
Asset Management Plan

APRIL 2014 – MARCH 2024

Asset Management Plan No. 21

A 10 Year Management Plan for Aurora Energy Limited

From 1 April 2014 to 31 March 2024

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**Plan prepared for Aurora Energy Ltd
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This issue approved by Aurora Board of Directors

March 2014

TABLE OF CONTENTS

1	Executive Summary.....	1
1.1	Background and Objectives.....	1
1.2	Service Levels and Performance	5
1.3	Risk Management.....	7
1.4	Lifecycle Asset Management.....	8
1.5	Network Development.....	9
1.6	Operational Context.....	10
1.7	Financials.....	10
1.8	Improvement Planning.....	11
2	Background and Objectives.....	13
2.1	Business Activity, Goals & Objectives.....	13
2.2	Purpose of AMP.....	13
2.3	Accountabilities, Responsibilities and Stakeholder Interests.....	15
2.4	Asset Management Drivers and Planning Assumptions.....	18
2.5	Asset Management Policy and Process.....	24
2.6	Asset Management Systems and Information	24
3	Service Levels and Performance.....	30
3.1	Consumer Consultation.....	31
3.2	Evaluation of Performance.....	35
3.3	Service Level Targets & Justification	47
3.4	Capability to Deliver	49
4	Risk Management.....	50
4.1	Introduction	50
4.2	Context.....	50
4.3	Responsibilities for Risk Management	50
4.4	Risk Process & Methodology.....	52
4.5	Network Risks.....	54
4.6	Business Risks.....	61
4.7	Risk Mitigation.....	64
5	Life Cycle Asset Management	68
5.1	Introduction	68
5.2	Network Overview	68
5.3	Asset Details by Category.....	78
5.4	Lifecycle Policies and Strategies.....	79
5.5	Lifecycle Asset Management Strategies.....	82

5.6	Operations & Maintenance Forecasts.....	117
6	Network Development.....	120
6.1	Introduction	120
6.2	Planning Criteria	122
6.3	Growth and Demand Forecasting	127
6.4	Project Prioritisation	129
6.5	Growth and Demand Predictions.....	130
6.6	Network Development.....	150
6.7	Capital Expenditure Forecasts.....	166
7	Improvement Planning & Programme.....	167
7.1	Introduction	167
7.2	Gap Analysis	167
7.3	Asset Management Maturity Assessment Results.....	168
7.4	Improvement Programme.....	171
	Glossary of Terms.....	174
	Appendix A - Table of Guidelines for Security of Supply	175
	Appendix B - Compliance Matrix	177
	Appendix C - Asset Management quality control documentation	179
	Appendix D – Network Development project list	181

1 Executive Summary

1.1 Background and Objectives

1.1.1 Key Business Activity, Goals & Objectives

Aurora's key business activity is the management and delivery of electricity to approximately 82,908 consumers within Dunedin and Central Otago. To do this, Aurora manages and maintains a range of assets including 513km of sub-transmission lines, 53,700 poles, 36 zone substations, over 2300km of high voltage line, nearly 800km of high voltage cable, approximately 6650 distribution transformers and 1810km of low voltage distribution, plus a variety of other electrical infrastructure including street lighting. Together, these assets have a total replacement cost of approximately \$670M. The map below illustrates Aurora's network boundaries compared to the other electricity distribution businesses (EDB's) in New Zealand.

Aurora's vision is to provide a network that meets the community's needs for reliable energy and shareholder requirements for adequate returns through targeted reinvestment, best practice asset management and tailored innovation.

To achieve this, our objectives focus on managing our assets prudently 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. Our service objectives are therefore based on eight key principles or 'service attributes', being: Safety, Reliability, Quality, Responsiveness, Efficiency, Compliance and Financial sustainability; underpinned by Continuous Improvement.



Source: This map contains Critchlow Limited copyright data.

1.1.2 Purpose of AMP

Aurora faces many challenges and issues when trying to achieve key activity objectives and must do so whilst also ensuring the interests and expectations of stakeholders are met alongside regulatory compliance requirements. We continually work to find the most appropriate balance between performance, risk and cost over the life-time of assets managed. Aurora's Asset Management Plan (AMP) documents this approach by outlining the asset management processes and practices used to develop optimised lifecycle management strategies.

Our AMP is therefore a vital component of our planning process that demonstrates how we address multivariate requirements by integrating management, financial and technical practices to deliver the strategies and initiatives planned for our electricity assets.

This AMP demonstrates how Aurora intends to meet key goals and objectives, looking ahead 10 years from April 2014. Mandatory information disclosure requirements, as determined by the Commerce Commission, are also incorporated into the structure and content of this AMP.

1.1.3 Stakeholders

Aurora recognises that a key asset management function is to understand who our stakeholders are, what they value and why. This information helps to determine the Levels of Service (LoS) stakeholders require (or expect) and associated willingness to pay.

Our key stakeholders are:

- Customers and Consumers
- Shareholder - Dunedin City Holdings Ltd.
- Employees
- Board Members
- Retailers
- Distributed Generators
- Contractors
- Government Agencies; Commerce Commission
- Transpower
- General Public
- Other stakeholders (developers, landowners, property investors)

We have identified our stakeholder interests through communication relating to contractual arrangements, use-of-system agreements, submissions, surveys, and board meetings. These interests are considered as part of our assessment of asset management drivers and accommodated through our asset management strategies where appropriate.

If a specific conflict between stakeholder interests is identified then we will adopt an appropriate conflict resolution process to suit the issue and stakeholder concerns.

A review of stakeholder needs and values commenced in 2013 and will continue over the coming year in order to ensure that our service levels and performance targets are still appropriate and align with the expectations for the services being delivered.

1.1.4 Asset Management Drivers and Planning Assumptions

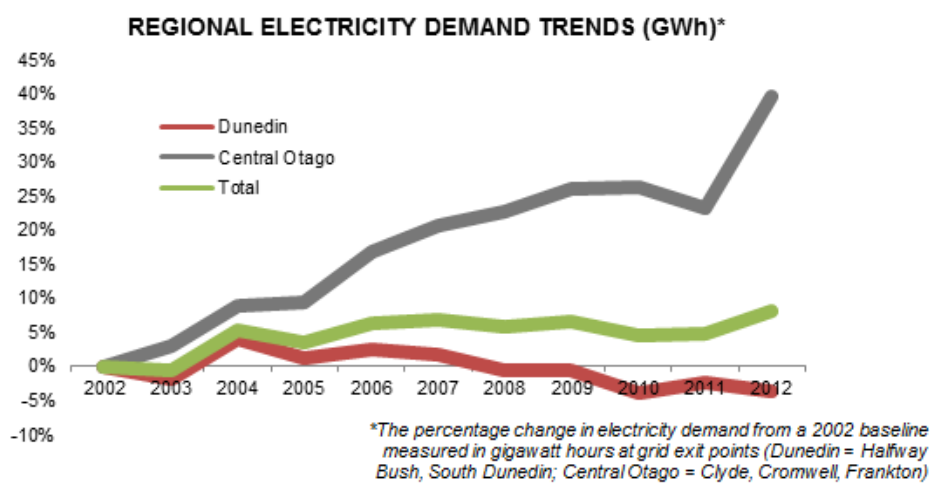
Aurora faces some potentially challenging issues in both the short and long term that may impact on key activities and functions. These issues represent challenges and policy choices that must be addressed in order for the activity to achieve its key objectives. These challenges manifest themselves through a variety of external and internal drivers that can be grouped as follows:

- Stakeholder Expectations
- Standards and Legislation
- Industry Structure and Governance
- Environmental Issues and Natural Hazards
- Affordability and Financial Sustainability
- Population and Demand Trends
- Ageing Infrastructure
- Alternative Energy Sources / Distributed Generation
- Technology

Managing the impact of rapid growth in irrigation demand (through conversion of land for dairying) in Central Otago is a key focus for Aurora over the next 5 – 10 years, particularly as actual and anecdotal evidence indicates rapid progress in such developments. It is currently assumed that access to water resources will not be a disabling factor in the continued conversion of land for dairying in the short-medium term within the Central Otago region. However, such assumptions will be reviewed by Aurora as and when necessary.

Overall, our planning assumptions acknowledge the aging network in Dunedin and the growth patterns in Central Otago. It is assumed that Dunedin's growth is likely to remain relatively static and that growth in Central is likely to continue; but that the primary driver for this growth in some parts will be through meeting irrigation needs (as outlined above) as opposed to residential development (see graph below).

These circumstances present challenges specific to each network and may include the potential for stranded infrastructure, limitations on affordability of service improvements, and increasing maintenance requirements for the existing infrastructure.



Aurora is equally cognisant of the potential impact that climate change may have on weather patterns and the risks these may pose to network reliability and operability; as such, these aspects are considered as part of the network development planning process. It is also assumed that the push for affordability and financial sustainability will continue. For Aurora, this means that optimisation is a critical consideration towards maintaining the levels of service we are committed to meeting within current budget.

Our shareholder, Dunedin City Holdings Limited, expects Aurora to achieve the economic, social and cultural objectives specified in our Statement of Intent, with financial strength and sustainability being key. Our consumers consider that price (cost) is more important than quality, but do not want to pay less if it means impacting upon quality (e.g. more interruptions). Our regulators require more transparency in how we manage our business and our contractors seek surety with respect to continuity of work. Territorial authorities want to ensure communities of business continuity during times of civil emergency and seek evidence that our knowledge and management of network risk for lifelines planning is robust. Our relationship with Transpower is an important aspect of this as is coordination of network development programmes. Regular and timely communication underpins all of the above.

Aurora is subject to increasing downward pressure from industry regulations and prevailing economic conditions. While the regulatory landscape appears to be settling after a number of years of development, there remains an element of uncertainty associated with the next regulatory period reset in 2015.

Over the coming year, we will continue to build on the work that has commenced for network risk and criticality alongside the current decision-making criteria, assumptions and prioritisation

methodology in order to provide greater transparency on decisions relating to network development projects.

1.1.5 Accountabilities & Responsibilities

Aurora must address a variety of expectations whilst also ensuring budgets and timeframes are met. To do this, Aurora ensures a robust management framework is in place for those accountable and responsible for asset management, ranging from General Managers through to Contracting Teams. Aurora has contracted asset management to Delta under a performance-related contract. Under this contract, Delta is required to meet defined 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. Overall management of Aurora's network assets is undertaken at the Dunedin and Cromwell offices. Ultimately, Aurora's Board of Directors is the overall body responsible for decision-making within the company. The asset management structure for our electricity assets is illustrated in Figure 2.3.

1.1.6 Asset Management Policy and Process

Aurora's asset management policy recognises that effective asset management requires a practical balance between performance, risk and cost throughout the lifecycle of all assets; as well as ensuring continuous improvement in asset management functions and capabilities to achieve key outcomes and objectives.

Aurora's asset management practices are driven by commitments to Safety, Reliability, Quality, Responsiveness, Efficiency, Compliance and Financial sustainability; underpinned by Continuous Improvement. Our integrated approach to asset management is illustrated in Figure 2.4.

We are committed to achieving alignment with best practice asset management that is fit-for-purpose and will implement appropriate asset management systems to govern the planning, investment, operation, maintenance and disposal of assets.

A robust risk framework will be used to identify and manage our risks and we will continue to improve the information we have on our assets in order to improve the planning and prioritisation of investment. In conjunction with this, Aurora will work to ensure that associated funding requirements are well planned, based on reliable information, with the impact of costs spread evenly over time. The importance of people and process cannot be understated and Aurora recognises that investment in training and development is critical to achieving business objectives.

1.1.7 Asset Management Systems and Information

Several systems and processes contribute to the management of Aurora's assets for network planning, maintenance programming, operational requirements, financial monitoring and performance measurement. These include GIS, SCADA, SAP, and Gentrack.

In 2012, Aurora commenced a review of the master asset data within the GIS along with review of the practices associated with the management and maintenance of the data. This continued in 2013 and as a result, various changes to process and practice has occurred to ensure the asset records are more complete and accurate.

Notwithstanding the good progress being made to improve the completeness and confidence in asset data, Aurora faces challenges in the areas of asset and works management. Many of the current asset management business processes and systems are supported by manual, paper-based environments. These provide barriers to both the efficient capture of data and the easy access to and processing of relevant data to create business intelligence and knowledge.

Developments in the information, communication and technology sector (ICT) provide opportunity for Aurora to consider introduction of increased levels of intelligence and performance. Emergent and proven technologies, coupled with decreasing relative technology costs, provide economically viable opportunities to better enable and support more efficient and effective asset management. Smart, easy to use and cost effective solutions will be tested in terms of their ability to enable and support. See Section 7 for further detail on improvements in this area for Aurora.

1.2 Service Levels and Performance

Aurora's levels of service have been developed in response to the asset management drivers outlined in the previous sections, as well as evaluation of past performance. Aurora monitors performance and measures success against specific targets for each of the service levels outlined on the Table on the following page.

Aurora's performance for 2012/13

The table on the following page shows Aurora's service levels, associated measures, targets and results for 2012/2013 as well as targets for 2013/14 and the 5 year average forecast.

For 2012/13, Aurora has complied with nearly all of its performance targets. In summary:

Service Level	Result against Target
Safety	Compliant
Environmental	Compliant
SAIDI and SAIFI (unplanned)	Compliant
SAIDI (planned)	Non-compliant
Faults (overhead network)	Non-compliant
Faults (underground network)	Non-compliant (minor)
Responsiveness	Compliant
Efficiency	Compliant

Service Criteria	Performance Indicator	Target	Actual	Targets	Avg Annual
		(2012/13)	(2012/13)	(2013/14)	(2014-2018)
Safety					
Safety of public	No. of incidents per year	0	0	0	0
Safety of personnel	No. of incidents per year	0	0	0	0
Safety of network assets	Compliance with standards	Compliance	C	Compliance	Compliance
Reliability / Quality					
Network Reliability	SAIDI (Planned)	14.0	21.8	14.0	13.6
	SAIDI (Unplanned)	70.0	53.8	70.0	68.4
	TOTAL	84.0	75.6	84.0	82.0
	SAIFI (Unplanned)	1.27	0.93	1.27	1.24
Faults per 100 km HV	No. per year	10.5	11.3	10.5	10.4
Faults per 100 km HV UG	No. per year	2.5	2.53	2.5	2.5
Faults per 100 km HV OH	No. per year	13.5	18.35	13.5	13.5
Customer Complaints	No of proven voltage complaints per 10,000 consumers per year	<10	4.0	<10	<10
Network Restoration	CAIDI (unplanned)	55	72	55	55
Responsiveness					
Restore supply following general network	Within 4 hours of notification (Dunedin)	<4hrs	80%	<4hrs	<4hrs
	Within 4 hours of notification in urban areas (Central)	<4hrs	restoration within 3 hours	<4hrs	<4hrs
	Within 6 hours of notification in rural areas (Central)	<6hrs		<6hrs	<6hrs
		Valid claims	Valid claims	Valid claims	Valid claims
Response to customer enquiries	Within 7 days Aurora will investigate and respond in detail or advise when a final response can be	0	0	0	0
Response to power quality or voltage	Within 7 days Aurora will investigate and respond in detail or advise when a final response can be	0	0	0	0
Notification of planned service interruption	Missing notification of planned interruption	0	1	0	0
Efficiency					
Load factor (%)	Energy into network/peak kW hours per year	54%	53%	54%	54%
Loss ratio (%)	Energy into network less energy delivered / energy into network	6%	5.6%	6%	6%
Capacity utilisation (%)	Peak network kW / installed distribution transformer capacity kVA	30%	34.5%	30%	30%
Environmental / Compliance					
SF6	No. of incidents per year	0	1	0	0
PCBs	No. of incidents per year	0	0	0	0
Oil spills	No. of incidents per year	0	0	0	0
Continuous Improvement					
Enhance core AM processes and systems	Average AMMAT Score			3	

Results indicate:

- A marked improvement in reliability, with a significant decrease in unplanned SAIDI and SAIFI for 2012/13 compared to previous years.
- Non-compliance with AMP performance targets occurred in SAIDI (planned)¹ and overhead network faults.
- Underground network faults were slightly above the target level and a marginally increasing trend over last 5 years seems apparent.
- Excluding planned shutdowns, the main causes of outages were due to vegetation, equipment deterioration, and third party interference.

¹ SAIDI – System Average Interruption Duration Index; SAIFI – System Average Interruption Frequency Index; CAIDI – Customer Average Interruption Duration Index.

- Of the 357 unplanned interruptions on the network in 2012/13, approximately 80% were restored within 3 hours. This is a higher rate of response compared to the previous year (73%).
- The number of proven voltage complaints has continuously complied with target levels, and displayed a notable decrease in 2012/13 compared to previous years.
- Safety and Environmental Compliance targets were met.

An independent review of Aurora's network over the 2010-2012 period was also carried out by Strata Consulting on behalf of the Commerce Commission, in response to Aurora's breach of the SAIDI boundary levels in 2010/11 and 2011/12. Some of the main findings included the need for more focus on vegetation management, collection and use of asset condition data and more targeted investment programmes.

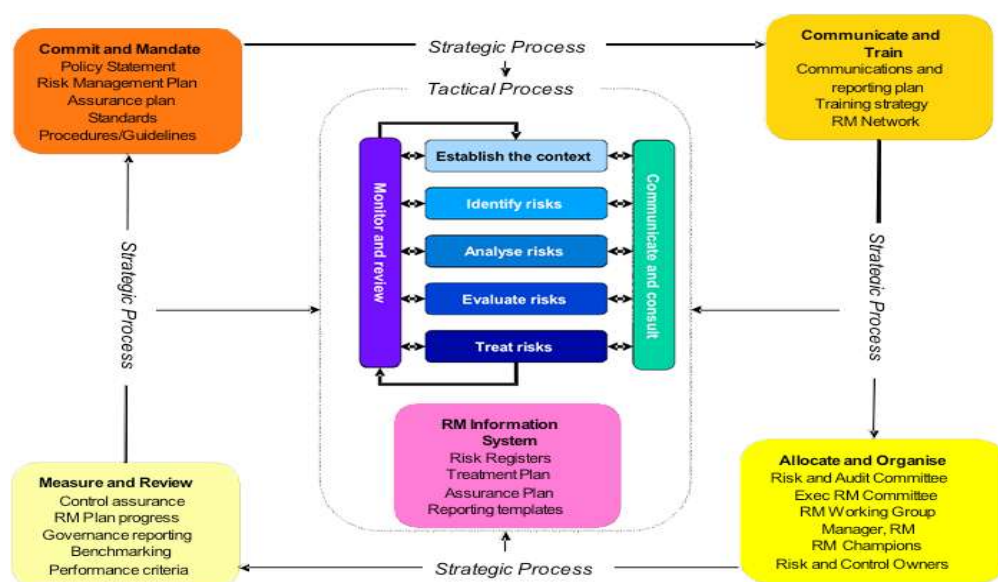
The development of a vegetation management plan as well as a review of the strategy for the subtransmission network was also recommended. These items have been incorporated into the Asset Management Improvement Programme (see Section 7 for further detail on this)

Further discussion on Aurora's performance and recommendations from the Strata review is contained within Section 3.2. A benchmark comparison with the industry is also included.

1.3 Risk Management

Aurora recognises risk management and asset management are inextricably linked. The risk management framework and practice being applied by Aurora is based on the AS/NZS ISO 31000:2009 risk management standard. The following diagram illustrates the risk management framework and process being applied.

Risks to Aurora are linked to safety (staff, contractors, public), reliability, quality, natural hazards, compliance, commercial, reputation, resources and so on. Aurora refers to the 'four R's approach - Reduction, Readiness, Response and Recovery – to assist with business continuity planning and manage network resilience.



This AMP identifies the main network and business risks for Aurora and the actions being taken to address these. These both inform (and are informed by) Aurora's approach to life-cycle management and network development.

Some of the main areas of focus are:

Network Reliability & Compliance - Poles & Vegetation

Wooden poles have been identified as a priority area. In particular, the number of condition 0 poles (poor condition) on the network is a concern for Aurora and focus is being placed on addressing this risk through a project to improve the quality of condition data. This will, in-turn, assist with targeted and prioritised renewal programmes.

Risks relating to network reliability and legislative compliance are also directing focus towards better vegetation management. Under the Electricity (Hazard from Trees) Regulations 2003, Aurora must attend to the vegetation with a rating of 0 (bad) without delay. There are currently over 5400 'Condition 0' areas that require cutting.

A significant portion of Aurora's planned maintenance budget has been spent on vegetation management annually to date. It has been difficult to assess the impacts of the current vegetation programmes on network reliability. This is the subject of ongoing analysis.

Age and obsolescence-related risks

Risks relating to age and obsolescence have driven a thorough review of Aurora's SCADA, control, communication and protection systems. A long term programme of required works has been developed and incorporated into this AMP. Other assets posing age-related risks include cast-iron potheads, Andelect fuses, oil-filled distribution switchgear and gas-filled sub transmission cables.

Capacity

Risks relating to capacity in the short-to-medium term (based on predicted demands against firm load capacity) are associated with the Cromwell, Frankton and Halfway Bush Grid Exit Point (GXP) supply areas. Of particular focus for Aurora is the Upper Clutha Valley sub-transmission network, within the Cromwell GXP area.

Fire, security, earthquake and asbestos risk (zone substation buildings)

Risks relating to safety and hazards - in response to recommendations from the Royal Commission for changes to the building legislation, more comprehensive assessments of fire, security and earthquake risk for all of Aurora's zone substation buildings are being carried out. Outputs from this will contribute to the development of a long term programme of works, which will be incorporated into Aurora's 2014/15 AMP. In addition, there is a potential asbestos risk within at least one of Dunedin's substation buildings and this will be addressed in 2014/15. Some provision has been made in the capital programme to mitigate this risk, however further investigations may reveal risks at other sites.

Further detail on the projects underway to address risk is outlined in the lifecycle and network development sections of this plan.

1.4 Lifecycle Asset Management

The life cycle management section of this AMP supplements the network development plan. It details the actions and expenditure necessary for maintaining and operating Auroras assets, covering planned maintenance, reactive maintenance, renewal and capital replacement. Planned maintenance is time and condition-based; reactive maintenance covers fault and emergency situations and replacement (upgrade or renewal) occurs when maintenance is no longer cost-effective or other drivers (e.g. system growth) warrant new investment in the network.

For 2014/15, Aurora will continue with the work that has commenced on reviewing and revising asset management strategies and plans to address some of the risks identified. Attention will be given to transformers, switchgear, poles, cables and link boxes amongst others.

Vegetation management is also a key issue for Aurora and we will continue to work with our contractors to find the most effective way to manage process and costs.

Aging assets are of particular concern in the Dunedin network, with some assets being over 100 years old and many assets between 60-80 years; as such, focus is also being placed on refining

renewals forecasts to determine the level of funding required versus that which is practically sustainable over the long term.

While parts of the central network are also aging, one of the main issues for Aurora in this area is ensuring our network policies and practices are adhered to by external contractors working on the network, recognising that workmanship and installation can significantly impact the lifecycle costs of our assets. This includes addressing the need for standardisation across assets and designs to promote efficiency and minimise risk. Managing the impact of rapid growth in irrigation demand in Central Otago is a key focus for Aurora over the next 5 – 10 years.

The table below summarises the value of Aurora's assets by category (based on the information provided for the Electricity Distribution (Information Disclosure) Requirements). Information on asset quantities and their general condition is detailed further in Section 5.

Asset Category	RC (\$000's)	% by \$
Subtransmission	\$ 56,195	8.4%
Zone substations	\$ 118,944	17.7%
Distribution and LV lines	\$ 135,505	20.2%
Distribution and LV cables	\$ 227,145	33.9%
Distribution substations and transformers	\$ 87,150	13.0%
Distribution switchgear	\$ 42,733	6.4%
Other	\$ 2,712	0.4%
Total (rounded)	\$ 670,384	100%

1.5 Network Development

Aurora recognises that expenditure can be driven by a variety of factors and we are committed to continually improving our understanding of the strategic and operational challenges that drive investment needs. The network development plan provided in this AMP outlines the investment required to maintain, enhance and develop the operating capability of Aurora's system. It details the expansion and upgrades considered necessary to accommodate predicted future network loading; and the projects required to address risk, reliability, safety and compliance.

A range of factors are used to assess the viability of development projects, including (but not limited to) compliance with safety design standards, security of supply, quality, capacity, economic and financial criteria. Prioritisation of programmes and projects is linked to Aurora's key activity objectives and associated service level attributes.

Major projects over the planning period include several substation upgrades in both Dunedin and Central. Significant investment is also being made in Dunedin's sub-transmission network over the next 10 years, with six sets of 33kV underground cables being replaced at an estimated cost of over \$17 million dollars.

Demand for irrigation in Central Otago is influencing load on the network and significant investment will be required if high potential growth scenarios become reality. A significant amount of time has already been spent on scoping a variety of options to ensure system growth can be catered for in this area.

Section 6 provides further detail on demand projections, future capacity and network development. Related forecast information is also provided on Aurora's website within the Information Disclosure report.

1.6 Operational Context

Analysis of trends for cost and reliability performance over the period 2008-2011 has recently been undertaken by the Commerce Commission for all 29 electricity distribution businesses within New Zealand. A summary of Aurora's performance relative to the industry average, measured across a range of activities, is provided in the table below.

This suggests that Aurora has managed its business over the recent past to hold both revenues and cost increases below industry average levels, however reliability breaches have occurred within this timeframe. Vegetation impacts and failures of specific types of equipment are considered to be the main causes.

For Aurora, capital expenditure is forecast to increase in order to target climbing asset replacement and renewal needs (particularly SCADA and communications) as well as responding to system growth (irrigation); with increased operational expenditure also reflecting age-related demands of the network as well as vegetation management imperatives. Forecast expenditure is summarised in the next section and detailed further in Sections 5 and 6.

Commerce Commission Review 2008 – 2011

Revenue, Expenditure and Reliability	Aurora	Average Industry
Revenue received from customers	3% increase	8% increase
Average unit price paid by small/residential customers	5% increase	8% increase
Operating Expenditure	1% decrease	2% increase
Capital Expenditure (avg unit capital expenditure*)	As per industry average	Stable/flat
Recent Reliability Trends	Although Aurora breached regulatory limits, the average duration and frequency of interruptions was below the industry average over this period	

*CAPEX per customer; CAPEX per MWh; CAPEX per \$ of RAB

1.7 Financials

A summary of our forecast capital and operational/maintenance expenditure is shown below. Detail behind the drivers for this expenditure is provided in Sections 5 and 6. Changes from previous forecasts are further detailed within this plan and comments are provided on the variance between actual spend against budget for the 2012/13 year. Aurora's website contains further information on forecast expenditure in the Information Disclosure Schedules.

\$'000	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24
O & M Expenditure	13,376	12,314	12,131	12,515	12,106	11,518	11,803	12,133	12,556	11,889
Capital Expenditure	32,898	34,584	24,219	22,878	24,598	19,523	21,838	19,133	18,883	17,533
TOTAL	46,274	46,898	36,350	35,393	36,704	31,041	33,641	31,266	31,439	29,422

1.8 Improvement Planning

Aurora recognises that asset management is as much about people and process as it is about investment in the network for physical asset improvements. It is important for Aurora to ensure that asset management practice is aligned with best practice and is always 'forward-looking' when it comes to improvement in practices and standards. To this end, an Asset Management Improvement Programme (AMIP) is underway.

Overall, the improvement programme covers 'process', 'people' and 'metric' aspects based on the Commerce Commission's assessment framework (Asset Management Maturity Assessment Tool or AMMAT). 'Process and people' improvements relate to how Aurora carries out asset management across the range of functional areas, plus the associated capabilities and competencies for achieving asset management objectives. 'Metric' improvements relate specifically to achievement of service levels (asset and customer) and performance targets.

The graph following shows the maturity assessment results to date. This illustrates there have been steady improvements made across all aspects of Aurora's asset management since the initial baseline assessment was carried out in 2011.

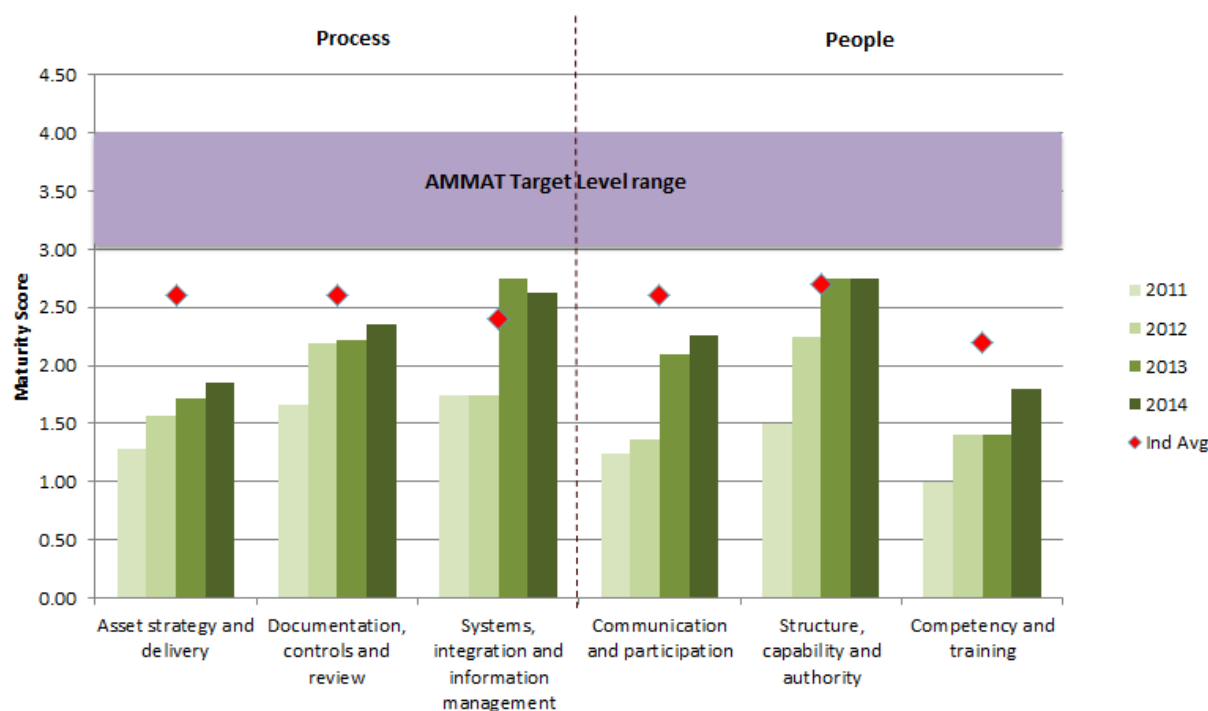
The areas that will continue to receive attention in 2014/15 are listed below. It is acknowledged that some of these still include the areas that have seen improvement in 2013/14 as they are still below the target level of practice (3 - 4).

- competency and training
- asset systems and information
- asset strategy and delivery

Specifically, the aspects that require focus under the above areas include:

- performance and condition monitoring
- use/maintenance of asset risk information
- investigations (asset-related failures, incidents, non-conformities)

See Section 7 for further details.



Asset Management Maturity Assessment results (2011-2014)

The framework for this improvement programme was initially based on the internationally accepted PAS55 standards, utilising the International Infrastructure Management Manual (IIMM) as a guiding document. In January 2014, the new suite of asset management standards (ISO 55000, 55001, and 55002) was published by the International Standards Organisation. It is intended that the AMIP undergoes a review in 2014/15 against the new standards and is modified where necessary to ensure alignment.

2 Background and Objectives

2.1 Business Activity, Goals & Objectives

Aurora's key business activity is the management and delivery of electricity within two distinct networks in Dunedin and Central Otago; and a small area in Te Anau (see Figure 2.1). Aurora's electricity network begins downstream of Transpower's transmission Grid Exit Points (GXPs). The Dunedin network is supplied from two GXPs at South Dunedin and Halfway Bush. The Central network is supplied from three GXPs at Clyde, Cromwell and Frankton. Aurora also manages a small embedded network in Te Anau (connected to The Power Company network, installed in 2005).

Specifically, Aurora manages and maintains: 513km of sub-transmission lines, 53,700 poles, 36 zone substations, over 2300km of high voltage line, nearly 800km of high voltage cable, approximately 6650 distribution transformers and 1810km of low voltage distribution, plus a variety of other electrical infrastructure including street lighting. Together, these assets have a total replacement cost of approximately \$670M. This makes Aurora the 6th largest electricity distribution business (EDB) in New Zealand delivering over 1,300 GWh of electricity to homes and businesses annually, with a total of over 130MW of distributed generation connection to the network.

The objectives of Aurora's activity are to ensure that the supply 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 for the more than 82,000 consumers within Dunedin and Central Otago. Aurora must balance and align these with the principal corporate goal of operating a successful business to achieve the economic, social and cultural objectives outlined in the Statement of Intent.

This Asset Management Plan (AMP) sets out Aurora's framework for addressing these needs through a robust approach to asset management and subsequent service delivery.

2.2 Purpose of AMP

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

Overall, the AMP demonstrates adoption of an integrated framework for asset management which ensures that Aurora:

- understands the main external and internal drivers that influence asset management and planning;
- understands stakeholder interests; consumer needs and expectations;
- understands network performance i.e. what network capacity, reliability and security of supply is required, both now and in the future to meet service level targets;
- sets service levels that will meet asset performance requirements balanced with consumer, community and regulatory requirements;
- 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 robust and transparent processes in place for managing all phases of the network life cycle, with emphasis on optimising asset utilisation and performance;
- 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.

The main AMP objectives are shown in Table 2.1 along with comments on how the objectives translate into practice.

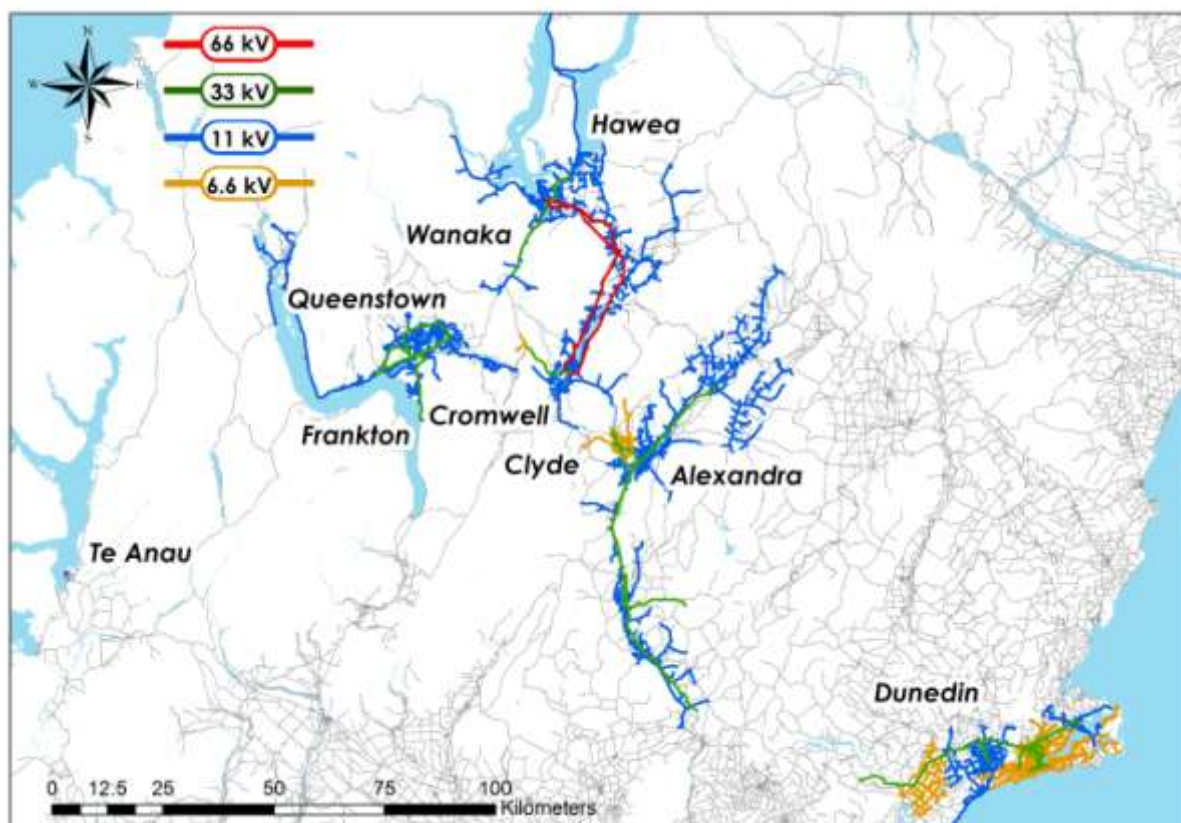


Figure 2.1 - The Aurora Network

Table 2.1 - AMP Objectives

Asset Management Plan objectives	What does it mean?
Defines: AM Objectives & Service levels to be provided. Targets/performance measures that Aurora aims to achieve & how service delivery will be monitored.	AM strategies & actions reflect the expectations of stakeholders, including customers. Progress will be tracked to determine if commitments are being achieved.
Translates: Strategic goals and <u>organisational</u> objectives into AM strategies and action plans	There is a link between corporate strategy and management of network assets
Describes: Planning assumptions and uncertainties. Risks associated with Aurora's network business. Risks of not meeting business and AM objectives.	Understand what network capacity, reliability and security of supply is required, both now and in the future, and what issues drive these requirements. Appropriate risk management practices form an integral part of normal business activities
Identifies: Forward works <u>programmes</u> required to: - meet agreed service levels, - address replacement/renewal needs, - cater for future growth, - address risk Cost estimates for delivering these <u>programmes</u> . Actions that enhance management performance & ensure continuous improvements.	That capital expenditure decisions are prudent and represent value to customers Asset replacement & network augmentation is undertaken with appropriate timing. Ensure that long-term functionality and value of assets is maintained. Operational efficiency and performance improvements.
Demonstrates: Responsible management of the network infrastructure. <u>That funds</u> are optimally applied to deliver cost-effective services that meet expectations.	AM strategies support revenue requirements and deliver a reasonable profit, in keeping with both shareholder expectations and regulatory constraints. An 'optimal life cycle' approach is taken to managing network assets.
Documents: Current AM practices used by Aurora re: policies, objectives, strategies, plans and systems adopted for the efficient management of its electricity distribution networks.	Decisions are made with systematic frameworks and guidelines. That robust and transparent processes in place for managing all phases of the network life cycle.
Achieves: Compliance with regulatory and legislative requirements Best practice asset management <i>(for the level of AM deemed appropriate for the <u>organisation</u>)</i> .	Electricity Distribution (Information Disclosure) Requirements 2012 are met. Best practice in managing the balance of performance, risk and cost is achieved. Established continuous improvement philosophy (process and people).

Corporate Business Processes and Asset Management Planning

Aurora's mission is to be the best performing infrastructure business in New Zealand. The Strategic Plan has identified asset management as a fundamental component for achieving the company's strategic objectives.

Figure 2.2 illustrates the cascade from Aurora's mission statement through to the AMP and provides context for how the different documented plans and business processes relate to one another and influence asset management, along with other external drivers such as the regulatory environment.



Figure 2.2 - Corporate Business Processes and Asset management Planning

2.3 Accountabilities, Responsibilities and Stakeholder Interests

2.3.1 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.

Delta has a dedicated Asset Management Business Unit, consisting of five core teams: Asset Management, Infrastructure Performance, Asset Systems, Delivery and Commercial; reporting to the General Manager, Asset Management. The General Manager, Asset Management reports to the Aurora board, along with the CEO. The Board reviews and authorises the AMP from which annual and 5 yearly budgets are set. Reports on significant projects are provided to the Board on a monthly basis, including regular reporting of KPI's and related asset management objectives.

Figure 2.3 details the accountabilities and responsibilities for asset management within the current 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 business unit. Table 2.2 provides more detail on actual responsibilities. Note that the current Aurora/Delta contract is undergoing a review in 2014.

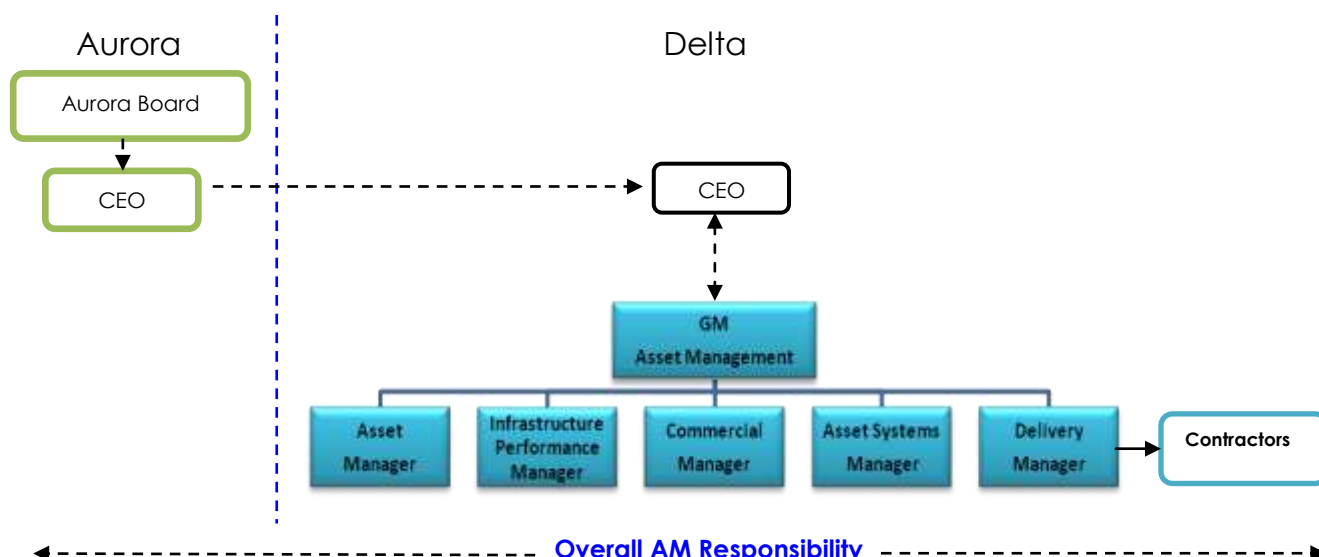


Figure 2.3 - Asset Management Accountabilities and Responsibilities

Table 2.2 - Delta's Accountabilities and Responsibilities for Asset Management

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	As and when necessary, external contractors and consultants are used for works associated with the annual operational, maintenance, capital replacement and network development programmes.

2.3.2 Stakeholder Interests

Aurora recognises that a key asset management function is to understand who our stakeholders are, what they value and why. Stakeholders are defined as groups or individuals with either a direct or indirect interest in Aurora's network asset management policies and practices. Table 2.3 summarises Aurora's main stakeholders and their interests. This table illustrates some of the issues Aurora takes into account, but is not exhaustive.

Where stakeholder conflict arises, Aurora applies certain criteria, with safety being the primary concern. Other criteria include: reliability/cost trade off, economic growth, environmental responsibility, legislative compliance. Ultimately, the Aurora Board will decide upon the most appropriate way to resolve any significant issue of conflict between stakeholder interests. Aurora also ensures alignment is maintained with Electricity and Gas Complaints Commission scheme requirements (see Section 3.1.4 for further detail).

It is clear that there are different service expectations across the range of Aurora's stakeholders. It is important for Aurora to have a clear understanding of these as they help to inform on the levels of service stakeholders require (or expect) and associated willingness to pay. Aurora uses surveys, open requests for feedback, safety reviews, industry forums and other means (such as internal review workshops) to identify interests. Also see Section 2.6.2 regarding communication and participation.

In addition to the above, a series of actions have commenced as part of Aurora's AMIP for reviewing Aurora's service levels. The intent of these actions is three-fold: (i) to evaluate current knowledge on Aurora's stakeholder base; (ii) review whether Aurora's service level commitments are still relevant and appropriate; and (iii) identify how Aurora may better communicate with all relevant parties in the future. This is to be supplemented with a concurrent review of service level performance measures and associated monitoring.

Table 2.3 – Stakeholder Interests

Stakeholder	Interest	How Stakeholder Interests are Identified
Shareholder	Adequate, stable, and secure return on investment Good corporate citizenship	Board meetings
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

Stakeholder	Interest	How Stakeholder Interests are Identified
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 / Regulator	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
Territorial authority	Minimising of environmental impacts (RMA) Local economic development Control of assets in road reserve Conversion of overhead to under-ground	Direct communication Submissions RMA Applications
NZ Transport Agency	Control of assets in road reserve Safety issues such as hedges on Aurora-owned land	Direct communication
Transpower	Reliability of supply Investment for growth	Direct communication re planning System operator communication
Media	News, background information	Direct communication

2.4 Asset Management Drivers and Planning Assumptions

Aurora faces some potentially challenging issues in both the short and long term that may impact on key activities and functions. These issues represent challenges and policy choices that must be addressed in order for the activity to achieve its key objectives. These challenges manifest themselves through a variety of external and internal drivers that influence Aurora's asset management practices, priorities and decision-making. These drivers are inextricably linked to principles defined in the Asset Management policy (see Section 2.5) and can be grouped under the following; and are discussed below.

- Stakeholder Expectations
- Standards and Legislation
- Industry Structure and Governance
- Environmental Issues and Natural Hazards
- Affordability and Financial Sustainability
- Population and Demand Trends
- Ageing Infrastructure
- Alternative Energy Sources / Distributed Generation
- Technology

Stakeholder Expectations

Heightened stakeholder awareness and service level expectations mean that better corporate responsibility is required for sustainably managing resources and monitoring impacts of Aurora's activities. Such interests may include increased expectations for the right to a quality service (timely, efficient, low-cost); less acceptance of anything otherwise (i.e. 'status-quo' is no longer considered as an acceptable option); and tension between affordability and service level expectations from different regions and also different sections of the community.

Given the above, Aurora is committed to providing a broad range of service levels for all stakeholders. These service levels cover aspects such as safety, capacity, continuity of supply, restoration of supply, efficiency, compliance and environmental responsibility. Stakeholder interests are accommodated by considering these within the decision-making framework for asset management investment and service delivery. Refer to Section 2.3.2 for further details on stakeholder interests.

Legislation and Standards

Aurora aims to achieve material compliance with all relevant legislation, regulations, standards and codes of practice that relate to how the electricity distribution network is managed and maintained, including any relevant environmental legislation. Associated documentation includes, but is not limited to:

- Electricity Act (1992)
- Electricity Industry Act (2010)
- Electricity (Safety) Regulations (2010)
- Electricity (Hazards from Trees) Regulations 2003
- Commerce Act (1986) (*incl Electricity Information Disclosure Requirements*)
- Civil Defence and Emergency Management Act (2002)
- Local Government Act (2002)
- Resource Management Act (1991)
- Building Act (2004)
- Public Works Act (1981)
- Health and Safety in Employment Act (1992)
- Health and Safety Regulations (various)
- NZ Electrical Codes of Practice

While the Commerce Commission has expressed an expectation of legislative stability for some years, there is significant legislative change in health and safety is imminent. The introduction of the Health and Safety at Work Bill has put more emphasis on Directors' and employees responsibilities, including penalties and requirements for increased staff involvement.

The regulatory workload, and therefore costs, is not likely to abate in the short term as the new rules are interpreted and applied. There is no foreseeable departure from the regulatory structure now in place. However, a change in government could result in structural change within the industry.

Central Government regularly amends or develops legislation, regulations, standards and policies. Examples include the Emissions Trading Scheme (ETS), Resource Management Act (RMA) and the Electricity Industry Act. Such reviews have either a direct or indirect effect on how Aurora may manage and maintain its electricity assets. For example, Central Governments' response to climate change may indirectly influence Aurora's network regarding the changing types and quantities of distributed generation² and recommendations from the Royal Commission report into earthquake-prone buildings and seismic strengthening are likely to lead to changes in building legislation. Such requirements are already driving the need for Aurora to allocate expenditure to its structural assets (e.g. zone substation buildings). Aurora must also comply with technical standards set by regulation,

² For example, the National Policy Statement for Renewable Electricity Generation (2011) contains provisions for small and community scale renewable electricity generation activities into Regional Policy Statements and Regional/District Plans.

such as minimum and maximum voltage set by regulation for the protection of consumer appliances.

At a regional and local level, Aurora's network spans three territorial authority areas, being: Dunedin City, Central Otago and Queenstown Lakes; contained within one regional authority boundary (Otago Regional Council). Council planning requirements set out minimum standards for local land use and development. In some cases these requirements impact on the location, appearance and housing of Aurora's above-ground assets; in other cases assets are required to be located underground.

Aurora also refers to local authority planning information on potential short, medium and long-term growth on the distribution network. Relevant aspects of this with respect to Aurora's development plan are discussed further in Section 6.

In 2013, Aurora commenced a scoping exercise into suitable district plan provisions to both protect Aurora's assets and to enable Aurora's activities. We have reviewed the three relevant district plans as well as the Otago Regional Policy Statement ("RPS"). It is our intention to maintain involvement in the plan review process that many Councils' are due to embark upon in order to ensure that Aurora's assets are appropriately represented and protected for the future.

Industry Structure and Governance

The structure of the New Zealand electricity sector has undergone significant reform over the last 10-20 years. Aurora is one of many local distribution companies towards the end of an industry 'chain', comprising of generators; a wholesale electricity market; transmission; electricity users and retailers. As such, Aurora is continually faced with the challenge of ensuring an appropriate balance between price and quality for electricity consumers, whilst restraining the impacts from any costs that may be passed on from the upstream aforementioned entities.

Aurora is subject to regulation under Part 4 of the Commerce Act 1986, for price-quality and information disclosure. Price-quality regulation is designed to ensure that EDBs have similar incentives and pressures to suppliers operating in competitive markets to innovate, invest and improve their efficiency. As such, Aurora is required to provide an audited self-assessment to the Commerce Commission against the DPP on an annual basis.

The key output for Aurora is the upcoming 2015 Default Price-Quality Path reset which sets the allowable revenue envelope for the five-year period from 2015-2020. This is discussed further in the following section.

Aurora also provides a disclosure statement (performance statement) on an annual basis which contains information related to asset management and other measures such as financial statements, through to technical measures such as transformer utilisation. This information can be found on Aurora's website.

The complete derivation of the compliance measures are included in the Information Disclosure and the Default Price-Quality Path Compliance Statements published annually on Aurora's website www.auroraenergy.co.nz.

Affordability and Financial Sustainability

Although parts of the global economy have shown some signs of recovery following the recent period of recession, obstacles to economic growth continue through the economic side effects of the European sovereign debt crisis, accompanied with slowing economic growth in the United States and China. The continued constraints on international, national, regional and community growth and development means that affordability is likely to be at the forefront of decision-making for some time yet.

The ability for Aurora to manage costs and debt over the short, medium and long term is crucial and may significantly influence the amount of funding available for infrastructure investment.

Currently, there are several large projects either in progress or being planned for over the next 10 years. However, those in the initial stages of scoping/appraisal are still subject to funding approval. Where funding does become available for such projects, it is imperative that its use is clearly justified. Aurora is working to further develop robust capital and maintenance programmes to ensure on-going life-cycle costs are estimated correctly and can be sustained in the future.

Along with budget limits and growth, the levels of service provided by Aurora may be constrained due to the actual cost of infrastructure as well as historic under-investment. Aurora intends to pursue a reduction in unnecessary operational and maintenance cost by working to implement optimised solutions; supplemented by working towards more standardised assets and designs where appropriate.

Environmental Issues

Peak Oil

There is growing concern that global oil prices will rise dramatically once 'easy to reach' deposits have become scarce and demand for oil outstrips supply. The timing of this is still relatively unclear; as is how it may actually affect the management of Aurora's network. However, many predictions suggest that the global peak in oil production will occur in the next few years, with around 60% of oil producing countries having peaked already; this indicates that the price of oil is likely to continue to rise and become more volatile.

Potential consequences of peak oil include the use of electricity for transport as a substitute for fuel; as well as increased use of renewable energy sources such as solar, hydro, geothermal and tidal power. Renewable energy sources in New Zealand, particularly wind-based generation, have been growing in importance, reflecting improved technologies and the economics of rising electricity prices. At a local level, renewable options are also becoming more affordable for the "average" consumer. There has been a noticeable increase in the amount of distributed (embedded) generation connected to Aurora's network in 2012 and 2013, and it is anticipated that this trend will continue.

Climate Change

There is increasing scientific certainty that the climate is changing on a global scale, which in-turn is reflected in changes to national, regional and local weather patterns. It is predicted that Otago's climate will become drier for extended periods, with increased mean temperatures and daily temperature extremes. Along with heavier (but less frequent) rainfall events, both areas may be subject to increased incidents of flooding and inundation resulting in asset damage. In particular, Dunedin may be at risk to the effects of sea level rise as it has significant areas of low-lying land, some of which is reclaimed. These areas may also experience increased fire risk with temperature increases; all with likely consequent increases to operational and maintenance requirements. Strong wind events also pose a significant risk to Aurora's assets. Overall, changes in weather patterns are acknowledged as one of the challenges faced by Aurora, particularly with respect to peak demand forecasting assumptions.

Natural Hazards

As alluded to above, the natural hazards that Aurora potentially faces in managing and maintaining the electricity distribution include: rain events, sea level rise, strong winds, fire, landslides & land creep, rockfall, erosion, snow/ice, undermining, tsunamis, earthquake (and associated processes, particularly liquefaction).

The likelihood of a seismic event that Christchurch has experienced happening in Dunedin or Central Otago is not clearly understood at present. The consequences, however, are likely to be significant and potentially catastrophic. Accessibility to, and availability of, essential services provided by Aurora could be limited-to-none and could affect the provision basic needs, including other services such as water supply (i.e. dependency on electricity for conveying (pumping) drinking water).

Lessons from the Christchurch earthquake have been invaluable to a range of infrastructure providers located both inside and outside of the affected areas. Aurora will continue to build a

better understanding of the potential impacts to its network from events of that nature and scale by collating as much relevant information as possible, including response and recovery demands plus associated costs. Aurora recognises that understanding our interdependencies with other utility providers, such as Transpower and Rounding Authorities, is fundamental for ensuring preparedness and business continuity in emergency situations. Aurora is also involved in the Otago Lifelines initiative being led by the Otago Regional Council. See section 4 for further detail.

Population and Demand Trends

Aurora's network feeds both high density urban loads (e.g. Dunedin; Queenstown) and diverse rural loads (e.g. Central Otago, but also some parts of the Dunedin network). Growth in demand for electricity can occur for several reasons, such as from an increase in population or the introduction of new end-use applications. Aurora's 5-year system maximum demand growth forecast for Dunedin is 0.6% p.a. and for Central is 2.6% p.a.

For Dunedin and Central, growth in demand has historically matched growth in population. However Central Otago has been more influenced by 'spurts' of localised demand, such as the property boom of the 2000's. Peak demands (in winter) are driven by school and public holidays, and associated ski field operations during these times.

More recently, emerging irrigation requirements for more intensive farming is posing a challenge to Aurora's network in Central Otago, particularly the Upper Clutha area. The recent pace and scale of irrigation development in this area places significant demands for increased capacity on the network. The impact of irrigation is likely to become a dominant influencing factor on summer peak, which potentially may increase if hotter drier periods are more frequent. Conversely, for many rural parts of Aurora's network (excluding Queenstown and Wanaka) the high cost of providing infrastructure has historically meant that additional capacity is not planned for, and only installed when needed.

Population for much of central Dunedin is forecast to remain relatively static and some areas expect population decline, although areas such as the Taieri Plains are experiencing some growth. Dunedin does not have the same economic drivers for assets or services that exist in places with, say, high levels of population growth. As such, any response to asset management drivers requires maximising the use of existing infrastructure wherever possible.

The above situation creates some specific challenges for Aurora asset management, with potential for stranded infrastructure, limitations on affordability of service improvements, and increasing maintenance required of the existing infrastructure. As a result, increasing emphasis is being placed on justifying investment requirements and the need to find system efficiencies.

Further detail on how growth and load forecasting is used for development planning is provided in Section 6.

Ageing Infrastructure

The nature of Dunedin's growth has meant that large quantities of network infrastructure were designed and built over a short timeframe, during periods of rapid population and industrial growth in the 19th century. As a result, the City contains a significant proportion of old and aging assets. As network assets reach the end of their useful life, their performance decreases.

Given the physical asset attributes of Dunedin's network, particularly the sub-transmission cables and critical zone substations, there is a risk of critical infrastructure failure. A key challenge across all of Aurora's asset categories is 'smoothing' the cost of associated upgrades and renewals, and to prioritise spend in areas where it will give the greatest benefits.

The network in Central Otago also has areas that are just as old as Dunedin, however more continuous growth has afforded an ability to upgrade over time. For example, much of Cromwell was rebuilt for the Clyde power station project of the late 1980's.

In response to these factors, it is recognised that Aurora must place more focus on understanding network risk profiles including those assets which are most critical to maintaining the delivery of service; and use this information to drive pro-active condition assessment and maintenance practices. Asset information is critical for this activity. Aurora will continue to improve the information it has about its infrastructure in order to improve the planning and prioritisation of new capital and renewals.

Technology and Alternative Energy Sources / Distributed Generation

Technological innovation, tailored to the characteristics of Aurora's network, offers potential to increase quality and avoid more expensive new options. Aurora is engaging smarter thinking about both the application of technology and the potential for investment. Technology adoption and innovation is an opportunity to bring about efficiencies in network performance. For example, if there is an increase in the frequency of severe weather events, there is likely to be regulatory, legislative and customer pressure to improve outage response and grid resilience.

An effective response will likely require technology investments that include upgrades to outage management and mobile workforce management systems, the integration of smart-metering, new 'big data' and analytics technologies for improved planning and prediction, and distribution automation to support fault location, isolation and service restoration; supplemented by mobile devices, wireless networks and mobile application software.

The acceleration of renewable and distributed energy resources is also likely to drive growth in information and operational technology spending. For example, Aurora may opt to support, in a targeted manner, consumer uptake of distributed generation (photovoltaic, micro-wind), which could offset the need to install or upgrade distribution in remote spur locations (such as a new dairy farm at the end of a line). In this example, investment in technology may help to improve situational awareness, reduce operational complexity and move Aurora toward more proactive grid management.

However, advancing technology can also potentially 'strand' conventional engineering assets and its progress is likely to have an impact on electricity consumption as well as generation. The level, extent and timing of this impact in Aurora's network is still uncertain.

New Zealand's electricity supply industry continues to develop through the convergence of power and telecommunications technologies. Smart grids are evolving and they will help manage rapidly changing demands, while maximising reliability and efficiency and improving resilience. Customer demand response will also play a part in managing the country's future peak energy demands.

As one of the leading countries in the use of renewable energy worldwide, there is further scope for New Zealand to generate a higher proportion of electricity from renewable resources (e.g. wind, solar, hydro, geothermal).

2.4.1 Planning period and Uncertainties

This plan covers the 2014 - 2024 period. It is important to recognise that there is a degree of uncertainty associated with any future forecasts or predictions over such planning timeframes. The previous section covered generic assumptions and sources of uncertainty that are considered applicable to Aurora's development planning process.

The following underlying assumptions also need to be taken into account when referring to this AMP:

- Annual budgets relating to the management of Aurora's network are based on the estimates provided in the AMP, which is reviewed and refined on an annual basis. To this end, the AMP identifies asset management strategies and high-level requirements which inform (and are informed by) detailed investigations and development reports.

- Authorisation of expenditure comes from a two-phase process: (i) approval of the AMP capital and maintenance programmes by the Board of Directors; and (ii) subsequent specific approvals for projects identified in the annual programmes.

While it is intended to carry out the programme as planned, it must be acknowledged that circumstances may change and Aurora may, at a later date, decide to take different actions to those it currently intends to take (with the exception of statutory liabilities). It is acknowledged that unanticipated equipment failures, storms, natural disasters, or material changes in local loadings may require a change to the planned investment programme outlined in this plan.

Aurora's review of its planning and forecasting criteria, assumptions and uncertainties continued in 2013/14, looking at a wide variety of aspects that influence demand on the Aurora network and how to source, collate, analyse and forecast the information in a more structured way.

The purpose of the review is to ensure that decisions remain aligned with the most recently available and reliable information and to enable Aurora to provide 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.

The Network Development plan in Section 6 provides further detail on the above points.

2.5 Asset Management Policy and Process

Given the drivers, assumptions and uncertainties outlined in the previous section, Aurora's asset management policy recognises that effective asset management requires an appropriate and practical balance between performance, risk and cost throughout the lifecycle of all assets; as well as ensuring continuous improvement in asset management functions and capabilities to achieve key outcomes and objectives.

Aurora is committed to achieving alignment with best practice asset management that is fit-for-purpose and will implement appropriate asset management systems to govern the planning, investment, operation, maintenance and disposal of assets.

Figure 2.4 provides an overall process diagram of the approach and framework for integrated asset management. Having an integrated approach is fundamental to delivering Aurora's asset management objectives.

Development of asset management processes and implementation of the proposed 'asset management system' (refer to Section 2.6) will assist in achieving a more systematic approach to asset management that links information together according to the process flow diagram.

A robust risk framework will be used to identify and manage risks and Aurora will continue to improve the information we have on our assets in order to improve the planning and prioritisation of new capital and renewals. In conjunction with this, Aurora will work to ensure that associated funding requirements are well planned, based on reliable information, with the impact of costs spread evenly over time. This will help to minimise the risk of declining service levels and control cost impacts.

Progress towards attaining advanced asset management continues in terms of alignment with best practice standards and guidelines, such as PAS55 and the International Infrastructure Management Manual. See Section 7 for further detail.

2.6 Asset Management Systems and Information

There are several systems and processes that contribute to the management of Aurora's network assets for network planning, maintenance programming, operational requirements, financial

monitoring and performance measurement. The text that follows describes the function of each system.

Geospatial Information System (GIS): The GIS acts as a master asset register and network connectivity model. The geospatial model of Aurora's electricity network extends from the transmission GXP's to the customer connection points. The GIS also acts as a master register for other complementary data (e.g. the cadastre, topography, etc.).

The management and maintenance of GIS records relating to Aurora's assets is on-going. Updates and changes are triggered predominantly by the business processes associated with capital and maintenance activities such as inspections, assessments, failure response, renewals and augmentations. Such updates generally occur by direct input. Updates and changes to other GIS records are triggered predominantly by the data owner and generally occur through systematic processing e.g. LINZ cadastre updates.

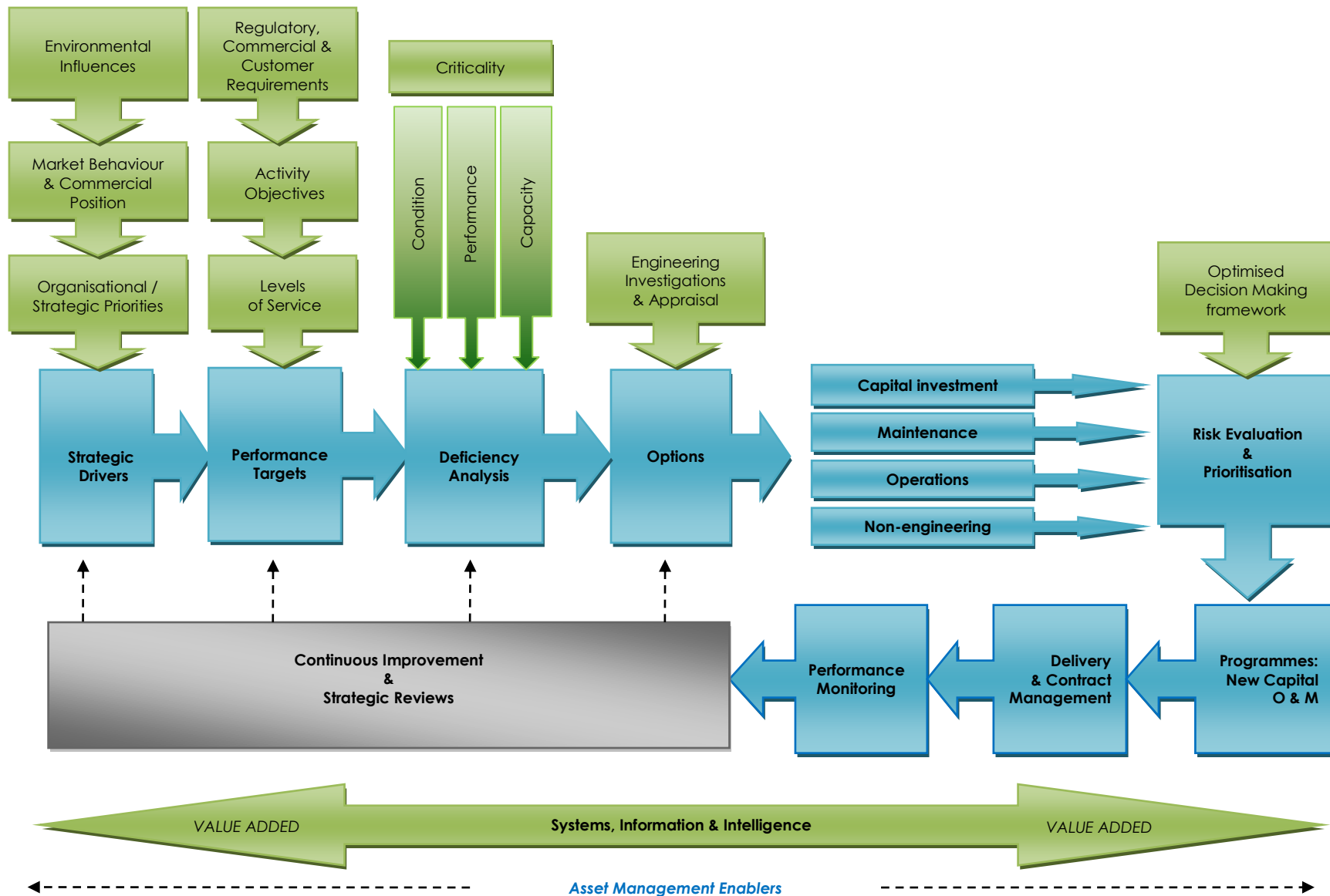


Figure 2.4 – Integrated Asset Management Framework

Network Connections Management: The process of negotiating and constructing new connections is electronically managed from application to livening. This information is fed into a database called Gentrack. Gentrack software provides network billing, network tariff management, network connection management, and meter asset tracking in an integrated package. Gentrack's ability to manage a wide range of network tariffs, charges and billing methodologies, coupled with interfaces to the electricity market registry, enables Aurora to automate a number of key network billing activities including; retailer file validation, market registry integration, fixed and variable tariff management, bill reversals, and network reconciliation.

An up-grade of Gentrack was completed in 2013. The principal drivers for upgrading the system include declining ability to support the legacy version and requirements for better integration with other financial and asset management systems, improved reporting and analysis as well as compliance with new Electricity Industry Participation Code Part 10, which came into effect in June 2013.

Financial, Work Order & Contract Management: The issue of work to (and inspection of) contractors is managed electronically within the SAP accounting software. The SAP system covers contract recording, reporting, costing, inventory control, estimating and quoting, contract and trade debtors, plant costing, creditors / general ledger, cashbook and fixed assets. Detailed monthly financial reports are produced as well as variance reports to monitor performance.

Maintenance Programming and Management: 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. Software such as Microsoft Project and Excel is used in conjunction with SAP to produce maintenance programmes.

Network Monitoring System (SCADA), Load Control and Outage Management: Aurora's monitoring, control, communication, protection and automation systems provide the electricity network with the key information and control capabilities that Aurora needs to operate. Load data, (demand and total energy), is collected and analysed for growth trend information and the outage management system is used for planning and notification of outages and production of interruption statistics. Most of these systems are running 7 days, 24 hours continuously and have been used extensively for network operation, safety control, equipment protection, outage management and decision making. A comprehensive review of these systems has been carried out and upgrade proposals are discussed in Sections 5 and 6.

Fleet Management: Aurora's asset management contractor, Delta, is trialling a GPS fleet management systems (Smartrak) that provides a number of reporting features including real time vehicle location, activity reporting, job allocation, integration with job management and customer service requests, location of fixed assets, route optimisation, driver behaviour and a suite of powerful reports that can be configured to meet specific needs.

Quality/Business Management System (BMS): The implementation of a structured framework for managing existing business systems and quality documentation occurred in 2013. The BMS (Q-Pulse) is an integrated system incorporating Risk, Quality, OHS and Environmental requirements and is essentially the electronic business management support system. Q-Pulse will manage a number of core business processes such as document and data control, incidents, corrective and preventive actions, audits (for many different types of audit activity) and assets (specifically, calibrated equipment).

2.6.1 Asset Information and Data Confidence

In 2012, Aurora commenced a review of the master asset data within the GIS along with review of the practices associated with the management and maintenance of the data. This continued in 2013 and as a result, various changes to process and practice has occurred to ensure the asset records are more complete and accurate.

Issues and Challenges

Notwithstanding the good progress being made to improve the completeness and confidence in asset data, Aurora faces challenges in the areas of asset and works management. Many of the current asset

management business processes and systems are supported by manual, paper-based environments. These provide substantial barriers to both the efficient capture of data and the easy access to and processing of relevant data to create business intelligence and knowledge.

The key issues are:

- **Advanced asset management.** Aurora's current asset management systems reflect a traditional asset management paradigm. Ownership and management of assets require more targeted and risk-optimised investment and maintenance decisions. This will require new tools and practices.
- **Right information/Right Time.** Asset management information needs to be easily accessible and reliable. Identification of key information gaps and challenges will provide a basis for prioritisation and timing of effort to address.
- **Integrated disciplined processes.** End-to-end business processes, workflows and dataflows need to be connected together to mitigate replication of data and unnecessary hand-offs. This will require standards and rule-based approaches to enable more efficient and effective practice.

Opportunities and improvements to address the issues and challenges are discussed in Section 7.

2.6.2 Asset Management Documentation, Controls and Review

Aurora has contracted asset management to Delta under a performance-related contract. Under this contract, Delta is required to meet defined 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. External reviews and audits of selected aspects of asset management practice and process have been undertaken on a regular basis. Along with adhering to a regular internal and external audit programme, recent reviews include:

- 2005. All ground-mounted transformers were assessed for risk of vehicle impact and subsequent oil leak into a water way.
- 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.
- 2008. Analysis and review of pole inspection records, monitoring, and data capture procedures. This has identified data deficiencies. Improvements to condition data records continue.
- 2010. A review of structural adequacy of selected zone substation buildings was initiated and a review of the Value of Lost Load was initiated which resulted in adoption of the values in this AMP.
- 2011. Reviews of maintenance practices, engineering approach to risk and security of supply issues were completed. The conclusion 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.
- 2012. A review of asset management processes against PAS55 standards and IIMM guidelines.
- 2013. An audit of the PSMS and re-establishment of a quality management review team for asset management.

An independent review of Aurora's network over the 2010-2012 period was also carried out by Strata Consulting on behalf of the Commerce Commission in response to Aurora's breach of the SAIDI boundary levels in 2010/11 and 2011/12.

The second assessment of Aurora's asset management maturity (as per Commerce Commission requirements) was undertaken at the end of 2013.

Aurora has processes and procedures documented to ensure non-compliance issues are addressed systematically, however the uptake and consistency of this process requires improvement. A review of the quality management system has been undertaken and a structured framework for managing the existing business systems and quality documentation commenced implementation in 2013. See Section 2.6 for information on the business management system being implemented to assist with asset management quality control documentation and Appendix C for a list of current asset management quality control documentation.

2.6.3 Communication and Participation

The communication of pertinent asset management information to and from employees and other stakeholders is improving; including appropriate top-down communication from Aurora's CEO. A series of presentations and workshops on various aspects of asset management were held with staff and contractors throughout 2012 and 2013 and these will continue as and when necessary (and in conjunction with the AMIP). Asset management requirements are well communicated to the financial function and communication to and from contractors is becoming more formalised and regular. Significant Transpower issues are both informally and formally reported to executive management as appropriate, and meetings are regularly held with Transpower to discuss both routine and emerging issues.

The focus for 2014/15 will be clarifying and reinforcing asset management strategy, plan(s) and objectives; including better communication of the asset management policy, asset performance information, specific asset strategies and planning information to both staff and contractors. Also see Section 2.3.2 regarding stakeholder interests.

3 Service Levels and Performance

The services provided by Aurora are driven by certain key principles or 'service attributes', being: Safety, Reliability, Quality, Responsiveness, Efficiency, Compliance and Financial sustainability; underpinned by Continuous Improvement.

In providing these services, Aurora's objectives are to ensure that the 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.

In order to monitor service delivered against requirements, values and expectations, Aurora surveys consumers, consults with stakeholders, and benchmarks against industry standards in order to ensure that Aurora:

- (i) meets commitments to service delivery and performance;
- (ii) understands customer values and level of service they require, and
- (iii) is aware of changing expectations.

There are also service levels that Aurora is required to uphold for various regulatory bodies, and to contribute to the overall well-being of the community. Section 2 identified Aurora's key stakeholders, consumer groups along with their interests in Aurora's service.

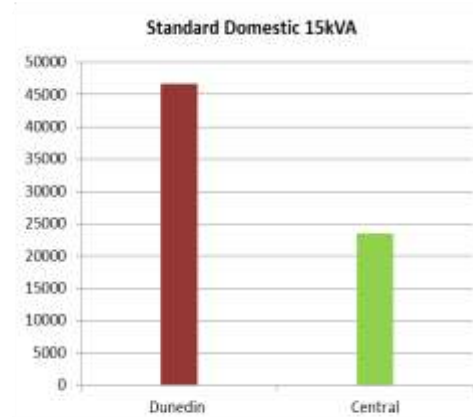
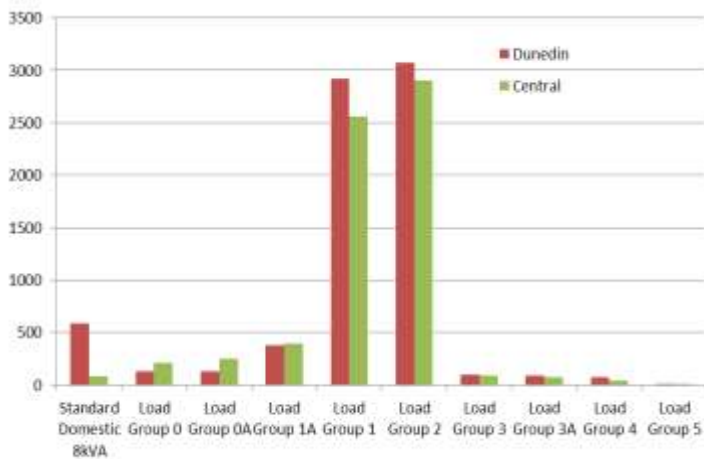
This section describes the consultation undertaken by Aurora, outlines the service levels and associated targets, presents performance results to date, and outlines justification for the levels of service provided. Financial performance is also discussed.

The service levels defined in this section can be categorised into consumer, technical and financial; and are used to help Aurora:

- inform key stakeholders of current and proposed levels of service and associated performance targets;
- focus asset management objectives & strategies to deliver the required service levels;
- identify costs and benefits of the services
- enable customers to assess whether service levels meet needs and expectations;
- measure of the effectiveness of actions taken through monitoring and reporting on related performance measures.

Consumer Types

The graphs below illustrate the types and numbers of consumer connections on the Dunedin and Central network. Clearly standard domestic 15kVA connections are the most prominent, particularly in Dunedin. Load groups 1 and 2 (15kVA and 16 - 149kVA respectively) are the next most dominant (again more in Dunedin than Central. Load Groups 0 and 0A are the only groups that feature more prominently in Central than Dunedin. The 0A load group represents 'temporary' connections, which are established to supply short-term construction needs for house building, for example and therefore reflects current growth characteristics within the Central network.



3.1 Consumer Consultation

User opinion on quality, price and service issues is surveyed by Aurora on an annual basis through telephone surveys and postal surveys. The postal survey focuses on price and quality (reliability). The telephone surveys cover other service-related issues such as restoration time and willingness to pay. Customers are selected at random for each survey.

3.1.1 Postal Surveys

Postal surveys commenced in 1999 and are continuous throughout the year (whereby 400 are sent out each month) so that:

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

The results to date are presented in Figure 3.1 and show the majority of consumers are trending towards preference for a lower price rather than better quality of supply.

However recent results do show a slight change compared to previous years with more people starting to show an interest in having better quality³.

³ Note that the response for the 2013/14 year is also shown (based on 8 months of data)

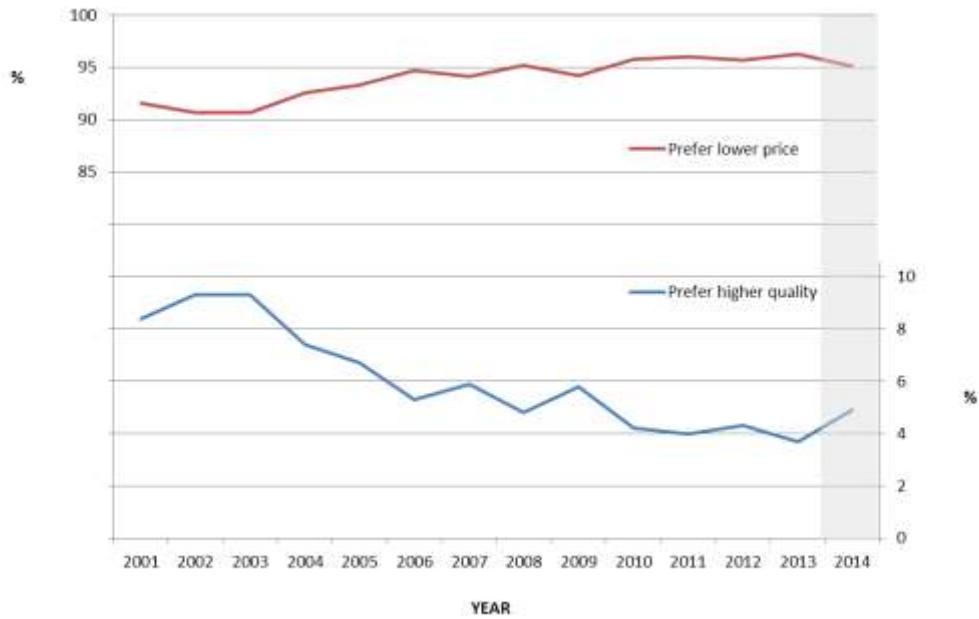


Figure 3.1 - Price Versus Quality Survey

3.1.2 Telephone Surveys

Aurora carries out annual telephone surveys of approximately 400 consumers, with 200 consumers from the Dunedin area and 200 from the Central Otago area. These consumers are selected at random, and the survey questions cover a range of price – quality and service related issues. The surveys commenced in 2006 and a comparison of the results between Dunedin and Central is presented in Table 3.1 with a sample of the results to date presented in graphs on the following page. Additional comments follow.

Table 3.1 – Summary of survey result trends (2006-2013)

Statement	Dunedin	Central	Comments
Agree that Price is more important than Quality	Decreasing (slightly)	Decreasing	Signals a preference for wanting better quality of supply
No. of interruptions being single most important issue relating to quality	Decreasing	Decreasing	Signals that other issues (e.g. voltage; length of interruption) may be emerging as being more important to consumers in the future
Do not accept 10% increase in line charges for 10% improvement in quality	Decreasing	Decreasing	Signals that there may be an emerging willingness to pay for better quality (i.e. more people open to an increase in line charges)
Acceptance of rebate if quality of supply could not be improved.	Increasing	Stable*	
Do not accept 10% decrease in line charges for, say, 10% more interruptions	Increasing	Decreasing	Dunedin – supports trend in wanting better quality
Acceptable timeframe for restoration of supply (weighted avg)	Decreasing**	Increasing	** Signals that Dunedin 's consumers may be becoming less tolerant of longer timeframes and may be expecting a higher level of service for responsiveness in the future.

* Increase over last 3 yrs

**Increasing overall, but last three years shows an emerging declining trend

Additional Comments

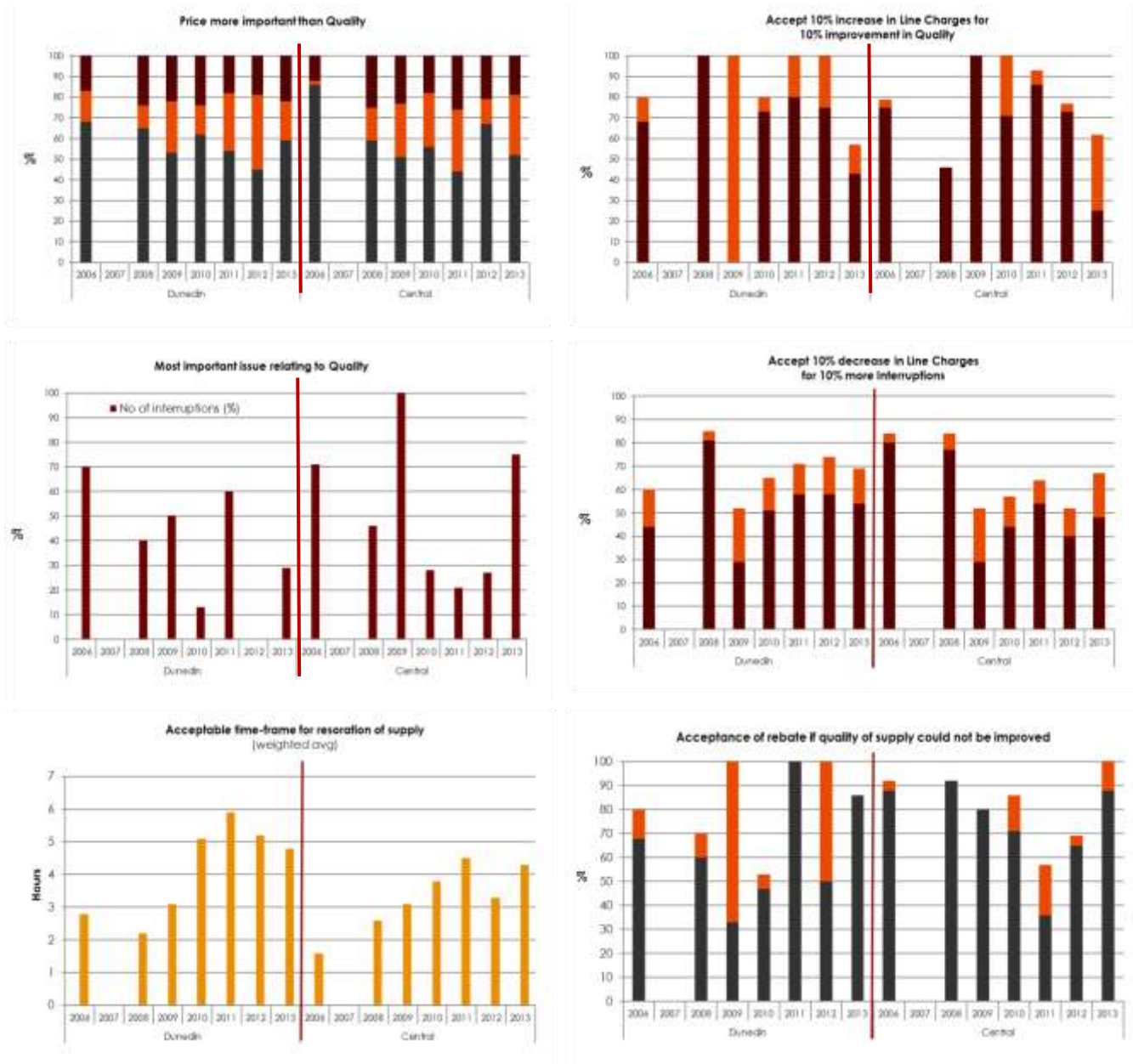
- Aurora's complaints register indicates a higher number of complaints associated with the network in Central Otago compared to Dunedin. The main issues being voltage, interruptions and line charges; however communication (lack of) has also featured strongly in complaints from consumers in terms of planned shutdowns.
- For Dunedin, Aurora's complaints register indicates more complaints regarding interruptions compared to voltage complaints. There are also some complaints regarding voltage and planned shutdowns, but these are well below those logged for the Central network

Suggestions for improvements contained within the surveys have indicated that consumers would like more communication and an improved service in terms of responsiveness. This applies to both rural and urban customers.

Note that the level of confidence associated with data and information gleaned from the surveys is considered to be uncertain largely due to limited sample sizes and the subjective views of respondents. See Section 2.3.2 on proposed improvements related to this.

Results from Telephone Surveys

	No
	Unsure
	Yes



3.1.3 Other Stakeholder consultation

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; notably Aurora's network reliability performance is below the industry average for reliability trends (see Section 3.3.2 for further detail).

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. Some of Aurora's large capacity connections in Dunedin and Central are shown below:

- Central Otago: QLDC, CODC, NZ Ski, Queenstown Airport and other large hotels such as Novotel and Corphorn.
- Dunedin: Otago University, Port of Otago, Turners and Growers, DCC, Cadbury, Fonterra, NZ Wood Mouldings, Southern DHB, Kiwirail, Ravensdown.

Specifically the congestion period demand management service that Aurora provides consists of customer assistance, customer education and monthly reporting to these consumers.

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.

Transpower warrant particular mention here given the interdependency that Aurora has with the national grid. Aurora meet with Transpower on a regular basis throughout the year to discuss capital programmes and ensure alignment where necessary (see Section 6).

In addition, dialogue continues with our respective roles and responsibilities in Otago lifelines. In this context, Transpower are interested in understanding how Aurora's network is developing and the customer demands driving development so they can ascertain how their planning can appropriately respond to it.

3.1.4 Customer complaints

Aurora is required, under the Electricity Industry Act 2010, to be a member of the Electricity and Gas Complaints Commissioner scheme. The scheme has a comprehensive constitution document approved by the Minister of Consumer Affairs, which prescribes the handling of complaints, including timeframes. The requirement for processing complaints regarding Aurora's service (including complaints about Aurora contractors) is detailed in Aurora's Handling of Electricity Complaints policy.

3.2 Evaluation of Performance

This section provides an evaluation of Aurora's technical/network performance to date and supplements the consumer feedback results discussed in Section 3.1

Results

Aurora has complied with nearly all of its performance targets for 2012/13. A summary is shown below and Table 3.2 presents actual results.

Service Level	Result against Target
Safety	Compliant
Environmental	Compliant
SAIDI and SAIFI (unplanned)	Compliant
SAIDI (planned)	Non-compliant
Faults (overhead network)	Non-complaint
Faults (underground network)	Non-complaint (minor)
Responsiveness	Complaint
Efficiency	Complaint

Table 3.2 : Service Level Performance Results for 2013

Service Criteria	Performance Indicator	Target (2012/13)	Actual (2012/13)
Safety			
Safety of public	No. of incidents per year	0	0
Safety of personnel	No. of incidents per year	0	0
Safety of network assets	Compliance with standards	Compliance	C
Reliability / Quality			
Network Reliability	SAIDI (Planned)	14.0	21.8
	SAIDI (Unplanned)	70.0	53.8
	TOTAL	84.0	75.6
	SAIFI (Unplanned)	1.27	0.93
Faults per 100 km HV	No. per year	10.5	11.3
Faults per 100 km HV UG	No. per year	2.5	2.53
Faults per 100 km HV OH	No. per year	13.5	18.35
Customer Complaints	No of proven voltage complaints per 10,000 consumers per year	<10	4.0
Network Restoration	CAIDI (unplanned)	55	72
Responsiveness			
Restore supply following general network failure	Within 4 hours of notification (Dunedin)	<4hrs	80% restoration within 3 hours
	Within 4 hours of notification in urban areas (Central)	<4hrs	
	Within 6 hours of notification in rural areas (Central)	<6hrs	
		Valid claims	Valid claims
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	0	0
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	0	0
Notification of planned service interruption	Missing notification of planned interruption	0	1
Efficiency			
Load factor (%)	Energy into network/peak kW hours per year	54%	53%
Loss ratio (%)	Energy into network less energy delivered / energy into network	6%	5.6%
Capacity utilisation (%)	Peak network kW / installed distribution transformer capacity kVA	30%	34.5%
Environmental / Compliance			
SF6	No. of incidents per year	0	1
PCBs	No. of incidents per year	0	0
Oil spills	No. of incidents per year	0	0

Performance results over the past 10 years follow, with comments on any notable trends. Financial performance for maintenance and capital expenditure for 2013 is presented in Section 3.2.7. A 'benchmark' comparison with the industry is also included.

During 2013, an independent review of Aurora's network over the 2010-2012 period was carried out by Strata Consulting on behalf of the Commerce Commission, in response to Aurora's breach of the SAIDI boundary levels in 2010/11 and 2011/12.

Some of the main findings from this included a requirement to place more focus on vegetation management, as well as the collection and use of asset condition data and more targeted asset investment programmes. The development of a vegetation management plan as well as a review of the strategy for the subtransmission network in Dunedin was also recommended.

These items have been incorporated into the Asset Management Improvement Programme (see Section 7 for further detail on this).

3.2.1 Safety

Aurora is committed to providing services that are safe to end-users, the general public as well as our own personnel and contractors.

Safety performance is measured through reporting and recording the number of incidents per year involving the public or personnel and/or non-compliance/non-conformance process. Results to date indicate very few instances when targets have been breached. Actions to address safety incidents, such as investigations and corrective actions, are outlined in Section 4 of this AMP. There were 0 incidents reported in 2012/13.

3.2.2 Reliability

3.2.2.1 SAIDI and SAIFI

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. Aurora measures its reliability performance through System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) as well as faults per 100km HV (lines and cables) and concurrently monitors customer complaints.

SAIDI provides an overall measure of asset performance. SAIFI assists to monitor frequency of interruptions and helps Aurora to track whether it is meeting expectations for ensuring fewer faults.

The input data necessary for calculating Aurora's reliability statistics is collected and recorded in an Outage Database for both planned and unplanned interruptions to supply; including the duration of the outage, number of consumers affected, and cause. Targets for these are referred to as 'quality thresholds' and are part of the Commerce Commission disclosure requirements.

Results for 2012/13 show a significant improvement on the previous two years, with interruptions being well below threshold targets.

Excluding planned shutdowns, the main causes of outages were due to vegetation, equipment deterioration, and third party interference. This is not dissimilar to the trends observed over the last 10 years (below).

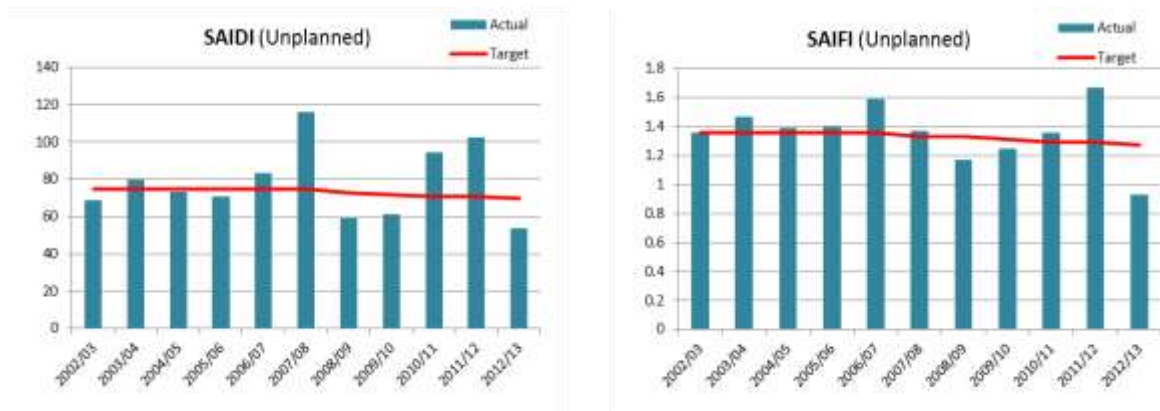
The comments following are for SAIDI and SAIFI results excluding Transpower initiated events.

Historical Performance - Quality Threshold Targets

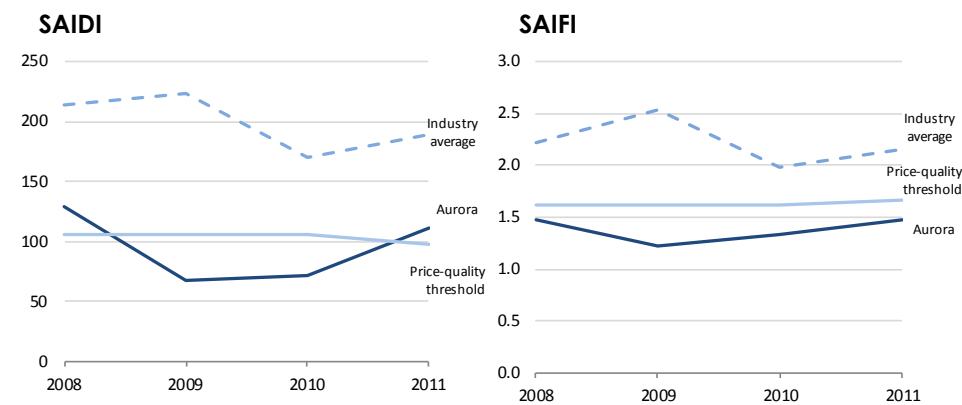
Trends for SAIDI and SAIFI over the past 10 years are shown below.

Excluding planned shutdowns, the recorded (known) cause of these interruptions was predominantly tree contact and weather (wind), equipment deterioration and third party incidents.

This poses a challenge for Aurora as consumer surveys have historically indicated they are not willing to pay more for an improvement in quality, preferring a decrease in charges with no more interruptions.



Overall, Aurora's average duration and frequency of interruptions was below the industry average over the 2008-2011 period. A comparison of Aurora's SAIDI and SAIFI trends 2008-2011 against the industry is shown below.⁴



Geographic Influences

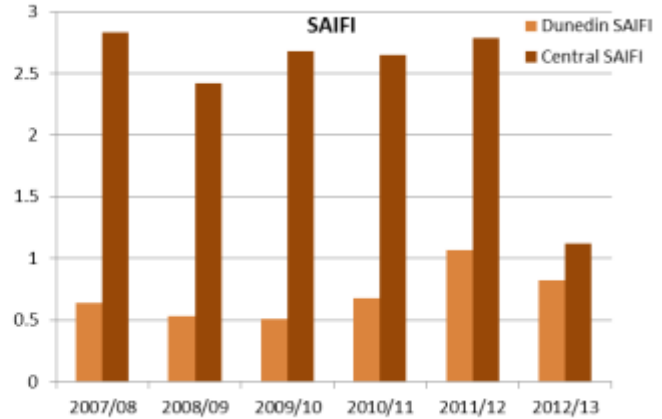
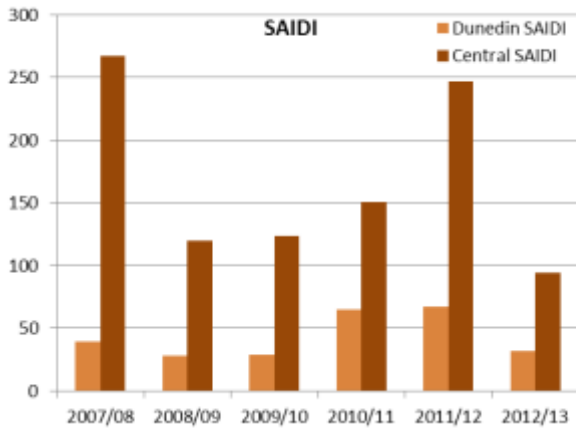
Aurora's total network covers two geographically diverse areas (Dunedin and Central), each with unique characteristics due to location, history of development, design/construction requirements, operations, maintenance and customer expectations. As such, the performance of these networks will vary in comparison as will the expectations of customers in each area. As a consequence, the type and scale of expenditure required will also vary.

Dunedin vs Central

A comparison of the total number of interruptions and restoration results are shown in the table below. The graphs that follow illustrate SAIDI and SAIFI for the Dunedin and Central networks. It is clear that the network in Central Otago experiences more interruptions with longer duration than Dunedin.

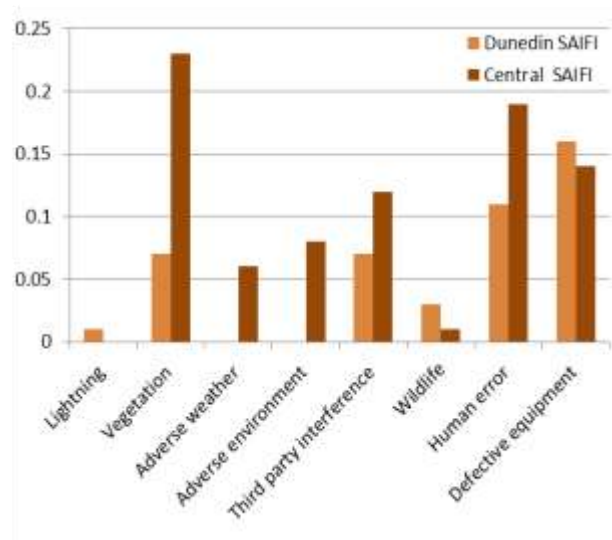
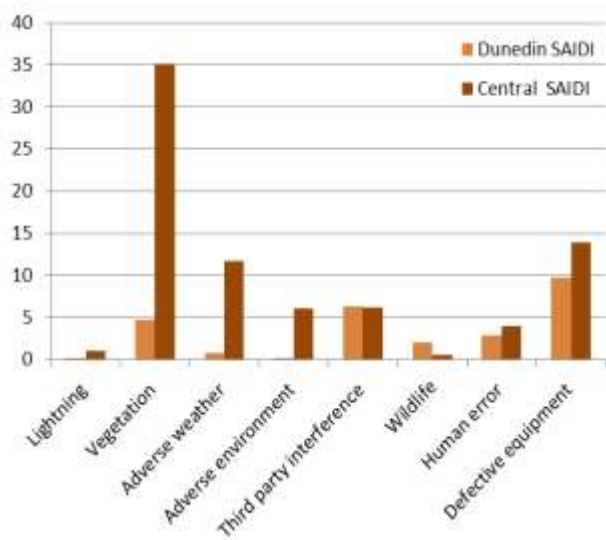
⁴ Commerce Commission NZ (2013) Electricity distributors' performance from 2008-2011. Public Version.

	Dunedin	Central
Total Interruptions	135	222
Restored within 3 hours	84%	78%



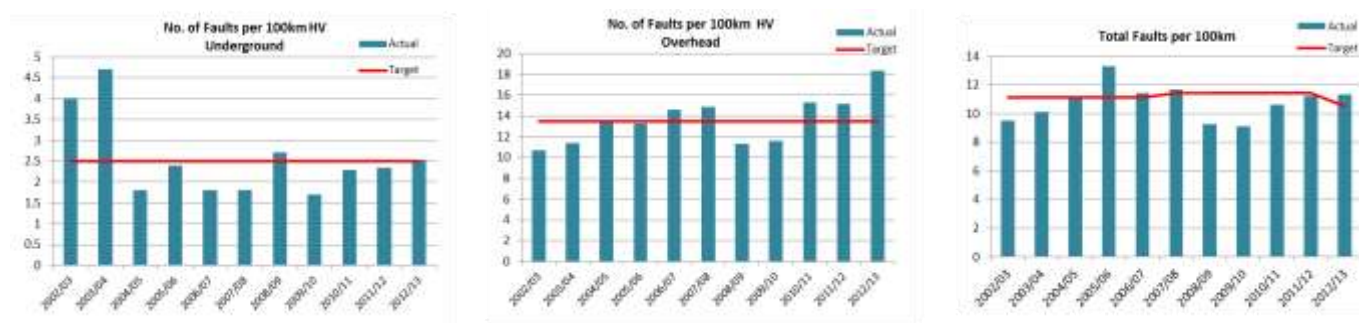
The graphs below illustrate the main cause of interruptions within each network for 2012/13. This clearly shows that vegetation is having a significant impact on the network in Central; with defective equipment having an influencing factor in Dunedin (note that there is also a high proportion of 'cause unknown').

The main equipment involved in the unplanned interruptions is associated with distribution lines (excluding LV) and includes poles, stay wires, cross-arms, braces, insulators, conductor, binders and ties.



Faults

Results for 2012/13 show that Aurora met the target set for underground faults and was slightly above target for overhead faults. Over the past 10 years, there has been a declining trend in underground faults compared to overhead, reflecting the fact that most reliability issues are associated with overhead lines. Over the last 4 years, there has been an increasing trend in the incidence of underground faults, although this is still below/equal to target.



Contract Performance Targets

While the regulatory quality thresholds set out above are the key performance targets that Aurora is monitored against, Aurora has also historically set 'stretch' targets in Delta's asset management contract requirements to drive continuous improvement and best practice asset management.

3.2.3 Quality

Aurora is committed to providing services that are both reliable and of high quality, particularly with respect to steady state voltage level. Variations to voltage can affect the quality of power delivered to the end user and may result in momentary fluctuations or affect consumer appliances, the cause of which is primarily due to rising loads or failing conductor joints. This mainly occurs during winter when loads are highest.

Aurora measures its quality performance through monitoring and responding to reports or complaints received during the year as well as via feedback in annual consumer surveys. Any complaints received during the year are logged and investigated to validate if they are voltage-related. Depending on the complexity of the situation, it may be some time before the cause is confirmed, solution designed and/or additional investment is made.

Aurora has set targets relating to the maximum number of valid voltage complaints over the total network, being (less than) 10 per 10 000 consumers per annum (so approximately 80 voltage complaints per year). Results over the past 4-5 years indicate that the number of valid voltage complaints received throughout any one year has ranged from 9 – 32.

Results for 2012/13 show that Aurora received 18 valid voltage complaints (11 in Dunedin and 7 in Central), well below target.

Central Otago respondents have consistently rated voltage fluctuations as a higher quality of supply issue than Dunedin.

3.2.4 Responsiveness & Restoration

Aurora is committed to resolving consumer issues in a responsible and timely manner. Because Aurora has contracted out management of its assets to Delta, Aurora monitors Delta's performance to ensure appropriate customer service levels are maintained for such matters as answering telephones and correspondence. Aurora's performance measure results for responsiveness are shown in Table 3.2.

For general customer enquiries and issues relating to power or voltage, Aurora's commitment is that within 7 days, it will investigate and respond in detail or advise when a final response can be expected due to the nature of the problem. 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.

Aurora provides a 24 hour service for direct fault calls and emergency contact⁵; and maintains a complaints register to log complaints and track resolution.

Further to this, Aurora has set a 'service guarantee' if the timeframe is exceeded (Table 3.3).

Table 3.3 - Service Guarantee

Service Criteria	Performance Indicator	Service Guarantee for exceeding the time-frame
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
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
Notification of planned service interruption	Missing notification of planned interruption	\$20 per ICP per missed communication

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:

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

The actual spend on service failure payments over the past 10 years is shown in Table 3.4. While variable, there is a general increasing trend in the number of events and therefore total paid.

Table 3.4 – Historic Service Failure Payments

Year to 30 June	Events	Consumers Affected	Total Paid	% 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%
2012	26	1183	\$79,275	0.103%
2013	4	646	\$34,247	0.040%

For 2014, Aurora will continue with its commitment to respond to enquiries regarding power quality or service interruption investigations within 7 working days.

3.2.4.1 Restoration

The long-term trends presented from the survey results in Section 3.1 indicate that consumers appear to be accepting a longer timeframe for restoration in both Dunedin and Central. However, results from the past three years indicate a shift in the long-term trend. Dunedin consumers appear less tolerant of

⁵ The 24 hour service has a limited capability and consumers are encouraged to call their retailer for up-to-date information on fault restoration.

longer restoration times than in the past. Consumer feedback also tells us that there appears to be some level of dissatisfaction with the response being provided.⁶

Of the 357 unplanned interruptions on the network in 2012/13, approximately 80% were restored within 3 hours. This is a higher rate of response compared to last year (73%). These results are well under Aurora's current service level response target times for restoring supply in urban Dunedin and Central.

For consumer groups, restoration target levels are shown in Table 3.5, and provide a more practical explanation of service level delivery. Aurora uses restoration information to provide a comparison between urban and rural network performance. Results show that there is an increasing trend of interruptions occurring in urban areas versus rural over the whole network (see graphs below).

In 2012, 16.4% urban consumers experienced more than four interruptions and 6.6 % rural consumers experienced more than 10 interruptions. This was similar to the previous year. The 10 worst performing feeders are outlined in the following section and this information shows that the majority of these feeders are located within the Central network.

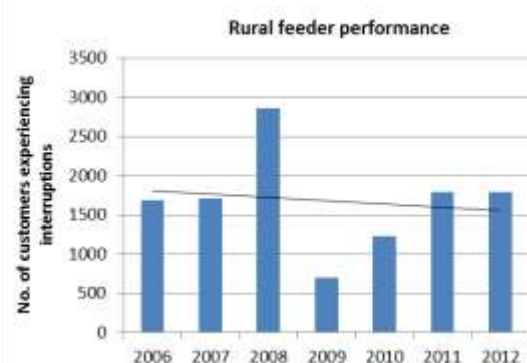
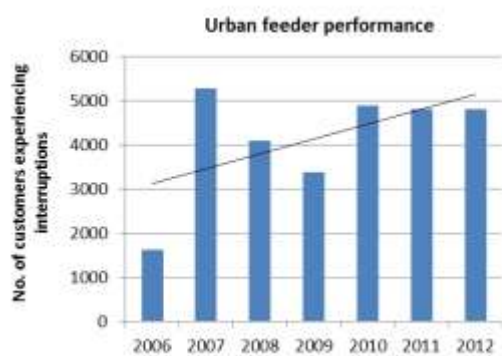


Table 3.5 Number and Duration of Outages by Consumer Location

General Location	Performance Measure	Target
Dunedin Network		
Otago University, Hillside Workshops	Outages no longer than 4 hours every 5 years	≤ 1
Dunedin urban CBD	Outages no longer than 4 hours every 5 years	≤ 1
Dunedin urban suburbs	Outages no longer than 4 hours per year	≤ 2
Taieri Plains, Otago Peninsula	Outages no longer than 4 hours per year	≤ 4
Central Otago Network		
Major urban areas in Central *	Outages no longer than 4 hours per year	≤ 2
Smaller towns in Central **	Outages no longer than 6 hours each year	≤ 4
Rural areas in Central	Outages no longer than 6 hours each year	≤ 10
Remote rural areas in Central	No. of outages each year	< 20

*Alexandra, Queenstown, Cromwell, Wanaka

**Arrowtown, Roxburgh, Clyde, Ettrick, Omakau, Lake Hawea, etc

⁶ Note, that it is currently unclear whether the survey results for length of interruptions definitively correlate with Aurora's service performance for 'responsiveness', as the means to adequately monitor and record such information is still being determined.

Worst Performing HV Feeders

The top 10 feeders assessed as being the 'worst performing' over the past 5 years are shown in Table 3.6. Of these, 80% are located within the predominantly rural areas of the Central network. The feeders shown in bold text are those that were associated with significant outages in 2010/11 and 2011/12.

Table 3.6 - Worst Performing Feeders

Rank	Feeder Description	Abbrev
1	Queenstown	QT5202
2	Frankton	FK7782
3	Ettrick	EK485
4	Arrowtown	AT7662
5	Wanaka	WK2756
6	Cromwell	CM891
7	Frankton	FK7783
8	Omakau	OM656
9	Mosgiel	MG6
10	Port Chalmers	1879

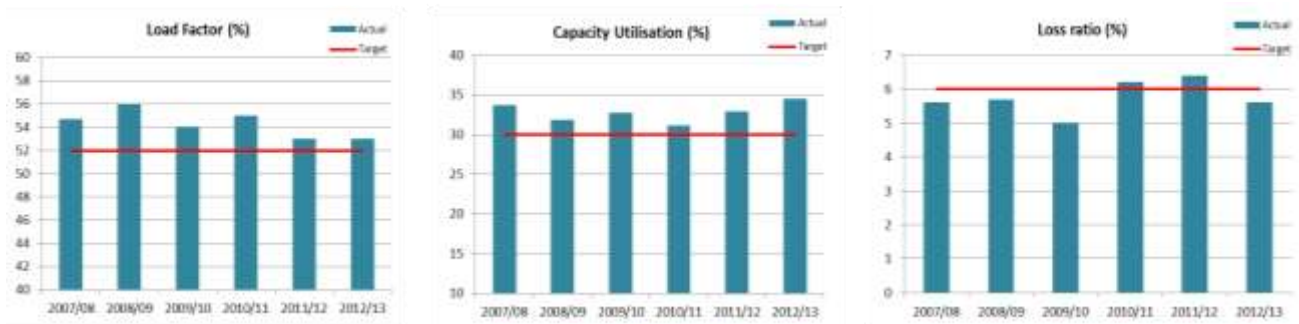
In response to these results a targeted capital investment programme for the worst performing feeders has commenced. Additional remote switching for rural areas has also been implemented in the recent past. The impact of targeted improvement on the 10 worst feeders is illustrated in Table 3.7. Refer to Sections 5 and 6 of this plan for further detail on related projects and expenditure.

Table 3.7 - Targeted Improvement in the 10 Worst Performing Feeders

Area	Improve Reliability	Measure	Target Level	Results	Achieved Y/N
Closeburn	QT5202	Reduce SAIDI and No. of Interruptions	Reduce by 25%	73% SAIDI reduction 50% Interruption reduction	Y Y
Fernhill	FH5308	Reduce SAIDI minutes	Reduce by 15%	83% SAIDI reduction	Y
Dalefield	DA7828	Reduce SAIDI minutes	Reduce by 15%	54% SAIDI reduction	Y
Remarkables park	FK7783	Reduce SAIDI minutes	Reduce by 10%	47% SAIDI reduction	Y
Sawyers Bay	PC4	Reduce SAIDI minutes	Reduce by 10%	58% SAIDI reduction	Y
Hawea	MA260	Reduce SAIDI and No. of Interruptions	Reduce by 10%	56% SAIDI reduction 92% Interruption increase	Y N
Luggate	WK2752	Reduce SAIDI and No. of Interruptions	Reduce by 10%	51% SAIDI reduction 77% Interruption reduction	Y Y
Pisa Moorings	CM891	Reduce SAIDI and No. of Interruptions	Reduce by 10%	86% SAIDI reduction 69% Interruption reduction	Y Y
Gibbston Valley	AT765	Reduce SAIDI and No. of Interruptions	Reduce by 10%	80% SAIDI reduction 36% Interruption reduction	Y Y
Omakau west	OM679	Reduce SAIDI and No. of Interruptions	Reduce by 10%	36% SAIDI reduction 54% Interruption reduction	Y Y

3.2.5 Efficiency

Aurora's energy efficiency is measured through load factor, loss ratio and capacity utilisation. Table 3.2 presents the results for Aurora's efficiency targets.



Load Factor

Better utilisation of capacity in the network can be gained through optimising the load factor, which is a measure of the average load that passes through the network divided by the maximum load experienced in a given year. A high load factor means power usage is relatively constant. Low load factor indicates that occasionally a high demand is set; however in order to service that higher demand, capacity is under-utilised for extended periods, increasing system costs. Aurora achieved a load factor of 53% in 2012/13 against a minimum target of 52%. Aurora's load factor has been slightly above target each year over the past 5 years and as such it is considered viable to revise the target to 54%.

Capacity Utilisation Ratio

This ratio measures the utilisation of transformers installed on Aurora's network and is calculated as the maximum demand experienced divided by the distribution transformer capacity on the network. For 2012/13, capacity utilisation was 34.5% against a minimum target of 30%. Over the past 5 years this has been slightly above target each year. It is expected that better utilisation may start to occur within the Central network due to emerging irrigation demands which may see increased use in summer.

Energy Loss Ratio

Energy losses mainly occur due to heating of lines, transformers and cables. Theft can also be an issue. In general, losses cannot be avoided and therefore all electricity networks experience losses to some degree. For 2012/13, Aurora's energy loss ratio was 5.6% against a maximum target of 6%. This is an improvement over the previous two years, which have been above target.

Pricing policies

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. 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. Details of Use-of System pricing methodology can be found on Aurora's website.

3.2.6 Compliance

There are a variety of regulatory compliance requirements that Aurora must meet when planning for and delivering services. These cover environmental, health & safety, hazards to name a few. Section 2 covered the main pieces of legislation that Aurora aims to achieve material compliance with when managing the electricity distribution network.

Along with targets for compliance with safety and safety standards (Section 3.2.1), Aurora aims to minimise or eliminate the risk of discharges to the environment from oil spills, PCB's and SF6. More recently, the risk of this has been further reduced through the use of oil filled circuit breakers ceasing in favour of vacuum circuit breakers.

However, the oil-based distribution switchgear used by Aurora is being discontinued and SF6 is likely to become the insulation medium.

In some parts of the network ester-based oil is used. This is considered as posing less of a risk to the environment in the event of a spillage. A review of on the policy for the type of oil used within different parts of the network is planned.

One environmental incident occurred within Aurora's network in the 2012/13 year, with a failure at Queenstown substation which resulted in the release of a small volume of SF6 being released into the atmosphere (from SF6 switchgear).

3.2.7 Financial Performance

Over the past 10 years, actual capital expenditure has been variable with respect to budget, however the last three years indicate an underspend. Maintenance expenditure has been less variable and has predominantly come in above budget. Table 3.8 presents results for 2012/13. The text below identifies the causes of variance.

Table 3.8 Financial Performance Results for 2013

Category	Budget 12/13 \$000	Actual 12/13 \$000	Variance	
			\$	%
Maintenance Expenditure				
Routine and Corrective Maintenance	3,200	2,186	1,014	32%
Vegetation Management	1,280	1,253	27	2%
Asset Replacement and Renewal	1,162	1,331	-169	-15%
Service Interruptions & Emergencies	3,941	4,259	-318	-8%
Total	9,583	9,029	-554	-6%
Capital Expenditure				
Customer Connection	5,351	6,671	1,320	25%
System Growth	477	2,152	1,675	351%
Asset Replacement and Renewal	9,422	6,374	-3,048	-32%
Reliability, Safety and Environment	567	1,986	1,419	250%
Asset Relocations	2,258	459	-1,799	-80%
Total	18,075	17,642	-433	-2%

Progress of maintenance initiatives and programmes

Overall maintenance expenditure was down slightly during the disclosure period. Delay in evaluating some inspection work, and associated project planning, translated into an underspend in 'routine and corrective maintenance and inspection'. This was, in part, offset by additional work required in 'service interruptions and emergencies' and 'asset replacement and renewal'. Non-network operational expenditure was materially incorrectly stated in the 2012/13 AMP. This has since been corrected.

Progress of development projects

It should be noted that the format for disclosing expenditure, in the second to last AMP, was not prescribed within the disclosure regime at that time. Accordingly, the target figures have been taken from Aurora's last disclosed AMP as the year CY forecast.

The main causes of variances in the CAPEX budget are outlined below:

The variance in **system growth** is primarily attributable to the Tarras water scheme being deferred, shifting the allocation into the 2013/14 year. The remaining actual spend is mainly attributable to Roxburgh zone substation refurbishment.

The variance in **asset replacement and renewal** expenditure is due to deferral as a consequence of supplier delays (Andersons Bay 33kV cable rejects, requiring re-manufacture), as well as re-appraisal of some transformer-related projects and optimisation of part of the system control, communications and protection programme.

Consumer connection and **asset relocation** expenditure is generally externally driven and less controllable than other categories. Additional emphasis was placed on reliability and quality of supply

projects in the later part of the disclosure years, resulting in an overall increase in total **reliability, safety and environment** expenditure.

3.2.7.1 Economic Efficiency

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

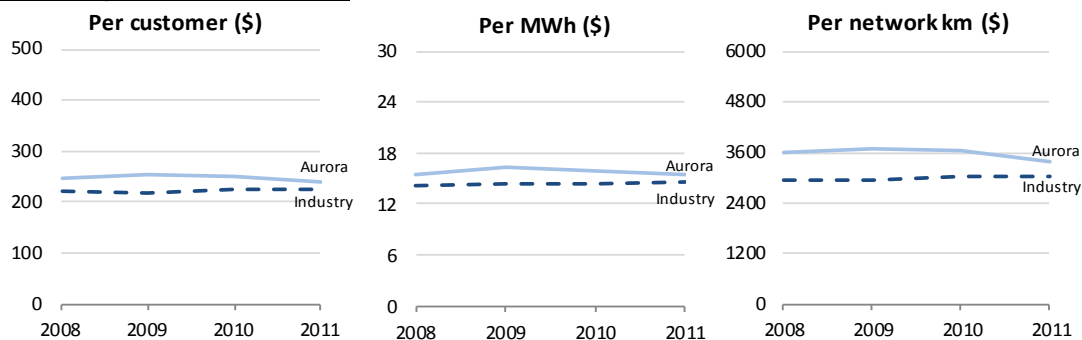
Aurora's consumer surveys have historically indicated that consumers perceive price as being more important than quality, and they are generally less willing to pay more for an improvement in quality (reliability), but at the same time also do not want to pay less if it means there may be more interruptions. As such, providing a cost effective, reliable and secure network for electricity delivery is a primary focus for Aurora.

The Commerce Commission places emphasis on measuring and reporting both capital and operational expenditure. As such, Aurora tracks progress against the industry average through the benchmarking information collated by PricewaterhouseCoopers on an annual basis (PwC 2013, Electricity Lines Business (2013) Information Disclosure Compendium) as well as referring to the Commerce Commissions performance report for EDB's.

A sample of Aurora's trends in operating and capital expenditure over the period 2008-2011 are shown in the graphs that follow. For Opex, Aurora has been slightly above the industry average but is also shown to be trending towards this. For Capex, Aurora has been slightly below the industry average but is also shown to be trending towards this.

Most of Aurora Energy's revenue is collected from residential and smaller commercial customers. Revenue from line charges increased by around 3% from 2008 to 2011, over and above inflation. Distribution line charge revenue from residential and smaller commercial customers stayed flat, but increased for medium-sized customers by around 20%.

Operating Expenditure trends



Capital expenditure trends



3.3 Service Level Targets & Justification

Service level targets for 2014/15 are shown in Table 3.9, including the proposed average annual targets for the next 5 years. A discussion on the reasons for the service level targets has been provided in Section 3.2, which forms the basis on which each service level target has been determined for 2014/15. In setting these, Aurora has given consideration to customer feedback/surveys, historic trends in network performance, knowledge of current network health/risk areas, economic viability and funding availability, with safety-first being paramount.

While the results outlined in the previous section as well as the benchmarking information generally support the proposed service level targets, they have also identified areas that need attention; and include: responsiveness/restoration and to a lesser extent, reliability. Sections 5 and 6 covers proposed performance improvements for the network to assist Aurora to address such issues; and asset management practice and process improvements are discussed in Section 7.

In summary, the main drivers that influence Aurora's service levels are related to business and stakeholder/consumer needs and legislative requirements; as these influence decisions about the range, quality and quantity of services provided.

Table 3.9 – Future service levels and targets

Service Criteria	Performance Indicator	Targets	Avg Annual
		(2013/14)	(2014-2018)
Safety			
Safety of public	No. of incidents per year	0	0
Safety of personnel	No. of incidents per year	0	0
Safety of network assets	Compliance with standards	Compliance	Compliance
Reliability / Quality			
Network Reliability	SAIDI (Planned)	14.0	13.6
	SAIDI (Unplanned)	70.0	68.4
	TOTAL	84.0	82.0
	SAIFI (Unplanned)	1.27	1.24
Faults per 100 km HV	No. per year	10.5	10.4
Faults per 100 km HV UG	No. per year	2.5	2.5
Faults per 100 km HV OH	No. per year	13.5	13.5
Customer Complaints	No of proven voltage complaints per 10,000 consumers per year	<10	<10
Network Restoration	CAIDI (unplanned)	55	55
Responsiveness			
Restore supply following general network	Within 4 hours of notification (Dunedin)	<4hrs	<4hrs
	Within 4 hours of notification in urban areas (Central)	<4hrs	<4hrs
	Within 6 hours of notification in rural areas (Central)	<6hrs	<6hrs
		Valid claims	Valid claims
Response to customer enquiries	Within 7 days Aurora will investigate and respond in detail or advise when a final response can be	0	0
Response to power quality or voltage	Within 7 days Aurora will investigate and respond in detail or advise when a final response can be	0	0
Notification of planned service interruption	Missing notification of planned interruption	0	0
Efficiency			
Load factor (%)	Energy into network/peak kW hours per year	54%	54%
Loss ratio (%)	Energy into network less energy delivered / energy into network	6%	6%
Capacity utilisation (%)	Peak network kW / installed distribution transformer capacity kVA	30%	30%
Environmental / Compliance			
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
Continuous Improvement			
Enhance core AM processes and systems	Average AMMAT Score	3	

3.4 **Capability to Deliver**

The AMP planning process intends to ensure that on-going and annual reviews of policy, process and performance informs asset management requirements and associated resource needs. While the targets are generally achievable given the current network configuration, condition and planned expenditure levels, there are some areas that do require further analysis to clearly understand how practical the current asset management objectives are, particularly as trends in actual expenditure against budget to date have been variable.

Recent changes to organisational structures, roles and responsibilities outlined in Section 2 have allowed for improved means of authorisation and business capabilities to support the implementation of asset management plans.

Skill shortages and current resource (personnel) limitations are acknowledged as a key factor influencing the timeframe required to plan and deliver the quantum of work programmed over the 10 year period. These risks along with others are discussed further in Section 4. While prioritisation processes assist to focus on areas considered to be high risk, further work is required to more accurately quantify and prepare for future needs (including training and development). Aurora will continue to work on gaining a better understanding of these needs over the coming year.

The following section discusses risks associated with the network and network performance as well as business risks that are being managed by Aurora.

4 Risk Management

4.1 Introduction

Aurora has contracted Delta to undertake asset management services under a performance related contract. Delta recognises that risk management is fundamental to asset management and as such has undertaken risk management and business continuity planning for the services and assets that Aurora is responsible for. Note that where references are made to Delta in this section, that reference by implication also includes Aurora as a result of the contracting arrangement in place.

4.2 Context

A review of risk management philosophy, framework and approach has been undertaken as part of a Risk and Business Continuity Project. The outputs from this are being used to introduce more robust risk management objectives, processes and systems so that Aurora can identify and plan for acceptable levels of risk. The approach to this is based on the AS/NZS ISO 31000:2009 Risk Management Standard and the risk management framework is demonstrated in the following diagram (Figure 4.1).

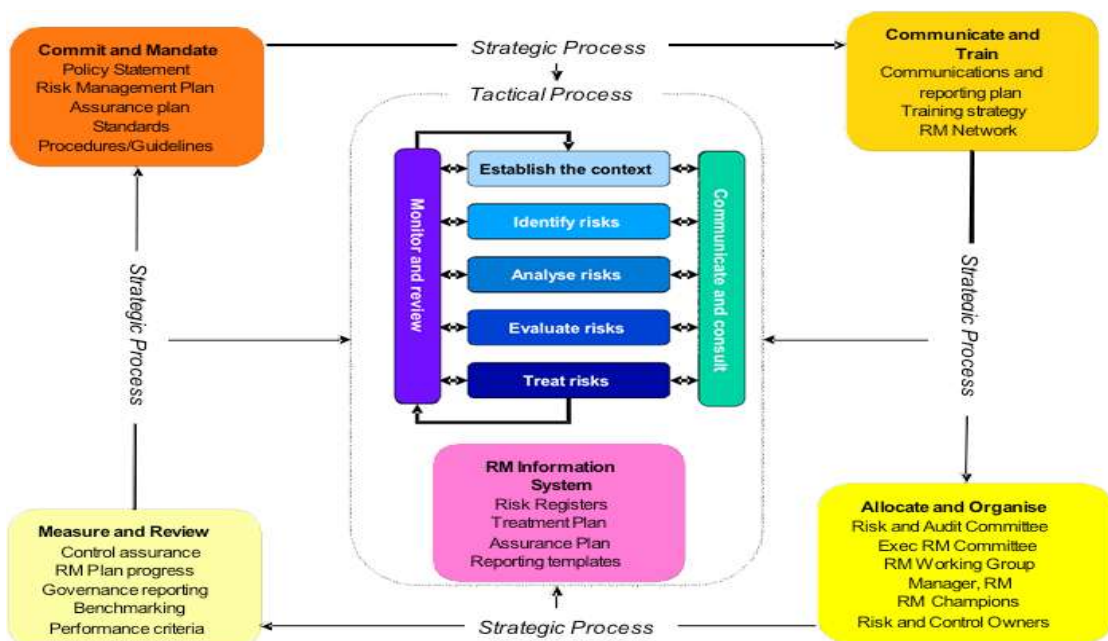


Figure 4.1 - Risk Management Process (AS/NZS ISO 31000:2009)

4.3 Responsibilities for Risk Management

Figure 4.2 sets out the responsibilities for risk management and is followed by commentary on risk responsibilities.

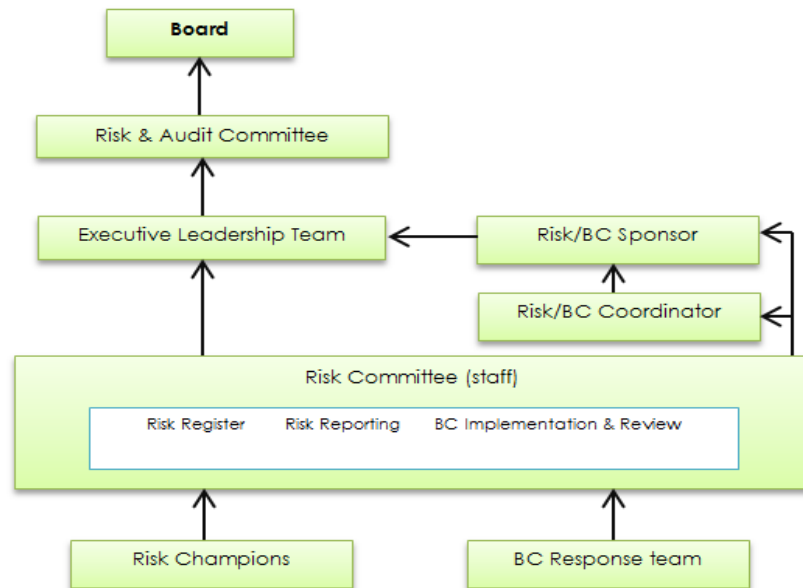


Figure 4.2 - Risk Management Responsibilities

Board

The Board have overall responsibility for risk management. Significant risks are reported to the Board. The Audit and Risk Committee is delegated the governance responsibility for risk management.

Audit and Risk Committee

The Audit and Risk Committee provides oversight of risk and assurance framework and performance.

The Audit and Risk Committee meets monthly to review the risk context, key risks and key controls.

Executive Leadership Team

All Executive Leadership Team members and their Managers are responsible for ensuring the implementation of the risk management process through implementation of risk plans / tools and processes; risk identification analysis and management within their function; risk analysis and evaluation at the leadership team level; staff capability and training for risk management.

Managers

Managers are responsible for managing risks within their portfolios through the application of risk management process and systems including training, risk identification, risk analysis (risk register), risk treatment and risk monitoring / reporting.

Project/Asset Managers and Staff

Project Managers and staff are responsible for the day-to-day management of project risks that affect the achievement of project / programme objectives through risk identification and analysis, risk management intervention (treatment plans) and monitoring, and risk reporting.

Suppliers/Contractors

Where an activity is outsourced, the supplier/contractor is to ensure that risk management plans, processes, systems and tools (e.g. risk register) are implemented, risk reporting to the manager responsible project being delivered by the supplier / contractor, and mitigation of risks in accordance with direction from the Principle.

Business Continuity Overview

A business continuity programme has been developed that supports risk management. Senior management have committed to leadership and sponsorship of the business continuity programme. This will help ensure that the organisational culture recognises that business continuity is an important part of normal business practice, and therefore an operational responsibility for all staff. To enable this to occur a Business Continuity Policy and Framework document has been adopted.

A Business Continuity Plan and a Business Continuity deployment plan (ready response guide) have been written to address major business interruptions.

4.4 Risk Process & Methodology

Risks are analysed in terms of treatment using the following methods:

- **Actively accept** – accept the risk and consider options for the treatment of the risk;
- **Passively accept** – accept the risk as it is, i.e. no further treatment is appropriate or possible at this time;
- **Transfer/share** – pass the risk in whole or part to others e.g. through contractual agreements or insurance. Appropriate where others are best able to manage the risk;
- **Avoid** – change parts of the activity so that there is no longer any exposure; and/or
- **Active treatment** strategies:
- **Minimise** – reducing the likelihood of experiencing the threat; and / or;
- **Mitigate** – reduce the consequence of experiencing the threat by means such as establishing 'post occurrence' contingency and disaster plans to reduce the consequence of experiencing the risk.

Risks need to be controlled and managed within acceptable limits to achieve the most satisfactory outcome. Where risk cannot be eliminated, training, competency, safe work practices and asset design / maintenance are used to control risks.

Risk also includes opportunities. Opportunities for network improvement, capital / operating expenditure spend (efficiency and effectiveness) and workplace practice efficiency need to be identified and where appropriate, accepted and implemented.

Risk is measured by likelihood / consequence as set out in the following table. The context in which each risk is addressed is the significance of the risk on the activity in question.

Table 4.1 Likelihood and Consequence Matrix

Likelihood of Frequency	Almost certain (5)	Class 2 Moderate	Class 2 Moderate	Class 3 High	Class 4 Critical	Class 4 Critical
	Likely (4)	Class 2	Class 2	Class 3	Class 4 Critical	Class 4 Critical
	Possible (3)	Class 1 Low	Class 2 Moderate	Class 2 Moderate	Class 3 High	Class 3 High
	Unlikely (2)	Class 1 Low	Class 1 Low	Class 2 Moderate	Class 3 High	Class 3 High
	Rare (1)	Class 1 Low	Class 1 Low	Class 1 Low	Class 2 moderate	Class 3 High
		Insignificant	Minor (2)	Moderate	Major (4)	Extreme (5)

The level of risk acceptability and the management of the classes of risk set out above are explained in the following table:

Table 4.2 - Acceptability / Management Required

Risk Level	Significance	Level of Risk Acceptability	Extent of Management Required (e.g. Prevention, Mitigation, Reporting, Auditing)
Class 1	Low	Tolerable if improvement is uneconomic.	Low-cost prevention or mitigation where justified. Should be periodically reviewed.
Class 2	Moderate	Most likely unacceptable; but may be tolerable if the cost of risk elimination or reduction is greater than the improvement gained.	Preventive measures and mitigation measures required, where practicable. Requires routine review.
Class 3	High	Unacceptable without further control or treatment; may be tolerable if the cost of elimination or reduction is significantly greater than the improvement gained.	Preventive measures are required where practicable. Mitigation measures required in all cases. Requires regular review. Reported immediately to the Divisional Manager.
Class 4	Critical	Intolerable. Risk reduction must be implemented.	Prevention and mitigation measures reported immediately to the Chief Executive.

4.4.1 Risk Management Policy

Aurora endorses and implements the following risk management policy statements. :

- That a risk management framework and process in compliance with good practice (using the AS/NZ ISO 31000:2009 Risk Management Standard) developed and maintained;
- All risks will be recorded, captured and maintained in the Risk Register;
- Significant risks must be identified, analysed, assessed and reported on a timely basis to the appropriate level of management;
- Project managers will ensure project risks are identified and captured in risk reports to management and the Audit and Risk Committee / Board;
- Risk controls or mitigations are current, tested and remain effective;
- Learning from incidents, investigations or other sources will be part of continuous improvement;
- Staff are adequately trained, skilled and resourced for managing risks;
- Risk management is part of the culture of operations of Delta and Delta's contractors;
- Risk performance measures will be used in management reporting processes;
- The risk management process outlined in the framework document is to be used at all times, except when management determines that because it has low levels of uncertainty or is less complex that it realises little or no value.

Risk Assessment

A risk assessment worksheet is used to capture detailed data on each risk. The worksheet identifies the following information:

- Risk assessment number
- Activity
- Risk description and hazards
- Risk category
- Consequence and likelihood assessment
- Worst foreseeable outcome
- Risk analysis
- Management / Effectiveness of controls

- Treatment options
- Risk action plan

The risk register contains the following data:

- Risk assessment number
- Risk type
- Risk name
- Description
- Status – active / dormant / closed
- Threat or opportunity
- Existing controls
- Consequence and likelihood assessment
- Score (out of 25)
- Treatment plan summary

Risk categories

The following list outlines the risk categories that are used to categorise the types of risks that Aurora has (or will identify) as part of its risk management programme:

- **Health and Safety** – a risk that threatens the physical safety of staff, contractors or the public.
- **Operational Capability** – a risk that reduces or prevents the company being able to successfully deliver its services or manage its assets.
- **Skills and Knowledge** – a risk that is created because the level of skills and knowledge about systems processes and asset management is not available.
- **Cultural/Community** – a risk where there is a direct impact to the community as a result of a system, process or asset failure.
- **Legal Compliance** – a risk where the company is found to have breached an existing regulation / compliance requirement, or where regulatory requirements impact on the ability and capacity of the company to manage its assets and services to meet the community requirements in a cost effective manner.
- **Financial** – a risk where the company will suffer a direct financial loss or fail to take advantage of an opportunity to generate a financial benefit.
- **Reputation** – a risk that could or does result in serious damage to the reputation of Aurora
- **Environment** – a risk that could or does result in a negative impact on the environment because of an activity being undertaken by Aurora.
- **Time (projects)** – a risk where failing to achieve time deadlines will result in a negative impact on assets and services.

The following section covers details on these categories under the headings of 'network' and 'business' risks.

4.5 Network Risks

The following section provides information regarding the main network-related risks linked to the asset management attributes of safety, reliability, quality and security.

4.5.1 Safety

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.

A healthy and safe environment is achieved by duties set by all parties associated with design, construction, maintenance and operation of Aurora assets.

Hazards are controlled through training, guidelines and standards. Potential hazards, in particular electrical hazards, must also be considered when new network installations are being designed and constructed.

Hazards have been included in the risk register under specific risk headings.

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.

Staff

Aurora requires Delta's line managers to take responsibility for themselves and their staff to manage hazards which may be present in their work areas. A risk based hazard assessment has been implemented and Delta uses a systematic approach to identify, assess and manage potential hazards in the work place. The Safety Action Groups (SAG) provides the mechanism for delivering and monitoring health and safety practices including reporting. Support from health and safety practitioners is also important.

Contractors

Contractors are responsible for ensuring that they meet all necessary safety requirements and obligations for working on Aurora assets. Under the HSE Act contractors are responsible for safety and competency of their employees working on Aurora assets. Contractors must have their own documented health and safety management systems and they are further reminded of their health and safety obligations when they sign a new contract. Regular site audits are carried out to ensure compliance. Since almost all work associated with Aurora's network is carried out by contractors (and the main asset management contract being with Delta), a risk register has been developed of specific known hazards along with recommended actions to control hazards. Most hazards can be managed if access to hazardous areas is restricted to competent personnel, and industry recognised safe working practises are used.

Public

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 (PSMS) has been developed and implemented by Aurora, 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.

Legacy assets

With long life networks there are inevitably a number of legacy assets that do not meet improved operational or safety standards. When staff become aware of assets or safety issues that do not meet modern expectations, they can report the issues via the network service request process and/or the CAPA (correct and preventative action) process. Appropriate mitigation measures are then determined, prioritised and actioned to reduce the risk to the general public, staff and contractors.

These actions may include full replacement or may include strategies to reduce risk until replacement can be achieved.

Examples of where those types of risk are being managed by Aurora are: zone substation buildings (in terms of fire protection, security, earthquake strengthening and the presence of asbestos in some building materials), legacy issues related to historic design and management of the central network; glass tube fuses; Andelect fuse boxes and older link-boxes; cast-iron pot heads and poles that are in poor condition preventing safe network operation.

Earthquake prone buildings

The Canterbury earthquakes of September 2010 and February 2011 raised awareness levels of the fragility of a large number of older buildings in New Zealand to withstand earthquake forces. Dunedin is susceptible to similar type damage to older buildings and to utility services in general, not just electricity supply.

In response to recommendations from the Royal Commission for changes to the building legislation, more comprehensive assessments of fire, security and earthquake risk for all of Aurora's zone substation buildings are being carried out. Outputs from this will inform the revision of the building maintenance and/or upgrade programmes for 2014/15 onwards.

Emergency response procedures are also being developed to take into account this specific risk.

4.5.2 Reliability

Risks that potentially impact on reliability include:

- Loss of staff / contractor capacity and / or capability
- Capacity to meet demand
- Funding for asset development / maintenance
- Skills and knowledge for new assets / restoration of faults
- Access / knowledge of staff / contractors of equipment and process manuals
- Adequacy of asset management programme
- Adequacy of equipment replacement programme

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.

Probabilistic analysis 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.

A "deterministic filter" to highlight areas of the network that require further economic analysis is shown in Appendix A.

Expenditure is presently planned to achieve the supply reliability targets set out in Section 3. See Sections 5 and 6 for detail on expenditure for project related to reliability.

Probabilistic analysis is also used to justify small scale projects, such the installation of reclosers to improve SAIDI. Also refer to Section 6 for an outline of the planning criteria used by Aurora.

4.5.3 Quality & Capacity

A key element for planning risk management strategies for assets is an understanding of the short, medium and long term requirements for maintenance of existing assets and the development of new assets.

The capacity requirement for the life of assets needs to address growth (positive and negative as noted in the above list) requirements for the consumer.

Key risks that potentially impact on quality include:

- Growth (negative and positive)
- Supply reliability
- Systems failure or inadequacy (information technology, systems knowledge)
- Loss of facilities
- Legislative / regulatory changes
- Investment in asset development and maintenance
- Third party supplier availability / default / competence
- Lack of standard procedures & work instructions

The following information relates to growth specifically:

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%.

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

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 on-going second order risk. Equipment is relocated if it is economic to do so.

4.5.4 Security

Security of supply is the ability of a network to meet the demand for electricity in certain circumstances where electrical equipment fails or where an incident compromises service delivery. Security of supply differs from reliability which has been addressed earlier in this section.

Key risks that potentially impact on security include:

- Natural disasters
- Critical supplier failure
- Aurora infrastructure failure – poles, substations, generators, lines
- Single-point dependencies
- Staff / contractor availability for extended outages
- Rural isolation of sites
- Reliance on the mobile substation

Providing the acceptable level of security (cost versus the customers 'willingness to pay' to provide a certain standard of security) is part of project planning requirements when developing new assets or considering maintenance requirements for existing assets.

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

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

- safety and environmental compliance requirements
- maintaining security of supply standards
- meeting reliability of supply targets.

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. The following table identifies areas of network 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.

GXP Area	n-1 Transpower Capacity MVA	Distributed Generation MW	n-1 Security
Halfway Bush	107	95.9	No
South Dunedin	81	2.2	Yes
Clyde	27	23.4	Yes
Frankton	66	4.1	Yes
Cromwell	50	5.6	Yes

Also see Planning Criteria in Section 6.2.

Hazard mapping

Aurora's network has been mapped against the hazard areas identified through work being carried out by the Otago Regional Council as part of lifelines planning. Aurora continued to build on this information throughout 2013 through further assessment and identification of critical sites/routes as well as risk interdependency issues, including off-grid critical assets. Aurora will be undertaking further work in 2014/15 on:

- Robustness/vulnerabilities to each hazard risk identified.
- High-level preparedness and plans for enhancement and further risk reduction.
- Emergency response dependencies and priorities, especially in relation to other lifelines.

This work will both inform and be informed by the risk management activities discussed in Sections 4.2 - 4.4

4.5.5 Criticality and Network (Asset) Risk Analysis

Over the recent past, Aurora's focus has turned to assessing and understanding critical assets and the risk profile of the distributed electricity network.

The framework for assessing criticality was further developed during 2013/14 and has initially been applied at zone substation level. From this, a priority list of zone substations has been generated which provides a means to prioritise both planned and unplanned works that might occur across multiple zone substations.

The following attributes were collected for each zone substation:

- Load at risk: Non-transferrable load at each zone substation
- # of Priority 1 Customer Connections – Hospitals
- # of Priority 2 Customer Connections – 3 Waters, Police, Fire and other emergency services
- # of Domestic ICP's
- Value of Lost Load

The main assumption asks "What is the impact of a major fault on feeders attached to this zone substation compared to any other?" The combination of these attributes provided a defensible basis for

prioritisation of works across zone substation feeders. An excerpt from the detail is shown on the following page and Box 1 provides an example of how it has been applied.

Such assessments provide a consistent basis for developing risk-based programmes of work across the portfolio of assets owned by Aurora. The aim of these programmes is to deliver value back into the network by targeting critical works as a priority.

List of Zone Substation	Relative Criticality Score
Halfway Bush	725.15
Frankton	578.80
Wanaka	491.23
Andersons Bay	404.34
Green Island	390.87
Cromwell	300.09
Port Chalmers	266.63
Alexandra	226.87
Arrowtown	171.01
Commonage	133.91
East Taieri	127.13

Box 1

Ground-mount Substation Fibreglass Covers

The Dunedin network features a large amount of ground mount switchgear and distribution substations installed within fibreglass enclosures. These enclosures have now begun to exhibit a number of structural failure modes (see below) that could result in a risk to public safety due to exposure of the HV/LV termination boards or busbars.

- UV Damage is a continuous threat to the structural integrity of the units. Units will become brittle under prolonged UV exposure leading to a diminishing load bearing capacity. A severely compromised unit could easily fail under a low applied mass (i.e. > 20kg).
- Wind is known to warp the enclosure causing the doors to become losses, opened and in some cases completely detached. This is in part due to a sub-optimal locking arrangement which uses a barrel type door lock (i.e. Yale or similar).
- Under high wind conditions the entire cover could feasibly become mobile if the mounting pins are not securely detached.

A two stage risk based programme to refurbish the enclosures was developed comprised of:

1. Inspection of all 276 ground-mount transformer sites in Dunedin city;
2. A refurbishment programme that will target the high risks sites as a priority.

The zone substation criticality list will then be used as a final layer of priority to the refurbishment programme.

The approach taken to identify areas of the network that are vulnerable to high impact, low probability events will be further developed in 2014/15.

The following provides a summary of some of the asset and network risks that Aurora is working through. 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. Sections 5 & 6 also contain detail on projects to address these issues.

Poles

Poles are assessed for their condition based on a scale of 0-6, with zero being very bad condition. Condition 0 means an overhead line structures which is at risk of failure under normal structural loads, and there is a risk of injury to any person or damage to property other than that of the owner of the line.

Of the 34,000 wooden poles on Aurora's network, 5% have nominally been evaluated as condition 0. Up to 40% of these have been labelled condition 0 as a precaution due to constraints on pole assessment (for example, concrete embedment). Technology options for direct measurements of pole strength to support revised condition ratings and cost estimates are under consideration. A trial of available technology is being undertaken in 2014.

Under the Electricity (Safety) Regulations (2010) condition 0 poles must be repaired or replaced no later than 3 months after finding the risk of failure. Based on this, there are currently 1670 condition 0 poles (as at December 2013) pending replacement.

Amongst the 1670 condition 0 poles, some have assets on them that require manual operation or hold other network assets, such as transformers; and some may have assets from other utilities (e.g. Telecom) attached.

Revised condition assessments will assist to rationalise the number of poles requiring replacement within the 10 year planning period.

Further to this, the work on pole condition assessment will be supplemented with the work that Delta is doing to develop and implement a more robust risk assessment framework that collates condition based observations and consequence of failure to produce an asset health index for each structure. This will also assist to improve the risk-based prioritisation process used to inform the replacement and maintenance programmes.

At present, a renewals budget of \$3M per annum has been allocated for pole replacement.

Vegetation Management

Vegetation has been assessed (in 2011) for proximity to Aurora's lines using a rating of 0-7, with zero being vegetation that represents an immediate danger to person or property through to a rating of 7 where the vegetation has been removed.

Under the Electricity (Hazard from Trees) Regulations 2003, Aurora must attend to the vegetation with a rating of 0 without delay. Based on this rating, there are 5,400 condition 0 areas that require cutting. Over a third of Aurora's planned maintenance budget has been spent on vegetation management annually to date. Additional funding for preventative maintenance was approved by the Board in 2013 with the intention that further works would target vegetation management.

It has been difficult to assess the impacts of the current vegetation programmes on network reliability. This is the subject of ongoing analysis.

Aurora is working with its contractors to improve the vegetation management process. The development of a more robust risk assessment and prioritisation framework is expected to improve its effectiveness.

Zone Substation buildings

Aurora has 36 zone substations and many (particularly in Dunedin) are housed in buildings that are up to 70 years old and likely to require significant upgrades to meet today's standards. Comprehensive assessments of fire, security and earthquake risk for all Aurora's zone substation buildings were carried out in 2013/14 and prioritised investment programmes developed for delivery from 2014/15 onwards. Additional investment for earthquake strengthening is likely as is the need to address the presence of asbestos in building materials. Some provision has been made for these needs in the expenditure programme, however it is likely that this requirement could potentially increase following detailed investigations and assessments. There is a potential asbestos risk within at least one of Dunedin's substation buildings and this will be addressed in 2014/15. Some provision has been made in the capital programme to mitigate this risk, however further investigations may reveal risks at other sites.

Capacity risks

Based on load growth forecasts and the aforementioned criticality assessments, the substations that reflect critical parts of the network (and are therefore a priority for Aurora to focus on) include:

- Dunedin - Andersons Bay, Green Island and Halfway Bush
- Central - Wanaka, Cromwell, Frankton and Alexandra

Altogether, there are 12 zone substations that do not have n-1 security and currently rely on the availability of the mobile substation for back-up in an emergency. Options to reduce this risk are being considered. See Section 6 for projects proposed to address these issues.

Security

Within the HV and LV distribution network there are also particular single-point dependency sites that only have one source of incoming supply. When failures occur on these parts of the network, mobile generators are required to assist with providing back-up supply, at a cost to Aurora (as they are leased). Options to mitigate this that are under consideration include purchase of a mobile generator.

Interdependence with other services

Many service organisations rely on the services of others to perform. In particular communication systems are of critical importance to all lifeline utilities. It is important to understand this interdependence in the recovery phase of any natural disaster or event that triggers a major business interruption.

As a member of the Otago Engineering Lifelines Group, Aurora recognises the importance of being part of a wider lifelines network to contribute to regional planning, preparedness and response capability.

4.6 Business Risks

4.6.1 Strategic

The operating environment for Aurora will remain challenging in the face of uncertain economic conditions and on-going pressure on local government expenditure.

Key issues that Aurora faces in the short / medium future include:

- Development and growth leading to demand growth (or lack of growth)
- Global influences on pricing / costs and service standards
- Investment and affordability – business competition; aging infrastructure
- Significant investment in upgrades and replacement
- Customer affordability for services and development requirements
- Cleaner energy
- Smarter energy
- Changing energy requirements – alternatives to electricity
- Changing shareholder (Council), regulatory and government environment (local and central government)
- District and Regional Planning documents – development controls, enforcement of consents
- Geographic spread of operational locations - isolation
- Safety – injury / death related to the asset development and delivery of services
- Organisational capability and capacity
- Natural disasters and climate changes – e.g. lake storage levels

Property Related Risk – Leased Land / Easements

Aurora lease land for radio sites and other network related uses. Rent reviews could significantly increase the cost of leasing land. For future security of land required currently under lease Aurora needs to consider whether a property purchase programme is needed to secure the land and ensure financial security.

Aurora has a number of easements for network services particularly over land owned by the Dunedin City Council (the shareholder). Council has started to charge a one off fee for future easements; and depending on the size of the easements, these costs are potentially significant. Aurora needs to consider other mechanisms such as designating the land in the District Plan.

4.6.2 Compliance

A key risk to Aurora is non-compliance with legislative and regulatory requirements. Aurora aims to achieve material compliance with all relevant legislation, regulations, standards and codes of practice that relate to how the electricity distribution network is managed and maintained, including any relevant environmental legislation. A list of the main pieces of legislation is provided in Section 2.4 and Aurora's business/quality management system provides the tool to ensure compliance is monitored and achieved. The following on provides further commentary.

Environmental

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 Local Authority District Plan 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.

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. However, it is noted that SF₆ used for Aurora's distribution switchgear is likely to increase in response to the existing oil-based options being discontinued.

Disclosure Requirements & Price-Quality

Aurora is subject to regulation under Part 4 of the Commerce Act 1986, for price-quality regulation and information disclosure. As such, Aurora is required to provide an audited self-assessment (compliance statement) to the Commerce Commission against the DPP on an annual basis as well as disclose other information related to asset management (performance statements) and other measures such as financial statements, through to technical measures such as transformer utilisation. See the Aurora website for more detail.

In 2012, the Commerce Commission published new determinations for information disclosure requirements (these supersede the 2008 requirements). This AMP has been revised from earlier versions to align with the regulatory requirements of the new Electricity Information Disclosure Determination 2012 and provides more comprehensive information on for Aurora's asset management practices and expenditure forecasts; (see Appendix B for compliance matrix).

Civil Defence

Aurora is defined as a utility under the Civil Defence Emergency Management Act and is required to ensure that it can operate to the fullest extent even if at a reduced level, during and after an emergency. Delta staff have roles within the Civil Defence structures in Otago. Delta staff take part in Civil Defence exercises as required.

Other

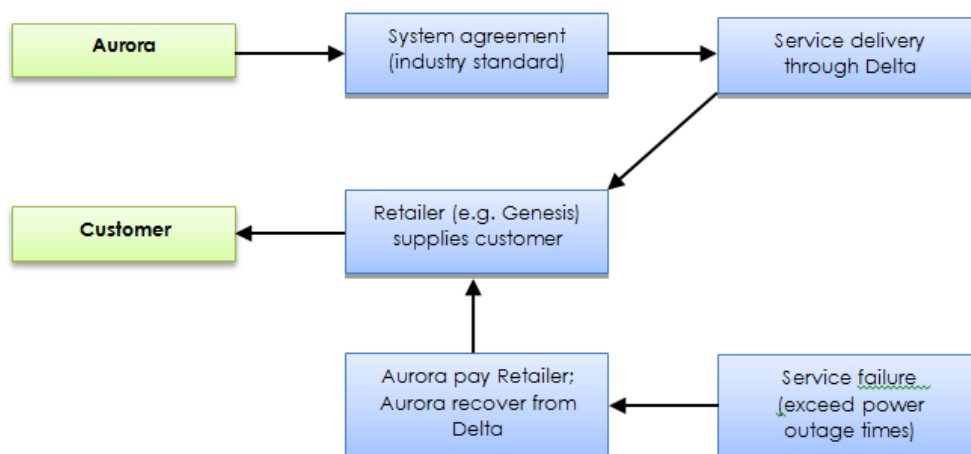
Recommendations from the Royal Commission report into earthquake-prone buildings and seismic strengthening may lead to changes in building legislation and related requirements are already driving the need for Aurora to allocate expenditure (e.g. zone substation buildings).

4.6.3 Commercial

Key commercial risks that Aurora has identified include:

- Finance
- Pricing
- Insurance
- Contracts
- Industry Submissions
- Optimisation & Sustainability

Section 3.2.4 discussed responsiveness and service failure payments. Aurora has agreements with retailers in terms of the supply of energy. The following diagram illustrates the linkages:



Use of System Agreement

Customer Service (Reputation)

Some of the risks that potentially impact on reputation and service include:

- Damage to Aurora assets by third parties affecting supply of power
- Speed of response to incidents / outages
- Staff / contractor skills and knowledge
- Customer-relations
- Not meeting level of service commitments

Customer / stakeholder interests are addressed in detail in Section 2.3 and 2.4 of this AMP.

Feedback has been sought from both customers and stakeholders through surveys, open requests for feedback, safety reviews, industry forums, and through day to day customer engagement (e.g. phone complaints).

4.6.4 Human Resources

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 is compounded with the need to design and order items such as power transformers before finishing detailed design. Resource consent processes and the possibility of objector delays creates further uncertainty.

4.6.5 Information & Process

Information and Technology Services and Equipment

Key risks have been identified in the areas of:

- Information services equipment (hardware and software)
- Telephony equipment
- SCADA
- Site information e.g. underground wiring plans

In delivering services, all staff depend on access to reliable, effective and efficient information and technology services and equipment. This includes access to systems and data. A disaster recovery plan for IT related information and services has been deployed and tested in the past.

Risk Programme

The risk management programme includes information and processes for the risk policy and framework, risk register, risk data collection sheet, and risk reporting.

Further work is planned for 2014 to continue to develop the risk register, risk assessment and information analysis, and risk reporting.

Post Incident Reviews

A process has been developed and implemented to undertake reviews after incidents that cause the activation of the business continuity plan or where the incident has a high potential or actual impact on Aurora services

The incident review process includes hot debriefs, cold debriefs and incident reports.

A report is provided on the findings of the review. Depending on the type of incident and the findings of the review the report may be reported to a line manager, general manager, Chief Executive, Audit and Risk Committee or the Board.

4.7 Risk Mitigation

4.7.1 Procedures and Plans

A risk management framework and implementation plan has been developed to identify and address risks to the business.

A risk register has been developed to capture data on each risk, any existing controls to treat the risk, the consequence and likelihood of the risk and a treatment plan summary.

The risk register is supported by a more detailed risk assessment worksheet that is designed to capture more detail about the risk including the effectiveness of current controls and the risk action plan for that particular risk.

Risk management documents developed include:

- Pandemic Planning
- Risk Management Policy
- Risk Management for Electricity Networks
- Civil Defence Policy re Electricity Supply
- Emergency Preparedness Plan
- Emergency Communications policy

4.7.2 Business Continuity and Emergency Response Planning

Emergency response planning is based on the concepts of the Four “R’s” used by emergency services, Civil Defence Emergency Response Organisations and many utility operators in New Zealand. This terminology is included in readiness and response documentation and training.

The Four “R’s” are:

Reduction – identifying and analysing risks to the business, assets and community, and taking steps to eliminate or reduce those risks

Readiness – Developing operational systems and capabilities before an incident occurs so that the organisation is prepared, trained and tested to respond in a way that will ensure the business can return to full operational capacity as soon as is possible

Response – Actions taken immediately after an incident occurs to protect life and assets, and take initial actions to ensure the business can consider returning to full operational capacity

Recovery – The coordination of the organisation (and potentially external organisations) to return the business to full capability (recovery can take weeks, months or years depending on the severity of the incident e.g. Canterbury earthquakes).

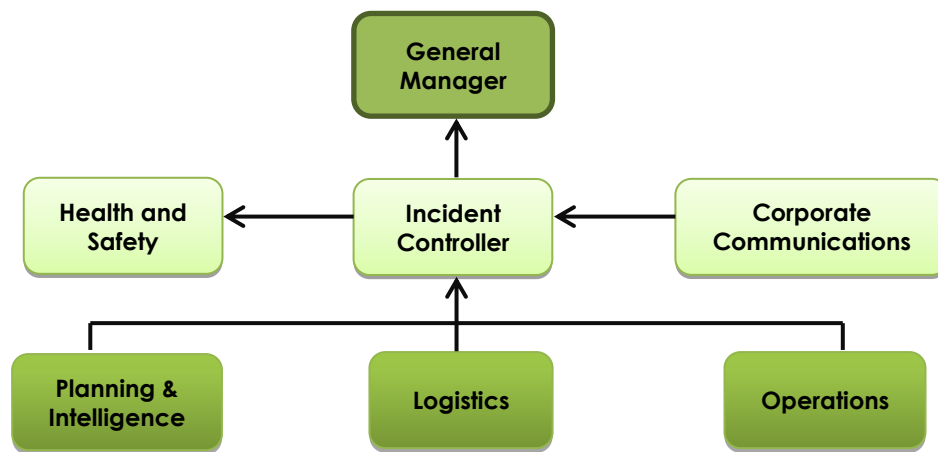
The company has a business continuity programme in place to respond to major incidents. The programme includes:

- Business continuity plan for response
- Response guide for use in an incident
- Responder training
- Plan exercise and testing programme to demonstrate capability and competence.

Operational incidents (e.g. asset breakage) are part of normal business operations and staff are trained to deal with those day to day situations as part of their training and development plans.

For major incidents business continuity planning is in place to respond to those incidents.

Response planning incorporates the use of the Coordinated Incident Management System (CIMS) which is used by emergency services, Civil Defence Emergency Response Organisations and many utility operators in New Zealand to respond on site and escalate incidents to senior management. The model is:



Coordinated Incident Management System Model

Aurora's contractor, 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 in a variety of quality control documents including.

Civil Defence

Civil Defence Emergency Management Act

Aurora is defined as a utility under this Act and is required to ensure that it can operate to the fullest extent even if at a reduced level, during and after an emergency.

A plan is in place 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 contained in quality controlled documents: Civil Defence and Emergency Preparedness Plan. These documents are updated every two years. 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.

Staff also have roles within the Civil Defence structures in Otago and 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 learnt to key staff.

Contingency Plans

Contingency plans have been developed to assist in the timely restoration of supply following an outage to a major distribution feeder or zone substation. It should be noted that it is not possible to offload peak loads at most substations for potentially rare "n-2" events; i.e. 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.

Other contingency plans include: Oil Spill Control; Incident Reporting and Investigation.

A Participant Outage Plan details how Aurora would manage severe energy shortages if the Electricity Commission declared that savings are required.

4.7.3 Conclusion

This section has highlighted the main network and business risks related to Aurora's activities. The following sections cover the lifecycle management practice and programmes as well as network development projects that are planned to minimise or mitigate many of these risks.

5 Life Cycle Asset Management

5.1 Introduction

The following section provides an overview of Aurora's network, details of the assets by asset category, the approach taken for management throughout their life cycle and associated expenditure forecasts.

5.2 Network Overview

An assets lifecycle commences with the identification of the need for an asset and terminates with the decommissioning of the asset or any liabilities thereafter (IIMM, 2011⁷). Aurora's manages electricity assets throughout their life cycle in three geographically separate networks (Dunedin, Central Otago and Te Anau), with both rural and urban characteristics, as shown in Figure 5.1 below. Delta operates the network, carries out network planning and develops the maintenance plans and programmes on behalf of Aurora; and Aurora is committed to enabling the implementation of these.

Approximately 60% of Aurora's overhead circuit length is located in rural/rugged terrain and approximately 40% in urban areas.

- The Dunedin network includes - urban areas of Dunedin, Mosgiel, and the inner reaches of the Taieri Plains, supplying over 53,700 customer connections. The Dunedin area is supplied from two Grid Exit Points (GXP's), between which Aurora has significant interconnection at 6.6 kV and 11 kV.
- The Central Otago network - 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; and supplies over 29,000 customer connections. The Central region is characterised by its separate river valley areas, mandating a radial network supplied from three transmission GXP's. Aurora has no high voltage interconnections between the Central GXP's.
- A small embedded network, connected to The Power Company network, was installed in Te Anau in 2005; and supplies over 80 customer connections.

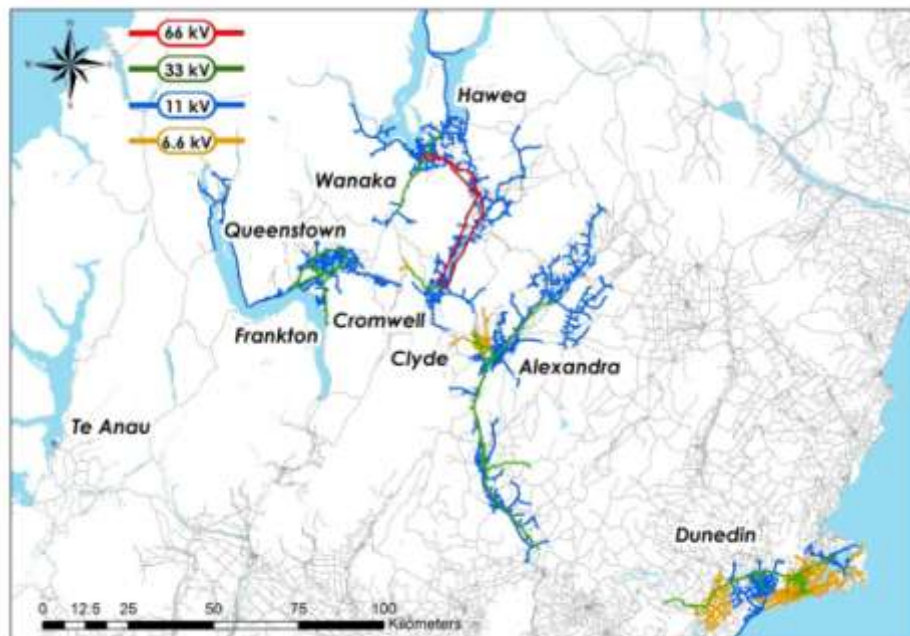


Figure 5.1 – Aurora Network

⁷ NAMS and IPWEA (2011) International Infrastructure Management Manual v4.0

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) (also see Section 3.1.1)

Load Characteristics

The load in all areas is dominated by residential and commercial load. All GXP areas have their peak demand in winter. For each GXP the daily peak loads for 2013 are shown in Figure 5.2.

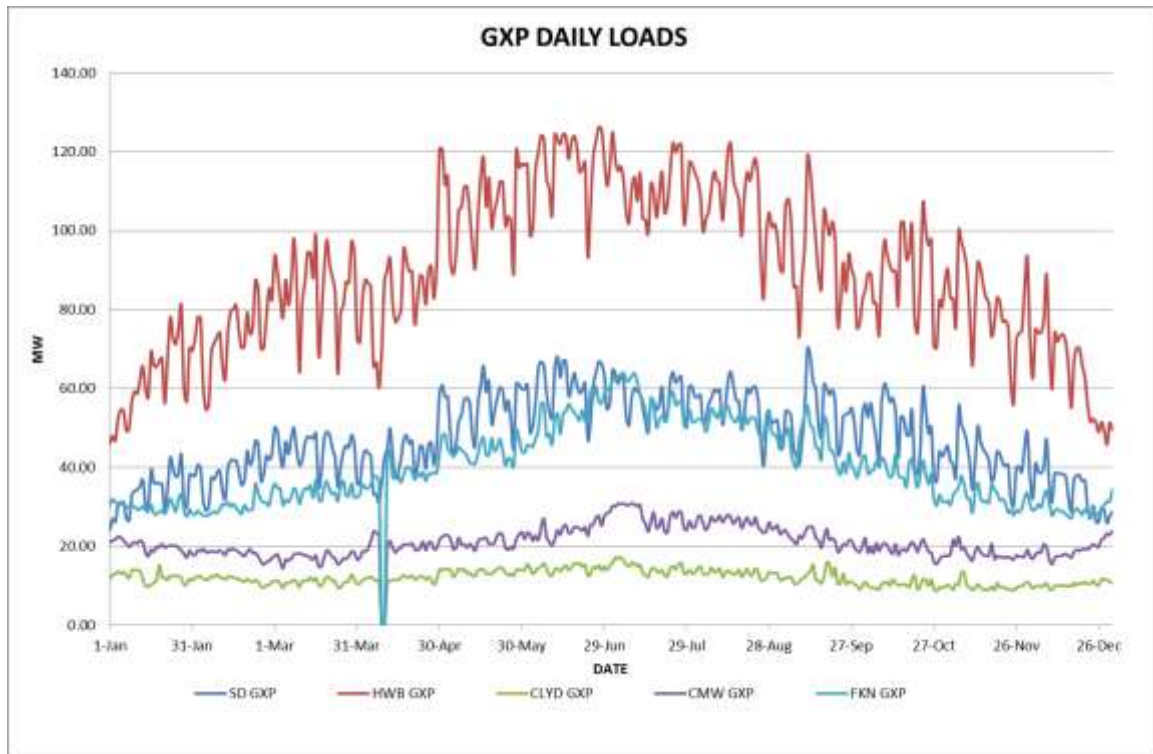


Figure 5.2 – Graph of Grid Exit Point Daily Load Peaks (2013)

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 leading to summer peaking at the Queensberry zone substation.

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. However, the Berwick Zone substation load is driven by dairy activities and as such has summer peaking.

Sections 6.3 and 6.5 contain further detail on demand forecasting and predictions.

2013 Load Data

The key load and distributed generation statistics for the 2013 year are presented in Table 5.1

Table 5.1 – GXP Load and Capacity Summary

(y/e 31 March 2013)

GXP	Clyde	Cromwell	Frankton	Halfway Bush	South Dunedin	Total
2013 peak MW including distributed generation	17.4	31.7	51.9	128.5	70.5	
2013 energy transported GWh	85	140	219	578	308	1338
Total number of ICPs	6,781	11,032	12,272	37,061	16,805	83,951
Off take n-1 capacity (24 hour winter post contingency) MVA	27	40.9	80	112	81	

Distributed Generation

Aurora has approximately 131MW of distributed generation connected to its networks. 118 MW is associated with generation dedicated to export and 12.9MW is associated with consumer installations connected behind load. See Table 5.2 for a schedule of distributed generation by GXP and owner. Table 5.3 provides 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 (CPD). There is a small quantity of consumer photovoltaic (PV) generation, a single small wind generator and two micro hydro connections. In the last year there has been a marked increase in applications to install small domestic PV units.

Table 5.2 – Schedule of Distributed Generation Dedicated to Export

(y/e 31 December 2013)

GXP	Generation Owner	kW
Clyde	Consumer	123
	Pioneer Generation Ltd	21,125
	Talla Burn Generation Ltd	2,150
Clyde Total		23,398
Cromwell	Consumer	2,073
	Pioneer Generation Ltd	3,550
Cromwell Total		5,623
Frankton	Consumer	2,009
	Pioneer Generation Ltd	2,131
Frankton Total		4,140
Halfway Bush	Consumer	6,697
	TrustPower	89,200
Halfway Bush Total		95,897
South Dunedin	Consumer	2,171
Grand Total		131,229

Table 5.3 – Summary of Distributed Generation

(y/e 31 December 2013)

Energy Source	Count	Rated kW	Proportion
Hydro	24	79,913	60.9%
Wind	6	38,302	29.2%
Diesel	21	10,033	7.6%
Process heat	1	2,240	1.7%
Wood	1	230	0.2%
PV	194	509	0.4%
Total		131,229	100%

5.2.1 Dunedin Network

The Dunedin network area is supplied from the Halfway Bush and South Dunedin GXPs 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 feed 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 5.3a and zone substation details are in Table 5.4.

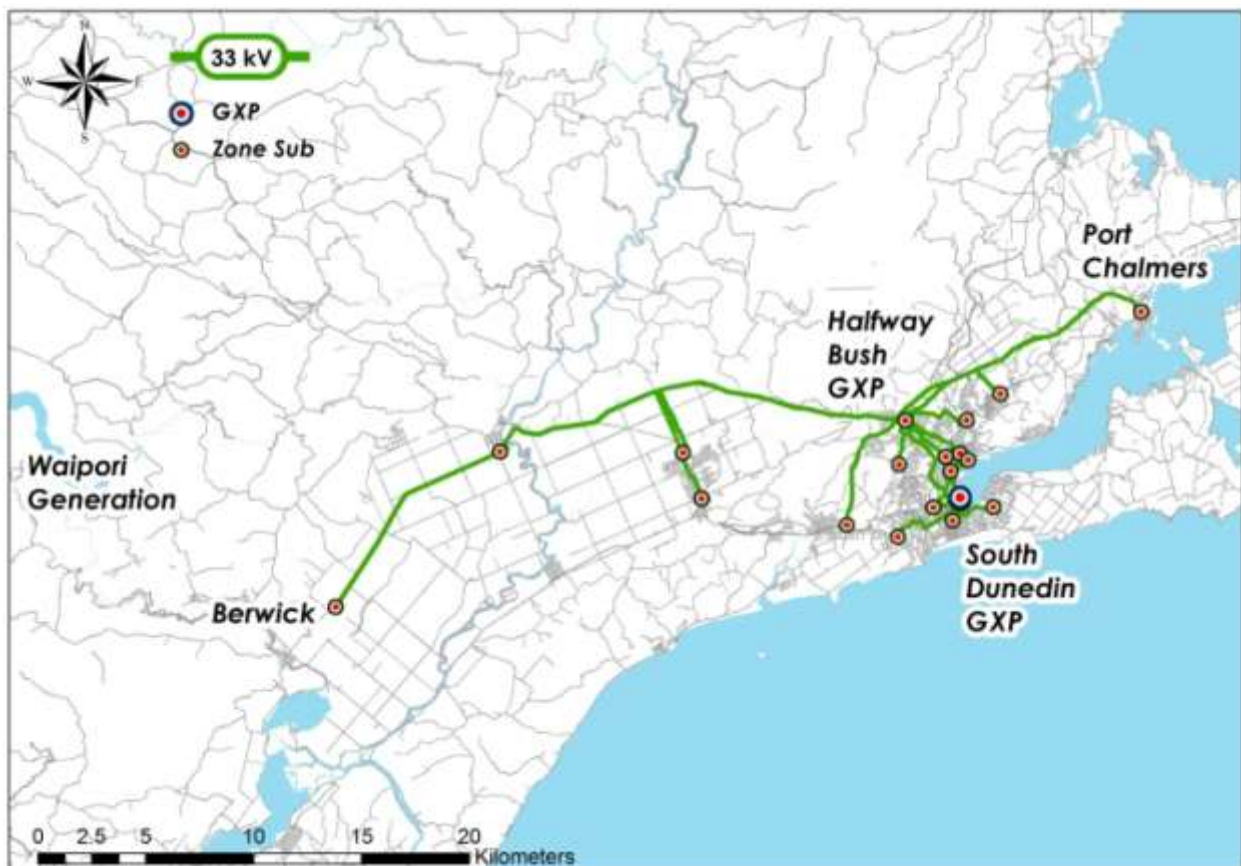
**Figure 5.3a - Dunedin Subtransmission Network**

Table 5.4 – Zone Substations in the Dunedin Area

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	17/24 +17/24	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	12/24 + 12/24	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

Dunedin Network – HV Distribution

HV distribution in the Dunedin area is via 187 HV feeders (Figure 5.3b). Four zone substations; Mosgiel, East Taieri, Outram and Port Chalmers have 11 kV feeders and the remaining fourteen have 6.6 kV feeders. The HV distribution voltage by location in Dunedin is shown in the map below.

All feeders are radial with a high degree of meshing in the metro areas. Some sites have dedicated parallel feeders, for example Otago University and the site formerly occupied by Hillside Workshops. There is an additional 9 km of 11 kV SWER that supplies the north western extremity of the Dunedin HV network. All new transformers installed are dual ratio 11/6.6 kV to facilitate eventual conversion to 11 kV.

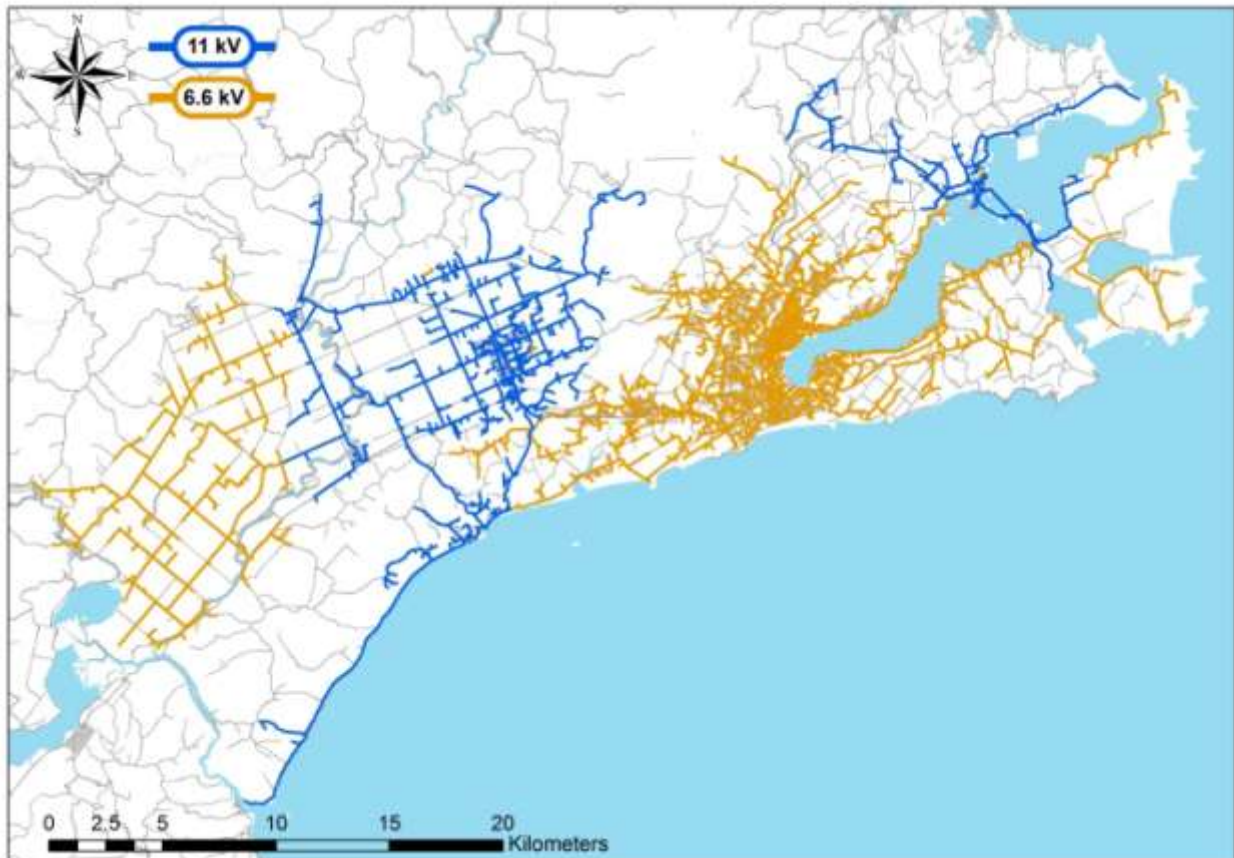


Figure 5.3b - Dunedin HV Distribution by Voltage

5.2.2 Central Network

The Central network is supplied via Frankton, Cromwell and Clyde Grid Exit Points. Further detail on these areas is provided in the sections that follow.

Frankton

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 (see Figure 5.4 and Table 5.5).

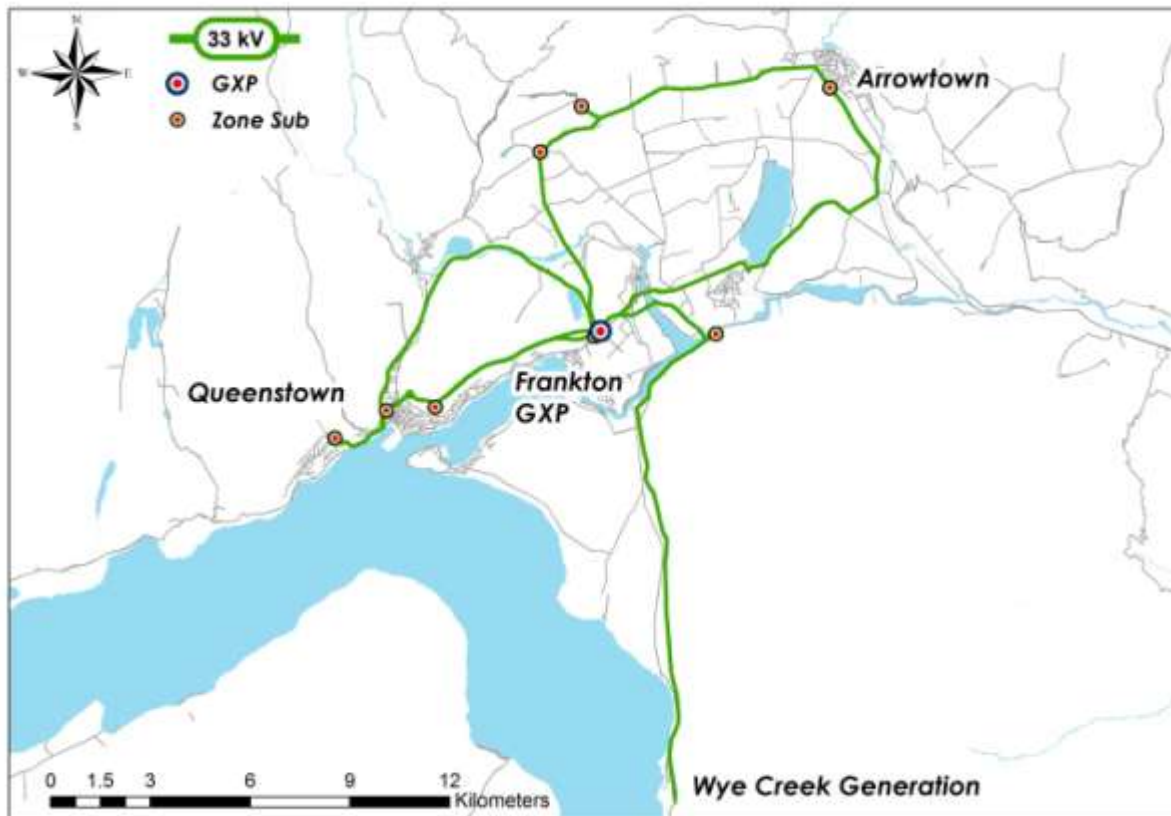


Figure 5.4 – Frankton Subtransmission Network

Table 5.5 – Zone Substations in the Frankton Area

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

Cromwell

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 (Figure 5.5 and Table 5.6)

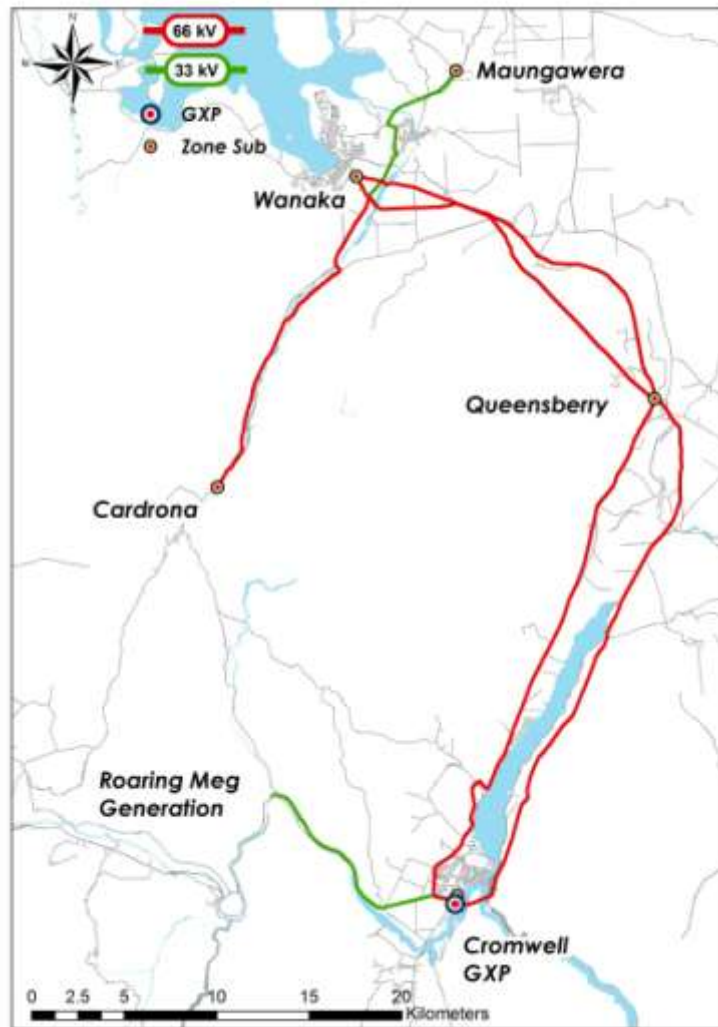


Figure 5.5 – Cromwell Subtransmission Network

Table 5.6 – Zone Substations in the Cromwell Area

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	30/10/24 + 30/10/24	Two 66 kV lines from Cromwell GXP with isolated sections of 66 kV cable	Y
Maungawera	3	Single 33 kV line from Wanaka	N
Cardrona	5	Single 33 kV line tee from Wanaka to Maungawera Line	N

Clyde

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 with Omakau and Ettrick supplied by a single 33 kV line. An overview of the network is shown in Figure 5.6 and zone substation details are in Table 5.7.

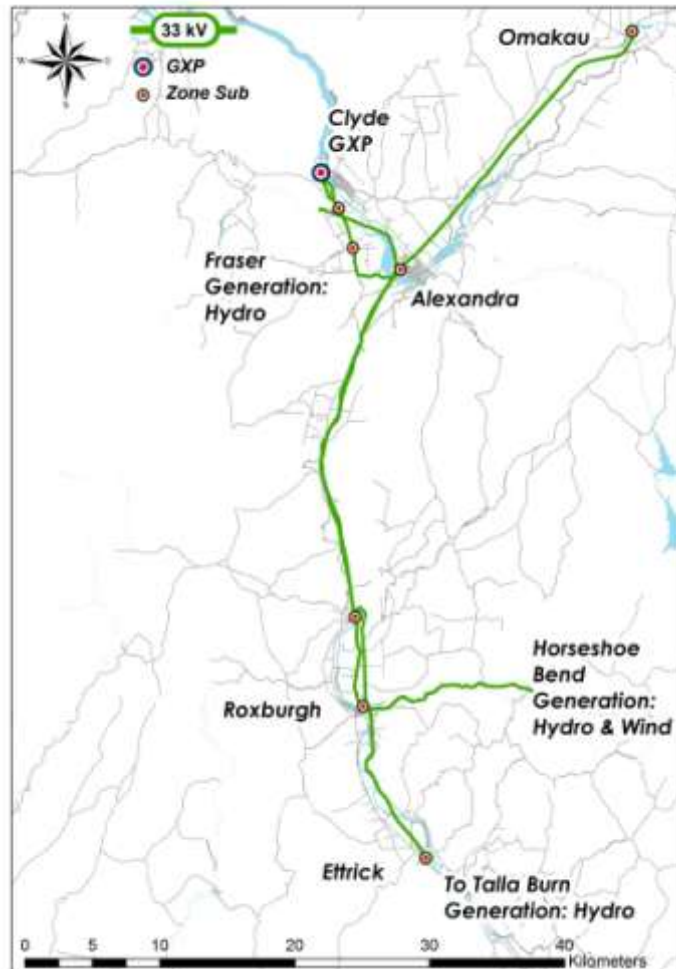


Figure 5.6 – Clyde Area Subtransmission

Table 5.7 – Zone Substations in the Clyde Area

Zone Substation	Transformer MVA	Subtransmission Configuration	n-1 Security
Ettrick	3	Single 33 kV line from Roxburgh	N
Roxburgh	5	Via two 33 kV lines from Alexandra	N
Alexandra	7.5/15 + 7.5/15	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 + 5/4	Tee off Alexandra to Clyde No. 2 33 kV line	N

Central Network - HV Distribution

HV distribution in the Central area is via 73 feeders (Figure 5.7). 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 the map below as are the quantities by voltage. HV cable insulation in the Central area is predominantly XLPE, with some PILC. In Central, there is a significant quantity of rural HV cable, due to local authority requirements and the high number of rural lifestyle subdivisions.

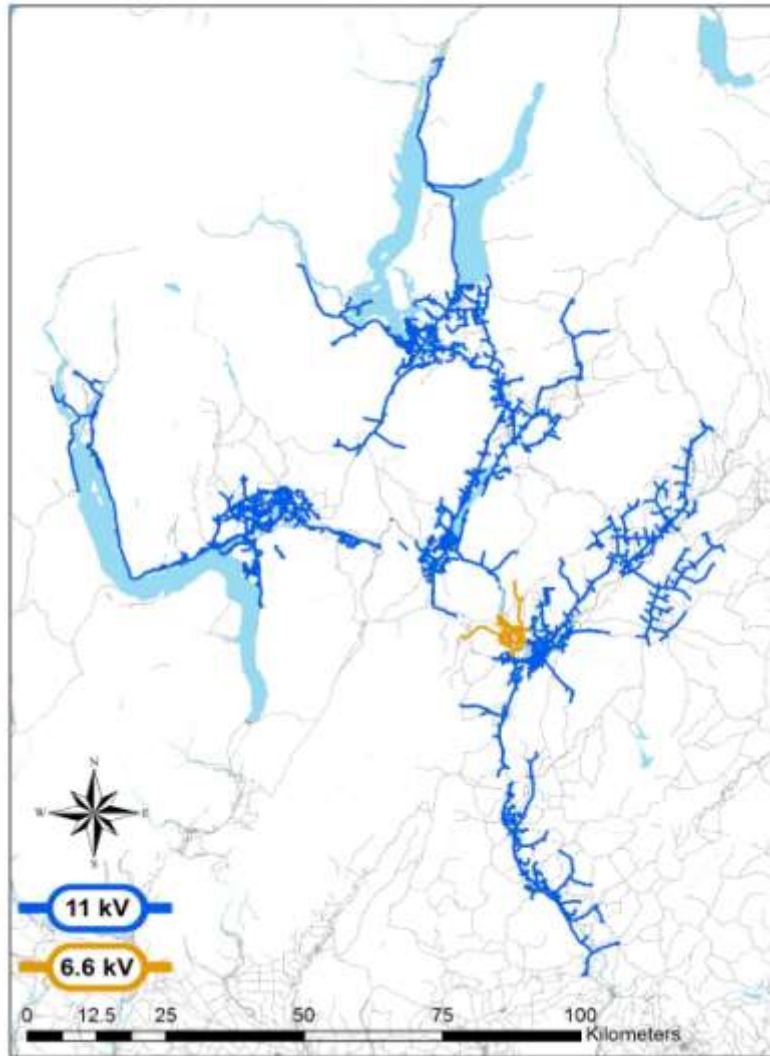


Figure 5.7 - Central HV Distribution by Voltage

Central HV Distribution Quantities

Voltage	% Overhead	% Underground
11 kV	75%	25%
6.6 kV	85%	15%
Total	75%	25%

5.3 Asset Details by Category

The quantity and value of Aurora's assets by category (based on the information provided for the 2012 Electricity Distribution (Information Disclosure) Requirements) is presented in Table 5.8 and 5.9. Further information on age, condition and performance is provided in the following section. See Section 2.4 for comments on data completeness and accuracy.

Table 5.8 - Asset Categories and Quantities

Voltage	Asset category	Asset class	Units	Quantity
All	Overhead Line	Concrete poles / steel structure	No.	20,383
		Wood poles	No.	33,325
		Other pole types	No.	54
HV	Subtransmission			
HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	513
	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	16
		Subtransmission UG up to 66kV (Oil pressurised)	km	25
		Subtransmission UG up to 66kV (Gas pressurised)	km	41
		Subtransmission UG up to 66kV (PILC)	km	12
	Zone substation Buildings	Zone substations up to 66kV	No.	27
	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	3
		33kV Switch (Pole Mounted)	No.	194
		22/33kV CB (Indoor)	No.	6
		22/33kV CB (Outdoor)	No.	48
		3.3/6.6/11/22kV CB (ground mounted)	No.	328
		3.3/6.6/11/22kV CB (pole mounted)	No.	32
	Zone Substation Transformer	Zone Substation Transformers	No.	66
HV	Distribution			
	Distribution Line	Distribution OH Open Wire Conductor	km	2,328
		SWER conductor	km	9
	Distribution Cable	Distribution UG XLPE or PVC	km	422
		Distribution UG PILC	km	366
		Distribution Submarine Cable	km	1
	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	43
		3.3/6.6/11/22kV CB (Indoor)	No.	12
		3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	6,308
		3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	448
		3.3/6.6/11/22kV RMU	No.	1,035
	Distribution Transformer	Pole Mounted Transformer	No.	4,188
		Ground Mounted Transformer	No.	2,461
		Voltage regulators	No.	37
	Distribution Substations	Ground Mounted Substation Housing	No.	2,461
LV	Low Voltage			
	LV Line	LV OH Conductor	km	1,048
	LV Cable	LV UG Cable	km	762
	LV Street lighting	LV OH/UG Streetlight circuit	km	206
	Connections	OH/UG consumer service connections	No.	84,875
Secondary	Secondary assets			
	Protection	Protection relays (electromechanical, solid state and numeric)	No.	429
	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	95
All				
	Capacitor Banks	Capacitors including controls	No	3
Other assets Other				
	Load Control	Centralised plant	Lot	6
	Load Control	Relays	No	2,193

Table 5.9 – Asset value by Category

Asset Category	RC (\$000's)	% by \$
Subtransmission	\$ 56,195	8.4%
Zone substations	\$ 118,944	17.7%
Distribution and LV lines	\$ 135,505	20.2%
Distribution and LV cables	\$ 227,145	33.9%
Distribution substations and transformers	\$ 87,150	13.0%
Distribution switchgear	\$ 42,733	6.4%
Other	\$ 2,712	0.4%
Total (rounded)	\$ 670,384	100%

5.4 Lifecycle Policies and Strategies

This section covers key information on maintenance, replacements/renewals and new capital across Aurora's asset categories. For clarification, the following expenditure definitions are provided:

Maintenance/Operational Expenditure - Ongoing day to day work required to keep the asset serviceable and prevent premature deterioration or failure. The main categories of maintenance are Service Interruptions and Emergencies, Routine and Corrective Maintenance and Inspection; and Vegetation Management. This also includes expenditure for minor renewals/replacements.

Renewal Capital - Major works that do not increase the asset's design capacity or performance capability (to deliver its original level of service or agreed alternative) but restore, replace or renew an existing asset to its original capacity and therefore may include the complete replacement of an asset that has reached the end of its life. Section 6 also contains detail on the major renewals projects.

New/Growth Capital (Asset Creation/Acquisition) - Capital work that creates a new asset or improves an existing asset beyond its existing capacity. This may be driven by a change in demand or generation on a part of the network resulting in the need for extra capacity or additional investment to maintain current security and/or quality of supply standards due to increased demand. Section 6 contains detail on projects related to network development.

5.4.1 Maintenance Policy and Strategy

5.4.1.1 Policy

The maintenance policy for Aurora's network sets requirements associated with maintenance and refurbishment of electricity network assets. This policy requires Aurora's contractors, Delta, to prepare maintenance plans and programmes for all asset categories, maintain records, carry out analysis, manage contractors, ensure resources are available and effective work management systems are established.

5.4.1.2 Strategy

Aurora's maintenance strategy is based on monitoring of asset condition to balance the risks. Aurora network maintenance is conducted in line with the risk management policy described in Section 4 and is reflective of customer, community, legislative requirements and efficiency drivers, which act against the background of safety and environmental responsibility in addition to fulfilling Aurora's business objectives. Effective maintenance management involves balancing these with the cost of maintenance against the cost of replacement, after including the consequences of failure in both scenarios.

Routine procedures for maintenance specific to each asset category have been developed. These 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). Aurora continues to refine its maintenance management systems by reviewing practices and policies regularly.

Maintenance Work Types

Aurora's maintenance work comprises the following elements:

Planned Maintenance comprises of work carried out to a predetermined schedule and allocated budget. It comprises routine/preventative, inspections, refurbishment/renewals/replacement. This includes the following:

Routine and Corrective Maintenance and Inspections:

- fault rectification work that is undertaken at a time or date subsequent to any initial fault response and restoration activities
- routine inspection and condition assessment
- functional and intrusive testing of assets, plant and equipment including critical spares and equipment
- helicopter, vehicle and foot patrols, including negotiation of landowner access
- asset surveys
- environmental response
- painting of network assets
- outdoor and indoor maintenance of substations, including weed and vegetation clearance, lawn mowing and fencing
- maintenance of access tracks, including associated security structures and weed and vegetation clearance
- customer-driven maintenance
- notices issued
- vegetation management

Note that if a 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 placed on a planned programme of work to be refurbished later, or may in-fact be disposed of if refurbishment cannot be justified.

The Strata review recommended that Aurora develop and publish a comprehensive vegetation management plan, which is regularly reported on to the Board. This plan is under preparation. Since June 2013, and in addition to an accelerated cutting programme, a substantial amount of analytical work has been undertaken to quantify vegetation management condition scores for all sites, investigate cutting scores and rates, and prioritise future work.

Routine Maintenance & Replacement/Renewal

This is carried out in response to the need to maintain network asset integrity for current security and/or quality of supply standards and includes expenditure to replace or renew assets incurred as a result of:

- the progressive physical deterioration of the condition of network assets or their immediate surrounds;
- the obsolescence of network assets;
- preventative replacement programmes, consistent with asset life-cycle management policies;
- the need to ensure the ongoing physical security of the network assets;

and includes replacement or refurbishment of components of an asset class (e.g. seals, bushings).

At present about 41% of total maintenance expenditure is allocated to routine and corrective maintenance and inspection. Further detail regarding this is provided in Section 5.6.

Unplanned Maintenance - Unplanned maintenance is usually carried out in response to an unplanned instantaneous event or incident that impairs the normal operation of network assets (e.g. service interruptions and emergencies). It is corrective (reactive) work, either temporary or permanent, required in the immediate or short-term to restore an asset to working condition so it can continue to deliver the required service or maintain its level of security. As such, this comprises work that must be performed outside the predetermined schedule as identified through defect reports, faults and emergency situations.

Unplanned maintenance also includes operational support such as mobile generation used during an outage or emergency response, plus any necessary response to events arising in the transmission system.

Identification of unplanned maintenance can come from a variety of sources such as the general public, Delta employees, emergency services. A network service request form is used to identify and record this information; and formally report network defects.⁸

Once a defect has been identified and reported it is logged on a defects register. A review is carried out to determine associated risk and the remedial action required, which is subsequently prioritised in a programme of planned works; however some defects may require immediate or urgent action.

Defect 'criteria' have been defined and these 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 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).

Other related maintenance activities include evaluating faults to predict maintenance or renewal requirements; and service disconnections.

At present about 25% of total maintenance expenditure is allocated to service interruptions and emergencies.

Vegetation Management

Under the Electricity (Hazard from Trees) Regulations 2003 Aurora, along with vegetation owners, is jointly responsible for protecting the security of the supply of electricity and the safety of the public by ensuring vegetation does not encroach on Aurora's electrical conductors.

Vegetation management involves felling, removing or trimming vegetation (including root management) that is in the proximity of overhead lines or cables. It includes expenditure arising from the following activities:

- inspection of affected lines and cables where the inspection is substantially or wholly directed to vegetation management (e.g., as part of a vegetation management contract). Includes pre-trim inspections as well as inspections of vegetation cut for the primary purpose of ensuring the work has been undertaken in an appropriate manner;
- liaison with landowners including the issue of trim/cut notices, and follow up calls on notices;
- the felling or trimming of vegetation to meet externally imposed requirements or internal policy, including operational support such as any mobile generation used during the activity.

Previously, around 13% of total maintenance expenditure was spent on vegetation management annually. Aurora is looking to increase that up to 34% on average over the next 10 years. The drivers for this have been discussed in previous sections.

⁸ A defect is a short-coming or deficiency (i.e. a device, component or network element may still perform or function in the required manner, however some kind of physical imperfection exists). If left uncorrected, may end up in a state where it is unable to perform its required function.

5.4.2 Asset Renewal Strategy and Policy

Asset Renewal Policy

Renewal or 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.

Asset Renewal Strategy

Asset renewal strategy encompasses three main approaches, each of which is appropriate for the different asset categories on Aurora's network.

A risk- and condition-based replacement strategy is applied where there is a significant implication due to failure, such as major health and safety risk, significant reliability of supply consequence or a major expense in repair. This strategy is applied where ongoing condition inspections are needed to comply with regulations or where the costs of condition monitoring are small compared with the costs associated with failure.

A run-to-failure strategy is applied to assets where the consequences of failure are not major and where the costs of ongoing condition monitoring may outweigh the costs of failure.

An age and obsolescence-based replacement strategy is applied to assets with a high level of technical complexity or a high level of interconnectedness with other network assets (that is, the operation of a system as a whole is dependent on the integrity of several assets). It includes the need to replace equipment because of the availability of spares, or for standardisation or changes in technology.

5.4.3 Decommissioning Policy

A policy on Site Decommissioning for Aurora's assets has been drafted. This standard sets out the requirements for site decommission of Aurora's electrical assets to ensure public safety, avoid environmental damage and avoid property damage.

The scope of this standard covers both overhead and underground assets. Major assets and any item that represents an elevated environmental risk, risk to property damage or risk to the public have been separately identified. For assets that fall outside this criteria, the standard must still be followed.

It is proposed that decommissioning of Aurora's electrical assets follow an environmentally sustainable process that considers certain steps for removing, assessing, remarketing and recycling. It is anticipated that the policy will be finalised and adopted in 2014.

The following section provides detail on Aurora's key asset categories and associated strategies for each.

5.5 Lifecycle Asset Management Strategies

5.5.1 Introduction

This section describes Aurora's existing assets by category. These categories are: Subtransmission, Zone Substation, Distribution, Low Voltage and Other/Secondary. For each category, the asset and its management approach are discussed under the headings below.

Asset description

A brief description of the type, function and location of each asset category.

Asset capacity/performance

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

Asset Data & Condition

A summary of the asset's current condition including an age profile and comments on asset information. See Section 2.6 for further detail on data completeness and accuracy.

Maintenance plan

The ongoing work plans required to keep the asset serviceable and prevent premature deterioration or failure. The main types of maintenance carried out on Aurora's network are outlined in the previous section.

Replacement plan

These are work plans that do not increase the asset's design capacity but restore, replace or renew an existing asset to its original capacity; major renewals/replacements are covered in Section 6.

Creation/acquisition plan

This is capital work that creates a new asset or improves an existing asset beyond its existing capacity. Aurora produces development reports (DR) for major projects; these provide detailed appraisal of issues, options and recommended solutions.

Disposal plan

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

Standards, policies, plans and other documentation relating to the management of these assets over their life cycle are presented in Appendix C. Financial forecasts for each maintenance activity type as well as asset category is provided in Section 5.6.

5.5.2 Poles

Asset Description

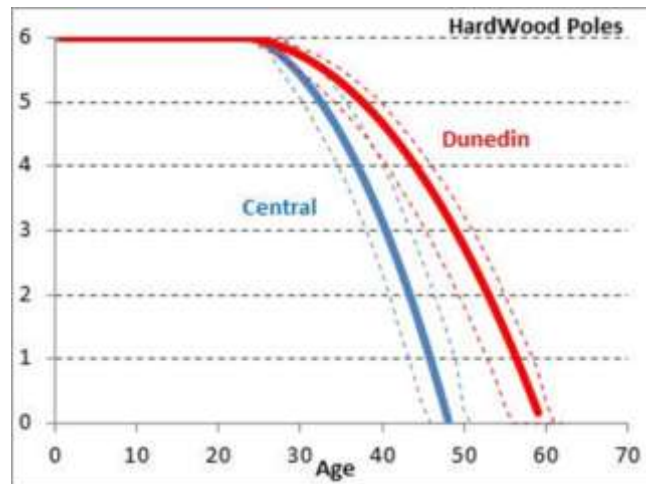
Aurora has approximately 53,760 poles, which are constructed of either concrete/steel, wood or other. These poles support subtransmission, distribution and low voltage conductors. Over 60% of Aurora's poles are wooden and nearly 40% are concrete/steel. The Dunedin network contains more concrete poles than Central (13,800 and 6,500 respectively); and Central has more wooden poles (18,000 and 15,200 respectively).

Aurora's geo-database contains the main asset attribute data for poles. Data currently held includes location, date installed, voltage class, material, condition, year manufactured.

Asset Age

The average age of poles on the Aurora network is approximately 46 years (see Figures 5.8 and 5.9). Comparing Dunedin and Central networks, the average age is 55 years and 40 years respectively, which indicates that the pole age distribution is older on average in Dunedin. Analysis has also shown that a 95% confidence interval is associated with this information, so it is reasonable to apply these assumptions to renewal forecasts and obtain a certain level of assurance (also refer to Asset Condition and Performance sub-section).

With respect to wooden poles, nearly 50% of Aurora's wooden poles are at or past their theoretical life and require replacement. Previous AMP's have stated that in coastal areas poles tend to last over 45 years. Further detailed analysis of hardwood poles in both Dunedin and Central (across all condition ratings) has found that, on average, poles in Dunedin have tended to last longer (around 60 years) compared to those in Central, which appear to be more aligned with the 45 year assumption (see graph on following page).



From the 1990's and up until recently, 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. Poles in rural areas, particularly Central, have also been subject to wear due to interference from stock where lines run through farmland (see photo).



Investigations into regional differences will continue in 2014/15 with the intention of informing renewal assumptions and associated expenditure programmes. Assumptions on unit costs are being reviewed and updated in preparation for the generation of revised pole renewal profiles.

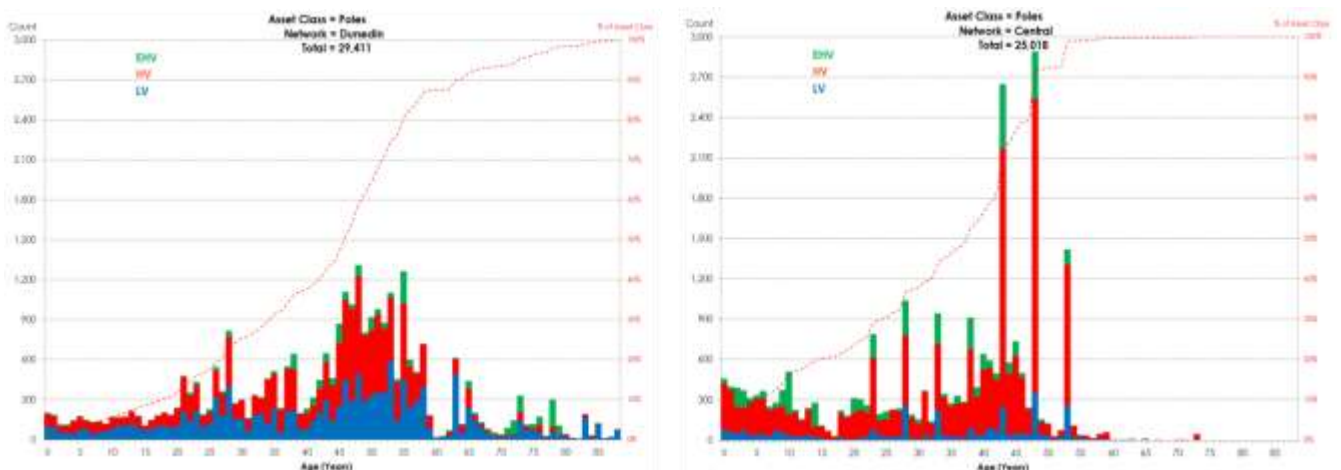


Figure 5.8 – EHV, HV and LV Poles Age Profiles (Dunedin and Central)

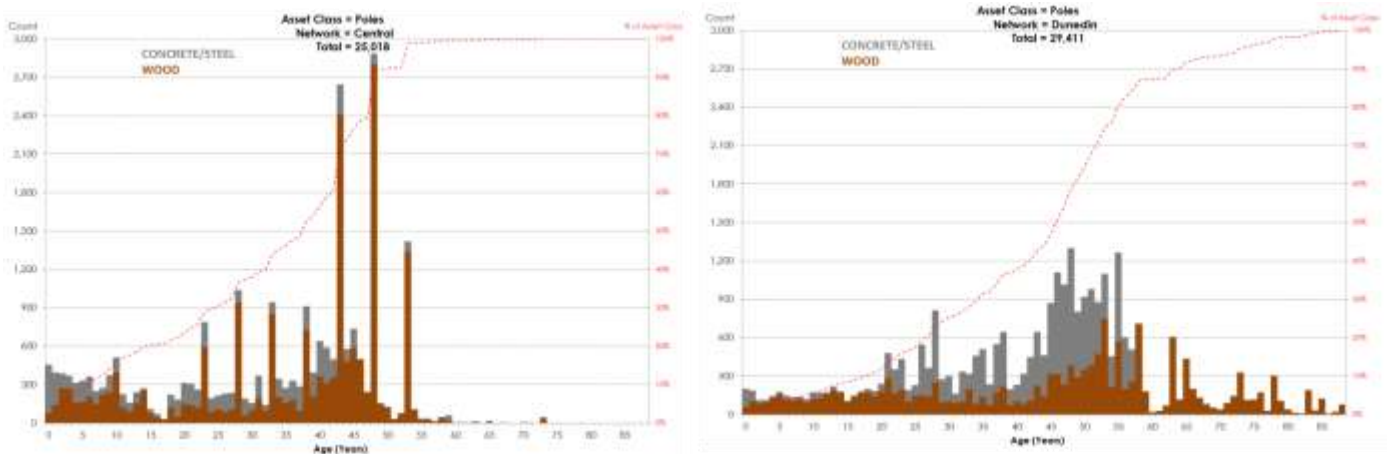


Figure 5.9 – Concrete and Wood Poles Age Profiles (Dunedin and Central)

Asset Condition and Performance

Figure 5.10a illustrates the profile of pole expiry rates on the Aurora network and provides a comparison between the Dunedin and Central networks.

Figure 5.10b shows the distribution of poor condition poles (Condition 0) currently in service on the Aurora network, which indicates a reasonably even distribution.

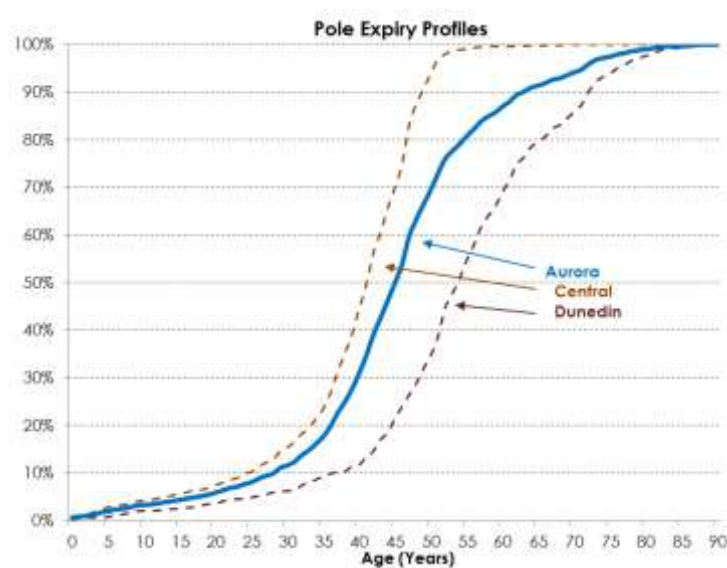


Figure 5.10a – Pole Expiry profile

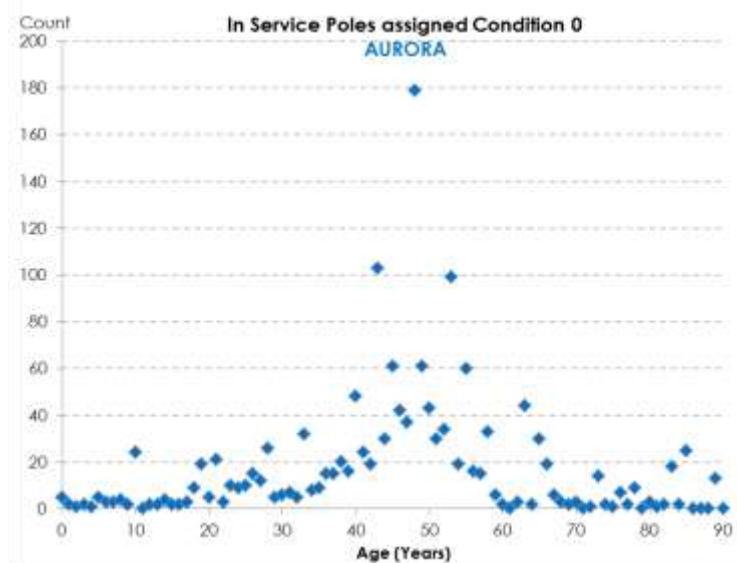


Figure 5.10b

The number of condition 0 poles on the network is a concern for Aurora and focus is being placed on addressing this risk. Condition 0 means an overhead line structure that is at risk of failure (under certain conditions described in the (Electricity Safety) Regulations (2010) must be marked and repaired or replaced not later than 3 months after finding the risk of failure.

Figure 5.11 below provides an indication of the quantity of poles within each condition grade for Dunedin and Central. It is important to mention here that pole failure through deterioration can occur within all asset condition ratings. Options for pole testing technology are currently being considered to assist in providing more objective and accurate condition assessments.

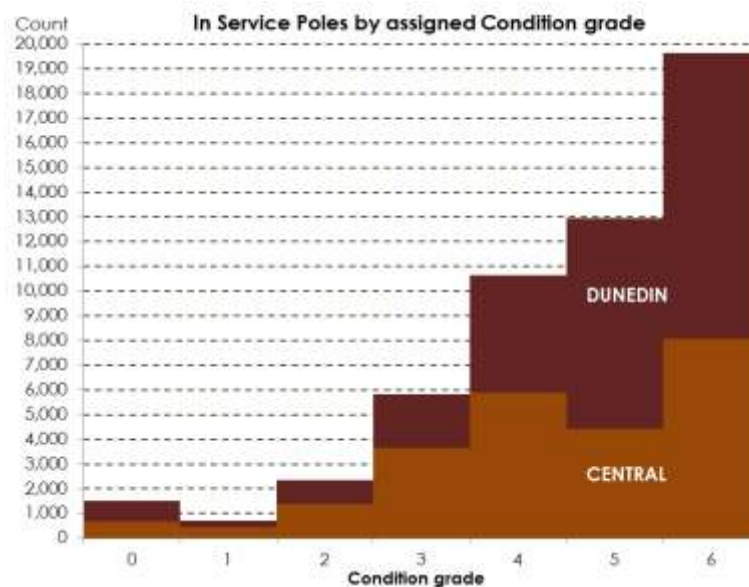


Figure 5.11 Pole Condition Grade

Maintenance Plan

All overhead poles are closely inspected on a regular basis, and condition assessments made and recorded, with priorities established for maintenance planning. In addition:

- Annual drive-by patrols are carried out on the larger subtransmission lines to provide a visual check on such aspects as leaning poles

- Subtransmission poles undergo detailed inspection at intervals predetermined by their last condition assessment with the interval ranging from two years for a pole that is considered to have three to five years of remaining life and ten years for a pole that is considered to have more than twenty years of remaining life.

At present, hardwood poles are being renewed at the rate of about 1.5% per year. The pole age profile implies that renewal requirements will continue to increase over the planning period.

A sum of \$3M per year of capital has been allocated for renewal/replacements associated with poles (see below).

Replacement Plan

A program is underway to replace poles that are in poor condition. A holistic approach has been used over the last few years, which combined the pole, pole hardware and vegetation condition data to develop targeted programmes.

A sum of \$3 million was allocated for the 2013/14 year and a similar quantum of work is allocated from 2015/16 onwards. A review and update of pole renewal requirements will be carried out in 2014/15 in light of new assessment criteria and better data becoming available. It is likely that funding for renewal requirements for this asset category will be required to increase over the coming years.

A framework for risk assessment and prioritisation has been developed and will be rolled-out in 2014. 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.

Disposal Plan

As per proposed decommissioning policy outlined in Section 5.4.3.

5.5.3 Subtransmission

5.5.4 Subtransmission Lines (66 kV and 33 kV)

Asset Description

Subtransmission lines provide important security to Aurora's network, conveying electricity from GXP's to zone substations. A description of Aurora's subtransmission network, including capacity information, is provided in Section 5.2 and Tables 5.4-5.7.

Asset Capacity/Performance

Nearly 50% of Aurora's overhead subtransmission is over 40 years old. The number of faults has averaged approximately 5.5 per 100 km per year for subtransmission lines over the last 5 years.

Asset Data and Condition

Aurora's geo-database contains the main asset attribute data for subtransmission lines. Data currently held includes conductor size, age and nominal and operating voltage. Other paper-based records such as as-builts are also available. Updated data generally comes from routine inspections (as outlined in the maintenance plan in the following section) or related works.

The present condition of any line is a factor of its age, the environmental impacts of the locations it traverses, and its maintenance history. The 33kV and 66kV lines are considered to generally be in good condition. Based on existing loading, no significant expenditure is expected within the planning period, with the exception of the projects being driven through system growth.

The age profile of subtransmission lines (33kV and 66 kV) is shown in Figure 5.12. There are lines that are 105 years old. These 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.

It is currently assumed that 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.

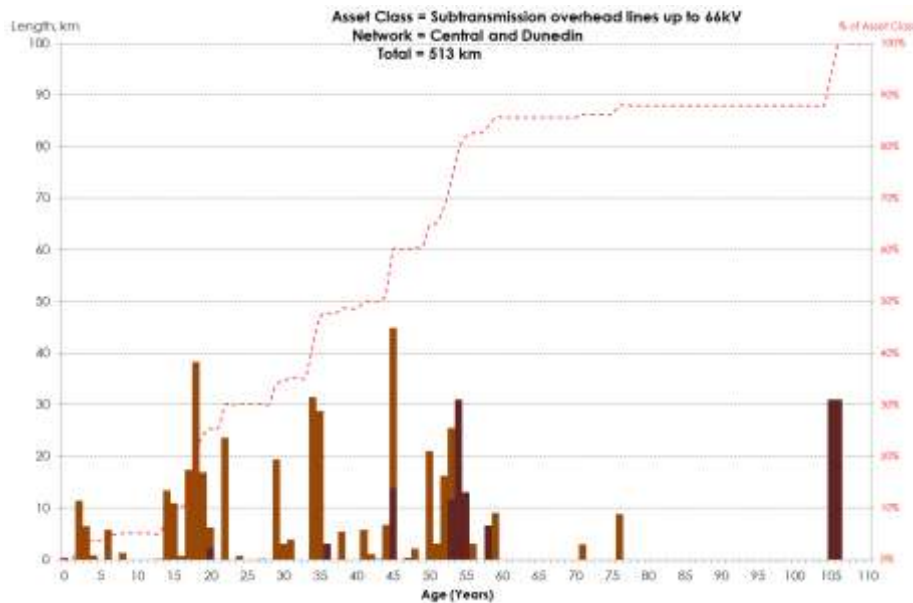


Figure 5.12 - Subtransmission Lines age profile – up to 66kv

Maintenance Plan

Along with poles, all overhead lines are inspected on a regular basis, and condition assessments made and recorded, with priorities established for maintenance planning. In addition 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 and so on.

Maintenance forecasts are projected using the assessed condition where the assessed condition of each major component of each line is coded against condition criteria which are used to set maintenance priorities.

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

Creation/Acquisition and Disposal Plan

For planned projects related creation/disposal of assets in this asset category see Section 6.6 – Network Development.

5.5.5 Subtransmission Cables

Asset Description

A description of Aurora's subtransmission network, including capacity information, was provided in Section 5.2. Aurora has 33kV subtransmission cables, which are mainly found on the Dunedin. Additionally there are pockets of 66kV subtransmission cables in Central where a section of overhead line has been undergrounded through new subdivisions.

Cables are characterised by their insulation system and the types installed for Aurora's subtransmission are PILC, gas-filled, oil-filled and XLPE. XLPE are considered the most economic choice for subtransmission cables. Aurora uses single-core XLPE cables, as opposed to three-core, as this facilitates the effective application of water blocking tapes. The cable conductors are copper or aluminium.

Dunedin's central city subtransmission cable network consists of 10 pairs of 33kV transformer feeder circuits, from the Halfway Bush and South Dunedin GXPs and a tie cable between the Ward Street and Neville Street substations. The geographic layout for Dunedin is shown in Figure 5.13

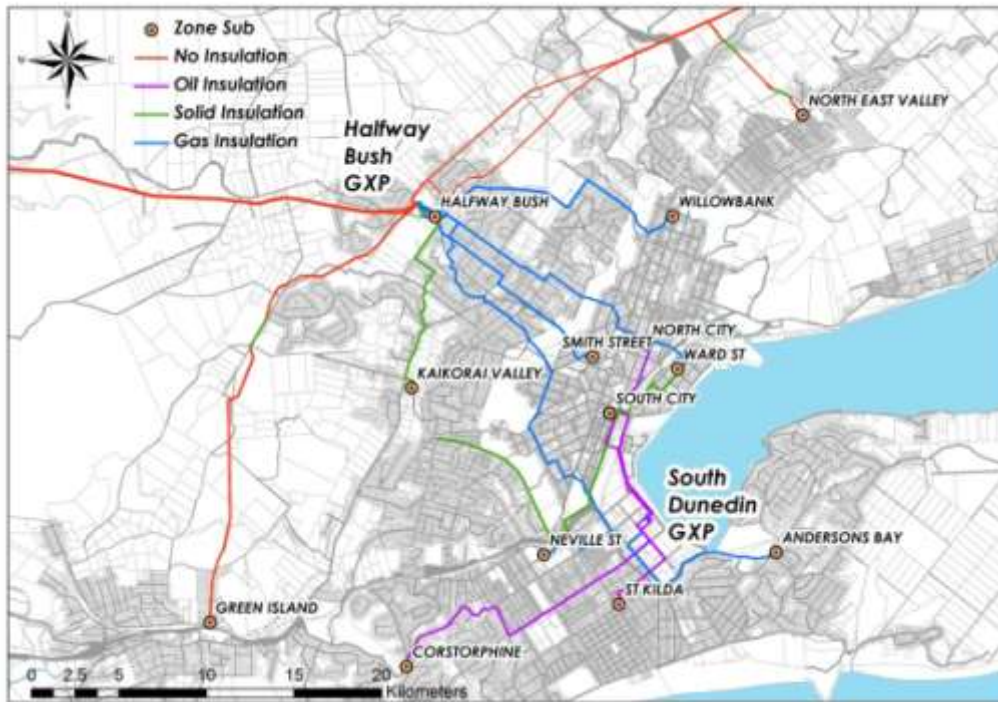


Figure 5.13 - Dunedin Subtransmission 33kV cable network

Asset Capacity/Performance

In Dunedin, the PILC cables suffer from oil draining from the paper (particularly if installed on steep slopes). This phenomenon has been the cause of several faults on the Kaikorai Valley subtransmission. Gas cables have been more prone to outages that are difficult to locate, mainly due to gas leaks. In Central Otago, thermal resistivity is an issue so site specific requirements are set for new subtransmission cables.

Leaks have also been observed to occur regularly at cable joints, particularly 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.

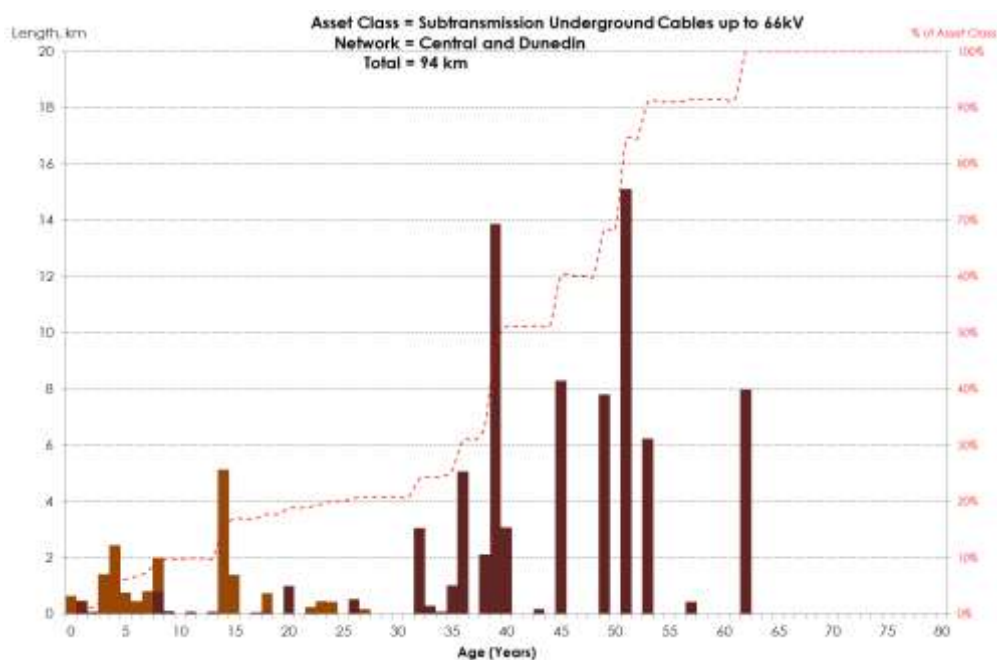
The cause of leaks has also been linked to corrosion of bronze tapes due to deterioration of the cable rubber sheath, which allows moisture to enter the cable (see photos). Investigations and analysis have identified that gas cables in particular have had a high failure rate development report DR12). Historic performance indicates that over the last 20 years, there have been outages due to gas cable failures nearly every year.

**Failed Bronze Tape****Degraded Rubber Sheath**

Asset Data and Condition

Aurora's geo-database contains the main asset attribute data for subtransmission cables. Data currently held includes location, insulation type, date installed, conductor size, age and nominal and operating voltage; other paper-based information is also available.

The age profile for all 33kv subtransmission cable types is presented in Figure 5.14; the majority were installed in the 1950's, 60's and 70's. With a theoretical useful life of 70 years, nearly 60% of Aurora's underground subtransmission is over 40 years old. In 2011 partial discharge testing of the cables in Kaikorai Valley was carried out and the results were satisfactory, however routine partial discharge testing of these cables needs to be established.

**Figure 5.14 – Subtransmission Cables (33kv) age profile**

Maintenance Plan

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.

Pressure gauges and alarms are installed on the gas and oil-filled cables. The gauges are read monthly and the alarms are tested at six-monthly intervals, and the outer sheath electrical integrity on most cables is tested annually.

The 33 kV underground cables do not have a planned refurbishment programme. The cables are relatively maintenance free with the exception of issues previously described. However, when a fault does occur, it is expensive to repair, being very labour intensive. For example, the average time to locate and fix a gas leak approximately 400 hours. Damaged by third parties (for example - road openings) also drive reactive maintenance needs.

With limited routine testing and maintenance carried out in the recent past, gas cables are of concern to Aurora and as such many are scheduled for replacement within the next 7 years. Further review of Aurora's oil cables is also intended to be undertaken in the near future with the view to developing a more robust replacement programme.

Replacement Plan

The proposed timing of replacement for 33kV cables in Dunedin is highlighted in the table below. This is an initial program and performance of the cables could alter priorities. Cost estimates are shown in Table 6.13 (page 152), with proposed costs being spread over two years due to the large scale of each project. The Andersons Bay cable replacement commenced in 2012 and while there were some delays during 2013, it is programmed to be finished in 2014/15.

GXP	Cable Name	Type	Installed	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Halfway Bush	Neville St*	Gas	1961							
	Willow bank	Gas	1963							
	Smith St	Gas	1959							
	Ward St	Gas	1967							
	Kaikorai	PILC	1950							

**Part of Neville St Substation upgrade (Project ID 2324) - it is proposed the replacement of the Neville Street 33 kV gas cables be carried out at the same time as the substation upgrade; and the connection be moved from the HWB GXP to the South Dunedin GXP.*

The rationale for the priority is as follows:

- 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.
- Willowbank has a moderate priority as it will be possible to fully off-load Willowbank but the cable is the unreliable bronze tape type.
- Kaikorai Valley cables have had partial discharge testing carried out and the results were satisfactory, however past performance indicates recurring issues due to cable paper drying out through oil migrated as previously described. As such, replacement is scheduled for 2018/19
- 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.

Creation/Acquisition & Disposal Plan

Delta has recommended that the long-term configuration of Dunedin 33 kV subtransmission network retains the existing transformer feeder configuration but with the Neville Street substation supplied from the South Dunedin GXP.

5.5.6 Zone Substations

5.5.6.1 Zone Substation Buildings

Asset Description

There are 36 zone substations on the Aurora network. The majority of the buildings consist of concrete, brick, plaster materials, with a few wooden. The age of these buildings ranges from 2-70 years old, with most of the structures being established in the 1950's-1990's. Fences around the buildings also comprise of various materials including wood and metal.

Maintenance Plan

Buildings, Grounds, Fences

There is regular maintenance of zone substation buildings, grounds and fences: 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. A number of buildings will have exterior paint work carried out within the planning period.

The buildings were assessed by external consultants in 2009 and a 10-year building maintenance plan (2010-2020) was developed. This plan details requirements for yards, roofs, external walls, doors, windows, plumbing, electrical services, and the interior. This information has been incorporated into Aurora's maintenance programme and prioritised as necessary

In response to recommendations from the Royal Commission for changes to the building legislation, more comprehensive assessments of fire, security and earthquake risk for all of Aurora's zone substation buildings are being carried out. Outputs from this will inform the revision of the building maintenance and/or upgrade programmes for 2014/15 onwards.

Replacement Plan

Buildings, Grounds, Fences

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.

Creation/Acquisition Plan

Several zone substations are programmed for significant upgrade of transformer and switchgear equipment within the AMP planning period. In addition, new buildings will be constructed where new substation assets are established (see Section 6 and Table 6.13).

The major substation projects are Neville Street, Roxburgh (underway) and Outram. Soil tests at the existing Neville Street site indicate the land is very vulnerable to liquefaction during an earthquake and any structures on the site should have piled foundations and investigations have identified that the most economic upgrade option is to completely rebuild the substation on land adjacent to the existing site. The site for this has been identified and is currently leased to an external party; the lease for this site ends in 2015. This new site also contains significant trees on the Dunedin City Council register and as such Aurora will liaise with the DCC regarding this issue.

5.5.6.2 Zone Substation Switchgear

Asset Description

Switchgear (circuit breakers) are installed to provide safe interruption of both fault and load currents during power system faults. They are placed in the network to aid with protection of line, cable, transformer and ripple injection assets. Aurora has both outdoor and indoor 33kV switchgear.

Asset Capacity/Performance

There are 18 VWVE breakers on the network and moisture ingress has been a problem with other units. Failures have been attributed to moisture in the oil due to the failure of the bushing extension seals causing corrosion of the aluminium extension tubes. A full investigation is underway on the condition and management of the remaining VWVE units in service on the network.

In 2012/13 switchgear at one zone substation failed and work has been carried out to replace these assets.

Asset Data and Condition

Aurora's geo-database contains the main asset attribute information for switchgear. Data currently held on this database includes age, location, type/model. Other information available includes that collected through routine maintenance programmes, as outlined in the following section.

The age profiles for 66 and 33 kV circuit breakers and 11 kV/6.6 kV circuit breakers are shown in Figures 5.15 and 5.16 respectively. A significant proportion of the 33kV switchgear (40%) is older than 40 years which is nearing the end of its theoretical life. Around 35% of the 6.6kV and 11kV ground mounted switchgear is older than 40 years.

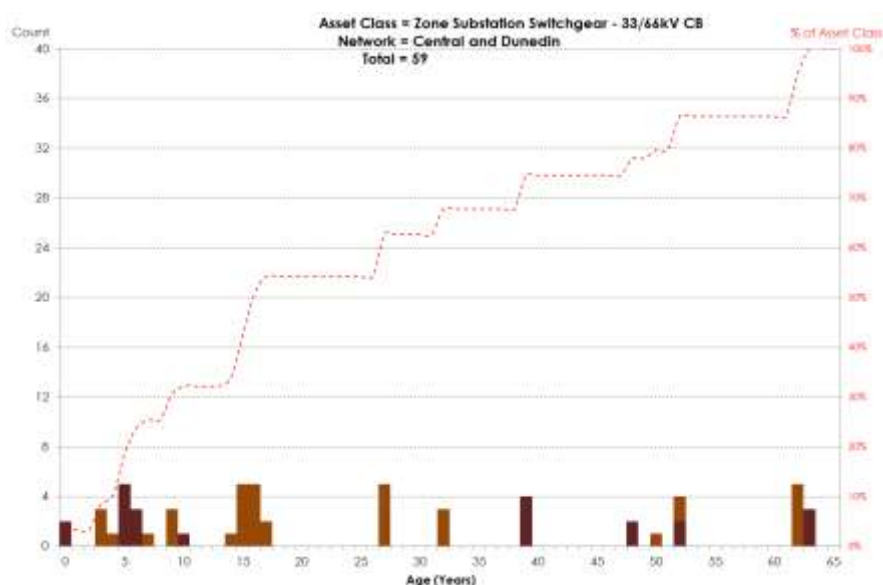


Figure 5.15 – 66 and 33 kV Zone Circuit Breakers age profile

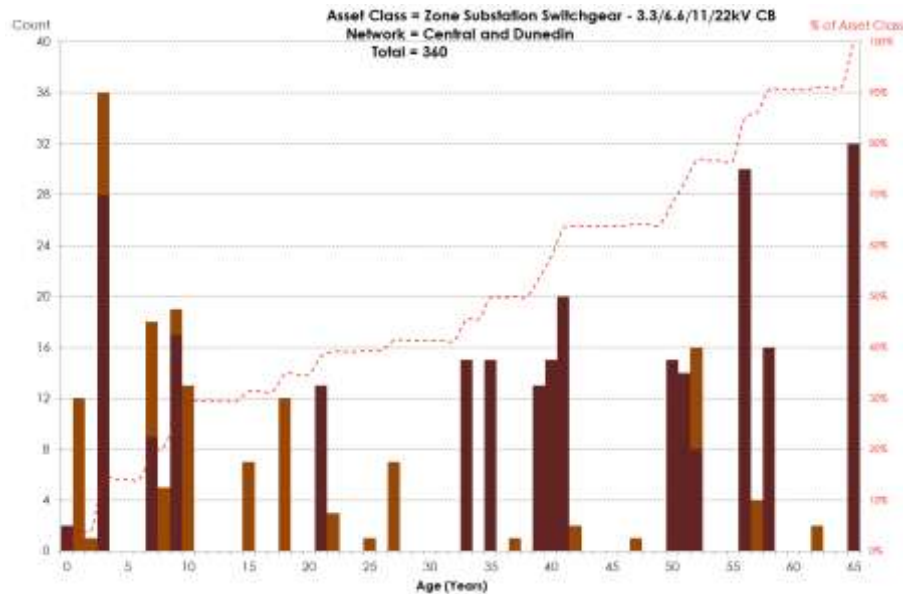


Figure 5.16 – 11 kV and 6.6 kV Circuit Breakers Age Profile

Maintenance Plan

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 to infrequent major overhauls, costing in the order of a few hundred dollars per breaker to several thousand dollars respectively.

Servicing expenditure for circuit breakers is determined through an analytical model, whereby 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.

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 the use of thermographic cameras to identify "hot spots".

Specifically, maintenance includes:

Circuit Breakers - oil circuit breakers are given an overhaul at 4-year intervals or after operation under severe fault conditions.

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

Painting of outdoor circuit breakers is undertaken on a rolling basis with, major repaints at 10-year intervals.

Renewals/Replacement Plan

A review of Aurora's replacement programme for switchgear is being carried out. This review builds on previous analysis undertaken for programming circuit breaker renewals, which was 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. This replacement programme is still subject to confirmation via further economic analysis, however Port Chalmers and Alexandra 33kV switchgear replacement is programmed for 2014/15.

11kV switchgear replacements:

Queenstown 11kV Switchboard (half) replacement

Half of the Queenstown 11kV switchboard was replaced in 2013 after a catastrophic failure. The remaining half of the switchboard has been left untouched (it had to remain in service until the new half was commissioned to retain supply to Queenstown). Now that the new half of the switchboard has been commissioned it is intended to offload the old half and assess its condition. The assessment will attempt to determine if a similar failure could occur to this half and what remedial action might be taken to prevent such a failure. Full replacement of the second half of the switchboard is expected to cost \$1.7M. This has been tentatively scheduled for 2018. Depending on the outcome of the inspection this may be advanced or delayed.

Alexandra zone substation 11kV Switchboard Replacement

The Alexandra 11kV switchboard is an unusual design. It features indoor switchgear in an outdoor cover. The layout of the switchboard makes it difficult to inspect the condition of bus bar and (more importantly) the bus coupler switch, without fully offloading the whole switchboard. It is planned to do an inspection in the near future. A full replacement of this switchboard at a cost of \$1.5M is proposed to commence in 2021. The outcome of the proposed inspection may advance or defer this project.

Halfway Bush zone substation 11kV Switchboard replacement is also tentatively scheduled for 2022, the driver for this being primarily age-related.

The majority of the remaining zone substation 6.6/11kV switchgear replacements are being done in conjunction with major substation upgrades, however the proposed timing of this package work is illustrated in the table below (see Section 6.5 for detail).

Substation	Number CBs	14/15	15/16	16/17	17/18	18/19	19/20	20/21
<i>Neville Street</i>	14							
<i>Halfway Bush</i>	16							
<i>Green Island</i>	15							
<i>Smith Street</i>	15							
<i>Earnsclough</i>	1							
<i>Roxburgh T1 & T2</i>	2							
<i>Clyde-Earns. T1 & T2</i>	2							
<i>Andersons Bay</i>	15							
<i>Willowbank</i>	15							
<i>Outram</i>	8							
<i>Maungawera</i>	1							
<i>Arrowtown T1 & T2</i>	2							

Zone substation 6.6/11 kV switchgear replacement

5.5.6.3 Zone Substation Transformers

Asset Description

In order to transform sub-transmission voltages (e.g. 33kV) to distribution voltages (e.g. 11kV), power transformers are installed at zone substations. These have tap changers to assist with maintaining the required delivery of voltage on the network. Most zone substations have two power transformers which have bunds to contain any oil spill and fire walls between the transformers to minimise the risk of fire spreading in the event of catastrophic failure.

Asset Capacity/Performance

The transformers are capable of operating continuously at their rated capacity or at a higher rating for shorter periods depending on the ambient air temperature.

While the 33kV and 66kV transformers have been relatively trouble free some recent failures have resulted in a review of the suite of transformers. In recent years there have been two transformer failures. A more intensive monitoring and maintenance program is being developed to mitigate the possibility of further failures.

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.

Asset Condition

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. The communications and software for the Trojan was updated in 2013/14.

It is assumed that transformers subject to moderate loading, minimal through faults, prudent monitoring and maintenance practices should last for at least 60 years. The age profile of zone substation transformers is shown in Figure 5.17. The oldest four transformers are at the Neville St and Outram substations.

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

The seals on the older breathers at the substations have deteriorated and are scheduled for upgrade.

Asset Data

Aurora's geo-database contains the main asset attribute information for zone substation transformers. Data currently held includes location, type, installation date, manufactured date, purchase date, serial number and rating. Records on the loading on the transformers are obtained via the SCADA system and analysed regularly. Section 6 contains further detail on loads.

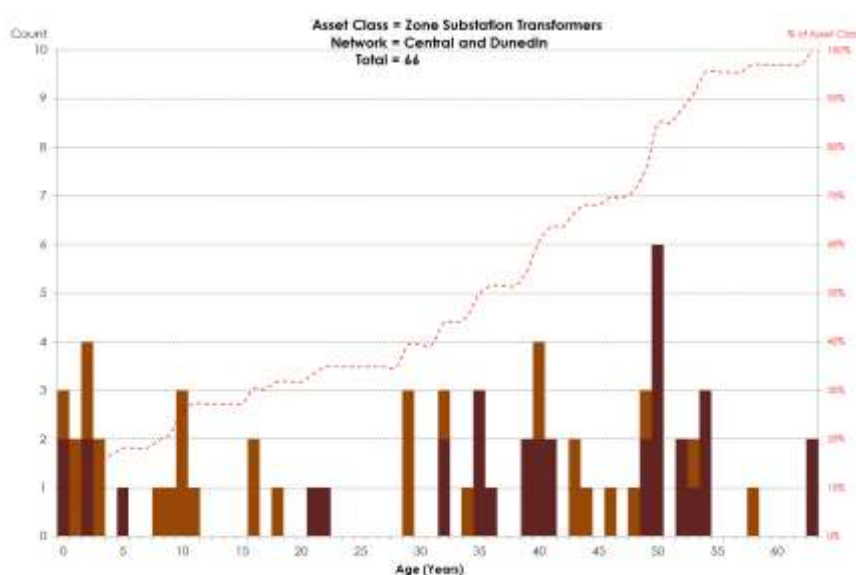


Figure 5.17 - Zone Substation Transformers 66 and 33 kV Age Profile

Maintenance Plan

Aurora is taking a prudent approach to works programming for these assets, with enhanced assessment criteria and condition based monitoring techniques being reviewed and 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.

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

Routine scheduled work on transformers and tapchangers is undertaken on a contract basis.

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.

Tapchangers are refurbished at intervals based on a predetermined number of operations or time interval depending on which threshold is first triggered. The usual work required is the dressing or replacement of contacts, and filtering of oil, but springs and driving mechanisms are also checked. The intervals for overhaul of tapchangers is dependent on type based on industry knowledge and historical performance.

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. 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.

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

Replacement Plan

There is a replacement plan for breathers on older transformers to be upgraded 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.

Major transformer replacement is occurring in conjunction with zone substation upgrade projects. Outram Zone Substation and Neville Street Zone Substation are programmed for replacement within the next 3 years. The Outram zone substation is nearing the end of its economic life. It is proposed the substation be rebuilt with one 5 MVA transformer with a parking bay for the mobile substation. Further detail on Neville Street zone substation is contained in Section 6.

Replacement of the transformers at both Port Chalmers and Mosgiel Zone Substations is also proposed for 2022/23 and 2023/24 respectively at an expected cost of \$2M (each). While both proposals are primarily driven by age-related needs, major load growth due to possible expansion of the Port may require the Port Chalmers zone substation transformer replacement at an earlier date. Load growth will continue to be monitored.

Replacement of both transformers and switchgear at Willowbank and Green Island substations is proposed, commencing in 2020 and 2023 respectively, with an estimated cost of \$5M each.

Creation/Acquisition Plan and Disposal

See Section 6.6 – Network Development for further detail. Disposal is as per proposed decommissioning policy outlined in Section 5.4.3.

5.5.6.4 Other Zone Substation Equipment

Battery banks

Battery banks at substations include flooded and sealed lead acid cells with various life expectancies, with several that have exceeded their nominal life of 20 years. 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. A replacement program is underway.

Earthing

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.

5.5.7 Distribution

5.5.7.1 Distribution Lines (11kV and 6.6kV)

Aurora's overhead distribution system consists of 2335km of HV lines, taking supply from zone substations as 'feeders' which form a network to supply distribution transformers (including SWER) totalling approximately 40% of Aurora's total network. Of this, approximately 70% of overhead HV line is located on the Central network and 30% on the Dunedin network.

Within Aurora's distribution network there are in the order of 5,000 potheads (mixture of high voltage and low voltage). Analysis to date indicates that in the order of 10% of the potheads are cast iron, although this is currently being reviewed and validated. Failure of these pose significant health and safety risk to both public and staff and a thorough assessment of these has commenced with the intention to develop a prioritised renewal programme. In the interim operational methods have been issue to mitigate the potential hazard of staff working in close proximity of cast iron potheads.

Asset Performance

Section 3 outlined that Aurora's 2012/13 performance results for overhead line faults were slightly above target and that there appeared to be a slight increasing trend. It is currently assumed that 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 type 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.

Asset Condition and Data

Aurora's geo-database contains the main asset attribute information for distribution lines. Data currently held on this database includes conductor size, length, age and nominal and operating voltage. Other information available includes that collected through construction and routine maintenance programmes outlined in the following section. Figure 5.18 details the age profile of HV lines by conductor age and pole age. Approximately 40% of conductor is aged more than 45 years.

Maintenance Plan

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; and the procedures in the Electricity (Hazards from Trees) Regulations 2003 are followed.

A complete survey of the overhead network was completed in 2011. This assessed the impact of vegetation with the data recorded in Aurora's GIS. This information has been used to develop a programme of works targeting specific feeders on an annual basis, which combines vegetation, pole inspection and performance (reliability) information. It is expected that maintenance expenditure on HV lines will rise over the planning period, being predominantly driven through pole replacement needs and vegetation management as opposed to conductor replacement (also see Section 5.5.2).

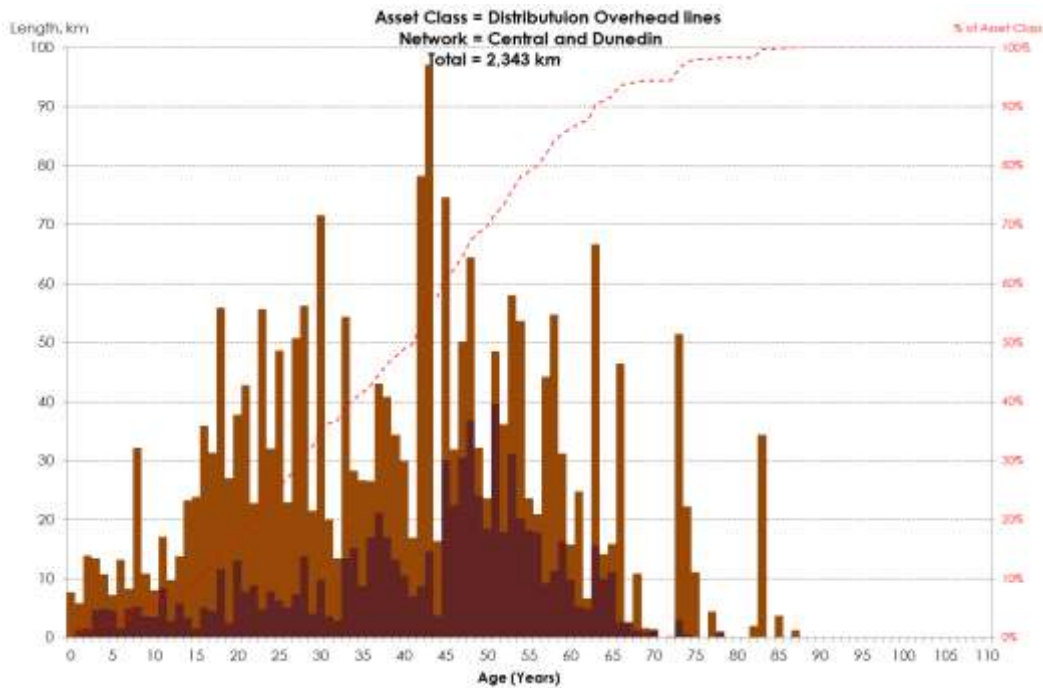


Figure 5.18 – Distribution Lines (11 kV and 6.6 kV) Age Profile

Replacement Plan

At present there is no HV conductor and cross-arm renewal programme, in both the Dunedin and Central areas. The sufficiency of this will be reviewed in 2014/15 as Aurora further develops its targeted feeder replacement programme for pole and pole hardware renewal in conjunction with vegetation management permitted under the Electricity (Hazards from Trees) Regulations 2003.

Creation/Acquisition and Disposal Plan

For planned projects related the creation of assets in this asset category (see Section 6.6 – Network Development). Disposal is as per proposed decommissioning policy outlined in Section 5.4.3.

5.5.7.2 Distribution Cables (11kv and 6.6kV)

Asset Description

Aurora's underground cable distribution system is 790km of circuits totalling approximately 15% of Aurora's total network (including a submarine cable). Of this, 45% is PILC and 55% XLPE/PVC. HV cable insulation in the Dunedin area is predominately PILC with some XLPE. For many years, all new cable has been rated for 11kV operations even when it operates at 6.6kV.

Asset Capacity/Performance

Deterioration of HV distribution cable has not been a particular problem to date, 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. There is also a submarine cable across the harbour that has been trouble free since the early 1990's.

Asset Data and Condition

Aurora's geo-database contains the main asset attribute data for subtransmission cables. Data currently held includes location, insulation type, date installed, conductor size, age and nominal and

operating voltage; other paper-based information is also available. The age profile of HV cable is shown in Figure 5.19.

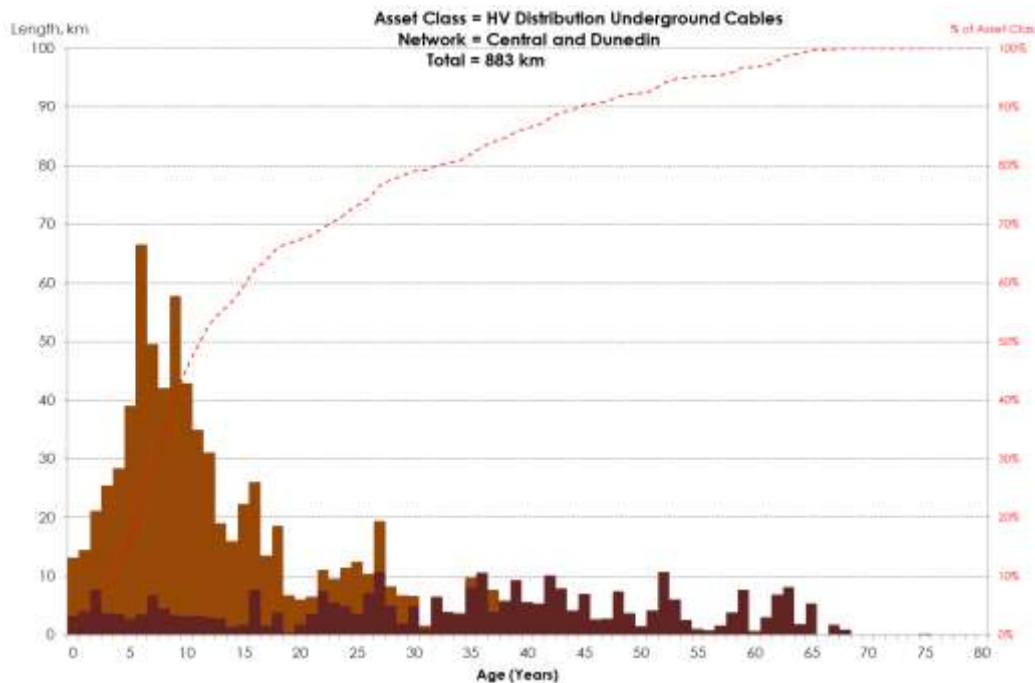


Figure 5.19 - Distribution Cables (11 and 6.6 kV) Age Profile

Maintenance Plan

No routine inspections of cables or associated equipment are made.

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.

Replacement Plan

There is currently no programmed replacement expenditure allocated to this asset category.

Creation/Acquisition and Disposal Plan

Additional cables are installed in response to overhead to underground conversions (driven by Local Authorities) or are developer-driven as a result of new connections and subdivisions; or through other growth or upgrade plans (see Section 6.6 – Network Development). No plans to dispose of this asset other than minor disposal associated with changes and rearrangements in the network.

5.5.7.3 Distribution Switchgear

Asset Description

Switchgear is the combination of switches, fuses or circuit breakers. Aurora has various classes of switchgear including ground-mounted, pole-mounted, reclosers and sectionalisers and those which are associated with RMU's; located both indoor and outdoor. Together, these assets help to provide protection for primary equipment on the distribution network and assist with network reliability. A circuit breaker is the primary component that interrupts faults and there are four main types: oil, gas (SF₆), vacuum and air. The main type of switchgear on currently Aurora's distribution network is oil, however this switchgear is being discontinued by its suppliers and Aurora is considering other options, which looks likely to be SF₆ switchgear.

Asset Capacity/Performance

Switchgear associated with ring-main units has been relatively maintenance free, and checks on oil levels and general condition are included in the substation inspection round. However, given the associated age profile of some oil-based switchgear, focus will be given to this asset category for determining revised maintenance and renewals needs.

Fuse switch

Within the central network there are particular fuses that have limited fault rating. These are found on distribution pole top substations and are glass tube "Pacific" fuses, which are being progressively replaced as part of Aurora's expenditure programme.

Within Dunedin's CBD (including South Dunedin), Andelect fuse boxes were installed in the 1950's and 1960's when these areas were converted from overhead to underground distribution. See the photo below 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



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.

Also, a number of distribution substations have oil circuit breakers. The Reyrolle Type C switchgear on Aurora's network is now over 60 years old, obsolete and expensive to maintain.

Asset Data and Condition

Aurora's geo-database contains the main asset attribute information for switchgear. Data currently held on this database includes age, location, type/model. Other information available includes that collected through routine maintenance programmes outlined in the following section.

Many switches and fuses were installed in the 1940's-1990's and many are therefore near to or past their theoretical useful life (of around 35-40 years) and require replacement. The age profiles for ground and pole mounted switchgear for Central and Dunedin is shown in Figure 5.20. This illustrates there is a higher proportion of older assets located within the Dunedin network.

Note that due to the age profile of oil switchgear, the maintenance procedures and intervals are being reviewed and benchmarked 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.

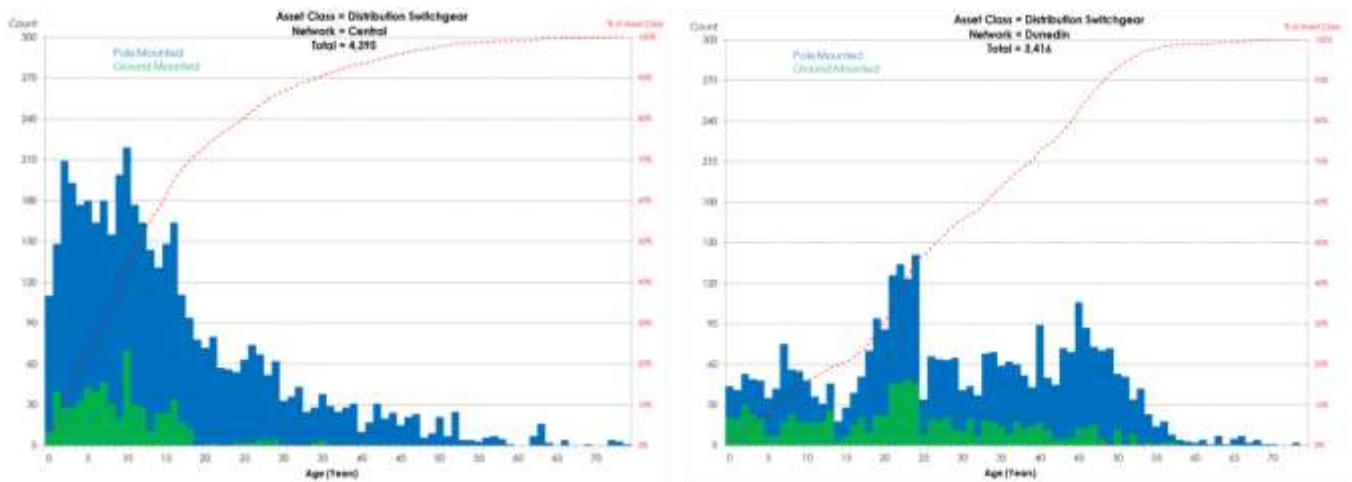


Figure 5.20 – HV Switchgear Age Profile (Central and Dunedin)

Maintenance Plan

Inspection expenditure for this asset category is presented in Section 5.6.

For each type, make and model of circuit breaker, intervals for minor and major services, and the type of work to be carried out is defined, with the interval monitored against failure rates. These services are infrequent major overhauls, costing up to several thousand dollars.

Checks on oil levels and general condition for ring-main switchgear are included in the monthly substation inspection round.

Greater emphasis is now also 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".

Replacement Plan

Aurora's budgeted maintenance expenditure for renewals and replacement costs are shown in Section 5.6; capital expenditure is presented in Section 6.7. Provision has been made for replacement of some oil-based switchgear on an annual basis.

Note that 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 planning period.

The Reyrolle Type C switchgear is proposed to be replaced within the planning period and Pacific fuses are also being progressively replaced over the next 10 years.

A budget of \$36,000 per year over the next 10 years has been set for the replacement of Andelect fuse boxes based on an average estimated cost of \$6000 each. 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.

Creation/Acquisition & Disposal Plan

For planned projects related creation/disposal of assets in this asset category see Section 6.6 – Network Development.

5.5.7.4 Distribution Transformers

Asset Description

Distribution transformers are installed on our network to transform voltage to a suitable level for customer connections. The main types of distribution transformers on Auroras network are pole and ground mounted as well as voltage regulators (of which there are 24). There are over 4200 ground mounted transformers and over 2400 pole mounted transformers. Auto-transformers are used in some parts of the network to also enable the interconnection of 11 kV and 6.6 kV sections.

The types of ground-mounted distribution transformers include.

- **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.

Asset Capacity/Performance

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. Ground mounted transformers range in size from 15 to 1000 kVA.

Transformer utilisation is measured as the ratio of maximum demand in kVA to installed rating. Total system demand to total distribution transformer capacity gives an indication of overall distribution transformer capacity. For the 2012 year, this was 817MVA for the Aurora network, which was 2MVA more than the previous year.

Asset Condition and Data

Data currently held in Aurora's information systems for this asset category includes: location, type, age, maintenance history, test results, inspections. For transformers and regulators updated condition and performance data comes from routine or reactive inspections.

Figure 5.21 details the age profile of in-service Aurora-owned distribution transformers. Approximately 34% of the pole mounted transformer population is past the theoretical asset life of 45 years, with several being installed before 1940. Investigations on electrical clearances and ground clearances for pole mounted transformers were carried out in 2013 and consideration is now being given to options and actions for addressing issues raised. Where anomalies are identified, further investigation to identify appropriate solutions may be required.

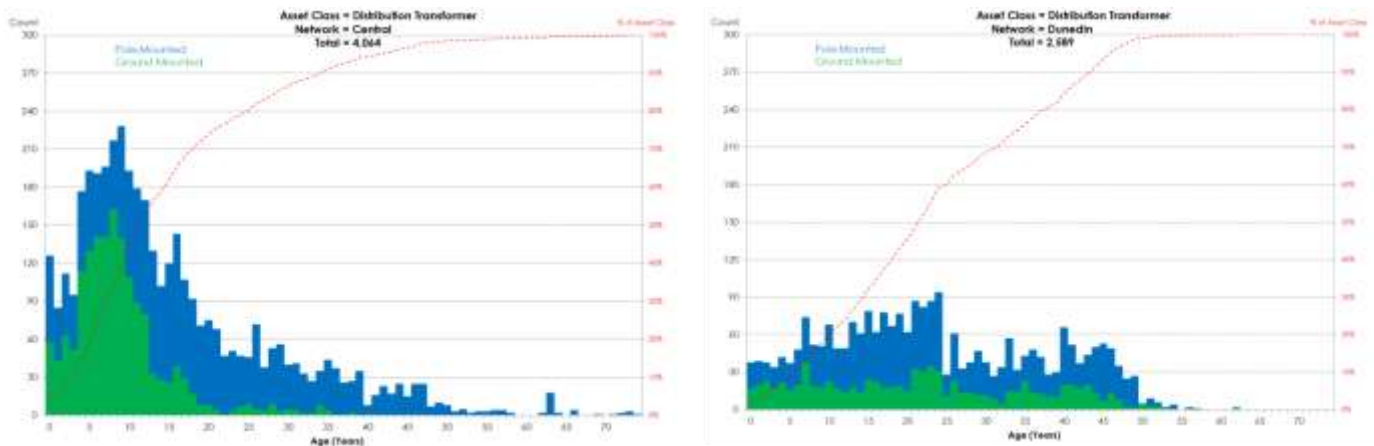


Figure 5.21 - Distribution Transformers Age Profile

Maintenance Plan

Aurora's budgeted maintenance costs are provided in Section 5.6

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.

Replacement Plan

Aurora's budgeted maintenance replacement costs are provided in Section 5.6; and capital replacement costs are presented in Section 6.7.

Distribution Transformers

Provision has been made to replace distribution transformers that are damaged or deteriorated such that they are uneconomic to repair. A budget of \$250,000 per year over the next three years has been established for this and increasing to \$400,000 per year from 2019/20 onwards to address growing age-based renewal needs.

Voltage Regulators

The 6.6kV voltage regulator at Otakou on the PC3 feeder is an old Ferranti moving coil unit manufactured in 1947 and requires replacement. A proposed solution is to convert the supply beyond Otakou to 11kV which may eliminate the need for a regulator. Funding has been allocated for this in 2014/15 and a determination of the most appropriate solution is pending.

Creation/Acquisition and Disposal Plan

For planned projects related to the creation of assets in this asset category see Section 6.6 – Network Development. Disposal is as per proposed decommissioning policy outlined in Section 5.4.3.

5.5.7.5 Distribution Substations

Distribution substations comprise the transformer (sub-categorised in the previous section), transformer pad, HV and LV fusing, and an earth mat. The main types of distribution substations on Aurora's network are pole mounted, ground mounted and underground. In addition, many distribution substations are housed in structures that also require maintaining.

Asset Capacity/Performance

Dunedin

A significant rainfall event in Dunedin in February 2005 lead to five underground distribution substations flooding. During this event these had to be off-loaded, with the subsequent failure of one transformer after the event.

Central

In the Central area, many distribution pole top substations are fused with glass tube "Pacific" fuses. These fuses have limited fault rating and are undergoing replacement as outlined in previous sections.

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. This pilot wire system, controlled by interfacing Decabit relays installed at distribution substations, supplies approximately 2,000 consumers. Refer to Section 5.5.18 for further detail.

Asset Data and Condition

Data currently held in our information systems for this asset group includes: location, type, age, maintenance history, test results, inspections.

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 behind ventilation mesh and there are also safety issues with the LV distribution boards. A programme to replace these is being rolled out.

Two-pole substations are also of concern to Aurora and a programme to replace these is also being rolled out.

Maintenance Plan

Aurora's budgeted maintenance costs are provided in Section 5.6

Depending on the level of maintenance required, refurbishment may occur within the year (for minor items), placed on the maintenance programme or may require further assessment to determine the level of intervention required.

All ground mounted substations are inspected at three yearly intervals. Those that have HV circuit breaker equipment installed, have their tripping batteries checked three monthly and, where applicable, alarms are tested six monthly. Some ground-mounted substations have HV circuit breaker equipment installed, which helps Aurora to reduce the consequence of tripping.

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

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

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

Replacement Plan

Aurora's budgeted maintenance replacement costs are provided in Section 5.6; and capital replacement costs are presented in Section 6.7.

Underground substations

A programme is underway to seal and mechanically ventilate underground substations vulnerable to surface flooding or replace them with ground mounted substations if practicable.

"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 out to 2024 at an estimated cost \$250,000 per year.

Creation/Acquisition Plan

The Network Development section of this AMP (Section 6) contains projects relating to the establishment of new or upgraded assets on the network.

Disposal Plan

Disposal is as per proposed decommissioning policy outlined in Section 5.4.3.

5.5.8 Low Voltage (0.4 kV)

Aurora has over 1800km of Low voltage (LV) circuit (overhead and underground) and over 200km of street-lighting circuit (overhead and underground). The following sections cover low voltage lines, cables, street lighting and connections.

Historically there has been little-to-no investment in the LV network. Preparation of the PSMS has heightened awareness in the industry that LV systems are not getting the asset management attention required. A review is required of Aurora's LV network, as per the EEA guidelines, to understand the nature and scale of issues on the LV network and respond accordingly. This is likely to include the requirement for additional expenditure in the future. Based on the current known LV network needs, provision has been made in the 2014/15 programme.

5.5.8.1 LV Lines

Asset Description

Aurora has 1037 km of LV line (55% of total circuit length). 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.

There are two types of LV overhead on the network, being predominantly open wire with only a few kilometres of Aerial Bundled Cable (ABC).

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. Although growth has slowed in the recent past, it is still continuing at a higher rate when compared to Dunedin which is steadily reducing the relative proportion of overhead LV.

Asset Capacity/Performance

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

Asset Condition

Figure 5.22 shows the age profiles for LV lines, cables and street-lighting. Approximately 40% of LV conductor is over 40 years.

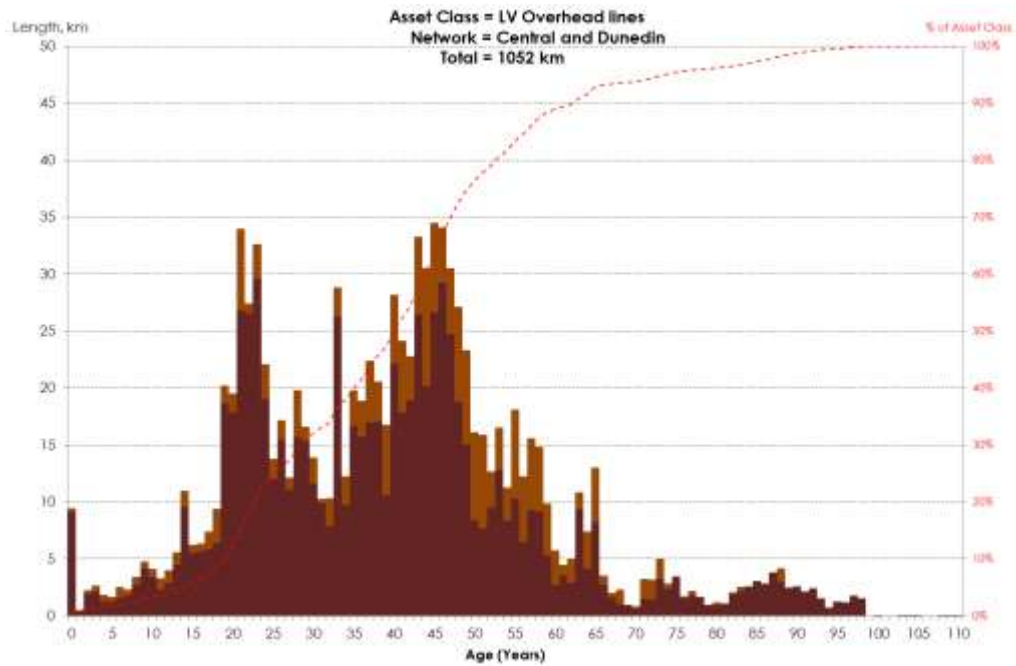


Figure 5.22 – LV Distribution Lines Age Profiles

Asset Data

Data currently held in Aurora's geo-database for this asset category includes: location, conductor type, size and age; and information collected via network inspection rounds.

Maintenance Plan

Maintenance activity is generally aligned with the pole inspections where observations are made on a routine basis as the network undergoes inspection rounds.

Replacement Plan

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.

Creation/Acquisition Plan

Construction of low voltage distribution lines are generally in response to customer connection requirements only (see Section 6.6.10)

Disposal Plan

Aurora disposes of overhead lines to meet customer requirements or where other drivers may exist, such as underground conversion projects required by territorial local authorities.

5.5.8.2 LV Cables

Asset Description

Aurora has 825 km of LV cable. Most LV cable is cross-linked polyethylene (XLPE). However, in the Dunedin CBD, paper-insulated lead covered (PILC) cable is present.

Asset Capacity/Performance

The performance of LV cables is generally good; the majority of failures are due to damage from third party installation or some other disturbance as opposed to asset deterioration.

Asset Condition

The oldest LV cables have not indicated any significant signs of reaching the end of their economic lives. See Figure 5.23 for age profiles of LV cables.

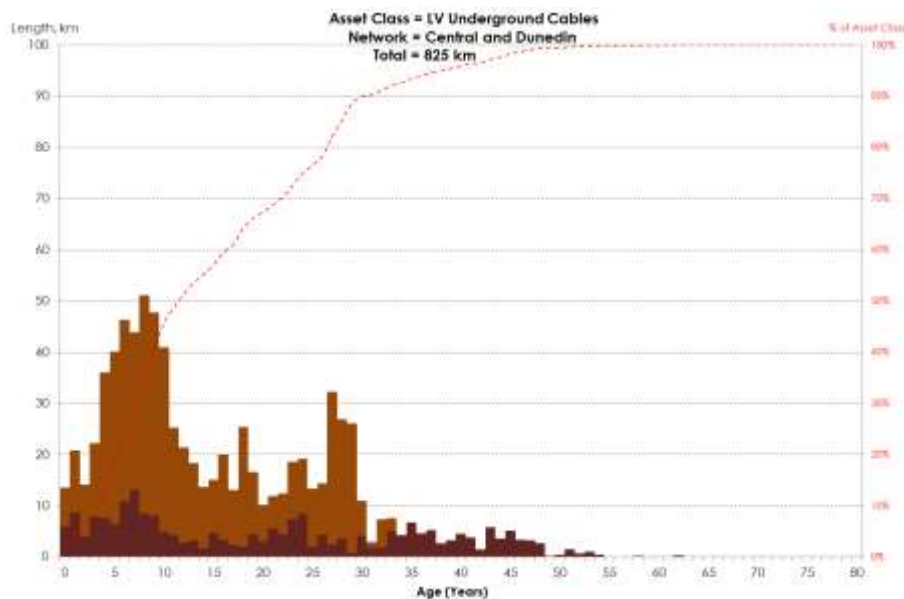


Figure 5.23 – LV Distribution Cables Age Profile

Link boxes in Dunedin and Central are of concern to Aurora and further assessment of these is required to further develop the replacement plan discussed below. In central, obsolete link pillars are driving the replacement programme.

Asset Data

Aurora's geo-database contains the main asset attribute data for LV cables. Data currently held includes location, insulation type, date installed, conductor size, age and nominal and operating voltage.

Maintenance Plan

Five-yearly inspections of underground 400 Amp LV link boxes in the Dunedin central business district are carried out. There is currently no programmed maintenance replacement expenditure allocated to this asset category as capital replacement plans are being rolled out as described below.

Replacement Plan

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

Underground Link Box Replacements

In Dunedin, there are 246 underground LV link boxes. Some of these boxes require replacement due to ageing and overloading; the latter of which is predominantly attributed to protection issues. It is proposed to replace three boxes per year for the duration of the planning period at a cost of \$150,000 per year.

Creation/Acquisition and Disposal Plan

No plans to dispose of this asset other than minor disposal associated with changes and rearrangements in the network.

5.5.8.3 LV Street-lighting

Aurora has 269km street-lighting circuit (overhead and underground). Figure 5.24 shows the age profile for street-lighting. 73% of the street-lighting circuit was installed between 1940 - 2000 and 16% are over 40 years old.

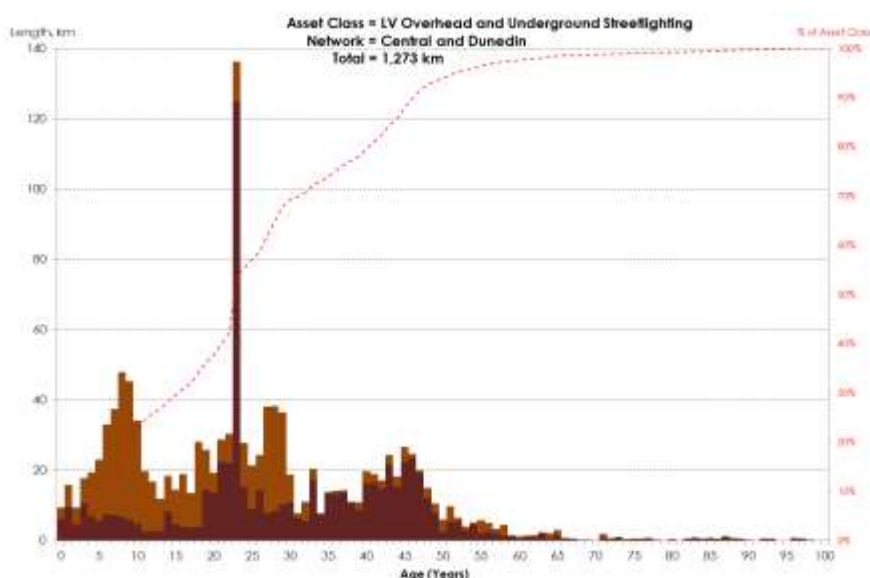


Figure 5.24 – Street-lighting (lines and cables) age profile

5.5.9 Connections

See and Section 5.6 for Aurora's maintenance and replacement expenditure forecasts and Section 6.6.10 for further comments

5.5.10 Other Network Assets (Secondary Assets)

Aurora's secondary assets comprise of equipment that provides: monitoring, control, communication, protection and automation functions. For Aurora, most of these assets are running 24/7 and are used extensively for network operation, safety control, equipment protection and asset management decision making. They are fundamental to the control and operational capabilities of the network.

Aurora's existing operating systems, SCADA hardware and load control systems were installed between 12-25 years ago and most are facing technological obsolescence with limited ability for use and operation with more modern protocols and systems.

Aurora has carried out a comprehensive review of its SCADA, control, communication and protection systems (SCCP), including a risk assessment due to aged and incompatible secondary equipment. From this, a number of options and solutions have been identified. Detailed assessments of these were carried out in 2013/14 in order to verify the scope, feasibility and economics for the options and solutions being proposed; and how each assists to mitigate the risks identified.

Eight projects make up the proposed programme for Aurora's SCCP systems (Figure 5.25). As a result of more detailed analysis in 2013, the timing and cost estimates have been revised. The updated estimated cost associated with each is outlined in Table 5.10 and Figure 5.26.

The SCCP programme of works was presented to the Board at the start of December 2013 and a peer review of the South Dunedin GXP and Upper Clutha SCCP elements of work has validated the approach being taken.

The text that follows provides further detail on Aurora's communications, SCADA, protection and load management systems.

Maintenance expenditure is shown in Section 5.6.

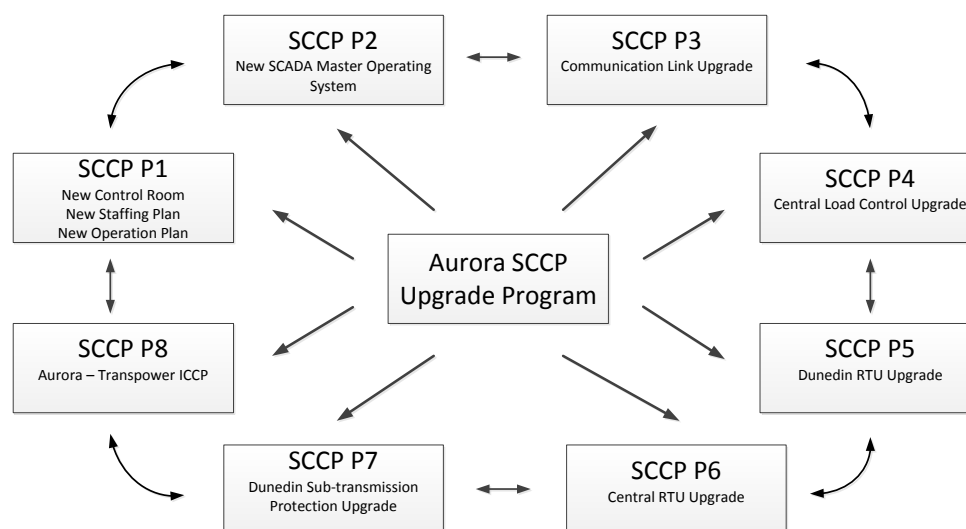


Figure 5.25 – SCCP Overview

Table 5.10 - Proposed SCCP projects (\$000)

	2014/15	2015/16	2016/17	2017/18
SCCP P1 - New Control Room	450	240	200	600
SCCP P2 - New SCADA (+ DMS+OMS) System	1,800	1,800	1,800	
SCCP P3 - Communication Link Upgrade	1,220	1,173	1,217	
SCCP P4 - Central Load Control System Upgrade	150			
SCCP P5 - Dunedin RTU Upgrade	970	670	1,040	250
SCCP P6 - Central RTU Upgrade	360	345	374	
SCCP P7 - Dunedin Subtransmission Protection Upgrade	720	420		210
SCCP P8 - Aurora and Transpower ICCP Link	10	220	120	
Grand Total	5,680	4,868	4,751	1,060

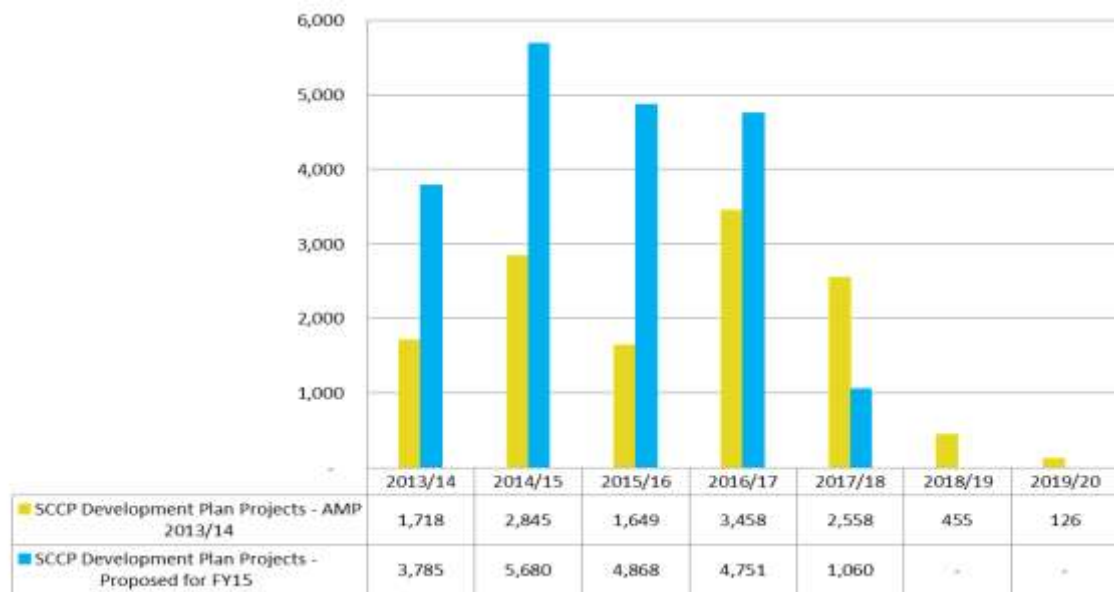


Figure 5.26 - Changes in estimated SCCP expenditure compared to 2013 AMP

5.5.10.1 Communication

Communication systems are integral to the remote indication and control of network equipment and enable communications between office-based operations with staff/contractors in the field. Communications are via a number of repeater sites located on various hilltops. Aurora also has a series of lease or rental agreements for its multiple radio sites. A number of these are pending review and renewal.

Asset Description

Dunedin

The existing communications system in the Dunedin area consists of a mixture of copper pilots, fibre optic cables, and UHF radio. A pilot cable network, installed with 33 kV cables, provides communication with twelve of the eighteen zone substations. The SCADA communications in Dunedin are also mostly via copper pilots using the Conitel protocol. However the SCADA to Mosgiel, East Taieri, Outram and Berwick Substations is via a UHF radio repeater (see Section 5.6.18.2 for further detail on SCADA).

Central

The existing Central Otago communications systems are predominately via VHF and UHF due to the large distances involved. The only existing fibre optic circuits are for short communications links.

Maintenance Plan

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.

No UHF or VHF systems have been identified as requiring renewal or refurbishment, however any significant upgrades form part of the SCCP programme.

Creation/Upgrade and Renewal Programme

See Table 5.10 for proposed SCCP programme.

Disposal Plan

Disposal is as per proposed decommissioning policy outlined in Section 5.4.3.

5.5.10.2 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.

Dunedin

A total of 23 Remote Terminal Units (RTUs) have been installed in Dunedin substations and most of these units were installed in 1987 when the SCADA system was first introduced in the Dunedin network.

In each substation, the SCADA RTU is connected to field devices such as switches, PLCs, IEDs (Intelligent Electronic Devices), protection relays. All the aggregated information from the field devices is sent between the master station and the RTU for supervision and control. Most of the RTUs communicate to the master station in Conitel protocol.

The existing RTUs have been very reliable but face technological obsolescence due to their inability to use modern master station communication protocols and communicate with IEDs such as protection relays.

Central

The existing Central network consists of 64 RTUs for substations and remote devices like auto-reclosers and voltage regulators. All RTUs are Abbey RTUs. Communications between the Central RTUs and the Cromwell Master Station are in Abbey HDLC protocol via radio links. The existing RTUs have been very reliable but the Abbey communication protocol is only supported by the Abbey SCADA operating system.

Maintenance Plan

Current routine and preventative maintenance includes:

12-monthly checks - 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.

4-yearly tests - 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.

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

Any revised future maintenance requirements for SCADA assets will be clarified as the SCCP programme develops.

Creation/Upgrade and Renewal Programme

See Table 5.10 for proposed SCCP programme.

Disposal Plan

Disposal is as per proposed decommissioning policy outlined in Section 5.4.3.

5.5.10.3 Protection

Protection systems are established in order to protect the electrical network in the event of power system faults. Aurora's protection comprises of: voltage transformers (VT) current transformers (CT) and protection relays. These are predominantly used to protect high voltage assets by isolating the faulted section from the rest of the network. Fuses may also perform a similar function depending on network configuration. The main types of relays used in the Aurora network are: electromechanical, analogue and digital.

Translay protection systems have been used extensively on the Dunedin 33kV sub-transmission networks. The existing Translay system used in the Aurora network is an electromechanical design and the system is at the end of its operational life. Most of the existing Translay protections were installed as part of the cable installation and the age of these devices varies between 30 and 52 years.

Current assumptions are that the age of protection relays is generally the same as the associated switchgear. Protection relays are generally upgraded to modern IED relays when the associated switchgear is replaced.

Aurora does not currently have specific age profile data for the protection relays; however this issue is being addressed as part of the data completeness and accuracy review process.

Older feeder protection relays are proposed to be upgraded to SEL relays and this forms part of the SCCP programme. The benefits of installing these relays are:

- Implementation of auto reclose on feeders is made easier
- Improved performance through implementation of separate sensitive earth fault and normal earth fault protection
- the provision of additional fault data & detailed post fault analysis as the SEL relays are modern IED devices that can communicate directly with the SCADA RTU

Maintenance Plan

Current routine and preventative protection system maintenance includes:

Biannual tests for 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.

Six year inspections for earth connections - above ground earth connections, for all equipment, are inspected and maintained at six-yearly intervals. Sample underground connections to the main earth grid are also checked at six-yearly intervals for physical deterioration. Earths identified during routine inspection as requiring attention will be refurbished as required.

The future requirements for Aurora's protection systems maintenance planning will be reviewed and revised where necessary as part of the SCCP programme delivery.

Creation/Upgrade and Renewal Programme

See Table 5.10 for proposed SCCP programme.

Disposal Plan

Disposal is as per proposed decommissioning policy outlined in Section 5.4.3.

5.5.10.4 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 and Aurora owns 2195 ripple control relays that are used to switch street lighting circuits.

A new 317 Hz 33kV injection system was installed in 2011 adjacent to the South Dunedin and Halfway Bush GXP and operates in parallel with the 1050Hz system. Ripple receivers will be progressively changed from 1050 Hz to 317 Hz, with 1050Hz injectors progressively removed.

Central Load Management

The majority of load management in the Central area is via Decabit 317 Hz ripple injection plants. These injectors are all solid state units with a nominal life of 20 years. The Central injection plants are controlled by a custom made system dating from 1996. The load control system used in Central Otago was originally installed well before the SCADA system and therefore ran on equipment completely separate from the SCADA system.

A PLC located at the Alexandra Substation makes all the load control decisions. Load control data to and from the three Transpower GXP points of Frankton, Cromwell and Clyde, plus data from the local Generation stations is fed into the PLC at Alexandra. This load control data consists of the GXP metering pulses, generation metering pulses, channel statuses, ripple plant keying and ripple plant alarming.

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.

Maintenance Plan

Ripple signal checks, carrying of strategic spares stock, replacement units for rental and a fault callout service are currently carried out on an annual basis via the routine contactor checks. Contacts will be renewed as part of this where necessary.

Motor-generator sets are being monitored and routine maintenance will be carried out where identified as necessary.

The solid state coupling cells at North East Valley zone substation and in the Central network are virtually maintenance free.

CO₂ flood systems in load control coupling cell cubicles are inspected annually. Pressure cylinders are tested at regulated intervals dependent upon age (5 year intervals for pressure tests). Inspection is carried out internally, with repairs and pressure testing conducted by external contract. The roll out timeframe is for 317Hz ripple units in consumer sites will dictate the decommissioning timeframe of the existing 1050Hz plants / CO₂ installations at each zone sub.

Replacement Plan

Ripple Injection – zone substations

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.

Dunedin Street Lighting Ripple Control Receivers

Aurora owns 2195 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.

5.5.10.5 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.

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 of the South Dunedin Check Metering is in progress and is occurring in conjunction with other work associated with the Transpower upgrade from outdoor to indoor switchgear. It is proposed to upgrade the Halfway Bush Check Metering when Transpower upgrades the switchgear at Halfway Bush. This work is now covered under the SCCP project.

5.5.11 Mobile Substations/Generation

Asset Description

Aurora owns three mobile distribution substations with a voltage configuration of 11kV/6.6 kV/400V. One 500kVA unit is based at Cromwell, with a 300kVA and 500 kVA unit based in Dunedin. These units are standby units for continuation of supply during transformer replacements or repair be they planned or unplanned and are custom fitted to commercially available truck chassis.

Additionally Aurora owns a 5 MVA 66/33/11/6.6 kVA mobile substation which is based at Cromwell as a backup for Zone Substation outages or Zone Substation transformer maintenance. Due to the scale of the 5MVA mobile substation the setup is on a four axle stepped semi-trailer with front and rear hydraulic outriggers for levelling and stabilising when deployed.

With the establishment of Cardrona Zone Substation, the temporary containerised 500kW generator that was installed in the Cardrona valley to provide additional capacity during the ski seasons is not currently in service. Its future re-deployment is under consideration.

Asset Capacity/Performance and Condition

The performance of mobile distribution substations is generally good; the majority of repairs are more related to the vehicle carrying the unit involving WOF or COF compliance.

Performance of the 5MVA mobile substations is generally good and again the majority of repairs are more related to the vehicle carrying the unit involving WOF or COF compliance.

With the containerised 500kW generator future being under review it is currently in storage.

The 5MVA mobile substation exceeds the NZ Transport Agency "Vehicle Dimensions and Mass 2002" Rule 41001 in height and width and as such has been granted an exemption under Exemption VDM09/079 and associated document B990258.

Central based 5MVA fitted to TMC Trailer Four axle stepped semi-trailer.

Asset Data

Data currently held includes past registration and ownership forms in hardcopy on file.

Maintenance Plan

On a regular basis the mobile distribution substations are condition assessed with checks as per RS30, electrically tested and maintain valid WOF's and COF's.

Replacement Plan

There is currently no programmed replacement expenditure allocated to this asset category.

Creation/Acquisition and Disposal Plan

There are currently no plans to dispose of these assets. The purchase of an additional mobile generator is being considered in order to reduce the risk and cost associated with transformer sites on the distribution network that no back-up supply options available.

5.5.12 Other

Ladders, portable earthing equipment, and safety gear

All ladders, portable earthing equipment, and safety gear used in zone substations are inspected or tested at six-monthly intervals. Anything identified as requiring refurbishment during these six monthly inspections will be refurbished as required.

Towers - 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. It is estimated that it would cost \$150,000-\$200,000 to refurbish each tower with a total cost of \$800,000 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 over the next two years.

5.6 Operations & Maintenance Forecasts

Operational expenditure is split into 4 main categories, as per the new Electricity Distribution (Information Disclosure) Requirements 2012. Expenditure allocations are listed below (as a % for 2014/15) and forecasts presented in the tables that follow⁹.

Service Interruptions & Emergencies – 25% of total maintenance expenditure allocation, compared to 41% in 2013/14.

Vegetation Management – 32% of total maintenance expenditure allocation, compared to 13% in 2013/14.

Routine and corrective maintenance and inspection – 41% of total maintenance expenditure, compared to 33% on 2013/14

Asset Replacement and Renewal – 2% of total maintenance expenditure allocation, compared to 12% in 2013/14.

The replacement and renewal forecast expenditure is substantially less than that shown in 2012/13. This has been largely driven by expenditure for pole renewals being optimised and funded from the capital budget, particularly as these are predominantly high value works. Any minor corrective works required for these assets during the year is funded from the 'routine, corrective and inspections' category.

This type of work is predominantly more than minor due to the asset needs of the network and therefore capitalised through larger work programmes. However, further analysis during 2014/15 is still required in order to aid the development of better informed renewal maintenance requirements.

A third party damage allowance of \$750,000 per annum is now included in the Table 5.11, in the service interruptions 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.

Table 5.11 - Operations & Maintenance Costs Summary (\$000)

Maintenance Expenditure	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24
Service Interruptions and Emergencies	3,330	3,330	3,330	3,330	3,330	3,330	3,330	3,330	3,330	3,330
Vegetation Management*	4,333	4,333	4,333	4,333	4,090	4,090	4,090	4,090	4,090	4,090
Routine, corrective maintenance & inspections**	5,468	4,416	4,243	4,631	4,465	3,882	4,167	4,497	4,920	4,253
Replacement & Renewal***	245	235	225	221	221	216	216	216	216	216
Total	13,376	12,314	12,131	12,515	12,106	11,518	11,803	12,133	12,556	11,889

* See Table 5.12 for detail

** See Table 5.13 for detail

*** See Table 5.14 for detail

The above maintenance and renewals expenditure lines are further disaggregated in the following tables to show costs against each asset category.

⁹ Constant pricing capital expenditure was inflated to reflect forecast nominal prices from CPI growth data 2014/15 – 2017/18 sourced from the New Zealand Treasury Half Year Economic and Fiscal Update (Dec 2013). The Treasury CPI growth value from 2017/18 was taken to calculate nominal pricing over 2018/19 – 2023/24 in lieu of available forecast data for this period.

Overall :

- The forecast maintenance expenditure total 2014/15 AMP 10yr period is \$ 122.3M
- the forward programme seeks to increase the average annual spend on **planned** activities over the forecast period compared to the 2013/14 AMP. This is largely driven through vegetation management, earth repairs and building maintenance requirements.
- the forward programme will reduce the average annual spend on **operations** over the forecast period compared to the 2013/14 AMP. This is largely driven through expenditure on Chorus change-overs (telecom pole replacements) now being funded from the capital budget.
- the forward programme will reduce the average annual spend on **faults** over the forecast period This change is largely driven through the expectation for a reduction in faults given the increased investment in vegetation management as well as the improved processes to deal with expenditure on unplanned events.

Table 5.12 - Vegetation Management

	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24
Central	2,241	2,241	2,241	2,241	2,241	2,241	2,241	2,241	2,241	2,241
Dunedin	2,093	2,093	2,093	2,093	1,849	1,849	1,849	1,849	1,849	1,849
Total	4,333	4,333	4,333	4,333	4,090	4,090	4,090	4,090	4,090	4,090

Table 5.13 - Routine, Corrective Maintenance & Inspections Expenditure by Asset Category (\$000)

(\$000's)	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24
Central	2,881	2,071	2,227	2,320	2,547	2,002	2,012	2,041	2,806	2,258
Subtransmission	35	35	35	35	35	35	35	35	35	35
Zone Substations	876	250	246	337	809	224	275	321	825	220
Distribution Lines and Cables	1,532	1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522
Distribution Substations	417	243	403	405	160	200	160	142	403	460
Other Network Assets	21	21	21	21	21	21	21	21	21	21
Dunedin	2,586	2,345	2,016	2,310	1,918	1,881	2,155	2,455	2,114	1,994
Subtransmission	81	78	78	96	78	78	78	78	96	78
Zone Substations	423	331	278	542	344	247	361	547	321	240
Distribution Lines and Cables	1,376	1,366	1,341	1,341	1,341	1,341	1,341	1,341	1,341	1,341
Distribution Substations	646	535	281	297	121	178	340	455	319	301
Other Network Assets	62	35	38	35	35	37	35	35	37	35
Total	5,468	4,416	4,243	4,631	4,465	3,882	4,167	4,497	4,920	4,253

Table 5.14 - Replacement and Renewals Expenditure by Asset Category (\$000)
(Dunedin & Central Combined)

Asset Category	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24
Subtransmission	0	0	0	0	0	0	0	0	0	0
Zone substations	20	10	10	10	10	5	5	5	5	5
Distribution and LV Lines	0	0	0	0	0	0	0	0	0	0
Distribution and LV Cables	0	0	0	0	0	0	0	0	0	0
Dist. substations & transformers	220	220	210	206	206	206	206	206	206	206
Distribution Switchgear	5	5	5	5	5	5	5	5	5	5
Secondary Assets/Other	0	0	0	0	0	0	0	0	0	0
Total	245	235	225	221	221	216	216	216	216	216

6 Network Development

6.1 Introduction

This section outlines the network development plan and capital expenditure required to maintain, enhance and develop the operating capability of Aurora's system.

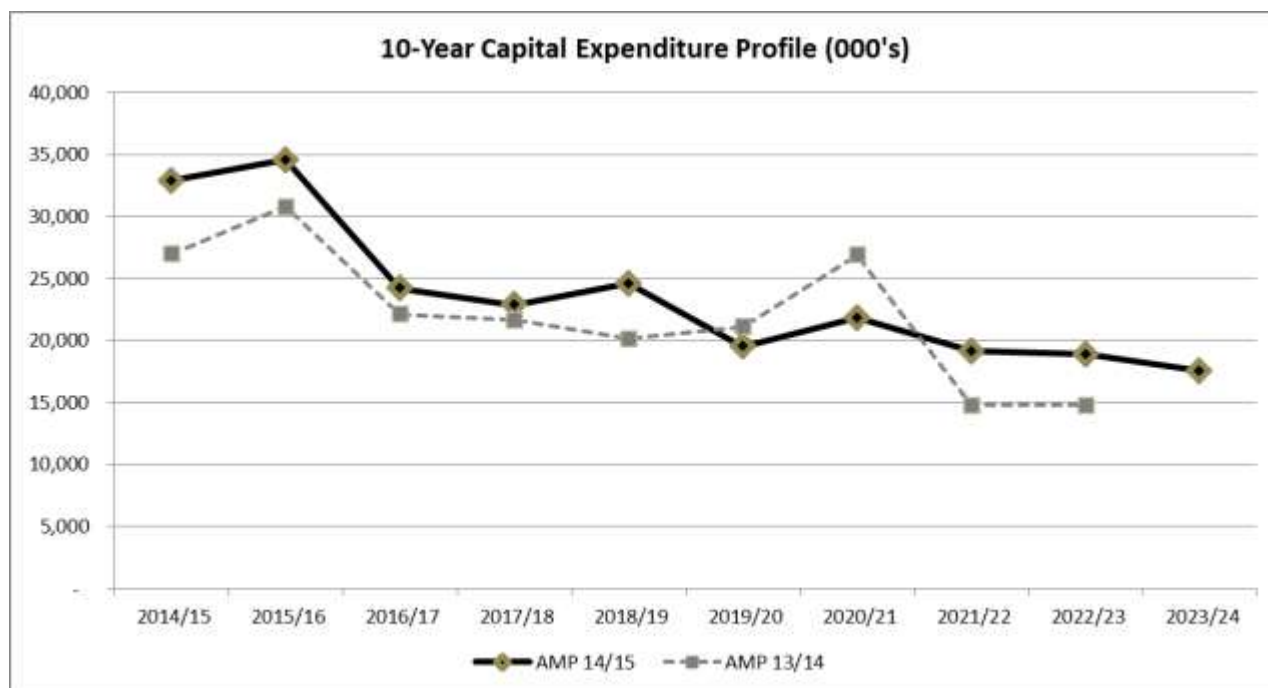
The overall aim of this section is to clearly justify investment needs and identify funding requirements over the short, medium and long term. The key drivers for capital investment were highlighted in Section 2.4, and include:

- growth in demand (existing and new consumers)
- enhancement of network reliability and security
- meeting legislative requirements, safety and reliability standards
- replacement of aging assets
- community expectations
- emergency preparedness
- technology

The sections that follow provide an outline of the planning criteria, assumptions and prioritisation frameworks applied to Aurora's development planning processes. Growth and demand forecasting and predictions are then presented followed by the proposed plans to address the network development requirements.

A summary of the changes in the capital expenditure profile compared to that reported in the 2013/14 AMP is provided in the graph on the following page. The main drivers for the changes are:

- Load growth demand driven by dairy conversion irrigation needs requiring the construction of two substations (Lindis Crossing and Camp Hill).
- Renewals expenditure driven by the revised SCCP project costs and phasing,
- Works that have previously been deferred as well as installation of 33kV zone substation circuit breakers at Omakau and Remarkables.
- The capitalisation of work driven by Chorus change-overs and the inclusion of funding for the cast iron pothead replacement programme.
- The inclusion of expenditure for the Omakau mobile substation project and a mobile generator have also contributed to the proposed increase.
- A revised date for the Upgrade of the Cromwell 33/66kV Auto Transformers
- Some provision has also been made for both low voltage service/link pillars and switchgear from 2015/16 onwards.



Definitions for the expenditure categories are outlined below (based on the Commerce Commission determination information). The forecast capital expenditure against these categories for each network area is detailed further in Sections 6.5, 6.6 and 6.7.

Definition for expenditure categories

Reason for Work / Primary Driver	Sub-Category	Commerce Commission description
Consumer connection		Establishment of new customer connection point or alterations to an existing connection point, and includes expenditure on assets relating to connection assets for which expenditure is recoverable in total, and injection and off-take points of connection
System growth		A change in demand or generation on a part of the network resulting in the need for extra capacity or additional investment to maintain current security and/or quality of supply standards <i>due to increased demand</i> . Includes SCADA and telecommunications assets.
Asset replacement and renewal		Expenditure on assets for replacement and renewal
Asset relocations		Resulting from the need to relocate assets due to 3rd party requests, requests from the roading authority or other needs. Also includes under-grounding of overhead network assets.
Reliability, safety and environment	Quality of supply	The need to meet improved security and/or quality of supply standards to reduce overall interruption/fault rates on the network, and minimising SAIDI and SAIFI.
	Legislative and regulatory	New regulatory or legal requirement resulting in the creation of, or modification to network assets.
	Other reliability, safety and environment	To improve network reliability, safety or to mitigate the environmental impact of the network.

6.2 Planning Criteria

When a deficiency is identified, the process for considering options and developing solutions commences. There can be several options available for resolving issues or risks identified and not just limited to capital expenditure for new or upgraded assets. Other options may include: do nothing, demand management, operational solutions. A range of factors are used to assess the viability of each solution, including (but not limited to) compliance with safety design standards, security of supply, quality, capacity, and capital return.

6.2.1 Security

Aurora recognises security of supply as being fundamental to ensuring a network continues to perform. It is the ability to meet demand and continue to provide a service in circumstances when equipment fails.

The more secure a network, the greater ability to continue to perform and/or the faster recovery time when a fault on the system occurs. Reliability on the other hand is different in that it is a measure of how the network actually performs e.g. frequency or duration of interruptions to supply.

By increasing the security of the network the potential for single points of failure can be mitigated. Appendix A outlines 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.

Security is factored into planning the development of Aurora's network by closing supply loops when economically viable. This statement holds true for both high voltage feeders and low voltage networks. During the initial scoping and appraisal stage for feeder or distribution substations, considerations are made for incorporating feeder interties along with low voltage connections between networks.

6.2.2 Power Quality

6.2.2.1 Voltage Magnitude

Setting voltage criteria is another important step used by Aurora in order to ensure that regulatory requirements are met so that the voltage is maintained between $\pm 6\%$ at the point of common coupling.

Areas within Aurora's network that may experience changes in quality are associated with long rural distribution feeders. The customers near the end of these feeders have UTL data loggers installed 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.

The placement of voltage regulators is a method used to maintain voltage levels on rural feeders. The preferred approach is to avoid the use of voltage regulators if it can be economic to construct a new zone substation. Zone substations are seen as a more dynamic approach to managing voltage magnitude particularly if loading is predicted to increase on the line in question.

Network reconfiguration is also a method used if applicable to help ensure voltage magnitude requirements are maintained.

6.2.2.2 Harmonics

It is recognised that low harmonic levels must be maintained on Aurora's network to ensure no undue interference to all customers and to avoid unnecessary conductor upsizing.

In 2013 Aurora released a new connection requirement for the level of voltage and current harmonic distortion allowed at the point of common coupling. This is seen as a timely addition to the connection requirements as it ensures the network will be designed in an effective manner so that connections do not result in unnecessary maintenance expense.

The rural harmonic connection requirements can be found on the Aurora Energy website.

6.2.3 Equipment Ratings

Equipment ratings are used in development planning to allow new additions to meet identical or greater capacity requirements. Capacity ratings of key asset groups are specified in Table 6.1.

Table 6.1 – Assignment of Equipment Ratings

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 (also see Section 6.2.3.1)
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.

*see comments of feeder ratings below

† refer to Glossary of Terms

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.

Aurora has a "Feeder Loading" database that provides calculation of the ability to off-load a feeder. 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.

6.2.3.1 Overhead Conductor Rating

Historically overhead conductor on Aurora's network has been designed and operated to 50°C as per regulation requirements of the period. The current capacities of these lines are specified in accordance with Table 6.2.

Table 6.2 – Ratings of ACSR Overhead Conductor at 50°C

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

All new overhead line is designed for a temperature rating of 75°C. Therefore when assessing existing overhead line ratings the value presented in Table 6.2 for 50°C is used unless explicitly stated. This ensures appropriate clearances are met due to sag.

The current capacity of overhead conductor that will be operated at 75°C for all new installations, is in accordance with Table 6.3. All irregularities to this table are dealt with on a case by case basis. Sub transmission overhead lines may have differing values.

Table 6.3 – Ratings of ACSR Overhead Conductor at 75°C

Conductor	Ratings (Amps)		Volt Drop %/MVA/km		
	Winter	Summer	33 kV	11 kV	6.6 kV
Wolf	659	545	0.026	0.228	0.631
Dog	455	378	0.035	0.31	0.859
Mink	341	285	0.051	0.455	1.256
Ferret	269	226	0.071	0.634	1.742
Squirrel	175	148	0.131	1.168	3.179

6.2.4 Utilisation Thresholds

Utilisation threshold is the planning limit on the ratio of an assets maximum allowed capacity compared to that of the expected/actual loading. Utilisation thresholds are closely related to capacity determination as they influence the formula used to determine the size of distribution transformers placed in the network.

The questions posed around where the threshold should sit for utilisation is challenging due to the probability used to determine the load of a domestic street versus an industrial outfit, i.e. industrial is more predictable than residential. Once this is understood, then a picture of the expected yearly peak loading is obtained along with whether the probability that transformer rating could be exceeded.

When dealing with n-1 the utilisation threshold has new meaning as the requirement for the system will involve a single line of equipment being able to carry the total capacity, therefore utilisation will be under 50%. n-1 systems are therefore justified and planned through other methods. Another example where this ratio falls short is the rating of lines when the line has been designed to carry increased load in a contingency situation.

6.2.5 Capacity Determination

When a capacity or security gap is identified, it is important to consider different options as solutions. Determination of capacity required is dependent on two aspects: (i) expected peak capacity for the assets economic life; and (ii) the standardised capacities available.

The design and construction of Aurora's 11kV and 6.6kV feeder networks follow a standardised design which inherently produces stepped capacity levels. This is considered acceptable as it increases efficiency in network construction therefore keeping costs down.

Existing loading and hence available capacity is measured on each feeder through half hourly data records and via maximum demand indicators located in distribution substations. This information is collected yearly and aids the timing of upgrades and replacements.

6.2.6 Standardisation

There is constant and progressive movement to refine and add new network standard drawings and procedures to the design and construction of Aurora's network. This extends from standard earthing drawings through to complete project tender packages.

The type and sizes of transformers used on Aurora's network are identified in network standards. This allows for easy replacement along with a reduction in the number of required strategic spares. Due to the Dunedin and Clyde Earnsclough network operating at 6.6kV all new transformers purchased for these areas are dual ratio, offering the ability in the future to operate at 11kV. Using dual ratio transformers has increased costs therefore standardising transformer sizing is an important aspect in the management of Aurora's network.

Very rapid growth in the Central Otago region has prompted Aurora to review its policies and practices for the procurement of design and construction services associated with extensions to the electricity

network, whereby all new or amended network irrigation connections (supplied from Cromwell or Clyde GXP areas) will be managed, designed and constructed by Aurora's preferred contractor. This assists Aurora to avoid piece-meal solutions and inefficient investment. A high level of co-ordination and integrated network design is required in order to optimise expenditure for the long term benefit of electricity consumers.

Aurora has a register of network standard practices and drawings, which are intended as the model for good design and therefore any variation must be approved by Aurora.

6.2.7 Energy, Demand and Growth (see Growth & Demand – Section 6.3)

Energy and demand growth is influenced by a variety of factors. Growth in peak demand is what primarily drives network development. Changes in population and population behaviour are the main factors that affect load growth, each being influenced by a number of variables (or strategic drivers) as outlined in Section 2.

Estimating the size and location of future loads is integral to effectively plan for the future of Aurora's network. However, there is also a degree of uncertainty associated with any type of forecasting, so it is important for load forecasting to be viewed as a guide to determining an approximate time for intervention and a trigger to further develop a higher level of accuracy as that time nears.

A key input to the planning process is half hourly load data. This is analysed after each winter for all grid exit points, zone substations and HV feeders. Section 6.5 contains further detail on how growth and demand forecasting is carried out for Aurora's network planning and decision-making.

6.2.8 Economic Analysis

Probabilistic analysis is used by Aurora to calculate the 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 6.4.

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 voltage drop that determines 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.

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) (see below)
- on-going consumer outages (as per Table 6.4).

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

The cost of an outage using probabilistic analysis is determined by multiplying all the following parameters: 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.

Following a review by external consultants in 2010, the Values of Lost Load shown in Table 6.4 were adopted.

Table 6.4 – Cost Allocated to Energy not Supplied

Type of Interruption	Value of kWh Unserved
Unplanned – residential	\$20
Unplanned – other	\$20
Planned – residential	\$20
Planned – other	\$20

Value of Energy not Supplied

The value of energy not supplied, (also known as Value of Lost Load), is detailed in Table 6.4 above.

Quantity of Load Lost

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

Probability of an Outage

The probability of failure is assessed by using engineering judgement in considering past and likely future failure rates. Judgement is required as pure consideration of past failure rates tends to under predict the future. Typical default values are shown in Table 6.5 below.

Table 6.5 – Equipment Outage Probabilities

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

Probability of Outage During “At Risk” Time

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

Outage Duration

The duration of the outage will depend on the equipment that has failed, its location, and the nature of the failure. Typical outage times are given in Table 6.6 below:

Table 6.6 – Typical Equipment Outage Times

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
Power transformer <= 5 MVA	6 to 12 hrs	

Power transformer > 5 MVA	1 week to one year	Faults can range from minor tap-changer issues to total transformer failure
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6.2.9 Non-Network Solutions

There are several alternatives available instead of investing in new infrastructure when the network becomes constrained. These include demand-side management, distributed generation (see 6.3.1) and more recently, the potential opportunities from smart metering (although these are yet to be realised).

6.2.9.1 Demand Side Management (DSM)

Aurora offers a demand management program to consumers with a capacity greater than 150 KVA who have the potential to manage their Congestion Period Demand (CPD). As at 2013, 56 customers, consisting of 111 ICP's had signed up to this program. Aurora otherwise applies the pricing principals as set out in Part 6 of the Electricity Industry Participation Code 2010.

Aurora's CPD pricing methodology is one of the main mechanisms that enables Aurora to better utilise its distribution assets. This financially rewards the operation of standby generation plant during network congestion periods. Over the past few years, a number of consumers completed alterations to their diesel generation plant to allow it to operate during congestion periods.

Ripple Control

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. Ripple control is considered to be a cost effective DSM tool. Ripple controls involves sending signals through the network to control hot water cylinders. Aurora's use of ripple control has contributed to a 38MW difference between estimated peak demand and actual peak demand, 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. Further information on this DSM 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.

Smart Metering

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.

6.2.9.2 Do Nothing

The option to 'do nothing' must always be considered as part of option analysis and selection process. This may mean that it may be accepted 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.

6.3 Growth and Demand Forecasting

The following sections describe how growth and demand forecasting is carried out for Aurora's network, discusses how contributing factors are considered in the estimation process and how these are subsequently applied to network planning and decision-making.

Demand Forecasting Methodology

Historic trends provide a baseline from which growth in energy consumption can be estimated. Aurora derives load forecasts from historic trends in growth and subsequently adjusts these to reflect the impact of other significant factors such as distributed generation (see section 6.3.1), demand management and pricing methodologies, known load increases, engineering judgement and other variables such as weather patterns, changes in land-use and development requirements that may be driven by territorial authority district plan changes. Demand forecasting is undertaken by Aurora on an annual basis

Half hourly loading data is collected from GXPs and zone substations. This data is uploaded into an excel spread-sheet and an assessment of future loads is carried out using both growth (exponential) and linear prediction functions.

An initial point mid-way between the growth and linear predictions is taken from this and represents the growth value to be applied for planning purposes.

The half-hourly data is also applied to HV feeder analysis. At the HV feeder level, the ability to off-load each feeder is checked. Feeders that are identified as being 'at risk' are subject to further assessment to obtain further detail on predictions. At risk feeders are those deemed to be near their maximum rating or cannot be fully off-loaded.

Other variables taken into consideration as part of the demand forecasting process include information on sites for potential future development, seasonal variation and other temporal factors such as the day of the week or the timing of school/public holidays throughout the year. Other database and GIS information is also used for identifying the location and expected electrical demand of proposed developments such as subdivisions, which assists with refining HV feeder load predictions.

Growth and demand predictions are provided in Section 6.5

Improvements to Forecasting Methodology

Aurora has commenced a review and revision of its demand forecasting methodology with the intention to improve accuracy, transparency, consistency and repeatability in approach. It is proposed to incorporate a wider set of source data and other analytical information available from other organisations, such as NIWA, NZIER, MBIE, Statistics NZ and local authorities for example.

6.3.1 Distributed Generation

Although the main purpose of Aurora's distribution network is to deliver energy from the GXP's to consumers, there are circumstances where it can be more economic for the consumer to provide a source of energy – this is referred to as distributed generation. This AMP uses the term 'distributed generation' in place of embedded generation; it is considered to mean the same thing.

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. On the downside, however, distributed generation can also produce adverse effects on the network, including harmonic distortion, localised congestion, voltage instability, safety issues and network reliability issues. Accordingly, care is required when approving new distributed generation connections.

Aurora has guidelines and application information for the connection of distributed generation published on its website at www.auroraenergy.co.nz. Aurora examines each proposal with regard to the likely effect that the distributed generation will have on Aurora's network.

Aurora currently has 138.5 MW of distributed generation connected to its network. Hydro generation remains the predominant energy source for distributed generation on the Aurora's network at 57.7% of total generation capacity. Small-scale photovoltaic generation, at the other extreme, although comprising 79% of generation connections, comprises only 0.4% of total generation capacity.

Over the past year there has been a significant increase in applications for distributed generation connections, being approximately 63% more than the previous year. This increase has mainly occurred

in the Central Otago area, affecting the Clyde, Cromwell and Frankton GXP areas. Most applications have been for relatively small domestic connections (<10kW) and in most cases have minimal network impact, although over time the cumulative impacts of these should be further considered, particularly if evidence of clustered generation emerges.

The Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 requires Aurora to provide a 5-year forecast of distributed generation connections and capacity. Aurora's forecasts are summarised below. There is significant uncertainty in the forecasts, due to the relatively embryonic nature of small-scale distributed generation in New Zealand.

The degree to which the recent rate of applications to connect distributed generation will be sustained is uncertain. While the cost of photovoltaic cells is understood to be falling, aided by relatively low cost manufacture out of China, the cost of a distributed generation installation will remain out of reach for many consumers, particularly where retro-fitting to an existing dwelling is required. There remains some uncertainty regarding the planned connection of Contact Energy's Lake Hawea generation project, originally scheduled for 2017/18. The forecasts of connection numbers and capacity will neglect the Lake Hawea project until more certain.

	2014	2015	2016	2017	2018	2019
Total DG Connections	260	350	445	545	650	760
DG Capacity (kW)	139,000	139,300	139,600	139,900	140,200	140,500

Commercial arrangements for distributed generation vary. For small distributed generation (generally below 10kW), the default arrangements specified within Part 6 of the Electricity Industry Participation Code normally suffice. The commercial arrangements for larger generation warrant greater attention due to the greater use of system assets.

Aurora has developed a standard distributed generation Use-of-System agreement as a basis for commercial negotiations. The standard agreement has been developed with reference to the Code and appropriate conditions in retail Use-of-System agreements. Aurora considers that this approach maintains a degree of industry consistency and standardisation.

6.3.2 Other Issues

Designations, Consenting and Easements

The provisions of district and regional plans place controls on the establishment of new network infrastructure, such as the construction of lines and zone substations. These rules vary across the district council territories within Aurora's network area. Where a rule cannot be met, an application for resource consent, or a notice of requirement to designate the line route or substation, must be lodged with the council. Ideally, the resource consent or designation process needs to commence well in advance of the development project being needed so that issues are settled before construction starts as the lead-in time for gaining formal approval introduces an element of uncertainty/risk for such projects as it can also be very time consuming and costly.

6.4 Project Prioritisation

In general, the prioritisation of capital projects is linked to Aurora's key activity objectives (Section 2) and associated service level attributes for Safety, Reliability, Quality, Responsiveness, Compliance, Efficiency and Financial sustainability; underpinned by Continuous Improvement. Table 6.7 below provides an indication of project category and subsequent priority:

Table 6.7 – Project Priority List

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.

Risk-based decision making framework

The review of Aurora's planning and forecasting assumptions and uncertainties will continue in 2014/15, with consideration given to the current decision-making criteria and prioritisation methodology. Aurora is working towards providing more transparency on reasons why particular solutions or options have been chosen, and their priority. Focus will continue on the refinement and application of risk-based decision-making criteria.

6.5 Growth and Demand Predictions

Network energy through put for the year ending March 2013 was 1,330 GWh (including distributed generation), which was a decrease of 62MWh (4.5%) on the previous year. Overall demand growth on Aurora Energy's network has been mixed over the past 4 years. In the past year the number of domestic connections increased, particularly in the Central Otago network, but some categories of non-domestic connections declined in number.

Central

Modest population growth is expected in the central area supplied by the Aurora network (Clyde, Frankton and Cromwell) over the next few years. The 5-year maximum system demand growth forecast for the Central network is 2.6% p.a (based on the 2012 Information Disclosure)

Aurora expects growth in electrical demand to continue, which is the main driver for capital expenditure in this area. This growth is anticipated to be driven mainly through large-scale irrigation, with subdivision development having slowed in the recent past. Ski-field operations have a significant impact on demand, and peak loads are usually seen during the winter months. If this is coupled with very cold weather it 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.

Dunedin

Population growth is expected to remain relatively static in Dunedin over the next 10-20 years. For example, under the Statistics New Zealand medium growth scenario, Dunedin is projected to have an annual growth rate of 0.25% over the next 10 years (compared to a growth rate of 0.85% nation-wide). Growth in electrical demand is therefore expected to average between 0% and 1%, but there may be localised areas where growth will exceed this. Capital expenditure in the Dunedin area will therefore mainly be driven by the replacement of ageing assets, the conversion of overhead distribution to underground, and reliability improvements. Although, extreme cold weather events (such as a three-day snowfall that occurs during the week, and outside of the school holiday period) can add an additional 10% to the Dunedin peak demand.

6.5.1 Grid Exit Points

The historic and projected peak demands (in MW) for the network areas associated with each Grid Exit Point (GXP) are shown in Table 6.8; the demands are equal to the demand on the GXP plus embedded (distributed) generation. The Energy use normalised in 2002 GWh for each GXP is shown in Figure 6.1 and the load factor by GXP is shown in Figure 6.2.

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.

The demands at all GXPs during the 2013 winter were lower than predicted in the 2013 AMP. This is different compared to that observed during the 2012 winter, where all were higher than predicted (except for Halfway Bush), attributable to the colder winter in 2012 and relatively mild winter in 2013.

Table 6.8 - GXP area peak demands

Calendar Year			Clyde	Cromwell	Frankton	Halfway Bush	South Dunedin	
2005	Actual	GXP Off take + Embedded Generation (MW)	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	49.5	121.3	71.7	
2011			16.6	29.9	48.7	128.7	72.2	
2012			17.4	31.8	51.9	128.5	70.5	
2013			16.7	31.0	51.0	128.0	69.0	
2014	Predicted		16.9	32.3	52.1	127.9	71.1	
2015			17.0	33.2	53.1	128.5	71.8	
2016			17.1	34.2	54.1	115.2	86.5	
2017			17.2	35.1	55.2	115.8	87.3	
2018			17.2	36.1	56.2	116.4	88.1	
2019			17.3	37.1	57.3	117.0	88.9	
2020			17.4	38.1	58.3	117.6	89.8	
2021			17.5	39.2	59.4	118.2	90.6	
2022			17.6	40.2	60.5	118.8	91.4	
2023			17.7	41.3	61.6	119.4	92.2	
2024			17.7	42.4	62.7	120.0	93.0	
Past Grow th Rate (Trend 2007 to 2013)			0.04%	2.84%	1.50%	0.10%	0.23%	
2013 off take peak (MW excluding embedded generation)			7.1	27.6	50.2	110.5	69.0	
Off take n-1 Capacity (Continuous) MVA			27	40.9	66	100	81	
Off take n-1 Capacity (24 hr Winter Post Contingency MVA)			27	40.9	80	112	81	
Embedded Generation (2013 MW at time of load peak)			19.23	3.569	2.041	18.104	0	
Embedded Generation (2013 MW at time of off take peak)			3.013	2.604	0.792	8.402	0	

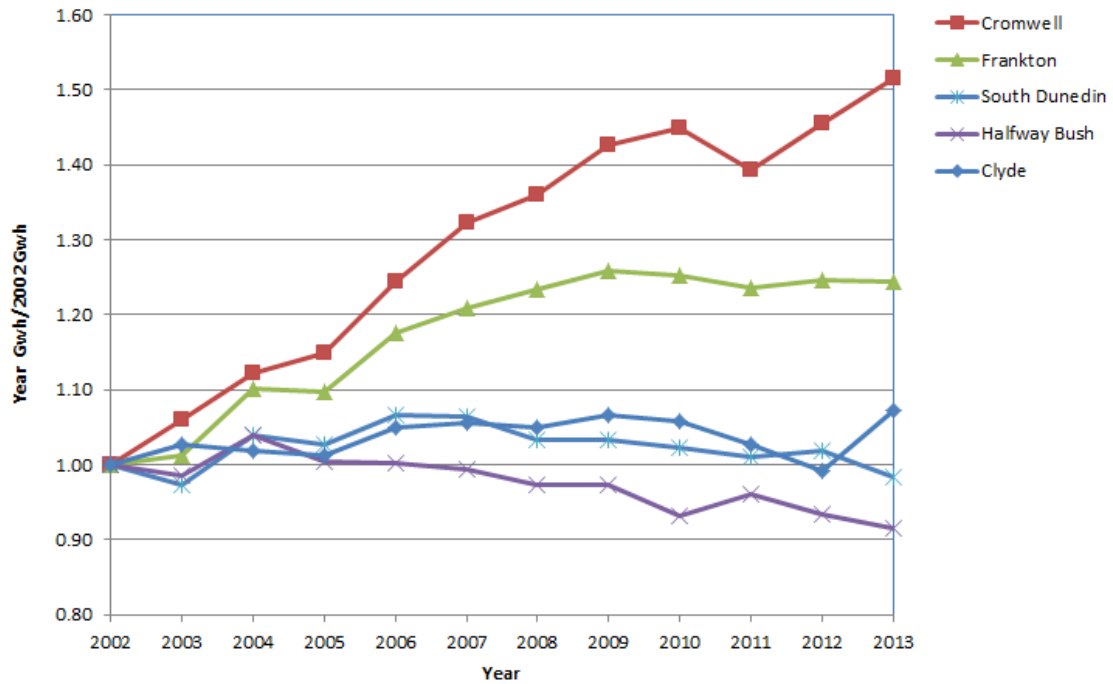


Figure 6.1 – Comparative growth in GXP energy (GWh 2002 normalised)

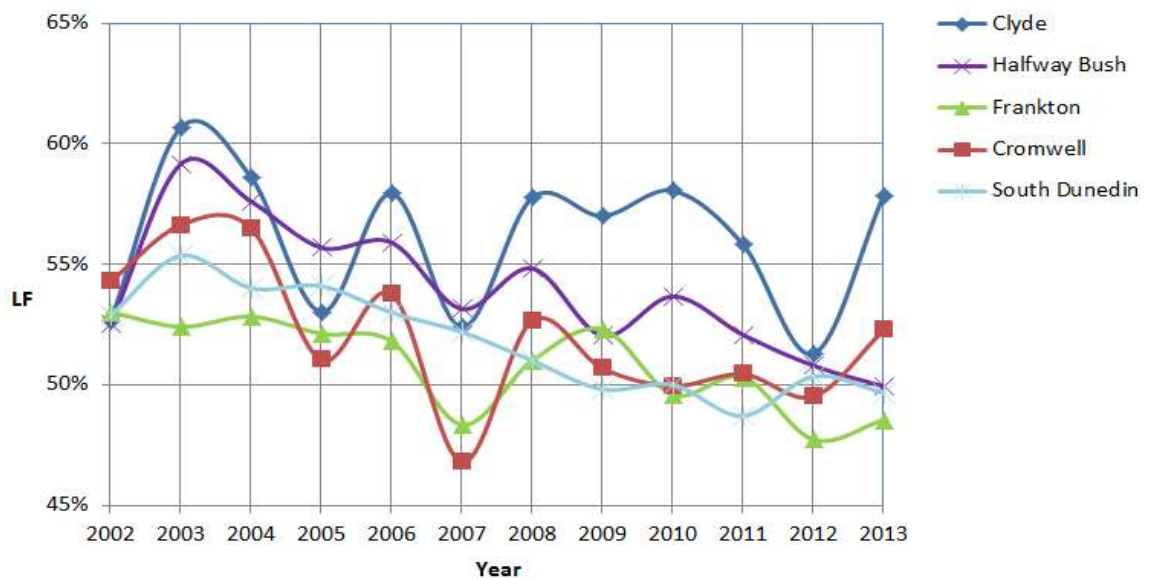


Figure 6.2 – Load factor by GXP

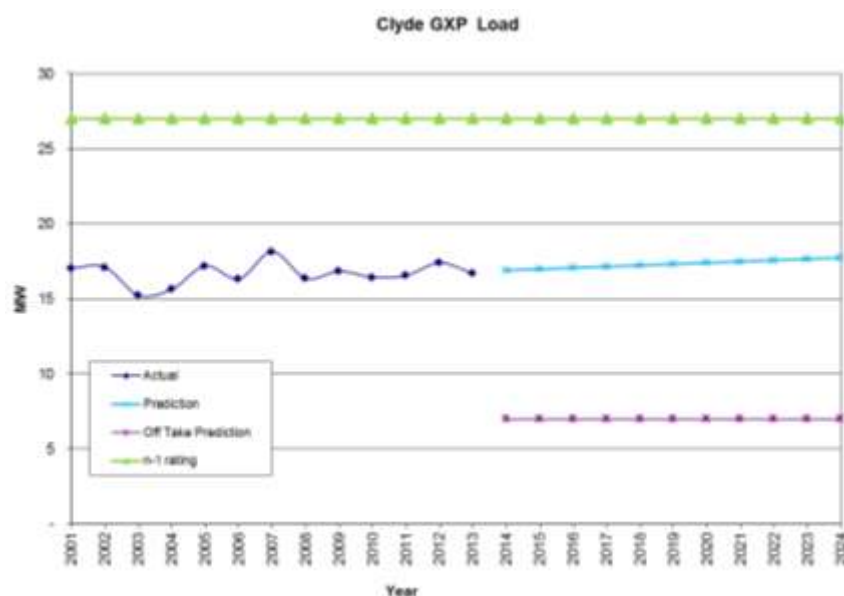
Table 6.9 : Comparison of 2013 actual and predicted loads

GXP	2013MVA Predicted	2013 MVA Actual	Difference
Clyde	17.0	16.7	-1.76%
Cromwell	33.3	31.0	-6.91%
Frankton	52.2	51.0	-2.30%
Halfway Bush	128.1	128.0	-0.11%
Sth Dunedin	72.4	69.0	-4.70%

Historic trends in load for each GXP are illustrated in the following sections and graphs 6.3-6.7 provide a revised load prediction based on the factors discussed in Section 6.4. The comments that follow highlight the main areas being monitored and/or addressed by Aurora.

Clyde

Clyde GXP load prediction is illustrated in Figure 6.3. Peak demand has ranged from 16.4MW – 17.4MW over the last 5 years. Growth has averaged less than 0.5% per year since 2004 and is not expected to accelerate during the planning period unless the Dairy Creek irrigation project proceeds. The distributed generation on this GXP almost meets total demand on the GXP. Should the embedded generation fail the maximum demand on the GXP would be approximately 17 MVA. However as this GXP has two 27MVA transformers it is considered that there is adequate GXP capacity at Clyde for the foreseeable future. The possibility of additional generation will continue to keep the off-take low. Clyde Ripple Injection replacement is planned (see Section 6 – Network Development)

**Figure 6.3 - Clyde GXP Actual and Prediction Loads**

Cromwell

Cromwell GXP load prediction is illustrated in Figure 6.4. Peak demand has ranged from 29.9MW – 31.8MW over the last 5 years. Although currently under the limit for n-1 of 40.9MW, loads are predicted to continue to increase, exceeding the n-1 rating around 2022, being influenced predominantly by winter demand (ski fields, winter tourism, and domestic winter loads). However growth from dairy irrigation is becoming increasingly important. Development reports have scoped issues and options (see DR 33, 45 and 160) and Section 6.5 of this AMP also covers the options considered to address this issue. The distributed generation on this GXP is 5.57MW and ripple injection was upgraded in 2009 providing the ability to cope with a connected load in excess of the current 50 MVA firm capacity (as well as the

future Hawea generation.) The impact of the Hawea Generation has not been included in the load prediction due to the uncertain nature of this project.

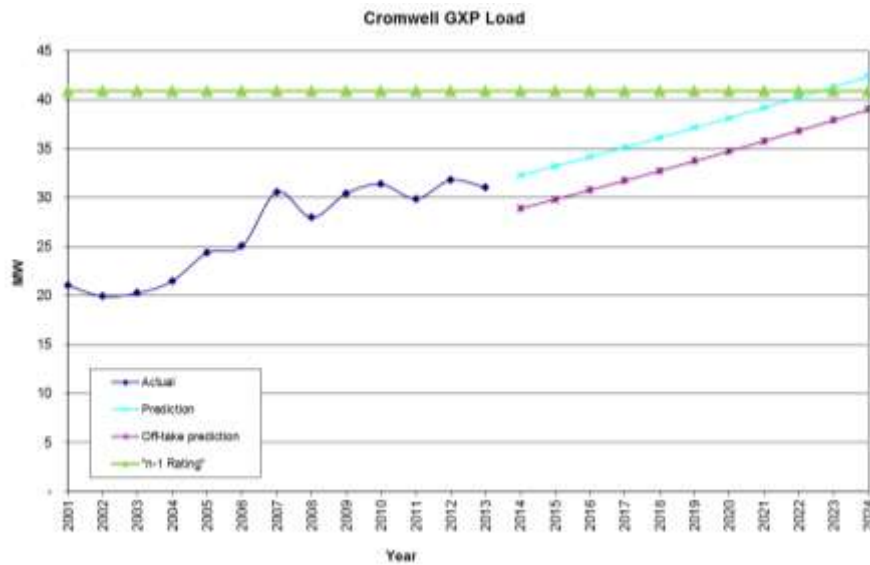


Figure 6.4 - Cromwell GXP Actual and Prediction Loads

Frankton

Frankton GXP load prediction is illustrated in Figure 6.5. Peak demand has ranged from 47.7 MW – 51.9MW over the last 5 years. Past trends indicate a growth rate around 1.5% p.a. The distributed generation on this GXP is 3.96MW. Electricity Southland Ltd (ESL) takes supply from this GXP as well as Aurora. The load predictions include an estimated allowance for the ESL load. It is predicted the 66 MVA continuous n-1 rating at this site will not be exceeded during the planning period as shown in Figure 6.5. In addition, the ripple injection plant at this site was upgraded in 2010 and the new injectors will cope with up to 100 MW of connected load.

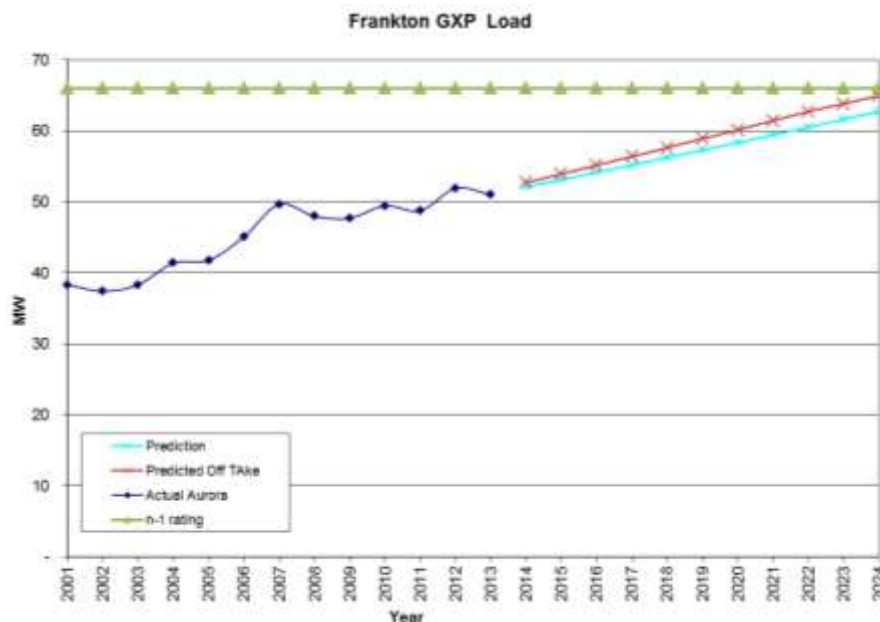


Figure 6.5 - Frankton GXP Actual and Prediction Loads

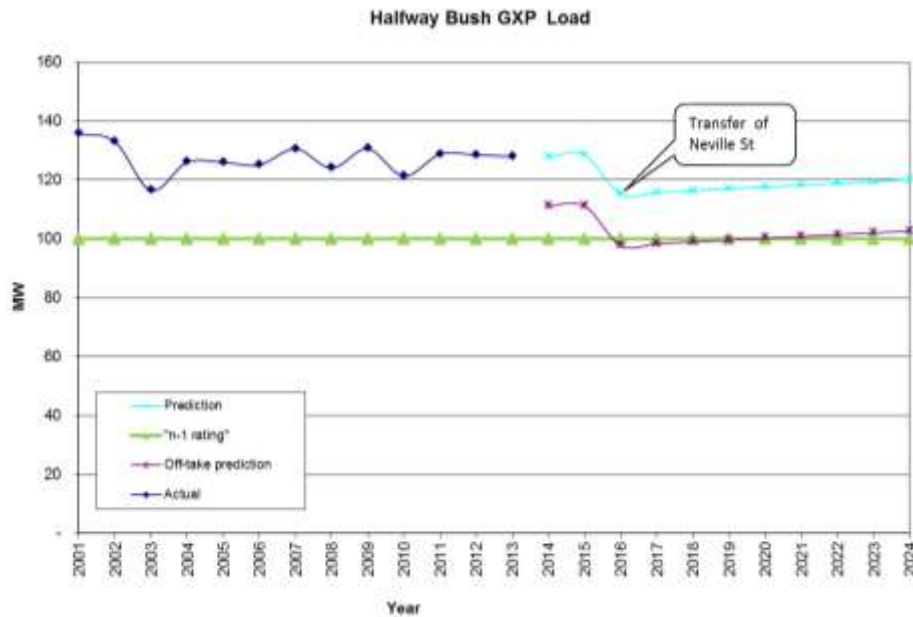


Figure 6.6 – Halfway Bush GXP Actual and Prediction Loads

Halfway Bush

Halfway Bush GXP load prediction is illustrated in Figure 6.6. Peak demand has ranged from 121.3MW – 130.6MW over the last 5 years. The off-take peak at Halfway Bush exceeds the 112 MVA post contingency rating. Past trends indicate a growth rate around 0.1% p.a. The distributed generation on this GXP is 95.8MW. The connection of the 36 MW TrustPower Mahinerangi wind farm occurred during 2011.

Table 6.10 in the following section (6.5.4) indicates the critical nature of this GXP, with a significant majority of priority 1 and 2 customers being supplied by zone substations in this area. Aurora recognises this and has developed a contingency plan - 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 period. Also up to 5 MW can be transferred to the South Dunedin GXP via the 6.6 kV network. However, this would still leave a shortfall and the contingency plan also addresses this (see development report DR24), which includes the transfer of the Neville Street substation load to South Dunedin (see below and section 6.5 for related development planning options).

South Dunedin

South Dunedin GXP load prediction is illustrated in Figure 6.7. Peak demand has ranged from 69.04MW- 72.22MW over the last 5 years, well under the 81 MVA limit. Past trends indicate a growth rate around 0.23% p.a. and over the forward 10yr planning period is expected remain relatively static, with the main impact on demand being through the transfer of Neville Street Substation from Halfway Bush to South Dunedin in 2015. While under the current network configuration there is adequate GXP capacity, with two 100 MVA transformers, it must be noted here that these have been assigned an 81 MVA limit by Transpower, due to metering accuracy limitations. This metering constraint is intended to be removed in 2014.

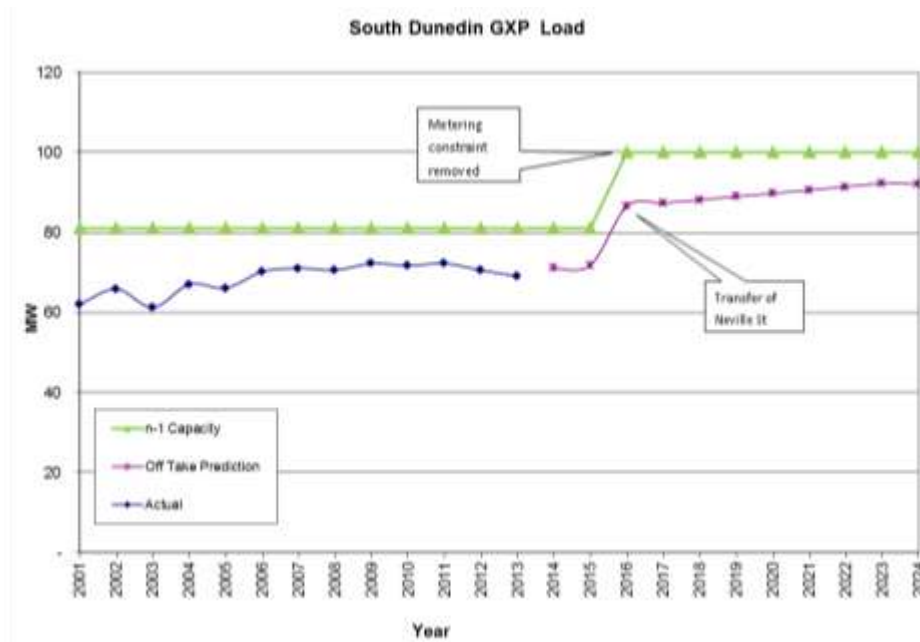


Figure 6.7 – South Dunedin GXP Actual and Prediction Loads

6.5.2 Maximum Coincident System Demand

The term Maximum Coincident System Demand means the summation of the off-take at each of the 5 GXPs serving the Aurora network, plus the contributed output of all distributed generation connected at high voltage, at a single point in time (i.e., 1 of 17,520 half-hours). GXP off-take is largely dependent on weather, and this may influence GXPs differently; for example, Central Otago versus Dunedin. Similarly, generation output depends largely on water availability (57.7%) and wind conditions (27.6%). Historical analysis suggests that coincident values have very little inherent predictability. The table below summarises the forecast. It should be noted that there is very little certainty in conducting such a forecast, and that the measure is largely meaningless, since it is the non-coincident maximum demand at each GXP that generally drives network cost.

	2014	2015	2016	2017	2018
Maximum Coincident System Demand (MW)	284	287	290	293	296

6.5.3 Subtransmission

Aurora's subtransmission network comprises various configurations (see Section 5.2). Graphs 6.8 - 6.12 illustrate historic trends in load for the subtransmission network and provide a revised load prediction based on the factors discussed in Sections 6.3 and 6.5. The comments highlight the main areas being monitored and/or addressed by Aurora where it is considered that capacity is a concern. For the Central network, these are listed below:

- Alexandra-to-Roxburgh subtransmission
- Clyde-to-Alexandra subtransmission
- Wanaka 33KV subtransmission
- Upper Clutha subtransmission
- Frankton-to-Queenstown
- Wakatipu Basin 33KV Ring

Where constraints are expected, the associated upgrades are discussed in the network development plan (Section 6.6).

The content of this section is structured by GXP area and begins with the subtransmission network in Clyde, Cromwell, Frankton followed by the Halfway Bush and South Dunedin networks.

Clyde

Alexandra to Roxburgh Subtransmission

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.

It is now difficult 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.

Clyde to Alexandra Subtransmission

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.

Cromwell

Wanaka 33 kV subtransmission

The Wanaka 33 kV subtransmission supplies Cadrona and Maungawera substations. The maximum n-1 rating of the 33 kV supply is 6 MVA if the 11kV is fully loaded.

At present, the Cardrona and Maungawera substations are supplied from the Wanaka 33 kV bus. The 2012 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 assuming the Riverbank Road substation is constructed.

Upper Clutha subtransmission

Figure 6.8 illustrates a single line diagram of the existing subtransmission system and Figure 6.9 illustrates the load predictions for the Upper Clutha, which is supplied from the Transpower Cromwell GXP at 66 kV and feeds Queensberry. The Queensberry transformer is connected to one of the two 66 kV lines, but can be connected to either.

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.

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 presented in Section 6.6.

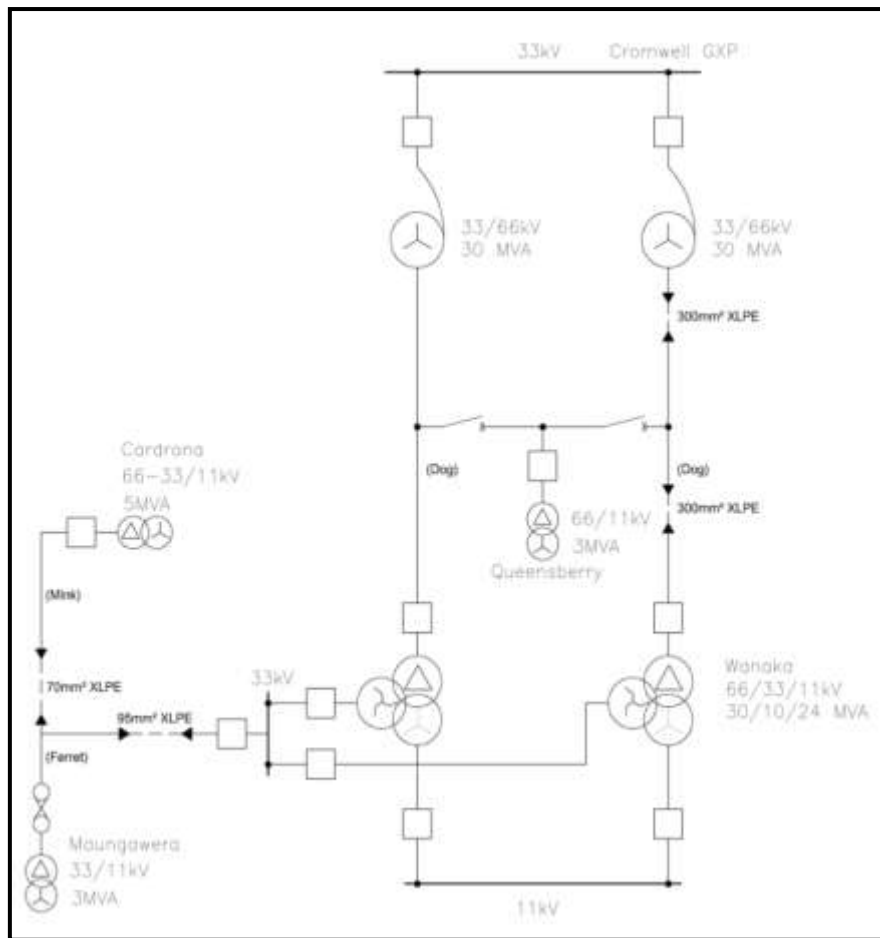


Figure 6.8 - Single line diagram of existing Upper Clutha subtransmission

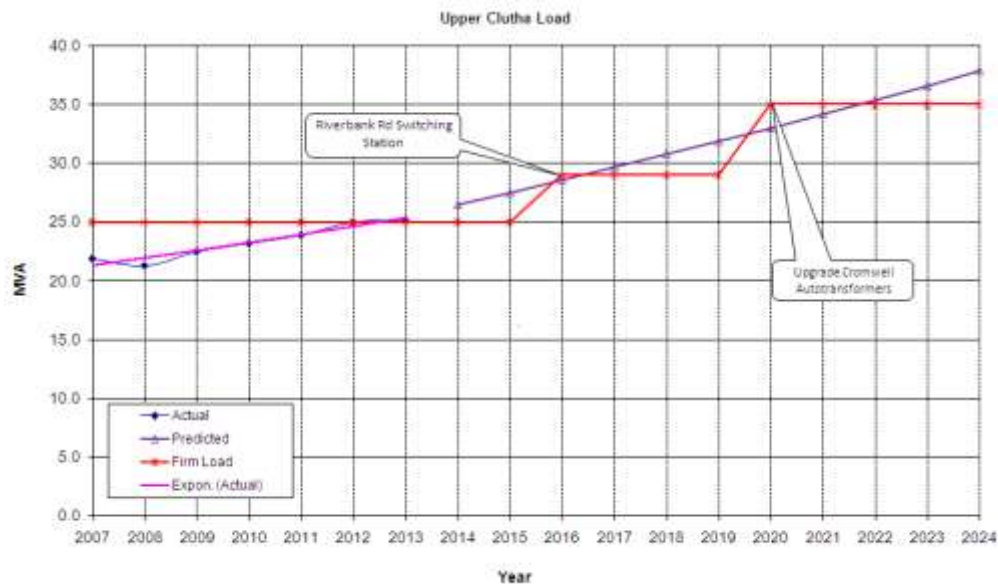


Figure 6.9 - Upper Clutha subtransmission

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. However, 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.

Cardrona Valley Subtransmission

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.

Frankton

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 6.10. When the subtransmission n-1 capacity is reached, it is currently considered that the most economic option to increase the delivery capacity to Queenstown, is to install a third transformer at the Queenstown substation (15 MVA) and provide additional 33 kV transmission capacity to the Commonage substation.

Wakatipu Basin 33 kV Ring

Figure 6.11 illustrates the load predictions for the Wakatipu Basin 33 kV ring, which supplies the Dalefield, Arrowtown, Coronet Peak and Remarkables substations and is run open at Arrowtown. 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 ring has a capacity of 22 MVA with all circuits in service. The ring load exceeded its n-1 capacity during the winters of 2012 and 2013, and Figure 6.11 indicates that it did. The timing of snow making at Coronet peak has a significant effect on the diversity which varies from year to year. See Section 6 for options to address this issue.

The Arrowtown peak load is currently predicted to exceed the rating limit of 9.7 MVA in 2021. The present n-1 capacity of the ring is 13 MVA with the constraint being the winter rating of Ferret conductor.

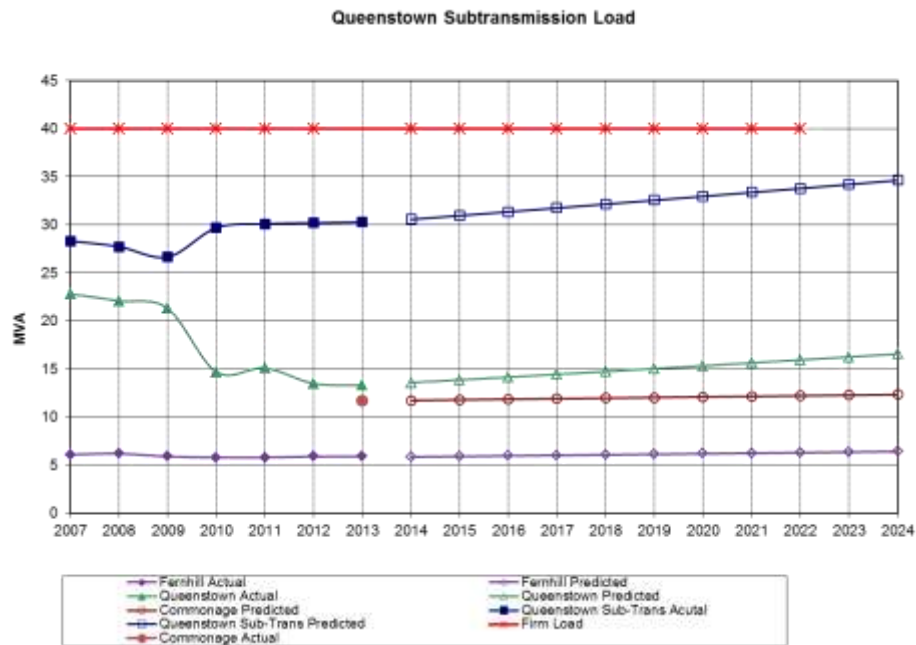


Figure 6.10 - Frankton to Queenstown subtransmission

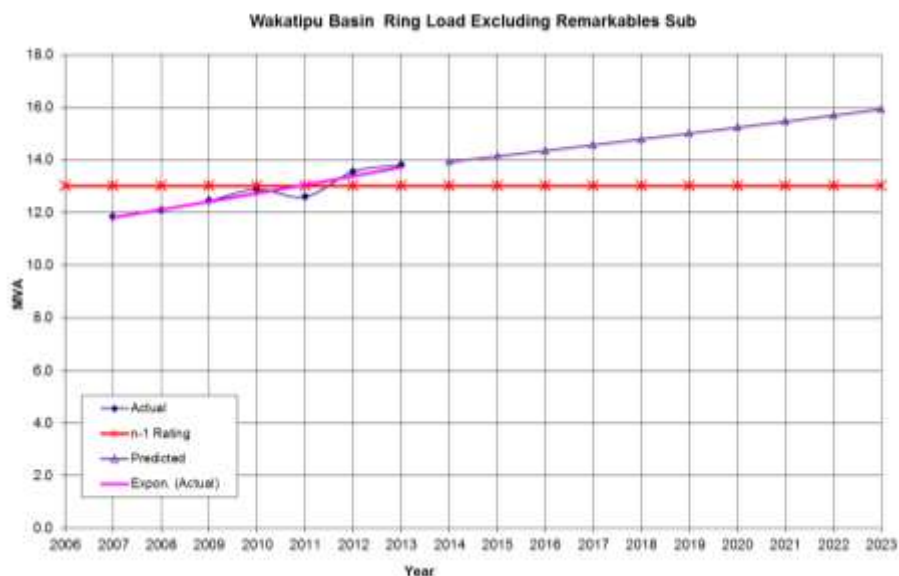


Figure 6.11 - Wakatipu Basin Subtransmission 33 kV Ring

Glenorchy Subtransmission

Glenorchy is presently supplied from Queenstown 11 kV Feeder 5202. This is the only line supplying the Glenorchy area; there is presently no back-feed to this area if there is an outage event on this part of the network. 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.

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.

A review of the load prediction was carried out in 2011, which indicated that it will not be possible to maintain the feeder voltage above design values after the winter of 2014. Options to upgrade are discussed in Section 6.

Halfway Bush

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 Fisher & Paykel 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.

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.

Port Chalmers Subtransmission

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.

6.5.4 Zone Substation Demand Projections

Aurora's network contains 36 zone substations, 18 in Dunedin and 18 in Central Otago. Table 6.10 provides actual figures on historical and predicted demands for all zone substations.

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

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.

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.

				Historical Loads MVA							Exp Growth Calc			Linear Trend Calc			Predictions			Predicted Demands Between Exp and Linear MVA												
Zone Substation	Transformer MVA	Firm Load MVA	n-1	2007	2008	2009	2010	2011	2012	2013	2013	2014	Previous Growth (Exp) %/yr	2013	2014	Previous Growth (Lin) MVA/yr	Exponential Growth %/yr	Linear Growth MVA/yr	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024			
Alexandra	7.5/15+7.5/15	15	15	12.4	11.4	11.9	11.6	10.9	11.7	10.6	10.9	10.7	-1.81%	10.9	10.7	-0.21	0.4%	0.04	10.9	11.0	11.0	11.0	11.1	11.1	11.2	11.2	11.2	11.3	11.3			
Anderson's Bay	15 + 15	18	18	16.6	15.7	15.7	15.3	16.0	15.4	16.2	15.7	15.6	-0.35%	15.7	15.6	-0.06	0.2%	0.16	15.8	15.9	16.0	16.1	16.1	16.2	16.3	16.4	16.5	16.6	16.7			
Arrowtown	5 + 5	7.5	6	7.7	7.3	7.6	7.9	7.6	8.3	8.3	8.2	8.4	1.78%	8.2	8.4	0.14	2.0%	0.15	8.4	8.6	8.7	8.9	9.0	9.2	9.4	9.5	9.7	9.9	10.1			
Berwick	3	3.6	0	1.2	1.3	1.2	1.3	1.3	1.3	1.3	1.3	1.3	0.98%	1.3	1.3	0.01	2.0%	0.03	1.3	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.6	1.6			
Clyde/Earnscleugh	4 +2	4.8	4	4.0	4.1	4.1	4.1	3.8	3.8	4.3	4.0	4.0	-0.06%	4.0	4.0	0.00	1.0%	0.04	4.1	4.1	4.1	4.2	4.2	4.3	4.3	4.4	4.4	4.4	4.5			
Coronet Peak	5	6	0	3.6	4.5	4.6	4.6	4.6	4.6	4.9	4.9	5.1	3.40%	4.9	5.0	0.14	0.3%	0.00	4.9	4.9	4.9	4.9	4.9	5.0	5.0	5.0	5.0	5.0	5.0			
Corstorphine	12/24 + 12/24	23	23	13.8	12.5	14.3	13.2	13.8	13.1	13.0	13.2	13.2	-0.40%	13.2	13.2	-0.06	0.0%	0.00	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2			
Cromwell	5/10 + 7.5	9.0	9.0	9.2	9.2	9.8	10.0	9.4	9.7	10.3	10.1	10.2	1.46%	10.1	10.2	0.14	4.0%	0.04	10.3	10.5	10.8	11.0	11.3	11.5	11.8	12.1	12.4	12.7	13.0			
Dalefield	3	3.6	0	2.3	2.1	2.1	2.3	2.3	2.7	2.7	2.6	2.7	3.70%	2.6	2.7	0.09	3.0%	0.07	2.7	2.8	2.8	2.9	3.0	3.1	3.2	3.2	3.3	3.4	3.5			
Earnscleugh	2	Used to increase Clyde/Earnscleugh firm capacity to 4.8MVA																		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
East Taieri	12/24 + 12/24	24	18.5	15.7	15.5	16.7	15.8	16.2	16.5	16.7	16.6	16.8	1.00%	16.6	16.8	0.16	1.0%	0.16	16.8	17.0	17.1	17.3	17.5	17.6	17.8	18.0	18.1	18.3	18.5			
Ettrick	3	3.6	0	2.0	1.8	2.1	2.0	1.7	2.0	2.5	2.1	2.2	2.42%	2.2	2.2	0.05	0.5%	0.01	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3			
Frankton	12/24 + 7.5/15	17	15	12.0	13.2	13.9	12.1	10.5	13.3	13.3	12.6	12.7	0.19%	12.7	12.7	0.03	3.0%	0.35	13.7	14.1	14.5	14.9	15.3	15.7	16.1	16.5	14.9	15.3	15.8			
Fernhill	7.5/10+7.5/10	10	10	6.1	6.2	5.9	5.8	5.8	5.9	5.9	5.8	5.8	-0.75%	5.8	5.8	-0.05	1.0%	0.05	5.9	5.9	6.0	6.0	6.1	6.1	6.2	6.2	6.3	6.4	6.4			
Green Island	15 + 15	18	18	14.2	13.8	13.7	13.4	14.0	13.7	13.7	13.6	13.6	-0.34%	13.6	13.6	-0.05	0.0%	0.00	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6			
Halfway Bush	15 + 15	18	18	14.2	13.8	14.5	14.6	14.8	14.6	14.5	14.7	14.8	0.66%	14.7	14.8	0.09	1.5%	0.23	14.9	15.2	15.4	15.6	15.8	16.1	16.3	16.5	16.8	17.0	17.3			
Kaikorai Val.	12/24 + 12/24	23	22	10.4	9.9	10.2	9.2	9.3	10.7	10.7	10.2	10.2	0.51%	10.2	10.3	0.06	1.0%	0.00	10.3	10.3	10.4	10.4	10.5	10.5	10.6	10.6	10.7	10.7	10.8			
Maungawera/Hawea	3	3.6	0	3.2	2.1	2.2	2.3	2.3	2.6	2.5	2.6	2.7	4.29%	2.6	2.7	0.10	1.8%	0.05	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.0	3.1	3.1			
Mosgiel	10 + 10	14	12	12.0	12.0	9.3	7.6	7.8	8.0	8.3	8.3	8.5	3.25%	8.3	8.5	0.26	2.0%	0.16	8.4	8.6	8.7	8.9	9.1	9.2	9.4	9.6	9.8	9.9	10.1			
Neville St	15 + 15	18	18	14.9	13.3	14.8	13.4	13.6	13.6	12.9	13.1	12.9	-1.69%	13.1	12.8	-0.24	0.0%	0.00	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1			
North City	14/28 +14/28	28	28	20.7	20.7	19.7	19.0	20.0	18.9	19.6	19.1	18.9	-1.16%	19.1	18.9	-0.23	0.0%	0.00	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.1			
North East Val.	9/18 +12/18	23	18	11.0	10.9	11.8	11.2	11.8	11.0	11.3	11.4	11.4	0.33%	11.4	11.4	0.04	1.0%	0.12		11.6	11.7	11.9	12.0	12.1	12.2	12.3	12.4	12.6	12.7			
Omakau	3	3.6	0	1.8	1.8	2.0	2.1	2.0	1.9	2.4	2.2	2.3	3.34%	2.2	2.3	0.07	2.5%	0.09	2.3	2.3	2.4	2.5	2.6	2.6	2.7	2.8	2.9	2.9	3.0			
Outram	3 + 3	5.6	3.6	2.8	2.7	2.8	2.9	3.0	2.9	3.0	3.0	3.1	1.58%	3.0	3.1	0.05	1.0%	0.03	3.0	3.1	3.1	3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.3			
Port Chalmers	7.5 +7.5	10	9	8.3	7.5	7.9	7.5	7.5	7.5	7.1	7.2	7.1	-1.80%	7.2	7.1	-0.14	0.0%	0.00	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2			
Queensberry	3	3.3	0	1.7	1.8	1.4	2.4	2.3	2.5	2.8	2.7	3.0	9.72%	2.7	2.9	0.19	4.0%	0.10	2.9	3.0	3.1	3.2	3.3	3.4	3.5	3.7	3.8	3.9	4.0			
Queenstown	10/20 +10/20	26	20	22.8	22.1	21.3	14.7	15.1	13.5	13.3	13.1	12.3	-6.15%	13.3	13.1	-0.20	2.0%	0.30	13.6	13.9	14.2	14.4	14.7	15.0	15.3	15.6	15.9	16.3	16.6			
Remarkables	3	3.6	0	0.8	0.8	0.8	0.8	1.0	1.2	1.2	1.2	1.2	7.98%	1.2	1.2	0.07	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	2.5	2.2	2.8	2.8	2.3	2.3	1.1	1.7	1.5	-8.60%	1.8	1.7	-0.16	1.0%	0.02	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9	2.0	2.0			
Smith St	15 + 15	18	18	16.9	16.1	16.8	15.8	16.9	16.7	16.1	16.4	16.3	-0.21%	16.4	16.3	-0.03	0.8%	0.17	16.5	16.7	16.8	17.0	17.1	17.3	17.4	17.6	17.7	17.9	18.0			
South City	9/18 +9/18	18	18	15.7	15.3	15.8	15.0	15.2	15.0	14.8	14.9	14.7	-0.89%	14.8	14.7	-0.14	0.5%	0.07	14.9	15.0	15.1	15.1	15.2	15.3	15.4	15.4	15.5	15.6	15.7			
St Kilda	12/24 + 12/24	23	23	16.3	15.6	15.7	15.3	15.5	15.3	15.6	15.3	15.2	-0.68%	15.3	15.2	-0.11	0.0%	-0.11	15.2	15.2	15.1	15.1	15.0	15.0	14.9	14.9	14.8	14.8	14.7			
Wanaka	12/24 +12/24	24	24	18.6	18.7	19.6	20.3	17.6	19.2	18.8	18.9	18.9	-0.10%	18.9	18.9	-0.02	4.0%	0.70	19.6	20.4	21.1	21.9	22.7	23.5	24.3	25.2	18.1	18.8	19.5			
Ward St	12/24 +12/24	24	24	11.3	11.4	12.5	11.9	14.3	14.2	12.7	13.8	14.3	3.31%	13.8	14.2	0.41	1.0%	0.14	14.0	14.1	14.3	14.4	14.5	14.7	14.8	15.0	15.1	15.3	15.4			
Willowbank	15 + 15	18	18	12.7	12.5	13.7	12.2	13.2	12.1	12.5	12.5	12.4	-0.53%	12.5	12.4	-0.07	0.0%	0.00	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5			
Commonage	14/17 +14/17	23	17	0	0	0	9.8	9.8	11.4	11.7	11.9	13.0	9.17%	13.3	15.8	2.42	0.5%	0.06	11.7	11.8	11.9	11.9	12.0	12.0	12.1	12.2	12.2	12.3	12.3			
Cardrona	5	5	0	0	0	0	0	1.9	3.1	2.8	3.1	3.1		2.9	3.5	0.59	2.0%	0.05	2.0	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.8	2.8	2.9			
Jacks Point *		10	0																						0.0	0.0	2.0	2.0	2.0			
Riverbank Rd		24	24														4.0%	0.32								0.0	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	22.2	22.2	0.00%	22.0	20.9	-1.12	0.0%	0.0	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.2			

* Jacks Point actual load is included in Frankton

Table 6.10 – Zone substation historical and predicted demands

The following section provides graphs and comments on demand projections for the zone substations considered a priority. Note that the section is structured by GXP area and begins with the zone substations in Clyde, Cromwell, Frankton followed by the zone substations in Halfway Bush and South Dunedin. Projects to address related issues are discussed in Section 6.6.

Clyde

Alexandra Substation

It was previously proposed that a second substation would be established to help eliminate future HV feeder off-loading constraints and provide a more secure supply to the Alexandra area. The Alexandra zone substation is now predicted remain within its firm load rating beyond the planning period.

No other significant demand-related issues are predicted for substations located in this GXP area within the 10 year planning period. However it is possible that irrigation load may unexpectedly grow, particularly in the Omakau area and a close watch on this load is required.

Cromwell

Cromwell Zone Substation

Figure 6.12 illustrates the load predictions for Cromwell zone 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 AMP 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 have reduced, with the 12 MVA limit now predicted for the winter of 2018. In the 2012 AMP, it was recommended that a May 2015 commissioning date be retained, however this has been revised and is now proposed to be deferred to 2016/17. There is still the associated risk of the mobile substation providing cover for this site, in addition to 10 other sites so there is increased potential the mobile will not be available when required.

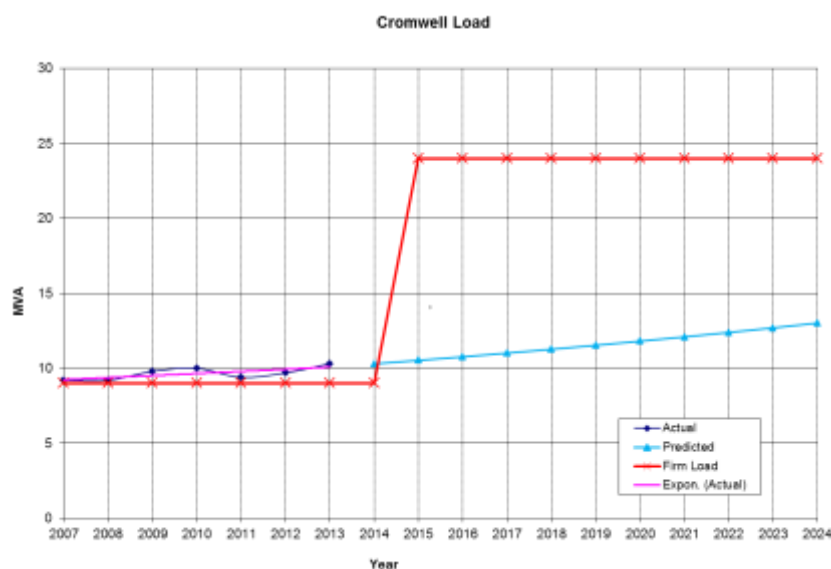


Figure 6.12 – Cromwell Zone Substation Load prediction

Queensberry Zone Substation

Figure 6.13 illustrates the load predictions for Queensberry zone 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. The substation load peaks in the summer. The Queensberry transformer is a 3 MVA ONAN unit, however fans have now been added to this transformer to increase its rating to 4MVA. A new 7.5MVA zone substation is planned to be installed in the Lindis

Crossing area which will reduce the loading on the Queensberry substation after it is commissioned in early 2015.

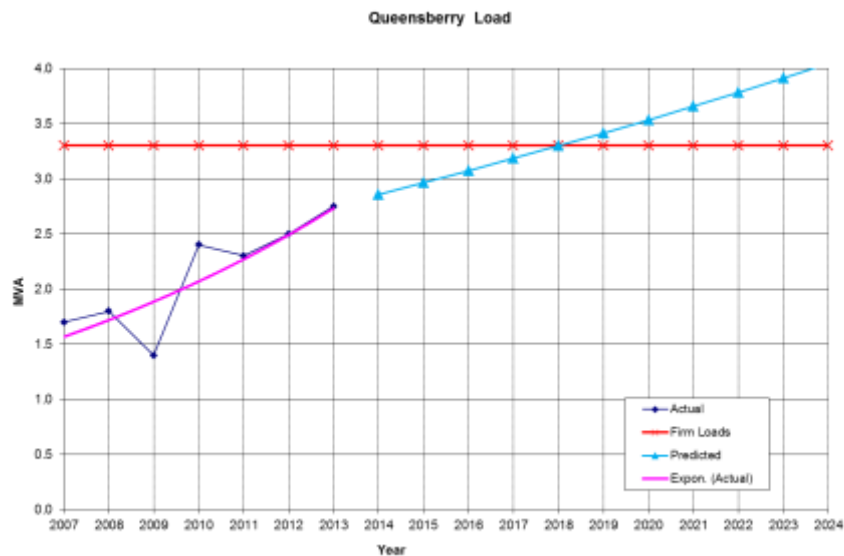


Figure 6.13 – Queensberry Zone Substation Load prediction

Wanaka Zone Substation

Figure 6.14 illustrates the load predictions for Wanaka zone substation. Load growth on the Wanaka zone substation has been significant in the recent past (9.3% annually from 2003 to 2009). It is now predicted the growth will be significantly lower than historical values. Construction of Riverbank Road substation will increase the ability to off-load Wanaka.

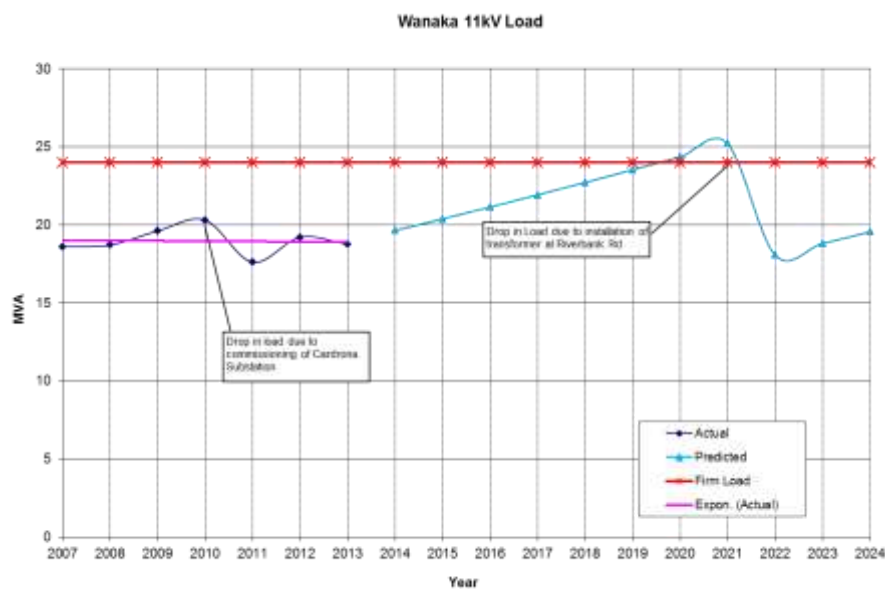


Figure 6.14 – Wanaka Zone Substation Load prediction

Maungawera Zone Substation

The increase in irrigation load means that the Maungawera substation is now running at its maximum capability (see Figure 6.15). This substation is to be replaced with the new 7.5 MVA Camp Hill Road substation, planned to be commissioned early in 2015.

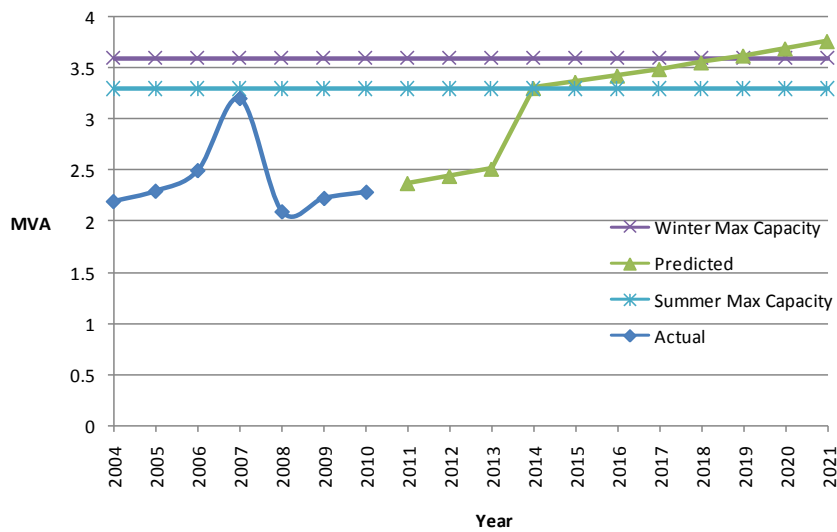


Figure 6.15 – Maungawera Zone Substation Load prediction

Frankton

Arrowtown Zone Substation

Figure 6.16 illustrates the load predictions for Arrowtown zone substation. The Arrowtown substation demand during the 2012 winter was 8.3 MVA which exceeded its firm rating of 7.5 MVA. 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 was 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 however there is increasing risk that it will not be available when required. Options to address this are discussed in Section 6.5

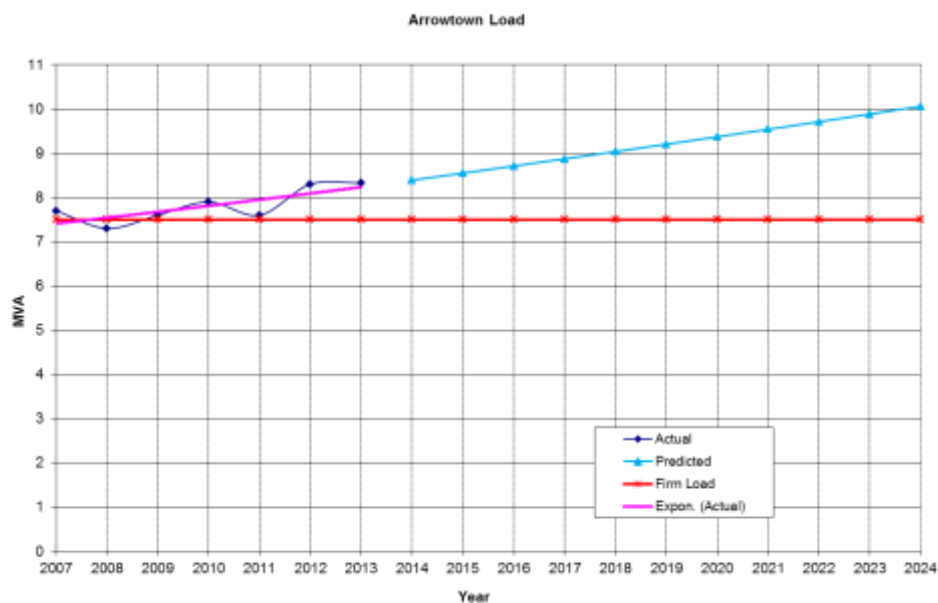


Figure 6.16 - Arrowtown Zone Substation Load prediction

Frankton Zone Substation

Figure 6.17 illustrates the load predictions for Frankton zone 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. A growth rate of 100 kVA per year has previously been the assumed rate 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. However, the uptake of lots has been slow to date, although there is anecdotal evidence of this beginning to pick-up again. A review of the assumed growth rate will be carried out in 2014/15, with appropriate adjustments made to the assumptions for timing of the proposed substation. Construction of Jacks Point will increase the ability to off load Frankton.

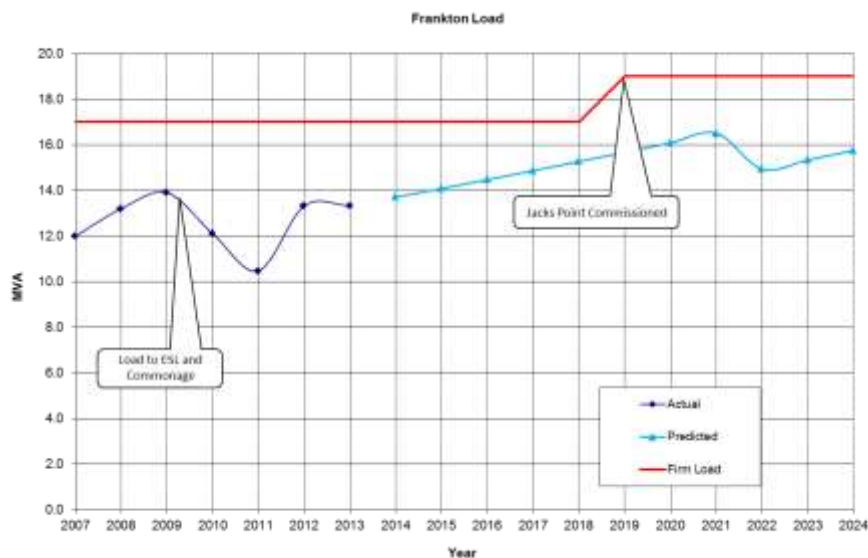


Figure 6.17 - Frankton Zone Substation Load prediction

Remarkables Substation

Figure 6.18 illustrates the load predictions for Remarkables zone substation. The Remarkables ski field has a four stage upgrade planned. However the exact timing of each stage is uncertain. Stage one is completed and has increased the field maximum demand to approximately 2 MVA. Stage 2 will add an extra 200 kW.

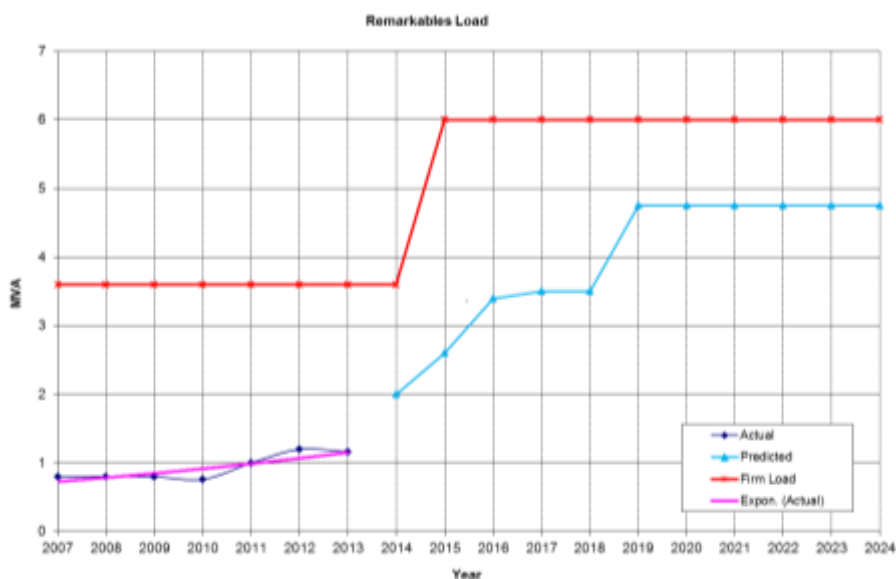


Figure 6.18 - Remarkables Zone Substation Load prediction

Halfway Bush

Smith Street Zone Substation

Figure 6.19 illustrates the load predictions for Smith Street zone substation. Smith Street load is currently predicted to reach its firm rating prior to the 2021 winter. 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. It is proposed that Smith Street be upgraded to 24 MVA transformers and the HV switchgear be replaced prior to the winter of 2020.

Neville Street Zone Substation

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 6.6.

Halfway Bush

Figure 6.20 illustrated the load predictions for halfway Bush zone substation and shows that there are no issues short-term.

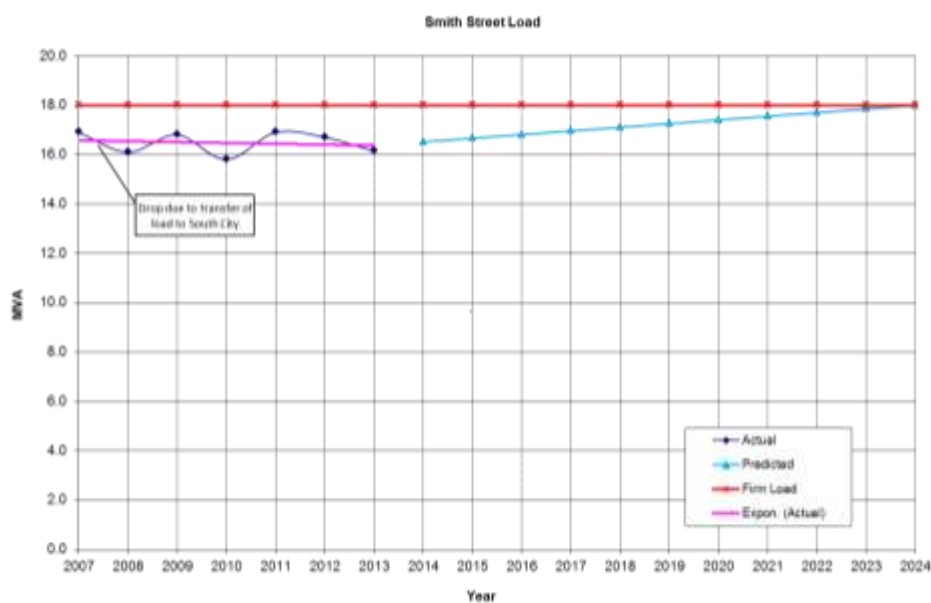


Figure 6.19 – Smith Street Zone Substation Load prediction

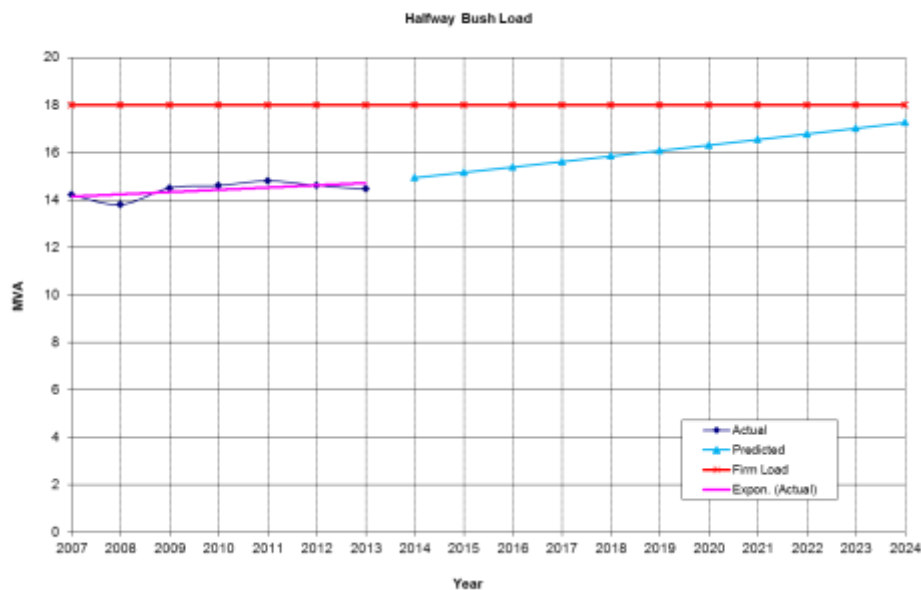


Figure 6.20 – Halfway Bush Zone Substation Load prediction

South Dunedin

Andersons Bay Substation

Figure 6.21 illustrates the load predictions for Andersons Bay zone substation. Load on the Andersons Bay substation has been variable. It is not currently predicted that the load will reach the firm capacity within this planning period. Some load could be transferred to St Kilda but it is expected that most of the equipment at Andersons Bay will be at the end of its economic life in 2021 so it is proposed the substation be upgraded with new transformers and switchgear at this time.

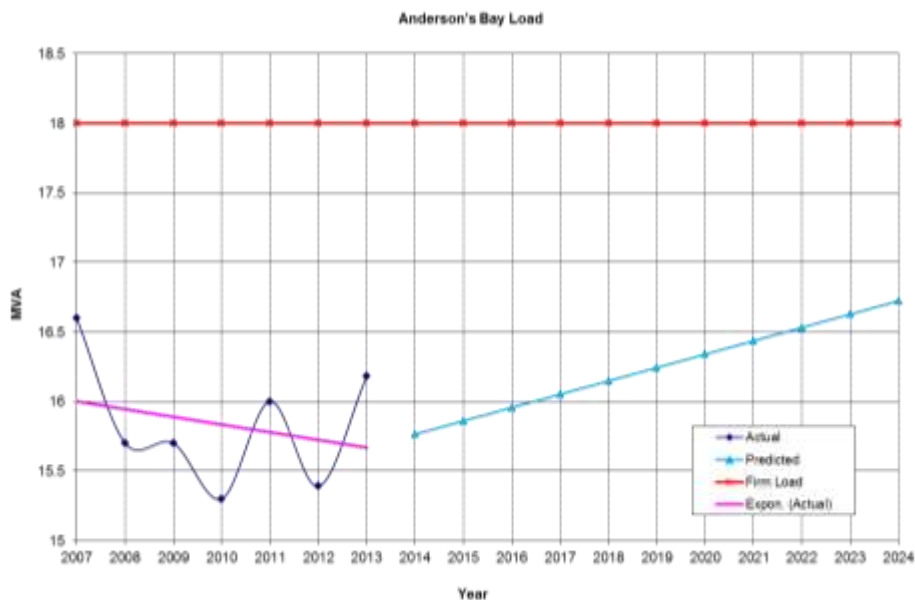


Figure 6.21 - Andersons by Zone Substation Load prediction

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. The installation a 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.

6.5.5 Zone Substation - Non-Transferable Load

Along with demand projections, load risk analysis is also carried out on an annual basis to monitor and mitigate risk of complete loss of service. Together, this information is used as part the planning and decision-making criteria for new capital investment and renewal needs.

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. Table 6.11 lists the zone substation non-transferable load sorted by magnitude of the winter non-transferable MW¹⁰. This provides a clear statement of "load at risk" Table 6.12 combines this with the load prediction information as well as information in priority customers to provide a picture of high-risk areas of Aurora network.

¹⁰ 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. Note that a review of load at risk commenced in 2012 and updated figures will be provided in Aurora's 2014/15 AMP.

Table 6.11 – Zone substation non-transferable load schedule

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	12.0	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
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

Based predicted demands against firm load capacity, the substations that Aurora considers to be potentially at risk of capacity issues in the 10 year planning period are shown Table 6.12

Table 6.12

GXP area	Substation
Cromwell	Cromwell, Queensberry, Wanaka, Maungawera
Frankton	Arrowtown
Halfway Bush	Smith Street

Based predicted demands against firm load capacity, the substations that Aurora considers to be potentially at risk of capacity issues in the long term (beyond 10yr AMP planning period) are:

This has formed part of the framework for assessing criticality, as discussed in Section 4. The following attributes were collated for each zone substation:

- Load at risk: Non-transferrable load at each zone substation
- # of Priority 1 Customer Connections – Hospitals
- # of Priority 2 Customer Connections – 3 Waters, Police, Fire and other emergency services
- # of Domestic ICP's
- Value of Lost Load

Considering all this information combined indicates that the potential high-risk areas of Aurora's network are:

- Dunedin - Andersons Bay, Green Island and Halfway Bush
- Central - Wanaka, Cromwell, Frankton and Alexandra

6.6 Network Development

This section outlines the network development plan required to upgrade Aurora's distribution system. It details the expansion and upgrading considered necessary to accommodate predicted future network loading. The plan also proposes works to improve network safety and reliability.

A detailed description of the projects to be carried out within the next 12 months is provided. Project proposed for the following four years are also covered, with detail provided for those that are significant (for example: the system control and communication projects). Those planned for the remainder of the AMP planning period are also highlighted. See Appendix D for further detail in the projects proposed within these timeframes.

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. The content of this section provides an overview of what is contained in the development reports. Reference to the detailed reports (DR) is made where necessary.

6.6.1 Overview of projects

The timing of major projects is presented in Table 6.13. The projects in this table are divided into those driven by System Growth and those driven by Renewals/Replacements.

Under each of these, projects are listed under the following categories: Subtransmission, Zone Substations, Distribution, Low Voltage and Other network assets (such as secondary assets).

The estimates are based on a financial year 1 July to 30 June (the 2014/15 year) does not include carry-overs from 2013/14. The definition of capital & operational expenditure categories were provided in Table 6.1 and based on the Commerce Commissions definitions for expenditure drivers.

Table 6.13 – Time Line of Major Capital Projects

Project Type	Asset Category	Project No.	Short Description	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	
Central	Growth	Subtransmission	3021 Upgrade auto transformers at Cromwell GXP	17,496	14,103	12,964	9,017	11,917	6,977	7,277	8,127	7,827	6,477	
			3216 Riverbank Road - Install 66kV cables from Riverbank Rd substation to Wanaka Sub and to UC2 line.	250	2,250			1,000	2,000					
			4161 Camp Hill Rd - 66kV line extension and 11kV cable	975										
			4182 Upgrade Glenorchy supply to 33 kV - land acquisition/designation & construction	540	540									
		Zone substations	3016 New Frankton 33kV GXP Feeder							1,500				
			2611 New Jacks Point zone substation							300	1,350	1,350		
			3019 Install 10 MVA transformers and new switchgear at Arrowtown Zone Sub.			220	1,980	1,980						
			3022 Riverbank Road 66kV switching and substation site - land acquisition (2629) & construction (3022)	100	1,950	1,950								
			3024 Cromwell substation upgrade - Install two new 24 MVA transformers		250	1,500	1,500							
			3437 Install 24 MVA 66/11kV transformer and 11kV switchgear at Riverbank Rd substation.				250	2,250						
			3438 New 66kV Switching Station at Queensberry								300	1,500	1,500	
			4135 Camp Hill Rd Substation build	4,510										
			4213 Lindis Crossing - land acquisition/designation (incl line relocation)	380										
			Lindis Crossing substation	2,233	2,233									
		Distribution and LV lines	TBC New Lauder substation								500	1,500		
			New Omakau substation			2,000								
			3059 New Connections Central	4,583	4,402	4,402	4,402	4,402	4,402	4,402	4,402	4,402	4,402	4,402
		Distribution and LV cables	3165 Wanaka - Three Parks feeder tie	600				150						
			3428 Install new HV feeder in Cromwell to Leitrum St	500										
			3044 OH to UG Conversion CODC Area	100	100	100	100	100	100	100	100	100	100	100
	Distribution substations and transformers	3045 OH to UG Conversion QLDC Area	375	375	375	375	375	375	375	375	375	375	375	
		3062 Central load growth projects (to be identified)	100	100	100	100	100	100	100	100	100	100	100	
		Renewal	Zone substations	TBC Alexandra ZS switchboard replacement					1,500					
	Distribution switchgear		3211 Replacement of Pacific fuses in Central network	60	60	60	60	60						
	Other network assets		TBC SCCP P3 - Communication Link Upgrade	1,220	1,173	1,217								
			SCCP P5 - Dunedin RTU Upgrade	970	670	1,040	250							
	Dunedin				4,491	13,221	4,650	7,836	8,196	7,681	7,791	3,986	3,986	3,986
	Growth	Zone substations	3038 Upgrade Andersons Bay substation (Tx's and switchgear)			450	1,350	2,700						
			3414 Upgrade Smith St Substation - new 24MVA transformers and HV switchgear					450	2,025	2,025				
			4179 Upgrade Outram Zone Substation											
			3058 New Connections Dunedin	300	2,700	900								
			3043 OH to UG Conversion Dunedin Area	1,145	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
			3061 Dunedin load growth projects (to be identified)	600	600	600	600	600	600	600	600	600	600	600
		Subtransmission	3171 Replacement of Kaikorai Valley 33kV PILC cables	100	100	100	100	100	100	100	100	100	100	100
			3469 Replace Ward Street 33kV gas cables				290	2,610						
			3470 Replace Willowbank 33kV gas cables						420	3,780				
		Zone substations	3471 Replace Smith St 33kV gas cables				390	3,510						
			4212 Port Chalmers to Peninsular Harbour Crossing						350	3,150				
TBC Replace Neville St 33kV gas cables			400	400										
2324 Rebuild Neville St zone substation on new site			200	1,800										
TBC Halfway Bush ZS switchgear replacement			600	5,400										
Mosgiel ZS transformer replacement											2,000			
Port Chalmers ZS Transformer replacement												2,000		
Distribution and LV cables		2622 Underground Link Box upgrades (Dunedin)		150	150	150	150	150	150	150	150	150	150	
		TBC Underground Substation Improvement Programme	50	100	100	100	100	100						
		3029 Replacement of Pole-mounted substations	36	36	36	36	36	36	36	36	36	36	36	
Other network assets		TBC Chorus changeovers	250	250	250									
	SCCP P1 - New Control Room	450	240	200	600									
	SCCP P6 - Central RTU Upgrade	360	345	374										
		3,950	3,110	2,590	880	670	670	520	520	520	520	520		
Dunedin/Central				350	350	350	350	350	350	200	200	200	200	
Growth	Zone substations	TBC Fire , Security, Earthquake & Asbestos Upgrades												
		Mobile Generator (300kVA)		750										
	Distribution substations and transformers	3200 Extra cost of Dual ratio distribution transformers	80	80	80	80	80	80	80	80	80	80	80	
		3032 Replacement of Andelect (LV wall) Boxes - Dunedin	120	120	120	120	120	120	120	120	120	120	120	
		TBC Replacement of oil-filled switchgear	120	120	120	120	120	120	120	120	120	120	120	
	Other network assets	TBC SCCP P2 - New SCADA (+ DMS+OMS) System	1,800	1,800	1,800									
		SCCP P7 - Dunedin Subtransmission Protection Upgrade	720	420		210								
		SCCP P8 - Aurora and Transpower ICCP Link	10	220	120									

The following section is structured by GXP area and begins with the Central Otago network (Clyde, Cromwell, Frankton), followed by the Dunedin network (Halfway Bush and South Dunedin).

6.6.2 Grid Exit Points

Clyde GXP

Section 6.5 indicated that there is adequate GXP capacity at Clyde for the foreseeable future. However, the replacement of ripple injection is planned. Ripple injection for Clyde GXP is based in the Alexandra zone substation. Although the existing injector has capacity to cope with many years of load growth, this asset has effectively passed its nominal life of 20 years, being installed in 1985. While there is a spare unit available (ex Frankton), it too is older than 20 years and given that spare parts are no longer available for either unit, replacement is deemed necessary to reduce the risk associated with failure. Development report DR123 investigates the future options for the Alexandra injection units and recommends that

Cromwell GXP

The Cromwell transformers were upgraded in 2009 resulting in the n-1 ratings listed in Table 6.14. Section 6.5 indicated that there is adequate capacity at Cromwell GXP for the short-term, however the off take load is predicted to exceed 40.9 MVA during the winter of 2022 and the load on Cromwell zone substation is growing with peak demand now exceeds its 9 MVA firm capacity. There is a protection limitation that constrains the rating of the T8 transformer at the Cromwell GXP site. One solution for this is to install duplicate protection on affected feeders. The main project associated with the Cromwell GXP area is Upper Clutha, discussed in Section 6.6. It is acknowledged that Transpower plans to convert the outdoor switchyard to indoors by 2025, but this work has yet to be scheduled.

Table 6.14 – Cromwell GXP transformer n-1 ratings

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

Frankton GXP

Section 6.5 indicated that it is predicted the 66 MVA continuous n-1 rating at this site will not be exceeded during the planning period. The ripple injection plant was upgraded in 2010 and the new injectors will cope with up to 100 MW of connected load. Constraints in the Wakatipu Basin Ring and/or growth in Jack's Point may drive the need to install an additional feeder (see Section 6.6.3). Installing an additional feeder should be straight forward, providing it is possible to obtain the existing switchgear model. In this case, Aurora is reliant on Transpower to advise before production of the current model ceases in order to facilitate advance purchase of a breaker if necessary (there is space in the switch room at Frankton GXP for two additional 33 kV feeder circuit breakers). There are currently no other major projects planned by Aurora at this GXP site within the next 10 years.

Halfway Bush GXP

Section 6.5 indicated that the off-take peak exceeds post-contingency rating. The connection of the 36 MW TrustPower Mahinerangi wind farm, which was established during 2011, assists to reduce some of the off take on the Halfway Bush GXP. Further to this, a contingency plan has been prepared in the event of failure of the Transpower transformer (Development Report DR24). Aurora also plans to move other substation loads (e.g. Neville Street) to the South Dunedin GXP by May 2015 when the Neville Street

substation and gas cables are upgraded, see Sections 5.5 and 6.6. This would reduce the demand on Halfway Bush by approximately 14 MVA.

There are also a series of projects being implemented by Transpower that Aurora has the opportunity to benefit from. For example: Transpower plans to convert the remaining outdoor 33 kV circuit breakers to indoor units in 2016. 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 take-off area. Transpower also 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 new 33kV cable cost by up to 30%.

South Dunedin GXP

Section 6.5 outlined a constraint where the 81MVA limit would be exceeded when the Neville Street Substation load is transferred to South Dunedin. 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 below.

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 2015. In conjunction with the switchgear conversion project, Aurora has requested that Transpower allow space in the new switch room to accommodate circuit breakers for the connection of the Neville Street substation to the South Dunedin GXP and to allow 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. In conjunction with this project Aurora is upgrading its protection relays on the South Dunedin Subtransmission.

Installation of NER on T1 and the South Dunedin GXP has been completed

6.6.3 Sub-transmission

The following sections outlines the subtransmission considered to warrant investment over the 10 year planning period in response to the key asset management drivers. The section is structured by GXP area, beginning with the zone substations in Clyde, Cromwell and Frankton then leading into the zone substations in Halfway Bush and South Dunedin.

Clyde

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 varied over time, and although the likely final extent of the project still has a high level of uncertainty, 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

Cromwell

Upper Clutha 66 kV

The Upper Clutha 66kV network is within the Cromwell GXP area. 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;
- upgrading the auto transformers at Cromwell and/or installation of a 66kV bus at Cromwell to 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.

A schedule of the required upgrade projects with estimated costs is presented in Table 6.15 (this assumes no support from the Hawea generation; see long term programme below).

Under the current scenario, however, 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. It is recommended land for the Aubrey Road substation be purchased well in advance of being required, if available.

Aurora has purchased land adjacent to the proposed Contact Energy generation¹¹ site to accommodate substation equipment and to provide 66 kV line access. During 2014, the land required for electricity purposes will be subdivided off the main block and designated for substation and transmission line use. This will enable Aurora to sell the balance of the land.

Long term programme

The long term geographic layout in is illustrated in Figure 6.20. Progress toward this configuration will depend on load growth and the installation of generation at Hawea (a project proposed to be delivered by Contact Energy). Development Report DR40, written in 2008, considered various connection options. There has been limited progress on the Hawea generation project and although the project is still 'active'. At present it is assumed that the original timeframe proposed to complete the generation still remains at 2017.

As such, projects for the establishment of the generation connection proposed by Aurora have been put on hold, with the exception of land subdivision as outlined previously. DR166, written in 2013, outlines the proposed path for continued upgrading of the 66kV capacity assuming the Hawea Generation does not go ahead.

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.

¹¹ 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.

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.

Table 6.15 – Upper Clutha 66 kV subtransmission project schedule

Project Details	Project No	Estimated \$000	Completion
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
Upgrade Cromwell Auto Transformers	3021	3,000	May 2020
Install transformer and 11 kV switchgear at Riverbank Road substation	3437	2,500	May 2019
Create 66 kV bus at Queensberry	3438	3,000	2023 +

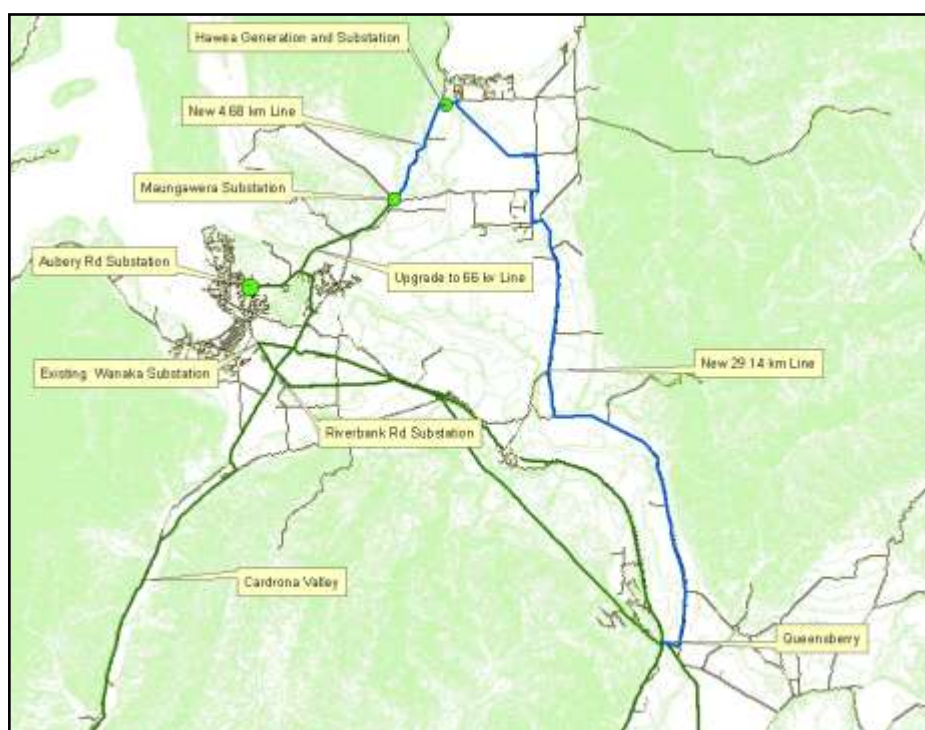


Figure 6.20 - Geographic layout of Upper Clutha long term subtransmission

Wanaka 33 kV

At present, the Cardrona and Maungawera substations are supplied from the Wanaka 33 kV bus. 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. The 2012 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.

Frankton

Wakatipu Basin 33 kV Ring

The Wakatipu Basin Ring is within the Frankton GXP area. Section 6.5 identified the need to improve the capacity of the ring (see Figure 6.21 for the configuration), which consists of Ferret and Mink conductor and short sections of cable. 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. The 70mm² cable upgrade was carried out in 2012.

Although the peak load on this ring is above its N-1 capacity, the constraint is the rating of the Ferret overhead conductor and the peak loads are occurring in very cold temperatures which would allow this conductor to be safely run at loads well above normal rating. As loads increase it would be appropriate to reassess/resag the section of Ferret conductor from Frankton GXP to Dalefield to increase its maximum temperature rating to 75°C.

In terms of the third circuit, there are two possible options. 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. It is proposed to install this outlet and a 33kV cable along the state highway to the Shotover River in 2020/21.

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 6.22 for the proposed circuit route and Figure 6.23 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. 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. Exact timing of this project is uncertain and at this stage no funding has been allowed, however this should be reviewed as load grows in the area.

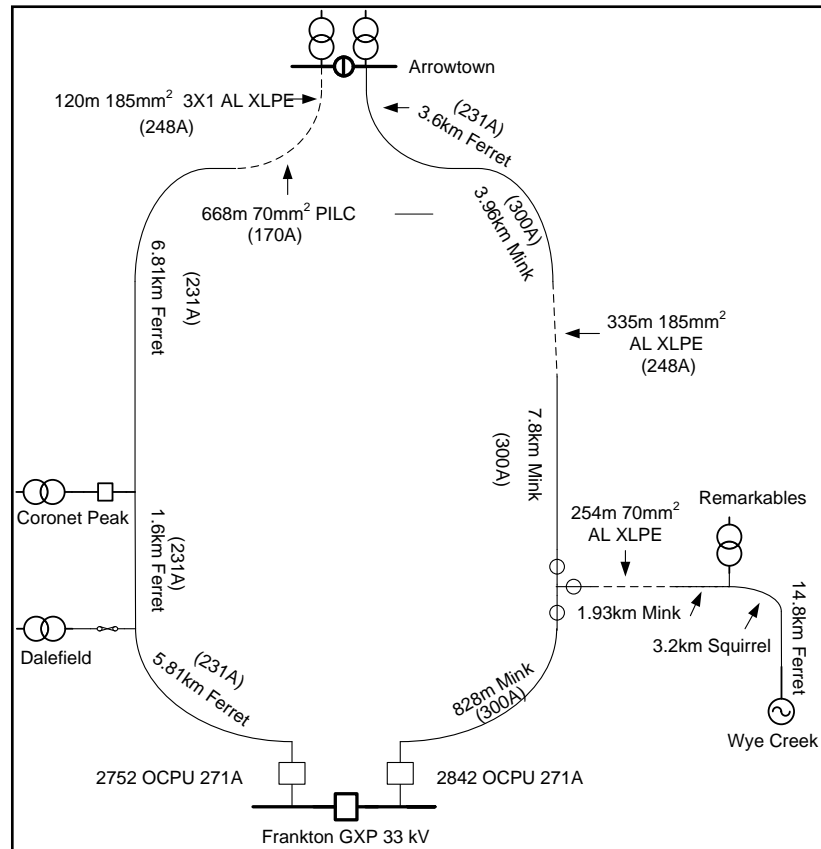


Figure 6.21 – Wakatipu basin 33 kV ring

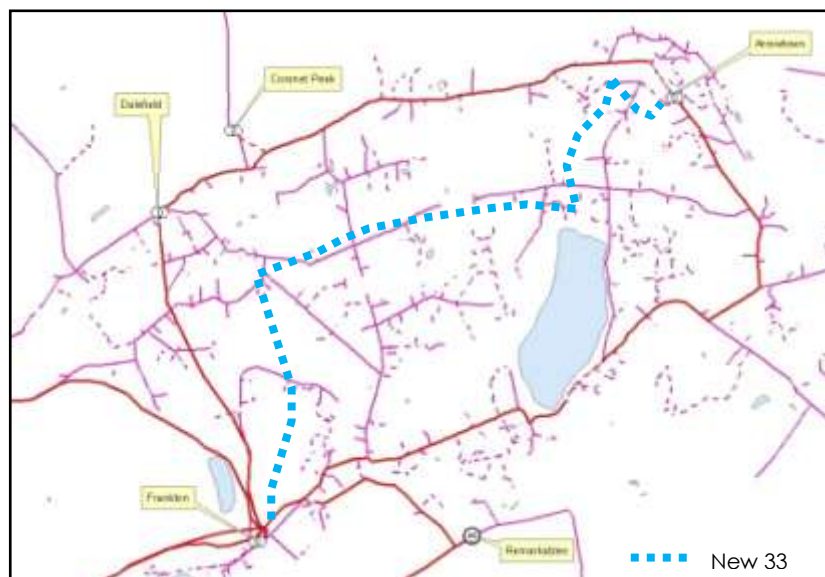


Figure 6.22 - Wakatipu ring upgrade – option 1 third line to Arrowtown

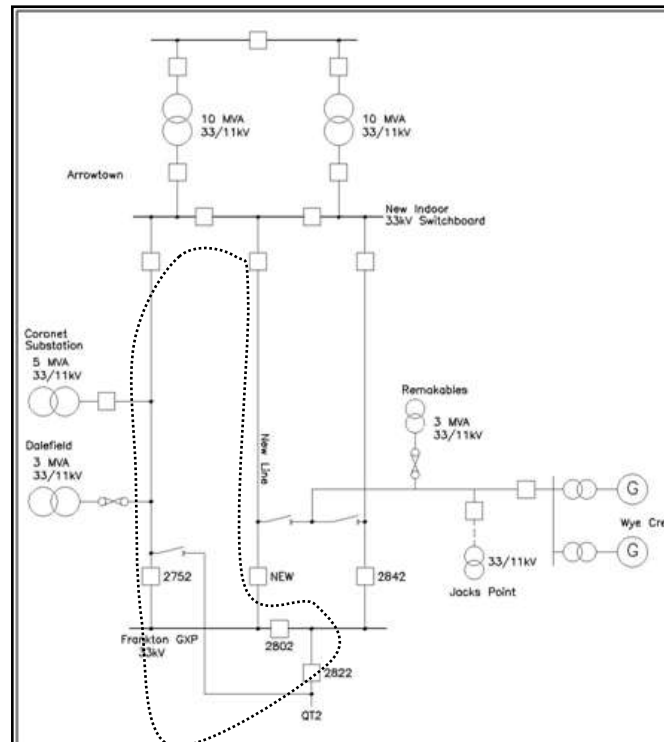


Figure 6.23 - Wakatipu 33 kV ring upgrade – SLD option 1

Shotover 33 kV River Crossing on Wye Creek Line

Previously it was considered that the 33kV aerial river crossing across the Shotover River was nearing the end of its economic life and a cable was proposed across the Shotover bridge. However recently the structures supporting this line have been inspected and found to be in much better condition than was initially thought. It is now proposed to leave this line in service and investigate the option of providing an alternative route via a short cable to the existing Arrowtown line that comes from the same 33kV feeder but via a different aerial river crossing.

Glenorchy

Development Report DR132 (project 4182) 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.

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.

Recent review of this proposal confirmed the original decision but also showed that installing a diesel generator at Glenorchy to provide a standby supply for 33kV faults is viable and economic. This project needs to go ahead as soon as practical beginning with land purchase or easement negotiations for the Glenorchy substation and generator.

6.6.4 Zone Substations

Aurora's network contains 36 zone substations, 18 in Dunedin and 18 in Central Otago. The following sections outline those that are considered to warrant further investigation or investment over the 10 year planning period in response to the key asset management drivers discussed in Section 2 as well as the growth and demand issues discussed earlier in Section 6.5. The following section is structured by GXP area, beginning with the zone substations in Clyde, Cromwell and Frankton then leading into the zone substations in Halfway Bush and South Dunedin.

Clyde

Alexandra Substation

There are no major capital projects planned for this site over this planning period, however 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.

Omakau & Lauder Substations

Farm land conversion to dairying is an activity that is showing significant signs of increasing over the next 5 – 10 years, particularly in the Manuherikia and Ida Valleys. The resultant increase in load growth on the network will require investment in new infrastructure for this part of the network.

A major driver for this growth can potentially be linked to rebuilding and significant expansion of the Falls Dam¹². This would allow a greater area of land to be reliably irrigated. Such a project could enable water to be supplied under pressure at the farm gate, so irrigation pumping load might be lower than otherwise expected. However dairy shed and pivot irrigator load will still be significant.

If the Falls Dam scheme does not go ahead it is likely that a smaller area of land would be converted to dairying. However this land would also likely have a proportionally higher irrigation pumping demand. Therefore, strong load growth is still expected and construction of a substation in Oamkau and Lauder is proposed.

Exactly which of these projects goes ahead first and when depends on the rate and exact location of new load growth. However it is expected the projects will cost in the order of \$2M each and it is tentatively proposed for one to be completed in 2018 and the other in 2021.

Cromwell

Queensberry Substation

The large Tarras irrigation scheme has not gone ahead and therefore the new Maori Point Substation was not built. Instead many farmers have installed individual irrigation schemes that have resulted in the existing Queensberry Substation reaching its maximum capacity. The proposed 7.5MVA Lindis Crossing Substation (planned for completion early in 2015) will augment the existing 4MVA capacity of the Queensberry substation.

Cromwell Substation

While *normal* load is not causing capacity constraints at present, 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. It has previously been proposed that the transformers be upgraded prior to the 2015 winter when it was predicted the load would reach 12 MVA. Present load predictions (see section 6.4.4) have reduced, with the 12 MVA limit now predicted for the winter of 2020. It is proposed that commissioning occurs in 2017(see DR 130).

¹² The Falls dam storage assets are owned by the Omakau Area Irrigation Company Limited and operated by Falls Dam Company Limited. The hydropower assets are owned and operated by Pioneer Generation Limited

In the event of a Cromwell transformer failure there is a 7.5/10 MVA transformer that is currently stored at Arrowtown (removed from Frankton) that will be available to be installed at Cromwell, but this would take several days to install. Load control could also be used to alleviate some issues during such an event. Also see comments for Arrowtown substation. Note that a review on the movement of transformers between zone substations is planned to ensure network needs are approached from a strategic perspective.

Wanaka Substation - Riverbank Road proposal

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 6.5.4. 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.

Maungawera Substation

Maungawera substation has now reached its maximum capacity. It was intended to upgrade this substation on the current site but difficulty with land purchase negotiations have meant that it is now planned to build the new substation 1.2km away from the current site along Camp Hill Road. When this substation is completed (planned for early 2015) the existing Maungawera substation will be decommissioned.

Frankton

Arrowtown Substation

The load is not predicted to reach 10 MVA during the planning period. However the upgrade proposed in the 2011 AMP - to install transformers during the 2016/17 summer to increase the firm capacity to 11.5 MVA - is still considered viable, particularly as there is increasing risk that the mobile substation will not be available when required because it is backup for 11 sites. In 2012, a parking bay was constructed in order to accommodate for the mobile substation at this site. The mobile substation can provide cover for a transformer outage up to a load of 10 MVA.

Associated with the future proposed upgrade is the installation of indoor 11 kV and 33 kV switchgear and supply the transformers from 33 kV circuit breakers rather than the fuses at present. The 33 kV switchgear configuration will be designed to accommodate the third 33 kV circuit as outlined in the Wakatipu Basin Ring proposal and detailed in Figure 6.24.

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.

Remarkables Substation

The Remarkables ski field has a four stage upgrade planned. Stage one is scheduled to be completed for the winter of 2014 and will increase the field maximum demand to approximately 2 MVA. Stage 2 will add an extra 200 kW. Rewiring work has been completed to remove transformer WS200 off the

Remarkables 11kV supply so that line drop compensation (LDC) can be used on the Remarkables Zone Substation to maintain acceptable voltage at the Ski Field. Refer to development report DR126 for detailed consideration of supply options for the Remarkables ski field. The timing and actual capacity required for stages three and four is uncertain so no financial provision has been made for these stages.

Proposed Jacks Point Substation

As outlined in section 6.5.4, timing of substation construction depends on uptake of the lots in this area, which has been slow in the recent past. A review of the assumed growth rate will be carried out in 2013/14, with appropriate adjustments made to the assumptions for timing of the proposed substation. The proposal at this stage is 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 exists and a 33 kV cable has been installed from the Wye Creek line to the site.

Jacks Point is presently supplied from Frankton feeder 7784 via recloser 7375R up to a load of approximately 2 MVA. 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 2017 winter so the installation of a pair of single phase 100A regulators has been scheduled for 2016/17.

Halfway Bush

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

Neville Street Substation

It is planned to move the Neville Street substation load to the South Dunedin GXP when the Neville Street substation and gas cables are upgraded, see Section 5.5 and 6.6. Part of the Neville St upgrade involves the establishment of a new substation site. This site is currently leased to an external party and the current lease agreement does not terminate until August 2015, by which time the premises must be vacated.

6.6.4.1 Zone Substation Buildings

An assessment of fire, security and earthquake risk for all of Aurora's zone substation buildings has been carried out. Outputs from this will contribute to the development of a long term programme of works, which will be incorporated into Aurora's 2014/15 AMP (also see Section 5 for further detail). Along with security and earthquake risk recommendations, this assessment will supersede previous recommendations on the risk and consequences of zone substation control room fire that identified sites to be fitted with gas flooding fire protection.

6.6.4.2 Zone Substation Switchgear

Switchgear associated with major projects is discussed in previous sections. The following outlines programmes for network-wide upgrades.

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 in both Central and Dunedin.

Installation of 33 kV Circuit Breakers

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. There is a proposed upgrade programme for fuse protected transformers.

Earthing Points

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. Design work and purchase of suitable fittings for this work has been completed and it is proposed to install these fittings in conjunction with future outages.

6.6.5 Distribution

The following outlines proposals for network-wide upgrades.

6.6.5.1 Distribution Lines

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. The main HV feeders that have reached or are reaching their load limits are programmed for upgrade or further investigation. Comments on the proposals to address these issues are provided below.

Wanaka

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. See development report DR124 for further analysis, although verification of cost estimates are now required. 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 6.25

New Wanaka Feeder 2757 - In the 2011 AMP 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. This is currently in the design phase and construction is planned for 2014/15 or 2015/16. See Figure 6.26 for proposed cable route and refer to development report DR135 for additional detail. Further assessment of the loading on this feeder is being carried out in 2014/15 to verify requirements.



Figure 6.24 - Location of tie cable between WK2756 and WK2752



Figure 6.25 - Route of new Wanaka 2757 feeder.

Cromwell

New Cromwell Feeder - It is 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. A new circuit breaker will be required to be installed at the Cromwell zone substation, however further appraisal and detailed design for this project is necessary in 2013/14 to verify the proposed expenditure requirements.

Willowbank

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 appraisal is yet to be carried out to identify an economic solution to this constraint.

Queenstown

QT 5232 has just reached its off-load limit an additional intertie with feeder QT 5242 close to switch 551 would facilitate offloading. QT 5262 is also approaching its load limit but no action is proposed at present; however this is being monitored. In the future, an additional intertie with feeder QT 5242 close to switch 555 would facilitate offloading.

Conversion of 6.6 kV Feeders to 11 kV

The majority of the distribution network in Dunedin along with the Clyde-Earnscliffe region operate nominally at 6.6kV. A strategic review for conversion from 6.6kV to 11kV is currently underway.

Both challenges and benefits exist in converting the remainder of the network to 11kV. The largest and most costly requirement is the replacement of distribution transformers to offer a ratio of 11000/400V and 6600/400V. Since 2009, Aurora has been installing dual ratio transformers connected to feeders operating at 6.6kV.

This is complimented with dual ratio transformers replacing zone substation transformers where applicable. Currently the Ward Street, Halfway Bush and Berwick transformers have been replaced with dual ratio winding sets leaving a large number of zone substation transformers yet to be replaced. Along with replacing distribution transformers, all cables and cable joints need to be capable of insulating for 11kV and all overhead clearances need to be checked and rectified if not acceptable.

Converting to 11kV results in increased capacity of the distribution network; with the required current carrying capacity of the line being reduced by 40% for delivering the same power. This can lead to opportunities to extend asset life until thermal limits are met again.

Converting to 11kV also allows for greater voltage stability along feeders. This is due to reduced voltage drop as a result of reduced load. The reduced voltage drop for the same power supplied allows for an increase in the intertie capacity of feeders under high load resulting in greater security of supply for the network.

Further analysis and planning into the conversion process is currently being undertaken to determine future expenditure needs. See section 6.6.8 for further detail.

6.6.6 Distribution Cables (HV)

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 is detailed in Section 6.7.

6.6.7 Distribution Switchgear

In the 2012 AMP, a schedule of HV feeder recloser projects was presented, which proposed renewing 2-3 reclosers per year over the next 3 years at a cost of approximately \$50,000 each. This will proceed as planned.

6.6.8 Distribution Transformers

Aurora has extensive 6.6 kV distribution in the Dunedin area and small amount in the Clyde Earnscliffe 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. When 6.6 kV zone substations are upgraded replacement transformers with both 6.6 kV and 11 kV capability may be installed.

For consumer initiated projects where dual ratio transformers are required, Aurora will fully fund the additional cost of dual ratio transformers. An allowance of \$80,000 per year has been made for this. See development report DR65 for further detail.

6.6.9 Distribution Substations

Underground Substations

In Dunedin, there are 18 underground substations. In 2005, a significant rainfall event resulted in flooding at five of these substations. Six substations have been fitted with ducting and forced ventilation to mitigate the risk of flooding in the future. It was previously proposed to continue with the waterproofing work on two substations per year however a review of the approach for mitigating this risk is being carried out in 2014/15 to re-evaluate the proposed works required. This review will verify the solutions and required expenditure for 2015 onwards.

6.6.10 Low Voltage (LV)

No significant new capital/upgrade projects have been identified in this AMP for this asset category, with the exception of customer connections detailed below.

Customer Connections

Network connections can range from a 60A single phase connection to a big subdivision, or a large industrial connection of several thousand kVA. To facilitate the connection of customers to the network, new customer connections cover the cost of the extensions to the Aurora network. Customers make a contribution toward the cost of this work in accordance with the Aurora capital investment policy. The creation of new connections, and hence expenditure for these, is entirely customer driven and subject to regional economic activity.

Aurora anticipates that the level of subdivision work in Dunedin for 2014 will not significantly change from status quo; and in Central likely to continue at a steady pace. However a review of the drivers and forecasts for customer connections is required and may lead to some readjustments to the annual budgeted expenditure. At present, the forecast for customer connections is illustrated in Table 6.16. The budgeted annual expenditure is presented in Section 6.7.

Table 6.16 - Forecast Consumer connections

	2014	2015	2016	2017	2018	2019	2020
Dunedin	54,351	54,624	54,897	55,168	55,439	55,715	55,985
Central Otago	30,656	31,346	32,038	32,728	33,422	34,112	34,803
Te-Anau	101	111	121	131	143	153	160
Total	85,108	86,081	87,056	88,027	89,004	89,980	90,948

6.6.11 Secondary Assets

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.

In 2011/12 AMP identified that additional investment in communication systems was likely and an initial allowance of \$1 million a year for three years starting 2013/14 was made. Subsequently, the recommendations have been further assessed in order to verify the scope, feasibility and economics for the options and solutions being proposed. Seven key projects make up an overall programme for Aurora's SCCP systems and these are presented in Section 5.5.18 and Table 5.10.

6.7 Capital Expenditure Forecasts

Capital expenditure is split into certain categories, as per the new Electricity Distribution (Information Disclosure) Requirements 2012. The proposed projects and programmes related to each of these categories were discussed in Sections 5 and 6. The tables below show proposed expenditure against the relevant asset categories¹³.

DUNEDIN	\$000	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
System growth		100	100	550	1,450	3,250	2,125	2,125	100	100	100
Asset replacement and renewal		4,736	12,601	3,506	6,486	5,046	6,006	8,316	6,786	6,836	6,836
Consumer connection		1,145	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Asset relocations		850	850	850	600	600	600	600	600	600	600
Rel, Safety and Env : Quality of supply		50	100	100	100	100	100	-	-	-	-
Rel, Safety and Env : Other		390	375	374	-	-	-	-	-	-	-
Dunedin sub-total		7,271	15,126	6,480	9,736	10,096	9,931	12,141	8,586	8,636	8,636
CENTRAL											
System growth		9,358	7,323	5,860	3,830	5,330	2,100	2,400	3,250	2,950	1,600
Asset replacement and renewal		5,090	3,553	4,117	3,210	3,060	1,500	1,500	1,500	1,500	1,500
Consumer connection		4,583	4,402	4,402	4,402	4,402	4,402	4,402	4,402	4,402	4,402
Asset relocations		475	475	475	475	475	475	475	475	475	475
Rel, Safety and Env : Quality of supply		1,636	300	-	-	220	-	-	-	-	-
Rel, Safety and Env : Other		285	45	45	45	45	45	-	-	-	-
Central sub-total		21,427	16,098	14,899	11,962	13,532	8,522	8,777	9,627	9,327	7,977
DUNEDIN/CENTRAL											
System growth		80	80	80	80	80	80	80	80	80	80
Asset replacement and renewal		2,170	2,170	2,170	420	420	520	520	520	520	520
Rel, Safety and Env : Quality of supply		350	350	350	350	350	350	200	200	200	200
Rel, Safety and Env : Other		1,600	760	240	330	120	120	120	120	120	120
Dunedin/Central sub-total		4,200	3,360	2,840	1,180	970	1,070	920	920	920	920
Grand Total		32,898	34,584	24,219	22,878	24,598	19,523	21,838	19,133	18,883	17,533

¹³ Constant pricing capital expenditure was inflated to reflect forecast nominal prices from CPI growth data 2014/15 – 2017/18 sourced from the New Zealand Treasury Half Year Economic and Fiscal Update (Dec 2013). The Treasury CPI growth value from 2017/18 was taken to calculate nominal pricing over 2018/19 – 2023/24 in lieu of available forecast data for this period.

7 Improvement Planning & Programme

7.1 Introduction

The value of assets, maintenance required and proposed capital expenditure outlined in the previous sections of this AMP mean that it is important for Aurora to ensure that asset management practice is aligned with best practice and is always 'forward-looking' when it comes to improvement in practices and standards. In response to this, an asset management improvement programme (AMIP) is being implemented. This improvement programme contains SMART objectives and is aligning with best practice by following the internationally accepted PAS55 standards and utilising the International Infrastructure Management Manual (IIMM) as a guiding document.

The improvement programme covers 'process', 'people' and 'metric' aspects based on the Commerce Commissions assessment framework (Asset Management Maturity Assessment Tool or AMMAT). This framework identifies 31 asset management functional areas based on PAS55.

'Process and people' improvements relate to how Aurora carries out asset management across the range of functional areas, plus the associated capabilities and competencies for achieving asset management objectives. 'Metric' improvements relate specifically to achievement of service levels (asset and customer) and performance targets.

The approach for monitoring progress and measuring success is as follows:

- Process & People improvements - co-ordinated and implemented as per the AMIP action plan; and progress is measured and reported as per the AMMAT (see Section 7.3).
- Metric improvements – asset management monitored and measured against defined Levels of Services and Performance Measures/KPI's (see Section 3). Physical improvements in the network that relate to these are outlined in Sections 5 and 6.

Three key aspects have been used to plan and develop the framework and actions for the AMIP. These are: (i) initial gap analysis; (ii) determination of target level for asset management practice; and (iii) identification of improvement areas. These are discussed in the following sections.

7.2 Gap Analysis

Key to achieving Aurora's asset management outcomes is assessing and understanding:

- (i) Where Aurora currently sits of the asset management maturity continuum i.e. its current level of asset management practice (in relation to alignment with PAS55);
- (ii) What the appropriate level of asset management practice is within the context of Aurora's business; and therefore
- (iii) Areas where changes to asset management processes and practice would produce improvements in financial performance, risk management and asset performance.

An initial gap analysis based on PAS 55 was undertaken in 2011. The outputs from this provided appropriate baseline indication of asset management maturity across a range of functional areas. Complimentary to this, an assessment was carried out to determine the appropriate level of asset management practice that should be targeted for the future. This assessment comprised of two phases:

- (i) A desk-top assessment to establish the over-arching target for asset management practice within the context of Aurora's business.
- (ii) An assessment of each asset management functional area in order to assign a specific target level so that monitoring of progress can be more easily facilitated.

These assessments have established a picture of the “current situation” and “required/targeted future state”. The ‘gap’ in-between has provided focus for a framework to produce the AMIP and associated action plan.

Stages of asset management maturity range from minimum/basic to advanced (0-4) and a general description of these is provided in Table 7.1. Overall, Aurora's target level for asset management maturity is Intermediate-to-Advanced.

Aurora is committed to achieving alignment with best practice asset management that is fit-for-purpose and as such is aiming for a maturity target level of practice ranging from 3 – 4 across the main functional areas of asset management.

Table 7.1 - Asset Management Maturity index

Maturity Level	PAS 55 Criteria	Description
Minimum	0-1 ↓	Basic technical approach undertaken at a level designed to meet <u>minimum</u> regulatory and organisational requirements for asset management, financial planning and reporting. Provides rudimentary guidelines and outputs to help inform some functional areas of asset management. Understanding of the elements required by best practice asset management is minimal. The organisation is in the process of developing a common understanding of these.
Core	2 ↓	Builds on basic technical approach, acquiring more technical information and increasing improvements. Development of approaches and practices across all functional areas of asset management. Some risk management; limited automated analysis. The organisation has a basic understanding of the requirements of best practice. It is in the process of deciding how the elements of best practice will be applied and has started to apply them.
Intermediate	3 ↓	Builds on ‘core’ practice plus more robust asset management techniques with improved maintenance management. Frequent use of risk-based approaches/risk management & asset lifecycle management, with more automated analysis. Understands key assumptions and uncertainties. Has started to develop and establish decision-making techniques based on ODM. The organisation has a good understanding of best practice requirements. It has decided how the elements of best practice will be applied and work is progressing on implementation.
Advanced	4	Builds on ‘intermediate’ practice with optimization of systems, activities, programmes to meet current and future LoS. Advanced and integrated AM, with mature collection and analysis processes for key asset information, risk, costs and treatment options; enabled through robust improvement framework for development of capabilities, technologies and practices. All elements of best practice are in place and are being applied and are integrated. Only minor inconsistencies may exist. Relevant ISO certifications achieved. Some processes and approaches may go beyond requirements, pushing the boundaries of asset management to develop new concepts and ideas.

7.3 Asset Management Maturity Assessment Results

Figure 7.1 on the following page illustrates Aurora's progress for improving asset management process and practice.

The results show that there has been steady improvements made across all aspects of Aurora's asset management since the initial baseline assessment was carried out in 2011.

The areas that improved since last assessment are listed below. It is pleasing to note that three out of four were identified as areas requiring attention from last years' assessment. These are highlighted in bold below

- asset strategy and delivery
- documentation, controls and review
- competency and training
- communication/participation

This illustrates that pro-active progress is being made on implementing the AMIP. It is also clear that these results demonstrate the effects of a targeted strategy for asset management improvement within Aurora's asset management service providers, Delta.

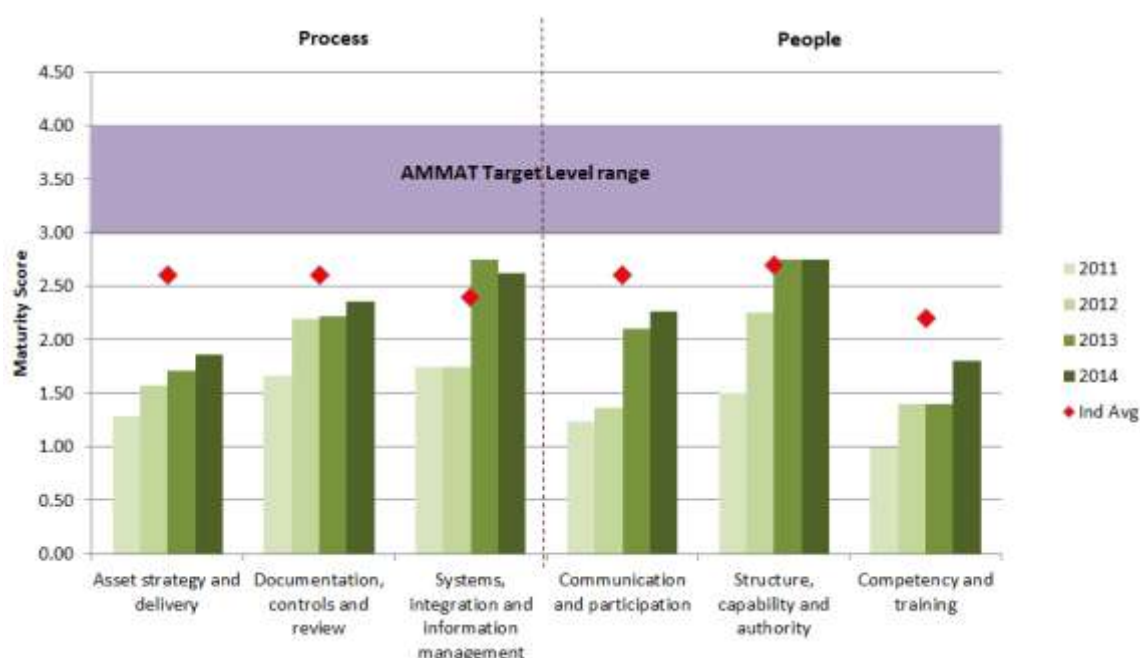


Figure 7.1 – Asset Management Maturity Assessment results (2010-2014)

The areas that will continue to receive attention in 2014/15 are listed below. It is acknowledged that some of these still include the areas that have seen improvement in 2013/14 as they are still below the target level of practice (3 - 4).

- competency and training
- asset systems and information
- asset strategy and delivery

Specifically, the aspects that require focus under the above areas include:

- performance and condition monitoring
- use/maintenance of asset risk information
- investigations (asset-related failures, incidents, non-conformities)

Aurora's website contains the full assessment report on Asset Management Maturity as per the Commerce Commission schedule requirements

The overall industry average was 2.52. Aurora's average was slightly below this at 2.28.

Figure 7.2 illustrates a detailed view on the results from the 2013/14 assessment. The full AMMAT assessment is provided in on Aurora's website. Recommended improvements from this assessment are

being incorporated into the improvement programme. The following section contains further detail on this.

Figure 7.3 provides further detail on Aurora's AMMAT score distribution compared to other the other EDB's. It is clear that a range of scores occurred between companies.

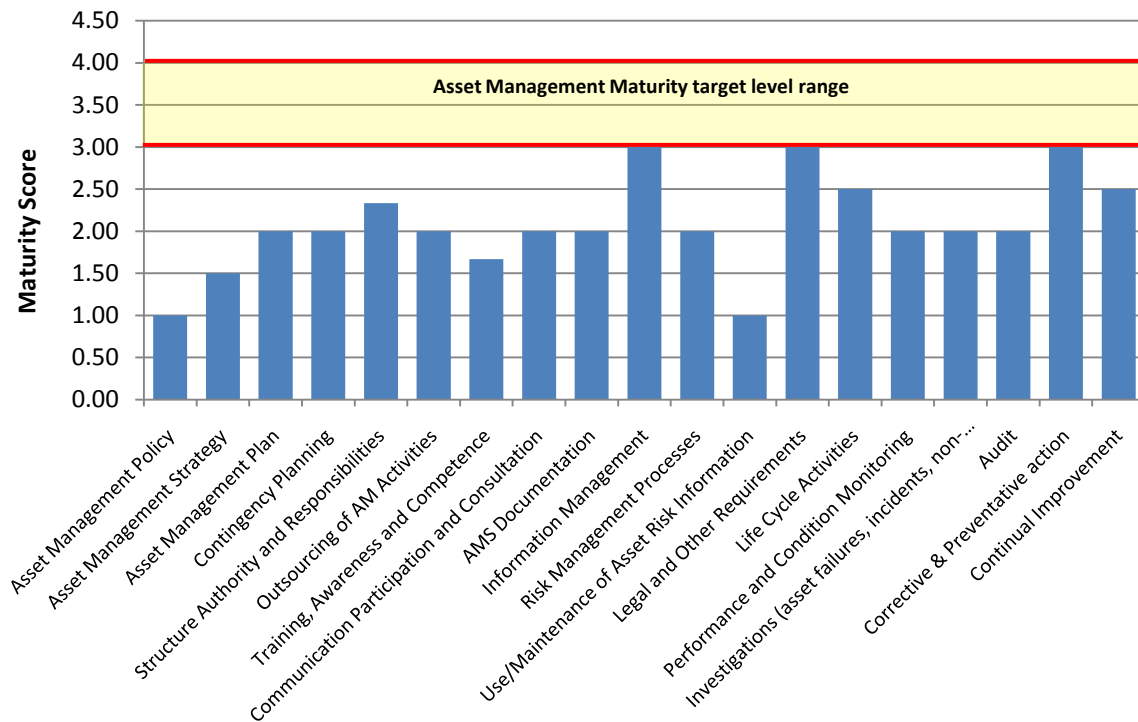


Figure 7.2 - Asset Management Maturity assessment results 2013/14.

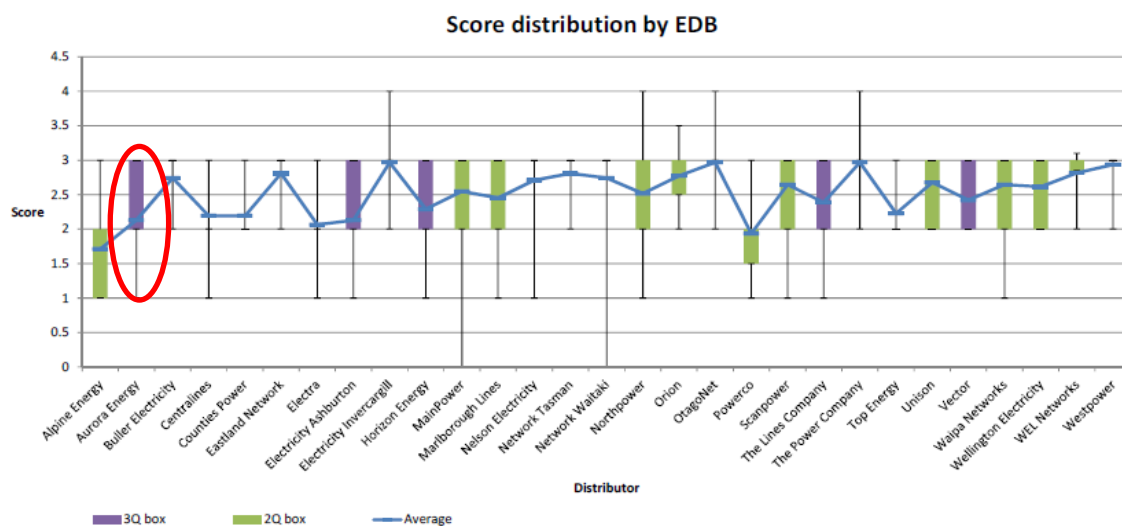


Figure 7.3 - Score distribution by EDB

7.4 Improvement Programme

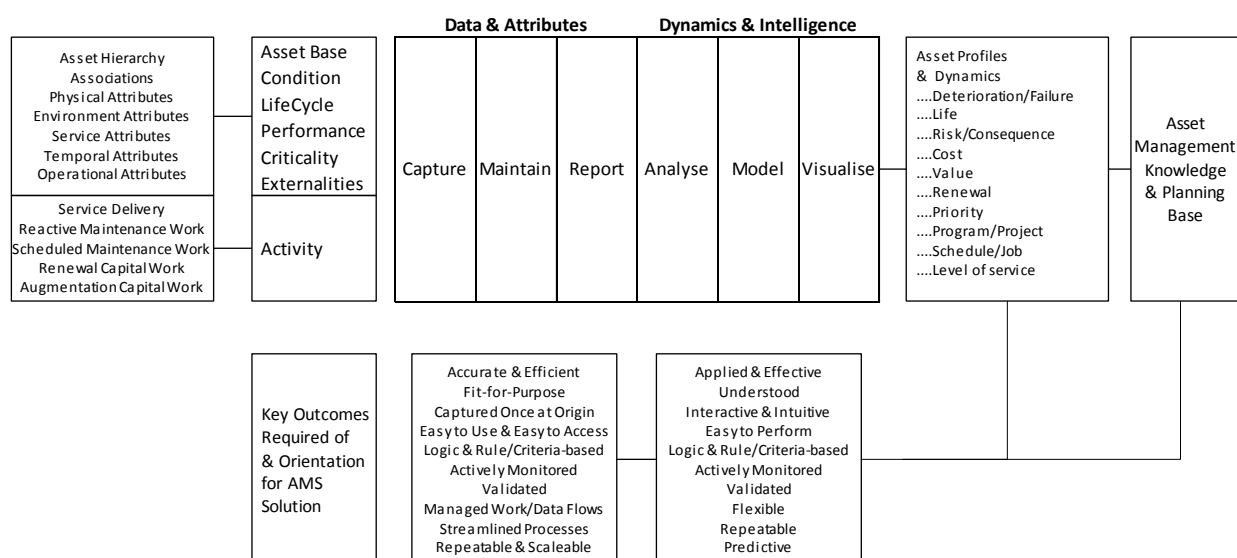
Aurora's improvement programme aims to address the gaps identified within each of these functional areas. This is a significant undertaking being the first overhaul of the underlying asset management practices for a number of years. The text below outlines the planned initiatives for the areas requiring attention as outlined in Section 7.3, being: Asset Strategy and Delivery; Documentation, Controls and Review; Competency and Training. Aurora also intends to continue to focus on developments for Asset Systems and Information. Further detail is contained in the Aurora's AMIP and action plan, as well as the AMMAT assessment provided as part of Information Disclosure on Aurora's website.

Asset Strategy and Delivery

Asset Management Policy - A draft policy has been developed and is in final form, pending any modifications from the approved 3-year strategic plan as well as outcomes from a review of the draft Asset Services Contract. The process of formalising and authorising Aurora's Asset Management Policy will be continued to completion in 2014.

Asset Management Strategy - the AMIP sets out a number of work-streams with actions to ensure that the asset management strategy is consistent with wider policies and strategies. Work-streams are in progress to ensure that the asset management strategy and policy are aligned to Aurora's strategic plan and feed into the Asset Services Contract that is currently under review. Regular customer surveys are also undertaken, and are in the process of being reviewed to confirm that the strategy is consistent with needs of stakeholders; and to ensure that the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship is taken into account appropriately.

In addition, the policy and strategy outcomes and priorities also provide the direction for the development and improvement of enabling and supporting asset management information systems, processes and practices. The diagram below examples the main aspects and dimensions being considered under the asset management system review framework.



Opportunities

To date progress on opportunities for improvements has focussed upon:

- building more quality assurance approaches into existing processes and practices to improve the completeness, currency and appropriateness of data
- commencing an "augmented intelligence" approach to the processing of data to generate value-add insights into business dynamics and performance.
- commencing the investigation of cost effective, value-add technology solutions to support and enable business go forward.

Developments in the information, communication and technology sector (ICT) provide opportunity for Aurora to consider introduction for increased levels of intelligence and performance. Emergent and proven technologies, coupled with decreasing relative technology costs, provide economically viable opportunities to better enable and support more efficient and effective asset management. Smart, easy to use and cost effective solutions will be tested in terms of their ability to enable and support :

Improved operational performance through

- capture of data once only at point of origin
(often mobile in the field)
- more efficient and robust data capture
(under a rule-based, validated process)
- improved situational awareness
(with real-time/near real-time data)
- better responsiveness

Reduced hand-offs
Reduced duplication
Right first time
Reduced administrative overhead
Improved response times

Improved strategic performance through

- more systems based approach to analysis
(making the data work hard)
- common, standards based approaches
- more easily repeatable and transferable
(cascading across processes and asset types)
- improved business knowledge
(augmented intelligence, data works hard)
- more informed planning and decision-making

Data made to work hard
Improved repeatability
Reduced duplication
Right first time
Reduced administrative overhead

A number of pilot trials of solution opportunities are planned to be progressed. Opportunities will be tested against a range of operational, tactical and strategic outcomes, including :

- implementing easy to use solutions
- reducing administrative burdens
- streamlining end-to-end processes
- facilitating the flow of information
- reducing cycle times
- improving resolution rates
- increasing productivity
- mitigating risk
- reducing lifecycle costs

Documentation, Controls and Review

While the number of policies, plans, processes and procedures for managing Aurora's network is extensive and annual audits and compliance reviews are carried out, many of the practices have not been revisited against internationally accepted practice for many years.

While Aurora has quality management processes and procedures in place to ensure any non-compliance issues are addressed systematically, review of the quality management system has highlighted areas for improvement, which are now the focus for 2014/15. For example, identification of legislative and regulatory changes occurs relatively informally and risks around authorised materials and products exist (a review of the materials purchasing and storage/supply is currently being carried out). A structured framework for managing the existing business systems and quality documentation is presently being implemented.

Use of asset risk information

Implementation of the revised risk assessment and management framework in 2013/14 has helped to develop a more robust risk-based approach to decision making and bring improvements to the use and maintenance of asset risk information and reporting. In conjunction, procedures for assessing asset condition are being reviewed; for example pole condition now includes wider features such as location sensitivity and customer criticality. As part of this work, software has been prepared to pilot trial a mobile pole inspection process. The project commenced field trials and testing in February 2014.

This work involves not simply tinkering with inspection processes but questioning the fundamental basis of the processes. This will require an extensive review across all assets and will continue with power transformers and ground-mounted switchgear in 2014/15.

Competency and Training

Core competency framework and development plans are being refined and retention of core engineering skills is recognised as key. The intention is for the improvement programme outputs to be used to identify emerging skill and competency requirements and drive co-ordinated training programmes.

Review of network performance

In addition to the above, the review of Aurora's network performance carried out by Strata Energy Consulting in 2013 (on behalf of the Commerce Commissions) highlighted 5 main aspects recommended for targeted focus and action. These are as follows:

- undertake a review of asset condition/health data to ensure that asset management decisions and plans are based on an accurate data set and that statutory disclosures are accurate;
- following the above, a review of asset strategies and planned expenditure is necessary;
- publication of a comprehensive vegetation management plan, the delivery of which is to be reported on annually to the Board;
- development of a (more detailed) strategy to address the aging 33kV subtransmission network in Dunedin;
- quantification of the expected benefits (realised and forecast) arising from Aurora's improvements in asset management methods and asset condition information.

Most of these were already captured by the asset management improvement programme and will continue in 2014.

7.4.1 Improvement Programme Monitoring

The AMIP action plan will be monitored and reviewed against SMART objectives and updated on an annual basis. The AMIP will then be adjusted accordingly (demonstrating an iterative cycle of continuous improvement), taking into account overall progress, changing business priorities, risks and affordability.

7.4.2 Summary

A formal review of asset management maturity, in advance of any stipulation by the Commerce Commission, identified the need to extensively revisit and upgrade the practices of asset management employed in managing the Aurora network. An AMIP has been established to guide implementation of processes, systems and capability referenced to internationally accepted methods. Many of the necessary structures are in early stages of definition with the detailed work of critically understanding the assets having commenced. Previously identified reinvestment in the Aurora network continues in parallel with the AMIP. Details of the extent of this work are described elsewhere in this Plan.

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
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 - Table of Guidelines for Security of Supply

(see 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.

Appendix B - Compliance Matrix

Commerce Commission – Electricity Information Disclosure Requirements 2012 (Appendix A)

CLAUSE	REQUIREMENT Commerce Commission)	AMP Section	Tables & Figures
Contents of the AMP			
3.1	Asset Management Plan summary	1.0	
3.2	Background and Objectives	2.1	
3.3	Purpose Statement	2.2	Table 2.1
3.4	AMP Planning period	2.4.1	
3.5	Date approved by Directors	Pg. 2	
3.6	Description of Stakeholder Interests 3.6.1 How interests are identified 3.6.2 What these interests are 3.6.3 How the interests are accommodated in AM practices 3.6.4 How conflicting interests are managed	2.3.2 / 3.1 2.3.2 2.4 / 3.3 2.3.2	Table 2.3
3.7	Description of accountabilities and responsibilities for AM	2.3	Table 2.2
3.8	All significant assumptions	2.4 / 2.4.1 6.4-6.6	
3.9	A description of the factors that may lead to material difference	2.4 / 2.4.1 6.6	
3.10	An overview of AM strategy and delivery	2.2-2.6	
3.11	An overview of systems and information management data	2.6	
3.12	Statement on data limitations and proposed improvements	2.6 / 5.0 / 7.0	
3.13	Description of processes used for: 3.13.1 Managing routine inspections and maintenance; 3.13.2 Planning and implementing network development projects; 3.13.3 Measuring network performance	5.5 6.0 3.2	
3.14	An overview of AM documentation, controls and review processes	2.6.2	
3.15	An overview of communication and participation processes	2.6.3	
Assets Covered			
4.1	High level description of the distribution area.	5.2	Table 5.1
4.2	Description of network configuration.	5.2 / 5.3 5.5.2-5.5.20	Tables 5.2 -5.7
Network Assets by Category			
4.4 & 4.5	Description of network assets by category	5.5	Table 5.8
Service Levels			
5.0 - 7.0	Service Levels, Performance Measures and Targets	3.0-3.3	Table 3.9
8.0 - 10	Justification for Target Levels	3.2-3.3	Table 3.9
Network Development Planning			

CLAUSE	REQUIREMENT Commerce Commission)	AMP Section	Tables & Figures
11	Detailed description of network development plans including: 11.1 & 11.2 Description of the planning criteria and assumptions. 11.3 & 11.4 Description of strategies or processes that promote cost efficiency 11.5 Description of strategies used to promote energy efficient operation of the network 11.6 Description of criteria used to determine capacity of equipment 11.7 The prioritisation methodology adopted for development projects. 11.8 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; including distributed generation and demand management 11.9 Analysis of network development options available and details of the decisions made to satisfy and meet target levels of service. 11.10 Description and identification of the network development programme and actions to be taken, including associated expenditure. 11.11 Distributed generation and related policies. 11.12 Non-network solutions and related policies.	2.4 / 6.2 6.2 6.2 6.4 6.3 / 6.5 6.6 6.6 6.4 6.2 / 6.3	Appendix A Appendix C Table 6.10 Appendix D
Lifecycle Asset Management Planning (Maintenance and Renewal)			
12	Detailed description of lifecycle asset management processes including: 12.1 Key drivers for maintenance planning and assumptions 12.2 Description and identification of routine and preventative inspection and maintenance policies, programmes, and actions to be taken for each asset category, including expenditure projections. 12.3 Description and identification of asset replacement and renewal policies and programmes or actions to be taken for each asset category, including associated expenditure projections.	5.0 2.4 / 5.5 5.4 – 5.6 5.4 – 5.6	
Non-network development, maintenance and renewal			
13	A summary description of material non-network development.		
Risk Management			
14	Details of risk policies, assessment and mitigation including: 14.1 Methods, details and conclusions of risk analysis 14.2 Strategies used to identify network vulnerabilities (to high impact low probability events) and resilience of the network 14.3 Policies to mitigate or manage risks of events identified in 14.2 14.4 Details of emergency response and contingency plans	4.0 4.4 - 4.6 4.4 - 4.6 4.7 4.7	
Evaluation of performance			
15	Details of performance measurement, evaluation, and improvement including: 15.1 Review of progress against plan, both physical and financial. 15.2 Evaluation and comparison of actual service level performance against targeted performance. 15.3 An evaluation and comparison of the results of asset management maturity assessment. 15.4 Analysis of identified gaps and identification of planned initiatives to address the situation.	3.2 3.2 3.2.1-3.2.7 7.0 – 7.3 7.3 / 7.4	Table 3.2 Figure 7.1 Figure 7.2
Capability to Deliver			
16	Describe the processes used to ensure: 16.1 The AMP is realistic and objectives can be achieved 16.2 Organisation structure and processes for authorisation and business capabilities will support implementation of the AMP.	3.4	

Appendix C - Asset Management quality control documentation

Activity	Exiting Documents
Asset Management - general	<p>QM013, Design And Development Activities QN15, Maintenance Policy QN16, Network Operation Policy QN17, Network Connections QN18, Voltage Quality QN19, System Planning QN20, Risk Management For Electricity Networks</p> <p>Connections QP1701A, Capital Investment Approval Process QP1701B, Capital Funding Requests QP1702, Capital Investment Schedules QP1703, Processing Connection Applications QP1706, Capacity Change Requests QP1709, Motor Connection Assessment QP1710, Network Connections To Street Lighting QP1711, Notice To Telecommunication Providers QP1715, Reapportionment Of Capital Contributions QP1716, Line Charge Schedules QP1719, Removal Of Metering Equipment QP1720, Distributed Generation Less Than 10kw QP1721, Sub-Transmission Cable Installation</p> <p>Voltage Control QP1801, Subtransmission Voltage Control QP1802, Voltage Complaint Procedure QP1803, HV And LV Voltage Control QP1804, Subtransmission Voltage Parameters QP1901, System Planning Procedures QP1918, Half Hour Data Loading Procedure</p> <p>Network Records QP2101, Land Record Maintenance QP2102, Relay Settings QP2104, Processing Feeder Plans QP2106, Processing Completion Notice QP2107, Cable Location Records QP2109, Network Outage Reports QP2110, Network Manuals QP2115, Filling in Completion Packages QP2116, Ripple Plant Tuning QP2117, Application for Surge Arrestors QP2118, GIS Data Entry Requirements</p> <p>GIS Electrical Data Entry Manual QP2153 – QP2180 contain various requirements specific to each asset class.</p> <p>Maintenance Procedures QP1502, SCADA Database Maintenance QP1504, Overhead Lines Inspection QP1507, Gas Cable-Leak Location QP1508, Overhead to Underground Conversions QP1509, Request to Move Aurora Works QP1510, Transformer Load Guide QP1511, Tree Near Electricity Equipment QP1512, ONAN Transformer Temperature Monitoring Maintenance QP1513, Vegetation Management QP1514, Public and Contractor Safety Services</p> <p>Maintenance Standards MS01.00, Circuit Breakers MS02.00, On Load Tap Changes MS03.00, Protection Relays MS04.00, 33kV Air Break Switches MS06.00, SCADA Analogue Testing</p>

Activity	Exiting Documents
	MS07.00, Intertrip Testing MS08.00, Ripple Control Equipment Zone MS09.00, Lead Acid Batteries MS12, Distribution Transformer Assessment and Refurbishment Maintenance Plans PN1501, Zone Substation Maintenance PN1502, Substation Maintenance, PN1503, HV & LV Lines and Cables Maintenance PN1504, Distribution Substation Maintenance PN1505, System Control Maintenance Plan Service Work Guides
Resource Management	Contractor Management Policy QP1101, Tendering and Contract Administration QP1102, Approved Supplier Schedule for the Aurora Network
Control of Work	QN12, Inspection and Testing QP1103, PC1400 & PC 1405 Work Orders and Purchase Orders QP1201, Test Report Requirements QP1202, Earth Testing and Inspections QP1203, HV Cable Testing QP1204, LV Cable Testing QP1205, Zone Sub Earth Testing QP1206, Polarity Testing QP1207, Protection Relay Commissioning Tests QP1704, Network Connection Inspection QP1705, Authorised Network Inspector Approval QP1902, Project Quality Plans

Appendix D – Network Development project list

Year 1 (2014/15)

Type	Asset Category	Project #	Short Description	2014/15
Growth	Subtransmission		3016 New Frankton 33kV GXP Feeder	
		3021 Upgrade auto transformers at Cromwell GXP		
		3216 Riverbank Road - Install 66kV cables from Riverbank Rd substation to Wanaka Sub and to UC2 line.	250	
		4149 Install 33kV circuit breaker at Omakau zone substation	20	
		4150 Install 33kV circuit breaker at Dalefield zone substation	100	
		4151 Install 33kV circuit breaker at Ettrick zone substation	120	
		4152 Install 33kV circuit breaker at Remarkables zone substation	10	
		4153 Install 33kV circuit breaker at Clyde-Earnsclough Substation	100	
		4161 Camp Hill Rd - 66kV line extension and 11kV cable	975	
		4182 Upgrade Glenorchy supply to 33 kV - land acquisition/designation & construction	540	
	Zone substations		2611 New Jacks Point zone substation	
		3019 Install 10 MVA transformers and new switchgear at Arrowtown Zone Sub.		
		3022 Riverbank Road 66kV switching and substation site - land acquisition (2629) & construction (3022)	100	
		3024 Cromwell substation upgrade - Install two new 24 MVA transformers		
		3038 Upgrade Andersons Bay substation (Tx's and switchgear)		
		3414 Upgrade Smith St Substation - new 24MVA transformers and HV switchgear		
		3437 Install 24 MVA 66/11kV transformer and 11kV switchgear at Riverbank Rd substation.		
		3438 New 66kV Switching Station at Queensberry		
		4135 Camp Hill Rd Substation build	4,510	
		4138 Subdivide Hawea land and obtain designation	50	
		4142 Establish Earthing Points at Central zone substations	15	
		4179 Upgrade Outram Zone Substation	300	
		4213 Linds Crossing - land acquisition/designation (incl line relocation)	380	
		Linds Crossing substation	2,233	
		TBC Mobile Generator (300kVA)	750	
		Omakau Mobile Substation	270	
		Fire, Security, Earthquake & Asbestos Upgrades	350	
	Distribution and LV lines		2298 Establish new Wanaka HV feeder (Golfcourse Rd)	220
		3058 New Connections Dunedin	1,145	
		3059 New Connections Central	4,583	
		3165 Wanaka - Three Parks feeder tie	600	
		3428 Install new HV feeder in Cromwell to Leitrum St	500	
		4207 Create intertie between QT5232 and QT5242 to facilitate the off loading of QT5232		
	Distribution and LV cables		3043 OH to UG Conversion Dunedin Area	600
		3044 OH to UG Conversion CODC Area	100	
		3045 OH to UG Conversion QLDC Area	375	
	Distribution substations and transformers		3061 Dunedin load growth projects (to be identified)	100
		3062 Central load growth projects (to be identified)	100	
		3200 Extra cost of Dual ratio distribution transformers	80	
	Distribution switchgear		3741 ET2 - Recloser at urban boundary	
		3743 CE195 - Recloser on Springvale Road spur		
		3744 AX168 - Recloser on Dunstan Rd spur		
		3745 AB9 - Recloser at Tomahawk		
		3746 AX168 - Recloser on Letts Gully spur	50	
		3747 Transfer of Part ET8 to new Mosgiel feeder	66	
		3748 Ettrick - Recloser on Timaburn Road spur	50	
		4137 Install voltage regulator in Jacks Point line, feeder FK7784		
	TBC QT5202 - Recloser at Closeburn			
Renewal	Subtransmission		3053 Replace Alexandra 33kV line breakers (3)	200
		3171 Replacement of Kaikorai Valley 33kV PILC cables		
		3469 Replace Ward Street 33kV gas cables		
		3470 Replace Willowbank 33kV gas cables		
		3471 Replace Smith St 33kV gas cables		
		3472 Replace Andersons Bay 33kV gas cables		
		4038 Replace Lower Shotover Intertie	250	
		4178 Replace Port Chalmers VVWE 33 kV circuit breakers	100	
		4212 Port Chalmers to Peninsular Harbour Crossing	400	
		TBC Replace Neville St 33kV gas cables	200	
Zone substations		2324 Rebuild Neville St zone substation on new site	600	
Distribution and LV lines		4204 Pole replacements - Dunedin Area	2,000	
	4205 Pole replacements - Central Area	2,000		
	TBC Castlron Pothead replacement	250		
	Replacement of JW3 switchgear			
Distribution and LV cables		2622 Underground Link Box upgrades (Dunedin)		
	TBC LV Service/Link Pillars (Central)			
Distribution substations and transformers		3031 Replacement of Distribution Transformers	250	
	3032 Replacement of Andelect (LV wall) Boxes - Dunedin	120		
	TBC Underground Substation Improvement Programme	50		
Distribution switchgear		2146 Distribution CB replacement - Great King St rectifier	120	
	3029 Replacement of Pole-mounted substations	36		
	3211 Replacement of Pacific fuses in Central network	60		
	3771 Replace KF recloser 1286R on AB4	50		
	3772 Replace one KFE recloser in Central - unit to be identified			
	3773 Replace one KFE recloser in Central - unit to be identified			
	3782 Protection of street lighting MCB's in Central			
	4184 Conversion of PC feeder (removal of Otakou auto Tx & voltage regulator)	150		
	TBC Replacement of oil-filled switchgear	120		
Other network assets		3351 Upgrade Green Island transformer breathers with Messko units		
	3353 Upgrade Arrowtown transformer breathers with Messko units			
	3354 Upgrade Cromwell transformer breathers with Messko units			
	3355 Upgrade Clyde-Earnsclough transformer breathers with Messko units			
	3753 Upgrade Dunedin GXP metering at Halfway Bush			
	3807 Replace transformer Buchholtz relays at Central zone subs	20		
	4122 Replace the HV feeder protection relays at Alexandra Zone Substation	120		
	4126 Replace the ripple injection frequency converter at Alexandra	120		
	4214 Replacement of Dunedin street lighting ripple control relays.	80		
	TBC Chorus changeovers	250		
	Replace transformer Buchholtz relays at Dunedin zone subs	30		
	SCCP P1 - New Control Room	450		
	SCCP P2 - New SCADA (+ DMS+OMS) System	1,800		
	SCCP P3 - Communication Link Upgrade	1,220		
	SCCP P4 - Central Load Control System Upgrade	150		
	SCCP P5 - Dunedin RTU Upgrade	970		
	SCCP P6 - Central RTU Upgrade	360		
	SCCP P7 - Dunedin Subtransmission Protection Upgrade	720		
	SCCP P8 - Aurora and Transpower ICCP Link	10		
	Upgrade Coronet peak transformer breathers with Messko units			
	Upgrade Willowbank transformer breathers with Messko units			
Grand Total			32,898	

Years 2 - 5 (2015/16 – 2018/19)

Project by Asset Type	Asset Category	Project No.	Short Description	2015/16	2016/17	2017/18	2018/19
Growth				17,410	14,317	12,287	15,807
Growth	Subtransmission			2,980			1,000
		3021	Upgrade auto transformers at Cromwell GXP				1,000
		3216	Riverbank Road - Install 66kV cables from Riverbank Rd substation to Wanaka Sub and to UC2 line.	2,250			
		4149	Install 33kV circuit breaker at Omakau zone substation	90			
		4150	Install 33kV circuit breaker at Dalefield zone substation				
		4151	Install 33kV circuit breaker at Ettrick zone substation				
		4152	Install 33kV circuit breaker at Remarkables zone substation	100			
		4153	Install 33kV circuit breaker at Clyde-Earnsclough Substation				
		4161	Camp Hill Rd - 66kV line extension and 11kV cable				
		4182	Upgrade Glenorchy supply to 33 kV - land acquisition/designation & construction	540			
		3016	New Frankton 33kV GXP Feeder				
	Zone substations			7,483	7,370	5,430	7,730
		2611	New Jacks Point zone substation				
		3019	Install 10 MVA transformers and new switchgear at Arrowtown Zone Sub.		220	1,980	1,980
		3022	Riverbank Road 66kV switching and substation site - land acquisition (2629) & construction (3022)	1,950	1,950		
		3024	Cromwell substation upgrade - Install two new 24 MVA transformers	250	1,500	1,500	
		3038	Upgrade Andersons Bay substation (Tx's and switchgear)		450	1,350	2,700
		3414	Upgrade Smith St Substation - new 24MVA transformers and HV switchgear				450
		3437	Install 24 MVA 66/11kV transformer and 11kV switchgear at Riverbank Rd substation.			250	2,250
		3438	New 66kV Switching Station at Queensberry				
		4135	Camp Hill Rd Substation build				
		4138	Subdivide Hawea land and obtain designation	280	280	280	280
		4142	Establish Earthing Points at Central zone substations				
		T8C	Omakau Mobile Substation				
		T8C	Mobile Generator (300kVA)				
		T8C	Fire , Security, Earthquake & Asbestos Upgrades	350	350	350	350
		4179	Upgrade Outram Zone Substation	2,700	900		
		4213	Linds Crossing - land acquisition/designation (incl line relocation)				
		4213	Linds Crossing substation	2,233			
		T8C	New Omakau substation		2,000		
		T8C	New Lauder substation				
	Distribution and LV lines			5,502	5,502	5,502	5,722
		2298	Establish new Wanaka HV feeder (Golfcourse Rd)				
		3058	New Connections Dunedin	1,100	1,100	1,100	1,100
		3059	New Connections Central	4,402	4,402	4,402	4,402
		3165	Wanaka - Three Parks feeder tie				150
	Distribution and LV cables	3428	Install new HV feeder in Cromwell to Leitrum St				
		4207	Create Intertie Between QT5232 and QT5242 to facilitate the off loading of QT5232				70
				1,075	1,075	1,075	1,075
	Distribution substations and transformers	3043	OH to UG Conversion Dunedin Area	600	600	600	600
		3044	OH to UG Conversion CODC Area	100	100	100	100
		3045	OH to UG Conversion QLDC Area	375	375	375	375
				280	280	280	280
	Distribution switchgear	3061	Dunedin load growth projects (to be identified)	100	100	100	100
		3062	Central load growth projects (to be identified)	100	100	100	100
		3200	Extra cost of Dual ratio distribution transformers	80	80	80	80
				90	90		
	Renewal						
		3741	ET2 - Recloser at urban boundary				
		3743	CE195 - Recloser on Springvale Road spur				
		3744	AX168 - Recloser on Dunstan Rd spur				
		3745	AB9 - Recloser at Tomahawk				
		3746	AX168 - Recloser on Letts Gully spur				
		3747	Transfer of Part ET8 to new Mosgiel feeder				
		3748	Ettrick - Recloser on Timaburn Road spur				
		4137	Install voltage regulator in Jacks Point line, feeder FK7784		90		
		T8C	QT5202 - Recloser at Closeburn	90			
				17,174	9,902	10,591	8,791
Renewal	Subtransmission			2,200	390	3,800	2,960
		3053	Replace Alexandra 33kV line breakers (3)				
		3171	Replacement of Kalkorai Valley 33kV PILC cables			290	2,610
		3469	Replace Ward Street 33kV gas cables				
		3470	Replace Willowbank 33kV gas cables		390	3,510	
		3471	Replace Smith St 33kV gas cables				350
		3472	Replace Andersons Bay 33kV gas cables				
		4038	Replace Lower Shotover Intertie				
		T8C	Replace Neville St 33kV gas cables	1,800			
		4178	Replace Port Chalmers WVVE 33 kV circuit breakers				
		4212	Port Chalmers to Peninsular Harbour Crossing	400			
	Zone substations			5,400	300	1,400	1,500
		2324	Rebuild Neville St zone substation on new site	5,400			
		T8C	Queenstown ZS switchboard replacement		300	1,400	
		T8C	Alexandra ZS switchboard replacement				1,500
		T8C	Willowbank substation rebuild				
		T8C	Halfway Bush ZS switchgear replacement				
		T8C	Port Chalmers ZS transformer replacement				
		T8C	Green Island substation rebuild				
	Distribution and LV lines			3,275	3,275	3,425	3,425
		T8C	Castlron Pothead replacement	250	250	400	400
		T8C	Replacement of JW3 switchgear	25	25	25	25
		4204	Pole replacements - Dunedin Area	1,500	1,500	1,500	1,500
		4205	Pole replacements - Central Area	1,500	1,500	1,500	1,500
	Distribution and LV cables			170	170	170	170
		2622	Underground Link Box upgrades (Dunedin)	150	150	150	150
		T8C	LV Service/Link Pillars (Central)	20	20	20	20
	Distribution substations and transformers			470	470	520	520
		3031	Replacement of Distribution Transformers	250	250	300	300
		3032	Replacement of Andelect (LV wall) Boxes - Dunedin	120	120	120	120
		T8C	Underground Substation Improvement Programme	100	100	100	100
	Distribution switchgear			216	216	216	216
		2146	Distribution CB replacement - Great King St rectifier				
		3029	Replacement of Pole-mounted substations	36	36	36	36
		3211	Replacement of Pacific fuses in Central network	60	60	60	60
		3771	Replace KF recloser 1286R on AB4				
		3772	Replace one KFE recloser in Central - unit to be identified				
		3773	Replace one KFE recloser in Central - unit to be identified				
		3782	Protection of street lighting MCB's in Central				
		T8C	Replacement of oil-filled switchgear	120	120	120	120
		4184	Conversion of PC feeder (removal of Otakou auto Tx & voltage regulator)				
	Other network assets			5,443	5,081	1,060	
		3351	Upgrade Green Island transformer breathers with Messko units				
		3353	Upgrade Arrowtown transformer breathers with Messko units				
		3354	Upgrade Cromwell transformer breathers with Messko units				
		3355	Upgrade Clyde-Earnsclough transformer breathers with Messko units				
		3753	Upgrade Dunedin GXP metering at Halfway Bush	45			
		3807	Replace transformer Buchholz relays at Central zone subs	20			
		4122	Replace the HV feeder protection relays at Alexandra Zone Substation				
		4126	Replace the ripple injection frequency converter at Alexandra	150			
		T8C	Replace transformer Buchholz relays at Dunedin zone subs	30			
		T8C	Upgrade Coronet peak transformer breathers with Messko units				
		T8C	Upgrade Willowbank transformer breathers with Messko units				
		T8C	SCCP P1 - New Control Room	240	200	600	
		T8C	SCCP P2 - New SCADA (+ DMS+OMS) System	1,800	1,800		
		T8C	SCCP P3 - Communication Link Upgrade	1,173	1,217		
		T8C	SCCP P4 - Central Load Control System Upgrade				
		T8C	SCCP P5 - Dunedin RTU Upgrade	670	1,040	250	
		T8C	SCCP P6 - Central RTU Upgrade	345	374		
		T8C	SCCP P7 - Dunedin Subtransmission Protection Upgrade	420		210	
		T8C	SCCP P8 - Aurora and Transpower ICCP Link	220	120		
		T8C	Chorus changovers	250	250		
		4214	Replacement of Dunedin street lighting ripple control relays.	80	80		

Years 6 - 10 (2019/20 – 2023/24)

Project by Asset Type	Asset Category	Project No.	Short Description	2019/20	2020/21	2021/22	2022/23	2023/24
				11,232	11,382	10,207	9,907	8,557
Growth				2,000	1,500			
	Subtransmission			2,000				
		3021	Upgrade auto transformers at Cromwell GXP					
		3216	Riverbank Road - Install 66kV cables from Riverbank Rd substation to Wanaka Sub and to UC2 line.					
		4149	Install 33kV circuit breaker at Omakau zone substation					
		4150	Install 33kV circuit breaker at Dalefield zone substation					
		4151	Install 33kV circuit breaker at Ettrick zone substation					
		4152	Install 33kV circuit breaker at Remarkables zone substation					
		4153	Install 33kV circuit breaker at Clyde-Earnsclough Substation					
		4161	Camp Hill Rd - 66kV line extension and 11kV cable					
		4182	Upgrade Glenorchy supply to 33 kV - land acquisition/designation & construction					
		3016	New Frankton 33kV GXP Feeder		1,500			
	Zone substations			2,375	3,025	3,350	3,050	1,700
		2611	New Jacks Point zone substation		300	1,350	1,350	
		3019	Install 10 MVA transformers and new switchgear at Arrowtown Zone Sub.					
		3022	Riverbank Road 66kV switching and substation site - land acquisition (2629) & construction (3022)					
		3024	Cromwell substation upgrade - Install two new 24 MVA transformers					
		3038	Upgrade Andersons Bay substation (TV's and switchgear)					
		3414	Upgrade Smith St Substation - new 24MVA transformers and HV switchgear	2,025	2,025			
		3437	Install 24 MVA 66/11kV transformer and 11kV switchgear at Riverbank Rd substation.					
		3438	New 66kV Switching Station at Queensberry			300	1,500	1,500
		4135	Camp Hill Rd Substation build					
		4138	Subdivide Hawea land and obtain designation					
		4142	Establish Earthing Points at Central zone substations					
		TBC	Omakau Mobile Substation					
		TBC	Mobile Generator (300kVA)					
		TBC	Fire, Security, Earthquake & Asbestos Upgrades	350	200	200	200	200
		4179	Upgrade Outram Zone Substation					
		4213	Lindis Crossing - land acquisition/designation (incl line relocation)					
		4213	Lindis Crossing substation					
		TBC	New Omakau substation					
		TBC	New Lauder substation		500	1,500		
	Distribution and LV lines			5,502	5,502	5,502	5,502	5,502
		2298	Establish new Wanaka HV feeder (Golfcourse Rd)					
		3058	New Connections Dunedin	1,100	1,100	1,100	1,100	1,100
		3059	New Connections Central	4,402	4,402	4,402	4,402	4,402
		3165	Wanaka - Three Parks feeder tie					
		3428	Install new HV feeder in Cromwell to Leitrum St					
		4207	Create intertie between QT5232 and QT5242 to facilitate the off loading of QT5232					
	Distribution and LV cables			1,075	1,075	1,075	1,075	1,075
		3043	OH to UG Conversion Dunedin Area	600	600	600	600	600
		3044	OH to UG Conversion CODOC Area	100	100	100	100	100
		3045	OH to UG Conversion QLDC Area	375	375	375	375	375
	Distribution substations and transformers			280	280	280	280	280
		3061	Dunedin load growth projects (to be identified)	100	100	100	100	100
		3062	Central load growth projects (to be identified)	100	100	100	100	100
		3200	Extra cost of Dual ratio distribution transformers	80	80	80	80	80
	Distribution switchgear							
		3741	ET2 - Recloser at urban boundary					
		3743	CE195 - Recloser on Springvale Road spur					
		3744	AX168 - Recloser on Dunstan Rd spur					
		3745	AB9 - Recloser at Tomahawk					
		3746	AX168 - Recloser on Letts Gully spur					
		3747	Transfer of Part ET8 to new Mosgiel feeder					
		3748	Ettrick - Recloser on Timaburn Road spur					
		4137	Install voltage regulator in Jacks Point line, feeder FK7784					
		TBC	QT5202 - Recloser at Closeburn					
Renewal				8,291	10,456	8,926	8,976	8,976
	Subtransmission			3,570	3,780			
		3053	Replace Alexandra 33kV line breakers (3)					
		3171	Replacement of Kaitorai Valley 33kV PILC cables					
		3469	Replace Ward Street 33kV gas cables	420	3,780			
		3470	Replace Willowbank 33kV gas cables					
		3471	Replace Smith St 33kV gas cables	3,150				
		3472	Replace Andersons Bay 33kV gas cables					
		4038	Replace Lower Shotover intertie					
		TBC	Replace Neville St 33kV gas cables					
		4178	Replace Port Chalmers WVE 33 kV circuit breakers					
		4212	Port Chalmers to Peninsular Harbour Crossing					
	Zone substations			250	2,250	4,500	4,500	4,500
		2324	Rebuild Neville St zone substation on new site					
		TBC	Queenstown ZS switchboard replacement					
		TBC	Alexandra ZS switchboard replacement					
		TBC	Willowbank substation rebuild	250	2,250	2,500		
		TBC	Halfway Bush ZS switchgear replacement			2,000		
		TBC	Port Chalmers ZS Transformer replacement				2,000	
		TBC	Green Island substation rebuild				2,500	2,500
		TBC	Mosgiel ZS transformer replacement					2,000
	Distribution and LV lines			3,525	3,600	3,600	3,650	3,650
		TBC	Castrol Pothead replacement	500	600	600	650	650
		TBC	Replacement of JW3 switchgear	25				
		4204	Pole replacements - Dunedin Area	1,500	1,500	1,500	1,500	1,500
		4205	Pole replacements - Central Area	1,500	1,500	1,500	1,500	1,500
	Distribution and LV cables			170	150	150	150	150
		2622	Underground Link Box upgrades (Dunedin)	150	150	150	150	150
		TBC	LV Service/Link Pillars (Central)	20				
	Distribution substations and transformers			620	520	520	520	520
		3031	Replacement of Distribution Transformers	400	400	400	400	400
		3032	Replacement of Ardelect (LV wall) Boxes - Dunedin	120	120	120	120	120
		TBC	Underground Substation Improvement Programme	100				
	Distribution switchgear			156	156	156	156	156
		2146	Distribution CB replacement - Great King St rectifier					
		3029	Replacement of Pole-mounted substations	36	36	36	36	36
		3211	Replacement of Pacific fuses in Central network					
		3771	Replace KFE recloser 1288R on AB4					
		3772	Replace one KFE recloser in Central - unit to be identified					
		3773	Replace one KFE recloser in Central - unit to be identified					
		3782	Protection of street lighting MCB's in Central					
		TBC	Replacement of oil-filled switchgear	120	120	120	120	120
		4184	Conversion of PC feeder (removal of Otakou auto Tx & voltage regulator)					
	Other network assets							
		3351	Upgrade Green Island transformer breathers with Messko units					
		3353	Upgrade Arrowtown transformer breathers with Messko units					
		3354	Upgrade Cromwell transformer breathers with Messko units					
		3355	Upgrade Clyde-Earnsclough transformer breathers with Messko units					
		3753	Upgrade Dunedin GXP metering at Halfway Bush					
		3807	Replace transformer Buchholz relays at Central zone subs					
		4122	Replace the HV feeder protection relays at Alexandra Zone Substation					
		4126	Replace the ripple injection frequency converter at Alexandra					
		TBC	Replace transformer Buchholz relays at Dunedin zone subs					
		TBC	Upgrade Coronet peak transformer breathers with Messko units					
		TBC	Upgrade Willowbank transformer breathers with Messko units					
		TBC	SCCP P1 - New Control Room					
		TBC	SCCP P2 - New SCADA (+ DMS+OMS) System					
		TBC	SCCP P3 - Communication Link Upgrade					
		TBC	SCCP P4 - Central Load Control System Upgrade					
		TBC	SCCP P5 - Dunedin RTU Upgrade					
		TBC	SCCP P6 - Central RTU Upgrade					
		TBC	SCCP P7 - Dunedin Subtransmission Protection Upgrade					
		TBC	SCCP P8 - Aurora and Transpower ICCP Link					
		TBC	Chorus changeovers					
		4214	Replacement of Dunedin street lighting ripple control relays.					
Grand Total				19,523	21,838	19,133	18,883	17,533