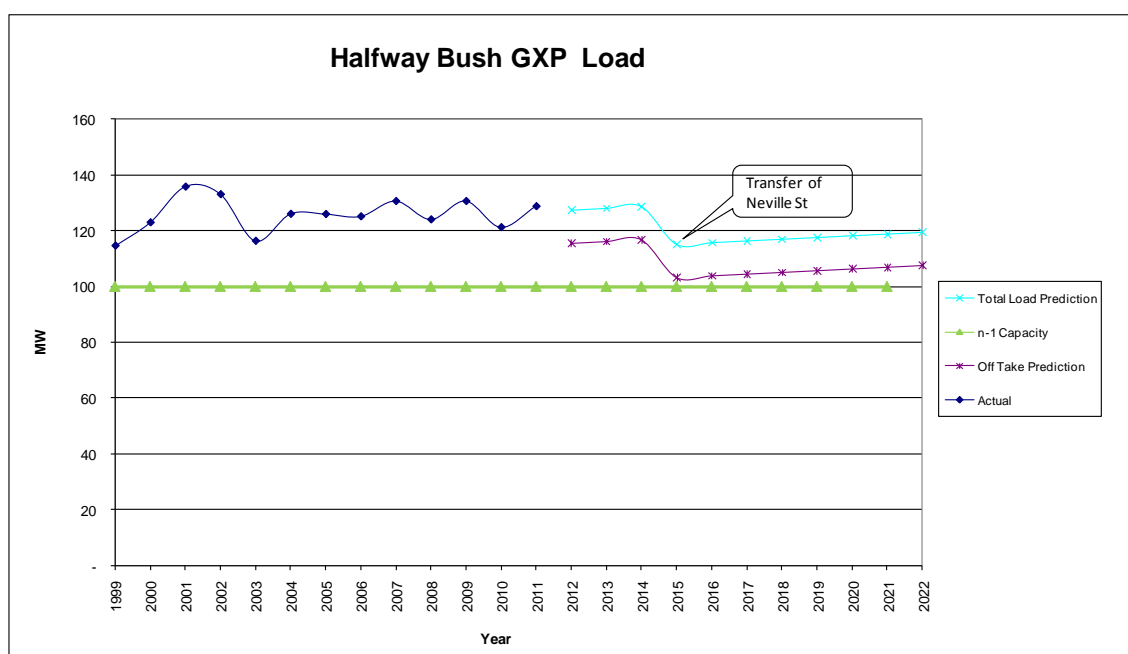


Figure 5-6 – Halfway Bush GXP predicted loads

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 72.2 MVA (2011) and well under the 81 MVA limit but, when the Neville Street Substation load is transferred to South Dunedin, as proposed in Section 6.5.1, 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 recalibration of the meters. This work will be carried out in conjunction with the switchgear up grade project detailed in Figure 5.7 below.

5.9.6.1 Conversion of Switchgear to Indoor

Transpower plans to convert the 33 kV switchgear at South Dunedin from outdoor units to indoor units with completion scheduled for early 2014. In conjunction with the switchgear conversion project, Aurora has requested that an additional circuit breaker be installed to facilitate the connection of the Neville Street substation to the South Dunedin GXP. Transpower has been requested to allow space in the new switch room to accommodate the re-connection of the South City No.2 feeder in the future. Refer to Development Report DR128 for details relating to the conversion project.

5.9.6.2 Installation of NER on T1

The South Dunedin GXP T2 is fitted with an NER but not T1. The installation of an NER on T1 would be advantageous to Aurora as it will enable future 33 kV cables connected to the GXP to have light duty screens instead of heavy duty screens due to the reduced earth fault current. The cost of installing the NER is expected to be less than the saving by having light duty screens on the future Andersons Bay and Neville Street cables. Transpower has been requested to prepare a detailed solution report on providing an NER. The T1 NER will need to be commissioned prior to March 2013 before the new Andersons Bay 33 kV cables are commissioned.

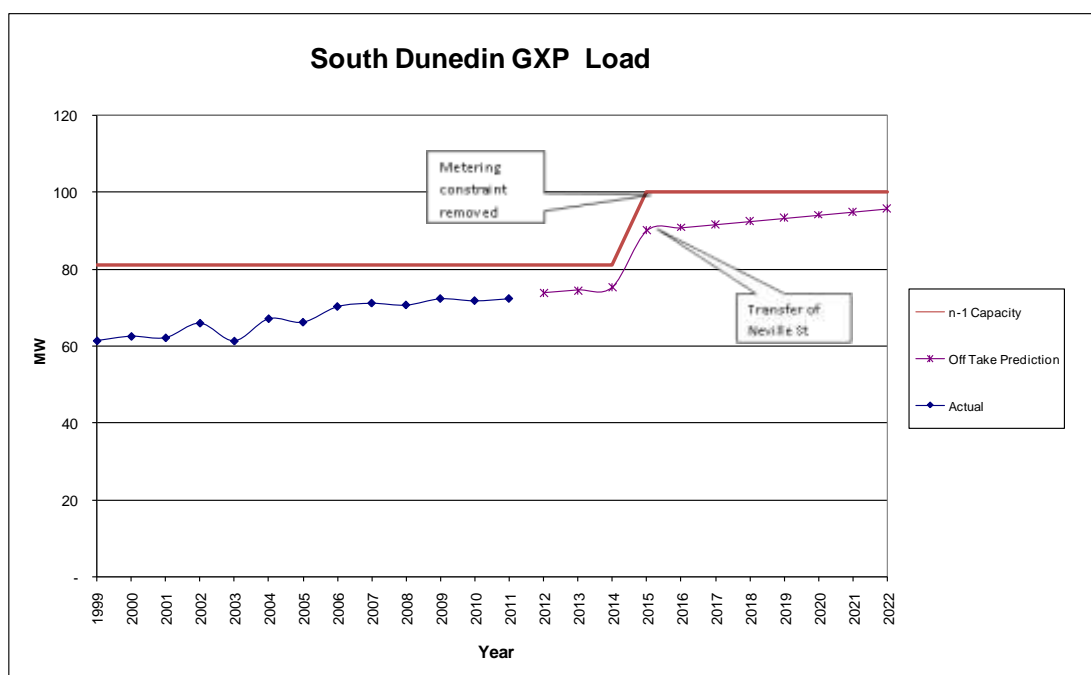


Figure 5-7 – South Dunedin GXP predicted loads

5.10 Subtransmission

This section reviews the loading on all subtransmission networks, and where constraints are expected upgrades are proposed.

5.10.1 Frankton to Queenstown

The Frankton to Queenstown subtransmission consists of three parallel circuits with Dog conductor and cables at the ends. The n-1 capacity of this network is 40 MVA and this load is not predicted to be reached within the 10-year planning period as shown in Figure 5-8.

It is currently considered that the most economic option to increase the delivery capacity to Queenstown, when the subtransmission n-1 capacity is reached, is to install a third transformer at the Queenstown substation (15 MVA) and provide additional 33 kV transmission capacity to the Commonage substation. This could be achieved by either the installation of a 33 kV cable under the existing Frankton to Commonage transmission lines, upgrading the lines or replacing the lines with two high capacity cables. This provides an additional 15 MVA of firm capacity without the need to construct a new substation. Financial provision is yet to be made for this work as it is beyond the 10-year planning period.

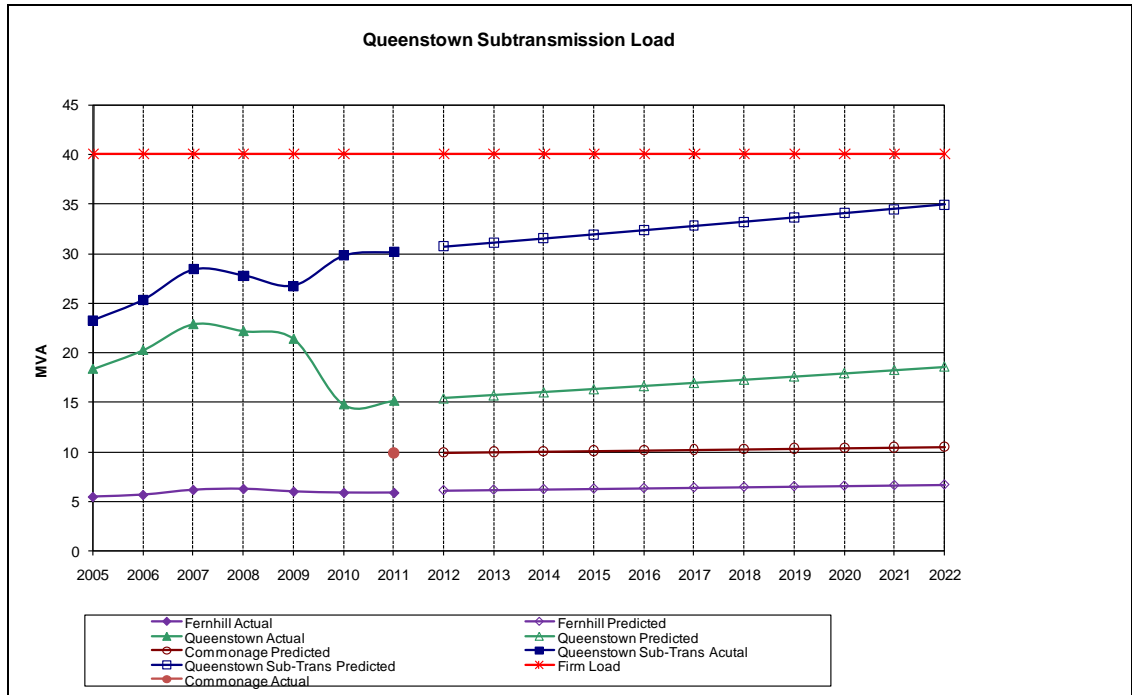


Figure 5-8 – Predicted loading on Frankton to Queenstown 33 kV subtransmission

5.10.2 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 5-9 for the configuration of the ring.

The Arrowtown peak load is currently predicted to exceed the rating of the 70 mm² cable (170 A 9.7 MVA) in 2021. The cable upgrade is now scheduled for the 2020/21 summer.

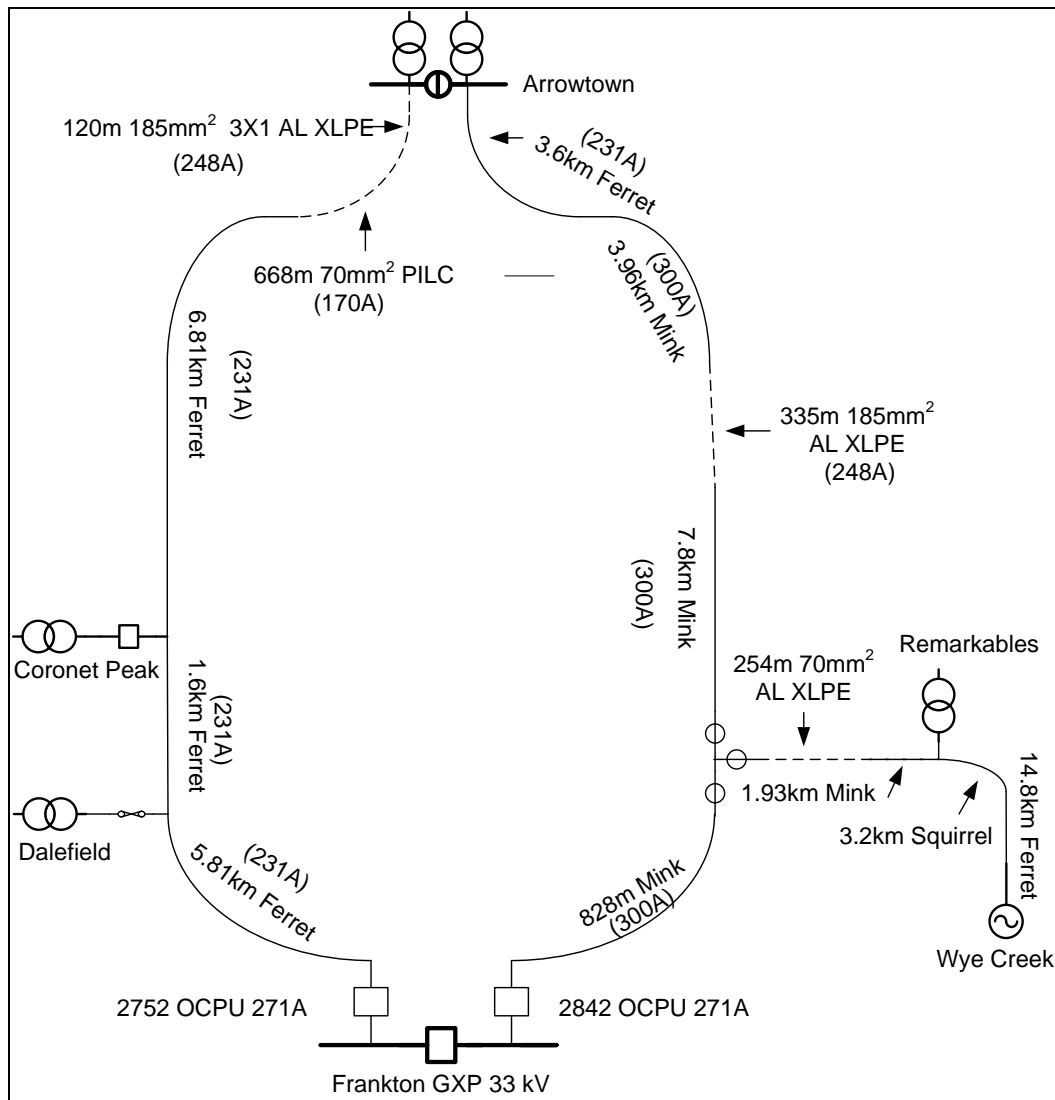


Figure 5-9 – Wakatipu basin 33 kV ring

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 185 mm² cable³ (14.1 MVA). The ring load is predicted to exceed its n-1 capacity during the winter of 2012 - see Figure 5-10 for loading predictions. The present and predicted peak loads on the ring were derived by combining the loads of the substations on the ring and applying a 0.87 diversity factor. The timing of snow making at Coronet peak has a significant effect on the diversity which varies from year to year.

To improve the n-1 capacity of the ring either requires 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 185 mm² 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.

³ The winter rating of the 185mm cable was confirmed to be 248 Amps in Maunsell report of 25 Aug 2008.

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 15.6 MVA, which is predicted to be beyond the planning period. 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 the one off addition of extra snow making at Coronet Peak.

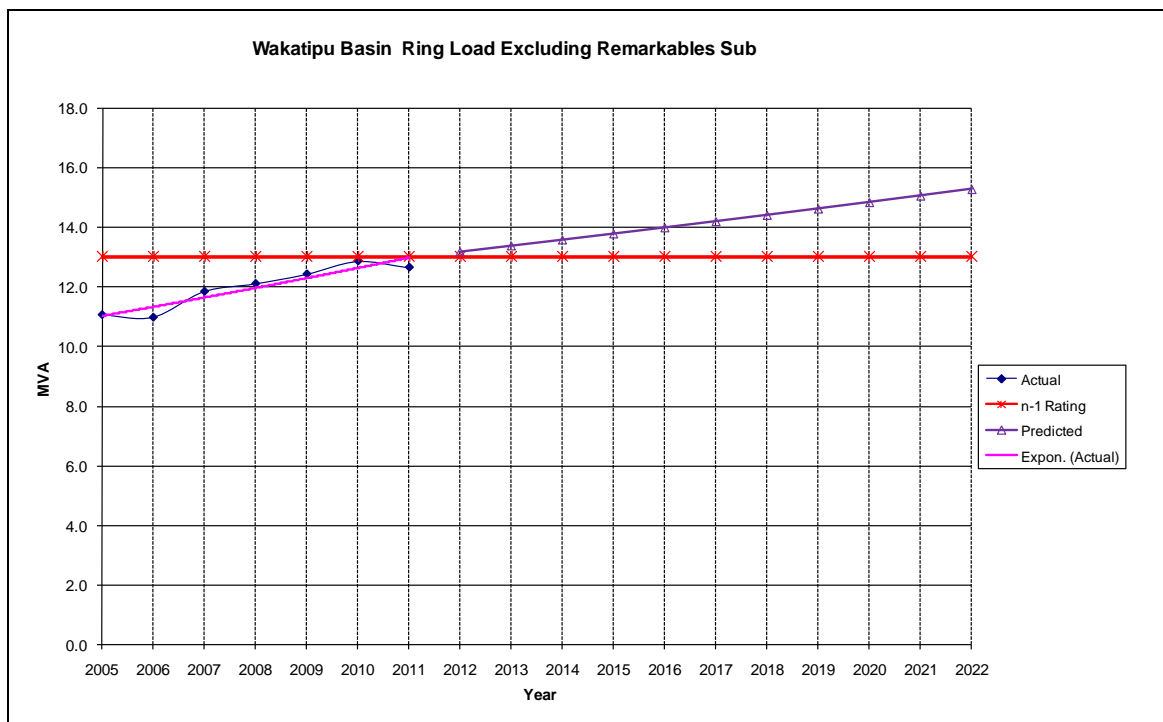


Figure 5-10 – Wakatipu basin 33 kV ring – predicted loading

Two options are considered for the installation of a third circuit. Both of these options require the installation of an additional 33 kV feeder outlet from the Frankton GXP. This outlet will also serve the Jacks Point substation when it is commissioned, which is projected for 2021/22.

The options for supplying the third circuit to Arrowtown from the North Bank of the Shotover River are detailed below.

Option 1 is to install an additional 33 kV circuit from the north bank of the Shotover River to Arrowtown. See Figure 5-11 for the proposed circuit route and Figure 5-12 for a single line diagram. The circuit would have 800m of cable at the Arrowtown end, 700m of cable at 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 5-123 for the circuit route and Figure 5-14 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 70 mm² 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.

Project Description	Estimated Cost \$000	Completion
Replace 668m of 70mm ² cable	\$ 300	May 2021
Install third 33 kV circuit	\$5,000	On hold

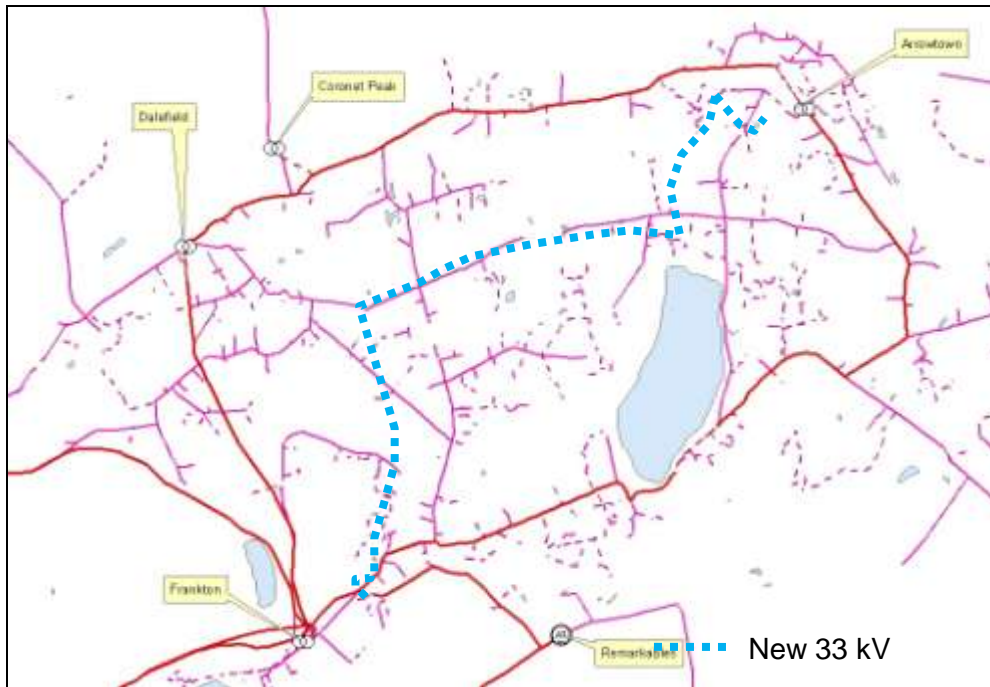


Figure 5-11 - Wakatipu ring upgrade – option 1 third line to Arrowtown

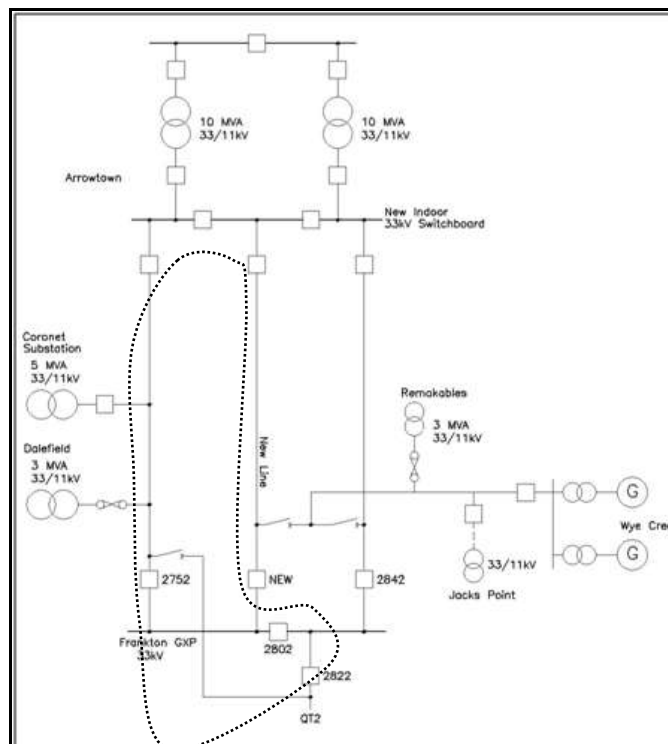


Figure 5-12 - Wakatipu 33 kV ring upgrade – SLD option 1

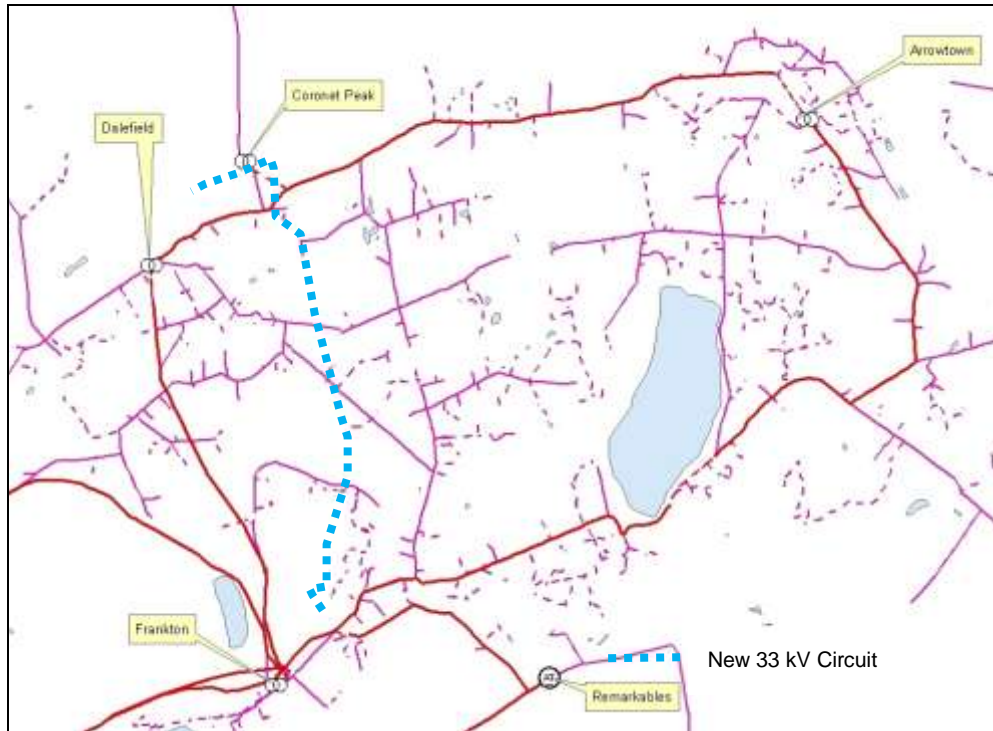


Figure 5-13 - Wakatipu ring upgrade – option 2 line to Coronet Peak

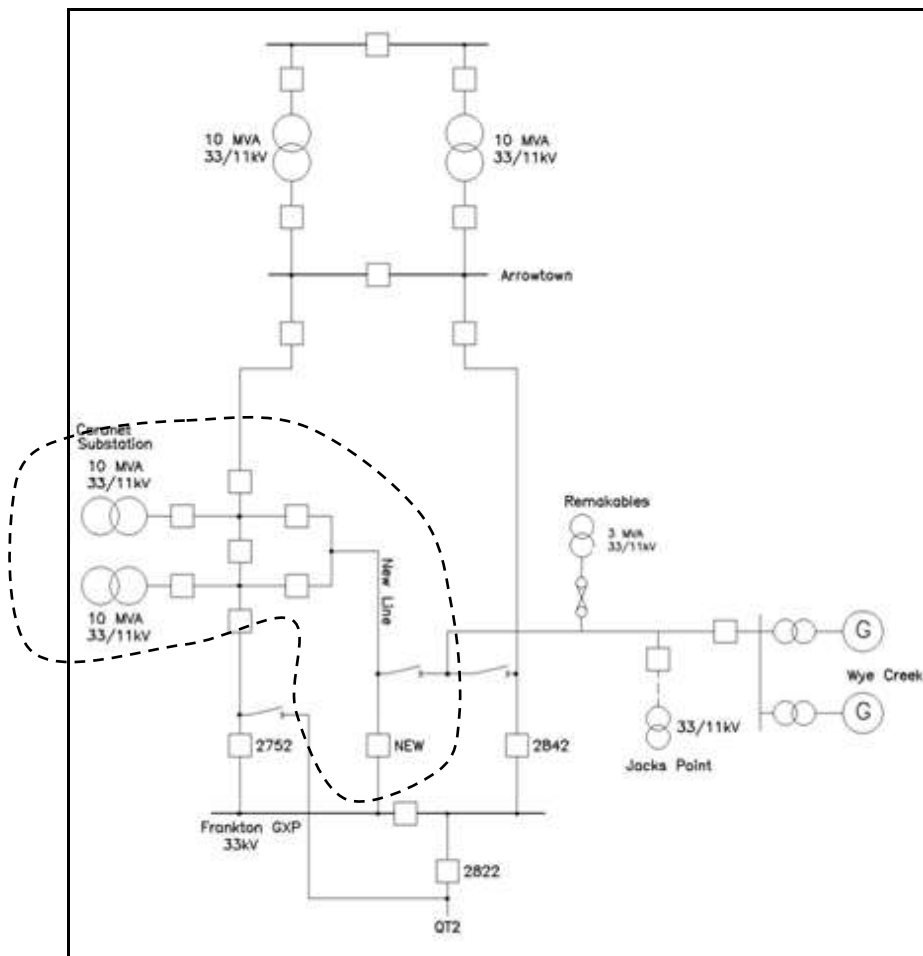


Figure 5-14 - Wakatipu 33 kV ring upgrade – SLD option 2

5.10.3 Wanaka 33 kV

The Wanaka 33 kV subtransmission network is supplied from the 33 kV tertiary windings of the Wanaka 66/33/11 kV, 30/10/24 MVA transformers. If the 11 kV is fully loaded the maximum n-1 rating of the 33 kV supply is 6 MVA.

At present, the Cardrona and Maungawera substations are supplied from the Wanaka 33 kV bus. The 2011 peak load was 4.5 MVA. It is not expected the 33 kV supply will become constrained within the planning period due to the plan to transfer the Cardrona substation load from 33 kV to 66 kV when the Riverbank Road substation is constructed.

5.10.4 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 and Cardrona are supplied at 33 kV from Wanaka. The Queensberry transformer is connected to one 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. The Cardrona line is insulated for 66 kV operation but is currently operating at 33 kV. The Cardrona transformer is a dual ratio 66-33 kV unit that is currently operating at 33 kV.

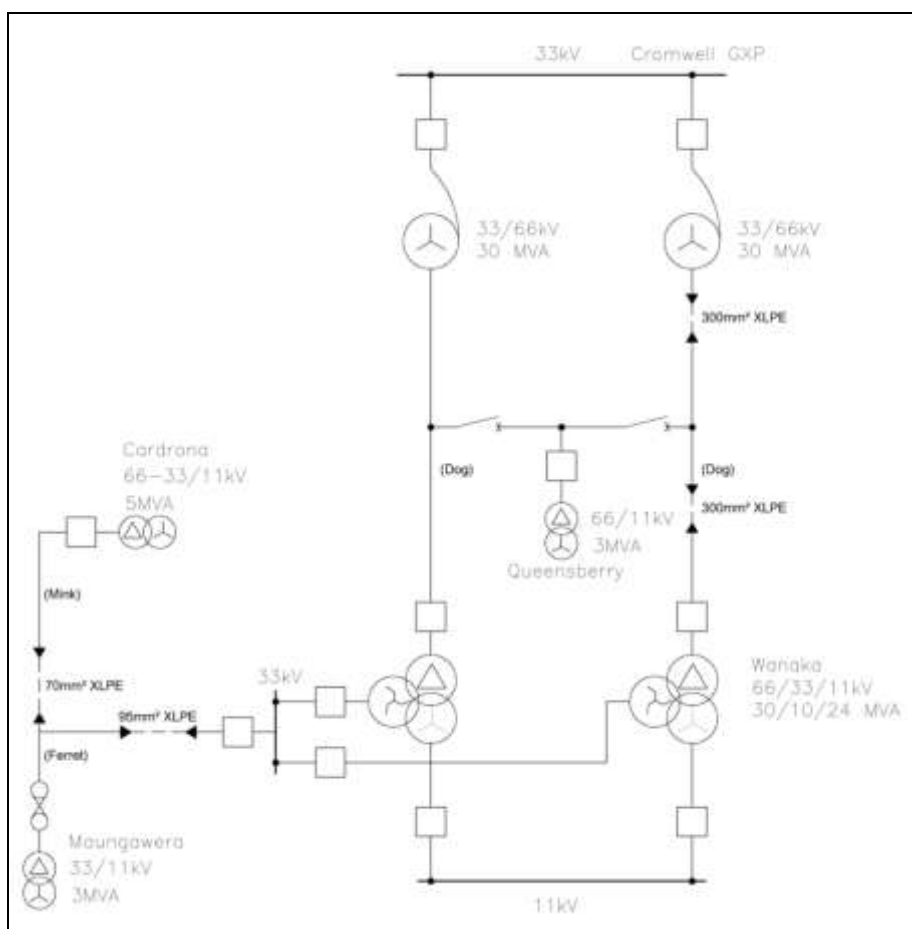


Figure 5-15 - Single line diagram of existing Upper Clutha subtransmission

A single line diagram of the envisaged long term configuration is shown in Figure 5-17 and a geographic layout in Figure 5-16. Progress toward this configuration will depend on load growth 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 Hawea generation is currently on hold by Contact. See Section 5.11.2 for details on proposed connection arrangement.

Previous plans had the Maungawera substation being replaced by a substation at Hawea. Due to the development of dairy farming close to the Maungawera substation it is now proposed to retain the Maungawera substation. The Hawea substation will not be required until the Maungawera substation is fully loaded.

The future Aubrey Road substation is not predicted 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 Riverbank Road substation, see Section 5.12.10. It is recommended land for the Aubrey Road substation be purchased well in advance of being required if available from a willing seller.

The n-1 capacity of the existing Upper Clutha 66 kV network has 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 will reduce these constraints are:

- installation of 66 kV bus at Riverbank Road that enables the Wanaka transformers to operate in parallel when one 66 kV 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 which assumes no support from the Hawea generation. Even if the Hawea generation project proceeds, water flow rate of change restrictions mean there is no guarantee of significant generation being available during an Upper Clutha 66 kV line outage.

In Table 5-14, the predicted Upper Clutha load is presented with 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 in Table 5-15.

The long term proposal to establish a 220/66 kV GXP at Queensberry will be very expensive and is expected to exceed \$30 million. 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 minimise 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 110 kV bus at Cromwell and construct a double circuit 110 kV line from Cromwell to Queensberry along the east side of the valley to supply two 110/66 kV transformers. It is possible that the installation of diesel generation that would only be operated in during a contingency event to defer a transmission upgrade could be economic.

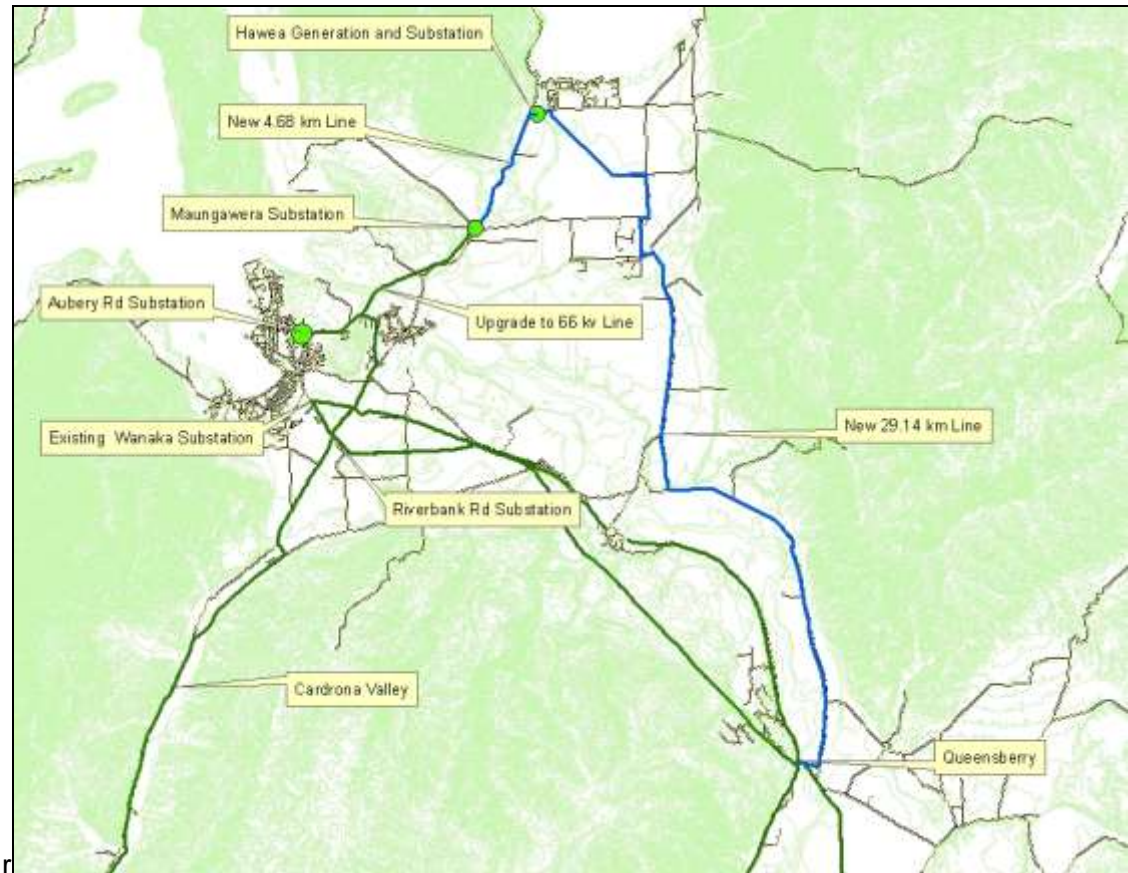


Figure 5-16 - Geographic layout of Upper Clutha long term subtransmission

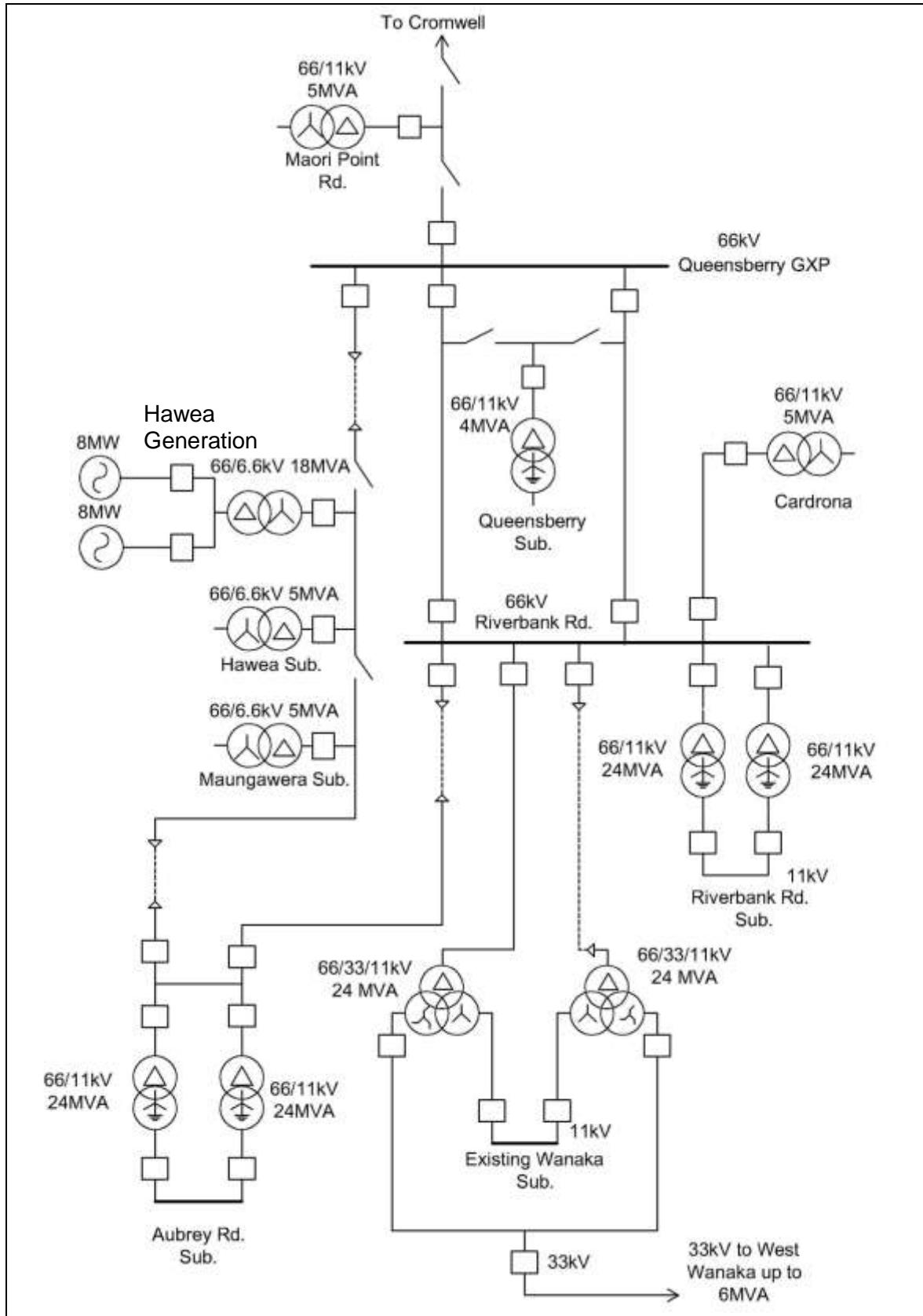


Figure 5-17 - Single line diagram of long term Upper Clutha subtransmission

Year	Predicted UC Load MVA	Description of Works	UC Network n-1 Capacity MVA	n-1 Capacity Minus Predicted Load
2012	24.5		25	0.5
2013	25.4		25	-0.4
2014	26.3		25	-1.3
2015	27.1		25	-2.1
2016	28.1	Riverbank Road switching station established	29	0.9
2017	29		29	0
2018	29.9		29	-0.9
2019	30.9		29	-1.9
2020	31.9		29	-2.9
2021	33.1	Establish 66 kV bus at Cromwell	33	-0.1
2022	34.3		33	-1.3

Table 5-14 - Schedule of works to maintain Upper Clutha subtransmission capacity

Project Details	Project No	Estimated \$000	Completion
Obtain land and designation for Riverbank Road switching station	2969	175	Dec 2012
66 kV transmission to Hawea	2514	3,500	On hold
Construct Hawea substation for generation connection	2798	3,500	On hold
Construct Riverbank Road switching station	3022	4,000	May 2016
Install 66 kV cables Riverbank Road to Wanaka and Riverbank Road to UC1	3216	2,500	May 2016
Establish 66 kV bus at Cromwell + third auto transformer	3021	2,000	May 2021
Install transformer and 11 kV switchgear at Riverbank Road substation	3437	2,500	May 2019
Create 66 kV bus at Queensberry	3438	3,000	2022 +

Table 5-15 – Upper Clutha 66 kV subtransmission project schedule

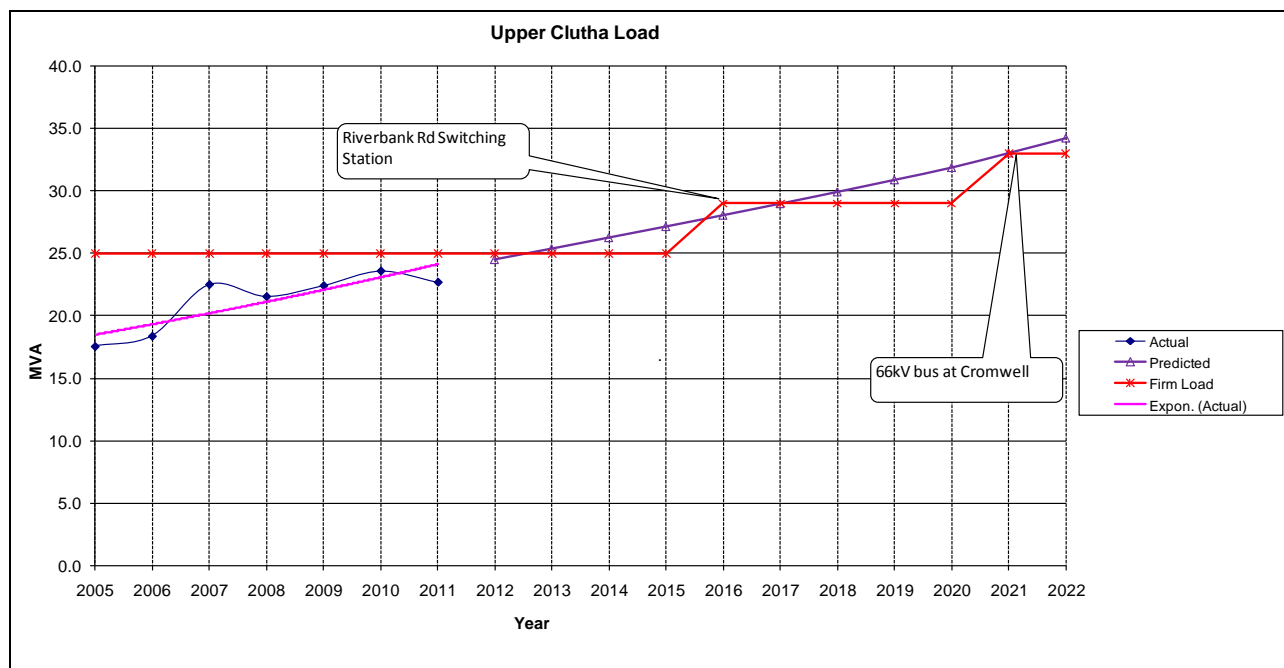


Figure 5-18 - Upper Clutha load projection

5.10.5 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). This constraint is managed 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 33 kV bus due to the operating voltage being at the maximum Aurora's zone substations in the area can tolerate.

5.10.6 Clyde to Alexandra

The Clyde to Alexandra lines have Dog conductor which provide a summer/winter n-1 capacity of 21/13 MVA which is adequate for loads expected within the planning period.

5.10.7 Taieri Subtransmission

The "A" and "B" lines are rated at 300/370 Amps (summer/ winter) while the "C" line is rated at 440/540 Amps. The loss of F&P load means that now under an 'n-2' contingency situation resulting in the loss of "C" line and no generation available from Waipori, the load can still be supplied via "A" and "B" lines.

Since the installation of 36 MW of wind generation by TrustPower it now has more generation than the lines can cope with. TrustPower manages the mix of hydro and wind generation to ensure the rating of the lines are not exceeded. TrustPower is installing a "run back" scheme to avoid the overloading of lines remaining in service should one of the three lines trip during high load times.

5.10.7.1 **Demarcation Isolators at Berwick**

It will be beneficial to have isolators in the “A”, “B” and “C” lines at the Aurora -TrustPower boundary. This will allow TrustPower to maintain its section of line and keep the Aurora section of line in service. It will also facilitate more efficient fault finding.

Estimated Cost \$75,000

Completion May 2013

5.10.7.2 **Mosgiel Laterals**

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.

5.10.8 **Port Chalmers**

The lines to Port Chalmers supply both North East Valley and Port Chalmers substations. The n-1 capacity of these circuits is 27 MVA which is well above loads predicted for the planning period.

5.10.9 **Cardrona Valley**

A subtransmission line to the new (5MVA) Cardrona substation was commissioned in 2011. It currently operates at 33 kV and will be upgraded to 66 kV when the Riverbank Road switching station is installed. The line will have a capacity in excess of 30 MVA when operating at 66 kV.

5.11 **Future Subtransmission**

5.11.1 **Glenorchy**

Glenorchy is presently supplied from Queenstown 11 kV Feeder 5202. The line was built for 33 kV operation in anticipation of future conversion. When converted to 33 kV, it will be supplied from the Fernhill substation where a 33 kV circuit breaker has already been installed for this purpose.

In 2006, 11 kV voltage regulators were installed at Closeburn which will defer the need for the 33 kV upgrade until the load on the feeder reaches approximately 1.5 MVA (78A). The peak load on QT5202 occurs when the Oxburn power station (400 kW) is out of service. Oxburn is a run-of-the-river station that normally operates continuously but is required to shut down during high rainfall events due to excessive gravel entering the river. The Oxburn power station is not able to run islanded and trips off line whenever there is a fault on QT5202.

In previous development plans, load predictions used maximum demands on QT5202; however, this did not give the total picture of the area load due to the effect of the Oxburn generator.

There was an incident in 2011 where QT5202 had an extended outage and the cold-load pickup caused the QT5202 over current protection to operate which prompted a review of the load prediction. This review consisted of merging the Oxburn and QT5202 half hourly data, and the resulting peak loads are shown in Figure 5-19 which shows that it will not be possible to maintain the feeder voltage above design values after the winter of 2014. Development Report DR132 outlines the upgrade options which are:

- upgrade line to 33 kV and install zone substations at Closeburn and Glenorchy;
- install a diesel generator at Glenorchy; and
- extend the 11 kV distribution from Fernhill to supply the Closeburn area.

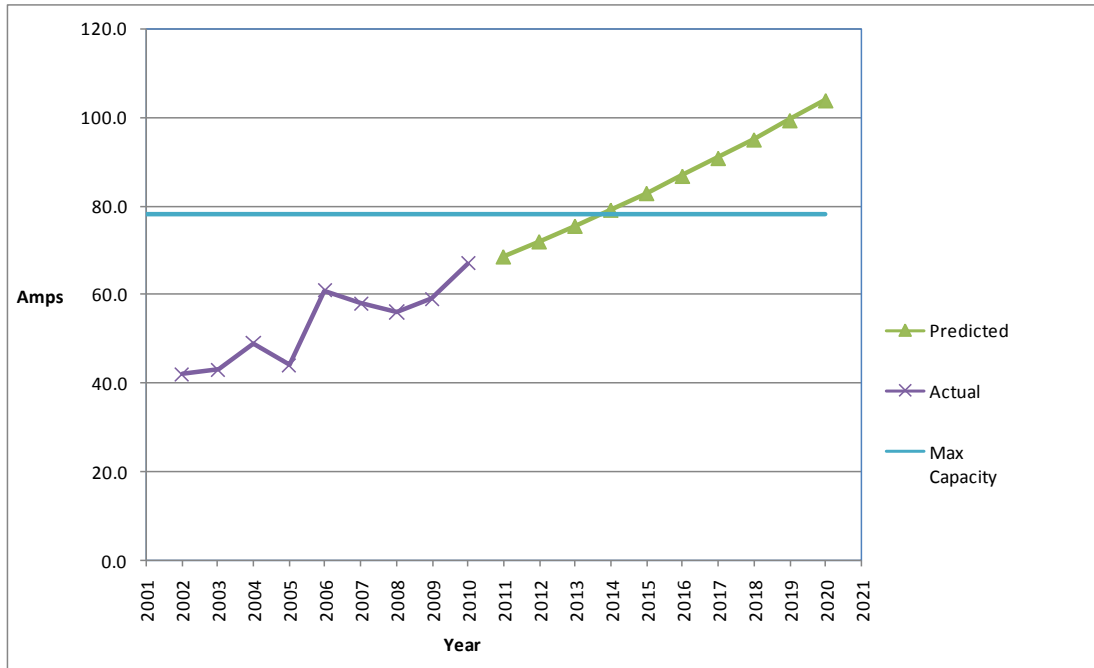


Figure 5-19 - QT5202 predicted loads

The option to upgrade the line to 33 kV is recommended. This option requires the establishment of zone substations at Closeburn and Glenorchy. Customers at Mt Creighton and transformer WQ25 will be supplied by 33 kV/415 volt transformers. The Closeburn substation will be located at the site of the existing voltage regulators. It is proposed the existing regulators be retained and a 2.5 MVA 33/11 kV sealed distribution type transformer be installed to supply the regulators from the 33 kV line.

It is proposed that 1 MVA transformer that was refurbished for the Remarkables substation be installed at Glenorchy and connected to the existing voltage regulators. Aurora does not own the land at the Glenorchy regulator site so easements or land purchase will be required.

Estimated Cost \$1.2 million

Completion: May 2015

5.11.2 Connection of Hawea Generation

In 2008, Contact Energy submitted an application to install 2 X 8 MW generators at Lake Hawea but it has not confirmed a starting date for the project and has given no indication of when it can confirm a starting date. Contact has recently applied to have its QLDC resource consent extended to 2017.

A development report DR40 was prepared in 2008 that considered various connection options. The present thinking is that the Maungawera line will be upgraded to 66 kV and extended to Hawea. Load growth on the Maungawera substation could make the upgrade of the 33 kV Maungawera line to 66 kV difficult due to the requirement to off load the Maungawera substation during construction.

Due to the uncertain timing, projects for the establishment of the generation connection have been put on hold and no provision is made for capital expenditure other than the land issues detailed below.

Aurora has purchased land adjacent to the Contact generation site to accommodate substation equipment and to provide 66 kV line access. It is proposed that, during 2012/13, the land required for electricity purposes be subdivided off the main block and this land be designated for substation and transmission line use. This will enable Aurora to sell the balance of the land.

Estimated Cost \$50,000

Completion: June 2013

5.11.3 West Wanaka and Treble Cone

The Treble Cone ski field has 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 toward Treble Cone and install the appropriate 33/11 kV zone substations.

A report has been prepared (see DR23) looking at various configuration options. No work has been scheduled due to the uncertain nature of the load growth in the area.

When poles are replaced between Wanaka and Glendhu Bay they will be fitted with 33 kV cross arms and insulators to facilitate a conversion to 33 kV.

5.11.4 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 made in this plan due to the uncertain nature of this project

5.12 Zone Substations

5.12.1 Demand Projections

The historical and predicted demands for all zone substations are shown in 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 will 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 this 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.

Aurora Energy Asset Management Plan 2012 - 2022

Zone Substation	Transformer MVA	Firm Load MVA	n-1	Historical Loads MVA								Exp Growth Calc			Linear Trend Calc			Predictions		Predicted Demands Between Exp and Linear MVA												
				2005	2006	2007	2008	2009	2010	2011	2011	2012	Previous Growth (Exp) %/yr	2011	2012	Previous Growth (Lin) MVA/yr	Exponential Growth %/yr	Linear Growth MVA/yr	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022			
Alexandra	7.5/15+7.5/15	15	15	10.8	10.9	12.4	11.4	11.9	11.6	10.9	11.5	11.6	0.40%	11.5	11.6	0.04	0.4%	0.04	11.6	11.6	11.7	11.7	11.8	11.8	11.8	11.9	11.9	12.0	12.0			
Anderson's Bay	15 + 15	18	18	14.6	14.9	16.6	15.7	17.1	15.3	16.0	16.3	16.5	1.28%	16.3	16.5	0.20	1.0%	0.16	16.5	16.7	16.8	17.0	17.1	17.3	17.5	17.7	17.8	18.0	18.2			
Arrowtown	5 + 5	7.5	6	6.4	7.2	7.7	7.3	7.6	7.9	7.6	7.9	8.1	2.49%	7.9	8.1	0.18	2.0%	0.15	8.1	8.2	8.4	8.5	8.7	8.9	9.0	9.2	9.4	9.5	9.7			
Berwick	3	3.6	0	1.1	1.1	1.2	1.3	1.2	1.3	1.3	1.3	1.4	3.20%	1.3	1.4	0.04	2.0%	0.03	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.6	1.6			
Clyde/Earnsclough	4 +2	4.8	4	3.6	3.7	4.0	4.1	4.1	4.1	3.8	4.1	4.1	1.38%	4.1	4.1	0.05	1.0%	0.04	4.1	4.2	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.5			
Coronet Peak	5	6	0	4.4	3.6	3.6	4.5	4.6	4.6	4.6	4.6	4.8	3.05%	4.6	4.8	0.12	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	12.5	12.8	13.8	12.5	14.3	13.2	13.8	13.9	14.1	1.46%	13.9	14.0	0.19	0.0%	0.00	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9			
Cromwell	5/10 + 7.5	9.0	9.0	6.8	7.9	9.2	9.2	9.8	10.0	9.4	10.4	10.9	5.51%	10.2	10.7	0.45	4.0%	0.04	10.5	10.8	11.0	11.3	11.5	11.8	12.1	12.4	12.7	13.0	13.3			
Dalefield	3	3.6	0	1.9	1.8	2.3	2.1	2.1	2.3	2.3	2.4	2.4	3.73%	2.3	2.4	0.08	3.0%	0.07	2.4	2.5	2.6	2.6	2.7	2.8	2.9	3.0	3.0	3.1	3.2			
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	0.0				
East Taieri	12/24 + 12/24	See Text	18.5	14.9	15.7	15.7	15.5	16.7	15.8	16.2	16.4	16.5	1.19%	16.3	16.5	0.19	1.0%	0.16	16.5	16.7	16.8	17.0	17.2	17.3	17.5	17.7	17.8	18.0	18.2			
Etrick	3	3.6	0	2.0	1.5	2.0	1.8	2.1	2.0	1.7	1.9	1.9	0.45%	1.9	1.9	0.01	0.5%	0.01	1.9	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.0	2.0			
Frankton	12/24 + 7.5/15	17	15	9.0	10.4	12.0	13.2	13.9	12.1	10.5	12.6	13.1	3.30%	12.6	13.0	0.35	3.0%	0.35	10.8	11.1	11.5	11.8	12.2	12.5	12.9	13.3	11.7	12.0	12.4			
Fernhill	7.5/10+7.5/10	10	10	5.4	5.6	6.1	6.2	5.9	5.8	5.8	6.0	6.1	0.95%	6.0	6.0	0.05	1.0%	0.05	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.6	6.6			
Green Island	15 + 15	18	18	13.8	14.0	14.2	13.8	13.7	13.4	14.0	13.7	13.7	-0.30%	13.7	13.7	-0.04	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	13.1	13.6	14.2	13.8	14.5	14.6	14.8	14.9	15.2	1.89%	14.9	15.1	0.26	1.5%	0.23	15.1	15.3	15.6	15.8	16.0	16.2	16.5	16.7	17.0	17.2	17.4			
Kaikorai Val.	12/24 + 12/24	23	22	11.9	10.3	10.4	9.9	10.2	9.2	9.3	9.1	8.8	-3.42%	9.1	8.7	-0.36	0.0%	0.00	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1			
Maungawera/Hawea	3	3.6	0	2.3	2.5	3.2	2.1	2.2	2.3	2.3	2.4	2.4	3.44%	2.3	2.4	0.08	1.8%	0.05	2.4	2.4	2.5	2.5	2.6	2.6	2.7	2.7	2.8	2.8	2.9			
Mosgiel	10 + 10	14	12	11.8	12.2	12.0	12.0	9.3	7.6	7.8	7.8	8.0	2.23%	7.8	8.0	0.17	2.0%	0.16	8.0	8.1	8.3	8.4	8.6	8.8	8.9	9.1	9.3	9.4	9.6			
Neville St	15 + 15	18	18	13.9	14.4	14.9	13.3	14.8	13.4	13.6	13.7	13.6	-0.78%	13.7	13.6	-0.11	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			
North City	14/28 +14/28	28	28	19.8	20.2	20.7	20.3	19.7	19.0	20.0	19.6	19.5	-0.56%	19.6	19.5	-0.11	0.0%	0.00	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6			
North East Val.	9/18 +12/18	23	18	10.8	10.8	11.0	10.9	11.8	11.2	11.8	11.7	11.8	1.42%	11.7	11.8	0.16	1.0%	0.12	11.8	11.9	12.0	12.1	12.2	12.4	12.5	12.6	12.7	12.8	13.0			
Omakau	3	3.6	0	1.6	1.6	1.8	1.8	2.0	2.1	2.0	2.1	2.2	4.63%	2.1	2.2	0.08	4.0%	0.09	2.2	2.3	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	2.9	2.8	2.7	2.8	2.9	3.0	2.9	3.0	1.52%	2.9	3.0	0.04	1.0%	0.03	3.0	3.0	3.0	3.1	3.1	3.1	3.2	3.2	3.2	3.2	3.3			
Port Chalmers	7.5 +7.5	10	9	8.1	7.9	8.3	7.5	7.9	7.5	7.5	7.5	7.4	-1.39%	7.5	7.4	-0.11	0.0%	0.00	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5			
Queensberry	3	3.3	0	1.6	1.9	1.7	1.8	1.4	2.4	2.3	2.1	2.2	4.80%	2.2	2.3	0.10	4.0%	0.10	2.3	2.4	2.5	2.6	2.7	2.8	3.0	3.1	3.2	3.3	3.4			
Queenstown	10/20 +10/20	22	20	18.3	20.2	22.8	22.1	21.3	14.7	15.1	15.1	15.4	2.45%	15.1	15.4	0.36	2.0%	0.30	15.4	15.7	16.0	16.3	16.6	16.9	17.2	17.6	17.9	18.2	18.6			
Remarkables	3	3.6	0	0.7	0.8	0.8	0.8	0.8	0.8	1.0	0.9	0.9	3.60%	0.9	0.9	0.03	Manual Prediction		2.0	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	2.3	2.5	2.5	2.2	2.8	2.8	2.3	2.6	2.6	1.29%	2.6	2.6	0.03	1.0%	0.02	2.6	2.6	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.9			
Smith St	15 + 15	18	18	18.1	16.5	16.9	16.1	16.8	15.8	16.9	16.2	16.0	-1.08%	16.2	16.0	-0.19	1.0%	0.17	16.3	16.5	16.7	16.8	17.0	17.2	17.3	17.5	17.7	17.9	18.0			
South City	9/18 +9/18	18	18	14.3	15.4	15.7	15.3	15.8	15.0	15.2	15.4	15.5	0.45%	15.4	15.5	0.07	0.5%	0.07	15.5	15.6	15.7	15.7	15.8	15.9	16.0	16.0	16.1	16.2	16.3			
St Kilda	12/24 + 12/24	23	23	15.2	15.4	16.3	15.6	15.7	15.3	15.5	15.6	15.6	0.02%	15.6	15.6	0.00	0.0%	0.00	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6			
Wanaka	12/24 +12/24	24	24	14.6	15.1	18.6	18.7	19.6	20.3	17.6	20.1	21.0	4.38%	20.0	20.7	0.73	4.0%	0.70	19.2	19.9	20.7	21.4	22.2	23.0	23.8	24.7	17.5	18.3	19.0			
Ward St	12/24 +12/24	18	24	10.6	11.6	11.3	11.4	12.5	11.9	14.3	13.3	13.8	3.81%	13.3	13.8	0.46	1.0%	0.14	13.4	13.6	13.7	13.9	14.0	14.1	14.3	14.4	14.6	14.7	14.8			
Willowbank	15 + 15	18	18	13.7	12.8	12.7	12.5	13.7	12.2	13.2	12.8	12.7	-0.43%	12.8	12.8	-0.06	0.0%	0.00	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8			
Commonage	14/17 +14/17	23	17						9.8	9.8							0.5%	0.06	9.9	9.9	10.0	10.0	10.1	10.1	10.2	10.3	10.3	10.4	10.4			
Cardrona	5	5								1.9							2.0%	0.05	2.0	2.0	2.1	2.1	2.2	2.2	2.2	2.2	2.3	2.3	2.3			
Jacks Point *		10	0																								2.0	2.0	2.0			
Riverbank Rd		24	24														4.0%	0.32									8.0	8.3	8.6			
MG + ET (Merged 1/2hr data)		30.8	30.8	26.0	27.3	26.5	26.5	23.5	23.1	22.8	21.2	21.2	0.00%	22.0	20.9	-1.12	0.0%	0.0	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6			
* Jacks Point actual load is included in Frankton																																
Subtransmission																																
	Diversity																															
QT Sub TX	0.98	40		23.2	25.3	28.3	27.7	26.7	29.7	30.1									30.7	31.1	31.5	31.9	32.3	32.7	33.2	33.6	34.0	34.4	34.9			
Arrowtown Ring (EX RM Sub)	0.87	13		11.0	11.0	11.8	12.1	12.4	12.8	12.6									13.2	13.4	13.6	13.8										

5.12.2 Alexandra Substation

The Alexandra zone substation is now predicted remain within its firm load rating beyond the planning period, see Figure 5-20 for load prediction.

Future options to reinforce the supply to Alexandra are to either upgrade the Alexandra transformers to 12/24 MVA units or establish a new zone substation. 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 5-21. 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. The proposed new substation location is on Alexandra town belt reserve land, so it is recommended that Aurora's intentions be signalled to CODC with a view to obtaining land for the substation and securing cable easements to the site.

Estimated Cost \$4.5 million

Completion: On Hold

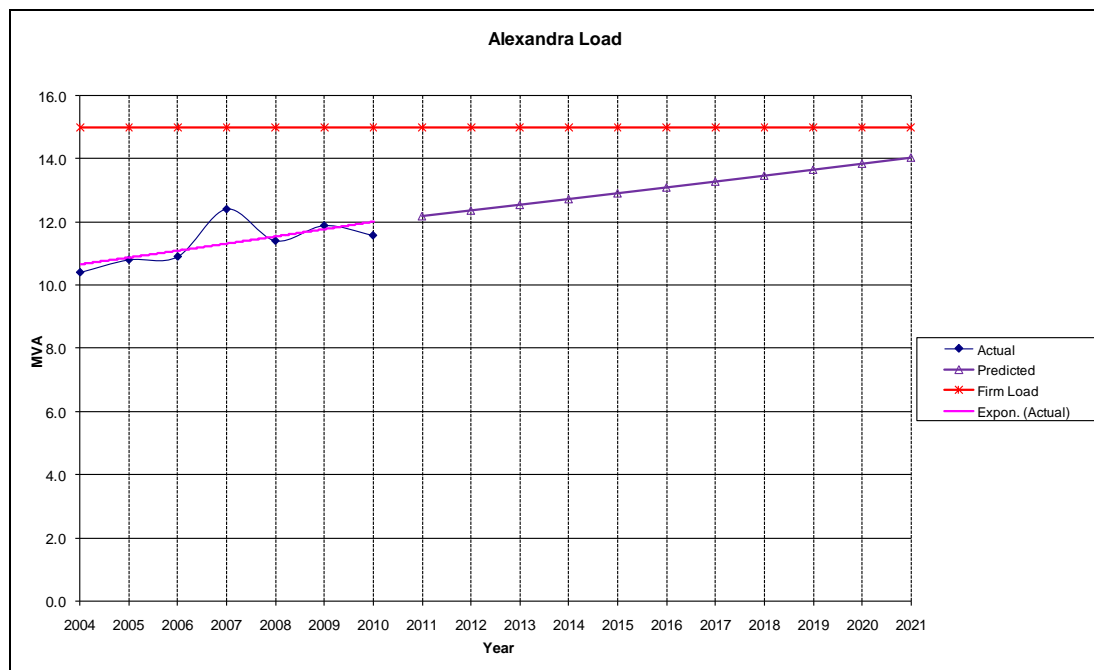


Figure 5-20 - Alexandra load prediction



Figure 5-21 - Location of proposed new Alexandra zone substation

5.12.3 Andersons Bay Substation

Load on the Andersons Bay substation has been variable as indicated in Figure 5-22. It is currently predicted that the load will reach the firm capacity in 2021. 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.

Estimated Cost \$4.5 million

Completion: May 2021

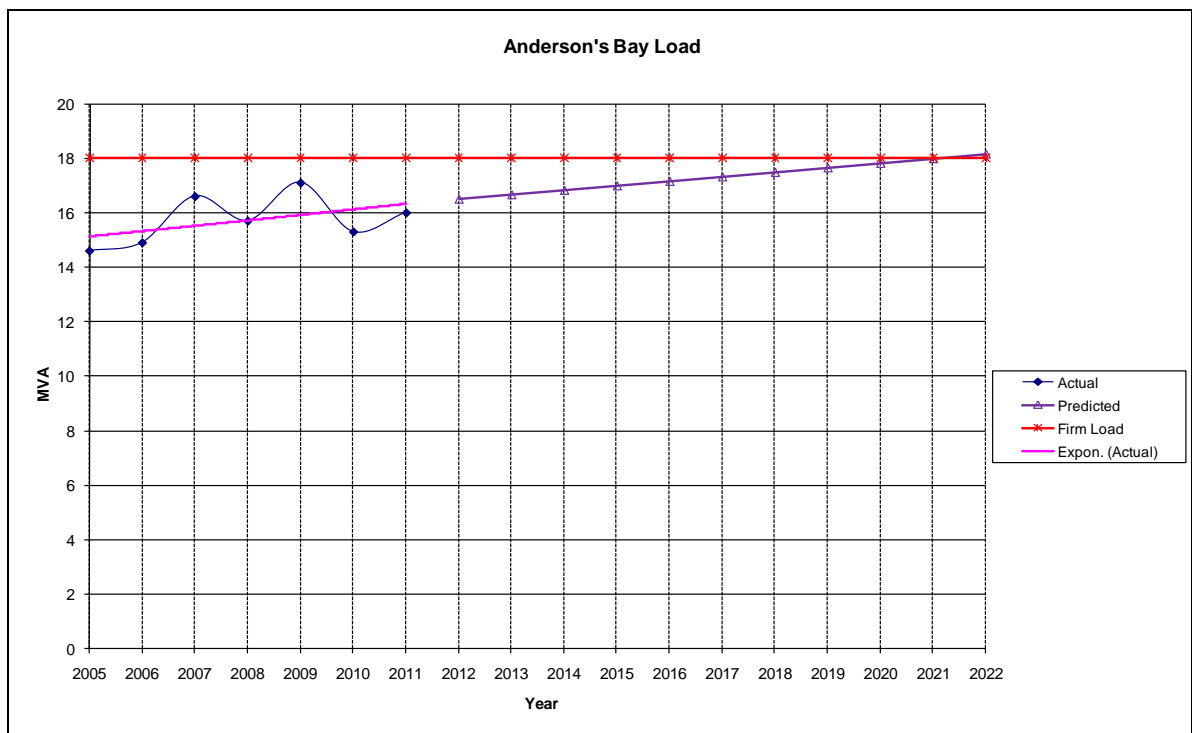


Figure 5-22 - Andersons Bay load prediction

5.12.4 Macandrew Bay Substation

Slow steady load growth on the Otago Peninsula is expected to result in feeder off-loading issues with feeder AB7 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 5-23. 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. This project is not currently scheduled but this will be reviewed annually. An option to resolve the feeder off-loading problem 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

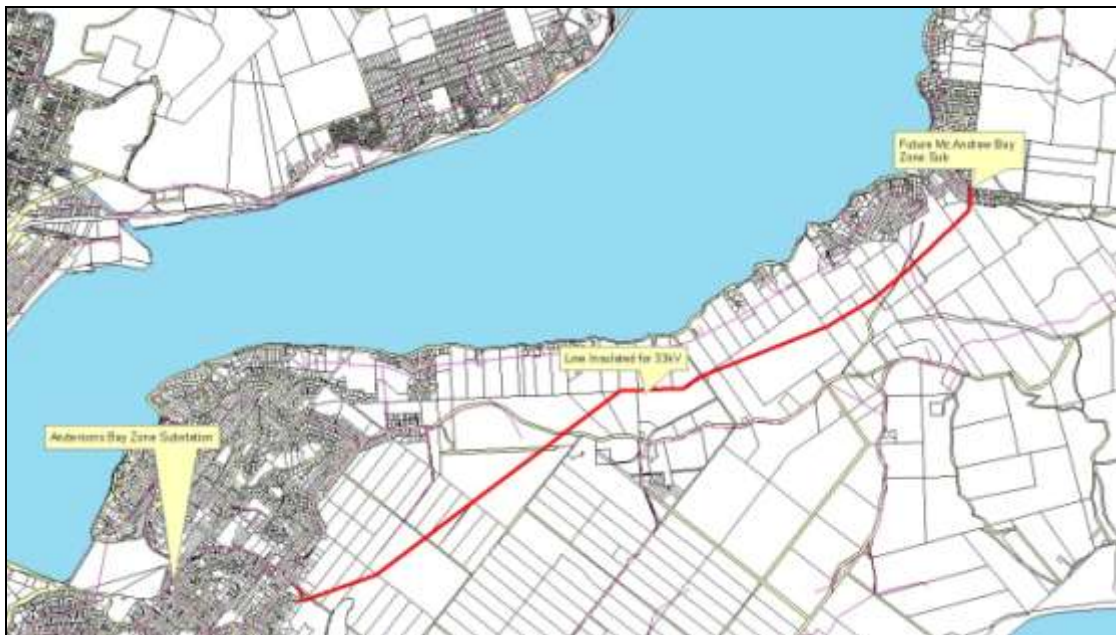


Figure 5-23 - Proposed Macandrew Bay zone subtransmission

5.12.5 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 load is currently predicted to reach its firm rating during the 2022 winter.

It is proposed that Smith Street be upgraded to 24 MVA transformers and the HV switchgear be replaced prior to the winter of 2020. The existing transformers and switchgear that was purchased in 1957 will be 63 years old by then and replacement likely to be justified on reliability grounds. It is proposed to replace 33 kV gas cables supplying Smith Street at the same time, see Section 6.5.1.

Estimated Cost \$4.5 million

Completion: May 2020

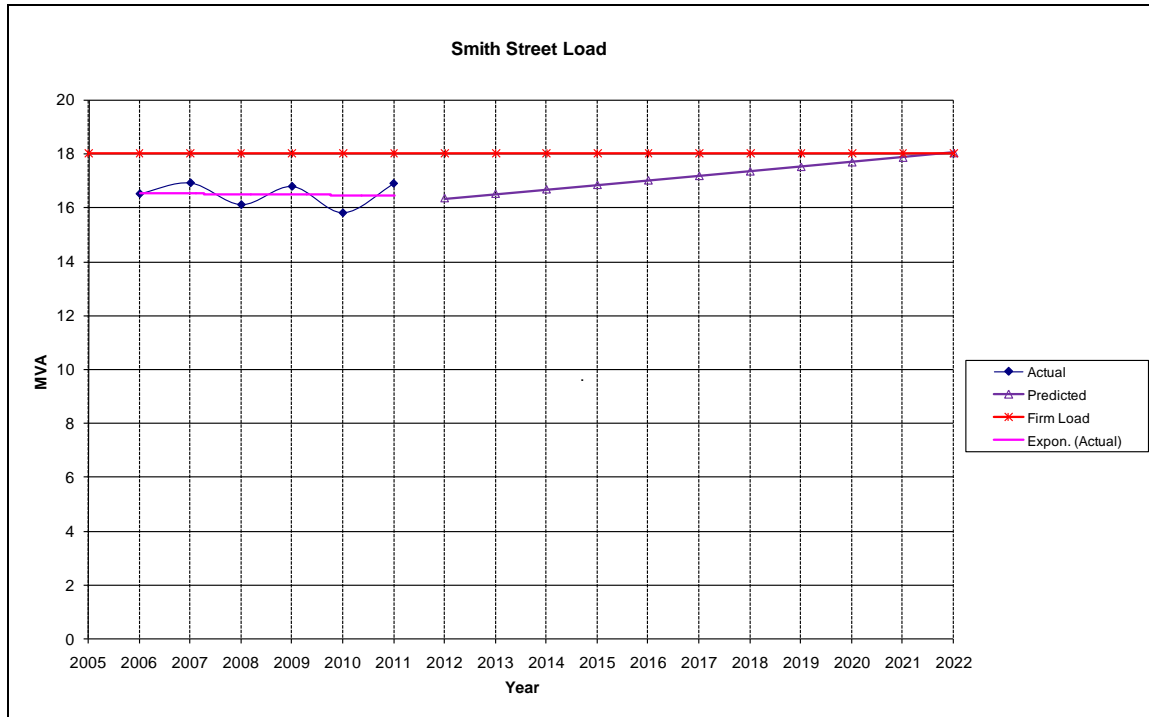


Figure 5-24 – Smith Street predicted loads

5.12.6 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 5-25 for predicted loads on the Arrowtown substation. The firm rating is on the basis of loading one transformer to 120% (6 MVA) and transferring 1.5 MVA to the Coronet substation via feeder AT7692. In 2009, the 3 MVA spare transformer was located at Arrowtown to provide cover in the event of one of the 5 MVA units failing. This transformer has been moved to the Remarkables substation to cater for additional demand at the Remarkables ski field. A parking bay for the 5 MVA mobile substation is being established prior to the 2012 winter. The mobile substation can provide cover for a transformer outage up to a load of 10 MVA.

The load is not predicted to reach 10 MVA during the planning period. Now that the mobile substation is covering 11 sites there is increasing risk that it will not be available when required, so it is recommended that the upgrade proposed in the 2011 plan still proceed which is 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. The noise from the existing 5 MVA transformers is in excess of the District Plan requirements. Noise tests on the 10 MVA Frankton transformer indicate they can meet boundary noise limits but will require the transformer fans to be replaced with new low noise units.

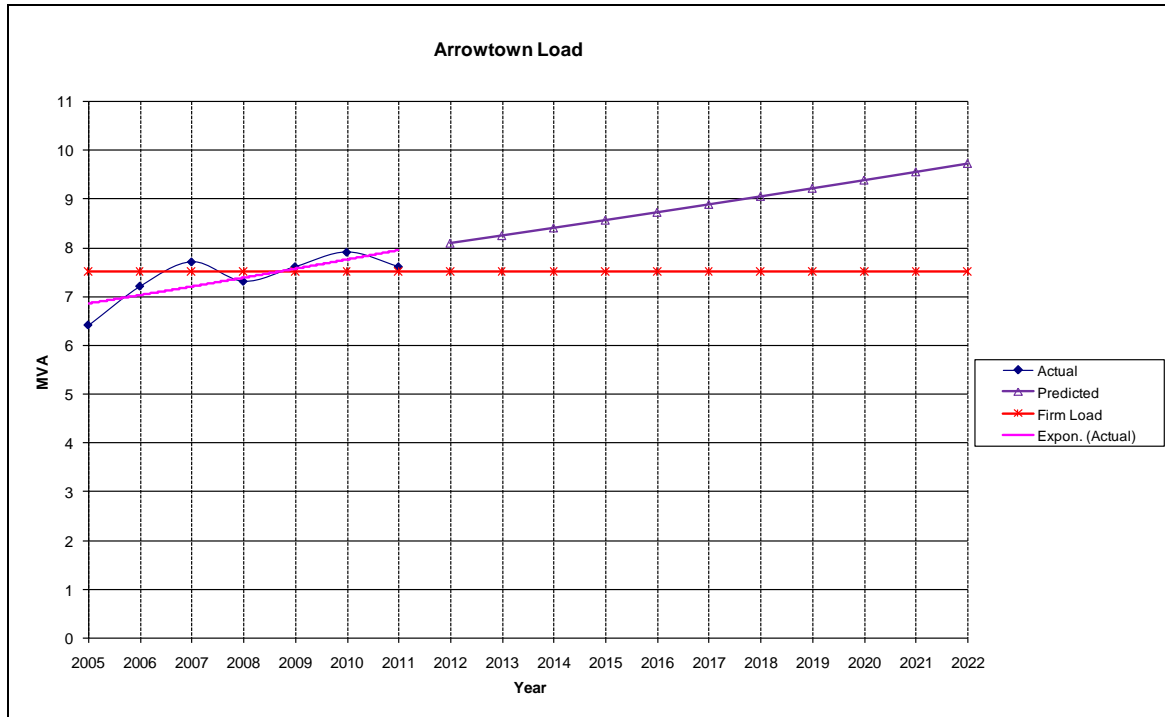


Figure 5-25 – Arrowtown predicted loads

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 all reclosers that can be redeployed elsewhere on the network. The 33 kV switchgear configuration will be designed to accommodate the third 33 kV circuit as proposed in Section 5.10.2 and detailed in Figure 5-12.

Project	Cost	Completion
Mobile substation parking bay	\$82,000	May 2012
New switch room and transformer upgrade	\$4 million	May 2017

5.12.7 Queensberry Substation

There has been strong growth in load on the Queensberry substation due to irrigation load. There has been considerable variability in the peak loading from year to year as indicated in Figure 5-26. The substation load peaks in the summer. The 2010 peak load was 2.4 MVA.

The Queensberry transformer is a 3 MVA ONAN unit and it is assumed it can be overloaded by 10% during the summer to 3.3 MVA⁴. Present predictions are for the load to exceed 3.3 MVA during the summer of 2022. The transformer rating can be increased to 4.4 MVA by the addition of fans. If the Tarras irrigation project proceeds and the new Maori Point Road substation established, as detailed in Section 5.12.8, the Queensberry substation could be removed; however, it is proposed the substation be retained until there is an application for the transformer.

⁴ A 20% overload is considered acceptable for winter conditions

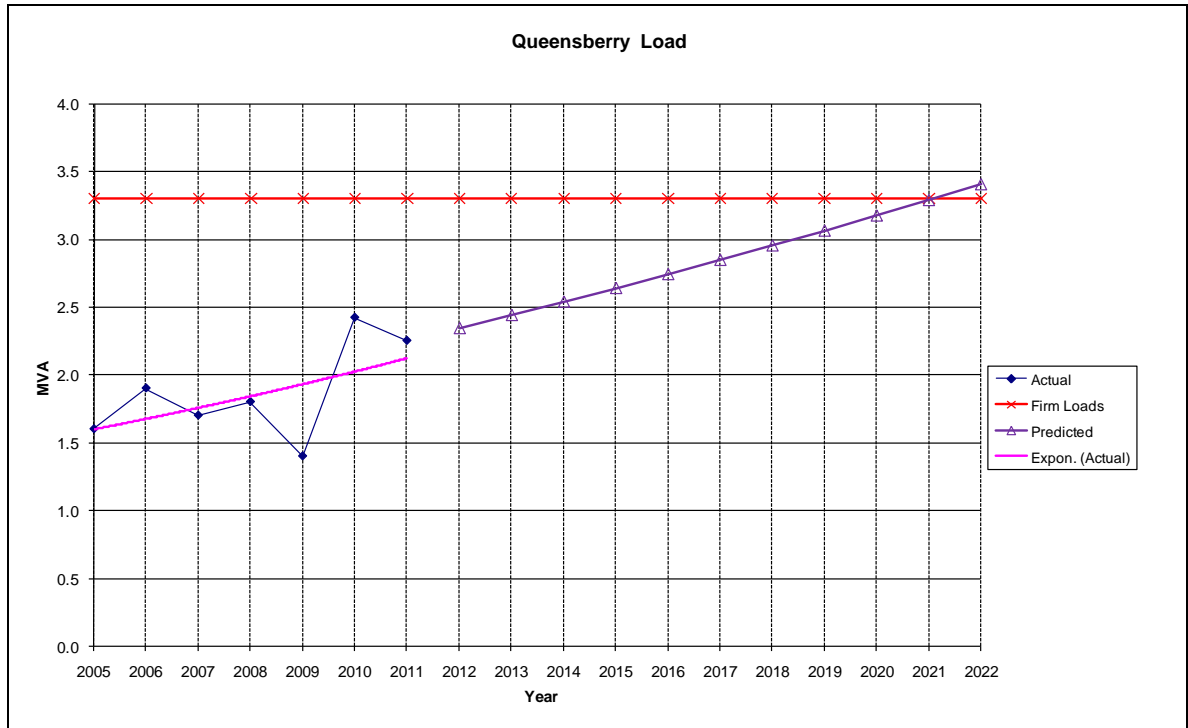


Figure 5-26 – Queensberry load predictions

5.12.8 New Maori Point Road Substations for Tarras Irrigation Scheme

An irrigation scheme has been proposed for the Tarras area that could require up to 11 MW of pumping. The current proposal will require a new 2 X 20 MVA zone substation to be constructed at the west end of Maori Point Road and be supplied from the Upper Clutha UC2 66 kV line. See development reports DR133 and DR133A for project details.

Estimated Cost \$7.0 million

Completion: January 2013

5.12.9 Cromwell Substation

The load on Cromwell is growing and the peak demand now exceeds its 9 MVA firm capacity. The 5 MVA mobile substation is being used to provide n-1 cover. In the 2011-21 plan, it was proposed the transformers be upgraded prior to the 2015 winter when it was predicted the load would reach 12 MVA. Present load predictions (Figure 5-27) have reduced, with the 12 MVA limit now predicted for the winter of 2018. However, it is recommended the May 2015 commissioning be retained as the mobile substation is now providing cover for 10 other sites so there is increased risk the mobile will not be available when required.

The 7.5/10 MVA transformer removed from Frankton, that is currently stored at Arrowtown, will be available to be installed at Cromwell in the event of a Cromwell transformer failure, but this would take several days to install.

Estimated Cost \$2.5 million

Completion: May 2015

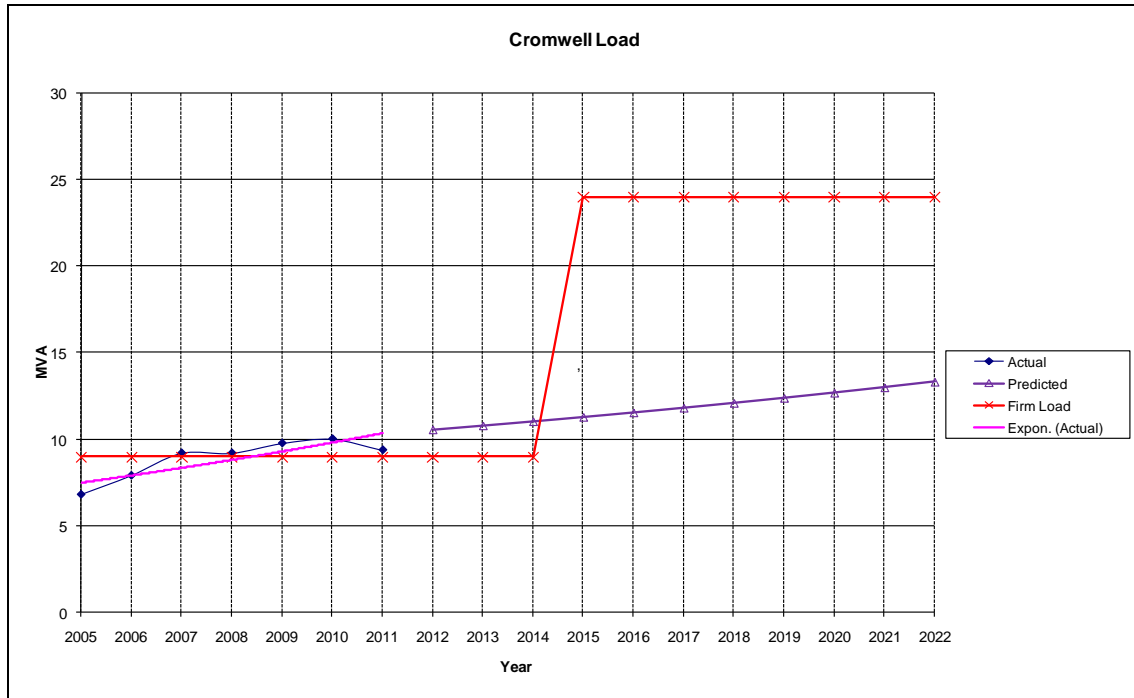


Figure 5-27 - Cromwell zone substation loading projections

5.12.10 Riverbank Road Transformer and 11 kV Switchgear

Load growth on the Wanaka zone substation has been exceptional (9.3% annually from 2003 to 2009). It is now predicted the growth will be significantly lower than historical values; see Figure 5-28 for load projections.

In the 2009-2019 Development Plan, it was proposed that Wanaka be off-loaded by the construction of a new substation in Aubrey Road. It is now considered the most economic solution is to install one 24 MVA transformer with associated 11 kV switchgear at the Riverbank Road switching station prior to the winter of 2019. 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 Aubrey Road. The advantages of Riverbank Road over Aubrey Road are:

Riverbank Road will be supplied by duplicate 66 kV circuits whereas Aubrey Road would have been on a 66 kV spur; and the cost of installing a transformer at Riverbank Road will be significantly less than setting up a new substation in Aubrey Road.

The Riverbank Road switching station is scheduled to be commissioned in 2016 to reduce volt drop during an outage on one of the upper Clutha 66 kV circuits, refer to Section 5.10.3. It is proposed to install a 24 MVA transformer at Riverbank Road in 2018/19 with a second transformer being installed when it is no longer possible to completely off-load Riverbank Road onto adjacent substations; however, this is expected to be beyond the planning period.

Estimated Cost \$2.5 million

Completion: May 2019

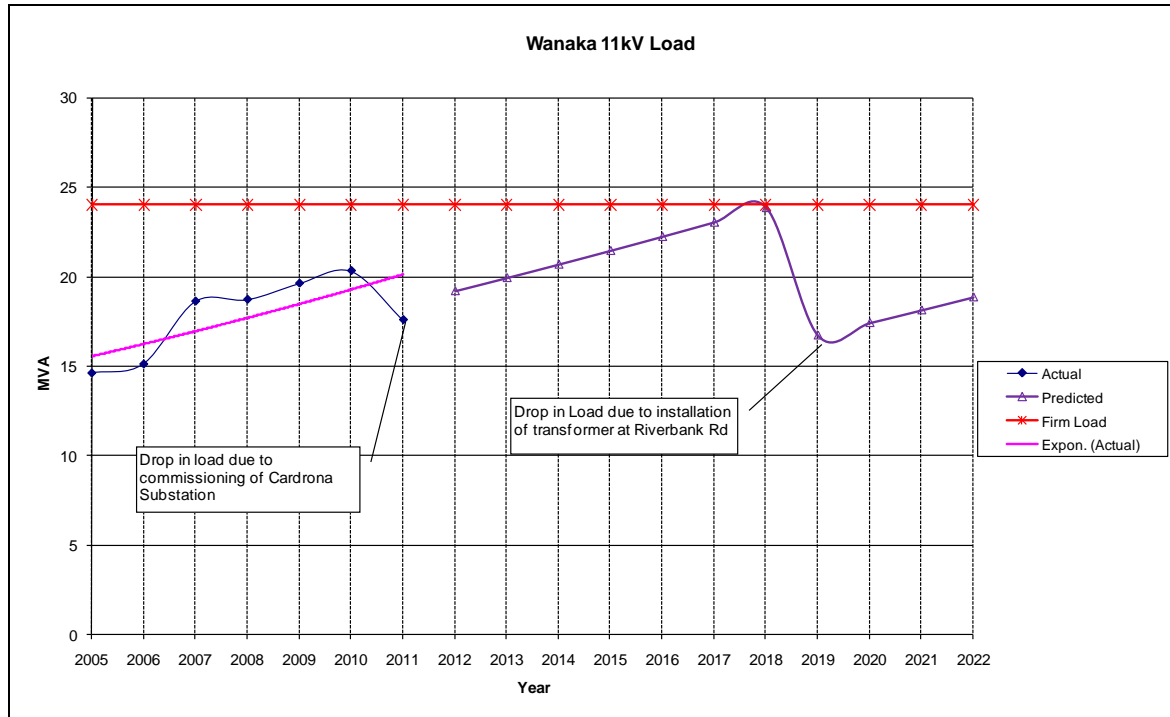


Figure 5-28 – Wanaka 11 kV predicted loads

5.12.11 Maungawera Substation

In the 2011-21 Plan, it was proposed that the Maungawera substation be removed and a new substation be established at Hawea which would utilise the 66 kV transmission installed for the Contact Energy Hawea generation project. Since then, a significant four-stage irrigation load is proposed in the Camp Hill Road area to service a dairy farm development. Stage 1 of the project has already been implemented. This development will result in the load centre of gravity moving closer to Maungawera than Hawea and it is now proposed that the Maungawera substation be upgraded from a 3 MVA to 5 MVA when it becomes fully loaded instead of installing a substation at Hawea. The predicted loading on Maungawera is shown in Figure 5-29 which requires an upgrade prior to the summer of 2014. Development report DR126 contains detailed analysis and recommendations.

It is recommended that land be obtained during 2012/13 and the site be designated for electricity use. Consideration is being given to relocating the Cardrona generator at Maungawera. This could enable the deferment of the substation upgrade and it will provide some voltage support in the case of a 66 kV Upper Clutha line outage. The Cardrona generator needs to be removed as it is blocking access for the mobile substation into the Cardrona site.

Project	Estimated Cost	Completion
Land purchase and designation	\$100,000	June 2013
Construct new substation	\$3.2 million	September 2014

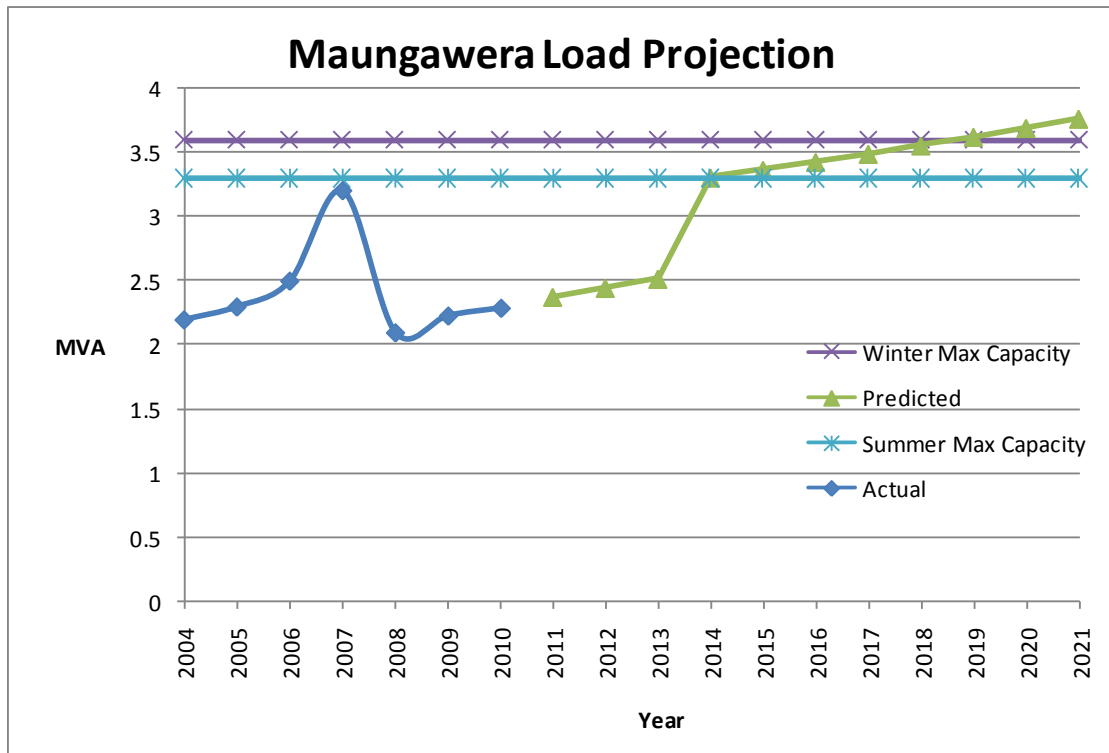


Figure 5-29 – Maungawera substation predicted load

5.12.12 Jacks Point Substation

The Jacks Point development has an ultimate capacity of 2,700 lots that will have a demand of the order of 8 to 10 MW. Jacks Point is presently supplied from Frankton feeder 7784 via recloser 7375R up to a load of approximately 2 MVA. When this load limit is reached, it is proposed to install a 33/11 kV substation at Jacks Point that will be supplied from the 33 kV line to Wye Creek. The substation will be designed to eventually accommodate two 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. A growth rate of 100 kVA per year is assumed until 2016, which is equivalent to approximately 30 houses, with the rate then increasing to 150 kVA a year. This prediction requires the substation to be installed prior to the winter of 2022. See Figure 5-30 for graph of load predictions.

To deliver 2 MVA to Jacks Point at 11 kV will require the installation of a voltage regulator when the load reaches 1.2 MVA. This is predicted to occur during the 2016 winter so the installation of a pair of single phase 100A regulators has been scheduled for 2015/16.

Project	No.	Cost	Completion
Install 11 kV voltage regulator	4137	\$90,000	May 2016
Jacks Point substation	2611	\$3.0 million	May 2022

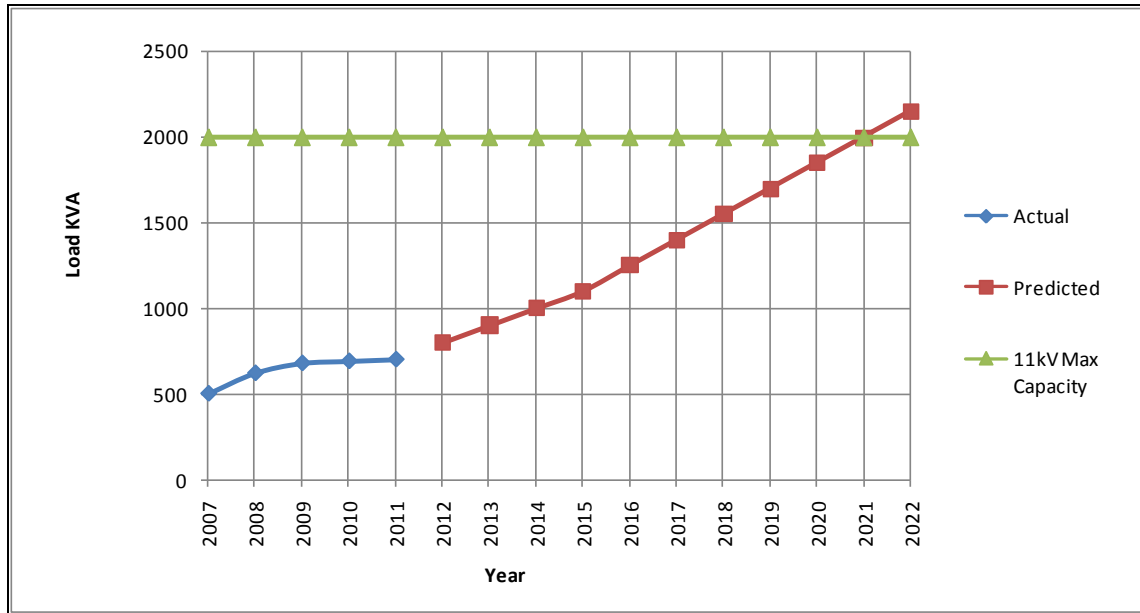


Figure 5-30 - Loading on recloser 7375R (Jacks Point area)

5.12.13 Remarkables Substation

The Remarkables ski field has a four stage upgrade planned. Stage one is scheduled to be completed for the winter of 2013 and will increase the field maximum demand to approximately 2 MVA. Stage 2 will add an extra 200 kW. This demand of 2.2 MVA can be met by the existing 3 MVA transformer at the base of the mountain by the application of line drop compensation (LDC) to maintain a constant voltage at the ski field. The application of this LDC will result in excessive voltage variation for the consumer supplied from distribution transformer WS200. It is proposed to install a Micro Planet LV voltage regulator at WS200 to keep the voltage within regulatory limits. A ski field load beyond 2.2 MVA will require either the establishment of a voltage regulator at the ski field, which could increase the maximum ski field load to 3.3 MVA but loads beyond this will require the establishment of a 33/11 kV substation on the field. Refer to development report DR126 for detailed consideration of supply options for the Remarkables ski field. The timing of stages three and four is uncertain so no financial provision has been made for these stages.

Project	Cost	Completion
Install Micro Planet 3 phase regulator at WS200	\$12,000	April 2013
Establish 33 kV substation at ski field	\$2.5 million	Hold

5.13 HV Feeders

A feeder rating is the minimum of its circuit breaker rating, outgoing cable rating, or CT thermal 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 calculated by the "Feeder Loading" database.

When it becomes impossible to completely off-load a feeder during peak load times, analysis is carried out to assess if the cost of eliminating the off-loading constraint is economic.

Remedial actions proposed to eliminate known feeder loading constraints are detailed below.

5.13.1 Conversion of 6.6 kV Feeders to 11 kV

Aurora has extensive 6.6 kV distribution in the Dunedin area and small amount in the Clyde Earnsclough area. 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 network 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. The additional cost for dual ratio transformers is approximately 20%. 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.

\$80,000 per year to 2022 and beyond

Transformer Voltage	Clyde Earnsclough				Dunedin 6.6 kV Area			
	2010		2011		2010		2011	
	Count	%	Count	%	Count	%	Count	%
6.6 kV	103	49%	84	44%	1,469	83%	1,435	81%
11/6.6 kV	107	51%	109	56%	305	17%	327	19%
Total	210		193 ⁵		1,774		1,762	

Table 5-17 - Dual ratio transformer conversion progress

5.13.2 Dunedin Feeders

5.13.2.1 Willowbank 2

The only tie with WB2 is with WB8. The load on both these feeders has been steadily increasing and it is not possible to fully off load WB2 at peak load times. An economic solution to this constraint has yet to be identified.

5.13.2.2 Neville Street 5

NS5 can only be off loaded onto NS1 or NS12. Neither of these feeders can take the entire load of NS5. It proposed that an air break switch be installed in Maryhill Terrace near Avoca Street that will enable the NS5 load to be split between NS1 and NS12.

Estimated Cost \$20,000

Completion: May 2013

⁵ The reduction in total appears to be due to the 11 kV transformers beyond the Springvale Rd 6.6/11 kV auto transformer having been incorrectly included in previous data.

5.13.2.3 Neville Street 12

NS12 can only be off loaded onto NS6 or NS5. Neither of these feeders can take the entire load of NS12. By shifting the open point between KV1 and NS6 from ABS379 to ABS1652 then the entire NS12 load can be transferred to KV1.

Estimated Cost \$0

Completion: June 2012

5.13.3 Frankton GXP Area HV Feeders**5.13.3.1 Queenstown 5232**

QT 5232 has just reached its off-load limit an additional intertie with feeder QT 5242 close to switch 551 would facilitate offloading.

Estimated Cost \$70,000

Completion: May 2014

5.13.3.2 Queenstown 5262

QT 5262 is also approaching its load limit but no action is proposed at present. In the future, an additional intertie with feeder QT 5242 close to switch 555 would facilitate off-loading.

5.13.3.3 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 only practical option for moving the works is to place them underground. It is proposed that additional cables be installed with this project to accommodate load growth to secure space in the road reserve and to avoid future trenching in this very busy section of highway. See development report DR74 for details. 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 roundabout. An allowance of \$500,000 for the 2013/14 year and estimates will be refined when the scope of the works is defined.

Estimated Cost \$500,000

Completion: December 2013

5.13.4 Cromwell GXP Area HV Feeders**5.13.4.1 New Wanaka Feeder 2751**

It is not possible to fully off load WK2758 during peak load times In the 2011 plan it was proposed that a HV connection with WK2752 to be installed during 2011/12. The proposed "Three Parks" development prompted a review of this project and it is now proposed a new Wanaka feeder be established using the existing WK2751 circuit breaker. This new feeder will supply the Three Parks area and provide an intertie with Feeders WK2758 and WK2756. The approximate route of the new feeder is shown in Figure 5-31 and the area of the three Parks development is shown on Figure 5-32. See development report DR124 for detailed analysis.

Estimated Cost \$600,000

Completion: May 2014



Figure 5-31 - Location of tie cable between WK2756 and WK2752

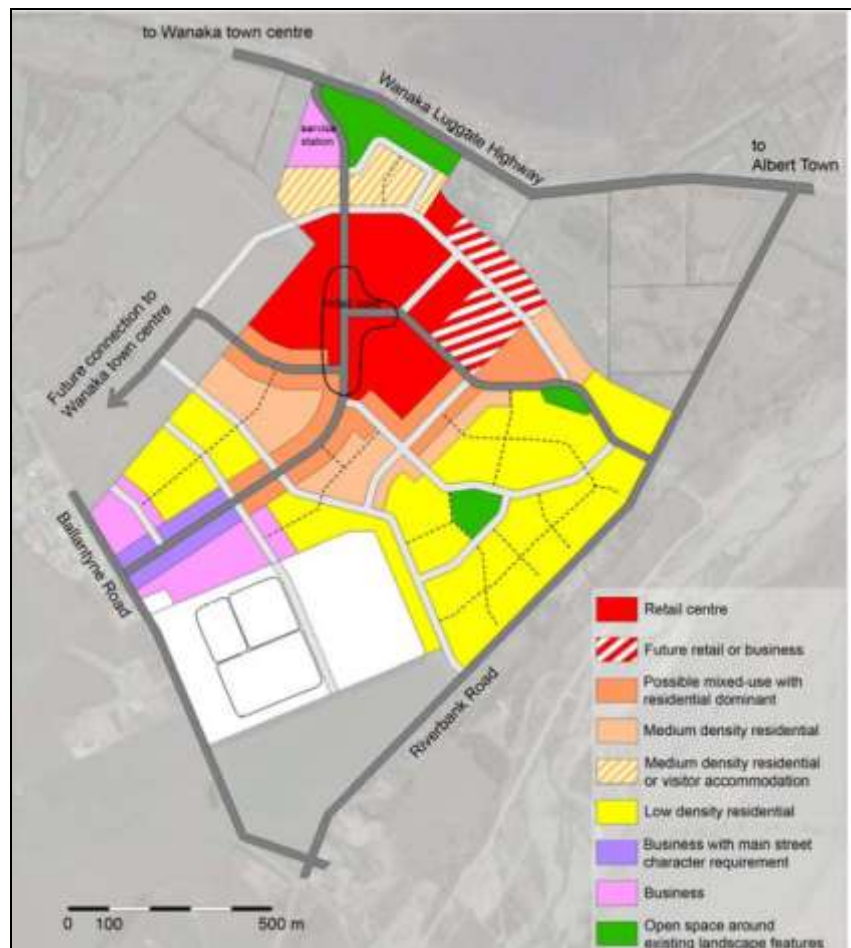


Figure 5-32 - Proposed Layout of the Three Parks Development

5.13.4.2 Establish New Wanaka Feeder 2757

In the previous plan it was proposed to establish a new feeder in 2013 to facilitate the off loading of WK 2753. A review of the project has resulted in the project being split into two stages, with stage one implemented in 2013/14 and stage two in 2016/17. See development report DR153.

Stage one of the project is to install approximately 950m of 300mm² AL cable from the Wanaka substation to Dungarvon Street. The second stage of the project is to replace the 480 metres of HV overhead in Dungarvon Street with 300 mm² AL cable. The feeder circuit breaker is already installed at Wanaka and cabled into the road reserve. The undergrounding of the HV in Dungarvon Street will require the installation of two ring main units and two fuse switches to supply substations presently supplied from the overhead. See Figure 5-33 for cable route.

Project	No.	Estimated Cost	Completion
New feeder to Dungarvon Street	2298	\$220,000	2013/14
Upgrade HV in Dungarvon Street	4206	\$250,000	2016/17



Figure 5-33 - Route of new Wanaka 2757 feeder.

5.13.4.3 Upgrade of Maungawera Feeder to Devon Dairy

As the Devon Dairy development expands, it will be necessary to upgrade the 11 kV lines between the Maungawera zone substation and the development to avoid excessive volt drop. It is estimated the upgrade will be required when the Devon Dairy demand reaches 1 MVA. See Figure 5-34 for the line route.



Figure 5-34 - Route of line upgrade to Devon Dairy Development

Estimated Cost \$420,000

Completion: Sept 2014

5.13.4.4 New Cromwell Feeder

It is now not possible to fully offload CM831 at peak load times. 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 will be required to be installed at the Cromwell zone substation.

Estimated Cost \$500,000

Completion: May 2014

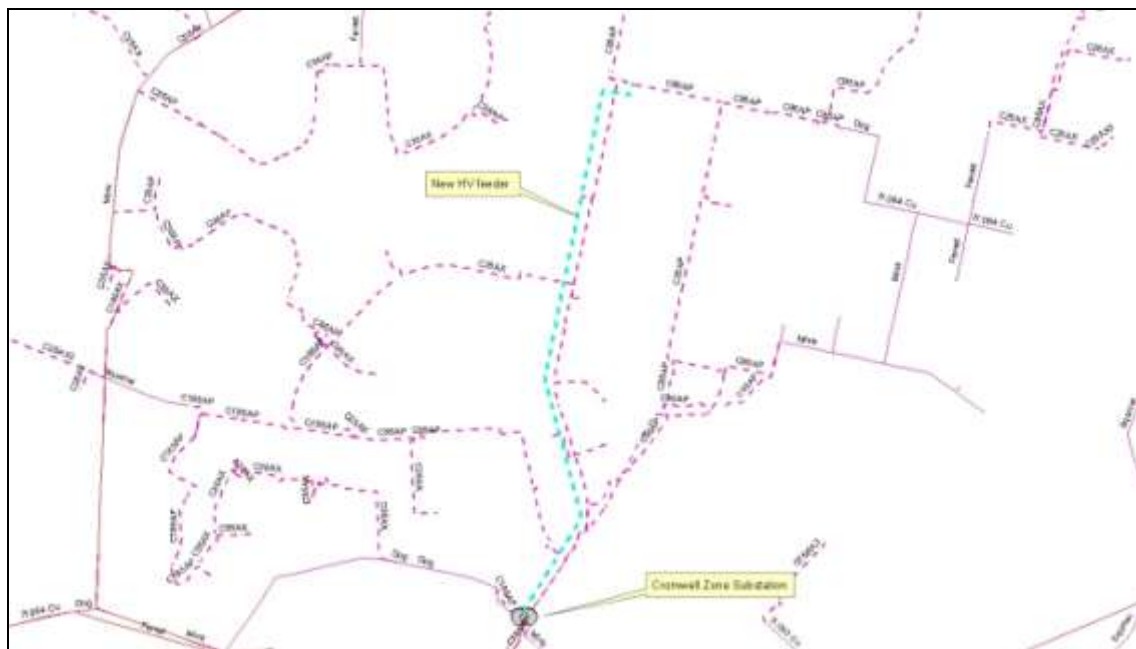


Figure 5-35 - Proposed route of new Cromwell HV feeder

5.13.4.5 HV Distribution and Substations for Tarras Irrigation Scheme

The proposed Tarras Irrigation scheme requires the installation of a new series of substation and interconnecting feeders, either overhead or underground. An overview of the additional HV distribution required is shown in Figure 5-36. See Development Reports DR133 and DR133A for a detailed analysis of the scheme requirements. A final decision on the scheme proceeding is still to be made. The present time line is for a decision to be made in March 2012 with an 18 month construction time, which would see the scheme operational by the spring of 2013.

Estimated Cost \$3.8 million

Completion: September 2013



Figure 5-36 - Overview of additional lines and cables to supply Tarras irrigation

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 Zone Substations

5.14.1.1 Non-Transferable Load

Under probabilistic planning, any “unlikely” event can be investigated for economic opportunity to mitigate it, and this is routinely done for Aurora assets. However, for zone substations, and regardless of degree of equipment redundancy, any complete loss of service is likely to be viewed externally as imprudent. To mitigate this risk, a clear statement of “load at risk” appears below. In the event of a complete outage occurring at a zone substation, only a portion of the substation load can generally be transferred to adjacent substations below lists the zone substation non-transferable load sorted by magnitude of the winter non-transferable MW (Table 5-18).

The risk management plan for zone substations is contained in Policy Document QP 1602/21. This procedure contains schedules for off-loading zone substations. It is reviewed every two years and was last reviewed in October 2010.

Zone Substation	% Domestic	Winter Loads (MW)			Summer Loads (MW)		
		2008-2010	Non-transferable		2008-2010	Non-transferable	
		MW	MW	%	MW	MW	%
Wanaka	80	20.3	18.8	92	13.5	12	89
Alexandra (2007)	40	12.4	12.3	99	9.6	9.4	98
Andersons Bay	95	17.1	10.0	59	11.3	6.2	33
Cromwell	50	10.0	8.9	88	7.7	6.7	87
Frankton	40	13.9	6.1	44	10.4	3.9	38
Commonage	60	9.8	6.0	61	5.5	4.4	80
Port Chalmers	50	7.9	5.8	73	7.1	4.3	61
Green Island	80	13.7	5.7	42	11.6	4.7	41
North City	0	20.0	5.5	28	16.9	4.8	28
Arrowtown	75	7.9	5.4	68	5.9	4.4	75
Queenstown	60	14.7	5.1	35	11.9	3.9	33
Mosgiel	20	8.4	5.0	60	7.0	3.4	49
St Kilda	70	15.7	4.9	31	13.5	3.1	23
Corstorphine	95	14.3	4.7	33	9.5	2.9	31
Ward Street	30	12.5	4.6	37	12.0	2.8	23
Neville Street	60	14.8	4.3	29	11.7	3.1	23
Clyde/Earns	20	4.1	4.1	100	4.1	4.1	100
Halfway Bush	95	14.6	2.5	17	10.9	2.6	24
Smith Street	0	16.8	2.4	14	14.1	0.7	5
Omakau	10	2.0	2.0	100	2.1	2.1	100
Kaikorai Valley	50	10.2	1.9	19	8.7	1.3	15
North East Valley	95	11.8	1.8	15	8.2	0.3	4
Willowbank	60	13.7	1.7	12	11.0	0.6	5
Roxburgh	20	2.6	1.7	65	2.8	1.9	68
Fernhill	90	6.2	1.3	21	4.4	0.1	2

Zone Substation	% Domestic	Winter Loads (MW)			Summer Loads (MW)		
		2008-2010	Non-transferable		2008-2010	Non-transferable	
		MW	MW	%	MW	MW	%
Maungawera	10	2.3	1.0	43	2.1	0.7	33
South City	0	15.8	0.9	20	13.4	0	0
Remarkables	0	0.8	0.8	100	0	0	0
Coronet Peak	5	4.6	0.5	11	1.	0	0
East Taieri (2)	75	16.7	0.5	3	12.8	0	0
Outram	60	2.8	0	0	2.5	0	0
Dalefield	30	2.3	0	0	1.6	0	0
Queensberry	10	1.7	0	0	2.4	0	0
Ettrick	10	1.7	0	0	2.1	0	0
Berwick	10	1.2	0	0	1.2	0	0

Table 5-18 – Zone substation non transferable load schedule

Future projects that will improve the ability to off load zone substations are

- construction of Jacks Point will increase the ability to off load Frankton;
- construction of Riverbank Road substation will increase the ability to off-load Wanaka.

5.14.1.2 Zone Substation Fire Protection

A report was prepared on the risk and consequences of a zone substation control room fire at selected substations. The report recommended that gas flooding fire protection be installed at several zone substations. After assessing the risk it is recommended the three sites listed below be fitted with gas flooding fire protection.

Zone Sub	Cost \$	Completion
Wanaka	\$150,000	June 2013
Cromwell	\$150,000	June 2013
Port Chalmers	\$150,000	June 2014

5.14.1.3 Earthquake Proofing of Buchholz and Temperature Relays

Older transformers are fitted with Buchholz and temperature relays containing mercury switches. These switches are prone to causing false tripping of transformers during earthquakes. An allowance has been made to progressively upgrade the relays to units designed to withstand earthquakes.

Area	Cost \$	Completion
Dunedin	\$30,000 per year	2011 to 2015
Central	\$20,000 per year	2011 to 2015

5.14.1.4 Installation of Earthing Points at Zone Substations

Many zone substations in the Central Region do not have dedicated earthing points in outdoor switchyards. It is proposed that earthing points be established where necessary and be located to enable the application of earths without the use of ladders. This will make the application of earths easier and safer. The exact scope of the work required has yet to be defined so the estimated cost is just a preliminary allocation.

Estimated Cost \$50,000

Completion: June 2013

5.14.1.5 Installation of 33 kV Breakers on Fused Transformers

Several zone substation transformers in Central are only protected by 33 kV HV fuses. If a transformer protected by HV fuses has a fault then there is high probability the damage to the transformer will be extensive such that the transformer will be uneconomic to repair. If a transformer has both HV and LV circuit breakers, the Buchholz relay can clear faults quickly to limit winding damage. The Roxburgh T1 Transformer had to be scrapped after a fault in November 2011 that was cleared slowly by fuses. See Table 5-19 for a schedule of fuse protected transformers and the proposed upgrade program.

Site	Transformers	Estimated \$	Completion
Omakau	3 MVA	\$100,000	May 2013
Dalefield	3 MVA	\$100,000	May 2014
Ettrick	3 MVA	\$100,000	May 2013
Roxburgh			Fix at sub rebuild
Arrowtown	Two 5 MVA		Fix at sub rebuild
Clyde/Earnsclough	4 MVA + 2 MVA	\$100,000	May 2015
Earnsclough	2 MVA		Not Justified
Maungawera	3 MVA		Fix at sub rebuild
Remarkables	3 MVA	\$100,000	May 2014

Table 5-19 - Schedule of fuse protected zone substation transformers

5.14.2 HV Distribution Projects

5.14.2.1 Underground Substation Flood Proofing

In Dunedin, there are 19 underground substations. A heavy rain event, in 2005, flooded five of these substations. Six substations have been fitted with ducting and forced ventilation to mitigate the risk of flooding. It is proposed to continue with the waterproofing work on two substations per year as per Table 5-20.

Substation	Project No.	Cost \$	Year
Bath Street U/G	3786	\$50,000	2012/13
Central Mission U/G	3787	\$50,000	2012/13
Century Theatre U/G	3788	\$50,000	2013/14
Dowling Street No 1 U/G	3789	\$50,000	2013/14
Hanover Street No 1 U/G	3790	\$50,000	2014/15
Hope Street	3791	\$50,000	2014/15
Moray Place No 1 U/G	3793	\$50,000	2015/16

Substation	Project No.	Cost \$	Year
Moray Place No 3 U/G	3794	\$50,000	2015/16
St Andrew Street U/G	3795	\$50,000	2016/17
Stuart Street Pit U/G	3796	\$50,000	2016/17

Table 5-20 - Schedule of U/G substations to be waterproofed**5.14.2.2 Protection of Street Lighting MCBs in Central**

There are several substations in Central with LV MCBs protecting street lighting circuits that have a fault rating less than prospective fault level at the substation. It is necessary to fit HRC fuses upstream of these units. The exact extent of this problem has yet to be determined, but an allowance has been made for remedial work.

Estimated Cost \$20,000

Completion: May 2013

5.14.2.3 New Feed to Cromwell Business Area

Current reliability and security of supply to New World, Mitre 10 and Nichols is unacceptable. They are currently fed from feeder CM832, the rural OH line toward Lowburn, and group fused from FS 850. It is proposed these sites be supplied via CM823 by installing an SD switch at the CC61/CC62 switching station and installing a 185mm² cable from this switch to switch 8456. See Figure 5-37.

In association with this project, it is also proposed to mitigate the fire hazard at CC52 by installing separation fence between waste compound and transformer CC52/RMU.

**Figure 5-37 - Cromwell supply modifications**

Estimated Cost \$60,000

Completion: May 2013

5.14.2.4 HV Feeder Reclosers

In the 2011 plan, a schedule of HV feeder recloser projects was presented. The proposal to install reclosers adjacent to the Maungawera substation has been cancelled as they will not be required when the substation is upgraded as proposed in Section 5.12.11. The implementation of SCADA initiated reclose at Alexandra has been cancelled but instead auto-reclosing will be implemented via the new feeder protection relays proposed in Section 6.5.1. It is proposed the remaining projects proceed as planned in 2011 as per Table 5-21 below.

Project	Project Cost	Value of Energy Not Supplied	SAIDI Reduction	Cost per Min of SAIDI	Benefit/cost	Year
ET2 - recloser at urban boundary	\$50,000	\$ 74,472	0.371	\$134,771	1.5	2012/13
QT5202 - Closeburn recloser	\$50,000	\$ 60,892	0.350	\$142,857	1.2	2012/13
CE195 - recloser on Springvale Rd spur	\$50,000	\$ 90,323	0.315	\$158,730	1.8	2013/14
AX168 - recloser on Dunstan Rd spur	\$50,000	\$178,216	0.293	\$170,648	3.6	2013/14
AB9 - recloser at Tomahawk	\$50,000	\$61,280	0.293	\$170,648	1.2	2013/14
AX168 - recloser on Letts Gully spur	\$50,000	\$186,256	0.292	\$171,233	3.7	2014/15
Ettrick - recloser on Timaburn Rd spur	\$50,000	\$149,176	0.260	\$192,308	3.0	2014/15

Table 5-21 - Schedule of HV feeder recloser projects

5.14.2.5 Transfer of Part ET8 to New Mosgiel Feeder

The reliability of supply to customers supplied by ET8 can be improved by transferring some ET8 customers to a new Mosgiel MG8 feeder. There is a spare breaker at Mosgiel that for this purpose. A small section of ET6 and MG6 will also end up on the new MG8 feeder. See Figure 5-38 for an overview of the works. The project requires the installation of a ground-mounted three-way switch, two air break switches and some HV cabling.

Estimated Cost \$66,000

Completion May 2015

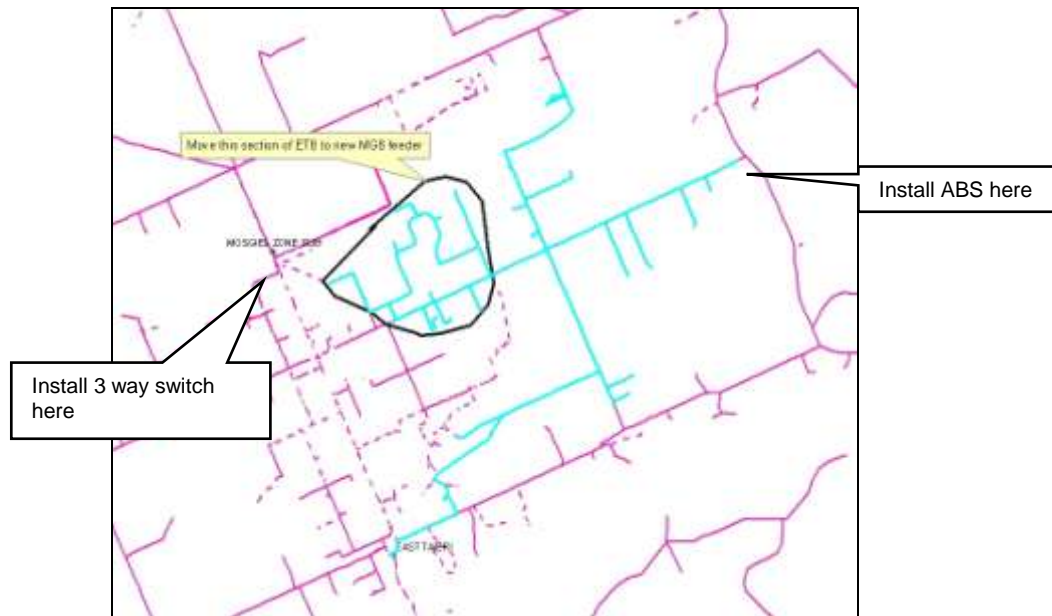


Figure 5-38 - Section of ET8 to be transferred to new MG8 feeder

5.14.3 System Control and Communication Projects

A review has been carried out on Aurora's communications systems that support protection signaling, SCADA systems and load management systems. A series of recommendations have been put forward covering fibre, voice radio, SCADA, load control, protection communications and disaster recovery. The recommendations identify areas where further investigation is required and suggest options to be considered for further economic analysis and subsequent cost estimation. Additional investment in communication systems is likely and an allowance of \$1 million a year for three years starting 2013/14 has been made. The actual quantum of cost will be determined over the next 6-12 months, as part of the development of an overall communications strategy.

Estimated Cost \$1 million per year for three years from 2013/14

Completion June 2016

5.15 Overhead to Underground Conversion Projects

Aurora has a policy of assisting local authorities to have overhead lines placed underground. In the Dunedin area this work is fully funded by Aurora. In other areas Aurora will contribute dollar for dollar up to an annual maximum equal to 2% of the annual line charges obtained from consumers in the local authority area.

Each year the budgets are adjusted to match the actual distribution line income received in the previous financial year. It has been assumed that line charge rates will increase by 1% per year. The projected expenditure by Aurora Energy Ltd is detailed in Table 5-22.

Project No:	3043	3044		3045	
	DCC	CODC		QLDC	
Year	Aurora \$000	Aurora \$000	CODC \$000	Aurora \$000	QLDC \$000
2012/13	600	160	160	255	255
2013/14	600	165	165	265	265
2014/15	600	170	170	275	275
2015/16	600	175	175	285	285
2016/17	600	180	180	295	295
2017/18	600	185	185	300	300
2018/19	600	190	190	305	305
2019/20	600	195	195	310	310
2020/21	600	200	200	315	315
2021/22	600	202	202	318	318

Table 5-22 – Overhead to underground conversion budget

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 5-23.

Project No:	3058	3059	Total \$000
Year	Dunedin \$000	Central \$000	
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
2021/22	1,200	7,000	8,200

Table 5-23 – 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 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)	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Fault and emergency	4,370	4,470	4,570	4,670	4,780	4,890	5,101	5,120	5,240	5,365
Refurbishment and renewal	1,340	1,370	1,390	1,430	1,460	1,490	1,520	1,550	1,590	1,630
Routine and preventative	3,640	3,740	3,850	3,950	4,060	4,170	4,290	4,400	4,530	4,665
Total	9,350	9,580	9,810	10,050	10,300	10,550	10,911	11,070	11,360	11,660

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

6.2.1.1 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.

6.2.1.2 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.

6.2.1.3 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

6.2.2.1 33 kV Transformers and Tapchangers

While the transformers have been relatively trouble free some recent failures have resulted in a review of the suite of transformers.

Acknowledging the age profile of the transformers, enhanced assessment criteria and condition based monitoring techniques are being determined. Asset criticality will be used to inform the frequency, type and level of assessment required. The outputs will be used to establish and initiate a better managed program for transformer renewal.

All transformers have their insulating oil tested annually for acid level, breakdown resistance, and moisture content. While DGA testing has been completed on an annual cycle some transformers that have been identified as requiring closer monitoring are likely to have a more frequent DGA testing regime.

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.

6.2.2.2 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.

6.2.2.3 **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.

6.2.2.4 **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.

6.2.2.5 **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 (see below). A précis of the regulations is published on Aurora's website.

6.2.3.1 **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.

A complete survey of the overhead network has been completed in 2011 to assess the impact of vegetation with the data recorded in the Geographic Information System in a newly established vegetation layer.

Taking the pole, pole hardware and vegetation condition data a holistic approach has been established with financial resources secured to target complete feeders for pole and pole hardware renewal in conjunction with vegetation management permitted under the Electricity (Hazards from Trees) Regulations 2003. See Section 6.5.2.

6.2.3.2 **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.

6.2.3.3 **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**

6.2.4.1 **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.

6.2.4.2 **Buildings and Grounds**

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

6.2.4.3 **Switchgear**

Ring-main switchgear has been relatively maintenance free, and checks on oil levels and general condition are included in the substation inspection round. Due to the age profile of oil switchgear the maintenance procedures and intervals are being reviewed and bench-marked against industry peers and manufactures recommendations to ensure a robust and consistent regime is followed. From this, an updated maintenance plan will be established. Risk and condition assessments are underway in order to better understand current state of these assets and to help further prioritise maintenance spend. 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**

6.2.5.1 **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.

6.2.5.2 **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.

6.2.5.3 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	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
Subtransmission	381	392	402	413	425	436	448	457	471	485
Zone substations	930	955	981	1,008	1,036	1,065	1,094	1,115	1,148	1,182
System control	165	169	174	178	183	188	194	198	204	210
HV and LV	1,795	1,844	1,903	1,950	2,004	2,058	2,119	2,186	2,250	2,318
Distribution substations	369	380	390	401	412	423	435	444	457	470
Total	3,640	3,740	3,850	3,950	4,060	4,170	4,290	4,400	4,530	4,665

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

6.4.1.1 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).

6.4.1.2 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.

6.4.1.3 Protection Pilots

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

6.4.2 Zone Substations

6.4.2.1 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.

6.4.2.2 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.

6.4.2.3 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.)

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).

6.4.2.4 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

6.4.3.1 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.

6.4.3.2 **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.

6.4.3.3 **Earths**

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

6.4.4 **Distribution Substations**

6.4.4.1 **Transformers**

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

6.4.4.2 **Substations**

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

6.4.4.3 **Buildings and Grounds**

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

6.4.4.4 **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 6.5.1).

6.4.5 **System Control**

6.4.5.1 **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.

6.4.5.2 **UHF and VHF Systems**

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

6.4.5.3 **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	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
Subtransmission	58	60	62	63	65	67	69	72	74	76
Zone substations										
System control										
HV and LV	1,047	1,069	1,080	1,112	1,133	1,154	1,174	1,190	1,220	1,250
Distribution substations	235	241	248	255	262	269	277	288	296	304
Total	1,340	1,370	1,390	1,430	1,460	1,490	1,520	1,550	1,590	1,630

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.

6.5.1 Subtransmission and Zone Substation Replacements

6.5.1.1 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.

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 is assumed that the deteriorated rubber sheath allowed moisture to enter the cable resulting in corrosion of the bronze tapes. Refer to Figure 6-1 and Figure 6-2.



Figure 6-1 – WB 2 Cable – Failed Bronze Tape September 2010



Figure 6-2 – WB 2 cable –degraded rubber sheath September 2010

Linetech Ltd reviewed the 2009 Aurora Development Plan and recommended that Aurora should schedule the replacement of all its gas cables. Linetech believes 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.

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 it is the unreliable bronze tape type and it is not possible to fully off-load Andersons Bay. Design of the new cables is underway and it is proposed to use lead sheathed single core XLPE cable due to the cables being installed below the water table for most of the route. The application of a lead sheath will extend the life of the cables.

The Neville Street and Smith Street cable upgrades are scheduled to be replaced in conjunction with the upgrade of the associated substation outlined on the following page.

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	Project No.	Estimated Cost \$000
South Dunedin – Andersons Bay	1961	2.7	2012/13	3472	3,000
Halfway Bush – Neville St	1961	6.82	2014/15	Included in project 2324. Neville Street substation upgrade	
Halfway Bush – Willowbank	1963	3.9	2017/18	3470	4,300
Halfway Bush – Smith St	1959	3.2	2019/20	3471	3,500
Halfway Bush – Ward St	1967	4.2	2020/21	3469	4,700

Table 6-4 – 33 kV gas cable replacement schedule

A report, DR12, has been prepared on the long-term configuration of Dunedin 33 kV sub-transmission network, and it recommends the existing transformer feeder configuration be retained but with the Neville Street substation supplied from the South Dunedin GXP.

6.5.1.2 **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 250 m 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. In 2011 partial discharge testing of the cables was carried out and the results were satisfactory. Replacement is now scheduled for 2018/2019 which is after the installation of NERs at Halfway Bush which allows light duty cable screens to be utilised. It is recommended that routine partial discharge testing of these cables be scheduled.

Estimated Cost \$2.9 million

Completion: December 2018

6.5.1.3 **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. Soil tests at the existing site indicate the land is very vulnerable to liquefaction during an earthquake and any structures on the site should have piled foundations. Investigations are underway to find a suitable site.

It is proposed the replacement of the Neville Street 33 kV gas cables be carried out at the same time and the connection be moved from the HWB GXP to the South Dunedin GXP.

Estimated Cost \$6.0 million

Completion: May 2015

6.5.1.4 **Roxburgh Substation Upgrade**

In the 2011 plan, it was proposed to upgrade the Roxburgh zone substation to remedy several issues at the site listed below. Since then, the Roxburgh T1 33/11 kV transformer (1.5 MVA) failed and it is uneconomic to repair. The remaining T2 transformer has insufficient capacity to carry the substation peak load that occurs during the spring frost fighting season. A more extensive upgrade is now proposed that includes the installation of an new 5 MVA transformer. It is proposed this upgrade be fast tracked to be completed by August 2012.

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 Teviot Power Station;

- new control room required;
- space and connection facilities required for the mobile substation.
- lightning arresters upgrade required; and
- 33 kV transformer protection needs to be upgraded from fuses to circuit breakers

Estimated Cost \$2.108 million

Completion: August 2012

6.5.1.5 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.

The Port Chalmers circuit breakers are relatively new Cooper VWVE units but one of these units failed in 2012 due to a faulty trip coil and when the unit was inspected in the workshop it was found to have significant moisture in the oil due to the failure of the bushing extension seals. There was significant corrosion of the aluminium extension tubes. It is not believed the unit is economic to repair. A spare RV unit was used to replace the failed VWVE unit. Aurora has 18 VWVE breakers on the network and moisture ingress has been a problem with other units.

It is proposed the Port Chalmers 33 kV circuit breakers be replaced with Siemens live tank vacuum breakers the same as the units being installed at the North East Valley zone substation. This will provide two spares to cover for other VWVE failures. A full investigation is underway on the condition and management of the remaining VWVE units in service on the network.

Substation	Notes	Year of Manufacture	E	Year	Cost (\$000)
Port Chalmers	Replace faulty VWVE breakers	2002	2	2012	160
Alexandra	Scheduled	1960	3	2013/14	200
Neville Street	Will be done in conjunction with substation rebuild	1948	3	2014/15	

Table 6-5 – Zone substation 33 kV switchgear replacement schedule

6.5.1.6 Zone Substation 6.6/11 kV Switchgear Replacement

The zone substation 6.6/11 kV switchgear is 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 indicates that the insulation resistance is not deteriorating so, hopefully, the upgrade can be delayed until 2020 when the substation is expected to be fully loaded and the transformers will require replacement.

The Willowbank 6.6 kV switchgear, which is the same type as the Andersons 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, and Maungawera. 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	2012/13	Note 1
Neville Street	1948 & 1953	Planned	14	2014/15	Note 1
Halfway Bush	1956	Monitor	16	-	
Green Island	1957	Monitor	15	-	
Smith Street	1958	Planned	15	2018/19	Note 1
Earnsclough	1960	Monitor	1	-	
Dalefield	1960	Planned	1	2011/12	\$80
Roxburgh T1 & T2	1960	Planned	2	2012/13	Note 1
Clyde-Earnsclough T1 & T2	1960	Monitor	2		
Andersons Bay	1961	Planned	15	2020/21	Note 1
Willowbank	1962	Monitor	15		
Outram	1963	Planned	8	2015/16	Note 1
Maungawera	1965	Planned	1	2013/14	Note 1
Arrowtown T1 & T2	1970	Planned	2	2016/17	Note 1

Table 6-6 - Zone substation 6.6/11 kV switchgear replacement schedule

Note 1: Switchgear upgrade done in conjunction with major substation upgrade.

6.5.1.7 Zone Substation Battery Replacements

Several Dunedin zone substations have Faure-X flooded lead acid batteries that have exceeded their a nominal life of 20 years. These substations also require new battery chargers to accommodate modern sealed lead acid batteries. A replacement program is underway and the remaining sites to be upgraded are listed in Table 6-7 below.

Substation	Battery Install Date	Replacement Year	Estimated Cost \$
Green Island	1990	2012/13	\$23,000
Kaikorai Valley	1989	2012/13	\$23,000
Smith Street	1990	2012/13	\$23,000
Neville Street	1988	Replace with sub rebuild 2014/15	

Table 6-7 - Schedule of zone substation battery and charger upgrades

6.5.1.8 Dunedin Zone Substations RTU Replacements

The SCADA remote terminal units at most Dunedin zone substations were installed in 1987. These units have been very reliable but face technological obsolescence due to their inability to use modern master station communication protocols and communicate with IEDs (Intelligent Electronic Devices) such as protection relays.

In the future, it is envisaged that Aurora's communications to zone substations will move to DNP3 over IP, new RTUs are required to facilitate this. When the existing master station reaches the end of its economic life, it is desirable the Conital communications protocol be abandoned as it is unlikely to be supported by most master station software suppliers. Provision has been made to upgrade five substations a year from 2012.

Estimated Cost \$250,000 per year for 3 years

Completion: May 2015

6.5.1.9 Upgrade of Transformer Breathers

It is proposed to upgrade the breathers on older transformers from conventional silica gel breathers with maintenance free dehydrating made by Messko (Type MTraB). These breathers have a built-in heating unit that dries the desiccant thus eliminating the need for periodic desiccant replacement. The seals on the older breathers at the substations have deteriorated and are likely to be leaking air hence are scheduled for upgrade.

The replacement has been completed at several sites and it is proposed the remaining sites be completed in accordance with Table 6-8 below.

Substation	No. of Transformers	Cost	Completion
Green Island	2	\$26,000	Dec 2012
Willowbank	2	\$26,000	Dec 2012
Arrowtown	3	\$39,000	Dec 2012
Cromwell	2	\$26,000	Dec 2013
Clyde/Earnsclough	2	\$26,000	Dec 2013
Coronet Peak	1	\$13,000	Dec 2013

Table 6-8 - Schedule of transformer breather upgrades

6.5.1.10 Replacement of the Alexandra HV Feeder Protection

The HV feeder protection relays at Alexandra are ASEA RACIC units installed in the 1980s. These relays are analogue solid state relays and they are believed to have reached the end of their economic life. One unit has failed already. The relays are not mounted on the associated switchgear but are all in a single control panel in the Alexandra relay room. They use the now obsolete ASEA Combiflex plug and mounting system which makes it difficult to replace an individual failed relay. It is proposed to upgrade to SEL 751A relays. The additional benefits of installing 751A relays are detailed below:

- It will be easy to implement auto reclose on feeders. In the 2011/21 plan it was recommended that auto reclose via SCADA be implemented on AX169,168 and 162 but this has been put on hold in favour of the relay upgrade option.
- Can implement separate sensitive earth fault and normal earth fault protection that will improve performance.

- The SEL relays are modern IED devices that can communicate directly with the SCADA RTU which will facilitate the provision of additional fault data.
- The fault recording facility of the SEL relays will facilitate detailed post fault analysis when required

Estimated Cost \$75,000

Completion: May 2013

6.5.1.11 Upgrade of Outram Zone Substation

The Outram zone substation is nearing the end of its economic life. There have been problems with slow operation of the 11 kV switchgear and the transformers which were manufactured in 1952 have a history of tap changer mechanical problems. The transformers have a nominal 31 kV voltage which forces the 11 kV to be operated higher than normal which requires non-standard distribution transformers. It is proposed the substation be rebuilt with one 5 MVA transformer with a parking bay for the mobile substation. It could be desirable for the transformer to have a 10% buck tap as per Berwick to avoid high voltage due to the Waipori generation. The HV switchgear would be replaced and installed in a new control room. It is anticipated the conversion of the ripple system to 317 Hz will be complete before the project commences removing the need to retain 1050 HZ injection equipment at the site.

Estimated Cost \$3.0 million

Completion: May 2016

6.5.1.12 Replacement of Shotover 33 kV River Crossing on Wye Creek Line

The 33 kV aerial river crossing across the Shotover River is nearing the end of its life. The existing river crossing structures have not been able to be inspected for structural integrity as they are in the river and not normally accessible. Options are to rebuild the line or to install cable (1.3 km) across the nearby road bridge. If the line were to be rebuilt it would be desirable to avoid having structures in the middle of the river but this would require higher structures on the banks either side of the river. However, the line is crossed by the Transpower 110kV line close to the south bank of the crossing which probably excludes higher termination structures.

The long-term plan was to utilise this river crossing for the third 33 kV supply to Arrowtown. This requires the section of 70 mm² cable (250 m) in the Glenda Drive industrial estate to be upgraded and the installation of a 33 kV cable (400 m) along Old School Rd. In light of the precarious state of the river crossing and difficulties in re-establishing a secure crossing it is now recommended that a 33 kV cable (300 mm² XLPE) be installed across the Shotover bridge along the route shown on Figure 6-3. Other benefits of the cable option are the elimination of the visual impact of the 33 kV line through the industrial estate and it will facilitate the installation of a duct in the cable trench for the installation of an additional 11 kV feed across the Shotover River to supply Lake Hayes Estate and the proposed Stalker subdivision.

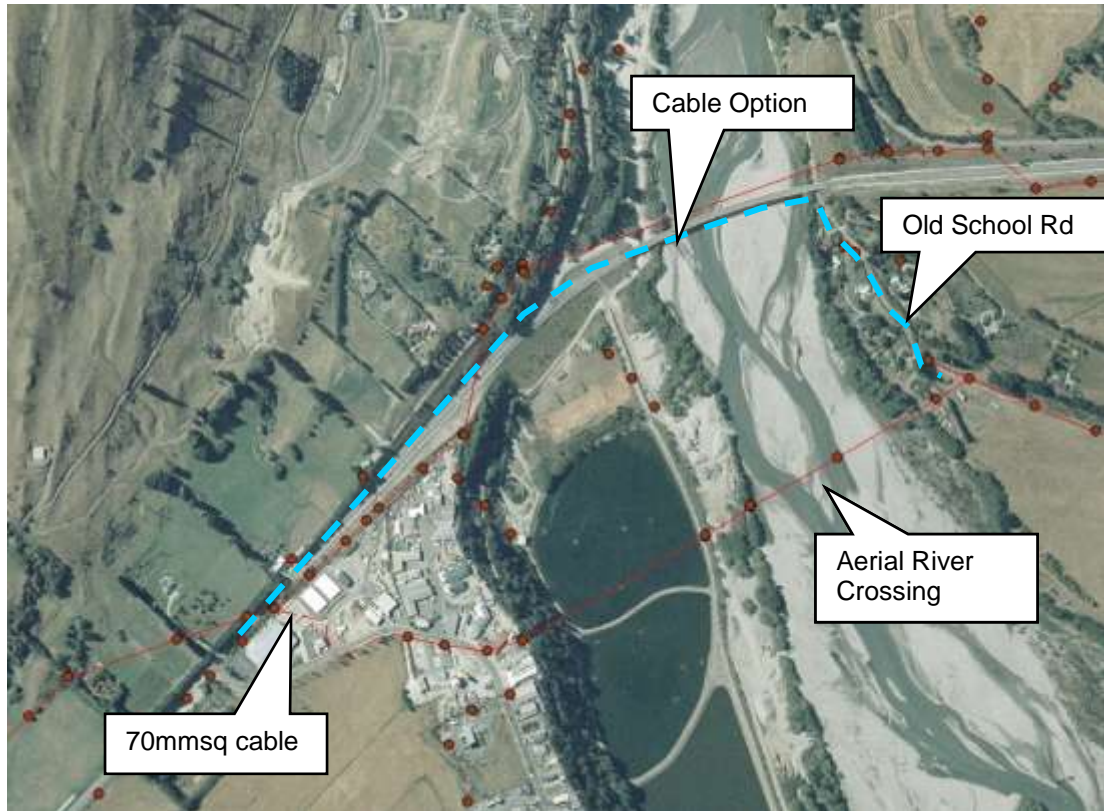


Figure 6-3 - Location of Shotover River Crossing

Estimated Cost \$1 million

Completion: December 2013

6.5.1.13 Replace Gates at North City Zone Substation

The wooden gates into the switchyard at North City substation have reached the end of their life. It is proposed they be replaced with metal gates similar to the units used for the Frankton substation upgrade.

Estimated Cost \$30,000

Completion: June 2013

6.5.2 HV and LV Distribution Replacements

6.5.2.1 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 6-9.

Site	Make	Date of Manufacture	Project No	Replacement Date	Cost (\$000)
Tyne Street Rectifier	Reyrolle	1948	2144	2011	120
Tennyson Street Rectifier	Reyrolle	1948	2145	2012	120
Great King Street Rectifier	Reyrolle	1948	2146	2013	120
Shacklocks	Statter AC2	1960	2276	Monitor	
High Street	Statter AC2	1960	2277	Monitor	
Ravensdown Fertilizer	J&P	1962		Monitor	
Hillside Workshops	J&P	1956		Monitor	

Table 6-9 – Distribution substation HV switchgear replacement schedule**6.5.2.2 Replacement of Distribution Transformers**

Provision has been made to replace distribution transformers that are damaged or deteriorated such that they are uneconomic to repair.

Estimated Cost \$120,000 per year

6.5.2.3 Replacement of Hazardous Central Ground Mounted Substations

In Central, there are some ground mounted substations that consist of BU-BU or CB-BU transformers in a Central Electric designed enclosure. Some of these substations are a hazard due to HV terminals being accessible ventilation mesh and there are also safety issues with the LV distribution boards. There is now only one substation to complete.

Substation Name	Size kVA	Project No.	Completion Date	Estimated Cost
WK37	150	3333	2011/12	\$50,000

6.5.2.4 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 10 years.

Estimated Cost \$60,000 per year from 2009 to 2018

6.5.2.5 Dunedin Underground Link Box Replacements

In Dunedin, there are 246 underground LV link boxes. Some of these boxes require replacement due to ageing and overloading. It is proposed to replace three boxes per year for the duration of the planning period.

Estimated Cost \$150,000 per year

6.5.2.6 **Andelect Fuse Box Replacements**

Andelect fuse boxes are mainly in the Dunedin CBD area and South Dunedin business district. They were installed when these areas were converted from overhead to underground distribution in the 1950s and 1960s. See Figure 6-4 for a typical example. Many of these boxes are installed on consumers' premises and can be down alleyways, inside buildings or mounted high on external walls. It can be difficult to gain access to the boxes and spare parts for them are no longer available. It is present policy for Aurora to fund the removal of these boxes and the re-establishment of the connection point in a ground mounted pillar box on the property boundary if the consumer mains are being upgraded. Approximately 12 per year are done at an average cost of \$6,000 each.

Estimated annual Cost \$36,000



Figure 6-4 – Typical Andelect box

6.5.2.7 **Replacement of “Two Pole” Substations**

When the poles supporting “two pole” substations become unsafe, the substation is re-established on the ground when practical. An allowance has been made to replace three substations a year from 2010 to 2019.

Estimated Cost \$250,000 per year

6.5.2.8 **Replacement of KFE and KF reclosers**

Aurora has two KF and 8 KFE reclosers installed in the field. These reclosers cannot be operated remotely and it is not economic to convert them for remote control. The ability to remotely control reclosers can speed up fault location and/or reduce man power requirements during permanent faults downstream of reclosers. During the planning period, it is proposed to replace the two older KF units in the Dunedin area and two other KFE units selected by age and projected savings in customer outage minutes (see Table 6-10).

Substation	Project No.	Year	Estimated \$
1286R on AB9 (KF)	3771	2012/13	\$50,000
KFE to be identified	3772	2013/14	\$50,000
KFE to be identified	3773	2014/15	\$50,000

Table 6-10 - Schedule of recloser replacements**6.5.2.9 Port Chalmers to Peninsula Harbour Crossing Upgrade**

There are six towers associated with the Port Chalmers 11 kV feeder 7 harbour crossing. These towers were installed in 1960 and have been relatively maintenance free until now. Linetech examined the towers and has recommended that, if they are to be retained, they 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 1990s.) It is estimated that it would cost \$150,000-\$200,000 to refurbish each tower with a total cost of \$900,000 to \$1.2 million.

Investigations are underway to determine if it is feasible and economic to install a second submarine cable crossing. A provisional allowance has been made for this project.

Estimated Cost \$800,000

Completion: July 2014

6.5.2.10 Replacement of Otakou Voltage Regulator

The 6.6 kV voltage regulator at Otakou on the PC3 feeder is an old Ferranti moving coil unit manufactured in 1947. It is recommended this regulator be replaced. An alternative solution is to convert the supply beyond Otakou to 11 kV which may eliminate the need for a regulator. Further investigation is required to determine the most appropriate solution.

Estimated Cost \$100,000

Completion: May 2014

6.5.2.11 Pole Replacements

A program is underway to replace wood poles that are in poor condition. \$3 million was allocated for the 2011/12 year and a further work is proposed for the next three years as per the schedule in Table 6-11 below. As outlined in Section 2.7, a risk assessment framework is currently being developed to enable a more structured approach to the prioritisation of works within the allocated budget for pole replacements.

Project No.	Area	Year	Estimated Cost
4204	Dunedin	2012/13	\$1 million
		2013/14	\$1 million
		2103/15	\$1 million
4205	Central	2012/13	\$2 million
		2013/14	\$2 million
		2103/15	\$2 million

Table 6-11 - Schedule of pole upgrade works

6.5.3 System Control and Load Management Replacements

As outlined in Section 5.14.3, a review has been carried out on Aurora's communications systems and a series of recommendations have been put forward. The recommendations identify areas where further investigation is required and suggest options to be considered for further economic analysis and subsequent cost estimation. Proposed replacements in the short term include the following:

6.5.3.1 Upgrade of Dunedin SCADA

The Dunedin SCADA master station computers were upgraded in March 2006. It is envisaged that the life of these units is six years so they are due to be replaced in 2012. However it is no longer possible to purchase a replacement computer that supports the present operating system. This upgrade has been deferred to 2013 but its cost has been increased to allow for a software upgrade at the same time.

Estimated Cost \$300,000

Completion: Dec 2013

6.5.3.2 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. This upgrade will require some upgrading of the associated communications network but the exact nature of the work is yet to be determined. Associated with this project is a review of the data communications future direction.

Estimated Cost \$300,000

Completion: May 2013

6.5.3.3 Replace Dunedin GXP Check Meters

The check meters at Halfway Bush and South Dunedin are nearing the end of their economic life. There have been un-resolved accuracy issues with the South Dunedin units. The replacement may include the upgrade of the systems used for logging the metered data. Additional investigation and design work is required to detail the required works but an allowance has been made to carry out the work in 2012.

Estimated Cost \$80,000

Completion: May 2013

6.5.3.4 Replacement of Dunedin Street Lighting Ripple Control Receivers

Aurora owns 2187 ripple control relays that are used to switch street lighting circuits. These relays need to be changed from 1050Hz units to 317HZ units to facilitate the decommissioning of the 1050Hz injectors. The actual replacement program has yet to be finalised but an allowance of \$80,000 per year for five years has been made for the conversion work.

Estimated Cost \$80,000 per
year for 5 years

Timing: 2012 to 2016

7 Risk Management, Business Continuity and Emergency Response Planning

7.1 Risk Management Framework

Delta has recently undertaken a review of its risk management philosophy, framework and approach as part of a Risk and Business Continuity Project. The outputs from this are being considered with the intention to introduce more robust risk management objectives, processes and systems and subsequently identify and target areas for improvement. The approach to this is based on the AS/NZ ISO 31000:2009 Risk Management Standard and the adoption of a new Risk Management Framework and Guidelines for Delta is a priority outcome.

The initial focus will be to provide more clarity around the corporate Risk Management Policy and Framework in order to ensure a more consistent, integrated approach to the assessment, treatment, monitoring and review of actual and potential events that could:

- influence the attainment of Delta's objectives (objectives can be at any level of the company being: strategic, operational, project, asset); or
- enhance, delay, hinder or prevent the delivery of services provide by both Delta and Aurora.

Delta's intention is that the new corporate Risk Management Policy and Framework will provide the over-arching structure that will cascade into the management of risks each of at these levels. Business Continuity planning and preparedness is an important element that Delta is also developing as part of the risk management project. Target date for project delivery is September 2012.

7.2 Management Policy and Risks

Delta's current risk management policy 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. It is intended that this policy will be reviewed as part of the work undertaken through the risk management framework improvements outlined above; with any subsequent updates or changes rolled-out as part of an improvement programme.

Overall, Aurora manages risks imposed by technological change, economic alternatives, load changes, distributed generation, and the environment. The main risks currently associated with Aurora's assets are described below in sub-sections 7.2.2 – 7.2.7. As part of the improvements to risk management outlined in the previous section, further focus will be placed on considering and understanding other risk categories such as strategic, political, regulatory/compliance, financial, process, people, information and service-related risks. Further rigour is currently being applied to assessing and understanding critical assets and the risk profile of the distributed electricity network. This information will form the basis of a risk-based approach to asset management and subsequent capital, renewal and operational investment requirements.

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
Information systems	Financial systems	<ul style="list-style-type: none"> Delegations Authorities Policy
	Archives	<ul style="list-style-type: none"> Company Filing Policy
	Filing system	

Generic Risk Area	Sub-Category	Policy Reference
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**7.2.1 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

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.

7.2.2 Network Capacity (i.e. 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 has increased 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.

7.2.3 **Network Reliability** (i.e. continuity of service)

Reliability is a function of:

- equipment duplication, which either avoids an interruption or shortens restoration times (i.e. 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.

7.2.4 **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.

7.2.5 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.

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.

In 2010, new safety regulations came into force which introduced new standards for public safety management systems to prevent harm to people and property from electricity and gas supply systems. In response to this, a Public Safety Management System has been developed and implemented, which provides a framework to:

- report and fix any potential hazards from electricity and gas equipment;
- maintain a hazards register;
- undertake regular audits to confirm compliance with the safety legislation.

Anyone who identifies a potential hazard must report it via existing safety systems. The safety page on Aurora Energy's website (www.auroraenergy.co.nz) can also be used by contractors and the public to report potential hazards.

7.2.6 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. It is noted 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.

7.2.7 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.
- November 2011. A review of asset management processes against PAS55 standards and IIMM guidelines.

7.3 Emergency Response and Contingency Plans

7.3.1 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.

7.3.2 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.

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.

7.3.3 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 quality control documents QP1601, QP1602, QP1603, QP1604, QP1605, QP1606, QP1607 and QP1609.

7.3.4 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. Reviews of how well the plans worked during major events have been completed within the last 2 years.

In addition to this, Aurora was one of the first two distributors to have its Participant Outage Plan approved by the Electricity Commission in 2009. 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	10-11 Target	10-11 Actual
SAIDI	Minutes	Minutes
Unplanned		
Underlying	61	94.6
Significant events	10	0.0
Planned	15	16.9
Aurora subtotal	86	111.5
Transpower	0	0.0
SAIDI grand total	86	111.5
SAIFI	Interruptions	Interruptions
Unplanned by Aurora	1.29	1.48

Table 8-1 - Target v Actual SAIDI and SAIFI 2010-2011

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 33.6 minutes above target. While there were no significant, (significant being defined as over 300,000 customer minutes), there were a number of weather events on Aurora's network resulting in vegetation contact with overhead lines and overhead line failures. Also there were no Transpower initiated event.

Planned interruptions were 1.9 minutes above the 20010-11 target figures. 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 2010 to 31 March 2011 was 10.8, which is an increase from 9.1 the previous year. Note that the forecast for 2011 – 2012 year is 10.5.

8.1.3 Low Voltage Complaints

Twenty nine valid voltage complaints were received for the year 1 April 2010 to 31 March 2011. 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 2010 to 31 March 2011.

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 8-2, below:

Category	2010/11 Actual \$000	2010/11 Budget \$000	Variance	
			\$000	%
Routine and Preventative Maintenance	2,523	2,265	258	11.4
Refurbishment and Renewal Maintenance	1,220	1,233	-13	-1.1
Fault and Emergency Maintenance	3,291	3,363	-72	-2.1
Total	7,034	6,861	173	8.0

Table 8-2 – 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 8-3.

Category	2010/11 Actual	2010/11 Budget	Variance	
	(\$000)	(\$000)	(\$000)	%
Customer Connection	4,726	5,400	-674	-12.5
System Growth	6,304	5,240	1,064	20.3
Asset Replacement and Renewal	7,832	12,000	-4,168	-34.7
Reliability, Safety and Environment	1,836	1,900	-64	-3.4
Asset Relocations	1,158	500	658	131.6
Total	21,856	25,040	-3,184	-12.7

Table 8-3 – Comparison of Actual Capital Expenditure with Plan

The causes of variances are:

- Customer connections work, which is consumer initiated, fell below budget as the finance crisis stymied virtually all new development work.
- System growth was above forecast due to the late commissioning of the Cardrona zone substation and subtransmission lines (\$0.7 million); final drainage works completion at Cardrona substation and above budget expenditure on localised growth projects.
- Asset replacement and renewal – is below budget due to completion of the Frankton zone substation upgrade falling across two financial years (\$1.7 million), and under budget expenditure on Dunedin undergrounding projects (\$1.0 million), ripple plant upgrades (\$0.7 million) and timing of localised renewal projects (\$0.8 million).
- 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.

Table 8 shows the major Aurora works items under construction as at 31 March 2011

Item	Value (\$000)	Status
Frankton substation upgrade	4,960	Substation lived, civil works for RMA compliance remain

Table 8-4 – Projects Under Construction

8.3 Gap Analysis and Identification of Improvement Initiatives

Various improvements have been identified within this AMP and subsequently programmed via capital and operational expenditures. Data management and utilisation improvement initiatives as well as development and implementation of a specific asset management system aim to improve current asset management capabilities, processes and the technological tools that support these.

Delta's Asset Management team carried out an initial gap analysis in November 2011 with reference to the PAS 55 standard as well as the IIMM guidelines. This provided an initial high-level identification of 6 key priority areas of focus, which are currently being worked on within an improvement plan. Reporting against this improvement plan will be incorporated in this section in future AMPs.

More specifically, recently identified improvements have included SCADA improvements to the Central network; and data quality improvements to GIS records, when economic to do so (this is on-going).

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;
- considering non-withdrawal 11kv switchgear which is smaller, requires less maintenance and easier to operate.
- 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 2021/22, 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 2010/11 to 2020/21	Actual 20010/11
Supply quality	No of proven voltage complaints per 10,000 consumers	10	4
Operating efficiency	Losses	6%	6.2%
Operating efficiency	Faults per 100 km line	10.5	10.8
Operating efficiency	Distribution transformer utilisation - kVA capacity per peak demand kW	30%	31.2%
Operating efficiency	Load factor - network input GWh / peak MW hours per year	52%	55%
Environmental effectiveness	Incidents of contaminant spill from network	0	compliant
Safety	Staff and contractors serious harm incidents	0	1
Safety	Public injury incidents	0	0

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
	2010/11	16.9	94.6	111.5	-	-	-	111.5
Target	2011/12	14.0	70.0	84.0	-	-	-	84.0
	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	65.0	78.0	-	-	-	79.0
	2019/20	13.0	65.0	78.0				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
	2010/11	0.14	1.48	1.62	-	-	-	1.62
Target	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	1.19	1.30	-	-	-	1.31
	2019/20	0.11	1.19	1.30				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
	2010/11	144.5	69.5	75.5	-	-	-	60.3
Target	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) <ul style="list-style-type: none"> (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 <ul style="list-style-type: none"> (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 <ul style="list-style-type: none"> (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.