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# Asset Management Plan

APRIL 2016 – MARCH 2026



PREPARED FOR AURORA ENERGY LTD  
BY DELTA UTILITY SERVICES LTD





## **Asset Management Plan No. 23**

### **A 10 Year Management Plan for Aurora Energy Limited From 1 April 2016 to 31 March 2026**

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This issue approved by Aurora Board of Directors

**March 2016**

## 1 CHIEF EXECUTIVE OFFICER'S STATEMENT

Energy powers everyday life. We are proud to supply the electricity infrastructure that underpins the economic and social well-being of the communities we serve in Dunedin, Central Otago and Queenstown Lakes. We are also pleased to present an updated Asset Management Plan (AMP) for the period 2016-2026 which documents how we intend to protect, enhance and operate the Network while meeting agreed levels of service to our customers and stakeholders.

### 1.1 Current Performance

In the last 12 months, Aurora Energy has made substantial investments in new and replacement assets to meet growing demand and to improve our risk profile. We have continued to focus on delivering high levels of safety, reliability and customer service to the community while delivering on our Shareholder's requirement for reasonable returns. This is despite unprecedented extreme weather events testing the resilience of the network and those maintaining it. However, weather-related events are not the only challenges facing the network.

### 1.2 Meeting the Challenges

#### 1.2.1 Regulatory Impacts

As an electricity distributor, Aurora Energy operates in a highly regulated environment. That environment, and any changes in it, greatly influences our plans.

The Commerce Commission's price quality path regulation operates in five-year regulatory control periods. After developing economic models for use in determining price and quality limits in early 2014, the Commerce Commission released its draft default price-quality paths for consultation in July 2014. The Commerce Commission then finalised price and quality settings for the next five years for 16 electricity distributor's including Aurora Energy in November 2014. Aurora Energy's maximum allowable revenue was set at \$56.5 million from 1 April 2015.

This reduction of 4.3 percent from last year, represented an improved outcome compared to the draft determination of a reduction of 6.5 percent, and includes the effect of a reduction in the weighted average cost of capital (or WACC) used for regulated businesses from 7.60 to 7.19 percent. For the subsequent four years ending 31 March from 2016 to 2020, Aurora Energy will only be allowed to increase pricing by a rate equivalent to the Consumer Price Index (CPI).

The Commerce Commission has made changes to their forecast and economic models as a result of submissions by Aurora Energy and other lines businesses. The outcome however, means that approximately \$6.5 million of planned work will not be compensated for in pricing over the regulatory period. Aurora Energy's forecast operational expenditure allowance increased by 3.0 percent, only partially reflecting increased expenditure on vegetation and pole remediation that commenced in FY14 and continues unabated.

The quality path remains similar to that which has applied in the previous regulatory period, with SAIDI and SAIFI maintained as the quality of supply measures, quality limits determined by reference to historic reliability performance, normalisation for maximum event days, and the overarching requirement to comply with the quality path for a minimum of two out of three years.

The Commerce Commission's general approach applies a sinking lid to quality standards by setting compliance limits with reference to a historical average. Like all sinking lid mechanisms, this could ultimately result in targets that are unsustainable (unless offset by an exponential increase in reliability investment). First quartile performers (including ourselves) will be affected the earliest in respect of compliance difficulties with reducing limits.

Aurora Energy's investment profile significantly influences the extent of planned outages required on the network. These factors, and more stringent health and safety practice involving greater use of de-energised work, could ultimately result in quality targets that are unsustainable. A customised price-quality path (CPP) remains an option for Aurora should it consider that an alternative price-quality path would better meet its particular circumstances (including a quality-only CPP).

### 1.2.2 Emerging Technologies

The emergence of new technologies, new energy sources and changing consumer demands such as local solar and wind generation and grid-connected battery storage are also challenging all participants in the energy sector to re-evaluate their future investment decisions, the regulatory framework and customer relationships. In coming years, the challenge will deepen for electricity networks to maintain an acceptable reliability and quality of supply for its consumers in the face of these emerging technologies and changing usage patterns.

While the direct impact of these trends remains relatively modest for now, over the long term the pace of change is expected to accelerate, pushed by consumer choice and the increasing economic viability of technologies in energy storage, generation and transport. Indeed in the near term, we expect overall energy demand to remain stable or increase modestly across the Aurora Energy network. The picture is similar to recent years with flat or declining energy demand in Dunedin (relatively static population and economic activity levels) and increasing demand in Central Otago (from irrigation projects and a growing population).

Nevertheless Aurora Energy is working to identify the most efficient means of meeting the new and changing infrastructure requirements that consumer investment in new technologies will place on the existing electricity system. A mix of conventional network investments and smart technology investments are likely to be necessary.

Realising the benefits of new technologies also requires us to invest in 'enabling' systems early in the planning period. As part of a major project to modernise our network management, control and communication systems, we will complete the first stage of a new advanced distribution management system and combined control centre this year.

We are also taking part in initiatives to promote the uptake of electric vehicles in New Zealand under the Drive Electric banner, establishing charging infrastructure at key locations on State Highway One, including on the Aurora Energy network.

## 1.3 Summary

Over the next 10 years, we plan to outlay total expenditure of \$417M to secure the future reliability of the network for our consumer and the communities we supply. This investment will support the achievement of challenging reliability targets and permit further reductions in network-related risk.

We hope you find the Plan informative and welcome any comments or suggestions on it which can be emailed to [Steve.Sullivan@thinkdelta.co.nz](mailto:Steve.Sullivan@thinkdelta.co.nz)

Grady Cameron  
**Chief Executive Officer**

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## 2 BACKGROUND AND OBJECTIVES

### 2.1 Planning Period

This Asset Management Plan looks ahead for the 10 years from 1 April 2016. While it is designed to be compliant with the requirements set out in the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 it goes beyond being just a regulatory document.

The AMP is a 'live' document and consequently will change over time as new information is incorporated and our approach to asset management is refined to ensure we are continually delivering the best outcomes for our stakeholders.

As might be expected the first five years of the AMP are based on detailed analysis of stakeholder expectations, demand forecasts and asset information resulting in a relatively high degree of accuracy. The latter period of the AMP is progressively less certain and is suitable for provisional planning purposes only.

### 2.2 Purpose of the AMP

This AMP documents the asset management practices Aurora uses to maximise the life cycle benefits and protect the long term value of its assets. It describes how we are going to protect, enhance and operate Aurora's network while meeting the communities need for reliable energy and our shareholders need for reasonable returns.

Our AMP also provides:

- visibility of the level of performance of the network;
- visibility of the risks Aurora's network faces, and systematic processes in place to mitigate those risks;
- guidance on asset management activities to our contractor;
- visibility of forecast investment programmes to external users of the AMP; and
- evidence of continuous improvement in our asset management practices.

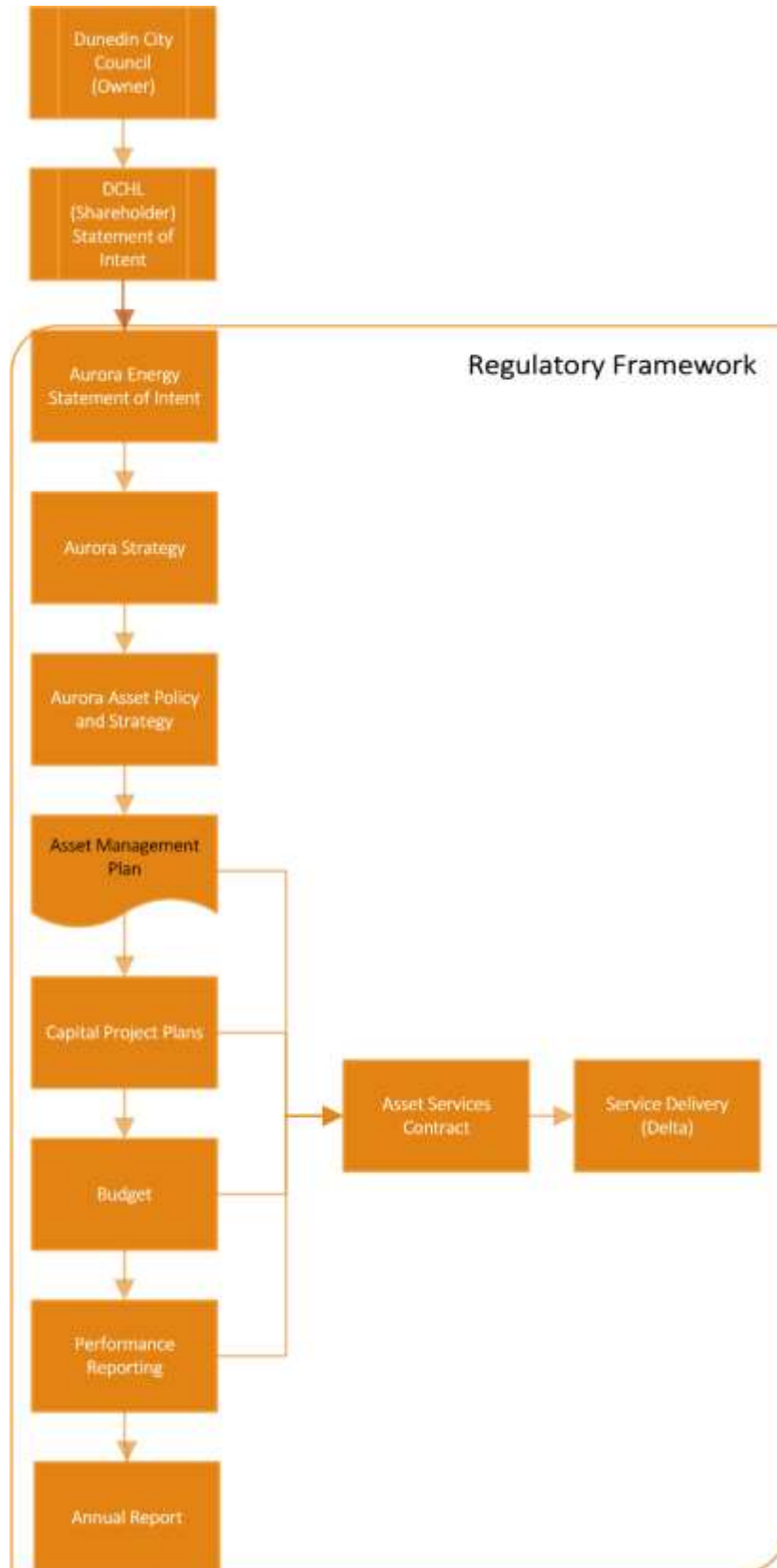
### 2.3 Business Activities, Goals and Objectives

Aurora Energy Limited is an electricity distribution business formed in 2003 as a wholly owned subsidiary of Dunedin City Holdings Limited. It is predominantly focused on the distribution of electricity to Dunedin city and Central Otago. Aurora Energy is unique among New Zealand electricity distribution businesses as it is solely an asset owner, with management and operations fully outsourced to its sister Company Delta Utility Services Limited.

Our business activities are channelled by our vision statement which 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."

Figure 2-1 Illustrates the cascade from Aurora's Statement of intent through to the Annual Report and provides context for how the different documented plans and business processes relate to one and other.

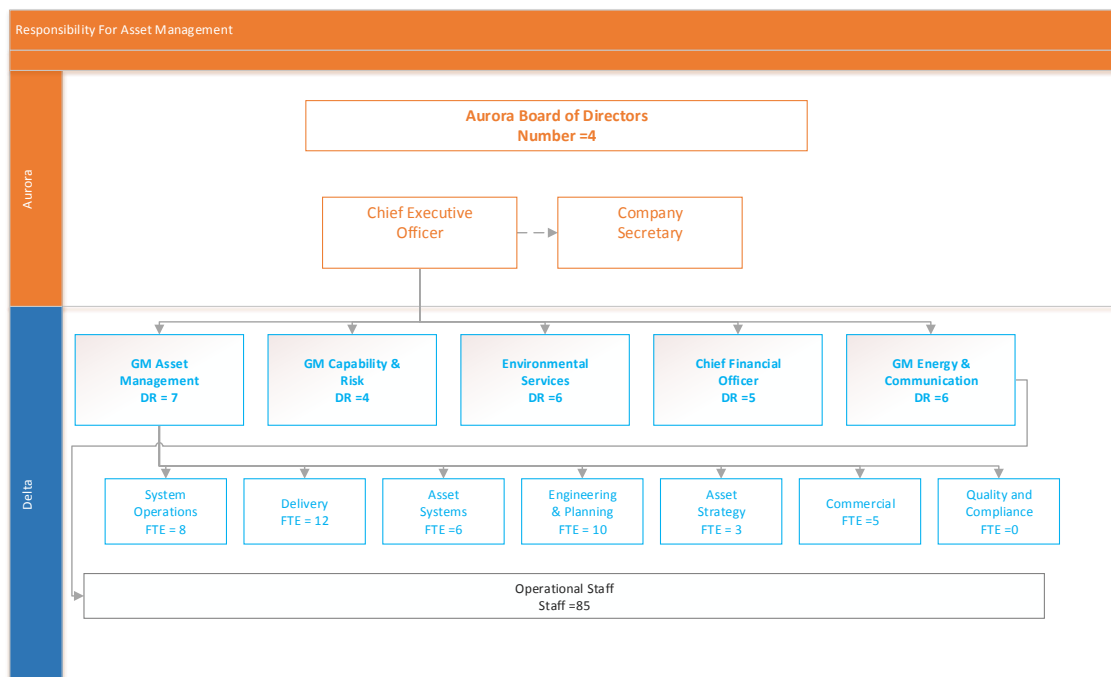


**Figure 2-1 Plans, Functions and Processes Covered by Asset Management System**

## 2.4 Accountabilities and Responsibilities for Asset Management

The senior level organisation structure for asset management is provided Figure 2.2 below. Aurora has contracted asset management to Delta under a performance-related contract that was renewed for a further 10 years on 1 July 2007. This contract is currently being reviewed to ensure it is fit for purpose and delivers the most cost efficient outcome for our stakeholders and customers.

The primary responsibility for the asset management of the electricity distribution network lies with the General Manager Asset Management and his six direct reports. The primary service provider function for the electricity network is fulfilled by the Delta Energy and Communications team working under the General Manager Energy and Communications.



**Figure 2-2 Asset Management Organisational Structure**

### 2.4.1 Governance

At Aurora, overall governance and decision-making rests with the Board of Directors and CEO. Like most organisations, support is provided by a group of General Managers each responsible for a functional area of the organisation. Core responsibilities include:

- determining the organization's strategic direction and focus;
- provide advice and counsel to executive leadership;
- determine the organisation's long-term goals and outcomes;
- enable the organisation to secure the resources necessary to implement its programs and services to accomplish its mission, vision, and goals;
- establish policies to safeguard and guide the use of resources and assets, including appropriate management of risk; and
- ensure clear, accountable performance management.

### 2.4.2 Executive

The primary responsibility for the management of the electricity network and preparation of the AMP lies with the Asset Management group. In broad terms, this group is responsible for:

- day-to-day operational management of the network;
- maintaining current and accurate information about the extent and performance of the network and assets;
- preparing detailed engineering designs for projects;
- ensuring a high quality Asset Management Plan is prepared and completed in line with industry best practice and meets necessary disclosure requirements;
- ensuring the electricity network is technically efficient, meets customer requirements for reliable, safe energy and is practical to operate;
- development and implementation of integrated asset management systems;
- setting electricity network security policies and standards;
- ensuring that asset investment provides an adequate and sustainable return to the Company's shareholders;
- monitoring technological and demand trends, assessing their potential impact and devising strategies to effectively deal with them in the network development plan;
- maintaining strategic relationships with local government bodies to support the long-term protection of our assets;
- responsible for efficient project and contract management to deliver the annual works programme - including new capital, renewals and maintenance projects; and
- managing Aurora's contracts with energy retailers and directly connected consumers, Transpower, distributed generators, embedded network owners, use-of-system pricing policies, regulatory matters, the billing of line charges and outage management.

### 2.4.3 Field Operations

The Energy and Communications team at Delta is responsible for the maintenance of the electricity network and for carrying out the physical work in the field. The Energy and Communications team interacts with Asset Management in number of important areas including:

- providing asset information that enables accurate timely analysis of condition and performance;
- assisting in the establishment of asset renewal and refurbishment programmes;
- undertaking the physical work involved in replacement and renewal of core assets (examples include poles, transformers, cross-arms and conductors);
- investigating asset failures;
- providing the initial response to faults and service interruptions; and
- implementing asset management policies, standards and scopes.

### 2.4.4 Outsourcing

Where the capability and resource exists, all field delivered works are managed through Aurora's principal service provider (Delta Utility Services Ltd). Control processes, including formal project specifications, audits, practical completion packages and KPI management, are used to assure work quality.



Where a service is required that Delta does not or cannot offer within its portfolio, Aurora will outsource to other providers. Examples of where this can occur include detailed design for major zone substations, procurement of large scale electrical equipment and civil earth works.

## 2.4.5 Other

Aside from the Asset Management and Energy and Communications teams, the Asset Management function is underpinned by:

- Capability and Risk – which provides health, safety, human resource management support, training and development, recruitment and performance management support;
- Tree Services – a separate dedicated Tree Services business unit was established within Delta in 2015, focussed on delivering efficient vegetation management services for Aurora and across the business; and
- Corporate Services – which provides financial accounting, management accounting, administration, treasury, property and information services (IT) support.

## 2.5 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.

Our key stakeholders along with their key interests and how they have been identified are detailed in Table 2.1.

**Table 2-1 Stakeholder Interests**

Stakeholder	Key Interests	How Stakeholder Interests are Identified
<b>Shareholder and the Board</b>	<ul style="list-style-type: none"> <li>• Safety of employees, contractors and public</li> <li>• Adequate, stable, and secure return on investment</li> <li>• Prudent risk management</li> <li>• Compliance</li> <li>• Accurate forecasts</li> <li>• Strong governance</li> <li>• Good corporate citizenship</li> </ul>	<ul style="list-style-type: none"> <li>• Board meetings</li> <li>• Shareholder briefings</li> </ul>
<b>Contractors which provide services to Aurora</b>	<ul style="list-style-type: none"> <li>• Safe working environment</li> <li>• Maintenance and design standards</li> <li>• Consistency</li> <li>• Maintaining good contractual relationships</li> <li>• Clear forward view of work</li> <li>• Continuity of work</li> </ul>	<ul style="list-style-type: none"> <li>• Contractual requirements</li> <li>• Quality documentation feedback</li> </ul>
<b>Electricity consumers</b>	<ul style="list-style-type: none"> <li>• Reasonable prices</li> <li>• Security of supply</li> <li>• Information on faults</li> <li>• Timely response to complaints</li> <li>• Safe and reliable supply of electricity</li> </ul>	<ul style="list-style-type: none"> <li>• Consumer satisfaction surveys</li> <li>• Direct liaison</li> <li>• Safety advertising</li> </ul>

Stakeholder	Key Interests	How Stakeholder Interests are Identified
	<ul style="list-style-type: none"> <li>Quality of supply</li> <li>Input into new-connection policies</li> </ul>	
<b>Electricity retailers and distributed generators</b>	<ul style="list-style-type: none"> <li>Line charges</li> <li>Reliability of supply</li> <li>Quality of supply</li> <li>Contractual arrangements</li> <li>How we manage customer complaints</li> <li>Ease of doing business with us</li> </ul>	<ul style="list-style-type: none"> <li>Use-of-System Agreements</li> </ul>
<b>Employees of Delta (main contractor)</b>	<ul style="list-style-type: none"> <li>Health and safety</li> <li>Creative work environment</li> <li>Career opportunities</li> </ul>	<ul style="list-style-type: none"> <li>Internal communications</li> </ul>
<b>Government / Regulator</b>	<ul style="list-style-type: none"> <li>Economic efficiency</li> <li>Compliance with statutory requirements</li> <li>Accurate and timely information</li> </ul>	<ul style="list-style-type: none"> <li>Submissions</li> <li>Relationship meetings</li> </ul>
<b>Landowners</b>	<ul style="list-style-type: none"> <li>Safety</li> <li>Easement conditions</li> <li>Access for maintenance/repair</li> <li>Compensation for significant interference</li> </ul>	<ul style="list-style-type: none"> <li>Direct communication and consultation</li> </ul>
<b>Property developers</b>	<ul style="list-style-type: none"> <li>New-connection policies</li> <li>Timely network expansion</li> </ul>	<ul style="list-style-type: none"> <li>Direct communication</li> </ul>
<b>Territorial authority</b>	<ul style="list-style-type: none"> <li>Public safety</li> <li>Minimising of environmental impacts (RMA)</li> <li>Support for economic growth</li> <li>Local economic development</li> <li>Control of assets in road reserve</li> <li>Conversion of overhead to underground</li> </ul>	<ul style="list-style-type: none"> <li>Direct communication</li> <li>Submissions</li> <li>RMA applications</li> </ul>
<b>NZ Transport Agency</b>	<ul style="list-style-type: none"> <li>Control of assets in road reserve</li> <li>Safety issues such as hedges on Aurora-owned land</li> </ul>	<ul style="list-style-type: none"> <li>Direct communication</li> </ul>
<b>Transpower</b>	<ul style="list-style-type: none"> <li>Reliability of supply</li> <li>Investment for growth</li> </ul>	<ul style="list-style-type: none"> <li>Direct communication</li> <li>System operator communication</li> </ul>
<b>Media</b>	<ul style="list-style-type: none"> <li>News, background information</li> </ul>	<ul style="list-style-type: none"> <li>Direct communication</li> </ul>

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

- network growth and development plans;
- comprehensive asset replacement strategies;
- developing solutions to address the worst performing areas of the network;
- implementation of security standards reflecting consumers' needs and expectations;
- safety plans;
- audit programmes;
- compliance with regulatory and legal frameworks;
- addressing quality of supply issues in a timely manner;
- optimisation of capital and operational expenditures;
- maintaining a sustainable business model
- provision of meaningful, accurate and timely information; and
- continuously striving to improve the quality of our service.

### 2.5.1 Managing Potential Conflicts

If a conflict between stakeholder interests is identified, then we adopt a scaled resolution process to suit the issue and the stakeholder concerns. 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.

## 2.6 Planning Assumptions

### 2.6.1 Significant Assumptions

#### 2.6.1.1 Population growth and energy demand

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). Demand growth remains a key investment driver for the electricity distribution network. Aurora's 5-year system maximum demand growth forecast for Dunedin is 0.6% p.a. and for Central is 2.0% p.a.

For both 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 2000s. Peak demands (in winter) are driven by school and public holidays, and associated ski field operations.

More recently, 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. Indeed, the impact of irrigation has become the dominant influencing factor on summer peak and this 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.

### 2.6.1.2 Service level targets

Our consumers have shown that they expect a reliable and secure supply of electricity and, indeed, Aurora remains a first quartile performer when viewed at the intersection of price and quality using the most readily available cost of delivery metrics. Consultation over many years tells us that consumers are satisfied with the long-term level of service we provide, favouring lower prices over a more reliable service.

As a result, we have set our annual targets for SAIDI and SAIFI to reflect average historical performance. After normalisation, this is approximately in alignment with both the limits determined by the regulator and the expectations of our customers.

### 2.6.1.3 Inflation assumptions

The key assumptions for our cost forecasts are discussed in section 7 where all dollars are in constant dollars and no allowance has been made for CPI adjustments, changes in foreign exchange rates, or local labour, plant and material rate changes.

## 2.6.2 Potential Uncertainties in Key Assumptions:

### 2.6.2.1 Edge technologies

"Edge technology" refers to end-customer investment in new technologies with a potentially large impact on the power system from both new sources of supply such as solar photovoltaic, and demand such as electric vehicles and distributed storage. Aurora, like other electrical distribution businesses, is facing significant uncertainty with regard to the potential uptake of these technologies which pose different challenges and opportunities as they drive changes in consumption patterns, customer behaviours and the operational management of the networks themselves.

Predicting the speed of uptake of such technologies is inherently challenging and is further complicated by our ability to deploy smart solutions as soon as they become available. In the first 3 years of this plan we have adopted a mostly conventional approach installing new assets as and when the network requires reinforcement.

In the later part of the plan we expect to adopt a combination of traditional asset and new technology solutions. By adopting this approach and investing a little more in the network today we hope to create enough flex in the network to cope with the potentially disruptive impact of new demand side technologies. Given the potentially high consequences associated with Edge Technologies we rate this uncertainty as moderate.

### 2.6.2.2 Embedded generation

We have assumed no larger scale generation connections within the 10 year planning period. We therefore rate the impact of this uncertainty on the plan as low.

### 2.6.2.3 Irrigation

While much of the growth in Central has been driven by the rapid demand for irrigation there is significant uncertainty surrounding how enduring this growth will be given the limited irrigable land, the impact of climatic changes on inflows to the area and fluctuating global dairy prices. We therefore rate the impact of this uncertainty on the plan as moderate.

## 2.6.2.4 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 connection growth in Dunedin for 2016/17 will not significantly change from status quo; and in Central, development is likely to continue at a steady pace, particularly commercial and residential development in the Queenstown Lakes District. A decline in the rate of new irrigation connection may be anticipated, especially in the Upper Clutha, as significant tracts of irrigable land have now been serviced. Additionally, the economic climate for Dairy is currently unfavourable, which may further slow the pace of irrigation developments. The forecast for customer connections is illustrated in Table 2.2. The budgeted annual expenditure is presented in Section 7.

**Table 2-2 Forecast Consumer Connections**

	2016	2017	2018	2019	2020	2021
<b>Dunedin</b>	54,452	55,027	55,287	55,549	55,809	56,070
<b>Central Otago</b>	31,729	32,436	33,093	33,751	34,409	35,069
<b>Te-Anau</b>	100	106	109	113	117	121
<b>Total</b>	86,281	87,569	88,489	89,413	90,335	91,260

## 2.6.2.5 Service Levels

### 2.6.2.5.1 Quality standards

Compliance with the quality path is expected to be an increasingly difficult proposition over the coming years. The manner in which the quality standards are set by the Commerce Commission is expected to have a material impact over time. The Commission's general approach applies a sinking lid to quality standards by setting compliance limits with reference to a historical average. For the 2015 reset of the default price-quality path for non-exempt distributors, the average was calculated over a 10-year reference period. Accordingly, where a distributor's performance is better than the quality limits, over the reference period, they are 'rewarded' with lower reliability limits that they must comply with.

### 2.6.2.5.2 Investment profiles

Aurora noted in its 2014 submission on proposed quality limits for the 2015 to 2020 regulatory period that "the quality target reset mechanism tends to apply a "sinking lid" that ratchets up service quality requirements over time. Like all sinking lid mechanisms, this could ultimately result in targets that are unsustainable unless offset by an exponential increase in reliability investment.

As noted above, Aurora's investment profile influences the extent of planned interruptions on the network. The principal activities being planned and undertaken by Aurora over the next few years are pole replacements, vegetation management (which both commenced in earnest in 2013) and conductor replacements.

Whilst, as discussed above, the calculation of compliance limits are based on a historical average and therefore inherently factors in an allowance for planned interruptions, the challenge for Aurora is that its current and intended level of planned interruptions is more than 60% greater than the average duration of planned interruptions over the reference period used to set the compliance limits (14.10 minutes).

Although the Commission has introduced a 50% weighting on planned interruptions for the period 1 April 2015 to 31 March 2020, this has no material effect on the compliance limits, since the weighting is factored into the limit calculations. At best, the 50% weighting provides Aurora with some additional flexibility to determine which planned events proceed and which might be deferred, as reliability performance approaches the compliance limits.

## 2.6.2.5.3 Health and Safety and Risk

Increased focus on managing health and safety risks, driven in part by the Governments "Working Safer" reforms, is also likely to impact on reliability performance in future years. It is possible that some "reliability friendly" work methodologies, such as live working, could become restricted as risk tolerance is driven lower.

## 2.6.2.6 Pricing Methodology

Aurora's pricing methodology has been stable, in terms of its pricing design, for many years. Archived copies of the pricing methodology demonstrate a mix of volumetric pricing for domestic connections, and capacity-based pricing for other connections. A review of the methodology is currently underway which seeks to address some of the developing / maturing technology issues facing distributors and the impact of regulatory constraints such as the Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (LFC regulations).

## 2.6.3 Potential Differences - Prospective Information and Actual Outcomes

It is important to recognise that there is a degree of uncertainty associated with any future forecasts or predictions over such planning timeframes. The following factors may lead to material differences between our forecasts and actual outcomes:

- material changes in local demand could lead us to change the timing of network projects;
- material differences in detailed design costs and exchange rates may influencing the economic viability of some projects. If higher costs are anticipated, some projects may be delayed, swapped or even abandoned;
- changes in the regulatory framework;
- one or more large energy consumers may connect to our network requiring specific network development projects;
- facilitating the rollout of a third party communications network on our overhead network could lead to resourcing issues and in the short term labour cost increases; and
- major equipment failure, storms and/or a major natural disaster may impact on our network requiring significant response and recovery work. This may delay some planned projects.

## 2.7 Aurora's Asset Management Policy

Our Asset Management Policy, which underpins our Asset Management framework, states that when managing our assets we will demonstrate our commitment by:

- embedding a strong safety culture continuously striving to reduce harm to employees and members of the public;
- providing a service that is cost effective and appropriately balances risk and performance;
- providing a distribution network that is secure, reliable and sustainable both now and for future generations;



- identifying, assessing and managing risk based upon the ISO 31000 standard;
- ensuring our investment strategies are based on maximising the life cycle benefits and protecting the long term value of our assets;
- maintaining compliance with all relevant legislative, regulatory and industry standards;
- making asset management decisions that are based on asset knowledge that is meaningful accurate and timely; and
- exhibiting an unrelenting commitment to continuous improvement, quality and application of best practice asset management principles.

## 2.8 Asset Management Drivers

The policy can be distilled into four broad Asset Management Drivers that define the need, priority and scope for asset management practices within Aurora. These are:

### 2.8.1 Safety Performance

We are committed to a safe and healthy work environment for our employees, contractors and the communities in which we operate; therefore, our aim is to ensure:

- zero fatalities;
- zero injuries causing permanent loss of bodily function;
- declining harm to people; and
- we are taking all practicable steps to ensure our assets do not represent a significant risk of serious harm to any member of the public.

We recognise the aspirational nature of our safety objectives particularly given Aurora operates in a high risk industry. However, we are committed to sending “Everyone Home Safe, Every Day”. In this context good is not good enough and we must continually strive for excellence.

### 2.8.2 Meeting Customer Service Levels

Aurora is committed to providing a broad range of service levels for all stakeholders. These service levels cover aspects such as safety, capacity, reliability, restoration of supply and technical efficiency. Our aim is to not just met customer expectations but continuously strive to exceed them.

### 2.8.3 Shareholder Returns

Aurora Energy's revenue is derived from its capacity to deliver energy – more energy or capacity equates to more revenue. Aurora manages its assets to meet Shareholder requirements for reasonable returns on investment.

### 2.8.4 Compliance

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. Associated documentation includes, but is not limited to:

- Electricity Act (1992);
- Building Act (2004);
- Electricity Industry Act (2010);
- Public Works Act (1981);
- Electricity (Safety) Regulations (2010);
- Health and Safety in Employment Act (1992);
- Electricity (Hazards from Trees) Regulations 2003;
- Health and Safety in Employment Regulations (various);
- Electricity Distribution Information Disclosure Determination 2012;
- NZ Electrical Codes of Practice;
- Civil Defence and Emergency Management Act (2002);
- Local Government Act (2002); and
- Resource Management Act (1991).

### **2.9 Planning priorities**

Given our Asset Management Drivers our key planning priorities are:

- ensuring safety performance remains our top priority for our employees, contractors and the public;
- managing asset capacity in Central Otago;
- continuing to plan, replace and/or modify aging high risk network Infrastructure;
- continuing to ensure our asset knowledge is meaningful accurate and timely;
- innovation to support delivery of the Asset Management Plan; and
- increased security around substations and equipment.

## 2.10 Aurora's Asset Management Process

Figure 2-3 shows the high level asset management process employed by Aurora.

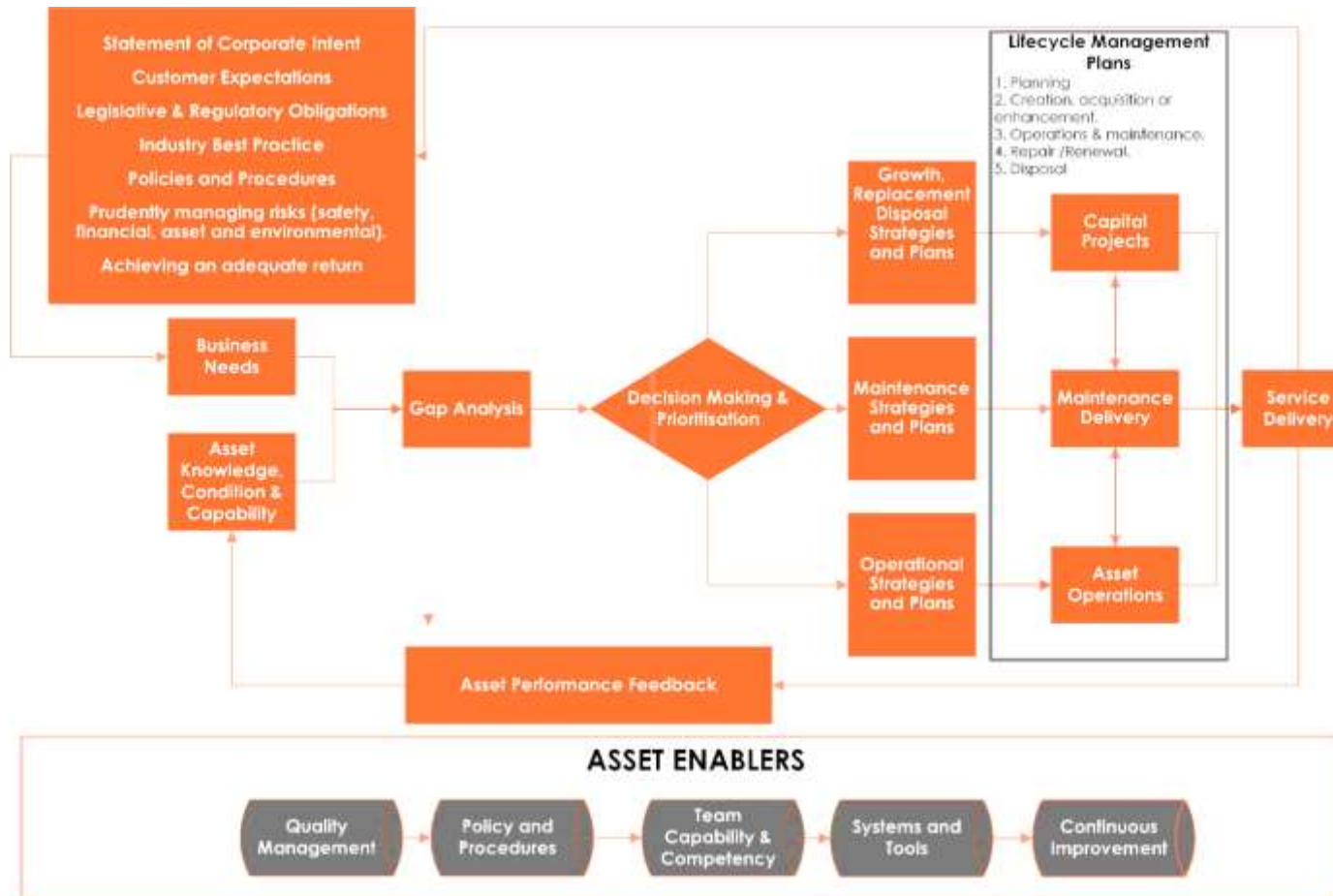


Figure 2-3 Aurora's Asset Management Process

Aurora's approach to asset management comprises six core functions underpinned by five key enablers. The six core functions are:

### 2.10.1 Understanding the Needs of the Business

In broad terms, the business requirements for the management of our distribution assets are:

- compliance with all legislative and regulatory requirements, all internal policies and procedures and application of industry best practice;
- exceeding the expectations of our customers;
- prudently managing risks (safety, financial, asset and environmental); and
- achieving an adequate return on investment for our stakeholders.

### 2.10.2 Understanding Asset Performance, Condition and Capability

Aurora's asset management team structure comprises roles and responsibilities that are focussed on ensuring that a comprehensive understanding of asset performance, condition and capability is well understood. The provision of credible information is critical to ensuring that the asset management plan is well informed.

### 2.10.3 Gap Analysis and Prioritisation

The gaps between the needs of the business and performance, condition and capability of the assets are identified, assessed and prioritised. The prioritisation is driven by a prudent trade-off between the management of risk, financial constraints and plant performance.

### 2.10.4 The Development of Strategies to Address the Gap

Maintenance, Operating and Development strategies are created to address the gap between what the business needs and the current state. The underlying plans and initiatives to implement these strategies then form the basis for the Asset Management Plan.

- growth, replacement and disposal strategies define the major capital works to be undertaken on the existing asset base to enhance performance, maintain compliance, extend the cost effective operational life of the assets and where appropriate retire and dispose of assets;
- *maintenance strategies* define the approach to maintenance and adherence to best practice principles that will maximise performance for the lowest possible lifecycle cost; and
- *operating strategies* define how the assets will be operated to maximise revenues based on their capability and any constraints that may exist.

### 2.10.5 Asset Lifecycle Management

Asset lifecycle management includes all those activities that are required to execute the asset management strategies and plans and generally comprises:

- design;
- construction and installation;
- commissioning;
- maintenance;
- operational management;
- implementation of renewal and upgrade works; and
- Retirement and disposal

### 2.10.6 Providing Continuous Feedback to Enhance Performance

Continuous feedback on asset management performance (financial, people, H&S, compliance and assets) is provided which drives continuous improvement. This ensures that all underlying activities continue to be appropriately directed, managed and controlled to deliver the business outcomes required.

### 2.10.7 Asset Management Enablers

The core asset management functions are underpinned by a number of enablers, which include:

- quality management;
- implementation of best practice tools, systems and processes;
- well-developed policies, procedures and documentation;
- the deployment of capable and competent teams; and
- a culture of continuous improvement.

## 2.11 Asset Management Systems and Information

Our information Technology mission is to improve capability through consolidation, integration and automation of our systems to better support 'end to end' business process and provide accurate data.

Our core systems from an asset management perspective are our:

- 1) Network Management system
  - a) advanced Distribution Management System (ADMS)
  - b) network monitoring system (SCADA)
  - c) outage management system (OMS)
- 2) Geographic information system (GIS)
- 3) Works management system
- 4) Mobile solutions (Xivic)
- 5) Financial management information system (SAP)
- 6) Business management system (QPulse)
- 7) Network connections management (Gentrac)
- 8) Vehicle tracking (Smartrac)

### 2.11.1 Network Management System (SCCP)

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 major upgrade of our Network Management system is underway and due to be completed in 2019. This upgrade includes new control room arrangements, new SCADA (supervisory, control and data acquisition system) incorporates a new ADMS and OMS, new communication links between control rooms and substations, new remote terminal units at each substation, new load control equipment, subtransmission circuit protection equipment and direct communication links between Aurora and Transpower.

### 2.11.2 Asset Data

The majority of our primary asset information is currently held in our Geospatial Information System (GIS). We hold information about our network equipment from GXP connections down to individual LV poles with a high level of accuracy.

Data quality has improved over time primarily as a result of an audit of the master data in 2013/2014 which highlight significant gaps and since then the application of continuous improvement techniques.

Aurora also uses Xivic by Adapt to store, analysis and report on pole and vegetation data.

### 2.11.3 Works Management

At present works management is performed by a number of non-integrated processes and systems (including but not limited to SAP, Xivic, and our GIS). Aurora is currently seeking to enhance productivity and competitiveness through adopting an Enterprise Asset Management (EAM) approach, in which electricity assets are managed by its ERP system through their entire lifecycles, in common with other network fixed assets. Based on work carried out in 2016 over the next few years we are seeking to:

- consolidate all core functions into SAP (Finance, Plant Maintenance/Service Management, Procurement, Human Resources, and Project Systems);
- expand SAP work orders and service orders configuration and design according to separation accounting structures between Aurora and Delta;
- migrate asset attribute data into SAP;
- integrate SAP with the GIS and mobility; and
- expand use of SAP Enterprise Data Warehouse and/or Xivic reporting and analytics across all assets.

### 2.11.4 Mobile Solutions

Condition Inspection results on selected maintenance activities are captured using the Xivic mobile solution. Our aim is to provide a consistent mobility mechanism for capturing inspection and condition information across all assets and maintenance activities.

### 2.11.5 Document Management System

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 Aurora's business management support system. Q-Pulse manages 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).



### **2.11.6 Financial Management Information System**

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.

### **2.11.7 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 upgrade of Gentrack was completed in 2013.

### **2.11.8 Fleet Management**

Aurora's asset management contractor, Delta, is installing a GPS fleet management systems (Smartrak) in all its vehicles. Smartrak 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.

### **2.11.9 Systems Road Map**

While significant progress has been made to improve our systems, we would be the first to recognise that we still have a way to go in order to achieve our aspirational goals.

At present the organisation uses multiple information systems to support 'end to end' process across business units. Data is located in multiple systems across this landscape and in some cases the data is duplicated. This has created inefficiencies for staff when performing tasks out in the field and in back-office processes. Essentially, it has led to the organisation being 'data rich, but information poor'.

A team of internal IT experts is currently looking to define how information is managed across the various systems and how we might provide a better platform for the future. The road map in Figure 2 4 was produced by the project team to highlight a number of key projects, how they integrate within the four core streams of work identified in our strategy (Increasing IT Capability, Digital Enablement, Information Management and Business Decision Making) and the expected delivery timeframes.

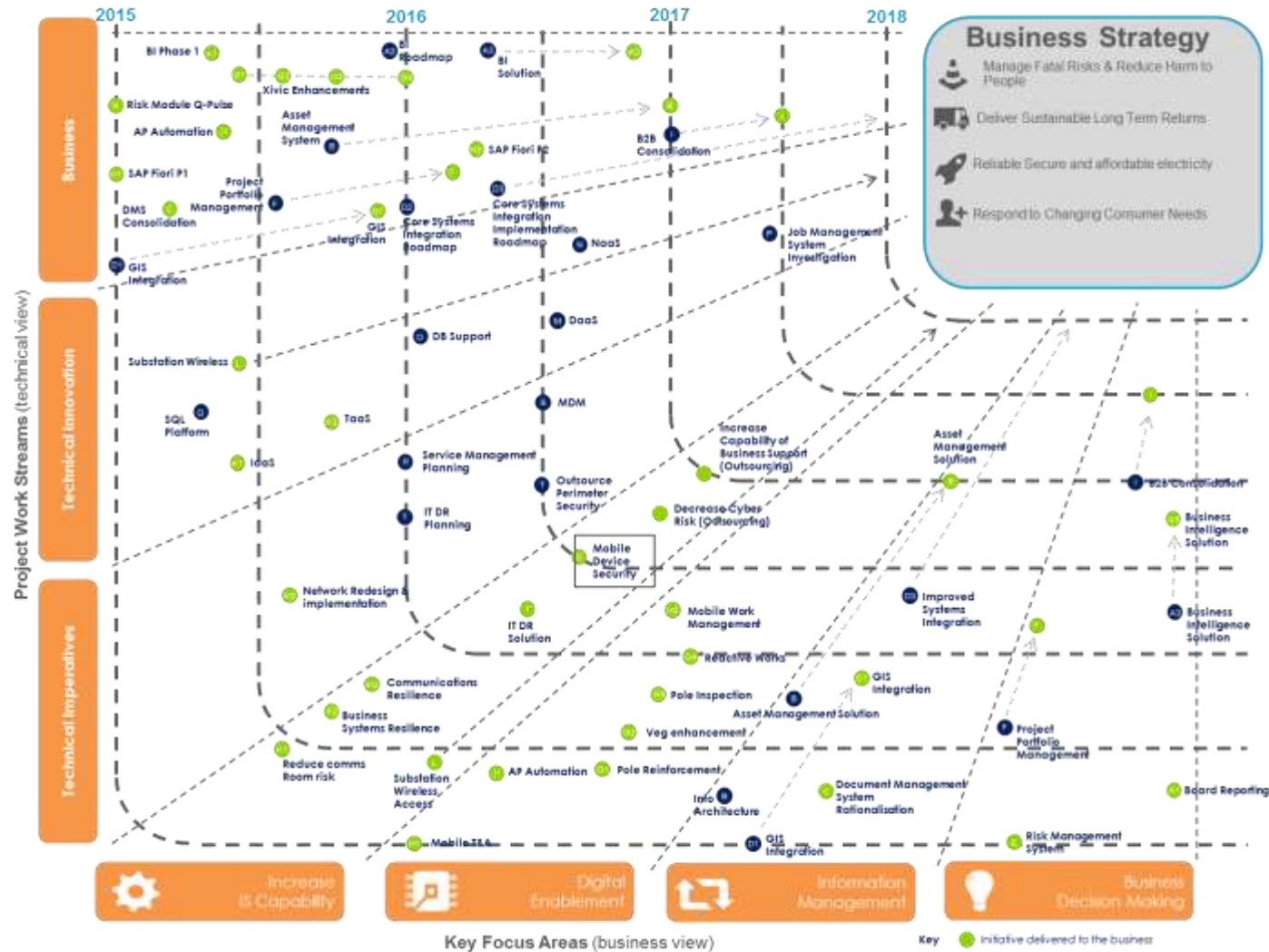


Figure 2-4 Information Technology Road Map

## 3 MEASURING PERFORMANCE

### 3.1 Overview of Service Levels

This section of the Plan outlines the performance levels required from our electrical distribution network by our stakeholders. Service levels cover aspects such as safety, responsiveness, reliability, adequate returns on shareholder investment, compliance and efficiency, summarised in Table 3.1.

Our aim is to not just meet our customer and stakeholder expectations but continuously strive to exceed them. The choice of measures enables Aurora to:

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

In setting our service level targets we have attempted to balance:

- safety considerations;
- customer consultation and benchmarks against industry standards;
- regulatory requirements;
- best practice asset management as described by ISO55001;
- historic trends in network performance; and
- knowledge of current network.

**Table 3-1 Service Level Measures**

Service Level	Measure	Performance Indicator (per annum)
<b>Safety</b>	Contractor safety	Total Recordable Injuries Frequency Rate (TRIFR)
	Public safety	Actual harm to public
<b>Reliability</b>	Average customer interruption duration	SAIDI
	Average customer interruption frequency	SAIFI
	Overhead	Number of interruptions per 100km
	Underground	Number of interruptions per 100km
<b>Power Quality</b>	Proven voltage complaints	Number per 10,000 customers
<b>Responsiveness</b>	Restoration of urban network interruption	Number of interruptions restored < 4 Hours
	Restoration of rural network interruption	Number of interruptions restored < 6 Hours
<b>Efficiency</b>	Load factor	% Energy into the network / peak kWh
	Loss ratio	% Energy into the network less energy delivered / energy into the network
	Distribution substation utilisation	% Total peak / total capacity
<b>Environmental</b>	Sulphur hexafluoride leaks	Number of incidents
	Polychlorinated biphenyl leaks	Number of incidents
	Maintain full compliance with Resource Management Act	Number of Breaches
<b>Financial</b>	Dividend subvention	(\$000s)
	Equity ratio	As at 30 June
	(Shareholder's Funds to Total Assets))	

## 3.2 Service Level Measures

This section describes the key performance measures we employ to monitor our performance.

### 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.

The metrics for safety performance are classified into two categories: those that affect the public and those that affect contractors undertaking work on the Aurora network. In the case of public safety the metric measures the number of actual serious harm incidents.

The safety metric for contractor safety involves a calculation of the Total Recordable Injury Frequency Rate (TRIFR).

### 3.2.2 Reliability

Network reliability performance is influenced by many factors including network design constraints, customer density (connections per km of line), exposure to environment, and extreme weather events. We aim to provide customers with a reliable power supply; however, service interruptions, both planned and unplanned, can and do occur at times.

The predominant measures of reliability of electricity networks are the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI).

- SAIDI is the average outage duration for each customer served per year.
- SAIFI is the average number of interruptions that a customer experiences per year.

In simple terms, these measures indicate the average duration and frequency of service interruptions, respectively, experienced by customers in a given network area. As these are average measures, individual customers will experience service interruptions more or less frequently than the average, and/or interruption durations that are longer or shorter than the average.

In general, customers in rural parts of the network can expect more service interruptions than average, since rural customers are generally supplied by a single circuit and there are no adjacent circuits that can be "switched in" to provide an alternative supply. In addition, rural supplies are mostly delivered via overhead lines that are exposed to harsher environmental conditions over a comparatively longer distance. Rural customers can also expect service interruptions that are longer than the average, as it takes longer for service crews to identify and repair faults, owing to the longer distances involved.

#### 3.2.2.1 Customer Contribution to Reliability Targets

Aurora regularly consults with its customers on price, quality and reliability issues. Consultation with our consumers has shown that they expect a reliable and secure supply of electricity. While recognising that individual expectations do differ and that service interruptions can and do occur, historically our customers have indicated satisfaction with the long term level of service we provide favouring lower prices over a more reliable service.

As a result we have set our annual targets for SAIDI and SAIFI to reflect average historical performance. After normalisation, this is approximately in alignment with both the limits determined by the regulator and the expectations of our customers.

### 3.2.3 Power 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, lightning strikes 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 will maintain your power supply within the following limits, except for momentary fluctuations, when measured at the Point of Supply:

- Voltage within  $\pm 6\%$  of 230 volts (between 216.2 volts and 243.8 volts) and
- Frequency within  $\pm 1.5\%$  of 50 hertz (between 49.25 hertz and 50.75 hertz).

It should be noted that voltage, in particular, can swing between the limits when electricity demand fluctuates. Greater demand causes voltage to drop, following which various items of network equipment, including transformer tap-changers and voltage regulators, will operate to maintain voltage levels. This variation will be more pronounced in rural areas due to the greater impedance of relatively longer lines, and may be particularly noticeable by customers near the 'edge' of the network.

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).

### 3.2.4 Responsiveness

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.

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 contact<sup>1</sup>; and maintains a complaints register to log complaints and track resolution.

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<sup>1</sup> The 24 hour service has a limited capability and consumers are encouraged to call their retailer for up-to-date information on fault restoration.

**Table 3-2 Service Guarantee**

Service Criteria	Performance Indicator	Service Guarantee for Exceeding the Timeframe
<b>Response to customer enquiries</b>	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
<b>Response to power quality or voltage</b>	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
<b>Notification of planned service interruption</b>	Missing notification of planned interruption	<b>\$20 per ICP per missed communication</b>

## 3.2.5 Technical Efficiency

Aurora utilises efficiency measures to ensure that the delivery of energy is efficient using load factor, loss ratio and capacity utilisation metrics.

### 3.2.5.1 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.

### 3.2.5.2 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.

### 3.2.5.3 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.

### 3.2.5.4 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 our Use-of System pricing methodology can be found on Aurora's website.



### 3.2.6 Environmental

Aurora remains committed to reducing environmental effects and does so by controlling the release of substances used in network assets that could cause adverse effects to the environment. In particular, this relates to oil and sulphur hexafluoride used in switchgear, and polychlorinated biphenyls.

### 3.2.7 Financial

#### 3.2.7.1 Dividends

Aurora provides a dividend to its shareholder, Dunedin City Holdings Limited (DCHL). Aurora avoids borrowing to fund this dividend which is instead derived from after tax profit.

Budgeted dividend levels between DCHL and its subsidiaries are agreed as part of the annual planning cycle, usually up to 75% of after-tax profit (subject to the maintenance of the target Equity Ratio).

## 3.3 Consumer Consultation

A customer engagement framework for Aurora is provided following in Figure 3.1. Customer opinion is fundamental to optimising our asset management practices. We acknowledge that individual needs and expectations differ and endeavour to ensure that as far as practice all our customers are satisfied with the level of service we provide and that no party is unduly advantaged or disadvantaged in the long term.

To determine customer requirements with regard to service level we survey our customers on quality, price and service issues on an annual basis through telephone surveys, postal surveys and direct customer engagement. The focus of our postal survey is on price and quality (reliability) while the telephone survey tends to cover other service-related issues such as restoration time and willingness to pay. Key account management is also an integral part of the overall framework to enhance customer insight and realise the full business potential from our customer relationships.

### 3.3.1 Postal Surveys

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

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

The results to date show the majority of consumers are trending towards preference for a lower price rather than better quality of supply. This survey was terminated in August 2015 owing to decreasing response rate.

### 3.3.2 Telephone Surveys

Aurora Energy Ltd (Aurora) has been surveying its residential and small commercial customers by means of a telephone survey since 2006. The survey is primarily focused on gauging feedback on a range of price, quality and service issues including:

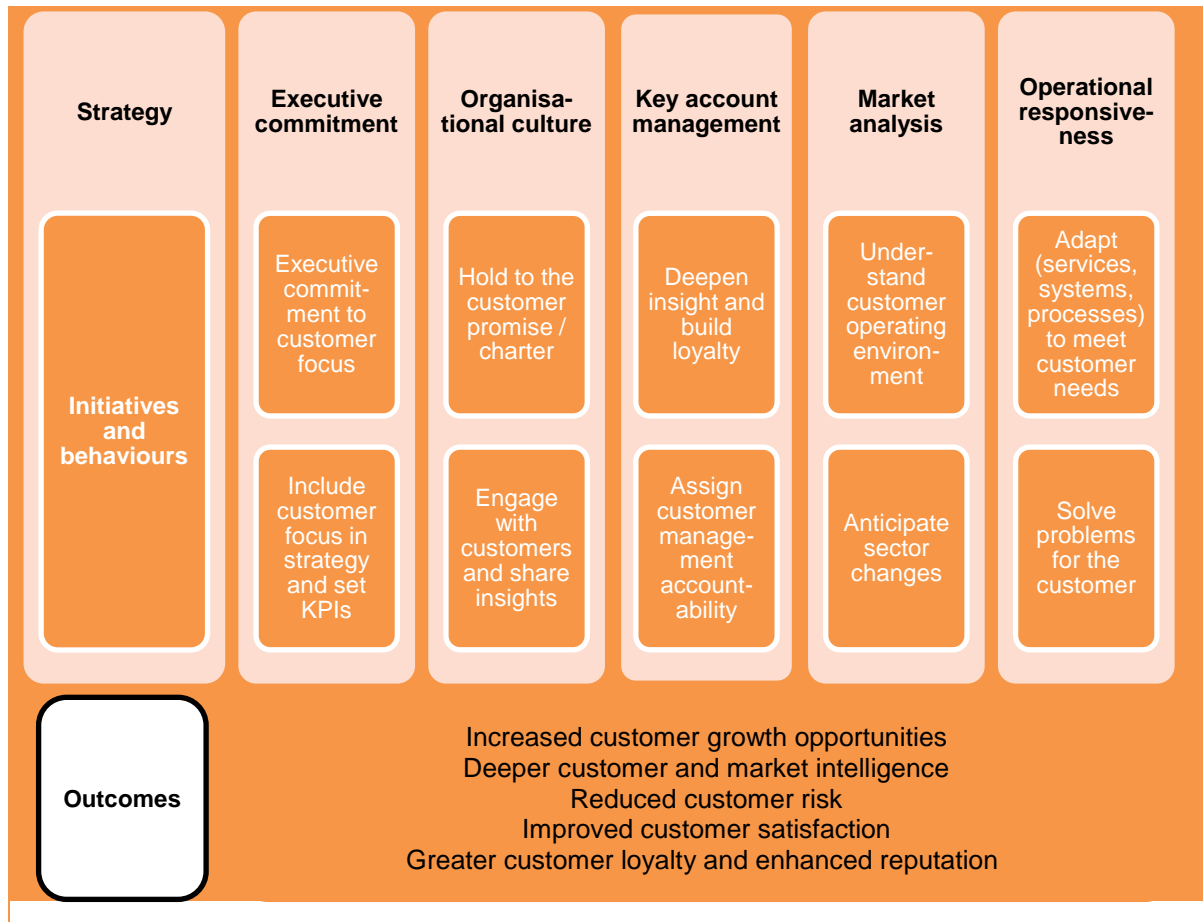
- Knowledge of retailer/line company names
- Relative importance of price and quality of supply as well as the acceptability of trade-offs
- Number and length of planned outages considered to be reasonable
- Advice and notice regarding planned outages
- Recent experience of unplanned outages
- Interest in paying a premium in order to reduce supply restoration times as well as to reduce supply interruptions
- Satisfaction with contacts in the event of unplanned supply interruption and
- Satisfaction with contacts involving other issues.

The survey involves a random sample of 400 customers (200 in Dunedin and 200 in Central) and is designed to have a margin of error of 4.9% at the 95% confidence level.

### 3.3.2.1 Summary Results 2015

The survey design was updated in 2015 to improve the experience of respondents and to ensure more statistically valid results. The principal results and conclusions of the 2015 telephone survey were:

- Customer expectations of restoration times after an unplanned outage have increased, with weighted average acceptable outage times reducing from 5 hours to 3.8 hours in a single survey year
- Both expectations of reliability and propensity to pay for higher reliability were significantly higher in the Central area than in the Dunedin network area, likely driven by growth, higher incomes and urbanisation
- Although customers have low levels of recognition of both retailers and line companies, they continue to be more aware of the Delta brand than Aurora
- 94% of customers were satisfied with the amount of information and notice provided for planned outage programme impacts. (These impacts have increased significantly in the Central area as a result of the large works programme) and
- 76% of customers who sought service in the 6 months prior to the survey were satisfied that they had spoken to the correct person and had received appropriate information.



**Figure 3-1 Customer Engagement Framework**

### 3.3.3 Consultation with Large Consumers

Aurora has a demand management program which targets large capacity connections and provides an opportunity for these consumers to offer feedback on a large number of issues, including service levels. Some of Aurora's large capacity connections in Dunedin and Central are shown below:

- Central Otago: Queenstown Lakes District Council, Central Otago District Council, NZ Ski, Cardona Ski field and Queenstown Airport.
- Dunedin: Otago University, Port of Otago, Turners & Growers, Dunedin District Council, Cadbury, Fonterra, NZ Wood Mouldings, Southern DHB, Kiwirail and the Ravensdown Fertiliser Co-operative.

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

### 3.3.4 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.

### 3.3.5 Other Stakeholder Consultation

#### 3.3.5.1 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.

#### 3.3.5.2 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. In 2015, Aurora commenced detailed discussions with the Otago Regional Council; Dunedin City Council; Central Otago District Council and the Queenstown Lakes District Council on the review of the various Regional and District Plans within the region.

These discussions have covered a variety of topics including our desire to introduce planning provisions relating to the protection of Regionally Significant Infrastructure and Critical Electricity Lines (CELs) which are crucial to the region's quality, reliability and security of electrical supply.

In order to progress the concept of CELs across the region Aurora has canvassed the experience of other Electrical Distribution Businesses, Transpower, participated in industry forums and actively engaging with rural interest groups to ensure that the need for and implications of the proposed planning provisions are clearly understood.

It is anticipated that 2016/17 will provide greater opportunities for Aurora to continue consultation and dialogue with interest groups on this issue.

### 3.4 Future Service Level Targets

Service level targets for the next 5 years are shown in Table 3.3 below. In setting these, Aurora has given consideration to safety, customer feedback, historic trends in network performance, knowledge of current network health/risk areas, economic viability and the availability of funding.

**Table 3-3 Five Year Service Level Targets**

Service Level	Measure	FY16	FY17	FY18	FY19	FY20
Safety	Contractor TRIFR	55.2	55.2	55.2	55.2	55.2
	Actual harm to public	0	0	0	0	0
Reliability	SAIDI	83.37	83.37	83.37	83.37	83.37
	SAIFI	1.45	1.45	1.45	1.45	1.45
	Overhead faults per 100km	10.5	10.5	10.5	10.5	10.5
	Underground faults per 100km	2.5	2.5	2.5	2.5	2.5
Power Quality	Voltage complaints per 10,000 customers	<10	<10	<10	<10	<10
Responsiveness	Hours to restoration Dunedin and Central (excludes Central rural)	<4	<4	<4	<4	<4
	Hours to restoration rural Central	<6	<6	<6	<6	<6
	Response to customer enquiries > 7 days	0	0	0	0	0
	Response to power quality or voltage complaints > 7	0	0	0	0	0
	Absent notification of planned interruption	1	1	1	1	1
Efficiency	Load factor %	54%	54%	54%	54%	54%
	Loss ratio	7.30%	7.30%	7.30%	7.30%	7.30%
	Utilisation %	31%	31%	31%	31%	31%
Environmental	Sulphur hexafluoride leaks	0	0	0	0	0
	Polychlorinated biphenyl leaks	0	0	0	0	0
	Breaches of Resource Management Act	0	0	0	0	0
Financial	Dividend /Subvention (\$000)	7500	7500	7500	7500	7500
	Equity ratio (as at 30 June)	42.5%	40.6%	38.6%	38.1%	37.7%

### 3.4.1 Capability to Deliver

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. 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).

## 3.5 Evaluation of Performance

In the following sections we review our performance against the targets stated in our previous AMP.

### 3.5.1 Performance Overview

Despite not meeting three of our service level targets, FY15 was a successful year given the substantial uplift in demand for capital and maintenance services as the network increased its asset renewal and maintenance programme and carried out capacity and systems upgrades.

### 3.5.2 Safety

The safety of contractors and public is one of the Aurora's primary service levels and remains a core area for ongoing improvement.

Delta implemented the Incident Cause Analysis Method (ICAMS) during 2014/15; this initiative has led to the implementation of a number of key actions and preventative measures following serious harm incidents to avoid, mitigate or eliminate future occurrences.

Aurora's safety performance has improved due to a number of initiatives including:

- development of a competency framework for all contractors working on the Aurora network. This also serves as an input into Delta's internal competency and training programme;
- promptly imposing de-energised work restrictions on Long and Crawford oil insulated switchgear following a fatality in Western Australia. A review of maintenance practices and selected renewals is currently under consideration;
- standardisation of PPE to protect against arc flash, detailed calculation of safe working distances for substation equipment and improved ability to mitigate through changes to fusing at the point of supply;
- a full review of substation security measures and upgrades to the SCADA alarms system monitoring entry points into substations. Perimeter fencing and access doors have since been upgraded to provide safe, reliable and secure access to and from substations for approved contractors;
- substantial enhancement of pole testing and renewal strategies including Implementation of objective testing of wooden poles using physical measurements, revised pole condition classifications and the introduction of external reinforcement technology to lengthen the life of poles that satisfy the appropriate testing criteria for useful remaining life; and
- implementation of Job Safety Analysis and a renewed emphasis on safety by design.

### 3.5.3 Reliability

Aurora Energy measures network reliability performance using two metrics: average duration (SAIDI) and average frequency (SAIFI) of service interruptions per consumer. These measures also govern Aurora's performance relative to regulated price-path quality compliance.

#### 3.5.3.1 Reliability Performance 2014/15

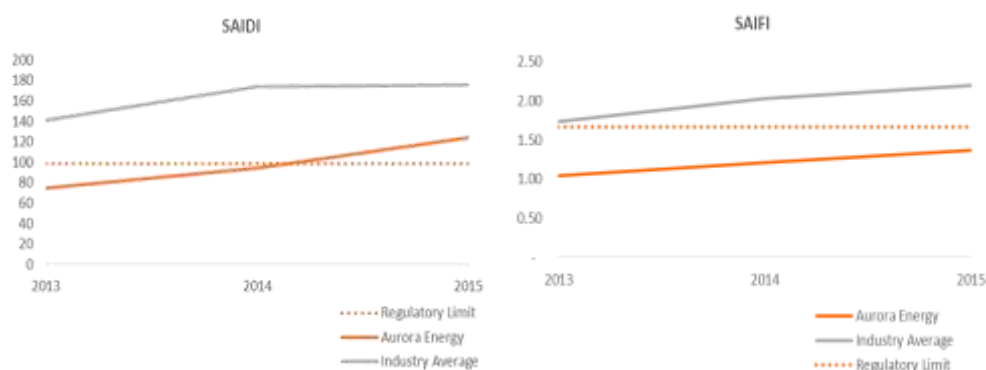
Aurora's SAIDI and SAIFI results for the year ending 31 March 2015 in the table below show that the limit for the average number of interruptions per customer was not exceeded during the period, however the average duration of outages did exceed the limit by 25.3 minutes.

**Table 3-4 SAIDI and SAIFI Performance (2015)**

	SAIDI	SAIFI
Year ending actuals	123.6	1.37
Regulatory limit	98.3	1.67
<b>Outcome</b>	<b>Not achieved</b>	<b>Achieved</b>

Despite a reduction in the number of interruptions, the average duration was greater than target levels in 2014/15. A significant component of this increase can be attributed to high impact low probability storm events and high winds in the period.

Indeed, Aurora's annual reliability performance results between 2013-15 (year ended 31 March) show Aurora out-performing the industry average – see Figure 3-2.



**FIGURE 3-2 SAIDI AND SAIFI PERFORMANCE 2013-2015**

### 3.5.3.2 Long term historical performance

Over the last ten years, Aurora's average interruption duration has tended to increase whilst over the same period consistent reduction in average number of interruptions experienced by network customers has been achieved.

Some periodic features are evident in the historical data where prevalence of interruptions – typically dominated by unplanned faults can be seen across both sub-networks most notably in the 2007, 2012 and 2015 periods see Figure 3-3.

The evidence of high impact interruptions during these periods across both sub-networks suggests the influence of environmental factors such as major storm events.

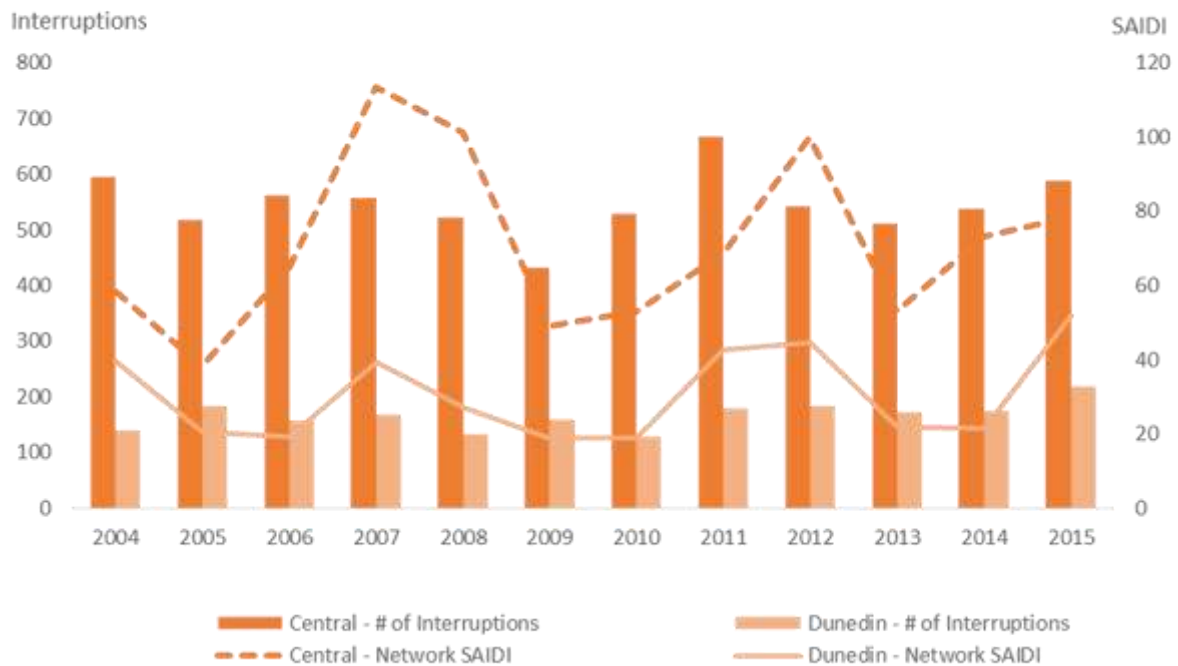


**FIGURE 3-3 TEN YEAR NETWORK RELIABILITY**



Owing to both the radial network configuration and the large area covered interruption duration is higher in Central Otago as shown in Figure 3-4.

**Sub-Network Contribution To Aurora SAIDI**



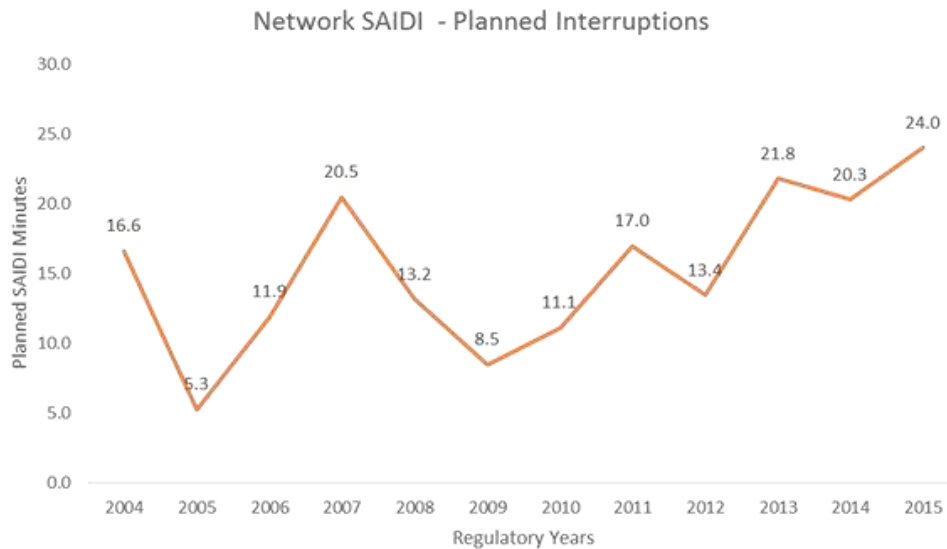
**FIGURE 3-4 10 YEAR SUB NETWORK CONTRIBUTION TO SAIDI**

### 3.5.3.3 Planned interruptions

Aurora periodically undertakes preventative, corrective maintenance and works to renew assets at end of life requiring a notified interruption to supply. The impact of an increasingly intensive maintenance and renewal programme is evident in the component of planned interruptions peaking in 2013 at 29% of network SAIDI.

The increase was the result of accelerated programmes of work to strengthen and support a safe and reliable network by implementing:

- accelerated pole replacements - an additional \$2M per annum was allocated to enable a greater number of poles to be replaced;
- Devar mechanical pole testing - traditional testing methods were augmented by an objective test enabling greater confidence in pole condition; and
- additional vegetation control resources - additional resource was allocated to increase capacity for vegetation management both in Dunedin and Central Otago.



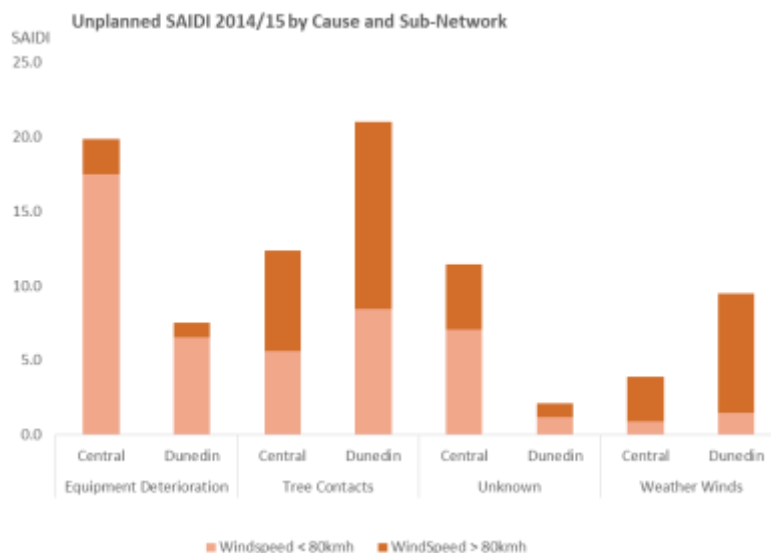
**Figure 3-5 Planned Interruption SAIDI Impact**

### 3.5.3.4 Unplanned interruptions

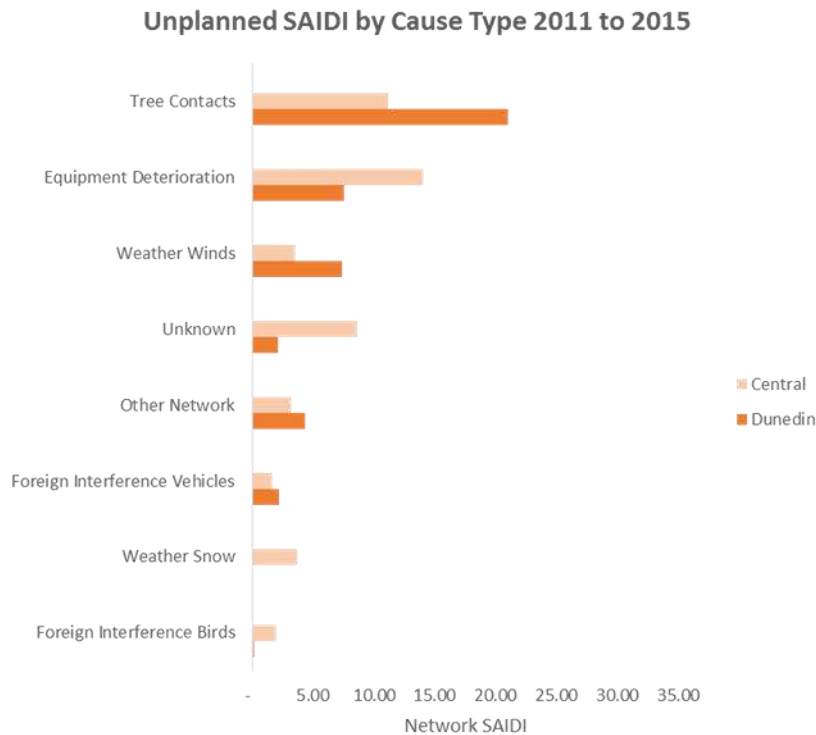
Service interruptions also result from events that occur without any prior indication making them more difficult to control. A common cause of unplanned faults is adverse weather, in particular wind events which impact on pole stability and overhead lines phase to phase contacts. Asset condition also affects reliability by failure due to end of life factors or reduced capacity under conditions outside of the design envelope.

On the Aurora network, faults involving tree contacts result in the greatest impact on average duration. This is especially evident in Central Otago where longer, exposed overhead spans are typically skirted by road side tree lines and wind breaks compared to Dunedin's largely urban network.

Interruptions resulting from storm events continue to adversely impact reliability metrics, particularly in exposed areas of the Central Otago network such as Roxburgh-Ettrick and the Omakau-Lauder regions, with a lesser contribution originating from the Halfway Bush, East Taieri and Dunedin Peninsula regions.



**Figure 3-6 Unplanned SAIDI by Cause and Sub Network**



**Figure 3-7 Unplanned SAIDI by Cause 2011-2015**

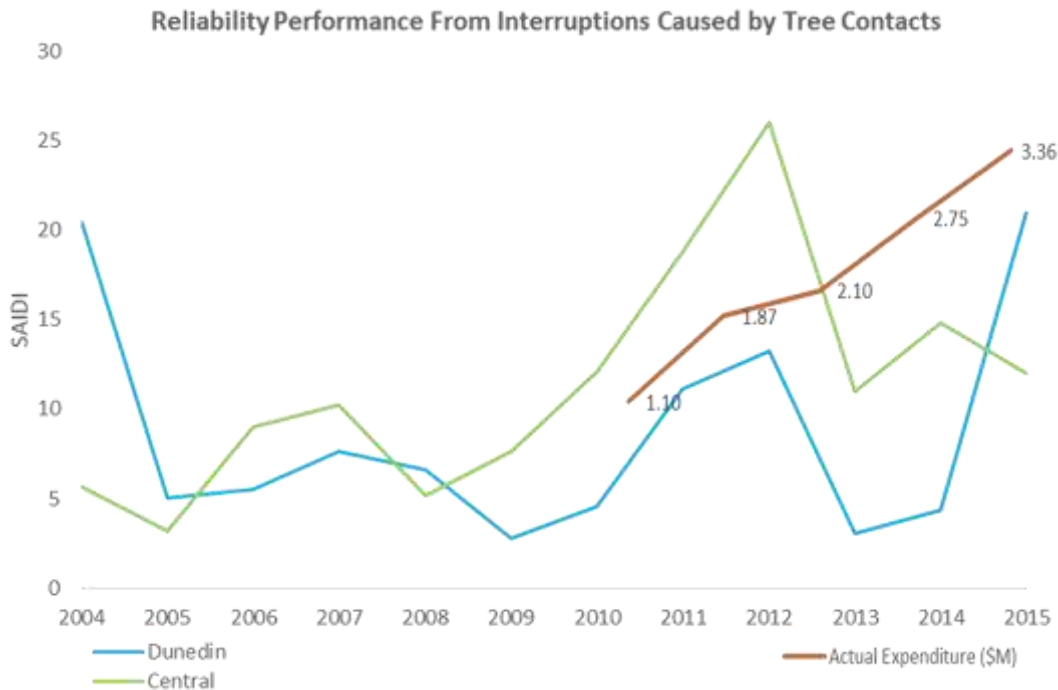
### 3.5.3.4.1 Storm events

Unplanned SAIDI is shown in Figure 3.7 occurring on days where maximum wind gusts proximal to the fault location exceeded 80kmh. Dunedin experienced a higher number of interruptions under these conditions where high wind gusts were more frequent during 2014/15.

Tree contacts are also higher during windy conditions, in part owing to vegetation blown into lines, or instances where a tree falls into overhead lines.

Longer rural spans tend to be responsible for the higher prevalence of interruptions with unknown cause in Central Otago.

Storm events continue to pose a significant risk to exposed area of the network. Further analysis of exposure and risk of assets from wind events is underway to be integrated into programme prioritisation.



**Figure 3-8 Tree Contact and Vegetation Expenditure**

### 3.5.3.5 Least reliable feeders

Aurora operates 246 high voltage feeders distributing energy to domestic, industrial and commercial consumers. Each feeder typically supplies approximately 200-300 households, businesses and bulk supply to large consumers. Feeder reliability is considered by accounting for unplanned interruptions at the distribution level.

Consumers are supplied either in urban areas featuring high/medium connection density or in lower density rural zones characterised by longer overhead spans or some mix of the two. Feeders are classed according to the number of consumers within four predefined boundaries following. A feeder is classed "Mixed" when both urban and rural consumers are present on the feeder, classed accordingly depending on the majority of consumer type.

- Urban – all consumers on the feeder lie within the urban boundary
- Rural – all consumers on the feeder lie within the rural boundary
- Mixed – Urban – the majority of consumers on the feeder lie within the urban boundary
- Mixed – Rural – the majority of consumers on the feeder lie within the rural boundary.

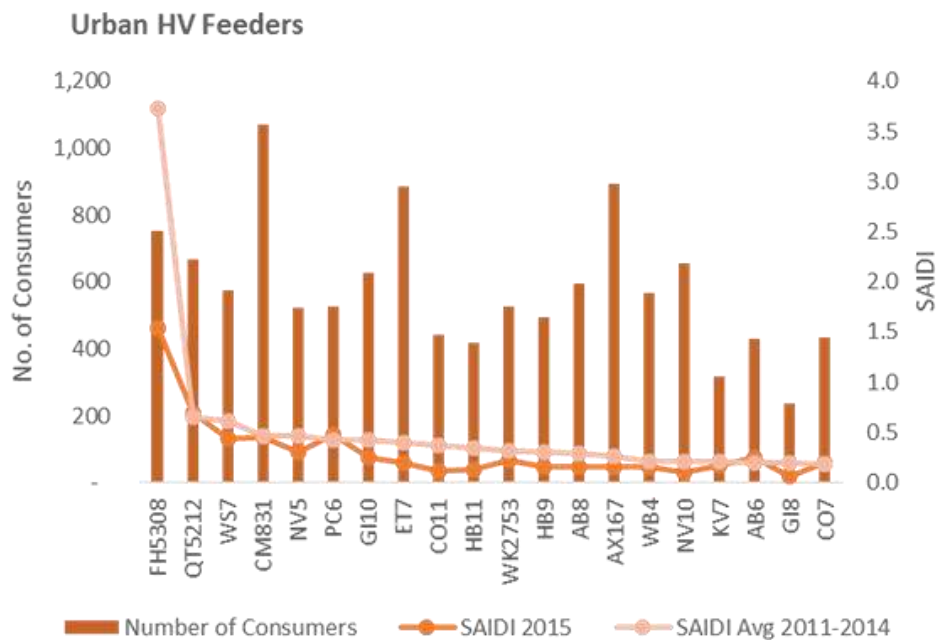
Feeder Type 2014/2015



**Figure 3-9 Feeder Types**

### 3.5.3.5.1 Urban feeders

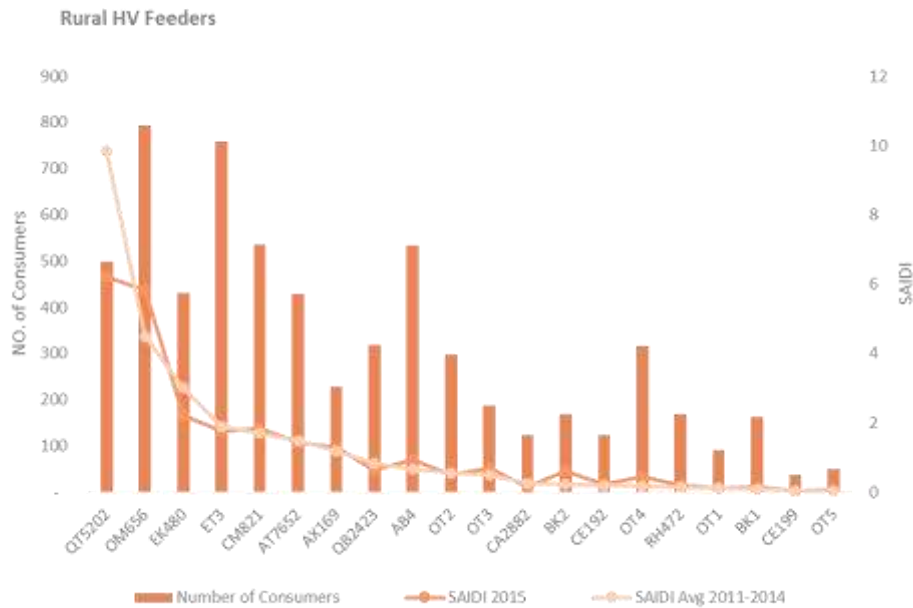
Typically, purely urban feeders have exhibited a lower SAIDI impact owing to lower response time and network intertie capacity as well as other factors that tend to result in more reliable supply such as past undergrounding projects lowering exposure to wind and tree contacts.



**Figure 3-10 Urban Feeder Performance**

## 3.5.3.5.2 Rural feeders

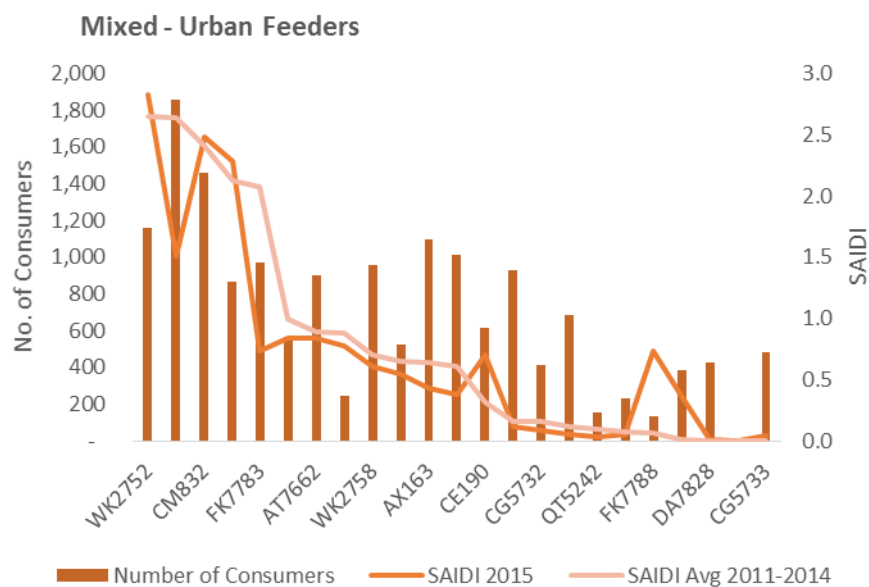
Aurora's rural HV feeders service low connection density radial spur lines and tend to incur greater interruption duration owing to greater patrol distances and prevalence of overhead assets serving areas at higher risk of high winds. Queentown QT5202 and Omakau 656 have been identified as high priority for vegetation programmes to drive reliability improvement.



**Figure 3-11 Rural Feeder Performance**

## 3.5.3.5.3 Mixed urban

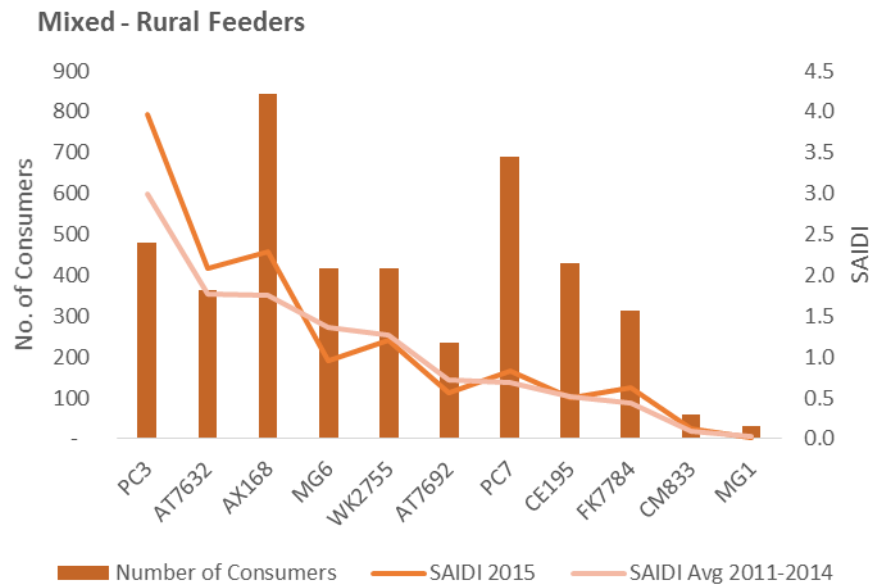
Mixed Urban feeders are mainly populated by high density urban connections with outlying rural spurs. Vegetation control in Wanaka 2756 successfully reduced SAIDI impact in 2014/15. Continued efforts to control vegetation in both Wanka and Frankton are expected to reduce the rolling 4-year average at the conclusion of the 2015/16 period.



**Figure 3-12 Mixed - Urban Feeder Performance**

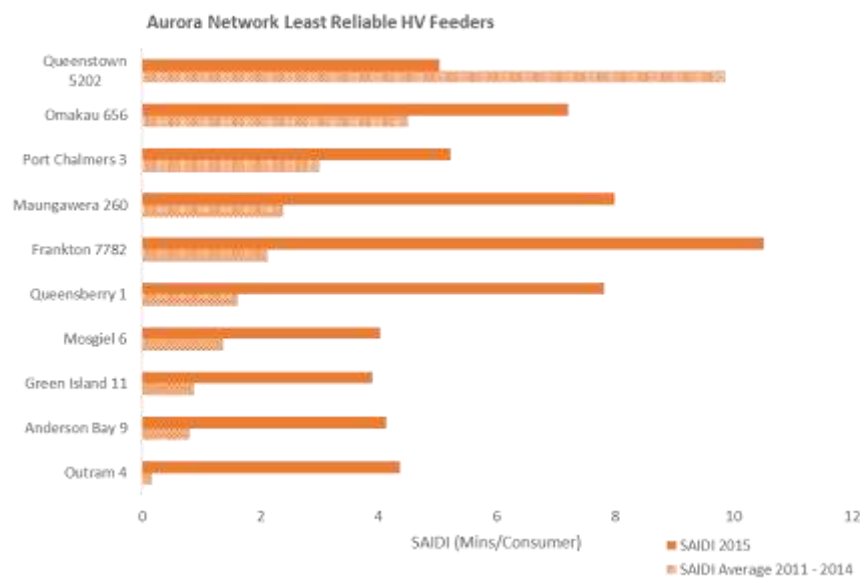
## 3.5.3.5.4 Mixed rural

Aurora has also identified mixed rural feeders as another high priority for reliability improvements. Port Chalmers 3 serves an area between Otakou and Taiaroa Head which is subject to the brunt of strong prevailing NE winds and its location at the end of the Dunedin Peninsula will often result in longer interruption duration. A programme to reinforce overhead assets in this area is under consideration.



**Figure 3-13 Mixed - Rural Feeder Performance**

A summary of Aurora's least reliable feeders determined on the basis of impact to network SAIDI over the preceding four years is shown below in FIGURE 3-14. Substantial performance improvements were realised in Queenstown's QT5202 feeder following targeted, and ongoing, vegetation reduction. Overhead assets in both Port Chalmers and Omakau remain high risk for SAIDI impact owing to both their exposure to high winds and relative isolation for fault correction. Various options to improve reliability in these regions are under review. Vegetation works in Maungawera 260 were programmed for the 2015/16 period which have reduced SAIDI impact.



**Figure 3-14 - Least Reliable Feeders Based on SAIDI**



## 3.5.4 Power Quality

In the 2014/15 period there were 3.75 proven voltage complaints per 10,000 customers which is well below the target (<10) set for the period.

## 3.5.5 Responsiveness

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 3-5 Historic Service Failure Payments**

Year to 30 June	Events	Consumers Affected	Total Paid	% Line Revenue
<b>2003</b>	11	1,148	\$63,336	0.119%
<b>2004</b>	16	415	\$25,410	0.048%
<b>2005</b>	24	896	\$51,553	0.091%
<b>2006</b>	14	324	\$21,435	0.036%
<b>2007</b>	15	246	\$13,210	0.021%
<b>2008</b>	16	1,171	\$61,717	0.092%
<b>2009</b>	14	671	\$36,094	0.044%
<b>2010</b>	24	794	\$48,653	0.068%
<b>2011</b>	33	1,897	\$143,366	0.195%
<b>2012</b>	26	1,183	\$79,275	0.103%
<b>2013</b>	4	646	\$34,247	0.040%
<b>2014</b>	18	1,816	\$101,186	0.0119%
<b>2015</b>	60	3,534	\$205,372	0.226%

For 2015/16, Aurora will continue with its commitment to respond to enquiries regarding power quality or service interruption investigations within 7 working days.

## 3.5.6 Technical 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.

### 3.5.6.1 Load factor

Aurora achieved a load factor of 53% in 2014/15 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%.

For 2014/15, capacity utilisation was 34.5% against a minimum target of 30%. Over the past 5 years this has been slightly above target each year. Better utilisation is expected within the Central network due to irrigation demands and changes in the summer usage profile.

For 2014/15, 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.

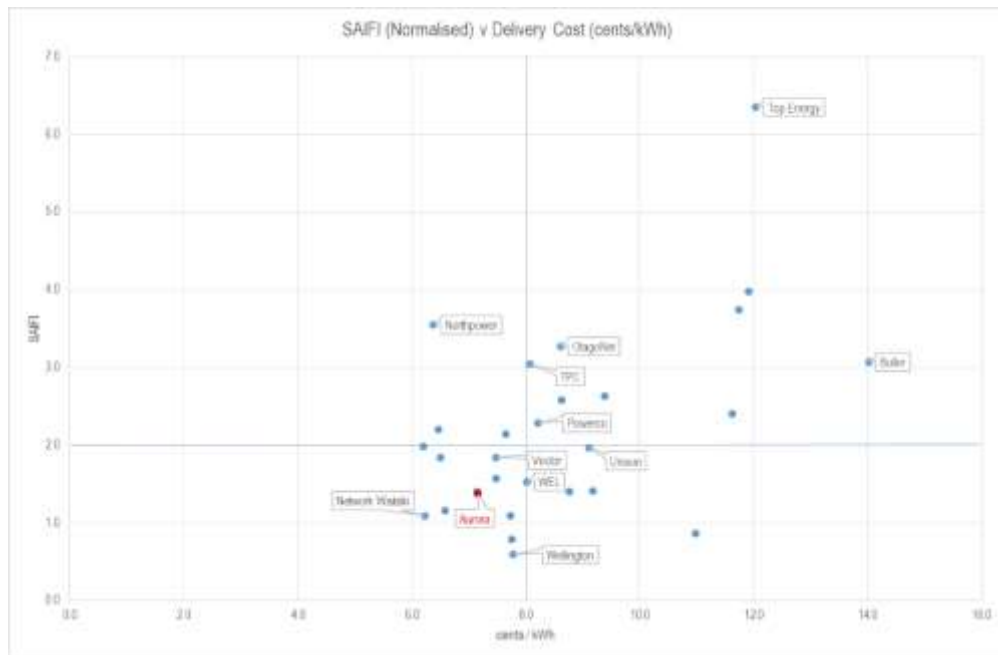
The North City 2 33kV cable is an important part of the subtransmission system linking the South Dunedin Grid Exit Point to North City zone substation. The 2.5km long 40 year old cable developed a leak in 2009 which has not been located despite a number of attempts using a variety of techniques. The leak, at an average of 2 litres per day, varies over time and has not become significantly worse over the interim period.

### 3.5.8 Benchmarking and Cost Efficiency

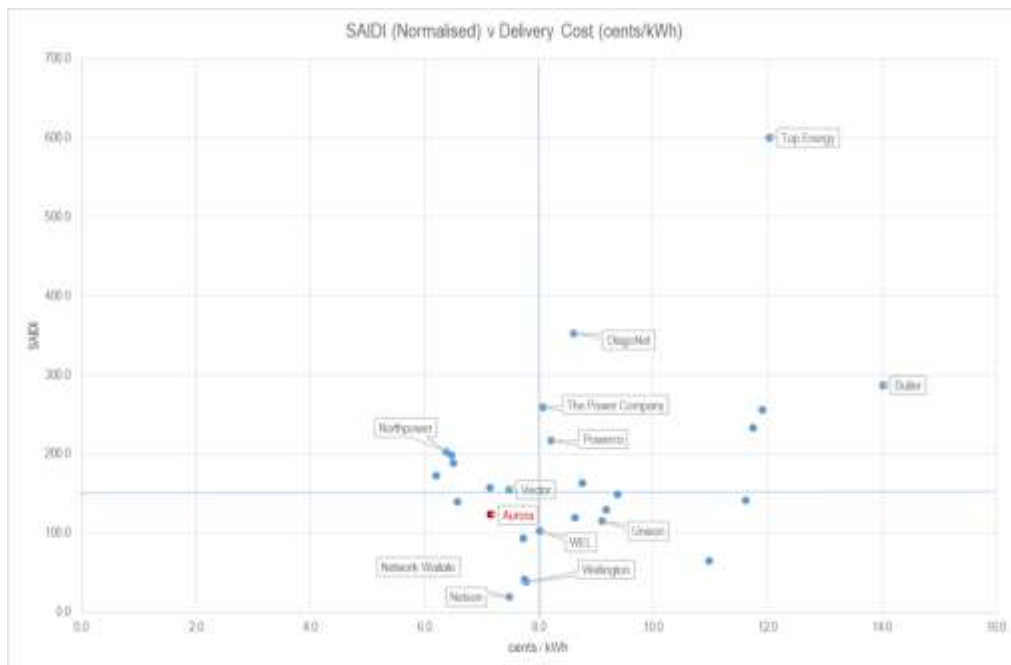
SAIDI (Normalised) v Delivery Cost (\$/ICP)

Utility	\$/ICP (approx.)	SAIDI (approx.)
Topanga	1150	600
Cloughet	2400	350
TFC	1600	250
PG&E	1400	250
Southern	1200	200
Veeva	1100	180
Wapsi	1050	210
Frontier	1100	250
Aurora	1050	120
WCL	1150	100
Union	1400	110
Wollaston	1200	30
Boston	1050	20

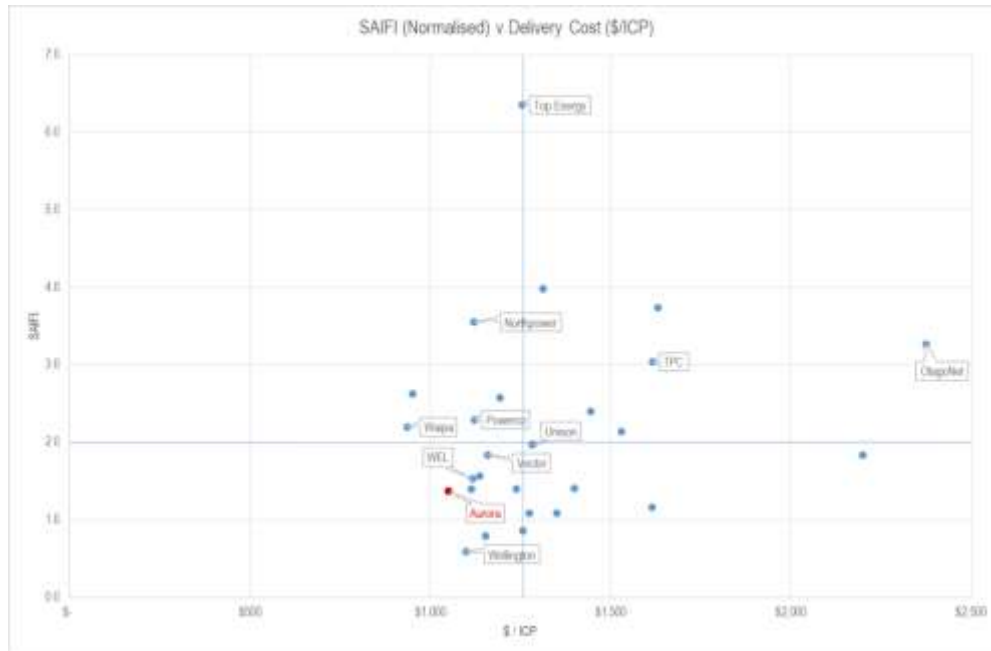
**Figure 3-15 Normalised SAIDI v delivery cost (\$/kwh)**



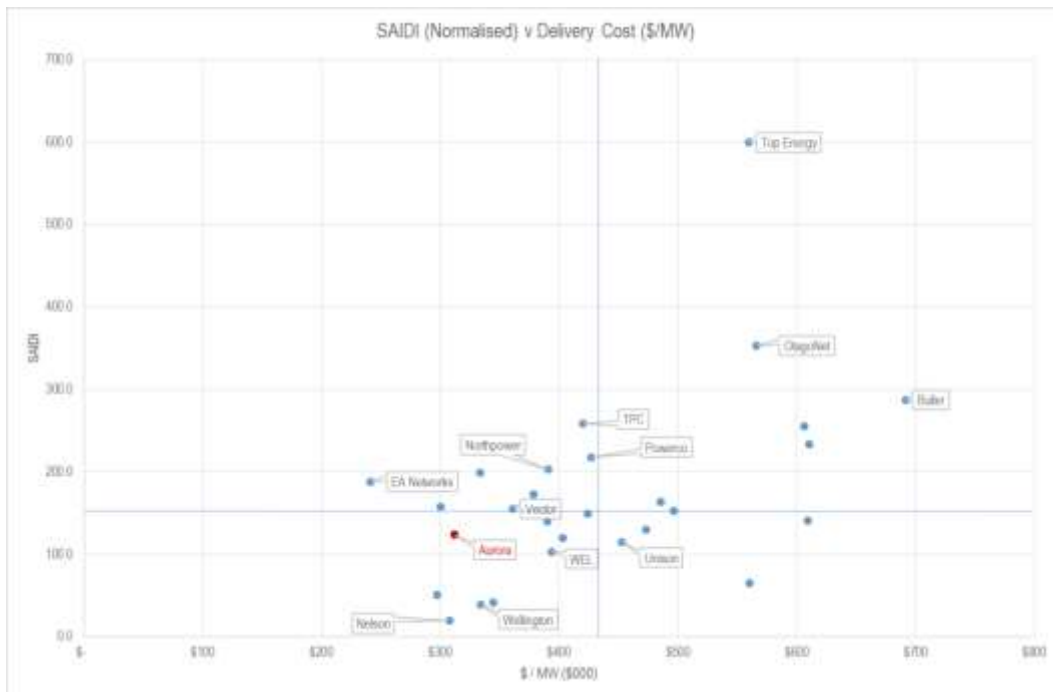
**Figure 3-16 Normalised SAIFI v delivery cost (\$/kWh)**



**Figure 3-17 Normalised SAIDI v delivery cost (\$/ICP)**



**Figure 3-18 Normalised SAIFI v delivery cost (\$/ICP)**



**Figure 3-19 Normalised SAIDI v delivery cost (\$/MW)**

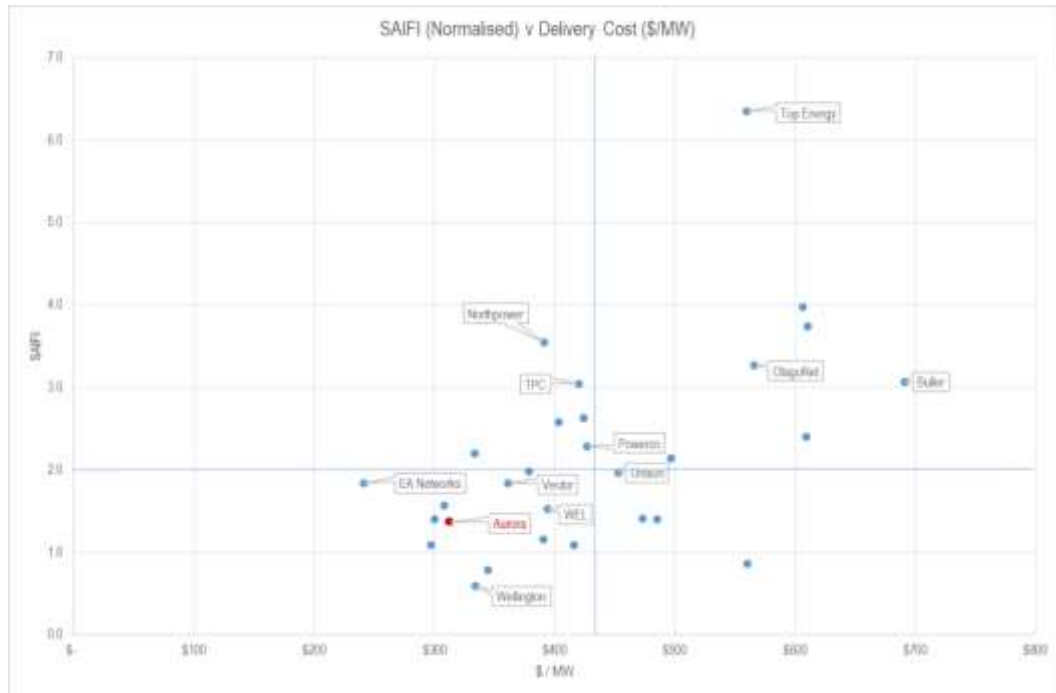


Figure 3-20 Normalised SAIFI V Delivery Cost (\$/MW)

## 3.6 Performance Results

Service Level	Measure	Performance Indicator (per annum)	Target FY15	Actual FY15
Safety	Contractor safety	Total Recordable Injuries Frequency Rate (TRIFR)	55.2	93.87
	Public safety	Actual harm to public	0	0
Reliability	Average customer interruption duration	SAIDI	98.3	123.6
	Average customer interruption frequency	SAIFI	1.67	1.37
	Overhead	Number of faults per 100km	10.5	20.25
	Underground	Number of faults per 100km	2.50	1.99
Power quality	Proven voltage complaints	Number per 10,000 customers	<10	3.75
Responsiveness	Restoration following general network failure	Within 4 hours of notification (Dunedin)	<4 Hrs	<4 Hrs
		Within 4 hours of notification in urban areas (Central)	<4 Hrs	<4 Hrs
		Within 6 hours of notification in rural areas (Central)	<6 Hrs	<6 Hrs

Service Level	Measure	Performance Indicator (per annum)	Target FY15	Actual FY15
	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 interruptions	Absent notification of planned interruption	1	10
Efficiency	Load factor	% Energy into the network / peak kWh	54%	54%
	Loss ratio	% Energy into the network less energy delivered / energy into the network	7.30%	6.0%
	Distribution substation utilisation	% total peak / total capacity	31%	30%
Environmental	Sulphur hexafluoride leaks	Number of incidents	0	0
	Polychlorinated Biphenyl leaks	Number of incidents	0	0
	Breaches of the RMA	Number of breaches	0	1
Financial	Dividend subvention	\$000	\$9,500	\$9,500
	Equity ratio (as at 30 June)	% Shareholders' Funds /total Assets	44.2%	44.1%

## 4 RISK MANAGEMENT

### 4.1 Introduction

Risk management is the process of identifying, assessing and responding to risks, and communicating the outcomes of these processes to the appropriate parties in a timely manner. An effective risk management system:

- Improves planning processes by enabling the key focus to remain on core business and helping to ensure continuity of service delivery
- Reduces the likelihood of potentially costly 'events' and assists with preparing for challenging and undesirable events and outcomes
- Contributes to improved resource allocation by targeting resources to the highest level risks
- Improves efficiency and general performance
- Contributes to the development of a positive organisational culture, in which people and agencies understand their purpose, roles and direction
- Improves accountability, responsibility, transparency and governance in relation to both decision-making and outcomes.

Aurora recognises that risk management is fundamental to asset management. 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.

To assist us manage our risks in an appropriate manner, we have adopted the fundamental risk management process described in AS/NZS ISO 31000 (Figure 4.1).

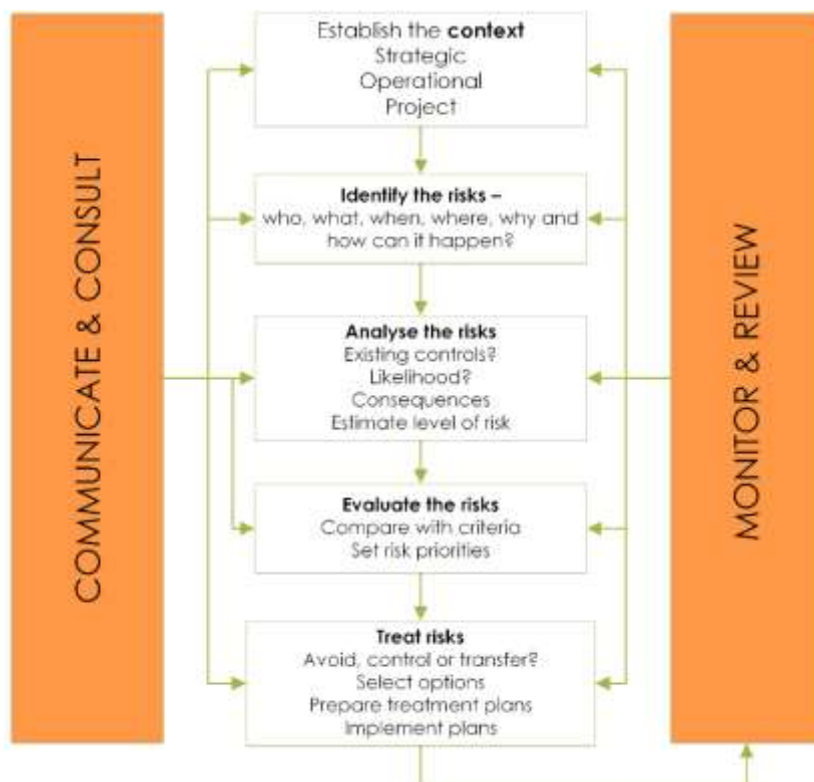


Figure 4-1 Risk Management Process (AS/NZS ISO 31000:2009)



## 4.2 Risk Process and Methodology

### 4.2.1 Establishing the Context

Establishing the risk management context of an activity is a pivotal step in the risk management process at Aurora. It defines the basic parameters within which risks must be managed and sets the scope for the rest of the risk management process.

### 4.2.2 Identifying Risk

When risks are identified they are described and monitored by those with accountability in specific areas. These risks both inform and are informed by our strategic and operational plans and standards. The requirements for the identification, rating, monitoring and communicating risks under each category is described in a series of supporting Standards.

All categories of risk are recorded in the risk register. The aim of this register is to summarise the risks, including likelihood of occurrence, consequences and mitigation.

### 4.2.3 Analysing Risks

Risk analysis establishes the level of significance of a risk and assigns a priority rating to each risk, taking into account any existing factors that operate to reduce or control the risk. Risk is measured by likelihood / consequence as set Figure 4.2.

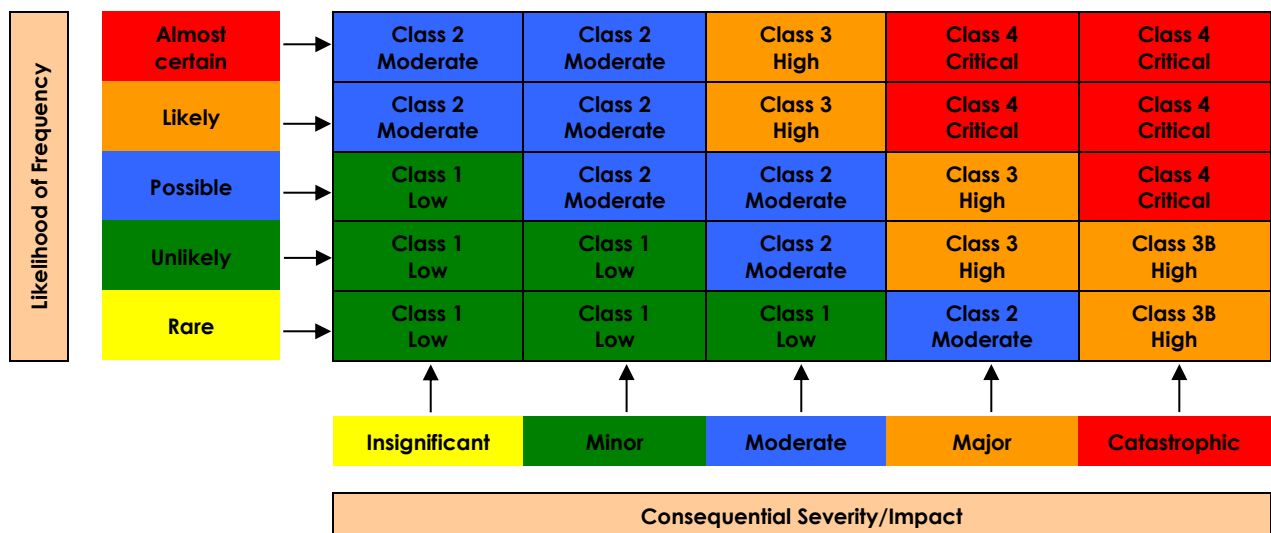


Figure 4-2 Likelihood And Consequence Matrix

### 4.2.4 Prioritising Risks

Priority is given to identifying and addressing high-level risks and those operational risks that are likely to impact most significantly on our business processes. Where the qualitative risk assessment indicates a Class 4 or 3B risk (Low likelihood / catastrophic consequence) a further quantitative risk assessment is completed. This may include but not limited to probabilistic assessment, Monte Carlo analysis or Bow Tie Analysis.

**Table 4-1 Risk Classification**

Risk Level	Significance	Level of Risk Acceptability	Countermeasure
Class 1	<b>Low</b>	Tolerable if improvement is uneconomic.	Low-cost prevention or mitigation where justified. Should be periodically reviewed.
Class 2	<b>Moderate</b>	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	<b>High</b>	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 3B	<b>High</b>	As Class 3. Low likelihood / high consequence risks - Additional quantitative risk assessment required before finalising risk assessment and treatment.	As Class 3 with additional Quantitative risk assessment required.
Class 4	<b>Critical</b>	Intolerable. Risk reduction must be implemented.	Prevention and mitigation measures reported immediately to the Chief Executive.

## 4.2.5 Risk Treatment

Our risk treatment consists of determining what will be done in response to the identified risks. In some cases there will be no existing treatment and appropriate treatment shall be determined. The decision of a treatment type is the first step in risk treatment planning.

At Aurora treatment may consist of one or more of 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
- **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.

The following sections outline 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:

## 4.3 Strategic Risks

Strategic risks relate to uncertainty in achieving Delta's strategic objectives which requires Senior Management & Board oversight and are typically a superset of the risk categories. Risks currently being categorised as strategic risks include:

- **Regulatory and Compliance Risks** – a key risk to Aurora is non-compliance with legislative and regulatory requirements;
- **Health and Safety** –this is a risk that arises from a safety control failure resulting in the fatality or serious harm of our staff, contractors or the public;
- **Critical Asset Failure** – a risk that arises from the failure of critical assets to perform their required function;
- **Resourcing Risk**- the risk of not obtaining adequate competent human resources for timely design and construction is an industry-wide risk. 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;
- **Financial** – a risk where the Company will suffer an unexpected significant Loss of revenue or cost Increase;
- **Natural Disaster** - as a lifeline utility Aurora has significant exposure to natural disaster. This risk is primarily about inadequate resilience and recovery following an emergency.

### 4.3.1 Compliance Risk

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.

### 4.3.2 Safety Related Risks

We operate in a high risk industry where a proportion of our people undertake tasks everyday which exposes them to the risk of harm. Nonetheless we are committed to providing a safe and healthy work environment for our employees, contractors and the communities in which we operate. We insist that everyone has the right to come to work with the expectation that they will return home safe and healthy, every day.

We believe there is no single factor that determines safety in an organisation –every factor determines the safety of the people within it. Safety is a by-product of the effectiveness of the business. Our safety model controls hazards by focusing on three core components the environment, policies and standards and our people.

### 4.3.3 Environment

The environment represents the physical aspects of our model. It includes our equipment, PPE, safety by design and housekeeping. If these things are effective in our Company then the risk associated with safety is reduced. If they are ineffective then we increase the risk of a fatality or serious harm incident.

## 4.4 Policies Standards and Practice

Our standards and practices guide our behaviour. Standards and practice include complying with "Safety Manual, Electricity Industry", which is a set of safety rules for the New Zealand Electricity Generation, Transmission and Distribution Industry. Practices also include the effectiveness of procedures for:

- identifying work risks and hazards;
- ensuring effective controls are in place by utilising Job Safety Analysis;
- testing for safety;
- working at heights;
- working alone;
- isolation, proving de-energisation and earthing; and
- ensuring protection from voltage difference.

Like the environment component, the more effective and efficient we implement these the greater the reduction in risk.

Aurora regularly undertakes audits against our standards using Nel Consulting Limited (NCL).

### 4.4.1 People

The people component of our model includes the skills, experience, competency, behavioural choices and team work of those working on our network. Since almost all work associated with Aurora's network is carried out by contractors (and the main asset management contract being with Delta), particular attention is given contractor management in our Health and Safety Plan which amongst other things requires the primary service provider:

- to ensure health and safety has appropriate focus and expertise;
- to measure and monitor key health and safety performance of itself and contractors working on the Aurora network;
- encourage employee participation and promote employee awareness;
- ensure all contractors working on the Aurora network are competent for the activities they are engaged to undertake, either directly by Aurora or under the primary service provider; and
- adopting leading industry practice through continual improvement.

### 4.4.2 Public Safety

Aurora is required to have a public safety management system (PSMS) under the Electricity Safety Regulations (2010). Delta holds and maintains a PSMS on behalf of Aurora which complies with NZS7901:2008 and is annually audited. The intent of our PSMS is to prevent serious harm to any members of the public or significant damage to their property.

An analysis of the system indicates that since 1 April 2015 there have been 68 incidents which have been entered as either a high or extreme risk. Not surprisingly failed poles and conductor down events account for 80% of total. The primary root cause in the case of conductor down events is vegetation while in the case of poles it can be attributed to end of life factors such as rot. Both the vegetation and pole replacement programmes are discussed in further detail following.

## 4.4.2.1 Vegetation management

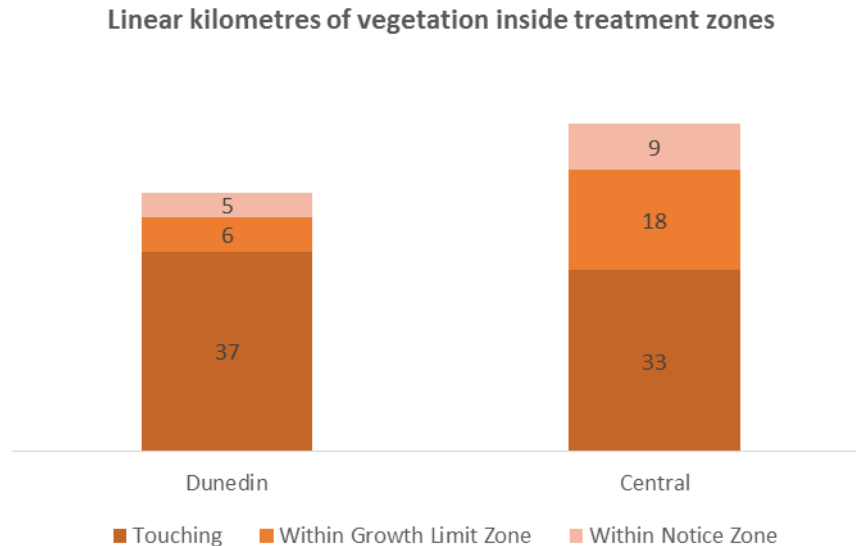
Vegetation in close proximity to power networks has a profound impact on network risk. Trees touching power lines are our most frequent cause of outages as a result of physical impact between the conductor and the vegetation. In such situations, arcing erodes the conductor until its mechanical strength is no longer able to withstand the tension. Vegetation also poses a major hazard by conducting electricity, with the potential to cause injury or death as a result of earth potential rise. Under the Electricity (Hazard from Trees) Regulations 2003 Aurora, along with vegetation owners, is jointly responsible managing the impact of trees on the network.

Following interruptions in 2012 funding was allocated to manage vegetation encroaching on overhead lines in both Dunedin and Central Otago. Record expenditure of \$8.21M was undertaken over the last three years to combat vegetation growth. This investment includes the development and successful implementation of a mobile data-capture platform enabling real-time update of data back to asset information systems using wireless tablets from the field.

### 4.4.2.1.1 Condition and performance

Following the implementation of mobile data capture Aurora now has access to a much richer source of information upon which to formulate plans for liasion, felling, removing or trimming of vegetation. The mobile solution has also impacted on the way we monitor and measure ourselves against the plan.

As at 31 December 2015, there are 70km<sup>2</sup> of line where the vegetation is in close proximity to the line, 24km<sup>2</sup> where the vegetation is within the growth limit zone and approximately 14km<sup>2</sup> where the vegetation is within the Notice zone condition – see Figure 4.3.



**Figure 4-3 Vegetation Within Treatment Zones**

## 4.4.2.1.2 Vegetation inspection plans

**Table 4-2 Vegetation control activities**

Activity	Purpose	Interval
<b>Vegetation liaison</b>	<ul style="list-style-type: none"> <li>Pre trim or fell inspection of affected lines and cables as well as well ensuring any work undertaken has been done in an appropriate manner.</li> </ul>	Continuously
<b>Planned maintenance - vegetation trim/ felling</b>	<ul style="list-style-type: none"> <li>Removal of vegetation from affected lines and cables as part of a planned program of work.</li> </ul>	Continuously
<b>Corrective maintenance – vegetation trim/ felling under Regulation 14</b>	<ul style="list-style-type: none"> <li>Removal of vegetation from affected lines and cables where vegetation poses an immediate health and safety risk.</li> </ul>	As necessary

## 4.4.2.1.3 Removal plans

Safety remains our top priority with respect to vegetation. In order to achieve our vegetation goals of more than 34,000 linear metres cut per year we:

- have established a dedicated business unit to address vegetation concerns; and
- are continually improving the mobile solution to provide more robust and timely risk assessments.

The increasing use of aerial surveys in 2017 is expected to improve the identification and prioritisation of work on problem vegetation sites.

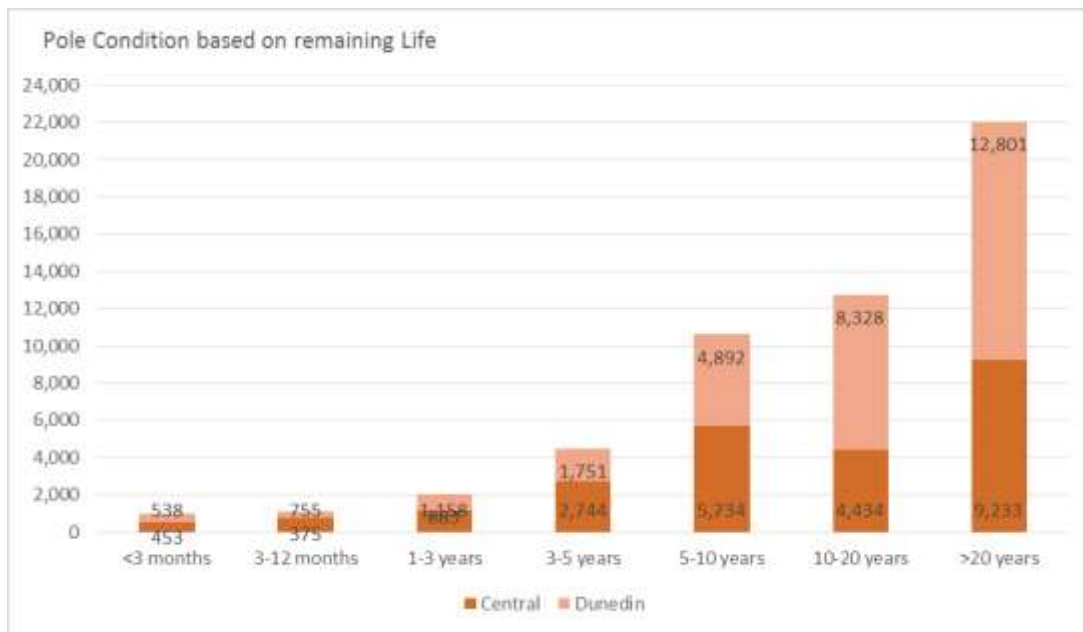
## 4.4.2.2 Pole replacement

Poles are assessed for their condition based on a scale of 0-6. Condition 0 means an overhead line structure which is at risk of failure under normal structural loads. As at December 2015, there are 991 condition zero and 1,130 condition 1 poles which require some form of intervention within the next 12 months.

Aurora recognises the risk to the public posed by deteriorating poles and has taken significant steps in the last 18 months to help address the backlog including:

- between 1 April 2014 and 31 December 2015 we have replaced 874 poles (28 of which failed in service) as a result of end of life factors;
- introduction of a Blue “Do Not Operate” tag in addition to the Red “Do Not Climb” tag. While this does not strictly improve the safety of the public it has significant benefits to our linesman providing them with additional information about non-structural defects that are present; and
- implementation of Deuar Mechanical Pole Testing (Deuar MPT) technology which enables direct measurement of pole strength to support revised condition ratings and remaining life estimates.

Table 4-3 - Pole Condition Remaining Life Estimates



#### 4.4.2.3 Pole reinforcement

Pole reinforcement involves restoring a pole which has reached its end of life due to below ground deterioration by installing a single-or in some cases a double-steel truss (or nail). By driving the truss (nail) and securing it alongside a wood pole, bending loads applied to the pole because of wind pressure, equipment, ice and wire tension are transferred to the truss (nail), which carries the load to the ground-effectively bypassing the decayed or damaged areas. These trusses (nails), when properly sized and oriented, are engineered to have the equivalent strength of the original wood pole.



**Figure 4-4 Reinforced Pole**

Pole reinforcement is a fast, effective and cost efficient solution when compared to replacement alone. By utilising reinforcement in parallel to our replacement program we will:

- accelerate the reduction in risk (by reducing both the likelihood and consequences) associated with in service failures of poor condition poles;
- increase the longevity of reinforced poles by approximately 20 years;
- reduce the impact traditional replacement on SAIDI by reinforcing using a “live line” technique; and
- significantly reduce the average cost of pole restoration.



#### 4.4.2.4 Protection Upgrades

In response to a number of incidents on our 6.6kV lines where protection did not operate a detailed investigation of our electrical protection options was conducted to help eliminate or mitigate the risk associated with “conductor down” events. Key actions arising from this investigation included:

- enabling earth fault monitoring alarms for all telemetered auto-reclosers on the Dunedin network;
- review of settings for feeders where “conductor down” events have not initiated protection trips; and
- piloting the implementation of sensitive earth fault protection via “arc-sense technology” within SEL relays. This functionality has been enabled on Roxburgh Feeders where modern SEL relays are installed, with projects initiated for priority feeders PC3 (the subject of this incident), Andersons Bay 9.

In addition to the action above, Aurora is exploring the early evaluation of other technologies for detection of low earth fault current faults that may have future potential including:

- utilisation of consumer smart devices, including smart-meters or end of line voltage detection relays, for reliable detection of voltage issues associated with downed conductors.

## 4.5 Asset Risks

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

The following provides a summary of some of the critical Network risks that Aurora is addressing in this plan.

### 4.5.1 Supervisory, Control and Data Acquisition (SCADA) Upgrade

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.

The SCCP project reduces the risks associated with these issues by implementing a new SCADA (system incorporating distribution and outage management systems, new communication links between control rooms and substations, new remote terminal units (RTUs) at each substation, new load control equipment, subtransmission circuit protection equipment and direct communication links between Aurora and Transpower.

The SCCP project has a construction timeline of approximately 7 years at an estimated cost of \$22.21 million. Once the programme is completed, a significant portion of the existing network control and operation risks will be eliminated. Network operational efficiency will also be significantly improved.

## 4.5.2 Zone Substation Buildings and Equipment

Aurora has 39 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 seismic risk for all Aurora's zone substation buildings and equipment were carried out in FY2015.

Since then Calibre has carried out detailed design and documentation of seismic upgrades to 100% of New Building Standard (NBS) for Importance Level 3 (IL3). The scope of the work carried out for each building comprised:

- review of DSA and available drawing records including site photos from previous inspection;
- a Desktop liquefaction study (Andersons Bay, North City, South City, St Kilda, Ward Street);
- a site visit to perform intrusive investigations and confirm feasibility of proposed strengthening concept;
- engineering design for the proposed concept;
- preparation of detailed drawings and design report;
- preparation of technical specification (drawing sheet) sufficient for building consent and construction; and
- Producer Statement (PS1).

The seismic strengthening program is shown below:

**Table 4-4 Seismic Strengthening Program (FY Year Ending 30 June)**

Risk ranking	2016	2017 (\$000)	2018 (\$000)	Total (\$000)
Design	\$279.11			\$279.11
Strengthening of buildings	\$125.50	\$934.50		\$1,060.00
Strengthening of equipment		\$320.50	\$657.00	\$977.50
<b>Total</b>	<b>\$404.61</b>	<b>\$1,255</b>	<b>\$657.00</b>	<b>\$2,316.61</b>

## 4.5.3 Gas Insulated 33kV Cables

Perhaps the most significant risk of a catastrophic asset failure relates to our remaining 33kV gas filled cables. Our analysis indicates that the primary failure mechanism is deterioration of the bronze tapes as a result of age. Typically gas cable faults are located where land disturbance has occurred due to new water pipes, fibre or power pole installations. This is due to voids being created in the soil that results in lower surrounding pressure on the cable allowing the lead sheath to rupture. The lead sheath is able to rupture due to the mechanical strength in the bronze tape having failed. As the mechanical strength supplied by the bronze tapes reduces, more failures of these gas cables are likely to occur.

**Table 4-5 Replacement Plan for 33kV Gas Filled Cables**

Zone Substation	Installed	2017	2018	2019	2020	2021	2022
Carisbrook	1961	Design					
Willowbank	1963						
Smith Street	1959			Design			
Ward Street	1967						

## 4.5.4 Oil Filled Switchgear

Aurora operates a fleet of around 856 RMUs dominated by ABB units (486). A programme of removal of deteriorating high risk oil filled Ring Main Unit (RMUs) on the network commenced in 2014. This short to medium term programme is focused on replacing the older Statter, Reyrolle and Long & Crawford units in that order. Some of the known criticalities on these units include:

### 4.5.4.1 Statter

- the oil chambers are not free breathing and all oil chambers are vulnerable to moisture ingress around gasket interfaces. The moisture can affect the fuse carriage insulation;
- corrosion around the operating shaft entry point on the load switches can lead to moisture ingress;
- voids can occur in the compound in the busbar system due to solar gain if not shielded;
- VLTB and VLTC could have a failure of a roll pin connecting the mechanism to the switch blade. This was subject to a modification;
- disruptive failures of busbars due to moisture ingress;
- disruptive failures of cable boxes due to moisture ingress; and
- disruptive failure of fuse chamber probably due to moisture ingress.

### 4.5.4.2 Reyrolle

- broken nylon trip arms;
- catastrophic failures of the main tank;
- multiple cable box failures some report damage through to main tank causing loss of oil; and
- cracked fuse found after reclosing low voltage circuit breaker repeatedly onto fault.

### 4.5.4.3 Long & Crawford

- These fuse switches can be particularly vulnerable to maintenance induced failure compared to other types. Criticality is usually on the contact settings of the fuse carrier which are fit for service when set according to the manufacturer's instructions;
- The alignment of the fixed and moving contacts on the fuse-switch are critical because they are a butt faced contact. The fixed contact risers must not be disturbed from their vertical position to ensure alignment;
- the viewing windows on the front of the main tank, as fitted in Aurora units, are a significant vulnerability adding additional risk to the operator; and
- there have been instances, not frequent, of end caps being blown off on fault and leaving exposed conductors which can then be re-energised.

While our primary focus is on removing the high risk units from the network we are also developing improved condition based strategies to manage the ABB units in long term.

### **4.5.5 Critical Electrical Lines (CELs)**

Aurora defines all of its 33kV and 66kV subtransmission lines and small portion of its 11kV infrastructure as critical electricity lines. CELs and their associated substations play an essential role in ensuring the quality, reliability and security of electricity supply.

However, just as important, CELs contribute to the social and economic wellbeing and health and safety of the region.

Figures 4.5, 4.6 and 4.7 provide an overview of the CELs' in both Dunedin and Central.



Figure 4-5 Cromwell Critical Electrical Lines





Figure 4-6 Frankton Critical Electrical Lines



Figure 4-7 Dunedin Critical Electrical Lines

## 4.6 Network Capacity Risk

An important aspect of planning a distribution network is to ensure that predicted network loads are compared with the capacity of the network. Our analysis indicates potential risks relating to the Cromwell, Frankton and Halfway Bush Grid Exit Point (GXP) supply areas in the short-to-medium term.

A particular focus for Aurora is the Upper Clutha Valley which has necessitated investment in Aurora's network in recent years including:

- construction and commissioning (November 2015) of a new 66/33/11kV, 7.5MVA, zone substations at Camp Hill;
- a range of projects aimed at providing secure supply to the Manuherikia Valley including:
  - the establishment of the Lauder Flat 33/11kV, 3MVA, substation. This project originally involved utilising a 1MVA transformer from the redundant Roxburgh Hydro substation, but is now utilising the 3MVA transformer from Maungawera, made possible by the expected commissioning of Camp Hill;
  - the design and construction of a mobile substation parking bay at Omakau, instead of a substation rebuild (made possible by the 3MVA transformer at Lauder);
  - the Manuherikia subtransmission river crossing and feeder reinforcement; and
  - a rebuild of the Omakau-Becks 33kV line
- a new switching station at the corner of Riverbank Road and Ballantyne Road in Wanaka, along with associated 66kV cabling. Riverbank road is expected to be commissioned in 2017.

## 4.7 Financial Risks

Financial risk relates to uncertainty in achieving its financial objectives. The methods for managing financial risk include:

- project, tender and contract management standards;
- business planning, budget, fraud standards, controls and audit processes; and
- strategic Review Committee standards.

## 4.8 Regulatory Risks

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.

## 4.9 Sustainability Risks

Sustainability risks relate to uncertainty in Delta achieving its environmental, community, cultural, people, and reputational objectives.

### 4.9.1 Community

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).

### 4.9.2 People

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.

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.

### 4.9.3 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.

## 4.10 Emergency Management

Our emergency response planning is based on the concepts of the Four “R’s” – Reduction, Readiness, Response, and Recovery used by emergency services, Civil Defence Emergency Response Organisations and many utility operators in New Zealand:

**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).

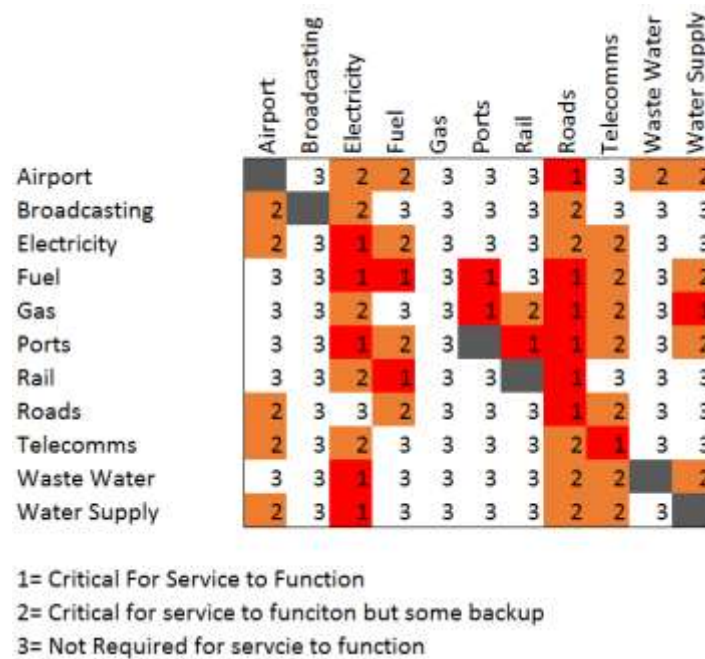
### 4.10.1 Classification of Incidents

Aurora uses a quick reference chart which highlights how we classify, respond and escalate emergency management incidents included in the appendix for reference.

### 4.10.2 Interdependence

All lifelines services rely to some extent on some or all of the other lifelines services in order to operate. Therefore, a hazard impacting on one lifelines network is likely to have a knock on effect on others. To mitigate the risk that arises from this interdependence, many lifelines have backup services should the lifelines service they rely on fail such as on-site generators.

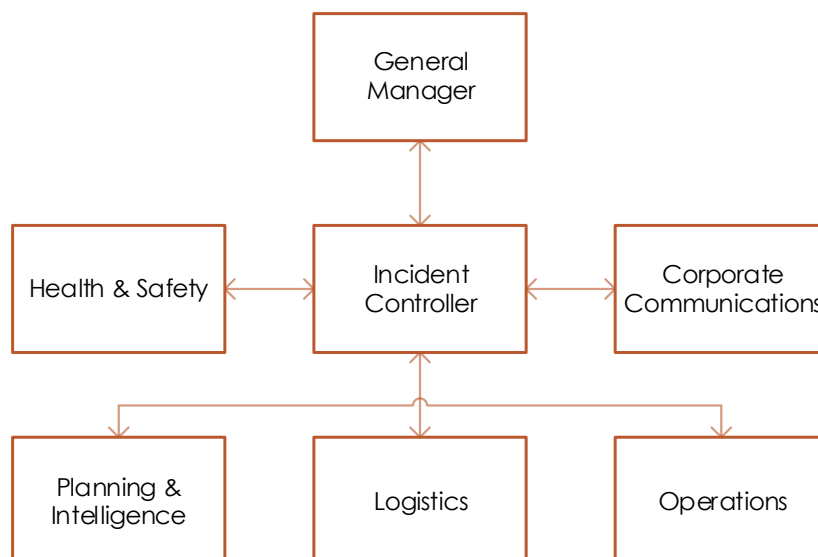
Figure 15 summarises the extent of interdependence between Aurora and other lifelines sectors. The figure reflects the impact on lifelines services following 1 week of outage of another lifelines service, in an emergency response situation. Dependence levels may be different in business-as-usual or shorter/longer duration outages.



**Figure 4-8 Lifeline Interdependency**

## 4.10.2.1 Command structure

Our 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 for managing the response to an incident involving multiple responding agencies. The model is:



**Figure 4-9 Coordinated Incident Management System Model**

## 4.10.3 Potential Impacts of Natural Hazards

In 2014-2015 Aurora participated in the Otago lifelines project. The purpose of this project was to assess the potential impacts of hazards on the region's lifelines infrastructure, identify mitigation strategies to reduce that risk and to improve critical infrastructure resilience.

This programme of work identified that Storm/Flooding, earthquakes and high winds are our major natural disaster risks and these are covered in more detail below.

### 4.10.3.1 Storm/flooding

While distribution lines are unlikely to suffer damage from floodwaters the biggest potential for damage is our substations which would become inundated with the potential for days to weeks for full restoration of services. Critical sites in flood risk areas include:

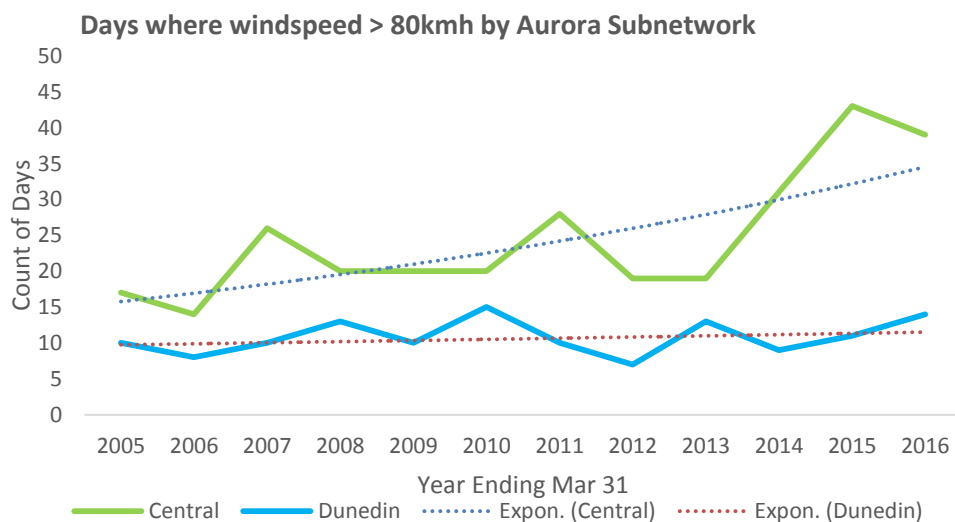
- South Dunedin substation which services 17,000 customers. Transpower is currently evaluating a project to link the Halfway Bush and South Dunedin substations to provide back-feed options if the South Dunedin substation is not operating;
- Mosgiel zone substation - mitigated using temporary barriers; and
- our underground substations in the Dunedin CBD.

### 4.10.3.2 High winds

Strong winds can occur under a number of different atmospheric conditions, including strong north-west winds lasting from 6-10 hours generated from a deep trough advancing across the Tasman Sea squeezing against an intense blocking anticyclone to the east of the South Island. Another high wind scenario is short (less than one hour) but extreme southerly wind gusts associated with a rapid progression of cold air up the eastern coast of the South Island.

The local network is typically designed to AS/NZS 7000 which allows for around 900-1200Pa or 160km/hr. wind speeds. Events in the last few years illustrates there can be widespread impacts in a significant wind event resulting in days to weeks restoration time for some customers.

Figure 4-10 indicates the number of days were wind speed exceeded 80 km/hour by Aurora sub network. This graph highlights a significant increase in the number of high – extreme wind days impacting our Central Network between 2010- 2016 (1 February 2016). Interestingly the Central network typically accounts for approximately 2/3 of our network System Average Interruption Duration Index (SAIDI).



**Figure 4-10 High Wind Days Historic Profile**

### 4.10.3.3 Earthquakes

A large number of active faults lie within Otago and many more outside the region are capable of affecting the region. While ground shaking will almost always be felt during large earthquakes, the occurrences of liquefaction, lateral spread and surface rupture are largely dependent on the size and style of earthquake.

### 4.10.4 Emergency Procedures and Plans

Aurora has developed a number of quality procedures and plans to enable us to respond to events beyond our control. These include:

### 4.10.5 Civil Defence Emergency Management Act 2002

Aurora is defined as a lifeline 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 that details how we would ensure the effective use and co-ordination of resources within Aurora's electrical supply area.

### 4.10.6 Business Continuity Plan

Delta has a 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; and
- plan exercise and testing programme to demonstrate capability and competence.

Our Business Continuity Plan (BCP) is designed to manage and support a number of scenarios, including IT system failure, major infrastructure failure, natural disasters and pandemics.

### 4.10.7 Contingency Plan

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.

### 4.10.8 Participant outage Plan

Our participant outage plan is designed to comply with the Electricity Commissions security of supply outage plan. The participant outage plan details how Aurora would manage severe generation shortages and /or significant transmission constraints.

## 4.11 Conclusion

This section has highlighted the main risks related to Aurora's activities and some of the work being undertaken to mitigate them. 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 LIFECYCLE ASSET MANAGEMENT**

### **5.1 Introduction**

Aurora manages electricity assets throughout their life cycle in three geographically separate networks (Dunedin, Central Otago and Te Anau), with both rural and urban characteristics. Delta operates the network, carries out network planning and develops the maintenance plans and programmes on behalf of Aurora. The Asset Management Plan has a 10-year horizon and describes the work required to manage the lifecycle activities of the assets to ensure risks, costs and performance are appropriately managed. The plan is refreshed annually to ensure it reflects the best available information.

### **5.2 Maintenance Policy and Strategy**

#### **5.2.1 Policy**

The maintenance policy for Aurora's network sets requirements associated with maintenance and refurbishment of electricity network assets. This policy requires the preparation of maintenance plans and programmes for all asset categories, the maintenance of records, ensuring resources are available and effective work management systems are established.

#### **5.2.2 Strategy**

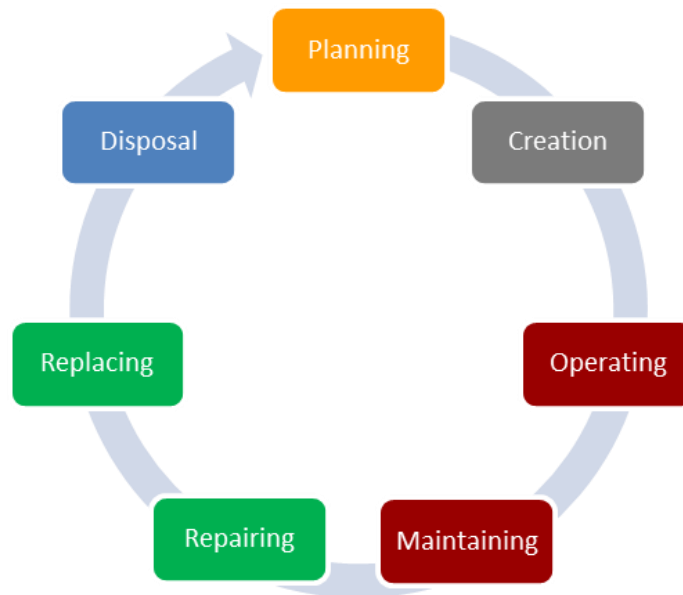
Aurora's maintenance strategy is based on monitoring of asset condition to achieve the optimal balance of risk, cost and performance. Aurora network maintenance is conducted in line with the risk management policy described in Section 4 and is reflective of safety, customer, community, compliance and shareholder expectations.

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.

### **5.3 Lifecycle Asset Management**

Lifecycle asset management encompasses all practices associated with considering management strategies as part of the asset lifecycle from planning to disposal. The objective of lifecycle asset management is to maximise economic return on physical assets over their life by achieving desired service levels, while effectively managing the risks inherent in owning and operating a large asset base.

Aurora's lifecycle activities span the following five stages as reflected in FIGURE 5-1 ASSET LIFECYCLE PROCESS below which is expanded upon further in the following sections:



**Figure 5-1 Asset Lifecycle Process**

### **5.3.1 Planning**

The planning phase covers confirming the level of service required and ensuring the most effective solution is found to meet that need. The planning lifecycle extends right through to approval and handover for implementation.

### **5.3.2 Creation, Acquisition or Enhancement of Assets**

Aurora Energy's assets are typically low-medium value, long-life; however, many of these assets are approaching or past their midlife. Consequently, a strategy of capital renewal is built in to our Asset Management Plan. All major works that are planned to be undertaken are preceded by verification of condition, issues, risks and potential solutions to mitigate the risks and realize improvement opportunities.

### **5.3.3 Operating and Maintaining Assets**

The operations phase includes real time operational control, outage coordination and contingency planning. In contrast the maintenance phase covers everything involved in retaining or restoring our assets to a state in which they can perform a required function. A successful maintenance programme ensures that work effort is executed as cost-effectively and efficiently as possible and that the equipment performs in accordance with the needs of the business.

#### **5.3.3.1 Maintenance types and strategies**

Maintenance strategies can range from run to fail through to sophisticated monitoring systems. Each strategy has a distinct cost and benefit associated with it, and each strategy is appropriate for a particular set of circumstances. The maintenance types and strategies adopted by the Asset Management Team are described below.

### 5.3.3.1.1 Preventative maintenance

Preventative maintenance is carried out at predetermined intervals or according to prescribed criteria, aimed at reducing the failure risk or performance degradation of the equipment. Examples include painting of network assets and maintenance of access tracks, including associated security structures and weed and vegetation clearance.

### 5.3.3.1.2 Condition-based Maintenance

Condition-based maintenance is work triggered by the condition of the equipment, as determined by inspections, tests or operational readings. Maintenance is then scheduled and performed at an appropriate time. The extent of this secondary condition-based maintenance work is based on the condition found and may be a repair or replacement of a particular item.

This strategy is typically 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.

### 5.3.3.1.3 Corrective maintenance

Corrective maintenance is a task initiated as a result of the observed or measured condition of an asset before or after functional failure. Corrective maintenance can be 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) or as part of our planned program of work.

### 5.3.3.1.4 Run to fail

A minimal, run-to-fail maintenance strategy is appropriate in certain circumstances. Aurora apply this strategy where the consequences of failure are not major and where the costs of ongoing condition monitoring may outweigh the costs of failure.

## 5.3.4 Repair and Renewal of Assets

Repairs are carried out in response to the need to maintain network asset integrity for current security and/or quality of supply and can be either planned or unplanned. In contrast 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.

For new or replacement assets, specifications are compiled and the scope is defined. The specification then becomes the basis for the detailed design, and subsequent testing, and installation. Aurora Energy works closely with its designers and suppliers to ensure that these stages are formally in place and works proactively to ensure the best outcome and to minimize risks.

## 5.3.5 Decommissioning/Disposals

A policy on site decommissioning for Aurora's assets has been drafted. This standard sets out the requirements for site decommissioned 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.

## 5.4 Asset Details by Category

The quantity and value of Aurora's assets by category (based on the information provided for the 2014 Electricity Distribution (Information Disclosure) Requirements) is presented in Table 5.8 included in the appendices. Further information on age, condition and performance is provided in the following section.

## 5.5 Asset Management Planning

### 5.5.1 Introduction

This section outlines Aurora's network assets from the point of view of functional groups. These groups represent an economical means of rationalising network assets by the function where lifecycle management strategies will comprise significant overlap. This approach marks a progression to a more consolidated approach to management of common asset types.

The functional groups that have been selected for forward asset lifecycle management are as follows:

Priority	Lifecycle Management Plans	Coverage
1	Support structures	Poles and cross-arms
2	Switchgear	CBs, reclosers, RMUs, air break isolators, sectionalisers, switches and fuses
3	Lines	Subtransmission, distribution, lv lines, conductor insulators and ancillary overhead assets
4	Transformers	TX, voltage regulators , auto TX
5	Cables	66/33KV HV / LV / STLT and cable terminations
6	Protection systems	Protection (relays / inter-trips / alarms / pilots), battery banks
7	Mobile plant	ZS mobile sub, distribution mobile subs, trojans, portable earths
8	Generators	Generators, emergency standby generators,
9	Communication Systems	Remote comms site, SCADA, sun workstation, ripple control units (ST & HV injection units)
10	Building and grounds	Zone, distribution and underground, radio huts, oil containment
11	Other primary equipment	Earths, earthing resistors, surge arrestors, UG/GM link boxes, LV pillars, earth grids, metering

### 5.5.2 Asset Description

This section contains a brief description of the type, function and location of each class within the asset functional groups.



## 5.5.3 Asset Condition and Performance

The Electrical Engineers Association (EEA) released guidelines<sup>2</sup> in January 2016 to assist electricity distribution businesses in the assessment of asset condition. Aurora was instrumental in the development of this framework through intensive engagement in the working groups held by the EEA.

Aurora has adopted an approach based on the framework presented within the AHI guidelines, that is, assessment of asset condition derived from a combination of different inputs weighted appropriately resulting in a condition grading system that is consistent across all assets classes.

This approach enables the effective renewals planning using a common set of definitions from excellent condition (C5) to replacement (C1).

Asset Condition Grade	Condition Interpretation
<b>C5</b>	As new condition
<b>C4</b>	Some deterioration present
<b>C3</b>	End of life drivers present, regularly monitored
<b>C2</b>	Intervention likely within 3 years
<b>C1</b>	Replacement recommended

Often age is used as a proxy for asset condition where obtaining useful data is either not cost effective or is yet to be implemented, or has previously been deemed to be of marginal benefit. When age is considered an appropriate proxy for condition, the calculation of remaining life serves to inform forward renewal/refurbishment programmes.

In the past, remaining life had been derived from the standard lifetimes used with regulatory<sup>3</sup> guidance however lifetimes calculated in this way have been found to be more representative of a period between the onset of unreliability and the maximum practical lifetime of an asset. Maximum practical lifetimes tabulated within the AHI guide have been employed to provide a more realistic input in the assessment of remaining life and condition grading.

Other inputs are used to assess condition either as a result of visual inspections, SCADA data, operational and/or fault history and condition monitoring. When all inputs are combined together the resulting score determines the final asset condition grade assigned to an individual asset.

Furthermore, by utilising a non-linear formula when calculating the relative effect of different condition inputs the resultant list of asset grades gives a score which sits between each of the above grades effectively providing a prioritisation for those units where renewal is recommended.

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<sup>2</sup> Asset Health Indicator (AHI) Guide 2016 (EEA)

<sup>3</sup> Handbook for Optimised Deprival Valuation of System Fixed Asset of Electricity Distribution Businesses 2010 (Commerce Commission)

### 5.5.3.1 Limitations of AHI

While there are benefits associated with the consistent application of AHI across all asset classes it should be highlighted that:

- the absence of objective and measurable characteristics of asset condition and reliance on indirect measures such as age can have a large and unduly pessimistic impact on the accuracy of ratings; and
- difficulties in determining the right mixture of data points and their weightings to assess the condition of assets can and does impact the accuracy of the ratings.

In essence AHI are not definitive but rather a tool that can be refined to support the application of good engineering judgement. AHI provide an indication of potential risk areas and highlight opportunities that can be more fully explored.

### 5.5.4 Inspection and Maintenance

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.

### 5.5.5 Planned Replacement / Refurbishment Plans

Replacement and refurbishment normally forms part of annual scheduled work to restore, replace or renew an existing asset to its original capacity. Renewal planning is accomplished through analysis of remaining life in conjunction with a risk based prioritisation.

### 5.5.6 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.

## 5.6 Support Structures

### 5.6.1 Asset Description

Aurora has approximately 54,086 poles, which are predominantly constructed out of either pre-stressed concrete or hardwood. These poles support subtransmission, distribution and low voltage conductors.

The other main components of pole structures, besides the poles themselves, are the wood or galvanised steel cross arms that support the insulators. Deteriorated cross arms on pole structures have generally been replaced by tallow wood cross arms with preferred lengths of either 2.1m or 2.7m for (11kV) depending on span length.

### 5.6.2 Asset Condition and Performance

Pole assets are assessed according to a condition rating (0 – 6), where Condition 0 indicates the highest urgency for renewal. Most poor condition poles in the fleet are old hardwood poles (90%) that tend to rot just below ground level, reducing the cross section area to a point where the structure cannot reliably carry design (Condition 1) or normal loads (Condition 0). There are as at 31 December 991 Condition 0 and 1,130 Condition 1 poles on the network.

The current rate of discovery of Condition 0 poles amongst those poles previously determined to be greater than 0 is around 15%. This is high compared to industry averages which typically range from 5-12%.

## 5.6.3 Inspection and Maintenance

Our Maintenance strategy for poles is outlined in TABLE 5-1.

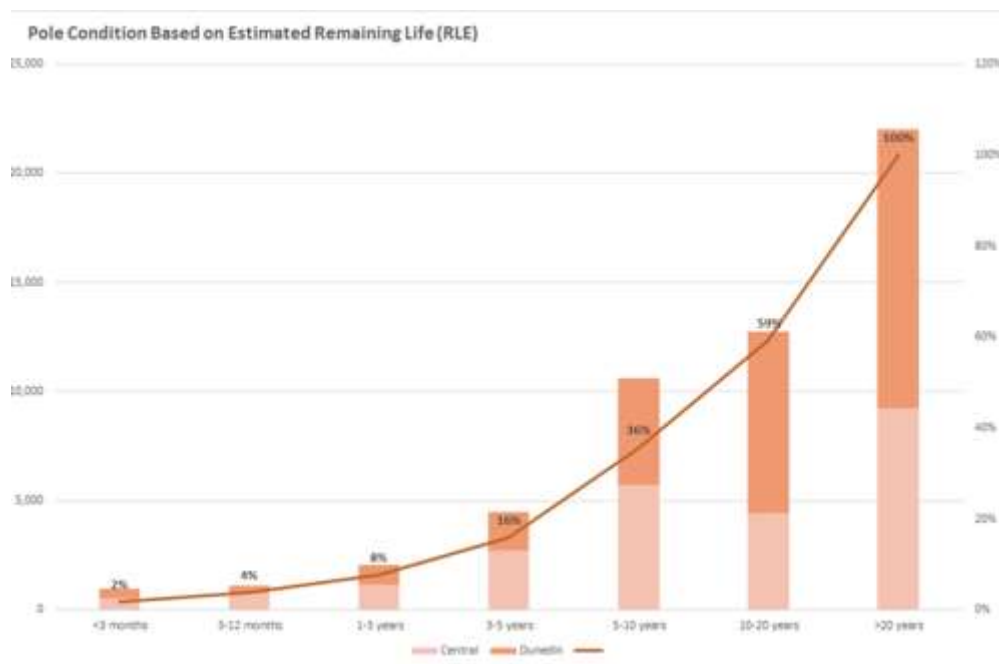
**Table 5-1 Pole Structure Maintenance Strategy**

Activity	Purpose	Interval
Detailed ground based condition assessment.	<ul style="list-style-type: none"> <li>Assess structural condition of poles using either Devar MPT or traditional dig probe and hammer testing</li> <li>Assess condition of insulators, hardware</li> </ul>	Minimum of every 5 years
Cross arm condition assessments	<ul style="list-style-type: none"> <li>Assess condition of cross arms to enable planned replacement</li> </ul>	Minimum of every 5 years

## 5.6.4 Planned Replacement / Refurbishment Plans

Aurora is committed to reducing the risks associated with deteriorating pole condition and from 2016 we have altered our lifecycle management plans to incorporate pole reinforcement in addition to our extensive pole replacement program. Pole reinforcement involves refurbishing the pole before it functionally fails.

As a result of key health and safety and reliability performance drivers, an additional \$2.5M over the life of the plan has been budgeted to proactively address cross arm and pole top hardware failures. This programme will be supported by the detailed condition assessments enabled by our overhead structure inspection regime.



**Figure 5-2 Condition of Pole Structures**

**Table 5-2 Forecast Annual Pole Replacement and Reinforcement**

Substation	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
<b>Pole reinforcement (Central)</b>	350	450	500	500	330	330	330	330	330	330
<b>Pole reinforcement (Dunedin)</b>	250	350	450	480	330	330	330	330	330	330
<b>Pole replacement Dunedin</b>	185	165	162	150	211	215	220	224	228	232
<b>Pole replacement Central</b>	155	160	189	185	114	116	118	120	123	125

## 5.7 Circuit Breakers

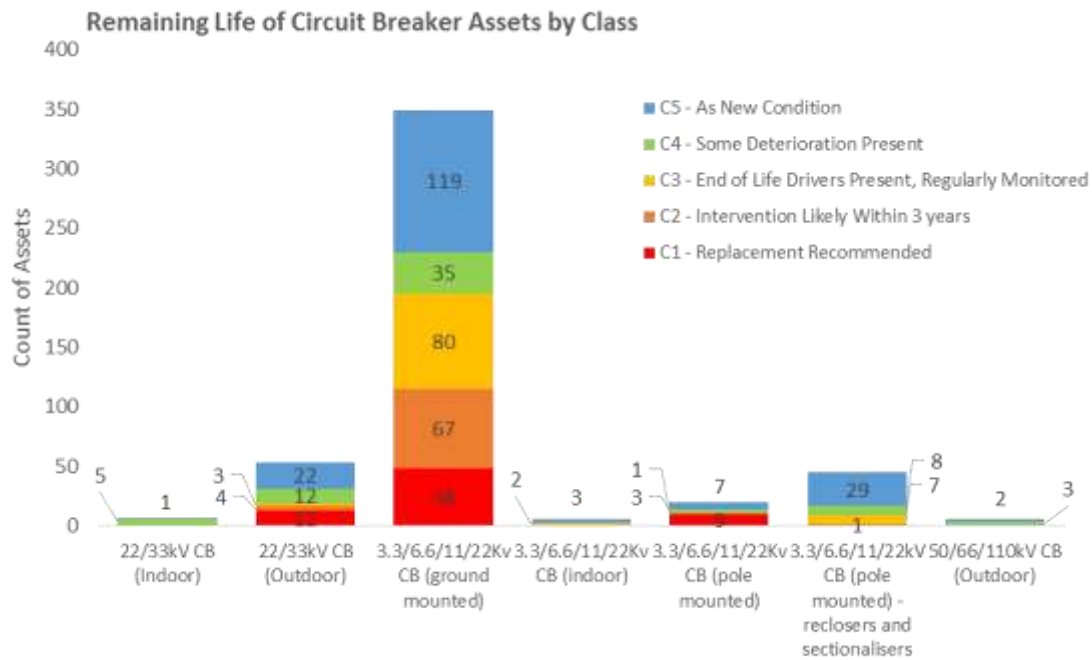
### 5.7.1 Asset Description

A circuit breaker is an automatically operated electrical switch. Its basic function is to provide safe interruption of current during power system faults. They are strategically placed in the network for line, cable and primary equipment protection. When a current is interrupted, an arc is generated. This arc must be contained, cooled and extinguished within an insulating medium, so that the gap between the contacts can again withstand the voltage of the circuit. Some examples of such insulating mediums are vacuum, oil and SF<sub>6</sub>. All of these types are present on Aurora's Network however the most commonly used type is the oil filled circuit breaker.

Circuit breakers can also be differentiated further by the function and configuration of the unit. 33kV circuit breakers are used to provide protection for zone substation power transformers from incoming subtransmission feeders and similarly 6.6/11kV units protect equipment from a power transformer downstream to high voltage distribution feeders. Auto-recloser units provide protection of customers upstream of rural spur lines. Recloser are also useful in protecting against transient interruptions such as tree contacts by immediately tripping the circuit following a fault and then closing again with the rationale the fault has cleared. Reclosing will only be attempted once or twice over a very short period of time.

### 5.7.2 Asset Condition and Performance

Circuit breaker condition grades were calculated from the combination of age and the number of fault operations as recorded in Aurora's outage management system. The analysis shows that of the 84 circuit breakers recommended for replacement a large number are within the within the 3.3/6.6/11kV ground mount category which are predominately high voltage distribution feeder circuit breakers. This cohort of units are exclusively oil insulated circuit breakers located in the Halfway Bush, Neville Street and Smith Street zone substations.



**Figure 5-3 Condition Of Circuit Breakers**

Maintenance data shows there are 9 VWVE 33kV circuit breakers on the network and moisture ingress has been a problem with these units. Failures have been attributed to moisture in the oil due to the failure of the bushing extension seals leading to corrosion of the aluminium extension tubes

### 5.7.3 Inspection and Maintenance

**Table 5-3 - Circuit Breaker Maintenance Strategies**

Activity	Purpose	Interval
<b>Visual Inspection</b>	<ul style="list-style-type: none"> <li>Check for signs of leakage if applicable (SF6 pressure and oil level), corrosion, tank distortion, broken porcelain, tracking on bushings</li> </ul>	1 monthly
<b>Thermal Imaging</b>	<ul style="list-style-type: none"> <li>To identify any hotspots which may indicate damage to the circuit breaker in order to prevent functional failure</li> </ul>	1 yearly
<b>Trip Timing</b>	<ul style="list-style-type: none"> <li>Ensure protection works as designed</li> </ul>	2 years
<b>Insulating Medium Analysis – Breaker Gas Analysis (BGA), Breaker Oil Analysis (BOA), SF6 Testing regime</b>	<ul style="list-style-type: none"> <li>Provide key information on the condition of the circuit breaker to inform maintenance requirements</li> </ul>	4 yearly
<b>Partial Discharge Test</b>	<ul style="list-style-type: none"> <li>Partial discharge measurement is carried out to assess the condition of the circuit breaker's solid insulation and is used in determining the remaining life of the circuit breaker.</li> </ul>	Half life (20 years) 5 years thereafter

Activity	Purpose	Interval
<b>Circuit breaker Overhauls</b>	<ul style="list-style-type: none"> <li>Restore condition of circuit breaker contacts and insulating oil</li> <li>Maintain/lubricate operating mechanism</li> <li>Confirm correct operation of system</li> </ul>	~10 years - however actually being performed 4 yearly to coincide with zone substation overhaul
<b>Operation Based Maintenance</b>	<ul style="list-style-type: none"> <li>To ensure the continued operation of the CB following a certain number of fault operations</li> </ul>	3 earth fault trips
<b>Painting of Outdoor CB's</b>	<ul style="list-style-type: none"> <li>Prevent corrosion</li> </ul>	10 years

## 5.7.4 Replacement / Refurbishment Plans

### 5.7.4.1 22/33kV CB (indoor)

No renewals are scheduled within the planning period.

### 5.7.4.2 22/33 kV CB (outdoor)

The 33kV VWVE circuit breakers located at the Port Chalmers zone substation were replaced in FY2016. Other 5.7.4.2 22/33 kV CB (outdoor) renewals are detailed below:

**Table 5-4 22/33kV Outdoor Circuit Breaker Replacement**

Substation	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
<b>Alexandra</b>	3									
<b>Neville Street</b>		3								
<b>Outram</b>		2								
<b>Roxburgh</b>				4						
<b>Wanaka</b>									3	

Additionally, new 33kV circuit breakers installations to replace fuse protection at Dalefield and Ettrick are scheduled for completion within FY2016. The 33kV CB will be replaced during the rebuild of the Clyde-Earnsclough substation.

### 5.7.4.3 3.3/6.6/11/22kV zone substation indoor CB

Replacement has been recommended for 63 units in this sub-group with a further 74 likely requiring intervention in the next three years. The immediate renewals concern high voltage distribution feeder circuit breakers located at Halfway Bush, Neville St and Smith Street zone substations which are scheduled to take place in line with other substation upgrades such as installation of new power transformers. Life extension maintenance including shorter cycles and detailed post-fault evaluations of the units will be intensified for the units located at Smith Street and Halfway Bush to ensure that the units remain in service until renewal.

**Table 5-5 6.6/11kv Indoor Circuit Breaker Replacement Programme**

Substation	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026
Halfway Bush						16				
Neville Street	32									
Smith Street				15						
Outram	5									
Andersons Bay	14									
Willowbank				15						
Green Island							15			

#### 5.7.4.4 3.3/6.6/11/22kV distribution substation ground mount CB

No renewals are scheduled within the planning period.

#### 5.7.4.5 3.3/6.6/11/22kV CB (pole mounted)

A small cohort of pole mount circuit breakers remains at a select group of central Otago zone substations. These will be progressively removed from service individually or due to other substation upgrades projects.

**Table 5-6 6.6/11kV Circuit Breaker Replacement Programme**

Substation	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Ettrick substation	1									
Roxburgh hydro substation	1									
Earnsclough substation			1							
Clyde - Earnsclough substation			6							

#### 5.7.4.6 3.3/6.6/11/22kV (pole-mounted) – reclosers and sectionalisers

A total of six reclosers were installed on the network in 2016 comprising of two renewals and 4 additional assets.

**Table 5-7 Recloser Works 2016**

Area	HV Feeder	Driver	Status
Andersons Bay Tomahawk Road	AB9	New asset	Complete
Alexandra Dunstan Road	AX168	New asset	Complete
Alexandra Letts Gully	AX168	New asset	Complete
East Taieri, Morris Road	ET 2	New asset	Complete
Cromwell, Lowburn	CM832	Renewal	Complete
Port Chalmers, Weir Road	PC3	Renewal	Complete

Future plans for recloser projects consist of continuing renewal of remaining KFE type reclosers in Dunedin and Central as well new assets installed in both sub-networks as per table 5.8 below.

**Table 5-8 Future Planned Recloser Installation Projects**

Project	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Recloser replacements in Dunedin		1								
Recloser replacements in Central	1		1	1	1					
New 11kV reclosers and switches Dunedin	1	1	1	1	1	1	1	1	1	1
New 11kV reclosers and switches central	2	2	2	2	2	2	2	2	2	2

## 5.8 Switchgear

### 5.8.1 Asset Description

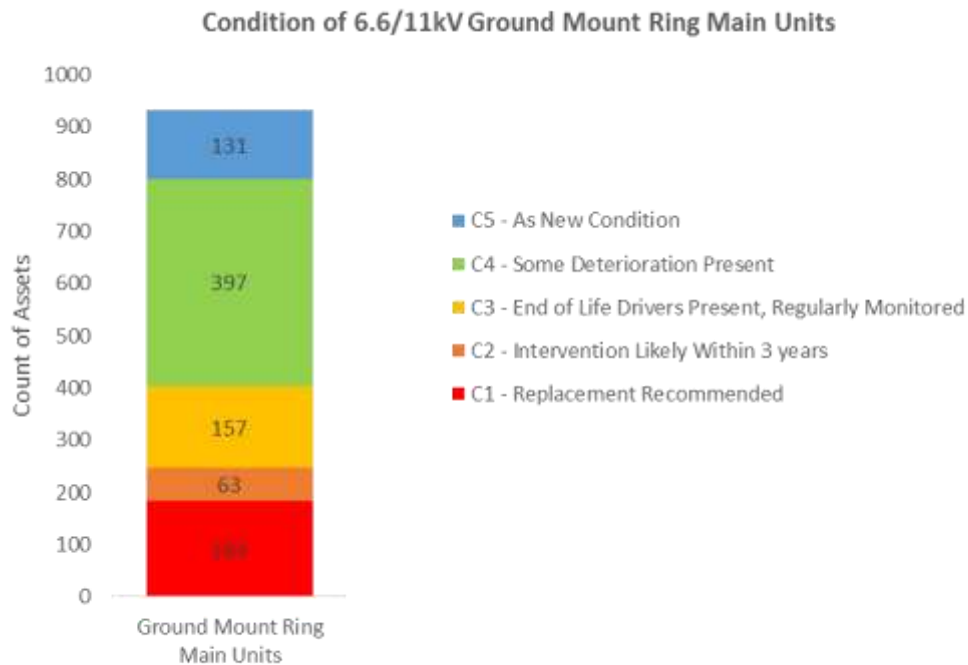
Distribution switchgear types include pole-mounted switches and fuses, ground-mounted ring main units and 6.6kV 11kV and 22 kV air break switches. Due to the diverse nature of distribution switchgear, maintenance strategies will vary substantially from type to type. Details of the maintenance requirements of distribution switchgear are listed in Table 5.9.

### 5.8.2 Asset Condition and Performance

#### 5.8.2.1 6.6/11kV ground mount ring main units

184 units were assessed as end of life under age assumptions; in order to make better practical forward planning decision a comprehensive maintenance regime will take place in 2017 to determine asset condition which will very likely change this distribution. Some renewals may result from this immediately reflected in the forecast allocation to be revised in next year's plan to make use of the condition data gathered during maintenance. A known group of ground mount switches are to be progressively replaced due to end of life which includes switchgear manufactured by GEC, Reyrolle and Statter.





**Figure 5-4 Condition of 6.6/11kV Ground Mount Ring Main Units**

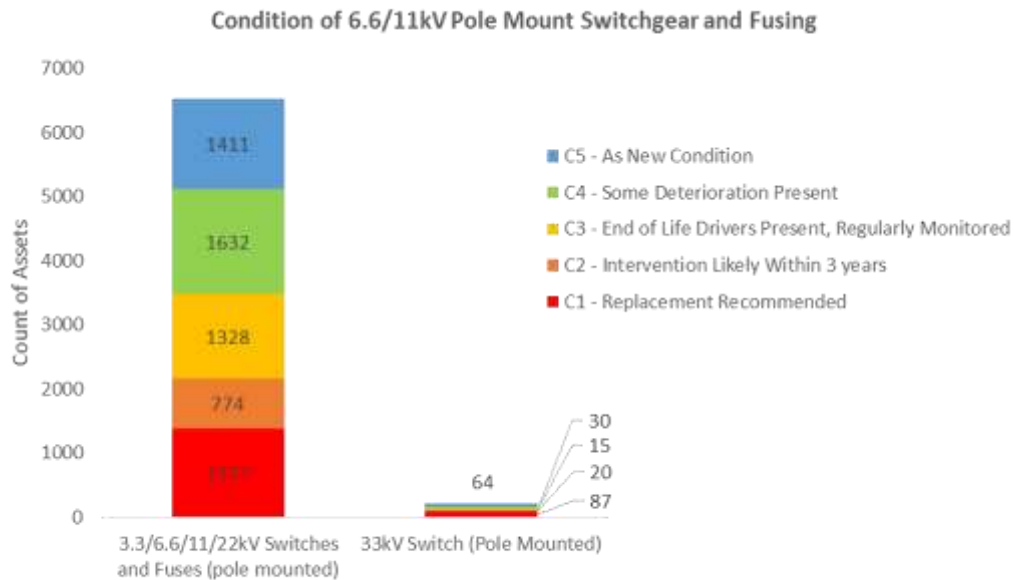
## 5.8.2.2 33kV switch (pole mounted)

Due to calculation of age condition 87 assets in this class are recommended for replacement.

## 5.8.2.3 3.3/6.6/11/22kV switches and fuses (pole mounted)

Repeated failures of the stand-off insulators (M2025) on the FD-A fuse mounts has led to a do not operate safety alert being issued last year. Samples of recovered and failed insulators (in mark 2 design) have been sent to the manufacturer who has concluded that the failure was due to corrosion of the aluminium used for a period as an insert in the product. The aluminium is prone to corrosion with the corrosion products causing the insulator to fail by cracking or shearing at the base of the cement. The FD-A fuse mounts age from the late 1960s until the 1990s; the product has gone through two design changes over the years with the original lead (Pb) setting being replaced with Portland cement and the threaded insert changing from brass to aluminium.

Canterbury Engineering's FD-A mounts are pictured below (left) and are distinct from the older EETEE fuse mounts which have a pin type insulator and not a standoff.



**Figure 5-5 Condition of 6.6/11kV Pole Mount Switchgear**

Both FD-A and EETEE fuse mounts have been previously described as 'ET' fuses which stems from one of the brands of fuse they typically carry and the fuse mount they replaced i.e. EETEE. 'ET' has become a generic term for such current limiting / HRC fuses in Dunedin.



## 5.8.3 Inspection and Maintenance

**Table 5-9 Switchgear Maintenance Plan**

Activity	Purpose	Interval
Condition Inspection	Condition inspection of oil filled ground mount switches.	6 yearly
Periodic oil-filled ring main unit condition assessment	Detailed condition assessment of entire fleet of ground mount oil filled 6.6/11kV ring main unit switchgear	10 yearly
33kV air break switches visual inspections	Identify visually apparent defects, carry out diagnostic testing, perform operational checks, cleaning and carry out minor repairs.	1 yearly
11/6.6kV air break switches visual inspection	Identify visually apparent defects, carry out diagnostic testing, perform operational checks, cleaning and carry out minor repairs	3 yearly

## 5.8.4 Planned Replacement / Refurbishment Plans

### 5.8.4.1 3.3/6.6/11/22kV RMU

A programme of removal of switchgear that are likely at end of life. Reliability and health safety drivers are met through progressive replacement of “orphaned” oil-filled ring main units. The focus of our replacement program is units which have already been assessed as defective and those units located outside resulting in accelerated aging.

**Table 5-10 6.6/11kV RMU Replacement Programme**

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Replace Statter/GEC/Reyrolle	2	5	5	8	8	8	8	8	8	8
Replacement of oil filler RMU switchgear	6	6	6	9	9	9	9	9	9	9

### 5.8.4.2 33kV switch (pole mounted)

A small cohort of 33kV switches are to be replaced in both Dunedin and Central Otago.

**Table 5-11 33kV Pole Mount Switch Replacement Programme**

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
33kV air break switch replacement Dunedin	1	1	1	2	2	6	6	6	6	6
33kV air break switch replacement Central	1	1	1	1	1	2	2	2	2	2

### 5.8.4.3 3.3/6.6/11/22kV switches and fuses (pole mounted)

Projects listed in Table 5.12 progressively remove pole mount fuse and HV switchgear with known issues.

**Table 5-12 6.6/11kv Pole Mount Switch Replacement Programme**

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Replace Pacific fuses	6	6	6	6	8	10	10	10	10	10
Replace FDA-1 fuses	62	62	62	62	62					
Replace EETEE fuses	20	20	20	20	20					
Replace 6.6/11kV air break switches (Dunedin)	15	20	20	20	20	20	20	30	35	35
Replace 6.6/11kV air break switches (Central)	20	20	20							

## 5.9 Transformers and Voltage Regulators - Power Transformers

### 5.9.1 Asset Description

In order to transform subtransmission voltages (e.g. 33kV) to distribution voltages (e.g. 11kV), power transformers are installed at zone substations. These units operate at variable voltages using 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.

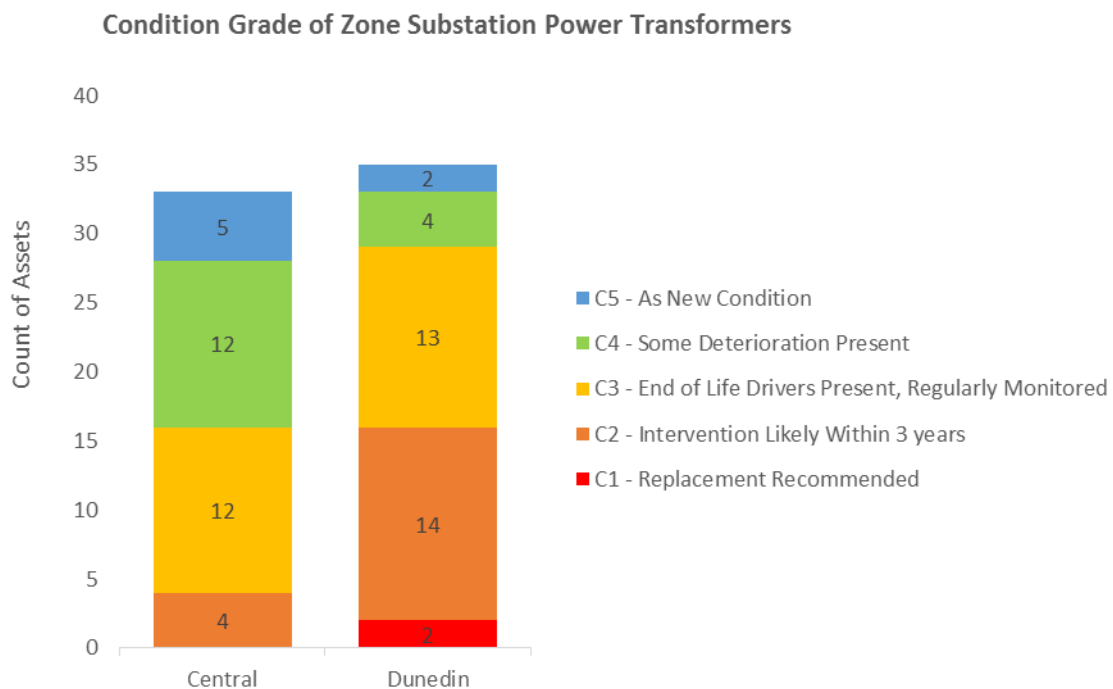
The transformers are capable of operating continuously at their rated capacity or at a higher rating for shorter periods depending on the ambient air temperature.

### 5.9.2 Asset Condition and Performance

Zone substation power transformers are long life assets required to operate with a high degree of reliability. Aurora power transformers have been relatively trouble free with the exception of transformers located at the Halfway Bush, Roxburgh and Ward Street substations which have been replaced due to end of life.

Power transformers undergo online dissolved gas analysis (DGA) testing to assess for insulating paper degradation and oil contamination as well as periodic maintenance to ensure that ancillary systems such as tap-changers remain within operational parameters.

The combination of DGA analysis results and age are combined to arrive at the asset condition grade; summarised for the fleet in Figure 5.5 following. Data suggests that of the 68 power transformers in the fleet, 10 are reaching end of life.



**Figure 5-6 Power Transformer Condition Grade**

## 5.9.3 Inspection and Maintenance

**Table 5-13 Power Transformer Maintenance**

Activity	Purpose	Interval
Preventative maintenance	<ul style="list-style-type: none"> <li>Oil level recordings</li> </ul>	2 weekly
Ground level inspection	<ul style="list-style-type: none"> <li>To identify apparent defects in the tank/ pipework including oil leaks and to ensure pumps and fans are operating correctly and record tap changer cycle</li> </ul>	Monthly
Transformer service maintenance	<ul style="list-style-type: none"> <li>Detailed close visual inspection of bushings, pipework and systems</li> <li>Confirm correct operation of cooling systems</li> <li>Repair minor damage/rust/leaks</li> </ul>	4 yearly
Corrective maintenance	<ul style="list-style-type: none"> <li>Repair any major defects</li> </ul>	As required
Oil tests and DGA testing	<ul style="list-style-type: none"> <li>Routine oil dielectric tests to evaluate condition of oil. Dissolved gas analysis to identify the presence of internal faults</li> <li>Furan analysis to evaluate the rate of transformer ageing</li> </ul>	1 year
Trojan plant dry out	<ul style="list-style-type: none"> <li>Remove Moisture content from oil</li> </ul>	Cyclic
Tap changers refurbishment	<ul style="list-style-type: none"> <li>Ensure continuing operation and reliability of tap changer</li> </ul>	At a maximum interval of 3 years or after a set number of operations
Painting of outdoor 33KV transformers		10 yearly

## 5.9.4 Planned Replacement / Refurbishment Plans

Major transformer replacement is occurring in conjunction with zone substation upgrade projects. Unlike Dunedin new installations are the major driver rather than refurbishment or replacement.

**Table 5-14 Zone Substation Power Transformer Programme**

Zone Substation	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Mosgiel substation power transformer replacement								2		
New Carisbrook power transformers to replace Neville street substation		2								
Upgrade Outram zone substation	1									
Port Chalmers substation power transformer replacement							2			
Install new 2 x 24 MVA power transformers at Cromwell substation		2								

Zone Substation	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Upgrade Clyde-Earnsclough zone substation (power TX??)			1							
Upgrade Andersons Bay substation power transformers		2								
Upgrade Arrowtown substation power transformers			2							

## 5.10 Transformers and Voltage Regulators- Distribution transformers

### 5.10.1 Asset Description

Distribution transformers are installed on our network to transform voltage to a suitable level for customer connections. The sub types of distribution transformers on Aurora's network are pole and ground mounted. There are currently 2733 ground mounted transformers and 4145 pole mounted transformers in service on the network. 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 no longer considered as standard design option ; and
- **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.

### 5.10.2 Asset Condition and Performance

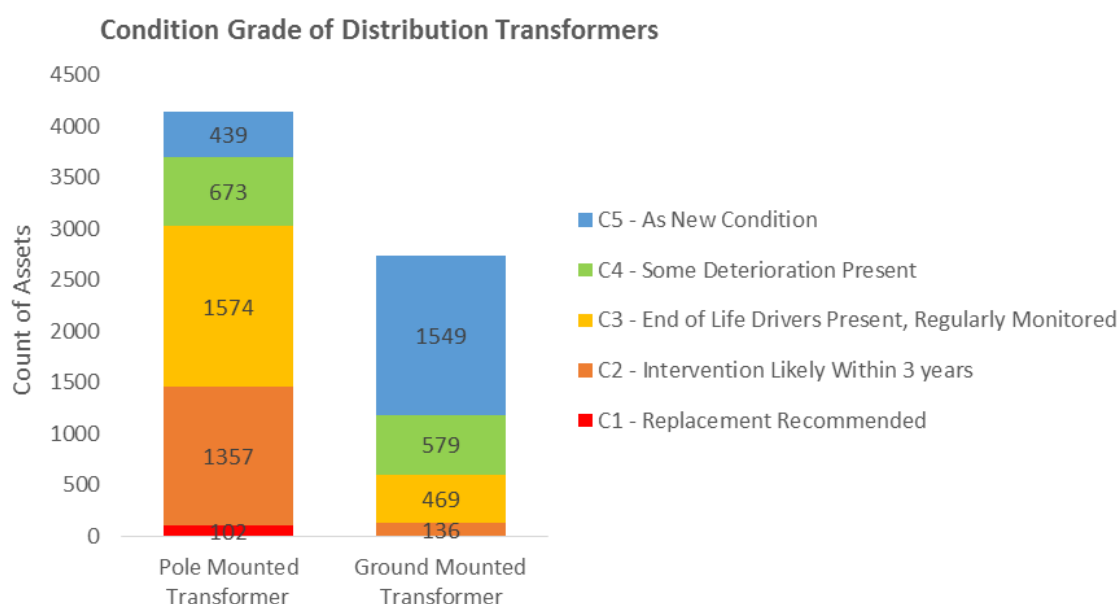
Analysis of the remaining life of distribution transformers is largely based on age as condition proxy. Based on this analysis a significant proportion of the pole mounted distribution transformer fleet may transition into renewals programming within the planning period.

## 5.10.2.1 Pole Mount Transformers

Based on calculation of age remaining life, there are 102 pole mounted transformers currently in service that have been graded in need of replacement, with 93 of those located in Central Otago. There is also a large number (1357) of assets within the C2 category indicating end of life may be imminent.

## 5.10.2.2 Ground Mount Transformers

The general condition of ground mount transformers is better than the pole mounted type with less than 5% of the fleet deemed to require replacement in the near future. Again this analysis is to be reinforced through changes to condition monitoring to provide greater certainty of condition.



**Figure 5-7 Condition of Distribution Transformers**

## 5.10.3 Inspection and Maintenance

**Table 5-15 Distribution Transformer Maintenance Plan**

Activity	Purpose	Interval
Underground substation DGA testing	<ul style="list-style-type: none"> <li>Routine oil dielectric tests to evaluate condition of oil. Dissolved gas analysis to identify the presence of internal faults</li> </ul>	1 Yearly
MDI readings	<ul style="list-style-type: none"> <li>Record maximum demand for the purpose of network development planning</li> </ul>	3 Yearly
Condition assessment of pole mounted transformers	<ul style="list-style-type: none"> <li>Visual inspection to assess rust/oil leaks</li> </ul>	Annual
Condition assessment of ground mounted distribution transformers	<ul style="list-style-type: none"> <li>Visual inspection to assess rust/oil leaks. Kiosk integrity evaluated, secondary protective screens placed in front of fuse ways, door locks assessed</li> </ul>	Annual

## 5.10.4 Planned Replacement / Refurbishment Plans

There are a number of factors shaping the management of distribution transformers. The relatively large fleet of assets are critical in that they provide service to large groups of customers or significant single consumers.

### 5.10.4.1 Pole Mount Transformers

The cost of replacing of an individual transformer is dependent on the configuration used and the rated voltage to which it operates which effectively determines the capacity of the asset.

The rated capacity of pole mounted transformers is an important consideration in the development of a renewal strategy. Pole mounted transformers operate from 5 kVA up to 750 kVA however changes to network design standard prohibit like replacement of pole transformers over 200kVA which must be ground mounted instead.

In order to best manage the large number of distribution transformers renewals, Aurora has adopted a strategy that targets end of life assets in a cost effective manner and provides greater certainty of asset condition and informs future renewals.

**Table 5-16 Pole Mount Transformer Renewal Strategy**

Rated Capacity	Strategy	Dunedin	Central	Total
< 30 kVA	Run to failure	5	90	95
30kVA - 200kVA	Replace in pole mount configuration	3	3	6
> 200 KVA	Replace in ground mount configuration	1	0	1
		<b>9</b>	<b>93</b>	<b>102</b>

A programme of condition-based monitoring will be deployed starting in FY17 to better assess remaining life of 2634 pole mounted transformers graded either C1 or C2 indicating end of life may be imminent. This new data shall form a new input into condition grading to confirm the appropriateness of the 1277 graded for replacement within the C1 band as well as assessment of the 1357 units within the C2 band where end of life drivers will likely be present.

### 5.10.4.2 Ground Mount Transformers

The plan currently makes allowance to replace 48% of Condition 2 grade ground mount distribution transformers over the planning period. This total breaks down to 59 in Dunedin and 6 in Central Otago as detailed in Table 5.17 below.

**Table 5-17 Ground Mount Transformer Renewal Programme**

Project	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Ground Mount Distribution Transformer Renewal (Dunedin)		2	4	5	8	8	8	8	8	8
Ground Mount Distribution Transformers Renewal (Central)					1	1	1	1	1	1



## 5.11 Transformers and Voltage Regulators - Voltage regulators

### 5.11.1 Asset Description

A voltage regulator is designed to automatically maintain a set voltage level. The length of some of our 11kV or 22kV distribution feeders necessitates the installation of voltage regulators partway along the feeders to maintain the correct voltage at the end of the feeder.

A voltage regulator may be set up to allow for only forward power flow and/or reverse power flow. The regulators are controlled by primarily digital controllers with a few older controllers in service. There are two voltage regulator sites in the HV distribution system in Dunedin refer Table 5-18. These two regulator sites are fitted with by-pass switches to allow supply to consumers downstream of the regulators should the regulator be taken out of service. This also allows fast removal of the regulators from service for maintenance.

**Table 5-18 Voltage Regulator Asset Description**

Site No	Site Name	HV Feeder	Regulator Type	Capacity kVA
3474	Macandrew Bay Regulator	AB4	T & J (Tap Changing)	3,000
7569	Brighton Regulator	ET3	Siemens (Tap Changing)	2,500

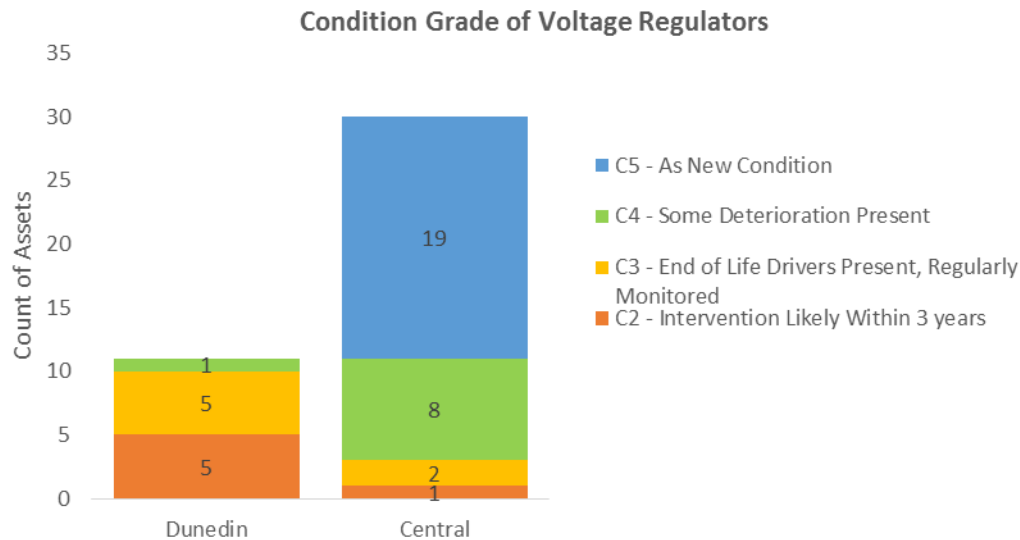
There are ten voltage regulator sites in the HV distribution system in Central as per TABLE 5-19. All sites are single phase units with three sites having 3 units fitted and 5 sites with 2 units fitted. All sites are constructed out of single phase units with two or three units installed at each site Bypassing is available at these sites but primarily consists of physically bridging past the regulators.

**Table 5-19 Central Voltage Regulators**

Site No	Site Name	HV Feeder	Regulator Type	Capacity kVA
75346	Lowburn	CM832	McGraw Edison SR32 (x2)	100 amp
85306	Makarora	MA260	McGraw Edison SR32 (x2)	100 amp
80931	Glendhu Bay	WK2754	McGraw Edison SR32 (x3)	50 amp
73069	Cardrona	WK2752	Siemens Type JFR (X2)	100 amp
80336	Movern Ferry	AT7632	McGraw Edison SR32 (x2)	
83077	Maungawera	WK2752	McGraw Edison SR32 (x2)	
73020	Glenorchy	QT5202	McGraw Edison SR32 (x3)	50 amp
74806	Closeburn	QTWN5202	McGraw Edison SR32 (x3)	100 amp
91477	Poolburn	OM656	McGraw Edison SR32 (x2)	
76375	Becks	OM656	McGraw Edison SR32 (x2)	100 amp

## 5.11.2 Asset Condition and Performance

Asset condition grading for voltage regulators was determined solely using age in lieu of other existing condition indicators. Overall condition of the fleet is likely good with a handful of units probably requiring intervention in the near future.



**Figure 5-8 Condition of Voltage Regulators**

## 5.11.3 Inspection and Maintenance

**Table 5-20 Voltage Regulator Maintenance Strategy**

Activity	Purpose	Interval
Visual inspection	<ul style="list-style-type: none"> <li>Prove functionality by exercising the tap changer and recording the event log</li> </ul>	1 yearly
Thermographic testing	<ul style="list-style-type: none"> <li>Identify faults</li> </ul>	1 yearly
Maintenance service - heavily loaded (>50% of capacity)	<ul style="list-style-type: none"> <li>Ensure continuing operation and reliability</li> </ul>	4 yearly or 100,000 operations
Maintenance service lightly loaded (<50% of capacity)	<ul style="list-style-type: none"> <li>Ensure continuing operation and reliability</li> </ul>	10 yearly or 200,000 operations

## 5.11.4 Planned Replacement / Refurbishment Plans

Based on current condition, our strategy is to undertake refurbishment where possible. Depending on the duty the regulator experiences it will be classed as heavily loaded or lightly loaded. This sets the requirements regarding time interval or operations for when the regulators are taken out of service and switched for replacement units. The units removed from service are then subject to workshop assessment.

Where this is not economic to maintain the regulator, the unit will be removed from service permanently and enter the disposal phase of the asset lifecycle which includes providing spare components to refurbish other units.

This strategy depends on augmenting inventory such that spare units are held in reserve within Aurora strategic stock at all times.

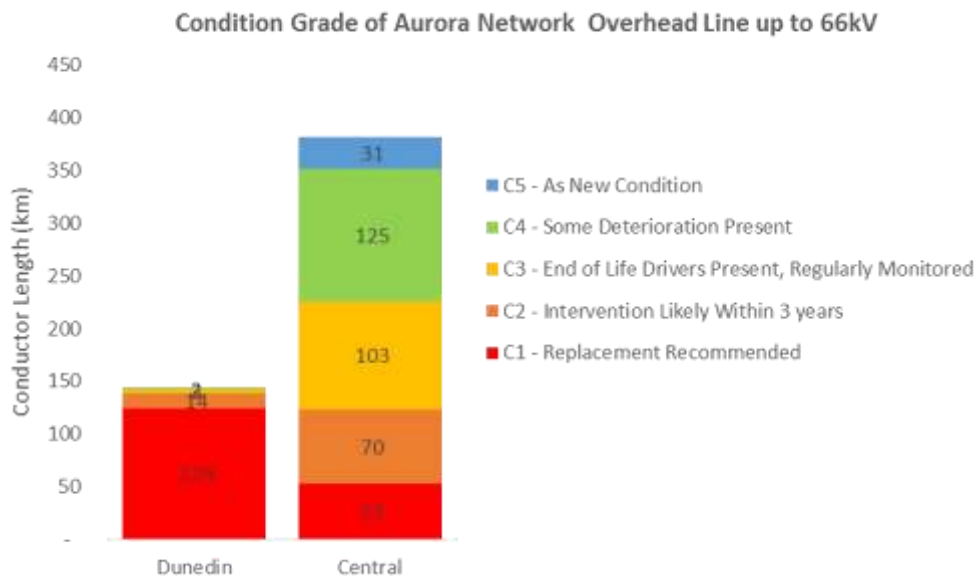
## 5.12 Overhead Lines - Subtransmission (33kV-66kV)

### 5.12.1 Asset Description

Subtransmission lines provide important security to Aurora's network, conveying electricity from GXP's to zone substations. Almost ¾ of overhead subtransmission lines are located in the Central Otago sub-network.

### 5.12.2 Asset Condition and Performance

Despite the fact that nearly 50% of Aurora's overhead subtransmission is over 40 years old the 33kV and 66kV lines are considered to generally be in good condition. Condition of all overhead lines assets are graded according to age and proximity to coastline. The impact of older coastal overhead infrastructure is evident in the lower condition grading in Dunedin.



**Figure 5-9 Condition of 33/66kV Overhead Conductors**

## 5.12.3 Inspection and Maintenance

Inspection and maintenance requirements for the 66kV and 33 kV network are listed in TABLE 5-21.

**Table 5-21 Subtransmission Line Maintenance**

Activity	Purpose	Interval
Ground and/or air inspections	<ul style="list-style-type: none"> <li>Identification and prioritisation of potential defects and vegetation infringements</li> <li>Collection of condition data for asset replacement planning</li> </ul>	Annual
Detailed condition based inspection	<ul style="list-style-type: none"> <li>Assess condition of conductor</li> </ul>	5 yearly
Fault patrol	<ul style="list-style-type: none"> <li>Identify cause of unidentified circuit breaker operations or trips to prevent recurrence</li> </ul>	On request if line trips on earth fault or over current
Thermographic inspection	<ul style="list-style-type: none"> <li>Identification of high resistance joints</li> </ul>	On request
Corrective maintenance	<ul style="list-style-type: none"> <li>Repair any defects</li> </ul>	As necessary to meet safety and service obligations
Acoustic testing	<ul style="list-style-type: none"> <li>Identification and prioritisation of potential defects</li> </ul>	On request

## 5.12.4 Planned Replacement / Refurbishment Plans

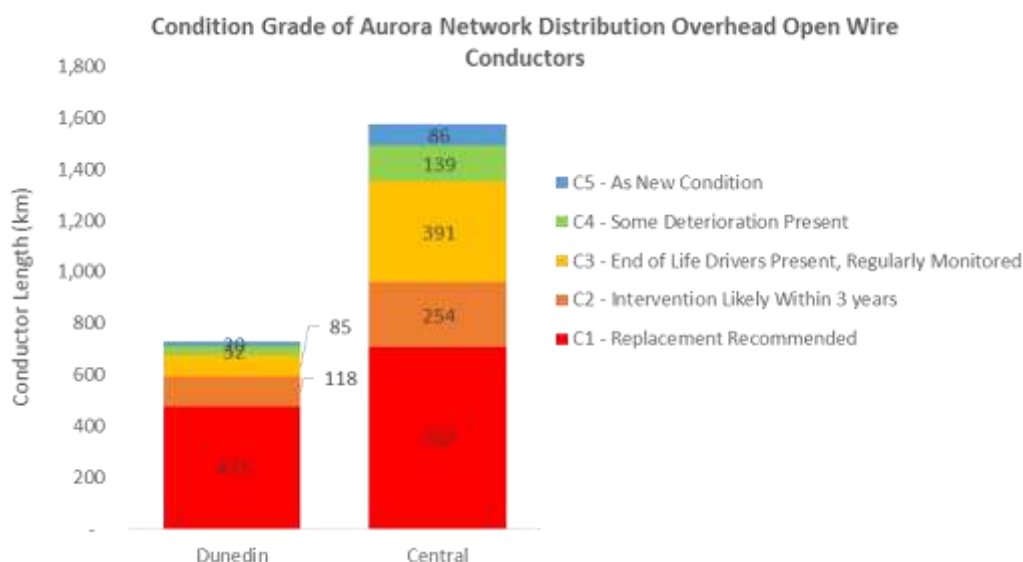
While there are some indications that our 33/66 kV lines particularly in Dunedin are aging actual line failures are extremely rare. As a result our current strategy is to fix on failure. The new condition assessment regime for 33/66kV lines introduced as part of this AMP will provide additional data to help inform future replacement priorities.

## 5.13 Overhead Lines – Distribution Lines (6.6kV and 11kV)

### 5.13.1 Asset Description

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.

### 5.13.2 Asset Condition and Performance



**Figure 5-10 Condition Grade of 6.6/11kV Open Wire Overhead Conductor**

### 5.13.3 Inspection and Maintenance

Inspection and maintenance requirements for distribution lines are detailed in TABLE 5-22.

**Table 5-22 - Distribution Lines Maintenance**

Activity	Purpose	Interval
Rolling inspection (~600km)	<ul style="list-style-type: none"> <li>To establish priorities for the maintenance programme</li> <li>Ensure the procedures in the Electricity (Hazards from Trees) Regulations 2003 are followed.</li> </ul>	Annual
Corrective maintenance	<ul style="list-style-type: none"> <li>Repair any defects</li> </ul>	As necessary to meet safety and service obligations
Detailed condition based inspection (in conjunction with pole inspection)	<ul style="list-style-type: none"> <li>Assess condition conductor</li> </ul>	5 Yearly

### 5.13.4 Planned Replacement / Refurbishment Plans

Aurora's current replacement plans for distribution lines are presently limited to high priority low span removal.

We acknowledge that based purely on our age related data pertaining to the onset of unreliability and maximum practical life there is a need to critically evaluate the level of replacement. We are commencing more detailed condition assessments in 2017 to inform and refine our understanding of asset condition.

A higher degree of certainty around actual condition will enable us to implement more efficient risk based replacement programs.

## 5.14 Overhead lines – 400V

### 5.14.1 Asset Description

Aurora has over 1037km of 400V distribution overhead lines and over 200km of street lighting mainly within the Dunedin urban area.

### 5.14.2 Asset Condition and Performance

Historically there has been little or no investment in the LV network which has led to heightened concerns about potential safety risks.

### 5.14.3 Inspection and Maintenance

Inspection and maintenance requirements for overhead lines are detailed in 5.24.

**Table 5-23 – LV Lines Maintenance Strategies**

Activity	Purpose	Interval
Detailed condition based inspection (in conjunction with pole inspection)	<ul style="list-style-type: none"> <li>Assess condition of insulators, hardware and conductor</li> </ul>	5 yearly
Corrective maintenance	<ul style="list-style-type: none"> <li>Repair any defects</li> </ul>	As necessary to meet safety and service obligations

### 5.14.4 Planned Replacement / Refurbishment Plans

There are no current plans to replace or refurbish 400V Lines.

## 5.15 Underground Cables - Subtransmission

### 5.15.1 Asset Description

Aurora operates 33kV subtransmission cables, chiefly located in the Dunedin sub-network with pockets of underground 66kV subtransmission located in Central Otago.

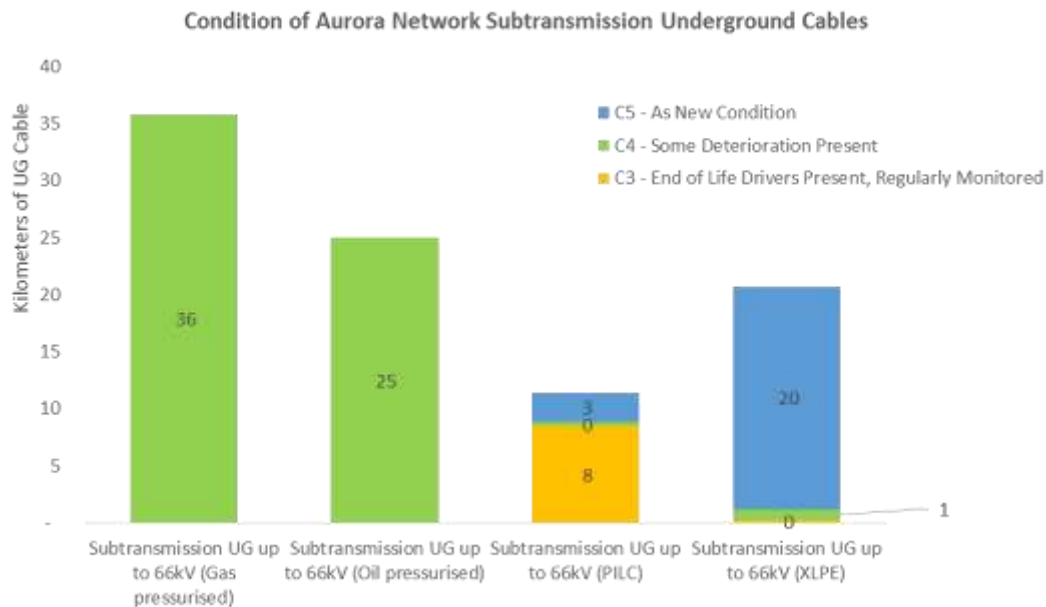
Aurora's subtransmission cables are mixture of Paper Insulated, Lead Covered (PILC), gas-filled, oil-filled and Cross-Linked Polyethylene (XLPE). However XLPE is considered the most economic choice. Aurora uses single-core XLPE cables, as opposed to three-core, as this facilitates the effective application of water blocking tapes.

### 5.15.2 Asset Condition and 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 (e.g. Willowbank) due to deterioration of the cable rubber sheath, which allows moisture to enter the cable. Investigations and analysis have identified that gas cables in particular have a high failure rate with outages nearly every year over the last 20 years.

Aurora currently has an issue associated with a fault on its North City 2 Oil Cable which is resulting in the loss of oil. The issue was originally discovered in 2009 and attempts to isolate the problem over the years have so far been elusive.



**Figure 5-11 Aurora Subtransmission Cable Condition**

### 5.15.3 Inspection and Maintenance

**Table 5-24 Subtransmission Cable Maintenance**

Activity	Purpose	Interval
Free cable location plans	<ul style="list-style-type: none"> <li>To reduce incidence of 3rd party damage to cables</li> </ul>	On demand
Above ground visual inspection	<ul style="list-style-type: none"> <li>To identify asset deterioration, or damage that could lead to future failure</li> </ul>	1 yearly
Corrective maintenance	<ul style="list-style-type: none"> <li>Repair of equipment that has failed in service</li> </ul>	As necessary
Oil and gas filled pressure tests	<ul style="list-style-type: none"> <li>Provide early detection of possible leaks</li> </ul>	2 weeks
Alarm tests	<ul style="list-style-type: none"> <li>Confirm condition of alarms</li> </ul>	6 monthly
Outer sheath electrical integrity testing	<ul style="list-style-type: none"> <li>To provide a relatively reliable evaluation of the condition of the cable, identify deterioration or damage that could lead to a future failure</li> </ul>	1 yearly
Post fault root cause analysis	<ul style="list-style-type: none"> <li>Determine root cause of cable failures to identify if end of life related failures are occurring</li> </ul>	As required



## 5.15.4 Planned Replacement / Refurbishment Plans

The proposed timing of replacement for 33kV cables in Dunedin is highlighted in the TABLE 5-25 below. This is an initial program and performance of the cables could alter priorities.

**Table 5-25 Dunedin 33kV Cable Replacement Program**

Zone Substation	Installed	2017	2018	2019	2020	2021	2022
Carisbrook	1961						
Kaikorai Valley			Design				
Willowbank	1963	Design					
Smith Street	1959			Design			
Ward Street	1967				Design		

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

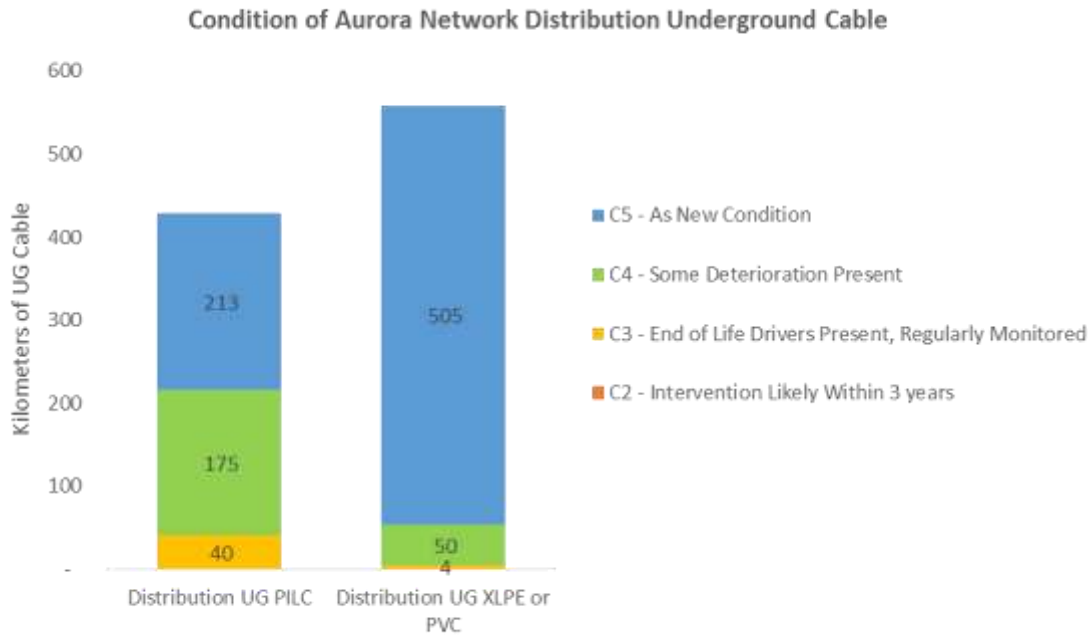
## 5.16 Underground Cables - Distribution Cables

### 5.16.1 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.

### 5.16.2 Asset Condition and 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. There is also a submarine cable across the harbour that has been trouble free since the early 1990s.



**Figure 5-12 Aurora Distribution Cable Condition**

## 5.16.3 Inspection and Maintenance

**Table 5-26 - Distribution Cable Maintenance**

Activity	Purpose	Interval
Corrective maintenance	<ul style="list-style-type: none"> <li>Repair of equipment that has failed in service</li> </ul>	As necessary

## 5.16.4 Planned Replacement / Refurbishment Plans

There are no current plans to replace or refurbish our distribution cables.

## 5.17 Underground Cables - Low Voltage (LV) Cables

### 5.17.1 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.

### 5.17.2 Asset Condition and Performance

The performance of LV cables is generally good; the majority of failures are due to damage from third party installation and poor initial installation at the terminations allowing water ingress.

## 5.17.3 Inspection and Maintenance

**Table 5-27 LV Cable Maintenance**

Activity	Purpose	Interval
Corrective maintenance	<ul style="list-style-type: none"> <li>Repair of equipment that has failed in service</li> </ul>	As necessary

## 5.17.4 Planned Replacement / Refurbishment Plans

There are no current replacement plans for LV Cable.

## 5.18 Communication Systems - SCADA

### 5.18.1 Asset Description

Aurora has two SCADA systems: a Foxboro system, dating from 1998, for the control of the Dunedin area, and an Abbey system dating from 2000, for the control of the Central network. These systems have traditionally been based on a master station (central control center) communicating with remote terminal units (RTU). A total of 23 Remote Terminal Units (RTUs) have been installed in Dunedin substations and a further 64 in Central. Communications between the Central RTUs and the Cromwell Master Station are in Abbey HDLC protocol via radio link. All RTUs are Abbey RTUs.

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.

### 5.18.2 Asset Condition and Performance

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.

### 5.18.3 Inspection and Maintenance

**Table 5-28 - SCADA Maintenance Strategies**

Activity	Purpose	Interval
Attenuation testing	<ul style="list-style-type: none"> <li>Monitor and record signal to ensure there is no reduction in strength</li> </ul>	2 yearly
110kV battery bank checks (Dunedin)	<ul style="list-style-type: none"> <li>Maximise the performance and service life of the batteries and ensure we know when our batteries are reaching the end of their useful life</li> </ul>	6 monthly / 2 yearly
UPS battery checks (Central)	<ul style="list-style-type: none"> <li>Batteries are the most vulnerable part of a UPS. Regular testing ensures we know when our batteries are reaching the end of their life</li> </ul>	1 yearly
Stand by generator checks	<ul style="list-style-type: none"> <li>Ensure the generator is able to be run and fuel levels maintained. An on load test is carried out 6 monthly</li> </ul>	6 Weekly / 6 Monthly

### 5.18.4 Planned Replacement / Refurbishment Plans

Aurora has carried out a comprehensive review of its SCADA, control, communication and protection systems (SCCP) and is in the process of replacing this equipment.

The SCCP project contains eight sub-projects that include new control room arrangements, new SCADA (supervisory, control and data acquisition) systems incorporating distribution and outage management systems (DMS and OMS), new communication links between control rooms and substations, new RTUs (remote terminal unit) at each substation, new load control equipment, subtransmission circuit protection equipment and direct communication links between Aurora and Transpower through ICCP (inter control communication protocol).

Following the detailed design of the SCCP project some associated refurbishment work has been identified including improved connectivity between Transpower and Aurora at the Half Way Bush GXP.

## 5.19 Communication Systems – General Communications Equipment

### 5.19.1 Asset Description

Communication systems are integral to the remote indication and control of network equipment, protection schemes 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.

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.

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. There are two radio links in Central Otago dedicated to providing communications for protection. These are Alexandra to Roxburgh and Cromwell to Wanaka.

### 5.19.2 Asset Condition and Performance

Aurora does not currently have specific age profile data for its communications systems.

The communication networks are the backbone of the SCADA data, protection and voice services that are relied on to operate the electricity distribution network. The performance of Aurora's existing communication system has deteriorated in recent years with increasing periods when communication systems have been unavailable for service.

The implementation of different interacting features between advanced distribution management systems and protection schemes will need to be supported by Aurora's communication networks.

Upgrading and improving of Aurora's communication network is a significant part of the SCCP project. The SCCP project focuses on the requirement design and build systems that support further integration of SCADA, protection and communications.

### 5.19.3 Inspection and Maintenance

**Table 5-29 – General Communication Equipment Maintenance**

Activity	Purpose	Interval
Protection pilot cable inspections	<ul style="list-style-type: none"> <li>Confirm continuity, insulation resistance and attenuation</li> </ul>	2 yearly for underground and annually for test overhead pilot conductor
Routine radio repeater inspections	<ul style="list-style-type: none"> <li>Check operational levels, recorded and adjusted if necessary</li> </ul>	1 yearly
UHF and VHF systems	<ul style="list-style-type: none"> <li>Check operational levels, recorded and adjusted if necessary</li> </ul>	12 monthly /4 yearly

### 5.19.4 Planned Replacement / Refurbishment Plans

Aurora has carried out a comprehensive review of its SCADA, control, communication and protection systems (SCCP) and is in the process of replacing this equipment.

## 5.20 Communication Systems - Ripple Control

### 5.20.1 Asset Description

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.

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.

### 5.20.2 Asset Condition and Performance

The existing Dunedin 1050Hz Ripple Injection system has been in operation for over 40 years.

Performance of the overall ripple injection systems is interdependent on the performance of controlling systems, communications and ripple receiver relay installations. The deteriorating performance of the ripple injection system can be associated to the aging 1050Hz system and related communications networks.

The programme to phase-out and decommission the 1050Hz system will improve the current performance issues being experienced on the Dunedin network. The upgrading of the communications networks will also improve availability of service.

The planned replacement of the legacy ripple injection PLC system in Central Otago (located at Alexandra) will address the issue of operating with a system that is hard to maintain, improve, and expand.

## 5.20.3 Inspection and Maintenance

**Table 5-30 - Ripple Control Maintenance Strategies**

Activity	Purpose	Interval
Comprehensive ripple equipment servicing	<ul style="list-style-type: none"> <li>Ensure operability of the signal generating equipment, associated motor starting contactors, signal impulsing contactors, and signal injection equipment.</li> </ul>	1 yearly (1050Hz) / 2 yearly (317Hz)

## 5.20.4 Planned Replacement / Refurbishment Plans

Ripple receivers will be progressively changed from 1050 Hz to 317 Hz, with 1050Hz injectors progressively removed.

## 5.21 Mobile Plant

### 5.21.1 Asset Description

Aurora owns three mobile distribution substation for use in the 11kV and 6.6kV network. One 500kVA unit is based at Cromwell, with a 300kVA and 500 kVA unit based in Dunedin. These mobile substation are used for both planned and fault work; offering a fast and cost effective means of bypassing permanently installed distribution substations. These mobile substations have been used for many years and are approaching the end of their life. As mobile assets they are subjected to repeated stress being installed and therefore their condition is closely monitored.

Aurora also owns a 5 MVA 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.

### 5.21.2 Asset Condition and Performance

The performance of mobile distribution substations has deteriorated in recent years. Work was completed in 2015 to repair these mobile distribution substations with major components such as LV trailing cable and LV boards repaired or replaced. Significant time has been spent reducing the hazards associated with installation including replacement of the low voltage switchboard, remote switching capability and other health and safety related improvements.

Each of the mobile distribution substations is unique as they are built into the chassis of the truck they are associated with.

Performance of the 5MVA mobile zone substation is generally good. 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.

### 5.21.3 Inspection and Maintenance

**Table 5-31 - Mobile Plant Maintenance**

Activity	Purpose	Interval
Mobile distribution substation inspections	<ul style="list-style-type: none"> <li>To ensure the optimal operating condition of the mobile distribution substation is maintained</li> </ul>	6 monthly
Mobile distribution substation installation and pre-livening checks	<ul style="list-style-type: none"> <li>Ensure the installation and livening is performed correctly and conducted safely</li> </ul>	Whenever a mobile distribution substation is deployed
Mobile distribution return from service inspection	<ul style="list-style-type: none"> <li>To ensure the mobile substation is in working order</li> </ul>	Whenever a mobile distribution substation is returned from the field
Corrective maintenance	<ul style="list-style-type: none"> <li>To repair known defects discovered through inspections</li> </ul>	As required

### 5.21.4 Planned Replacement / Refurbishment Plans

The current plan has us replacing 3 mobile distribution substations between 2017 and 2022 with the first replacement occurring in 2017.

Plan	2017	2018	2019	2020	2021	2022
5 MVA transformer spare		1				
New mobile distribution substation #1	1					
New mobile distribution substation #2				1		
New mobile distribution substation #3						1

A new 5 MVA transformer spare will be purchased in 2018 for use in either Central Otago or Dunedin. This unit will enable a large number of coinciding major capital projects in the first half of the capital programme to be rescheduled while providing long term security to the network.

With the increase in replacement of distribution substations in the network the need for mobile distribution substations has grown. A new mobile distribution substation is planned to be constructed allowing the old mobile distribution transformers to be retired when considered appropriate. The new mobile distribution substation design will take the form of a transportable container decoupling the truck from the substation. Safety is a key design criteria with hazards in the existing mobile substations to be removed by design in the new mobile substation.

### 5.21.5 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.

## 5.22 Generators

### 5.22.1 Asset Description

Aurora owns a containerised 500kW generator that was installed in the Cardrona valley to provide additional capacity during the ski seasons. Additionally there are units installed in Alexandra, Cromwell and Dunedin to provide power in the event of loss of supply to the network operations centre and essential services.

### 5.22.2 Asset Condition and Performance

There are no known performance issues with our in service generators. The 500kW unit is not currently in service however it will be re-deployed at Glenorchy in 2017 following an overhaul allowing critical line upgrades to be completed.

### 5.22.3 Inspection and Maintenance

**Table 5-32 - Generator Maintenance**

Activity	Purpose	Interval
Stand by generator inspections	<ul style="list-style-type: none"> <li>Confirm operability and condition</li> </ul>	1 monthly

### 5.22.4 Replacement / Refurbishment Plans

Replacement of back-up generation is programmed based on the manufacturer's estimated nominal economic life.

## 5.23 Protection systems

### 5.23.1 Asset Description

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 subtransmission networks.

## 5.23.2 Asset Condition and Performance

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.

Aurora does not currently have specific age profile data for its feeder protection relays. Current assumptions are that the age of protection relays is generally the same as the associated switchgear.

## 5.23.3 Inspection and Maintenance

**Table 5-33 - Protection Maintenance**

Activity	Purpose	Interval
Routine testing of relays (generally limited to secondary injection testing)	<ul style="list-style-type: none"> <li>To ensure proper protection of electrical equipment and systems</li> </ul>	Carried out when the associated primary equipment has been released for servicing
Intertrip testing	<ul style="list-style-type: none"> <li>Maintain the integrity of the intertrip systems</li> </ul>	6 monthly
Flooded cell battery checks	<ul style="list-style-type: none"> <li>Visually check condition of battery bank, check electrolyte levels, record battery bank voltages and specific gravity of each cell (6 monthly)</li> </ul>	2 monthly / 6 monthly
Sealed lead acid or alkaline cell battery checks	<ul style="list-style-type: none"> <li>Visually check condition of battery bank, check electrolyte levels, record battery bank voltages and specific gravity of each cell</li> </ul>	Yearly
Battery discharge testing	<ul style="list-style-type: none"> <li>Confirm condition of battery banks</li> </ul>	Yearly

## 5.23.4 Replacement / Refurbishment Plans

Protection relays are generally upgraded to modern Intelligent Electronic Devices (IED) relays when the associated switchgear is replaced. Older feeder protection relays are proposed to be upgraded to SEL relays. 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; and
- the provision of additional fault data and detailed post fault analysis as the SEL relays are modern IED devices that can communicate directly with the SCADA RTU.

## 5.24 Building and Grounds

### 5.24.1 Asset Description

There are 39 zone substations on the Aurora network 18 in Dunedin and 20 in Central. Our zone substations buildings range in age from 0-70 years old, with most of the structures being established in the 1950's-1990. Zone substations are high value critical assets within the Aurora distribution network. Asset maintenance and replacement programmes are therefore designed to provide a high degree of security and risk management.

### 5.24.2 Asset Condition and Performance

A comprehensive seismic assessment of all Aurora's substation assets was undertaken in 2014/2015. The assets vary in age and, as might be expected, the newer assets generally have better seismic strength. After evaluation of legislative requirements and industry practice, Aurora has adopted Importance Level 3 (IL3) for the seismic design and assessment of substation buildings and equipment.

Importance level 3 implies the design level earthquake has a return period of 1,000 years for the Ultimate Limit State (ULS) and 25 years for the Serviceability Limit State (SLS). A number of our zone substations do not meet this standard.

### 5.24.3 Inspection and Maintenance

Maintenance strategies for zone substation assets utilise a combination of condition assessment and fixed interval maintenance. Maintenance strategies for zone substations are detailed in TABLE 5-34

**Table 5-34 – Zone Substation Building Maintenance**

Activity	Purpose	Interval
Building, grounds and fencing corrective maintenance	<ul style="list-style-type: none"> <li>Rectify problems as necessary to meet safety and service targets</li> </ul>	
Substation grounds maintenance	<ul style="list-style-type: none"> <li>Lawn mowing, weed management</li> <li>Security inspections</li> </ul>	2 weekly
Underground visual inspections	<ul style="list-style-type: none"> <li>Identify visually apparent defects, clear rubbish, check oil levels, simulate flood conditions and check over operability</li> </ul>	3 monthly
Asbestos testing	<ul style="list-style-type: none"> <li>To detect air borne asbestos particles</li> </ul>	5 yearly
Fire protection inspection	<ul style="list-style-type: none"> <li>Ensure the ripple CO2 fire protection system is in working order</li> </ul>	1 yearly with a pressure test every 5 Years

### 5.24.4 Replacement / Refurbishment Plans

Legislative requirements and industry practice indicate that Aurora adopt Importance Level 3 (IL3) for the seismic design and assessment of substation buildings and equipment. In 2015/16 Aurora started a 5 year program of work to seismically strengthen its zone substation to 100% of importance level 3.

## 5.25 Other Primary Equipment

### 5.25.1 Asset Description

Other primary equipment includes Metering, Earths, earthing resistors, surge arrestors, Underground and Ground Mounted link Boxes, LV Pillars, and substation earth grids.

### 5.25.2 Asset Condition and Performance

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.

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.

### 5.25.3 Inspection and Maintenance

Activity	Purpose	Interval
Substation earthing inspections	<ul style="list-style-type: none"> <li>Inspection for presence of earth wire</li> </ul>	Continuously
Above ground earth connection checks.		6 yearly
400 AMP LV link box inspections		5 yearly
Earth grid testing	<ul style="list-style-type: none"> <li>Verify integrity of earth grid</li> </ul>	5 yearly
Corrective repairs	<ul style="list-style-type: none"> <li>Rectify problems as necessary to meet safety and service targets</li> </ul>	As required
Visual inspection of earths		Single Wire Earth Return (SWER) 3 yearly. else 6 yearly
Substation temporary earths	<ul style="list-style-type: none"> <li>Check integrity of earths</li> </ul>	2 yearly

### 5.25.4 Replacement / Refurbishment Plans

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.

In Dunedin, there are 246 underground LV link boxes. Some of these boxes are being replaced due to ageing and overloading.

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 covered under the SCCP project.

## 6 NETWORK DEVELOPMENT PLAN

### 6.1 Network Overview

Aurora manages electrical assets in two distinct geographical areas (Dunedin and Central Otago) shown in FIGURE 6-1.

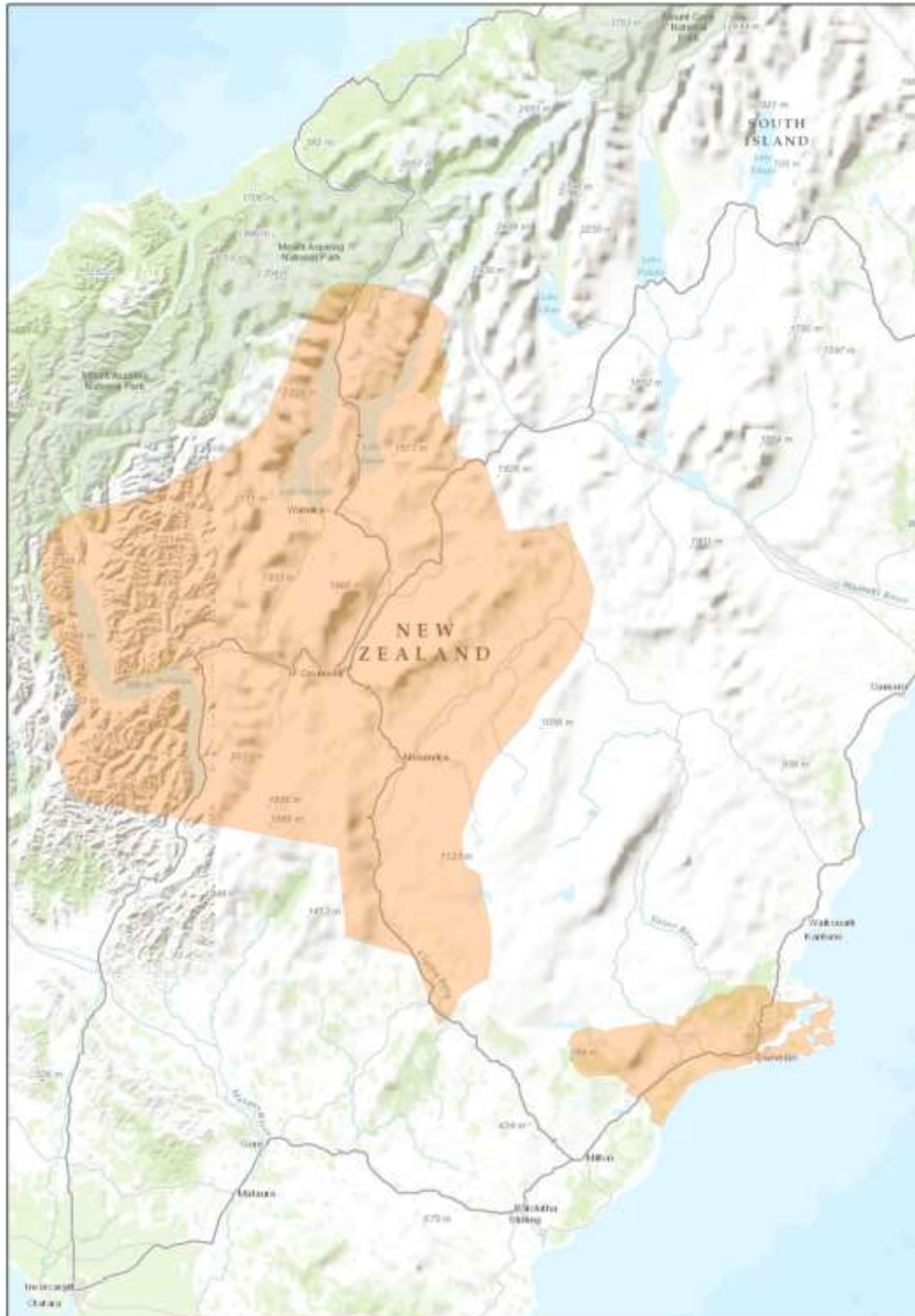


Figure 6-1 Aurora Network



The Dunedin network includes Dunedin city, Mosgiel and the inner reaches of the Taieri Plains and supplies approximately 54,400 customer connections. While 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 31,280 customer connections.

A small embedded network, connected to The Power Company network, was installed in Te Anau in 2005; and supplies over 400 customer connections.

### 6.1.1 Dunedin Network

#### 6.1.1.1 Halfway Bush and South Dunedin GXP's

The Dunedin network area is supplied from two GXP's at Halfway Bush and South Dunedin. The main Dunedin urban area is supplied by 18 transformer-feeder zone substations, with each substation having two 33/6.6 kV transformers - see TABLE 6-1. The North East Valley zone substation is teed off the Port Chalmers zone substation 33 kV circuits. The Taieri Plain area, including Mosgiel, is served by four zone substations which are supplied from the three parallel 33 kV lines between the Halfway Bush GXP and TrustPower's Waipori power scheme.



Figure 6-2 Dunedin Subtransmission Network

**Table 6-1 -Dunedin Zone Substations**

Grid Exit Point	Zone Substation	Transformer Capacity MVA	Subtransmission	n-1 Security
<b>Halfway Bush</b>	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
	Andersons Bay	15 +15	Two 33 kV XLPE cables from Sth Dn GXP	Y
<b>South Dunedin</b>	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

## 6.1.2 Central Network

The Central network is supplied via the Frankton, Cromwell and Clyde Grid Exit Points.

### 6.1.2.1 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 (Refer to FIGURE 6-3 and TABLE 6-2).



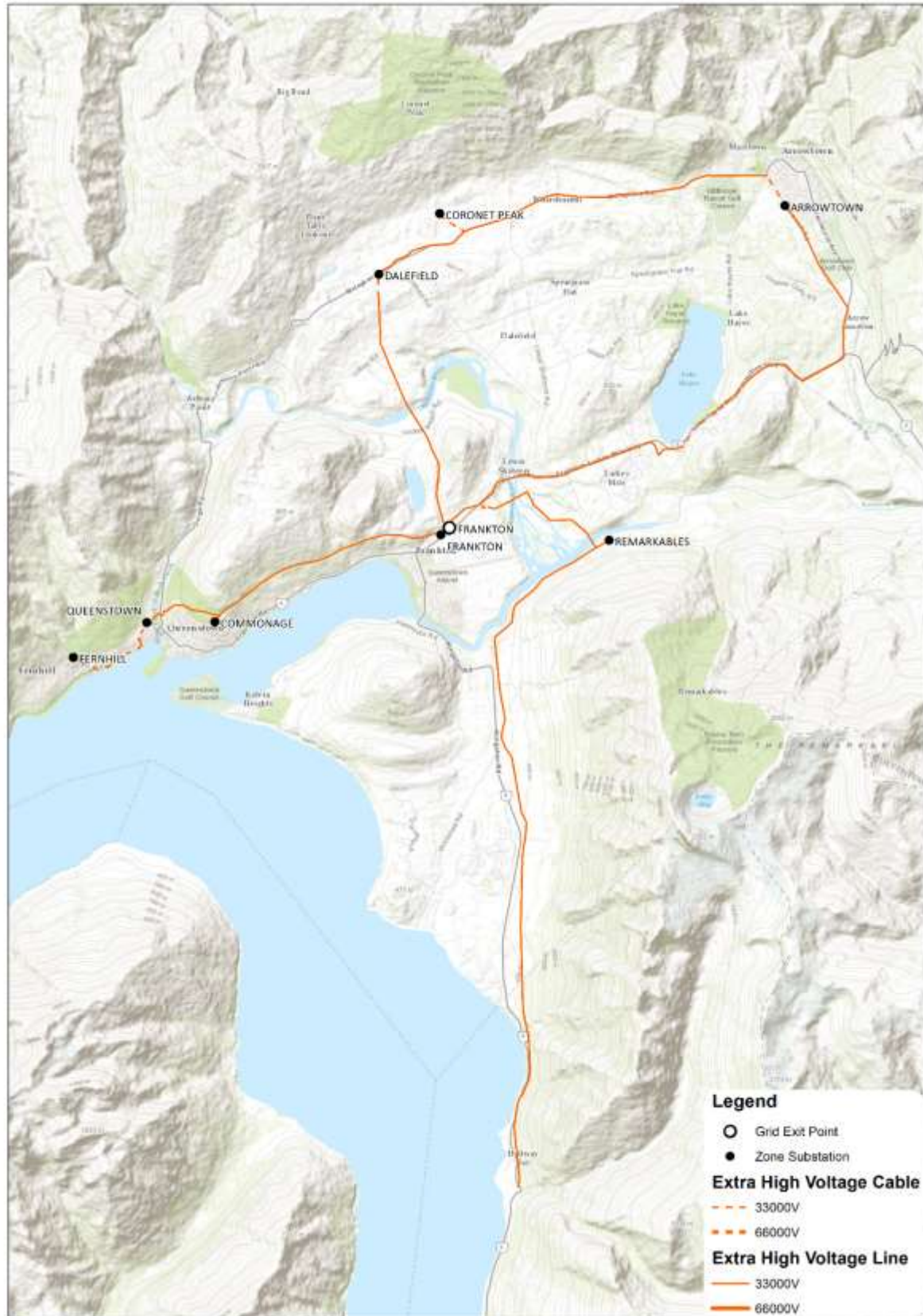


Figure 6-3 Frankton Subtransmission Network

**Table 6-2 Zone Substations in the Frankton Area**

Substation	Transformer MVA	Subtransmission Configuration	n-1 Security
Arrowtown	5 + 5	Supplied from Wakatipu Basin 33 kV ring	N
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

## 6.1.2.2 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 generation at the Roaring Meg power station. 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 6-4 and TABLE 6-3)

**Table 6-3 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	3/4	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
Lindis Crossing	7.5	Single 33kV line from Wanaka.	N
Camp Hill	7.5	On one of the Cromwell Wanaka 66kV Lines	N
Cardrona	5	Single 33 kV line tee from Wanaka to Maungawera Line	N





Figure 6-4 Cromwell Subtransmission Network

## 6.1.2.3 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 6-5 and TABLE 6-4.

**Table 6-4 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	Y
Clyde/Earnsclough	2 + 5/4	Tee off Alexandra to Clyde No. 2 33 kV line	Y
Lauder Flat	3	Single 33kV Line from Omakau	N

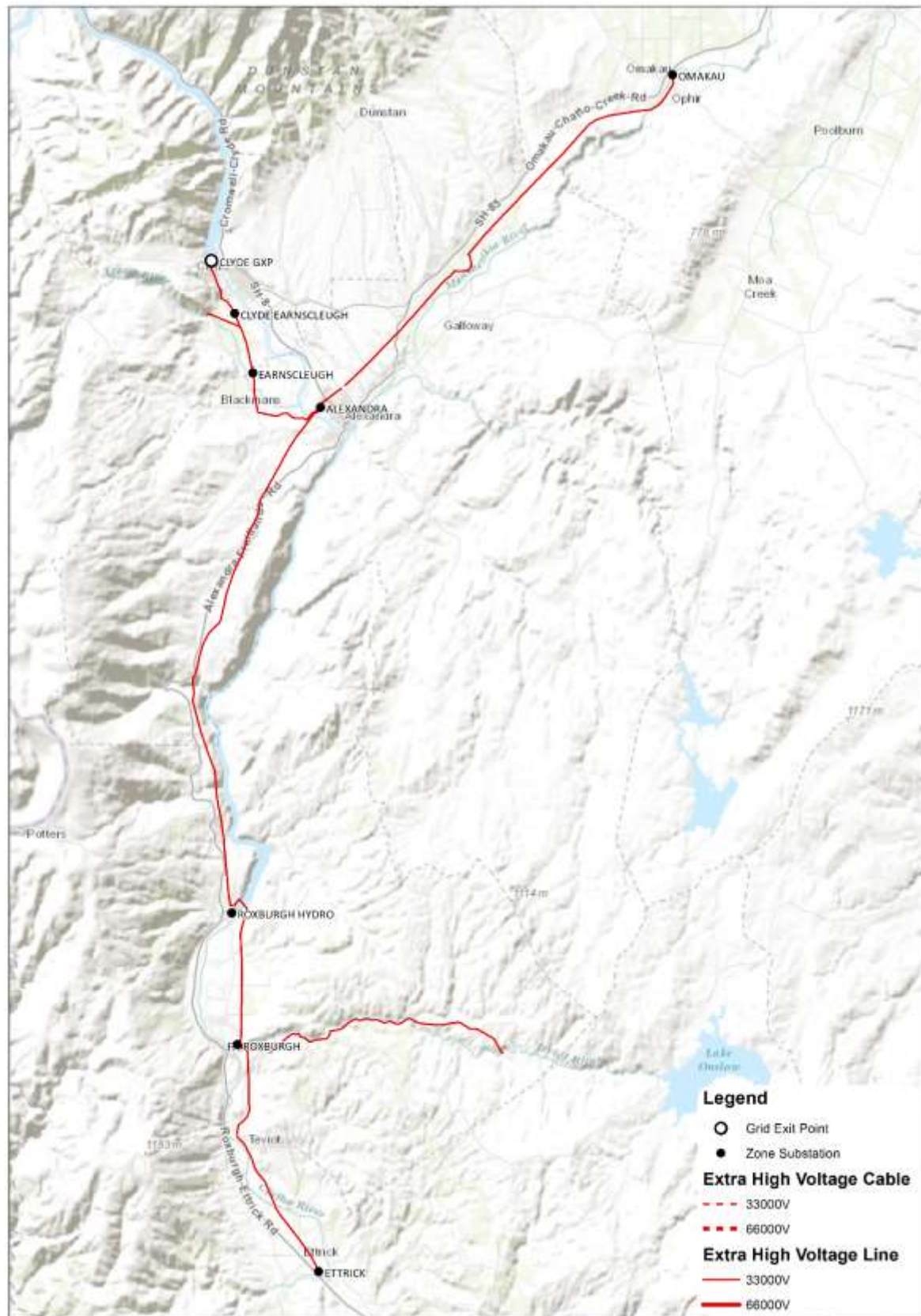


Figure 6-5 Clyde Area Subtransmission Network



## 6.2 Planning Criteria

The first stage of planning a distribution network is to ensure that existing network loads are monitored against current network capacity. When gaps in the network are identified, the challenging process of developing a solutions begins. A range of factors are used to assess the viability of each solution including safety, compliance with design standards, security, quality, load factor, capacity determination and economic returns. The next sections discuss the main planning criteria considered when solutions are developed.

### 6.2.1 Safety by Design

Whether it is prioritising a project or planning a distribution network safety is always afforded top priority at Aurora. The ability to eliminate or minimise risks is fundamental to raising safety performance. Through safety by design, we proactively 'design out' many of the risks people may have historically been exposed to. With the collaborative input of our contractors and stakeholders we detail how network solutions can be designed, constructed, operated, maintained and ultimately demolished in a safer way.

### 6.2.2 Security of Supply

Security of supply is the ability of a network to meet the demand for electricity when electrical equipment fails. The more secure an electricity network, the greater its ability to continue to perform and/or the quicker it can recover from a fault.

It is important to distinguish between reliability of supply, the actual performance of the network in terms of the amount and duration of interruptions, and security of supply, the innate ability of the network to meet the customer demand for energy delivery without interruption.

When planning for load growth we attempt to optimise the level of security and fault tolerance acceptable to our customers. This necessitates a balance between infrastructure investment and operational cost. Infrastructure investment is driven by security of supply requirements, while the reliability of supply actually achieved depends on a combination of security of supply and operational performance.

Our base security criteria are shown in TABLE 6-5. It is important to note that in all cases, if group peak demand exceeds the given range, any reinforcement expenditure is still subject to economic justification.

### 6.2.3 Power Quality

Power quality relates to the voltage delivered to the consumer's metering installation point for the specified load. It covers voltage magnitude, distortion and interference of the wave-form. Targets for the voltage levels are specified in the Electricity Industry Participation Code 2010 and industry standards. Aurora aims to provide quality supply to all customers within regulatory standards through good network design, responsiveness to low voltage complaints, and active monitoring of load conditions throughout the network.

#### 6.2.3.1 Voltage Magnitude

Regulations require voltage to be maintained between  $\pm 6\%$  at the point of common coupling. Here at Aurora remedial works are considered if the consumer's voltage is outside the regulated limits for more than 5% of the year.

## 6.2.3.2 Harmonics - distortion and interference

Harmonic voltages and currents in an electric power system are typically a result of non-linear electric loads. Non-linear loads such as Variable Speed Drives (VSDs), Switch Mode Power Supplies (SMPs), electronic ballasts for fluorescent lamps, welders, inject harmonic currents into the Network. These harmonic currents couple with the system impedances creating voltage distortion at various points on the Network. As a result, equipment such as computers, digital clocks, transformers, motors, cables, capacitors, electronic controls, etc., connected to the same point can suddenly malfunction or even fail completely.

The limits in TABLE 6-6 are used by Aurora to gauge harmonic voltage distortion lasting longer than one hour. For shorter periods, during start-ups or unusual conditions, these limits may be exceeded by 50%.

**Table 6-5 Security of Supply Guidelines**

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 100% GPD within 4 hours	Initially - nil 100% GPD within 4 Hours	Not applicable
U2	1.0 to 3MVA (6.6kV) or to 5MVA (11kV)	HV feeders	Initially - nil 100% GPD within switching time	Initially - nil 100% GPD within 4 Hours	Not applicable
U3	Up to 10 MVA	Small / medium zone substations	Initially - nil 100% GPD within switching time	Initially - nil 100% GPD within 4 Hours	Initially - nil 100% GPD within switching time
U4	Over 10MVA	Larger zone substations	Defined firm capacity	Initially - nil 100% GPD within 4 Hours	Initially - nil 100% GPD within switching time
RURAL					
R1	All	Rural customers (e.g. fed by a single transformer)	Initially - nil 100% GPD within 6 hours		
R2	0 to 3 MVA (6.6 kV) or to 5 MVA (11 kV)	Rural radial feeder	Initially - nil 100% GPD within 6 hours		
R3	0 to 5 MVA	Rural zone substation	Initially nil 100% GPD within 6 hours		



**Table 6-6 Maximum Voltage Distortion Limits in % of Nominal Fundamental Frequency Voltage**

Individual Voltage Distortion (%)	Total Voltage Distortion THDv (%)
3.0	5.0

## 6.2.4 Load Factor and Capacity Utilisation

We monitor loads on all our zone substation at half hour intervals. This information is used to prepare an annual asset renewal programme for the network. The utilisation of network equipment is indicated by load factor as well as the capacity utilisation of transformers in the distribution system.

The load factor is the ratio of electricity supply to customers (kWh) to the maximum demand (kW) for the period measured in hours. Load factor indicates how effectively the system capacity is matched to consumer peak demand.

A closely related concept is capacity utilisation which is the ratio of the maximum demand (kW) of the distribution system to the total distribution transformer installed capacity (kVA).

Our performance targets for capacity utilisation and load factor are set at 31% and 54% respectively.

## 6.2.5 Standardisation

To minimise long term cost there is constant and progressive movement toward standardisation of equipment on the network. Standardisation helps to reduce design and procurement costs enables standardised maintenance practices, improves operational flexibility and allows for a reduction in the number of strategic spares that need to be held.

Standardisation has been applied to distribution and zone transformers, poles, overhead lines, Installation practices and zone substation buildings.

## 6.2.6 Economic Returns

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.

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

## 6.3 Project Prioritisation

Prioritisation of network solution projects is a relatively complex process. At Aurora the primary factors to be considered when prioritising projects are:

1. Safety – our top priority when prioritising projects is always the removal or minimisation of safety related issues from the Network.
2. Satisfying customer expectations – we give priority to the constraints that are most likely to impact consumer supply through prolonged and/or frequent outages, or compromised power quality (voltage drop).
3. Compliance – our aim is to maintain compliance with all relevant legislative, regulatory and industry standards. Priority is given to projects which address any compliance gaps.
4. Satisfying Stakeholder expectations for adequate returns.
5. Contractor resourcing constraints - We aim to schedule work to maintain a steady work flow to contractors. This reduces the risk of our contractors being either over or under resourced.
6. Coordination with local authority civil projects - we aim to schedule our projects to coincide with the timing of major civil infrastructure projects by local authorities. The most common activity of this type is coordination of planned cable works with road widening or resealing programmes to avoid the need to excavate and then reinstate newly laid road.

After assessing their relative priorities the knowledge experience and professional judgement of our asset management team is relied upon to make the final decision regarding the exact timing of an individual project within the 10-year planning window.

When the next project selection process is undertaken all projects (including new additions) are reviewed and, depending on changes in information and priorities, either maintained in the planning schedule, advanced, deferred, modified, or removed from the programme.

## 6.4 Non-network Solutions

When the network becomes constrained it is not always necessary to relieve that constraint by investing in new infrastructure. There are several less costly alternatives including:

- Demand side management.
- Distributed generation.
- Customer Investment.

### 6.4.1 Demand Side Management

Demand side management (DSM) provides an alternative to traditional distribution network reinforcement. Demand-side management (DSM) programs consist of the planning, implementing, and monitoring activities which are designed to encourage consumers to modify their level and pattern of electricity usage for maximum mutual benefit.

#### 6.4.1.1 Ripple Control

Ripple control is an effective tool for implementing DSM. 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. Aurora's use of ripple control has contributed to a 38MW difference between estimated peak demand and actual peak demand, requiring much less investment in network capacity.

### 6.4.1.2 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.

### 6.4.2 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.

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](http://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 130 MW of distributed generation connected to its network. Hydro generation remains the predominant energy source for distributed generation on the Aurora's network at 92% of total generation capacity. Small-scale photovoltaic generation, at the other extreme, although comprising 90% of generation connections, comprises only 0.9% of total generation capacity.

The 2015 calendar year saw a 6% reduction in applications for distributed generation connections, when compared to the previous year. Most distributed generation applications are 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.

**Table 6-7 Distributed Generation Forecasts**

	2016	2017	2018	2019	2020	2021
Total DG Connections	510	696	908	1,147	1,412	1,703
DG Capacity (kW)	130,305	130,956	131,699	132,534	133,461	134,479

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.

### 6.4.3 Customer Investment - Capital Contributions Policy

When an application for a new or upgraded connection (larger connections only. Small connections generally have a lesser impact on the assets required to give or maintain supply) is submitted for review, we undertake an economic assessment of the connection to determine whether the investment is economic or uneconomic. Specifically the analysis:

- calculates the expected new revenue to be generated from the connection;
- estimates the whole-of-life cost of providing the connection, based on the Allocated Capital Cost, including depreciation recovery, operational costs, maintenance costs, and a proportional cost of upstream assets that have already be provided by Aurora; and
- calculates the present value of the investment to be made by Aurora, allowing for taxation. A positive present value supports investment in the connection by Aurora, whereas a negative present value indicates that it is not economic for Aurora to make the investment, and provides a basis for the Customer to make an additional payment to Aurora in respect of the new connection.

Where the economic investment analysis yields a positive present value, no capital contribution will be required from the Customer; however, where the economic investment analysis yields a negative present value, the Customer may be required to pay a capital contribution not exceeding the amount required to yield a present value of zero.

This policy ensures that the true cost of providing supply is passed on to the appropriate consumer and thereby allows them to make the right financial trade-offs.

## 6.5 Energy Growth and Demand

### 6.5.1 Overview

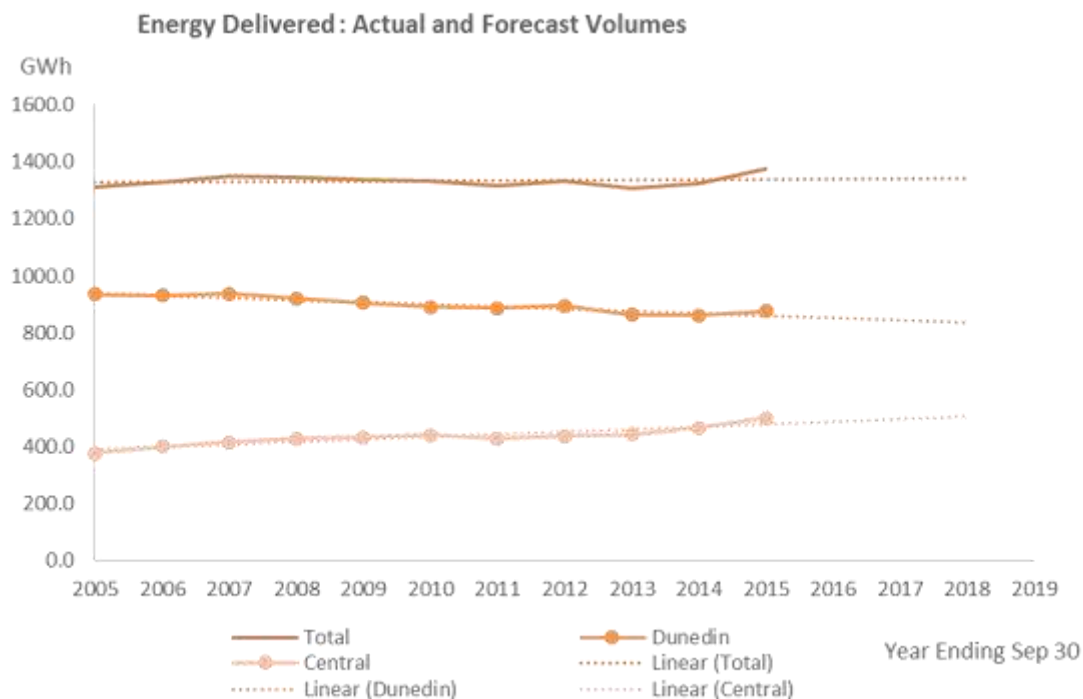
Network energy throughput for the year ending September 2015 was 1,377 GWh (including distributed generation), which was an increase of 51MWh (3.7%) on the previous year.

Modest GXP load growth (2% p.a) is predicted to return to the Central Otago area despite some significant one-off projects (such as the Remarkables Ski field developments). The large growth in irrigation load in the Tarras area has continued and irrigation load in the Hawea and Omakau areas is increasing. While this growth has caused a large increase in annual energy consumption and necessitated significant network investment it does not contribute to the GXP peak loads which are predicted to remain winter peaking for the foreseeable future.

In the Dunedin area we have experienced a small decline in electrical load over the past few years. This is partly due to economic conditions, a run of mild winters, increased efficiency in usage (e.g. Heat Pumps and more efficient lighting) and the lack of uptake of edge technologies (such as electric vehicles). Our expectations are for these conditions to continue with little or no load growth projected over the next 10 years. As a result investment in Dunedin will primarily be driven by the need to replace ageing assets, and maintaining existing levels of reliability.

## 6.5.2 Grid Exit Points

The historic energy delivered is shown in FIGURE 6-6



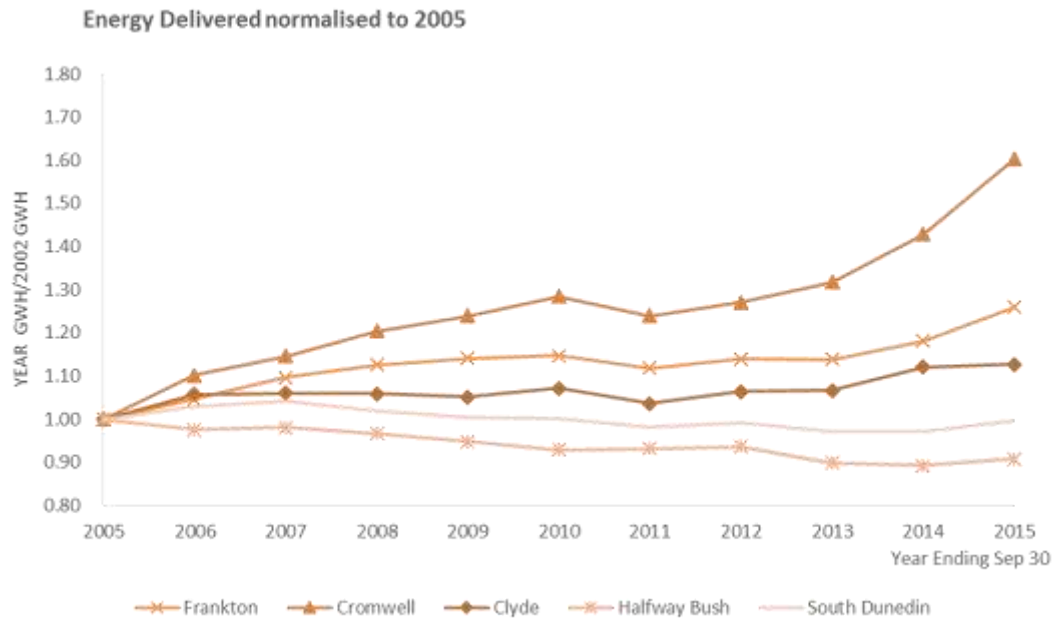
**Figure 6-6 Historic Energy Delivered**

The energy used normalised in 2005 GWh for each GXP is shown in Figure 6-7 and the load factor by GXP is shown in Figure 6-8.

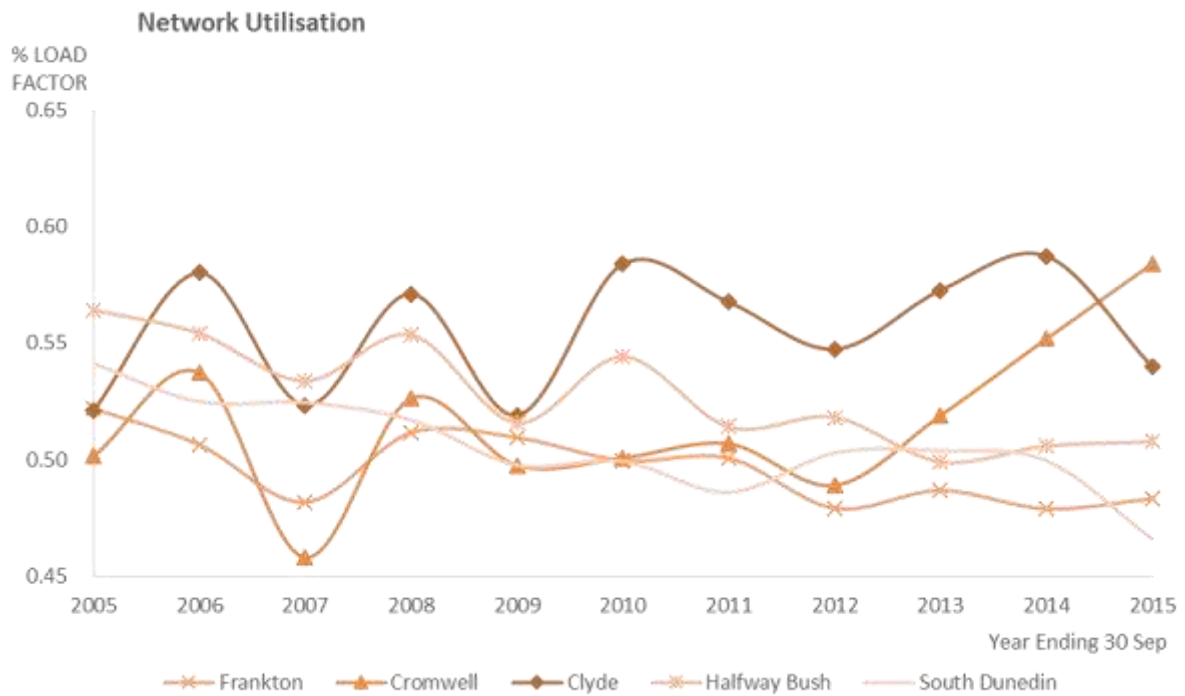
The peak loads for the GXPs are influenced to some extent by how we operate our load control plant. This is now driven by the Lower South Island (LSI) regional peak rather than the local peak in an effort to reduce Transpower costs. There are a number of factors that influence how well the LSI peak load co-relates to Aurora's peak load, including factors such as the level of embedded wind and hydro generation (in Aurora's and other LSI networks), the load consumed at the Bluff Aluminium smelter, and variations in weather across the region. These factors could cause Aurora's load control system to allow peak network loads significantly higher than if it was configured just to reduce local peak loads alone.

The continuing increase of the Cromwell load factor is attributed to an increase of summer irrigation which has increased the energy throughput without increasing the winter peak load.

The large growth in GXP demands especially at Clyde and South Dunedin GXPs during the 2015 winter were a result of load control operation, which allowed this load to rise substantially when load at other GXPs (and elsewhere in the lower South Island area) was low.



**Figure 6-7 – Comparative Growth In GXP Energy (Gwh 2005 Normalised)**



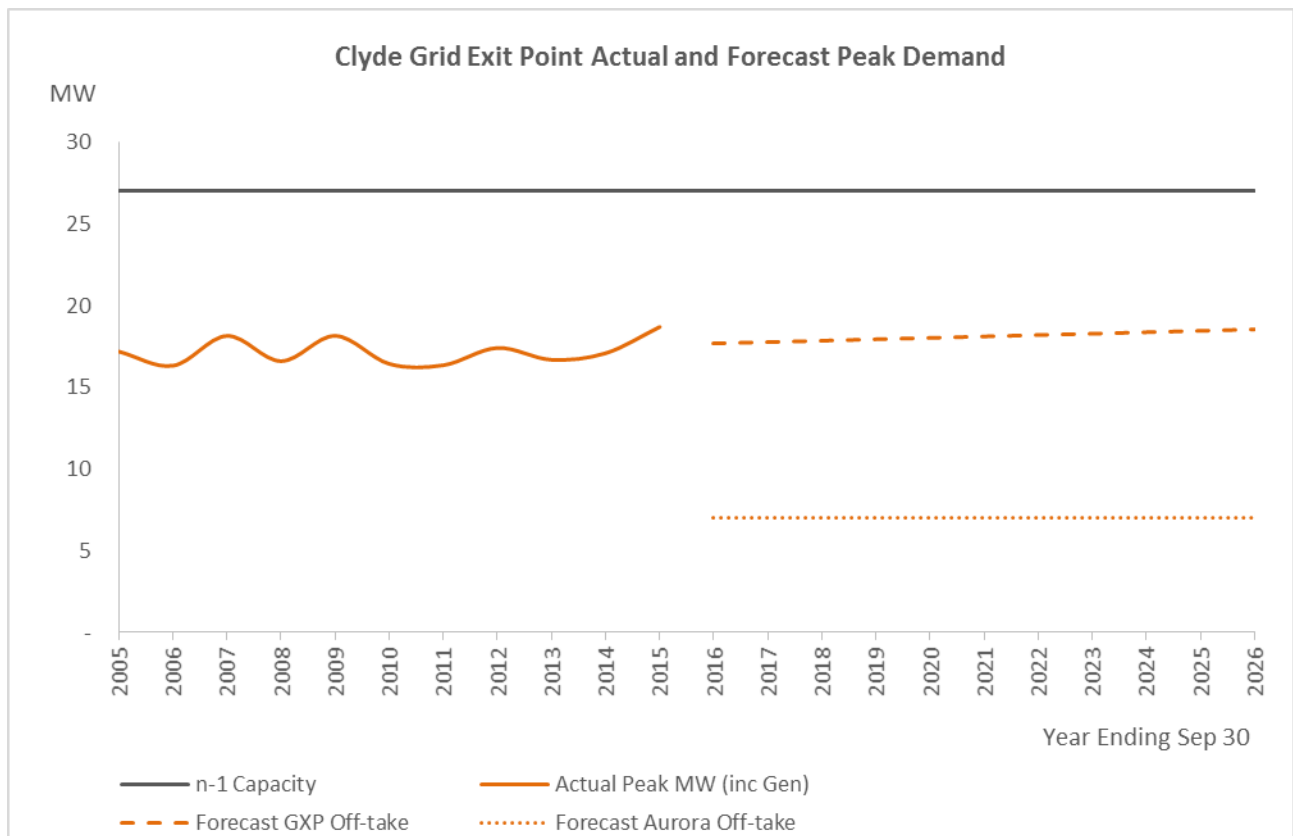
**Figure 6-8 Load Factor by Grid Exit Point**

**\*Table 6-8 Comparison of 2015 Actual and Predicted Peak Loads**

GXP	2015MVA Predicted	2015 MVA Actual	Difference
Clyde	16.8	18.7	11.31%
Cromwell	32	33.5	4.77%
Frankton	53.4	56.9	6.51%
Halfway Bush	126.1	127.0	0.68%
South Dunedin	69.7	76.5	9.76%

## 6.5.2.1 Clyde GXP

The Clyde GXP has two 27 MVA transformers. The embedded generation on this GXP almost meets the total demand on the GXP. Should the embedded generation fail, the maximum demand on the GXP would be approximately 17 MVA. There is adequate GXP capacity at Clyde for the foreseeable future. Energy growth has averaged less than 1% per year since 2004. This may increase slightly with growth in irrigation demands however the peak load in this area is expected to remain in winter. The significant growth in peak demand this last year is due to the operation of the load control plant as explained earlier. There is likely to be some additional small hydro generation at this GXP that will continue to keep the off-take low.



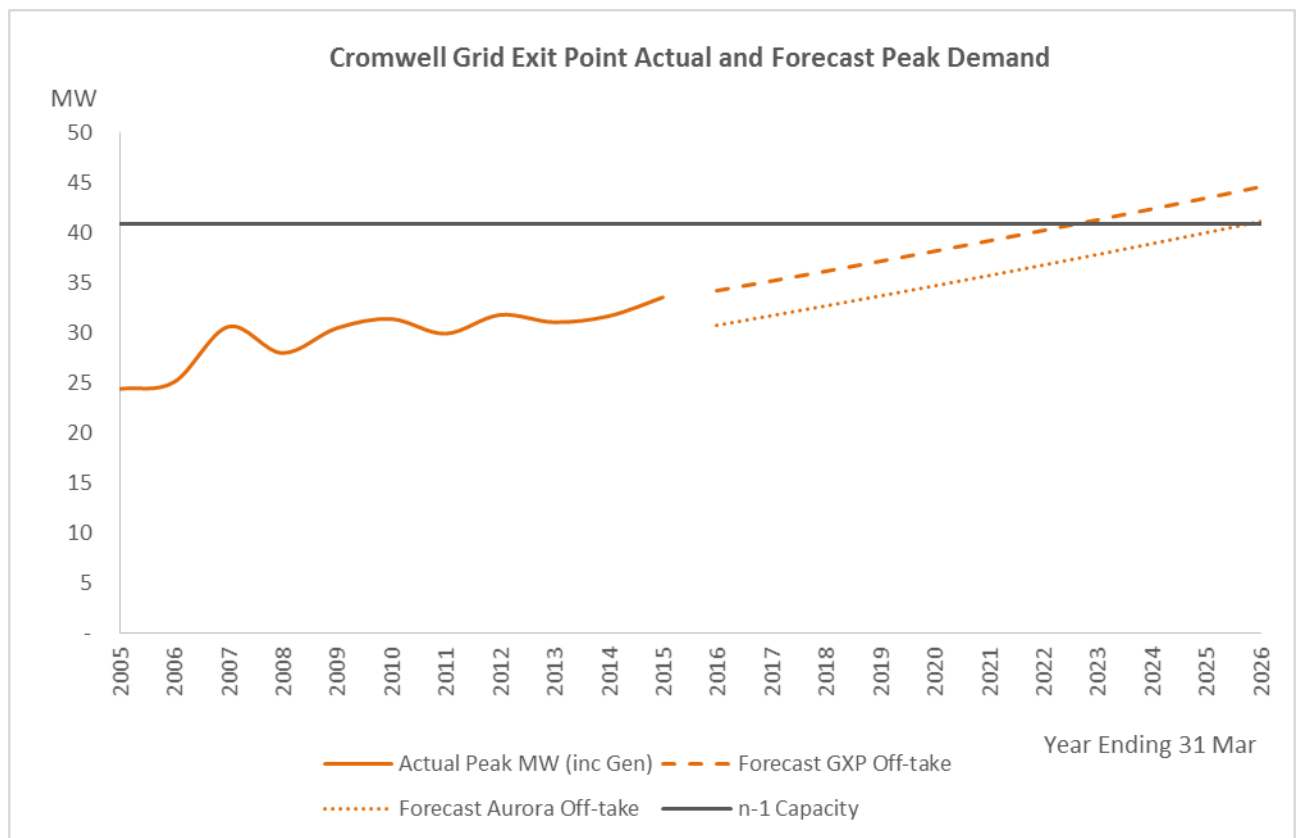
**Figure 6-9 – Clyde GXP Load**



## 6.5.2.2 Cromwell GXP

Cromwell GXP load prediction is illustrated in Figure 6-10. Although currently under the limit for n-1 of 40.9MW, loads are predicted to continue to increase. This is predominantly influenced by winter demand (ski fields, winter tourism, and domestic winter loads). 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.

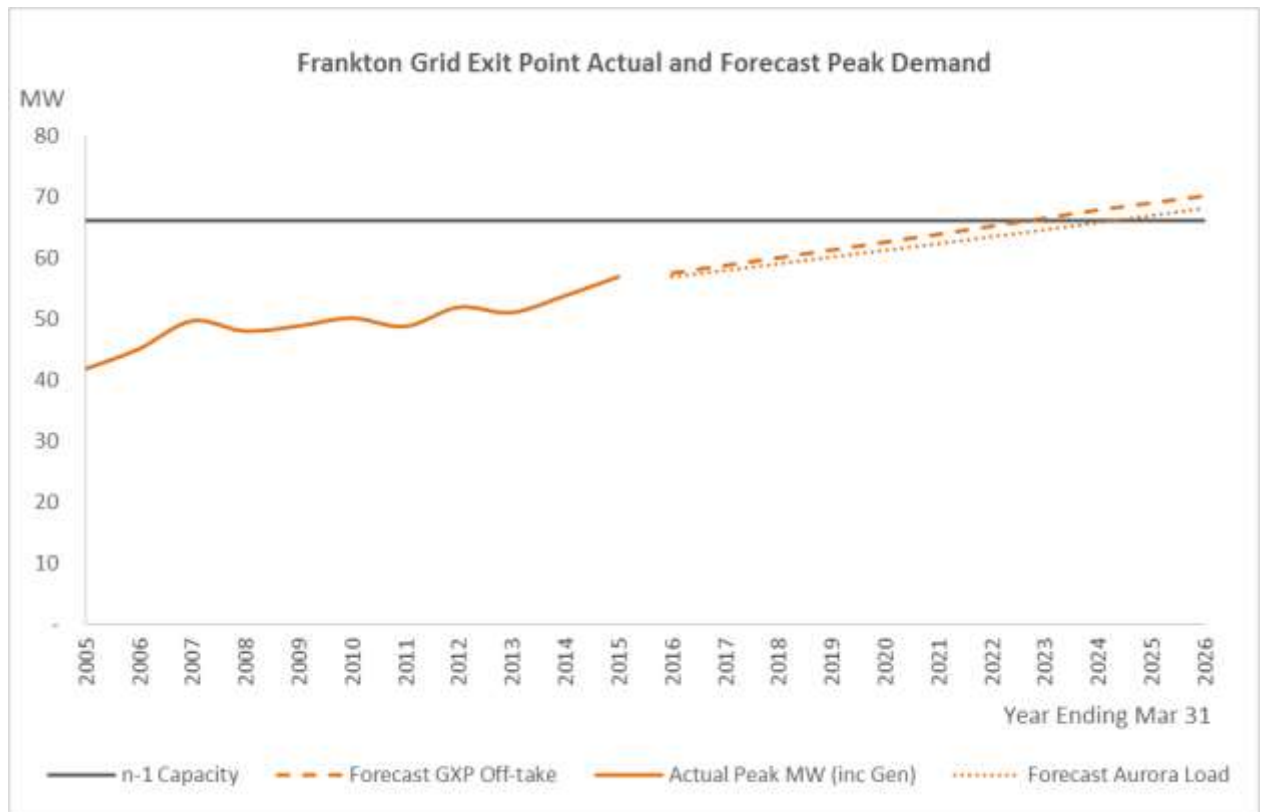
There has been a steady growth in energy usage on this GXP due to summer irrigation. This has yet to impact on the winter peak load. Although it is expected that the GXP remains winter peaking it is likely that the economic activity associated with the irrigation growth will drive continuing population increases in this area. If this is coupled with other winter growth (such as ski field developments) then very strong growth in peak demand could occur.



**Figure 6-10 - Cromwell GXP Actual and Prediction Loads**

## 6.5.2.3 Frankton GXP

Frankton GXP load prediction is illustrated in Figure 6-11. Past trends indicate a growth rate around 1.5% p.a. The distributed generation on this GXP is 3.96 MW. 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 may be exceeded during the planning period as shown in Figure 6.5. 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 6-11 - Frankton GXP Actual and Prediction Load**

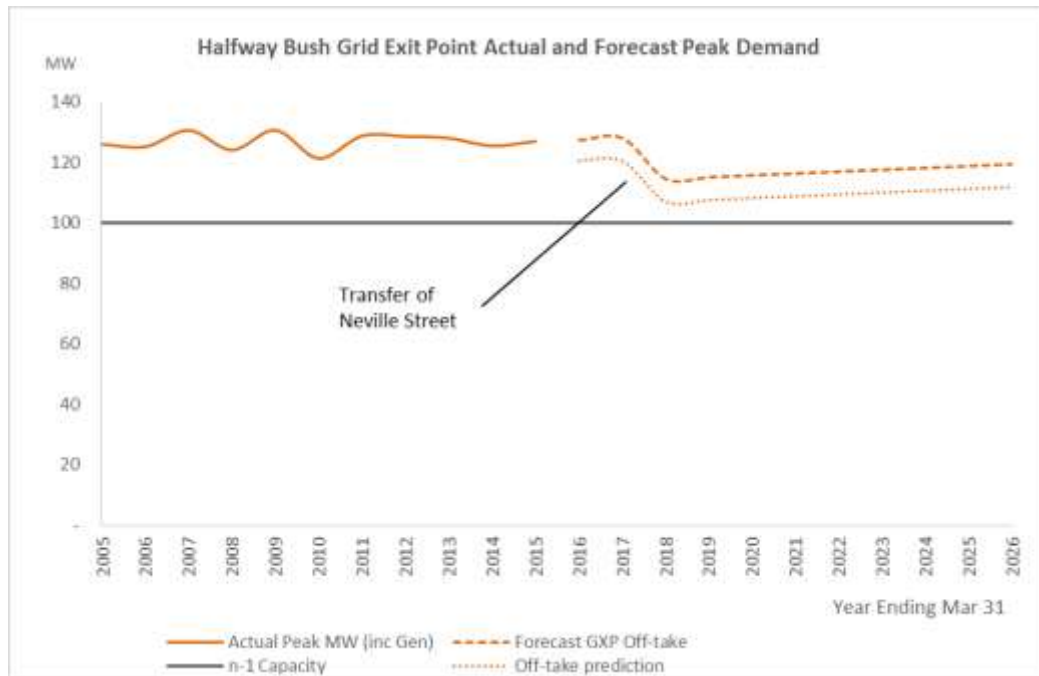
## 6.5.2.4 Halfway Bush GXP

Halfway Bush GXP load prediction is illustrated in FIGURE 6-12. *Currently the off-take peak at Halfway Bush exceeds the 112 MVA post contingency rating however past trends indicate minimal growth. The distributed generation on this GXP is 95.8MW.*

This GXP has a significant majority of priority customers (Hospitals, Emergency Services, Electrical Distribution) 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. Load can also be transferred to the South Dunedin GXP via the 6.6 kV network and in the future via the Neville Street (Carisbrook) – Ward Street 33kV tie cable.

Transpower plans to upgrade this supply point in 2018 which will involve replacement of the last of the old outdoor 33kV switchgear and replacing the two 50MVA T1 and T2 transformers with a new 100MVA transformer.

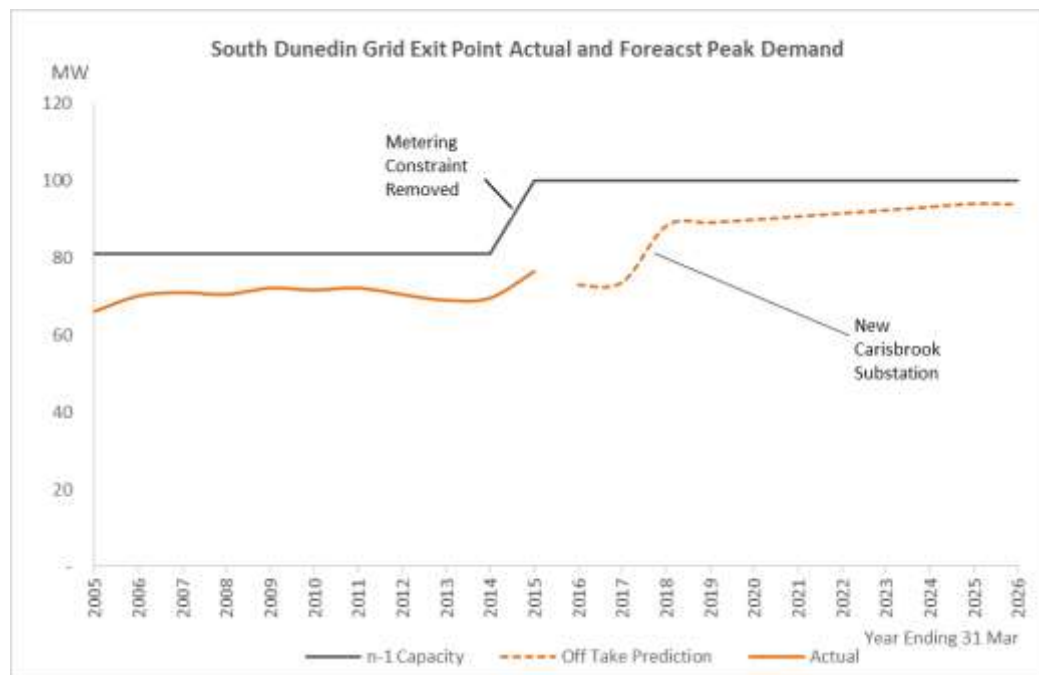
Otago Power now takes a small load from this GXP at 33kV.



**Figure 6-12– Halfway Bush GXP Actual and Prediction Loads**

## 6.5.2.5 South Dunedin

South Dunedin GXP load prediction is illustrated in Figure 6-13. Peak demand is well under the 100 MVA limit. Growth and over the forward 10 year planning period is expected remain relatively low, with the main impact on demand being through the new Carisbrook substation in 2020. This GXP did have an 81 MVA limit assigned by Transpower (due to metering accuracy limitations), and this metering constraint was removed in 2015.



**Figure 6-13 South Dunedin GXP Actual and Prediction Loads**

### 6.5.3 Zone Substation Demand Projections

Aurora's network contains 39 zone substations, 18 in Dunedin and 21 in Central Otago. Table 6-9 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.

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. Zone substations with a capacity of 7.5 MVA or less are not designed with n-1 security. The mobile substation or spare transformers provide cover along with load transfers to other substations.

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.

**Table 6-9 Zone Substation Loading**

Zone Substation	Firm Load MVA	N-1	Actual 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Alexandra	15	15	11.7	11.4	11.5	11.5	11.6	11.6	11.7	11.7	11.8	11.8	11.8	11.9
Anderson's Bay	18	18	15.6	15.6	15.7	15.8	15.9	16.0	16.0	16.1	16.2	16.3	16.4	16.5
Arrowtown	7.5	6	8.8	8.8	9.0	9.1	9.3	9.5	9.6	9.8	10.0	10.2	10.3	10.5
Berwick	3.6	0	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.7
Cardrona	5	0	2.9	2.5	2.5	2.6	2.6	2.7	2.8	2.8	2.9	2.9	3.0	3.0
Clyde/Earnsclough	4.8	4	4.2	4.2	4.2	4.3	4.3	4.4	4.4	4.4	4.5	4.5	4.6	4.6
Commonage	23	17	10.6	10.5	10.7	10.8	11.0	11.1	11.2	11.4	11.5	11.7	11.9	12.0
Coronet Peak	6	0	4.9	5.0	5.0	5.0	5.0	5.0	5.1	5.1	5.1	5.1	5.1	5.1
Corstorphine	23	23	14.0	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6
Cromwell	9.0	9.0	10.6	10.8	11.0	11.2	11.4	11.5	11.8	12.0	12.2	12.4	12.6	12.9
Dalefield	3.6	0	3.1	3.2	3.3	3.4	3.5	3.6	3.7	3.8	3.9	4.1	4.2	4.3
East Taieri	24	18.5	17.0	16.9	17.1	17.2	17.3	17.4	17.6	17.7	17.8	17.9	18.1	18.2
Ettrick	3.6	0	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3
Frankton	17	15	14.3	14.0	14.4	14.8	15.2	15.7	16.1	16.5	15.0	15.4	15.8	16.2
Fernhill	10	10	6.3	6.3	6.3	6.4	6.4	6.5	6.6	6.6	6.7	6.7	6.8	6.8
Green Island	18	18	14.0	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9
Halfway Bush	18	18	15.0	15.0	15.2	15.3	15.5	15.6	15.8	15.9	16.1	16.2	16.4	16.5
Kaikorai Valley	23	22	10.8	10.8	10.9	10.9	11.0	11.1	11.1	11.2	11.2	11.3	11.3	11.4
Lindis Crossing	7.5	0	4.5	4.3	4.4	4.5	4.7	4.8	5.0	5.2	5.3	5.5	5.7	5.9
Camp Hill	7	0	4.0	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8	4.9	5.0
Mosgiel	14	12	6.9	6.8	6.9	7.0	7.1	7.3	7.4	7.5	7.6	7.7	7.8	7.9
Neville St	18	18	13.1	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
North City	28	28	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8
North East Valley	23	18	11.4	11.5	11.5	11.6	11.7	11.8	11.9	12.0	12.1	12.2	12.2	12.3
Omakau	3.6	0	3.6	3.4	3.6	3.7	3.9	4.0	4.2	4.3	4.5	4.7	4.9	5.0
Outram	5.6	3.6	2.8	2.9	2.9	2.9	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.2
Port Chalmers	10	9	7.3	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Queensberry	4	0	3.0	2.8	2.9	3.0	3.1	3.2	3.3	3.4	3.5	3.7	3.8	3.9
Queenstown	26	20	14.0	14.1	14.4	14.7	15.0	15.3	15.6	15.9	16.2	16.5	16.8	17.2

Zone Substation	Firm Load MVA	N-1	Actual 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Remarkables	3.6	0	2.3	2.0	2.6	3.4	3.5	3.5	4.8	4.8	4.8	4.8	4.8	4.8
Roxburgh	6	0	1.8	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9
Smith St	18	18	15.2	15.6	15.7	15.9	16.0	16.1	16.3	16.4	16.6	16.7	16.9	17.0
South City	18	18	16.1	15.8	15.8	15.9	16.0	16.1	16.1	16.2	16.3	16.4	16.4	16.5
St Kilda	23	23	16.0	15.8	15.9	15.9	15.9	15.9	15.9	15.9	16.0	16.0	16.0	16.0
Wanaka	24	24	20.3	20.5	21.2	21.8	22.5	23.2	23.9	24.6	17.4	18.0	18.6	19.3
Ward St	24	24	12.8	13.2	13.4	13.5	13.6	13.8	13.9	14.0	14.2	14.3	14.4	14.6
Willowbank	18	18	12.5	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4
Jacks Point <sup>1</sup>	10	0								0.0	2.0	2.0	2.0	2.0
Riverbank Rd	24	24									8.0	8.0	8.3	8.6
MG + ET (Merged 1/2hr data)	30.8	30.8	23.8	23.9	23.9	23.9	23.9	23.9	23.9	23.9	23.9	23.9	23.9	24.0

Notes:

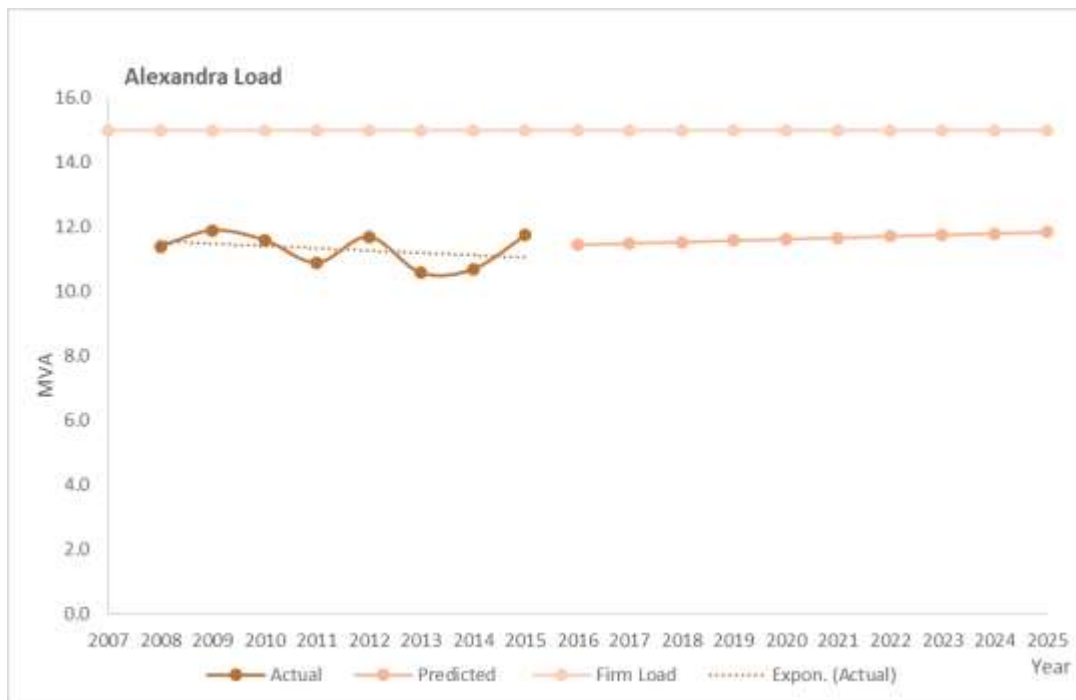
<sup>1</sup> Jacks Point actual load is included in Frankton

It is current practice for Aurora to take some risk and allow loads to exceed the n-1 capacity for a short time before upgrades are completed.

The 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 and Frankton followed by the zone substations in Halfway Bush and South Dunedin.

## 6.5.3.1 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 (Figure 6-14).

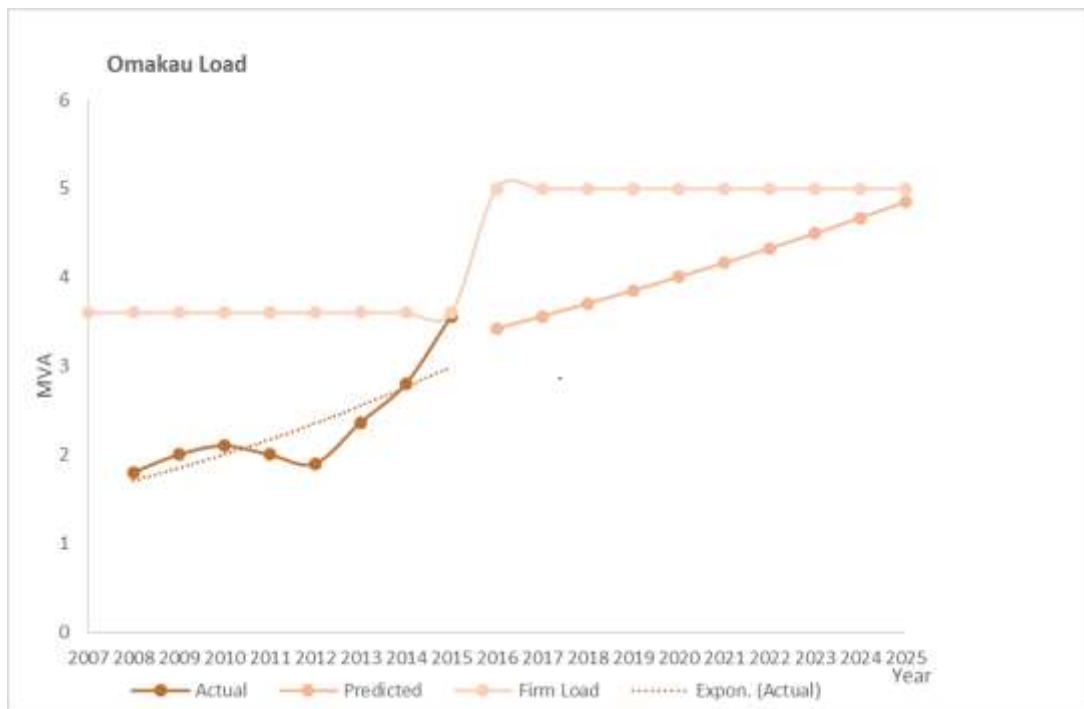


**Figure 6-14 - Alexandra Substation Load**

## 6.5.3.2 Omakau substation

There has been a large number of new connections for irrigation purposes in the Omakau area. This has steadily increased the peak load on this substation. It is expected the growth of these projects will continue and works to address the predicted overload of the existing Omakau substation are detailed in 7.2.1.5.





**Figure 6-15 - Omakau Zone Substation Load**

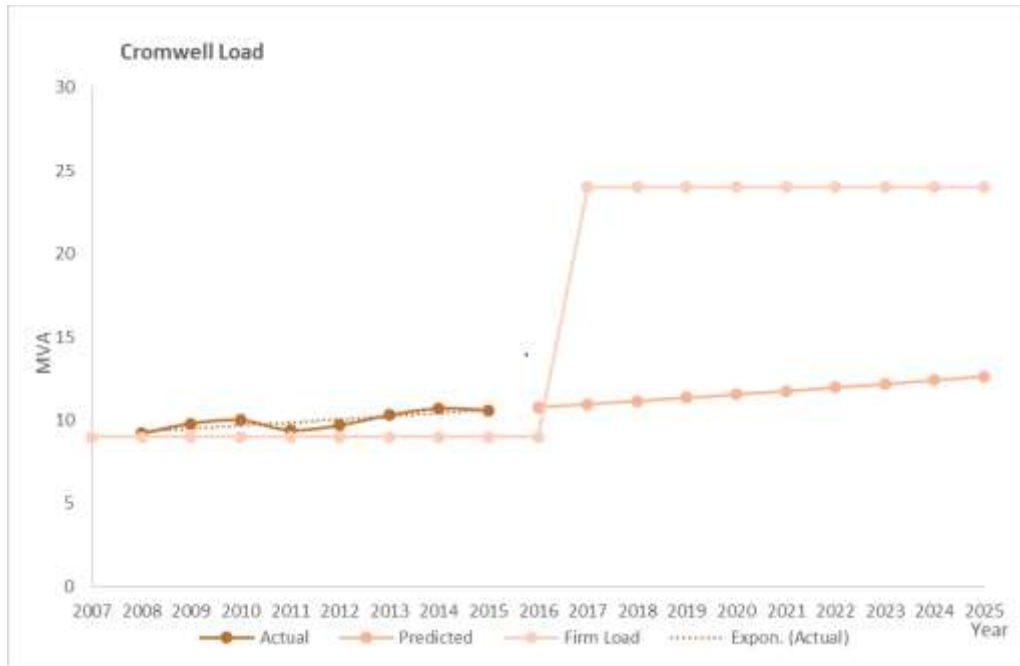
#### 6.5.3.3 Clyde-Earnsclough substation

Peak loads in the Clyde-Earnsclough area has been somewhat erratic over the last few years. The peak load on this substation has been historically driven by orchard frost fighting. This has reduced slightly over the last few years but more recently the load has increased again with the establishment of the gold-mining operation on Earnsclough Road. This goldmine has now closed, which may again cause a drop in the peak load supplied by this substation.

For many years, there has been a proposal to build a large irrigation scheme on the Clyde side of the river. The details of the proposal have changed numerous times and whether the scheme eventually goes ahead or not is uncertain. Even if this project does not go ahead, it is likely that there will be some other irrigation growth in this area. The most practical way to meet this future growth is to convert the area to 11kV.

#### 6.5.3.4 Cromwell zone substation

Figure 6-16 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. Present load predictions have reduced and it is now proposed that the transformer upgrade be deferred to 2022.

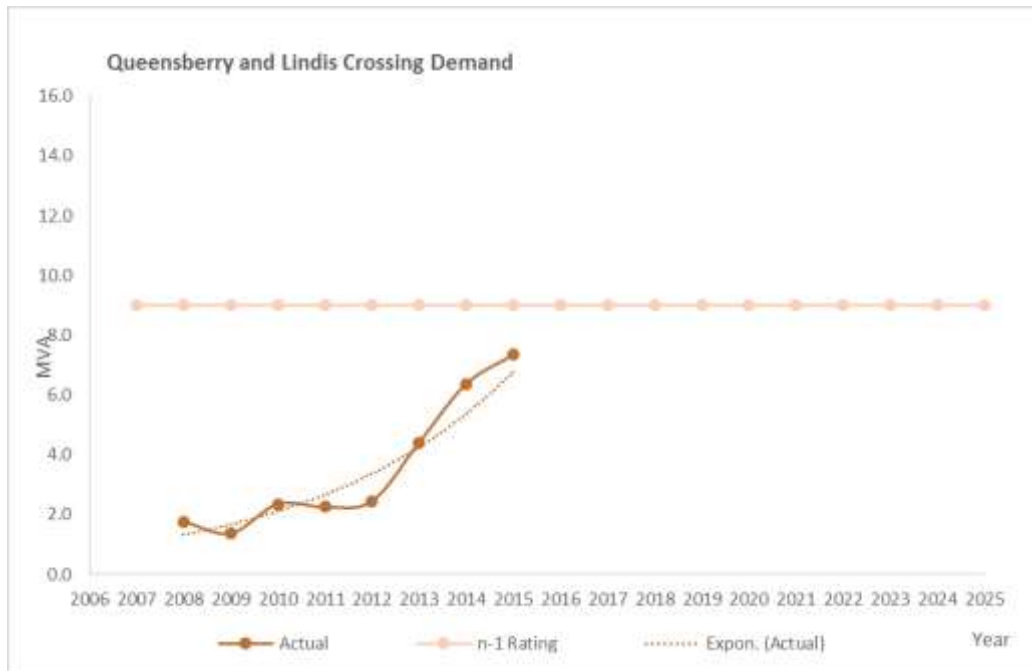


**Figure 6-16 - Cromwell Zone Substation Load**

#### 6.5.3.5 Queensberry and Lindis Crossing zone substations

These substations are considered together as they are relatively close. The Queensberry substation is a single transformer that was originally 3MVA but has been uprated to 4MVA with the addition of fans. The Lindis Crossing substation was commissioned in early 2015 and consists of a single 7.5MVA transformer. There is a mobile substation parking bay at both sites. In winter the loads are relatively light in this area and either one or the other substation can be taken out of service for maintenance without issue. In summer the irrigation load is significant and both substations are required for both capacity and voltdrop reasons. A failure of the Queensberry Transformer can be managed with the mobile substation. A failure of the Lindis Crossing Transformer would be handled by installing the mobile sub and transferring some load to the Queensberry substation, however this limits the N-1 capacity to 9MVA.

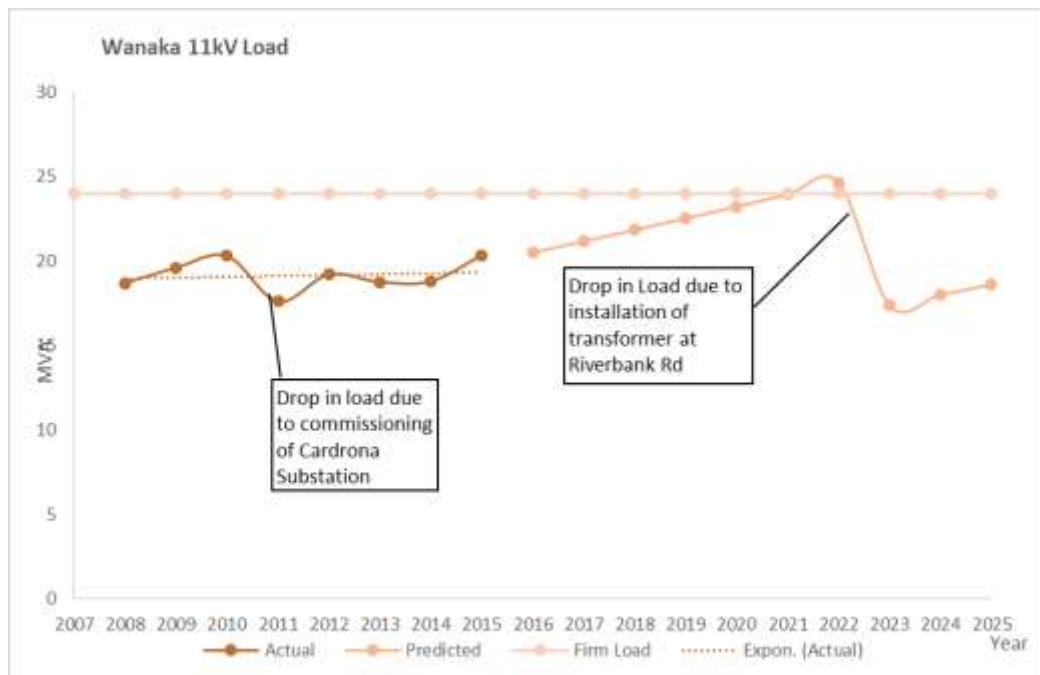
FIGURE 6-17 illustrates the historical load for the Queensberry and Lindis Crossing zone substations. There has been substantial growth due to irrigation load. It has been difficult to track load to some extent over the last few years as the mobile substation has been used to provide for the shortfall while the Lindis Crossing substation was under construction and historic metering data from the mobile substation is not complete. However the graph shows that load is growing rapidly and may in future exceed the 9MVA N-1 limit.



**Figure 6-17 – Queensberry and Lindis Crossing**

## 6.5.3.6 Wanaka zone substation

Figure 6-18 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.



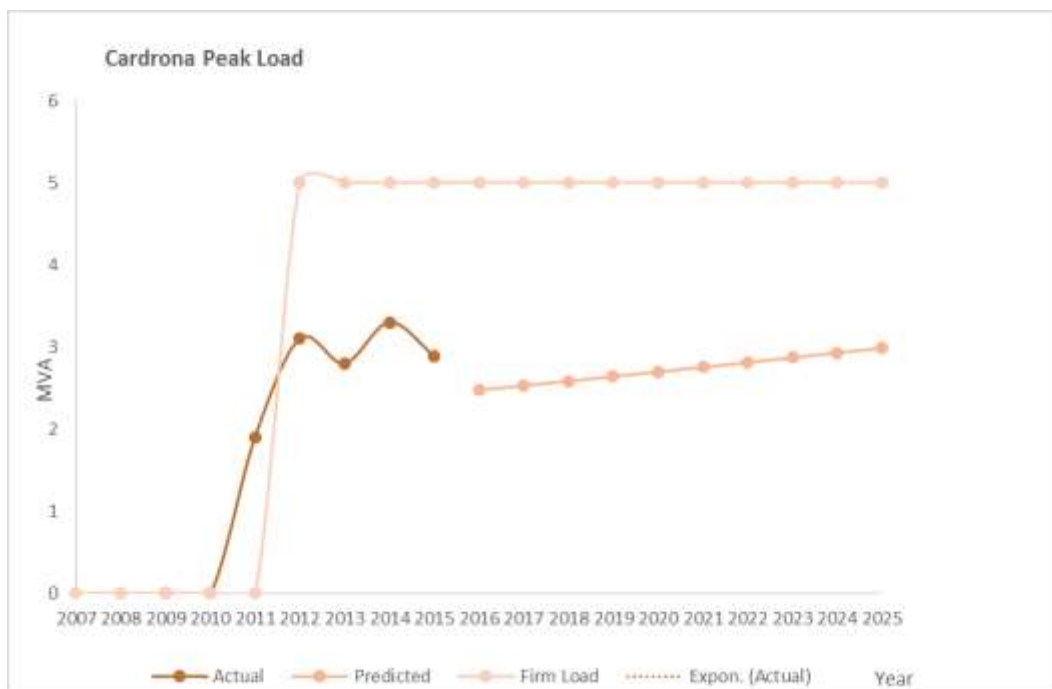
**Figure 6-18 – Wanaka Zone Substation Load Prediction**

## 6.5.3.7 Maungawera Zone Substation

The 3MVA Maungawera substation was exceeding its maximum load but this has now been replaced with the new 7.5 MVA Camp Hill substation, alleviating this constraint.

## 6.5.3.8 Cardrona Zone Substation

Figure 6-19 illustrates the load predictions for Cardrona zone substation. Although the prediction does not show it there is the possibility of significant growth in this area in conjunction with Ski Field developments. This could see the capacity of the substation exceeded. However the timing of these developments is uncertain.



**Figure 6-19 – Cardrona Zone Substation Load**

## 6.5.3.9 Arrowtown zone substation

Figure 6-20 illustrates the load predictions for Arrowtown zone substation. The Arrowtown substation demand exceeds 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. 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.

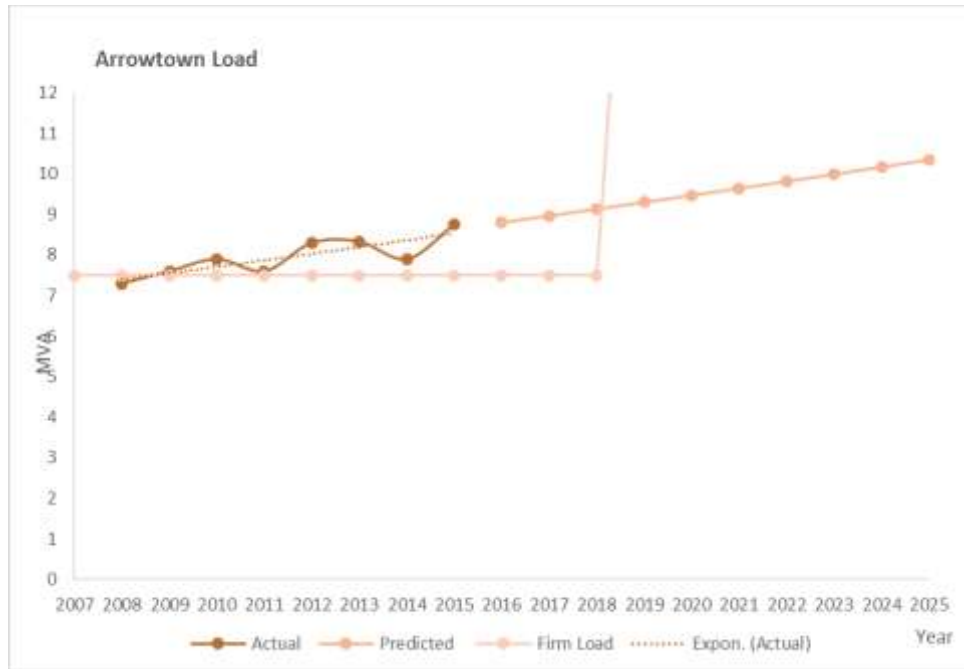


Figure 6-20- Arrowtown Zone Substation Load Prediction

#### 6.5.3.10 Frankton zone substation

Figure 6-21 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. Construction of Jacks Point will increase the ability to off load Frankton.

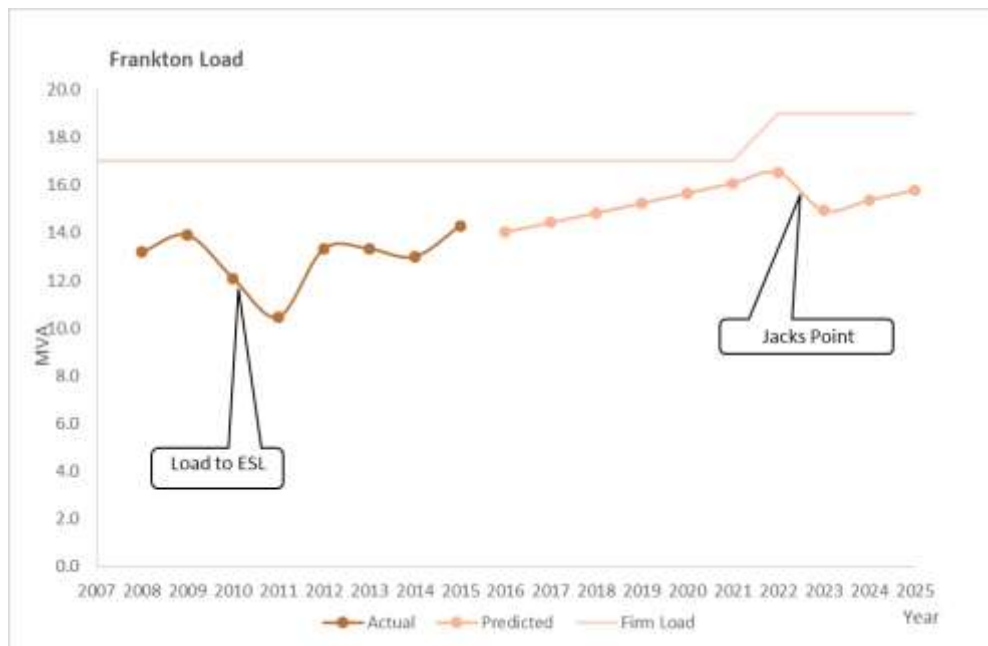


Figure 6-21 Frankton Zone Substation Load Prediction

### 6.5.3.11 Remarkables zone substation

6-22 illustrates the load predictions for Remarkables zone substation. The Remarkables ski field has recently increased significantly in load and further increases are planned. The increases so far have been met by applying a significant amount of LDC to the substation to overcome the voltdrop on the customer's 11kV overhead line and cable. This required the installation of an 11kV cable so that distribution transformer ws200 could be shifted to a supply from Lake Hayes estate (otherwise this transformer would receive excessive voltage).

We have received no advice from the customer regarding further load growth but understand they propose to install a significant diesel generator on site and use waste heat from the generator to heat the buildings on the ski field. If this generator is to be run in parallel with the network some consideration needs to be made regarding the possibility of back-feeding the 11kV and 33kV networks and some inter-tripping communications links may be required.

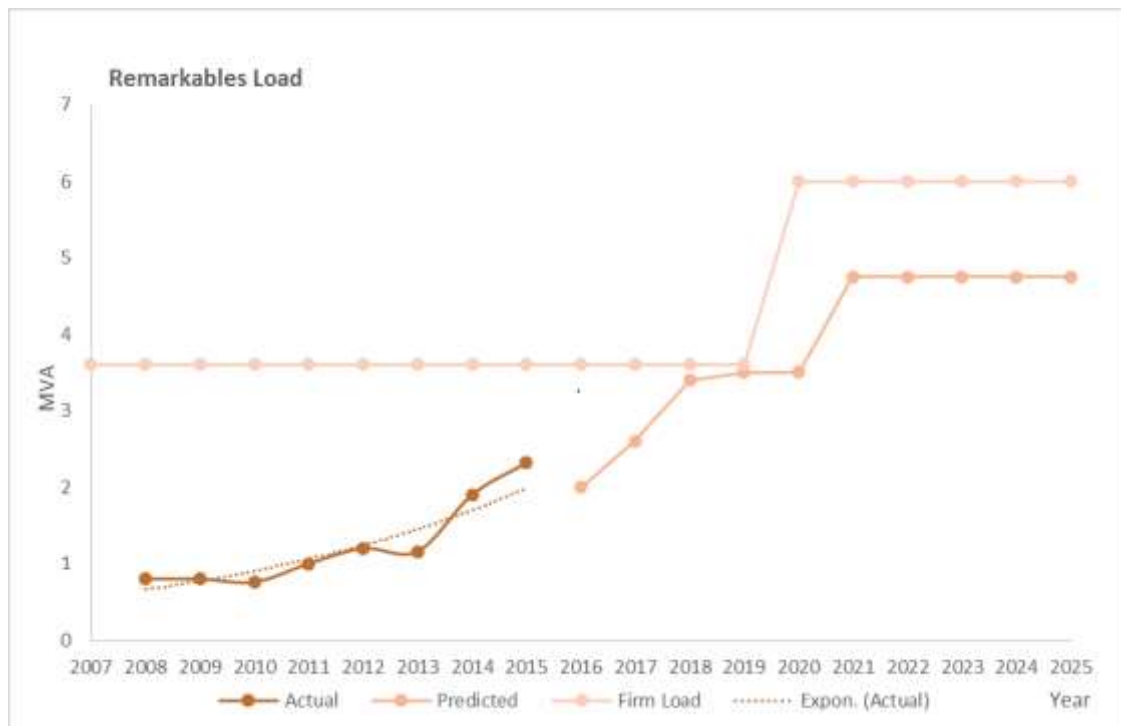
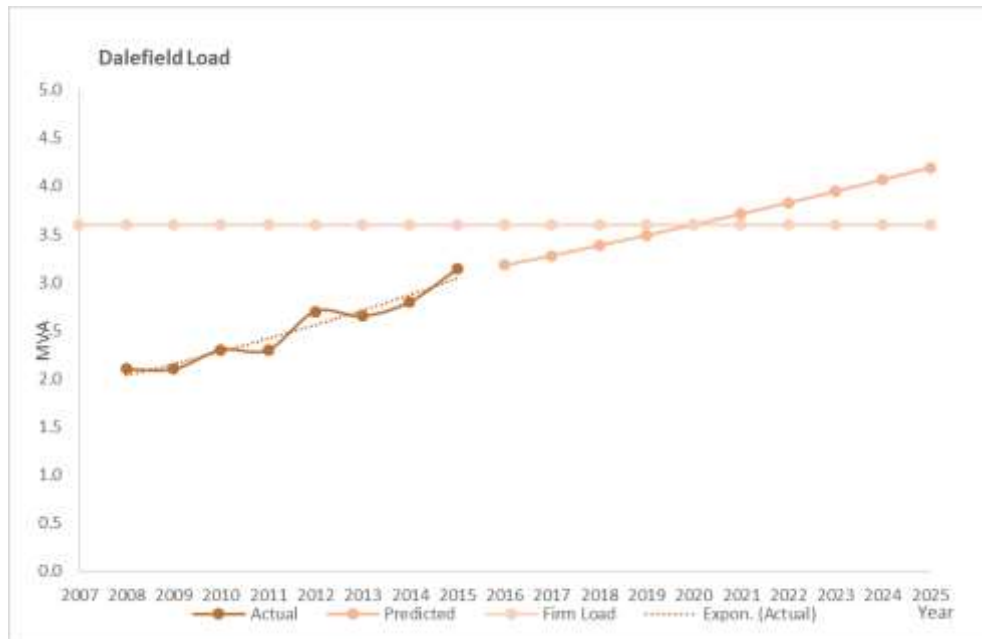


Figure 6-22 Remarkables Zone Substation Load Prediction

## 6.5.3.12 Dalefield zone substation

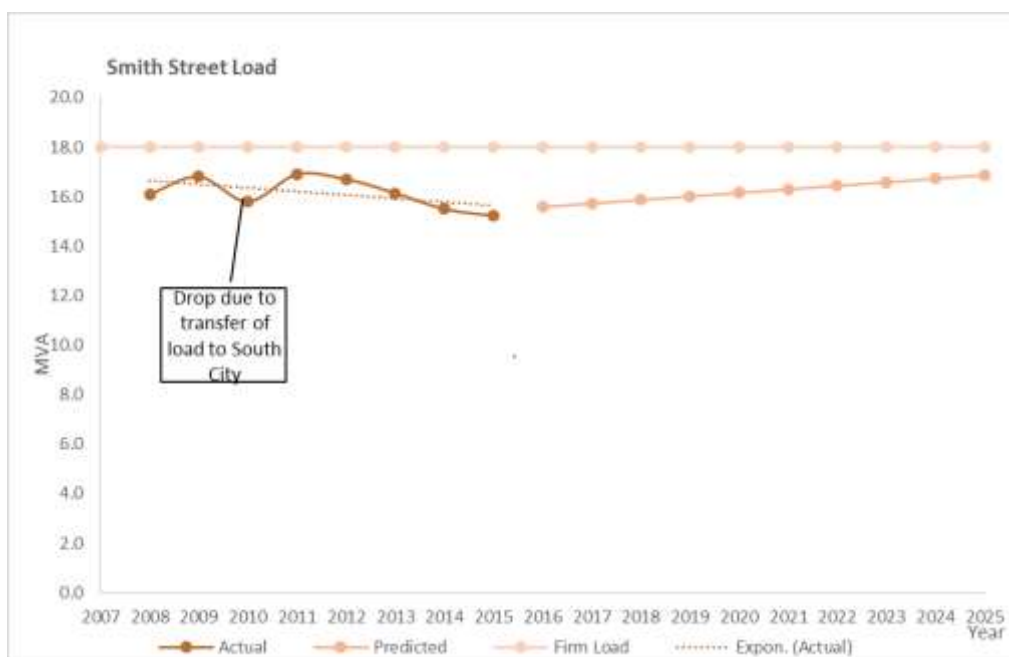
FIGURE 6-23 illustrates the load predictions for Dalefield zone substation. This area has seen strong growth recently. The load is predicted to exceed the substation capacity in 2020.



**Figure 6-23 Dalefield Zone Substation Load Prediction**

## 6.5.3.13 Smith Street zone substation

Figure 6-24 illustrates the load predictions for Smith Street zone 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. It is proposed that Smith Street be upgraded to 24 MVA transformers and the HV switchgear be replaced prior to the winter of 2022.



**Figure 6-24 Smith Street Zone Substation Load Prediction**

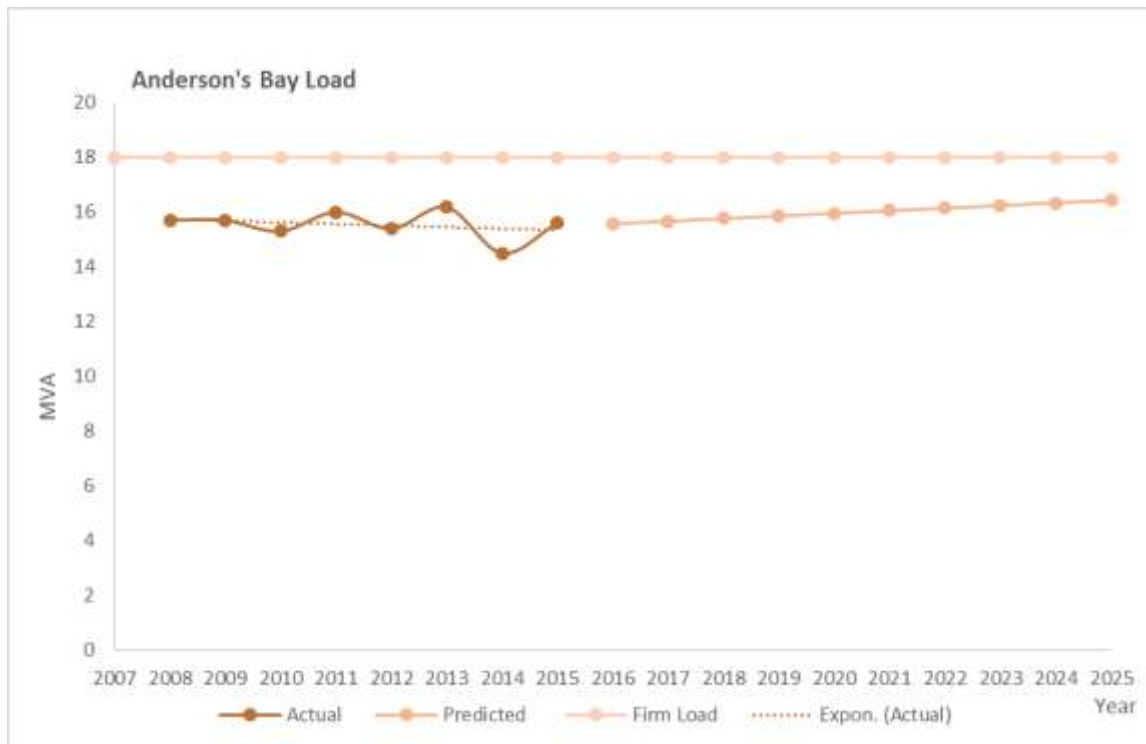


#### 6.5.3.14 Carisbrook (Neville Street) zone substation

It is planned to move the Neville Street substation load to the South Dunedin GXP before winter 2020 when the Carisbrook substation is constructed and the old Neville Street Substation and gas cables are decommissioned.

#### 6.5.3.15 Andersons Bay substation

Figure 6-25 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. It is expected that most of the equipment at Andersons Bay will be at the end of its economic life in 2019 so it is proposed the substation be upgraded with new transformers and switchgear at this time.



**Figure 6-25 Andersons Bay Zone Substation Load Prediction**

#### 6.5.3.16 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. Initially it was planned to resolve this constraint by establishing a zone substation at Macandrew Bay. Aurora already owns the land for the substation and there is a 33 kV line, currently operating at 6.6 kV, from Darnell Street to the Macandrew Bay substation site. Load growth has slowed recently and it is now expected that conversion of the Peninsula to 11kV will be more economic than the construction of a new zone substation. However the option to build a substation here in the future still exists.

## 6.6 Subtransmission

Figure 6-26 through to Figure 6-29 illustrate historic trends in load for the subtransmission network and provide a revised load prediction. 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

### 6.6.1 Alexandra to Roxburgh Subtransmission

There are two 33 kV lines between Roxburgh and Alexandra. These lines consist of sections 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. Note also that due to the change of the way Transpower is charging for use of the HVDC link Pioneer no longer deliberately spill water during periods of high injection. This change in operation may see increased difficulty in maintaining voltage within limits at Roxburgh and Ettrick and some investment or operational restrictions in generation levels may be required.

### 6.6.2 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.

### 6.6.3 Wanaka 33 kV subtransmission

The Wanaka 33 kV subtransmission supplies Cardrona and Camp Hill substations. The maximum n-1 rating of the 33 kV supply is 6 MVA if the Wanaka 11kV bus is fully loaded. However, in summer when the Wanaka 11kV bus is lightly loaded and n-1 capacity of 10MVA is available at the 33kV bus.

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, and the fact that the Camp Hill load is summer peaking.

### 6.6.4 Upper Clutha Subtransmission

Figure 6-26 illustrates the single line diagram of the existing subtransmission system and illustrates the load predictions for the Upper Clutha, which is supplied from the Transpower Cromwell GXP at 66 kV.

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; and
- firm 33 kV capacity at the Cromwell GXP.

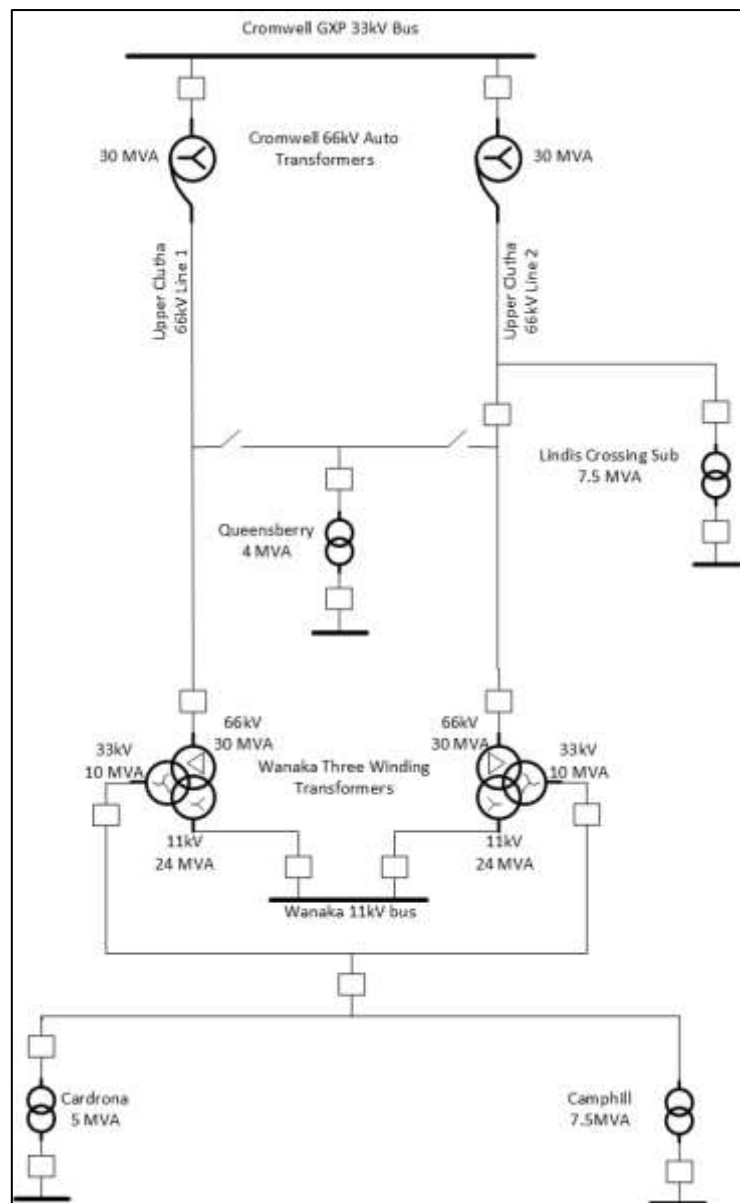
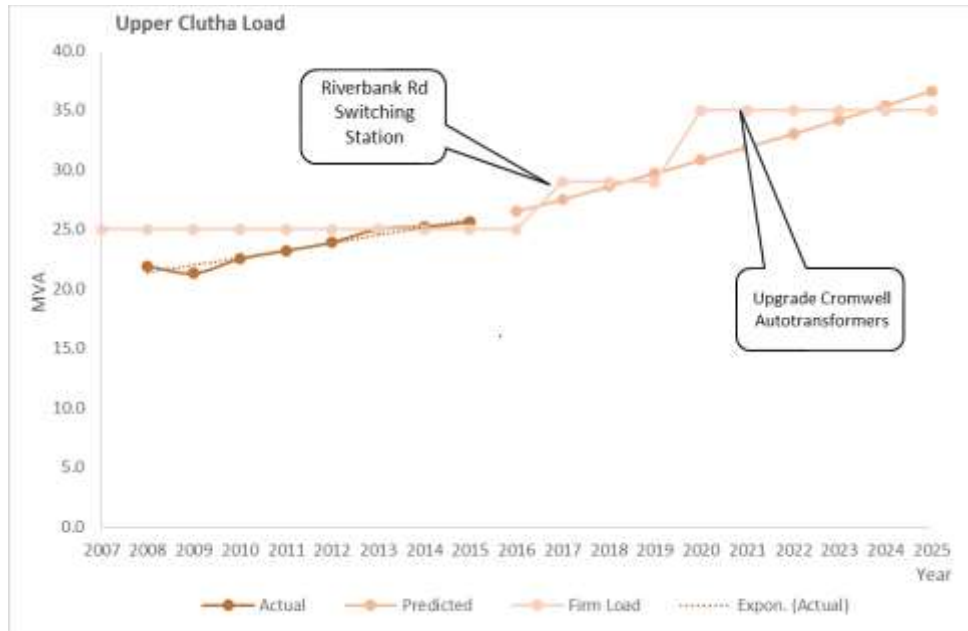


Figure 6-26 - Single Line Diagram of Existing Upper Clutha Subtransmission



**Figure 6-27 - Upper Clutha Subtransmission**

### 6.6.5 West Wanaka and Treble Cone

The Treble Cone ski field currently runs generators to supply its own peak loads and avoid overloading their existing supply capacity. The ski field has proposals to upgrade and stop generating. When this occurs, it is proposed to extend the 33 kV subtransmission toward Treble Cone and install an appropriate 33/11 kV zone substation.

A report has been prepared 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.

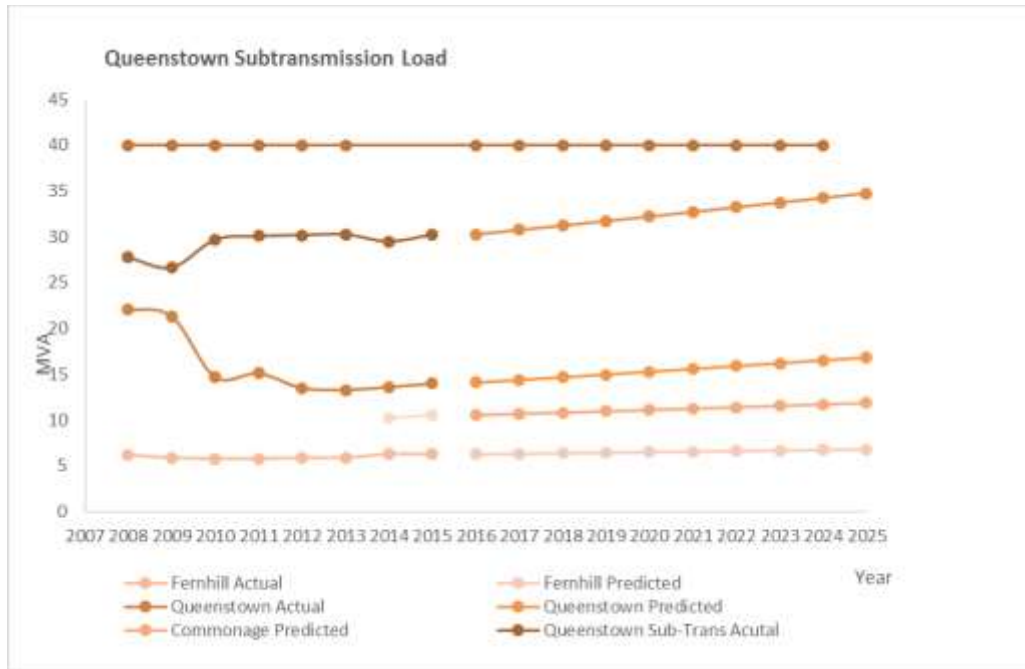
A piecemeal approach has been taken for recent connection enquiries on this line to allow these but only by requiring the construction of sufficient 33/11kV lines with appropriate conductor and running these circuits in parallel at 11kV so that the overall voltage drop at the Treble Cone Ski field remains unchanged with the introduction of the proposed new load.

### 6.6.6 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.

### 6.6.7 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 6-28. 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 provide additional 33 kV transmission capacity to the Commonage substation.

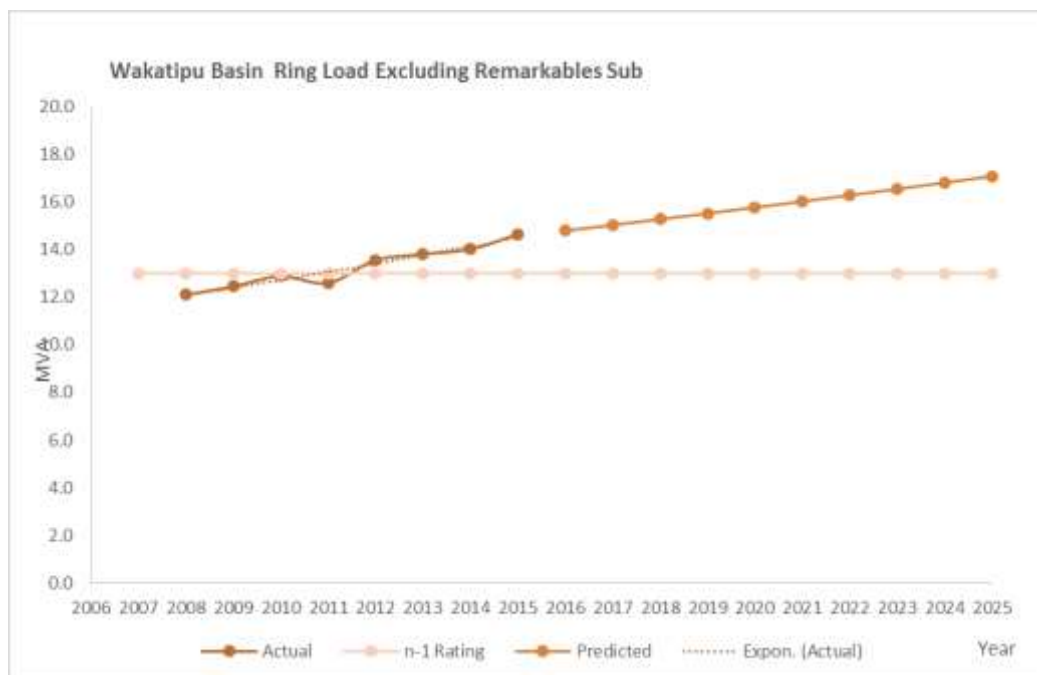


**Figure 6-28 Frankton to Queenstown Subtransmission**

## 6.6.8 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 has exceeded its n-1 capacity during the winters since 2012 shown in Figure 6-29. The timing of snow making at Coronet peak has a significant effect on the diversity which varies from year to year.



**Figure 6-29 - Wakatipu Basin Subtransmission 33 kV Ring**

## 6.6.9 Glenorchy Subtransmission

Glenorchy is presently supplied from Queenstown 11kV 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 33kV 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 that it would be difficult to maintain the feeder voltage above design values after the winter of 2014. Works to address this are outlined in 0

## 6.6.10 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.

## 6.6.11 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. It is considered that this project is uneconomic and that the long term solution to this problem is to upgrade the protection systems on the A, B, and C lines so that the 33kV bus can be solidly closed at Mosgiel. However the timing of this project is uncertain as it relies on future upgrades to communication circuits to become practical.

## 6.6.12 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.

## 6.7 Major Project Proposals

This section outlines the network development projects required to upgrade Aurora's distribution system. It details the expansion and upgrading considered necessary to accommodate predicted future network loading and future major renewals. The plan also proposes works to improve network safety and reliability.

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.

### 6.7.1 GXP Projects

Major work at the Halfway Bush GXP has been planned to coincide with a series of projects being implemented by Transpower. For example Transpower plans to convert the remaining outdoor 33 kV circuit breakers to indoor units in 2017-2018. At this time, it is desirable to have Transpower fit 33 kV Voltage Transformers (VT) to the Waipori lines which will eliminate the need for the outdoor VTs in the take-off area. It is also desirable that some short new cables be run directly to the Halfway Bush zone substation and Port Chalmers overhead lines to eliminate multiple cable terminations and remove some very old 33kV cables. Aurora's 33kV protection equipment is proposed to be upgraded at the same time.

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. 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 proposed that Transpower be requested to install Neutral Earth Resistors (NER) on the existing T5 transformer. 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%.

### 6.7.2 Zone Substation Proposals

TABLE 6-10 indicates the major projects being proposed at our zone substations:

**Table 6-10 Major Substation Works**

Location	Project Details	Project No	Estimated to Complete \$000	Completion
Clyde-Earnsclough	Construction of a mobile substation parking bay	6055	250	2018
Riverbank	Riverbank Road switching station	3022	8,323	2019
Outram	Substation rebuild	4179	4,300	2019
Omakau	Substation	5692	2,708	2019
Riverbank	Installation of one 24 MVA transformer	3437	2,500	2020
Anderson Bay	Substation rebuild	3038	6,550	2020
Neville Street	Substation replacement (Carisbrook)	2324	8,994	2020
Arrowtown	Transformer and switch gear upgrade	3019	5,000	2021
Clyde-Earnsclough	Substation upgrade	6184	4,000	2021



Location	Project Details	Project No	Estimated to Complete \$000	Completion
Cromwell	Transformers upgrade	3024	3,250	2022
Smith Street	Transformer upgrade to 24 MVA / new switchgear	3414	8,550	2022
Willowbank	Substation rebuild	6026	5,000	2023
Jacks Point	New substation build	2611	3,000	2024
Port Chalmers	Transformer upgrades	6028	2,000	2024
Green Island	Substation rebuild	6029	5,000	2025
Queensberry	New 66kV switching station	3438	3,300	2025

## 6.7.2.1 Clyde-Earnsclough and Earnsclough substations

Clyde-Earnsclough is the last area in Central Otago to still be operating at 6.6kV. T2 at Clyde-Earnsclough can be operated at either 6.6 kV or 11kV. It is currently a 4MVA transformer but would be 5MVA if changed to the 11kV tap. Normally this transformer feeds all the load and T1 is a backup only. T1 is a 2 MVA unit without an on-load-tap-changer, another similar 2MVA transformer at the Earnsclough substation is also available for backup should the load exceed 2MVA.

Both of the 2MVA transformers are very old and in poor condition. It is expected that long term only a single transformer substation is used to feed the area and the mobile substation used a backup.

In the short term the mix and arrangement of transformers at these substations will help with gradual conversion of the area from 6.6kV to 11kV. Construction of a mobile substation parking bay will also aid this conversion. It may be difficult to construct such a parking bay near the existing substation as there are issues with earthing and nearby Telecom cables.

It is proposed to do some design work to resolve these issues in 2017 and then construct the required parking bay in 2018.

## 6.7.2.2 Omakau Substation

It has become clear from the number and size of new irrigation connections that the Omakau zone substation will require upgrading. The existing site of the substation is constrained by the road reserve area it occupies and has possible flooding issues. Land has been purchased at a new site to the North of Omakau and work is well underway to establish a mobile sub parking bay here. Eventually it is proposed to develop this site into a full substation.

In the shorter term work is in progress to install the 3MVA transformer from Maungawera at new Site on Lauder Flat road to provide additional capacity.

## 6.7.2.3 Cromwell substation

Load on Cromwell is growing and the peak demand now exceeds its 9 MVA firm capacity. The 5MVA mobile substation is being used to provide n-1 cover. It is proposed that The Cromwell Transformers be replaced with 24MVA units in 2022(see DR 130)

#### 6.7.2.4 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 economical solution is to install one 24 MVA transformer with associated 11 kV switchgear at the Riverbank Road switching station prior to the winter of 2021. 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 2019 to reduce volt drop during an outage on one of the upper Clutha 66 kV circuits. It is proposed to install a 24 MVA transformer at Riverbank Road in 2020 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.

#### 6.7.2.5 Arrowtown substation

Arrowtown substation consists of two 5MVA transformers. A mobile substation parking bay is used to increase the firm capacity of this substation to 10MVA. The load is not predicted to reach 10 MVA during the planning period. The upgrade proposed in the 2011 AMP - to install transformers 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. However this work has now been delayed based on the purchase of a spare 5MVA transformer to ensure the mobile substation does not get tied up for a long period of time if there is a transformer failure.

Associated with the future proposed upgrade is the installation of indoor 11 kV 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 a third 33 kV circuit as outlined in the Wakatipu Basin Ring proposal.

#### 6.7.2.6 Coronet Peak substation

Coronet Peak substation normally only supplies the Coronet Peak ski field and a few other small customers. The Ski field has a load approaching the rating of the transformer and they normally control this peak accurately however failure of their control equipment saw an increase in peak load in 2014 which was associated with a tripping of the substation on overcurrent. The transformer could be safely loaded to 120% of its rating during winter. This would require adjustment of the existing protection settings. Discussions with the ski field will be required to see what their future plans for growth are.

Initially it was envisaged that Coronet Peak and Dalefield substations would provide back-up to each other (with the likely consequence that the Ski-field would run on reduced load in a contingency). The load growth on both these substations now has means that for a winter-time contingency almost no capacity would be available for the Ski-field.

To alleviate this constraint it is proposed to develop a Mobile sub parking bay at a location that would provide back-up to both Dalefield and Coronet Peak substations.

## 6.7.2.7 Proposed Jacks Point substation

The timing of substation construction depends on uptake of the lots in this area, which has been slow in the recent past. The growth rate will be reviewed annually, 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. However it may be more appropriate to look at increasing the capacity of the 11kV network via additional circuits and a study of this is proposed for the coming year.

## 6.7.2.8 Carisbrook 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 replaced. Part of the Neville St upgrade involves the establishment of a new substation site. It is planned to call this new site Carisbrook to avoid confusion over the two sites. The new Carisbrook substation is planned for commissioning in early 2020.

## 6.7.2.9 Outram substation

The 11kV bus at Outram was installed in 1961 and is of an unreliable type that we have replaced elsewhere on the network. The two 33/11kV transformers were manufactured in 1952 and are also at the end of their life. The 33kV CBs are of a type that has been found unreliable and we are replacing elsewhere on the network. The building and fence are also in poor condition and need replacing.

It is planned to rebuild this substation as a single transformer substation with a mobile sub parking bay. Construction may be difficult due to the overhead 33kV lines. An investigation needs to be completed to determine if the best plan is to underground a short length of some of these lines, raise the lines with additional poles, or purchase extra land so that the substation can be moved.

## 6.7.2.10 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 no longer expected to exceed its firm load within the planning period. It is proposed that Smith Street be upgraded to 24 MVA transformers and the HV switchgear be replaced prior to the winter of 2022. The existing transformers and switchgear that was purchased in 1957 will be 65 years old by then and replacement is likely to be justified on reliability grounds. It is proposed to replace 33 kV gas cables supplying Smith Street at the same time.

## 6.7.2.11 Willowbank substation

The Willowbank substation was constructed in 1963. The 6.6kV switchgear is the same model as that at Andersons bay and showing the same poor test readings. It is planned to rebuild this substation in 2023, however ongoing monitoring of the switchboard is required and may dictate an earlier replacement if condition worsens.

## 6.7.2.12 Green Island substation

Green Island substation was constructed in 1957. It is planned to rebuild this substation in 2025 by which time it is expected the existing equipment will be at the end of its life. This substation is on the boundary of the 6.6kV and 11kV networks and it may be warranted to convert the area to 11kV at the time of replacing this substation.

## 6.7.2.13 Halfway Bush substation

Halfway Bush substation was shifted in 1981. The original 6.6kV switchboard and Transformers were reused. The transformers have since been replaced in 2014. The (1955) 6.6kV switchboard is planned to be replaced in 2021 by which time it will be 67 years old.

## 6.7.2.14 Port Chalmers substation

The transformers at Port Chalmers were purchased in 1953. It is not expected that the firm rating of these 7.5MVA units will be exceeded in the planning period but Port Otago has indicated that it may consider upgrades that would see a step jump in load above the rating of these transformers. Even if the load does not increase it is planned to replace these transformers in 2024 by which time they will be 71 years old.

## 6.7.2.15 Andersons Bay substation

The Andersons Bay substation was constructed in 1961. The 6.6kV switchgear has been suspect for some time as it has a poor insulation test. Regular testing seems to show this is stable and is not deteriorating further. Although this substation is now not expected to exceed its firm capacity during the planning period it is proposed to rebuild this substation in 2019-20 by which time the equipment will be 58 years old and at end of life.

## 6.7.3 Subtransmission Proposals

The following sections which are summarised in TABLE 6-11 outlines the subtransmission projects considered to warrant investment or investigation over the 10 year planning period.

### 6.7.3.1 Clyde - Alexandra

The Clyde to Alexandra lines have Dog conductor which provide a summer/winter n-1 capacity of 21/13 MVA which is adequate for loads expected within the planning period. Possible alterations to these circuits include the addition of a second Fraser generation station and the addition of a new Dairy Creek substation. However the details, likelihood and timing of these projects is uncertain.

An upgrade of the Clyde-Alexandra 33kV protection equipment (in conjunction with the Fraser Generator) is planned. It is expected that the new protection will use line differential relays with the required communication between sites provided by UHF or low frequency microwave links. This work is planned for 2017-18 (see DR204).

### 6.7.3.2 Alexandra - Omakau

A single 33kV line feeds the Omakau area from the Alexandra substation. The steady load growth in the Omakau area has meant this line is becoming increasingly important and causes significant SAIDI issues when out of service for maintenance or faults. Construction of a second 33kV line to Omakau would be expensive but may become warranted in future. It is proposed to study the options, alternative, costs, and benefits of this project over the next few years.

#### 6.7.3.3 Upper Clutha 66 kV

The Upper Clutha 66kV network is within the Cromwell GXP area. The n-1 capacity of the existing Upper Clutha 66kV network has the following constraints:

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

Works that will reduce these constraints are:

- installation of 66kV 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; and
- installation of 66kV bus at Queensberry which will reduce the volt drop when one line section is out of service.

#### 6.7.3.4 Wakatipu Basin 33kV ring

The Wakatipu Basin 33kV ring (see FIGURE 6-30) supplies the Dalefield, Arrowtown, Coronet Peak and Remarkables substations and is run open at Arrowtown. The ring consists of Ferret and Mink conductor and short sections of cable. 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.

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 the future it is proposed to install a new 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 - see FIGURE 6-31.

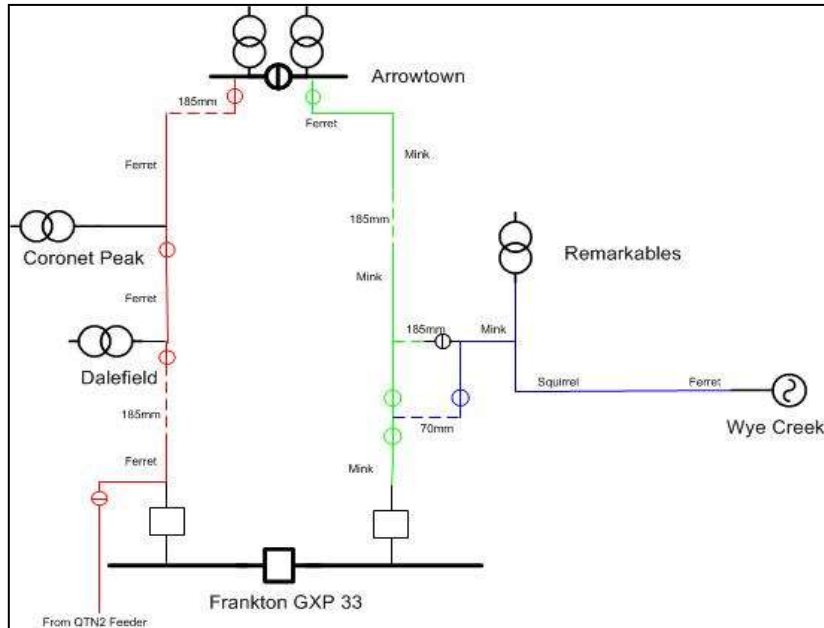


Figure 6-30 Wakatipu Basin 33 kV Ring

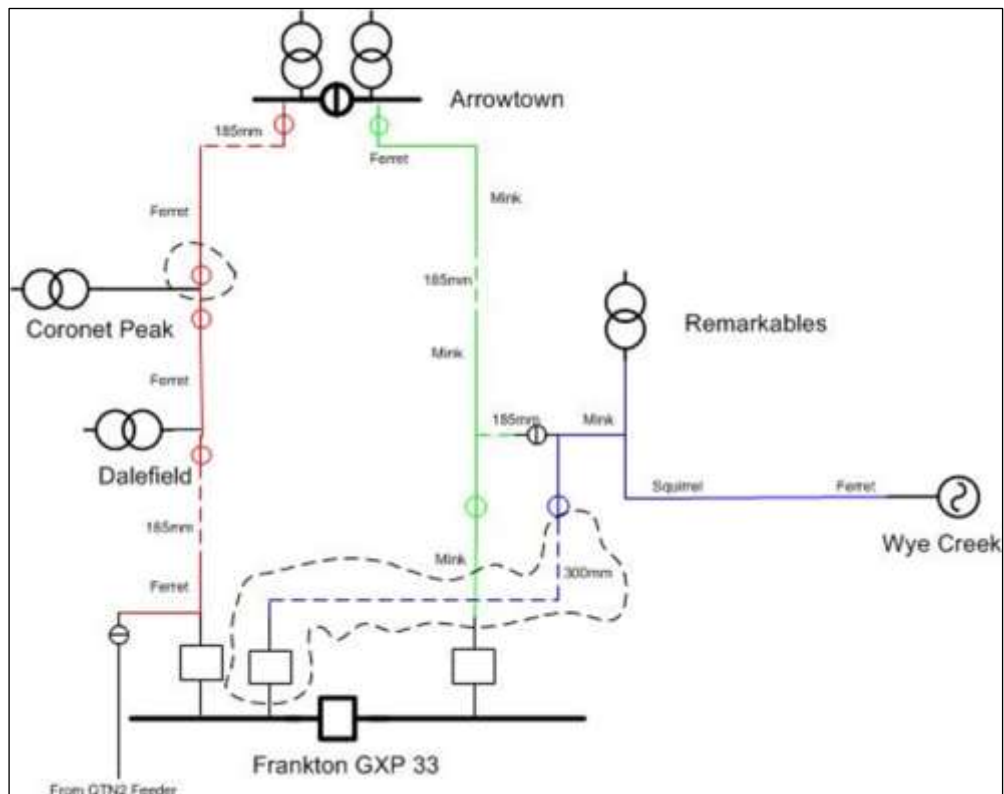


Figure 6-31 – New Frankton GXP 33kV Feeder

### 6.7.3.5 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.

Initially it was considered that extending the 11kV distribution from Fernhill to Closeburn would be very difficult but a more recent review of this shows that it is practical. Also installing a diesel generator at Glenorchy to provide a standby supply for line faults is viable and economic. These projects need to go ahead as soon as practical beginning with land purchase or easement negotiations for the Glenorchy substation and generator. In the longer term conversion to 33kV is likely to be required but with the 11kV distribution line extension a substation at Closeburn will no longer be required.

In the Glenorchy area there has been a significant installation of distributed solar generation plus a micro hydro installation. This in conjunction with the Pioneer Oxburn 400kW hydro station means that there is significant local generation and rather than designing the network to be able to supply all load (without support from generation) we could look at alternative measures making use of this generation, in conjunction with the proposed diesel generator, consumer owned batteries, and possibly future Aurora batteries.



**Table 6-11 Subtransmission Projects**

Location	Project Details	Project No	Estimated in this Plan \$000	Completion
Glenorchy	Underbuild Fernhill to Closeburn and install generator at Glenorchy	4182	461	2018
Neville Street	33kV cable replacement	5123	2,497	2018
Willowbank	33kV cable replacement	3470	3,900	2019
Halfway Bush	33kV cable replacement	6267	500	2019
Kaikorai	33kV cable replacement	3171	2,900	2020
Smith Street	33kV cable replacement	3471	3,500	2021
Ward Street	33kV cable replacement	3469	4,200	2022

#### 6.7.3.6 Gas Cables

Many of the 33kV cables from the Halfway Bush GXP are insulated by paper pressurized by nitrogen gas. These cables are very old. These cables have solid metal screens (either aluminium or lead) to retain the gas. Those with lead screens have bronze tapes to hold the lead against the pressure of the gas. These cables are now at the end of their life as the bronze tapes are corroded and failing. The failure of these tapes allows the lead to expand and fail. The aluminium screened cables are also now very old and have had some gas leaks especially at joints. Gas leaks are difficult to locate and expensive to repair. A gas leak requires the cable to be out of service for several days for repairs to be made and the cable to be re-pressurised.

The Smith Street and Ward Street cables could conceivably follow the same route. In order to reduce civil work costs it is planned to install these cables in the same trench by installing ducts for the Ward Street cables at the same time as installing the Smith street cables. This creates the small risk that a major land movement event could affect both substations. To alleviate this risk it is proposed that the trench from Smith Street to Ward Street be run past North City substation and tie cables installed from North City to both Smith Street and Ward Street. While this will require some additional 33kV switchgear, the saving in civil costs and the increased network flexibility this gives will more than compensate.

#### 6.7.3.7 PILC Cables

Older 33kV cables from the Halfway Bush GXP were insulated with oil impregnated paper. Unlike more modern paper insulated cables, the oil in these oil cables can migrate and in steep areas some of the paper can dry out over time and fail. We have had a number of failures of the Kaikorai Valley cables due to this effect.

The cable replacement plan for the Halfway Bush GXP cables is shown in TABLE 6-12.

**Table 6-12 Halfway Bush 33kV Cables**

Cable	Type	Installed	Complete	Notes
Neville Street	Gas – Bronze Tapes	1961	2018	In conjunction with substation rebuild – new substation to be fed from SDN
Willowbank	Gas – Bronze Tapes	1963	2019	
Halfway Bush	PILC	1955	2019	In conjunction with GXP upgrade
Kaikorai Valley	PILC	1950	2020	
Smith Street	Gas – Bronze Tapes	1959	2021	In conjunction with Substation Rebuild
Ward Street	Gas - AL Sheath	1967	2022	
Ward Street - Neville Street tie	PILC	1950	-	Not expected to be replaced. This PILC cable has been relatively reliable as it does not have any particularly steep sections. It also is not critical for the operation of the network, therefore it is planned to simply continue running this cable until failure.

## 6.7.3.8 South Dunedin Oil Cables

The 33kV cables from the South Dunedin GXP are predominantly pressurised oil cables. This avoids the problem of oil draining on steep sections but the again requires strength tapes to contain the lead. These cables are much younger than the Halfway Bush Cables. However, some oil leaks have been very difficult to locate. It is expected to begin a replacement program of these cables after the Halfway Bush GXP gas cables have been replaced.

**Table 6-13 South Dunedin 33kV Cables**

Cable to-	Type	Installed	Notes
Andersons Bay	XLPE	2014	Replaced poor condition gas cable
St Kilda	Oil	1980	
North City	Oil	1976	
South City	Oil	1972	3 cables installed (1 unused)
Corstorphine	Oil	1973	

## 6.7.4 Distribution Projects

### 6.7.4.1 Conversion of 6.6 kV Feeders to 11 kV

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

Aurora has adopted a long-term strategy of converting its entire 6.6 kV network to 11 kV. This could take 25 to 40 years to complete. This requires new distribution transformers installed on the Aurora 6.6 kV network be dual ratio units.

Conversion of the Clyde-Earnsclough area is expected to become economic in association with load growth in the area due to increased irrigation and dairy farming activity. Full conversion of Clyde-Earnsclough is expected to be staged over several years to keep costs relatively low and take advantage of opportunities as customer driven developments occur. However there are some proposed large developments that could accelerate the need for this. As a precursor to this conversion it is planned to extend some 11kV feeders from the Alexandra substation to the ends of the 6.6kV Clyde-Earnsclough feeders so that conversion of these feeders can be completed with minimal disruption and future load transfer points exist. Also conversion of small areas is planned by shifting existing open points, this includes the McPherson Road area and Airport Road area.

Conversion of small areas of the Dunedin network to 11kV is also considered justified to allow the removal of 6.6/11kV autotransformers and improve earth fault detection. It is proposed to upgrade the Weir road – Cape Saunders line to 11kV in 2016 and the Saddle Hill area in 2018.

**Table 6-14 6.6/11kV Projects**

Location	Project Details	Project No	Estimated in this plan \$000	Completion
<b>Dunedin</b>	Saddle Hill 11KV conversion	6274	400	2019
<b>Cromwell</b>	Install new HV feeder to Leitrum St	3428	750	2023
<b>Dunedin</b>	6.6/11kV Overhead Conductor Renewal	6288	1,750	2026
<b>Central</b>	6.6/11kV Overhead Conductor Renewal	6289	2,150	2026

## 7 FINANCIALS

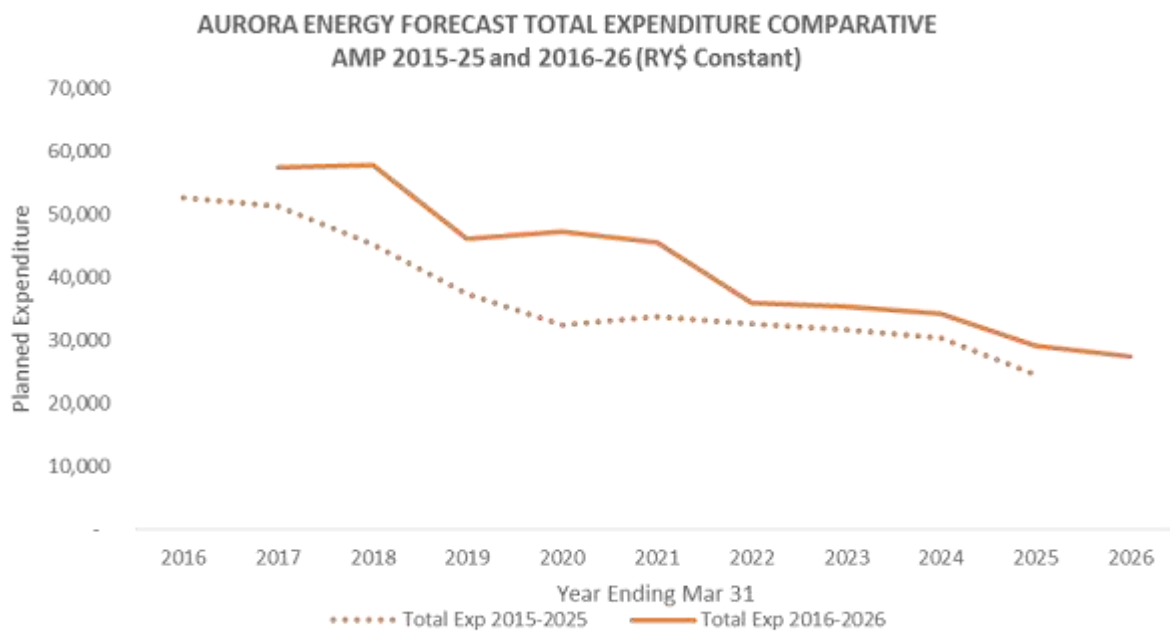
### 7.1 Financial Forecasts

Our financial forecasts are based on network operating and capital expenditure programmes and projects detailed in the lifecycle and network development sections of this plan. All figures in this section are in 'Constant' dollar terms and all capital projects are inclusive of contingency.

The total expenditure proposed over the 10 year planning period is expected to rise by \$45.2M compared to the 2015 AMP Update (\$417.0M compared to \$371.8M –see TABLE 7-1).

**Table 7-1 Asset Management 10 Year Plan Comparative**

Plan	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
AMP 2015-25	52.5	51.4	45.2	37.3	32.5	33.8	32.6	31.7	30.2	24.6		371.8
AMP 2016-26		57.7	58.3	46.2	47.3	45.4	35.9	35.4	34.3	29.2	27.4	417.0
<b>Difference</b>	-52.5	6.3	13.1	8.9	14.8	11.6	3.3	3.7	4.0	4.6	27.4	45.2



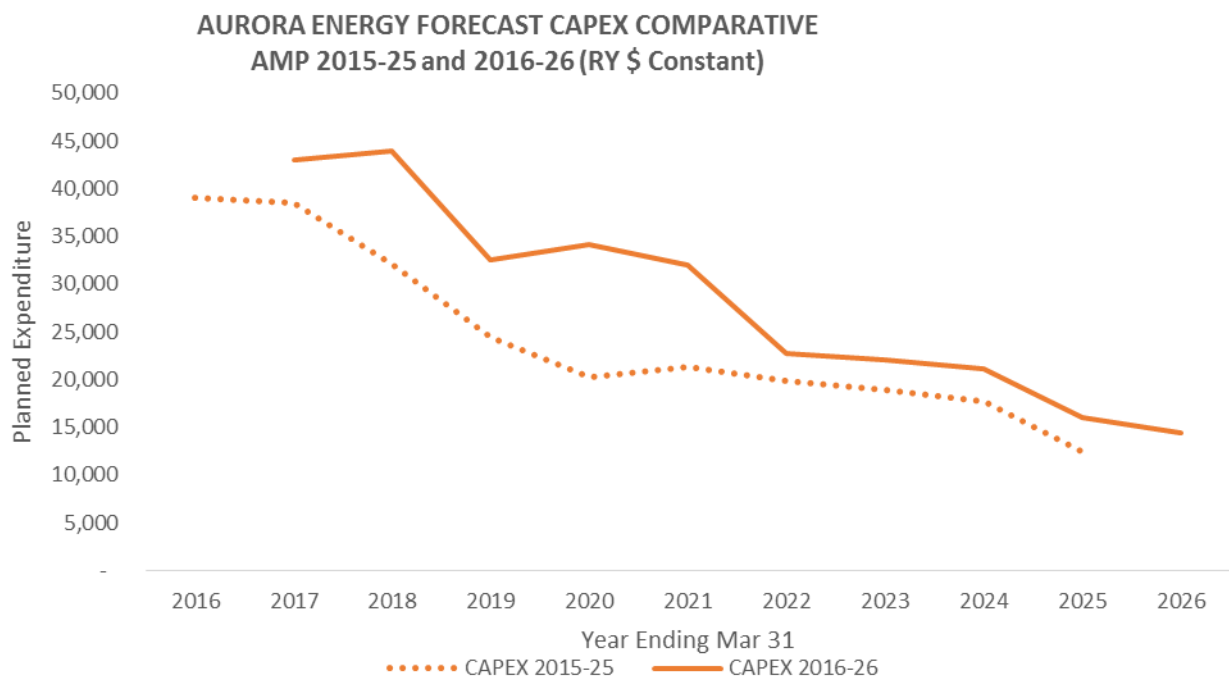
**Figure 7-1 Asset Management Plan 10 Year Expenditure Profile Comparative**

## 7.1.1 Capital expenditure

Capital expenditure is forecast to rise by \$38.0M to \$282.0M compared to the 10 year forecast presented in the 2015 AMP Update (see TABLE 7-2).

**Table 7-2 Capital expenditure 10 year plan comparative**

Plan	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
AMP 2015-25	39.0	38.5	32.1	24.4	20.3	21.4	19.8	18.9	17.7	12.5		244.6
AMP 2016-26		43.1	44.4	32.7	34.2	32.0	22.7	22.0	21.1	16.0	14.4	282.7
<b>Difference</b>	<b>-39.0</b>	<b>4.6</b>	<b>12.4</b>	<b>8.2</b>	<b>13.8</b>	<b>10.6</b>	<b>2.9</b>	<b>3.1</b>	<b>3.4</b>	<b>3.5</b>	<b>14.4</b>	<b>38.0</b>



**Figure 7-2 Capital Expenditure 10 Year Profile Comparative**

Between RY2017 and RY2019, capital expenditure is expected to increase by \$25.2M, almost half of which is associated with deferred zone substation expenditure for which there is no further opportunity for deferral. The key increases are:

- the impact of capital deferrals from previous periods associated with major zone substation projects totalling \$12.46M, including Riverbank Road Switching Station (\$2.65M), Carisbrook ZS (\$6.12M), Carisbrook Cables (\$1.8M) and the Omakau (\$1.42M) ZS projects;
- provision for a significant increase in Chorus driven service changeovers (\$2.84M), as Chorus accelerate their UFB programme; and
- a significant increase in our new connections capital budget relative to the last two years (\$5.54M), reflecting upwards revision of our expectations on short term growth in the Central network region.

These have been offset in the same period by decreases associated with:

- deferral of the Clyde-Earnsclough substation to reflect the fact that irrigation load growth has not crystallised in this location (-\$4.0M); and
- short term deferral of both the Arrowtown and Cromwell transformer projects made possible by a modified approach to spare transformation capacity in the Central network area (-\$5.69M).

TABLE 7-3 sets out all key variances for RY2017 to RY2019.

**Table 7-3 Differences to AMP 2015-2025 (RY2017-RY2019)**

Description	2017	2018	2019	Total
Carisbrook zone substation	0.47	4.22	1.44	6.12
New Connections	2.99	1.90	0.65	5.54
Chorus changeovers	0.93	1.34	0.58	2.84
New Omakau substation	-0.42	1.45	0.39	1.42
Riverbank Road 66kV switching and substation site	0.36	1.78	0.51	2.65
Andersons Bay upgrade		0.79	1.01	1.80
Carisbrook 33kV cables	1.12	0.54		1.65
SCCP	0.82	1.05	0.22	2.09
Distribution transformers	0.20	0.35	0.59	1.15
Overhead conductor renewal	0.23	0.30	0.60	1.13
Pole replacement/ reinforcement	0.25	-0.08	0.73	0.90
New and replacement reclosers	0.20	0.26	0.26	0.72
FDA-1 /ETEE & Chance	0.24	0.23	0.21	0.68
6.6/11/33kV air break switches	0.17	0.22	0.22	0.61
Circuit breaker replacements (VWVE 33 kV)	0.19	0.03	0.23	0.45
Arrowtown – transformer install 24 MVA	-0.38	-3.13	0.69	-2.81
Cromwell - install two new 24 MVA transformers	-1.19	-1.50	-0.19	-2.88
Upgrade Clyde-Earnsclough	-3.00	-1.00		-4.00
Other	1.40	3.67	0.14	5.20
<b>Three Year Capex Difference to 2015-2025 Plan</b>	<b>4.58</b>	<b>12.42</b>	<b>8.28</b>	<b>25.26</b>

Variances in the middle of the planning period between RY2020 and RY2022 compared to the 2015 AMP Update principally relate to:

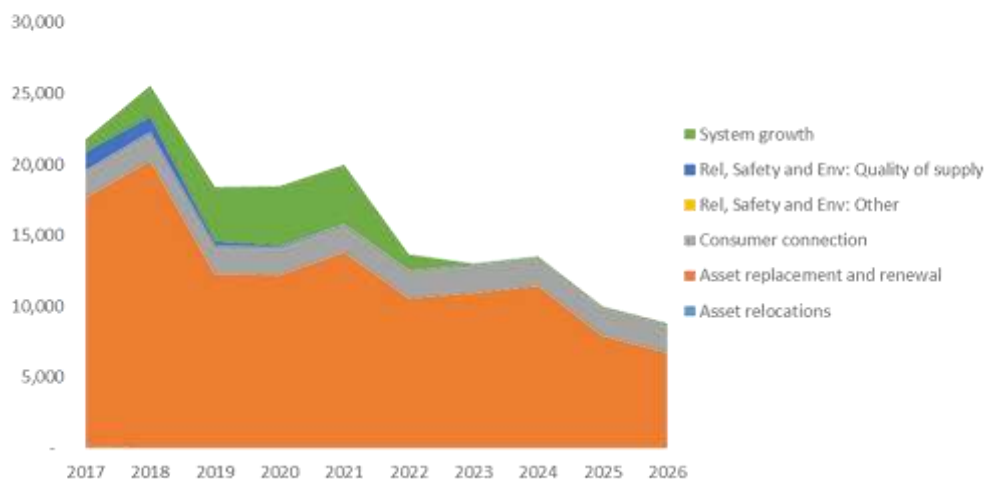
- increases in the scope and cost of a zone substation upgrade project at Smith Street (\$4.05M);
- completion of the Arrowtown and Cromwell transformer replacements (\$5.88M), deferred from earlier in the planning period;
- condition and risk based replacement of priority Statler, GEC and Reyrolle Ground Mount Switchgear (\$2.3M); and
- condition and risk based replacement of priority ground mounted distribution transformers (\$2M).

With many of the Aurora assets either well into the second half of their design life or approaching the end of their design life, additional provision for renewal expenditure has been made across a number of asset classes, refined through consideration of condition and asset health.

## 7.1.1.1 Capital Expenditure by Driver

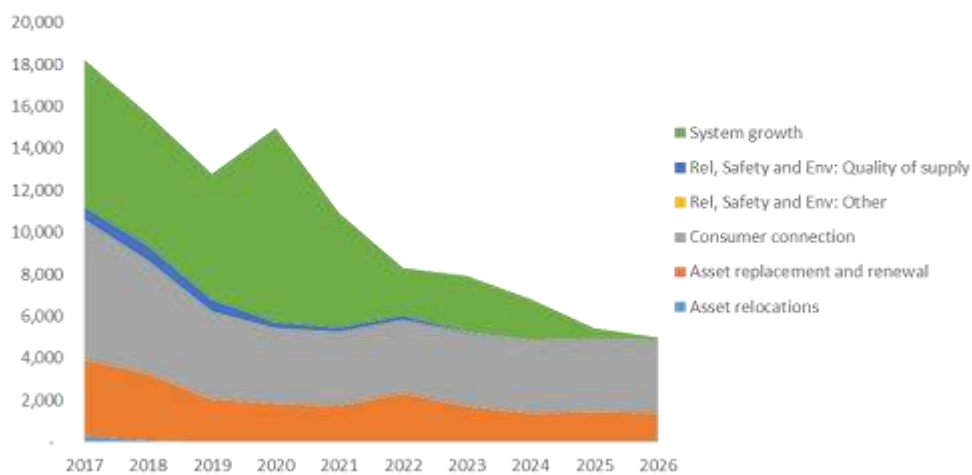
The drivers of capital expenditure within the Dunedin and Central sub-networks are materially different. In Dunedin the capital plan is driven by replacement and renewals (including Carisbrook Substation). In sharp contrast the Central network is driven by high levels of both irrigation demand and new connection growth. Refer FIGURE 7-3 and FIGURE 7-4

**Dunedin Capital Expenditure Profile By Driver (RY Constant \$000)**



**Figure 7-3 Capital Expenditure Profile by Driver**

**Central Capital Expenditure Profile By Driver (RY Constant \$000)**



**Figure 7-4 Capital Expenditure Profile by Driver**



## 7.1.1.2 Capital by asset class (RY \$M)

TABLE 7-4 summarises 10 year capital expenditure by major asset class, with more detailed breakdowns presented in the subsequent sections.

**Table 7-4 Capital Expenditure by Asset Class**

Asset Class	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Distribution and LV cables	1.48	0.75	0.47	0.39	0.34	0.45	0.49	0.49	0.49	0.49	5.84
Distribution and LV lines	13.97	12.29	11.62	11.37	11.31	10.21	9.70	9.65	9.50	9.45	109.06
Distribution substations and transformers	1.90	1.85	1.63	1.92	2.51	2.59	2.65	2.65	2.74	2.68	23.10
Distribution switchgear	1.69	1.66	1.79	2.16	1.93	1.66	1.62	1.58	1.56	1.56	17.21
Other network assets	9.43	6.23	1.45	0.08	0.45	0.15	0.45	0.15	-	-	18.38
Subtransmission	3.04	4.40	4.33	5.42	5.60	1.57	0.25	0.25	0.25	0.25	25.37
Zone substations	11.59	17.27	11.40	12.83	9.81	6.11	6.85	6.34	1.50	-	83.70
<b>Grand Total</b>	<b>43.11</b>	<b>44.45</b>	<b>32.68</b>	<b>34.15</b>	<b>31.96</b>	<b>22.74</b>	<b>22.00</b>	<b>21.11</b>	<b>16.04</b>	<b>14.43</b>	<b>282.66</b>

## 7.1.1.3 Major Zone Substation Expenditure (RY \$M)

Timing and scope differences relating to Carisbrook and Riverbank (\$10.6M), timing differences to Omakau (\$1.84M) and scoping changes to Smith Street and Andersons Bay (\$4.05M and \$2.05M respectively) dominate the changes to the zone substation program, which has increased by \$20.4M compared to the previous plan.

**Table 7-5 Major Capital Expenditure Projects**

Zone Substation	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Carisbrook	2.79	4.71	1.44	0.06	-	-	-	-	-	-	8.99
Smith Street upgrade	-	-	0.34	3.15	4.05	1.01	-	-	-	-	8.55
Riverbank Road	4.75	3.07	0.51	-	-	-	-	-	-	-	8.32
Andersons Bay Upgrade -	0.34	1.91	3.38	0.93	-	-	-	-	-	-	6.55
Green Island rebuild	-	-	-	-	-	-	1.88	2.50	0.63	-	5.00
Arrowtown - install 24 MVA transformers and new switchgear	-	0.38	1.81	2.25	0.56	-	-	-	-	-	5.00
Willowbank rebuild	-	-	-	0.19	1.75	2.44	0.63	-	-	-	5.00
Outram upgrade	0.98	2.58	0.75	-	-	-	-	-	-	-	4.30
Clyde-Earnsclough upgrade	-	-	-	3.00	1.00	-	-	-	-	-	4.00
New 66kV switching station at Queensberry	-	-	-	-	-	0.23	1.20	1.50	0.38	-	3.30
Cromwell install two new 24 MVA transformers	-	-	0.19	1.19	1.50	0.38	-	-	-	-	3.25
New Jacks Point	-	-	-	-	0.23	1.09	1.35	0.34	-	-	3.00
Riverbank Road install 24 MVA 66/11kV transformer and 11kV switchgear	-	0.19	1.75	0.56	-	-	-	-	-	-	2.50

Zone Substation	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Port Chalmers transformer replacement	-	-	-	-	-	-	1.50	0.50	-	-	2.00
Mosgiel transformer replacement	-	-	-	-	-	-	-	1.50	0.50	-	2.00
HWB ZS switchgear replacement	-	-	-	1.50	0.50	-	-	-	-	-	2.00
Omakau	0.870	1.45	0.39	-	-	-	-	-	-	-	2.71
Queenstown switchboard replacement	0.23	1.13	0.35	-	-	-	-	-	-	-	1.70
Alexandra switchboard replacement	-	-	-	-	0.23	0.98	0.30	-	-	-	1.50
New 5MVA transformer	0.04	0.61	0.20	-	-	-	-	-	-	-	0.85
Other	1.35	0.44	0.11	-0.01	-0.01	-0.02	-0.01	0	-0.01	0	1.08
<b>Total</b>	<b>10.48</b>	<b>16.47</b>	<b>11.22</b>	<b>12.82</b>	<b>9.81</b>	<b>6.11</b>	<b>6.85</b>	<b>6.34</b>	<b>1.50</b>	<b>-</b>	<b>81.60</b>

## 7.1.1.4 Fire, Security and Seismic Projects (RY\$M)

There have been no material changes to our Fire, Security and Seismic program

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Seismic Works	0.75	0.34	0.03	-	-	-	-	-	-	-	1.12
Fire, security, earthquake and asbestos upgrades	0.20	0.20	0.05	-	-	-	-	-	-	-	0.45
Other	0.15	0.26	0.10	0.01	-	-	-	-	-	-	0.52
<b>Total</b>	<b>1.11</b>	<b>0.79</b>	<b>0.18</b>	<b>0.01</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>2.09</b>

## 7.1.1.5 Major Subtransmission Projects (RY \$M)

Subtransmission expenditure has increased by \$4.6M compared to our previous AMP. The increase is primarily driven by a timing difference associated with the Carisbrook cables and the new 33/66kV overhead conductor renewal programs in both Dunedin and Central Otago starting in 2019.

**Table 7-6 Major Capital. Expenditure Subtransmission Projects**

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Replace Ward Street 33kV gas cables	-	-	-	0.32	2.94	0.95	-	-	-	-	4.20
Replace Willowbank 33kV gas cables	0.29	2.73	0.88	-	-	-	-	-	-	-	3.90
Replace Smith Street 33kV gas cables	-	-	0.26	2.45	0.79	-	-	-	-	-	3.50
Install 3rd 33/66kV auto transformer at Cromwell GXP and create 66kV bus	-	-	0.75	1.75	0.50	-	-	-	-	-	3.00
Replace Kaikorai Valley 33kV cables	-	0.22	2.03	0.65	-	-	-	-	-	-	2.90

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Carisbrook 33kV cables	1.88	0.62	-	-	-	-	-	-	-	-	2.50
Establish new Jacks Point feeder from Frankton GXP	-	-	-	-	1.13	0.38	-	-	-	-	1.50
33/66kV overhead conductor renewal in Dunedin	0.06	0.08	0.13	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.31
33/66kV overhead conductor renewal in Central	0.06	0.08	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.93
Replace Halfway Bush 33kV cables	0.04	0.35	0.11	-	-	-	-	-	-	-	0.50
Other	0.71	0.32	0.08	-0.00	-0.01	-0.01	-	-	-	-	1.13
<b>Total</b>	<b>3.04</b>	<b>4.40</b>	<b>4.33</b>	<b>5.42</b>	<b>5.60</b>	<b>1.57</b>	<b>0.25</b>	<b>0.25</b>	<b>0.25</b>	<b>0.25</b>	<b>25.37</b>

## 7.1.1.6 Major Distribution Substations and Transformers Projects (RY \$M)

Some new expenditure (\$13.2M) is included in this category to address the aging pole mounted and ground mounted distribution transformer fleet, predominantly occurring in the last 5 years of the plan.

**Table 7-7 Major Distribution Transformer and Substation Projects**

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Ground mounting of pole-mounted dist TX > 200KVA Dunedin	0.60	0.60	0.60	0.87	0.96	0.96	0.96	0.96	0.96	0.96	8.43
Renewal of ground mount dist TX Dunedin	-	0.15	0.35	0.48	0.73	0.80	0.80	0.80	0.80	0.80	5.70
Pole mount transformer replacement (50KVA-200KVA) Dunedin	0.10	0.14	0.20	0.23	0.33	0.36	0.36	0.36	0.36	0.36	2.79
Pole mount transformer replacement (50KVA-200KVA) Central	0.10	0.07	0.05	0.05	0.11	0.14	0.14	0.20	0.23	0.23	1.29
Central load growth projects (to be identified)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	1.00
Dunedin load growth projects (to be identified)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	1.00
Renewal of ground mount dist TX Central	-	-	-	-	0.08	0.10	0.10	0.10	0.10	0.10	0.58
Underground substation improvement programme	0.18	0.13	0.10	0.10	0.03	-	-	-	-	-	0.53
Ground mounting of pole-mounted dist TX > 200KVA Central	0.10	-	-	-	0.09	0.03	0.09	0.03	0.09	0.03	0.46

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
11kV voltage conversion Saddle Hill	-	0.30	0.10	-	-	-	-	-	-	-	0.40
11kV voltage conversion Weir Road		0.09	-	-	-	-	-	-	-	-	0.36
Other	0.62	0.16	0.03	-0.02	-0.02	-0.01	-0.01	0.00	-0.01	-0.01	0.54
<b>Total</b>	<b>1.90</b>	<b>1.84</b>	<b>1.63</b>	<b>1.92</b>	<b>2.51</b>	<b>2.59</b>	<b>2.65</b>	<b>2.65</b>	<b>2.74</b>	<b>2.68</b>	<b>23.08</b>

## 7.1.1.7 Major Distribution and LV Lines - Replacement and Renewal (RY \$M)

This category of expenditure is dominated by our pole replacement and reinforcement programme. New expenditure of (\$3.78M) is included to address poor condition overhead conductor.

**Table 7-8 Major Distribution and LV Lines Projects**

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Pole replacement /reinforcement	4.25	3.93	3.98	4.00	4.00	3.25	3.00	3.00	3.00	3.00	35.40
HV link replacement	0.30	0.08	0.23	0.30	0.30	0.30	0.30	0.30	0.30	0.30	2.70
6.6/11kV overhead conductor renewal in Central	0.06	0.08	0.21	0.25	0.25	0.25	0.25	0.25	0.25	0.25	2.09
Convert Clyde area to 11kV	0.24	0.30	0.30	0.41	0.45	0.11	-	-	-	-	1.81
Low span renewals	0.03	0.15	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	1.78
6.6/11kV overhead conductor renewal in Dunedin	0.06	0.08	0.17	0.20	0.20	0.20	0.20	0.20	0.20	0.20	1.70
Castlron pothead replacement	0.18	0.19	0.20	0.20	0.20	0.20	0.20	0.20	0.05	-	1.61
Install new HV feeder in CML to Leitrum St	0.11	0.04	-	0.15	0.20	0.20	0.05	-	-	-	0.75
Other	0.25	0.04	0.18	0.08	0.01	0.00	-	-	-	-	0.60
<b>Total</b>	<b>5.48</b>	<b>4.89</b>	<b>5.47</b>	<b>5.79</b>	<b>5.81</b>	<b>4.71</b>	<b>4.20</b>	<b>4.15</b>	<b>4.00</b>	<b>3.95</b>	<b>48.44</b>

## 7.1.1.8 Major Distribution and LV Lines - New Connections Budgets (RY \$M)

An additional \$9.7M has been budgeted for new connections over and above our 2015-2025 AMP plan.

We have assumed the current cycle of growth in the Central network area softens from 2017 with a static assumption from 2021. A more conservative profile has been assumed for Dunedin. In both cases, the timing and pace of development tends to be difficult to predict with any certainty.

**Table 7-9 New Connections Forecast Expenditure**

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
New connections Central	6.63	5.37	4.15	3.60	3.52	3.52	3.52	3.52	3.52	3.52	40.87
New connections Dunedin	1.86	2.03	2.00	1.98	1.98	1.98	1.98	1.98	1.98	1.98	19.75
<b>Grand Total</b>	<b>8.49</b>	<b>7.40</b>	<b>6.15</b>	<b>5.58</b>	<b>5.50</b>	<b>5.50</b>	<b>5.50</b>	<b>5.50</b>	<b>5.50</b>	<b>5.50</b>	<b>60.62</b>

## 7.1.1.9 Major Distribution Switchgear

The distribution switchgear asset class has been amended to address known issues with air break switches in Dunedin, FD-A fuses, VWVE circuit breakers and high risk orphaned oil-filled RMU units, which are in poor condition. The 9- year comparative difference between this plan and our previously disclosed plan is \$14.2M.

**Table 7-10 Major Distribution Switchgear Projects**

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Replace Statter/GEC/Reyrolle ground mount switchgear	0.15	0.43	0.50	0.73	0.80	0.80	0.80	0.80	0.80	0.80	6.60
Replacement of oil-filled switchgear	0.40	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	2.65
New 11kV reclosers and switches Central	0.10	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	1.27
Unbudgeted renewals	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	1.00
Replace 6.6/11kV air break switches in Dunedin	0.06	0.08	0.08	0.09	0.09	0.09	0.11	0.11	0.11	0.11	0.92
FDA-1 replacement	0.12	0.16	0.16	0.16	0.16	0.04	-	-	-	-	0.78
New 11kV reclosers and switches Dunedin	0.05	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.63
Replacement of 33kV air break switches Central	0.03	0.04	0.04	0.04	0.04	0.06	0.07	0.07	0.07	0.07	0.51
Replacement of 4 VWVE 33kV CB (Roxburgh)	-	-	-	0.33	0.11	-	-	-	-	-	0.44
Replacement of 3 VWVE 33kV CB (Wanaka)	0.10	0.03	0.23	0.08	-	-	-	-	-	-	0.43
Other	0.60	0.39	0.25	0.20	0.20	0.12	0.10	0.05	0.04	0.04	1.99
<b>Total</b>	<b>1.69</b>	<b>1.66</b>	<b>1.79</b>	<b>2.16</b>	<b>1.93</b>	<b>1.66</b>	<b>1.62</b>	<b>1.58</b>	<b>1.56</b>	<b>1.56</b>	<b>17.21</b>

## 7.1.1.10 SCCP (RY \$M)

The planned expenditure for the approved SCCP programme of work reflects the existing project as formulated and approved.

**Table 7-11 SCCP Project Planned Expenditure**

Description	2017	2018	2019	Total
C1139 SCADA	1.98	1.49	0.33	3.80
C1151 HWB and Subs	2.22	1.13	0.18	3.52
C1152 Central Comms and RTU	1.69	0.84	0.10	2.63
C1147 DUD - Central Link	1.08	0.42	0.07	1.57
C1153 MSS Construction	0.30	0.10	-	0.40
C1154 MST Construction	0.07	0.21	0.06	0.34
C1155 Three Control Room Upgrade	-	0.25	0.08	0.33
C1156 TP ICCP	-	0.17	0.06	0.22
C1145 Central Load Control	0.08	0.01	-	0.09
C1136 SDN	0.02	-	-	0.02
<b>Total</b>	<b>7.42</b>	<b>4.61</b>	<b>0.87</b>	<b>12.90</b>

## 7.1.1.11 Distribution and LV Lines and Cables (RY \$M).

**Table 7-12 Distribution and LV Cable Expenditure**

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
<b>Underground Link Box upgrades (Dunedin)</b>	0.15	0.15	0.15	0.26	0.30	0.41	0.45	0.45	0.45	0.45	3.23
<b>Other</b>	1.33	0.60	0.32	0.13	0.04	0.04	0.04	0.04	0.04	0.04	2.61
<b>Total</b>	<b>1.48</b>	<b>0.75</b>	<b>0.47</b>	<b>0.39</b>	<b>0.34</b>	<b>0.45</b>	<b>0.49</b>	<b>0.49</b>	<b>0.49</b>	<b>0.49</b>	<b>5.84</b>

## 7.1.1.12 Other Major Projects

Expenditure on other network assets increases \$4.9M over our previously disclosed plan with Chorus pole changeovers rising substantially to \$3.23M. Aurora is obligated to undertake this work which reflects Chorus's accelerated UFB programme and continued reliance on overhead fibre service drops.

It should be noted that this does not include provision for the impact of large scale accommodation of Chorus fibre distribution on Aurora's overhead network in Dunedin.

**Table 7-13 Other Major Projects**

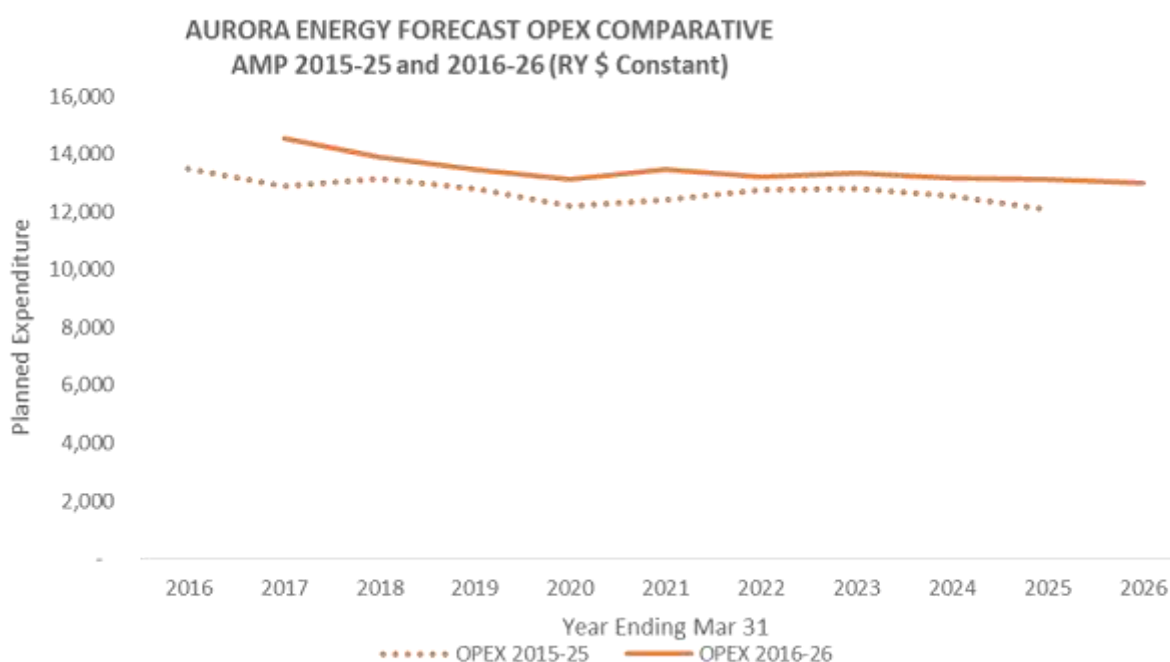
Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Chorus changeovers	1.18	1.40	0.58	0.08	-	-	-	-	-	-	3.23
New mobile distribution substations (3)	0.49	0.15	-	-	0.45	0.15	0.45	0.15	-	-	1.84
Other	0.35	0.07	-	-	-	-	-	-	-	-	0.42
<b>Total</b>	<b>2.02</b>	<b>1.62</b>	<b>0.58</b>	<b>0.08</b>	<b>0.45</b>	<b>0.15</b>	<b>0.45</b>	<b>0.15</b>	<b>-</b>	<b>-</b>	<b>5.49</b>

## 7.1.2 Operating Expenditure

Operating expenditure is forecast to increase by \$7.2M from \$127.2M to \$134.4M over the 10 year planning period.

**Table 7-14 Opex 10 Year Plan Comparative**

Plan	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
AMP 2015-25	13.5	12.9	13.2	12.8	12.2	12.4	12.8	12.8	12.5	12.1		127.2
AMP 2016-26		14.5	13.9	13.5	13.1	13.5	13.2	13.4	13.2	13.1	13.0	134.4
Difference	<b>-13.5</b>	<b>1.7</b>	<b>0.7</b>	<b>0.7</b>	<b>1.0</b>	<b>1.1</b>	<b>0.4</b>	<b>0.5</b>	<b>0.6</b>	<b>1.1</b>	<b>13.0</b>	<b>7.2</b>



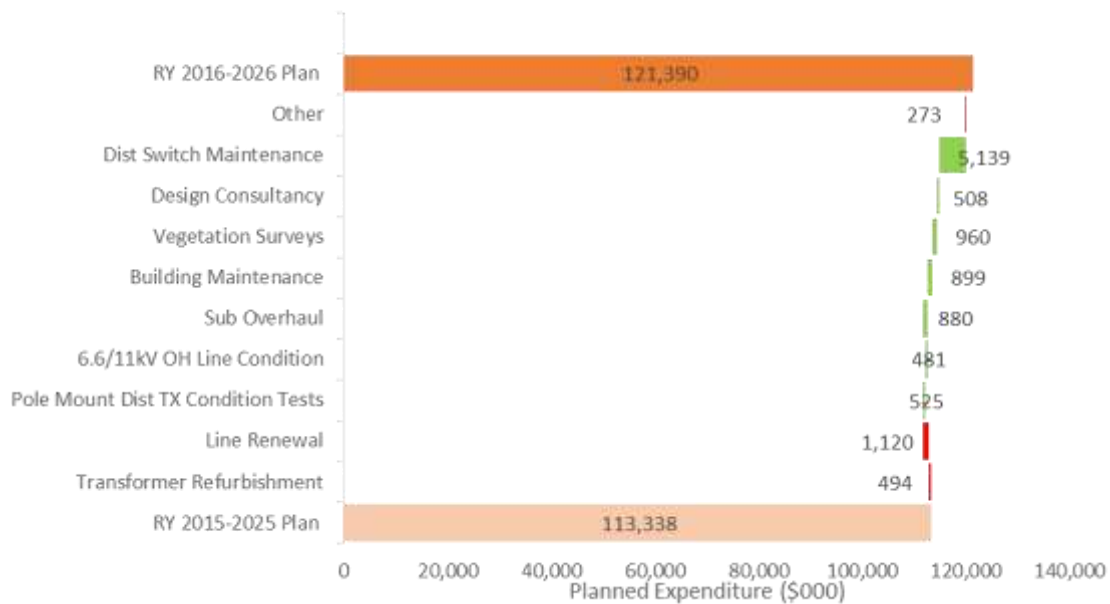
Adopting an advanced asset management approach to improve asset and business performance requires a detailed knowledge of asset condition. The most significant changes to our operating expenditure profile revolve around improved maintenance strategy and practice.

This plan allows for additional expenditure to improve our understanding of asset condition to enable better long term lifecycle management. These programs include:

- inspections and intrusive maintenance on our RMU fleet (\$5.9M) over the 10-year planning period – distribution switch maintenance;
- an aerial vegetation survey of our most critical lines (\$0.96M);
- condition inspections of our pole mounted distribution transformer fleet (\$0.53M); and
- condition inspections of our 6.6/11 kV overhead lines in Dunedin and Central (\$0.48M).



## OPEX AMP Comparative in Constant \$ RY2015-25 to 2016-26



**Figure 7-5 Opex 9 Year Plan Expenditure Profile Comparative**

An additional \$0.90M of building maintenance expenditure has been allowed over the life of the plan. Aurora has 39 zone substations and some (particularly in Dunedin) are approaching the end of their design life. These buildings require a heightened level of ongoing maintenance to address minor issues before they become expensive problems.

Performance and productivity improvements in faults resolution is expected to offset the increasing statistical likelihood of failures driven by network growth. Expenditure has been retained at historic levels, noting that this does not take account any provision for increases in peak wind speeds and the incidence of extreme events.

## 7.2 Changes and Progress on Key Initiatives

### 7.2.1 Progress on Major Capital Projects

While it is always intended to implement the programme as planned, there are a range of assumptions and uncertainties implicit in the AMP. Amongst other factors, material changes in loadings, unanticipated equipment failures and the refinement of designs and cost estimates all impact on the works programme.

The forecast capital expenditure variances compared to the approved AMP are set out below:

#### 7.2.1.1 Riverbank Road

In September 2015, the Board approved the construction of a new switching station at the corner of Riverbank Road and Ballantyne Road in Wanaka, along with associated 66kV cabling. Construction of the new switching station at Riverbank Road has been impacted by the requirement to undertake a detailed project review to finalise the scope.

This has resulted in the need to defer \$1.062M from FY2016 into FY2017. A detailed project cost review and scope development carried out by AECOM has indicated a total project cost of \$8.8M, which is \$1.38M or 18% above the original budget.

## 7.2.1.2 Carisbrook Substation, Carisbrook Subtransmission Cables

The strategy for designation of the substation site has progressed in conjunction with Gallaway Cook Allan, Mitchell Partnerships and a specialist landscaping consultant. Ongoing delays associated with ensuring the new site is free of contamination, and due diligence on site selection, have resulted in the need to defer \$2.65M from RY2016. Following detailed design which was carried out by Mitton ElectroNet there has been an uplift of \$3.8M uplift in capital expenditure to design, construction and commission Carisbrook.

The delays associated with the substation development have also resulted in timing delays to the Carisbrook subtransmission cables (\$752k) and associated SCCP work (\$330k). Our modified plan will see us complete design, consenting and ducting to enable an efficient closeout of these projects once the substation work is complete.

## 7.2.1.3 Lindis Crossing and Camp Hill Zone Substations

The Lindis Crossing substation and Camp Hill substation were commissioned in March 2015 and November 2015 respectively.

## 7.2.1.4 Clyde Earnsclough

Last year's AMP Update anticipated the need to upgrade the Clyde Earnsclough zone substation in 2016/17 at a cost of \$4M. At that time we indicated that the substation requirements were heavily dependent on the timing and eventual size of new irrigation schemes.

Given that peak loads in the Clyde-Earnsclough area have been somewhat erratic and the ongoing uncertainty surrounding irrigation developments, the upgrade of Clyde Earnsclough has been deferred into 2020-2021.

## 7.2.1.5 Manuherikia Valley (Omakau) Projects

In last year's we planned to construct a new 7.5 MVA zone substation at Omakau in 2015/2016 based on predicted summer load exceeding the 3MVA capacity of the existing site which was uprated to 3.6MVA by installation of cooling fans.

As a result of detail design delays the plan was initially modified to install the spare 1MVA Roxburgh Hydro transformer (33/11kV Dyn11) at Lauder flat. The plan was further modified when the 3 MVA Maungawera transformer became available following the successful completion of Camp Hill. The Lauder flat transformer was duly commissioned in December 2015 taking the transformer capacity in the Omakau area up to 6MVA which:

- has enabled us to defer the construction of the new larger transformer at Omakau reducing costs. The of Omakau substation site is still being developed but will now consist of a 33kV bus structure, mobile substation parking pay and 33kV circuit breaker feeding the Lauder Flat Road substation; and
- Under normal loading (outside the summer months) offers N-1 security to the area.

## 7.2.1.6 System Control Communications and Protection Upgrades (SCCP)

The SCCP projects are progressing in line with expectations and there has been no substantive changes to the program disclosed in our last AMP.

### 7.2.2 Progress on Key Maintenance Initiatives

The AMP Update 2015-2025 proposed a total Opex budget of \$13.51M for the 2016 regulatory year. Current forecasts have us exceeding this level of expenditure driven primarily by the increase in the number and severity of HV faults we have experienced including lightning strikes in May 2015, flooding in Dunedin in June 2015 and severe wind in the first week of October 2015.

Planned maintenance over the same period was \$7.71M with the majority of this spend associated with pole inspections (\$1.1M) and vegetation cutting, trimming and Liaison (\$4.33M) which are discussed in more detail below.

#### 7.2.2.1 Pole Inspections

Since 23 March 2015, Aurora has authorised two alternative methods of pole inspections for our wooden pole fleet a traditional dig, deflect and hammer test and Deuar Mechanical Pole Testing (Deuar MPT). Between 1 April 2015 and the 14 Dec 2015 a total of 4,676 poles have been tested utilising the traditional method and additional 1292 (794 in Dunedin and 498 in Central) using Deuar MPT. This is well below the expected rate which was designed to inspect the entire wooden pole fleet within 5 Years.

This year poles selected for Deuar testing were a mixture of condition grades with a bias toward those poles which either had not been inspected recently or were previously categorised using traditional methods as being in poor condition. While the number of inspections being performed is lower than expected the outcomes of Deuar MPT have exceeded expectations enabling us to:

- prioritise pole replacements with a greater degree of surety and focus on poles that have a higher predisposition to "failing in service";
- defer approximately \$2.9M in pole replacements based on reliable estimates of remaining life;
- accelerate the removal of approximately \$1.1M pole replacements which were found to be in worse condition than previously thought;
- improve health and safety outcomes by preventing what are conceivable fatal risks associated with inadvertently climbing defective poles.

#### 7.2.2.2 Vegetation Management

Vegetation in close proximity to power networks has a profound impact on network risk. As a result Aurora has dedicated a substantial amount of maintenance effort into cyclic tree cutting and vegetation control programmes. In 2016 our targets have been to:

- establish a standalone business unit responsible for day to day vegetation management;
- refine our mobile solution to provide data rich, robust and timely risk assessments;
- increase the level of vegetation liaison;
- increase the priority and amount of second cut being performed; and
- maintain the level of 1<sup>st</sup> cut at the record levels set in 2015 (34 km<sup>2</sup> – Financial year ending 30 June).

## 8 IMPROVEMENT PLANNING

The goal of infrastructure asset management is to meet a required level of service, in the most cost effective manner, through the management of assets for present and future customers. Having a good understanding of areas of strength and weakness compared with good asset management practices and using this understanding to maintain best practice is essential.

Our Improvement Program was developed by assessing and understanding:

- the challenges currently facing us;
- what the appropriate level of asset management practice is within the context of Aurora's business; and therefore;
- 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); and
- areas where changes to asset management processes and practice would produce improvements in financial performance, risk management and asset performance.

These are discussed in more detail below.

### 8.1 Key Challenges

There are a number of challenges facing the operation and maintenance of our equipment in the future key challenges that need to be addressed are;

- safety: How do we create a zero harm safety culture that everyone understands?
- achieving Adequate Shareholder returns while meeting the needs of the community for reliable secure energy in both high density urban and low density rural areas;
- dealing with complex sub networks with significantly different growth and demand profiles;
- ageing plant: many of our assets are now entering the second half of their design life. Whilst we have a planned refurbishment/replacement programme (detailed in the AMP) the purpose of maintenance is to care for these assets in a manner that extracts the maximum value now and in the future;
- attracting and retaining staff: a workforce that has a wealth of experience is a great asset however as staff retire or move on to new challenges expertise and IP is lost;
- training and competence: needs a strategic focus to ensure we have the correct skills available over the next three years;
- information management: the increasing volume of data both available and required to make informed decision creates challenges for those designing and using it;
- regulatory changes: a significant and growing demand is placed on the business from the regulator. Asset Management plays a part in responding to these changes by monitoring and reporting on equipment performance and realigning our processes accordingly;
- new technology: including those associated with distributed generation and smart grid initiatives;
- enterprise systems: increasing consolidation of software solutions and the use of business intelligence tools such as data mining/warehousing will bring training and acceptance challenges. In addition data integrity remains a challenge;

- developing and realising improvements by having an effective structure which is resourced adequately and working more collaboratively between teams and locations remains a challenge; and
- developing KPIs that are well understood and drive the behaviour required and demonstrate that the maintenance budget is being utilised effectively.

## 8.2 Targeted Level of Asset Management Practice

As you would expect different Asset Management standards utilise different maturity scales. Given that PASS 55 has been adopted by the Commerce Commission for the purposes of this AMP we have chosen to reference the maturity scale contained in that standard.

The Self-Assessment Methodology contained within PAS 55 considers five “levels” of maturity against which an organisation can measure its conformance. These are aligned with the principles of the International Infrastructure Management Manual (IIMM), as indicated in FIGURE 8-1.

Compliance with PAS 55:2008 is within Maturity Level 3. Aurora is committed to achieving a maturity level between 3 (competent) however we will be evaluate those areas of strategic importance to the business and establish the gap to level 4 (excellence).

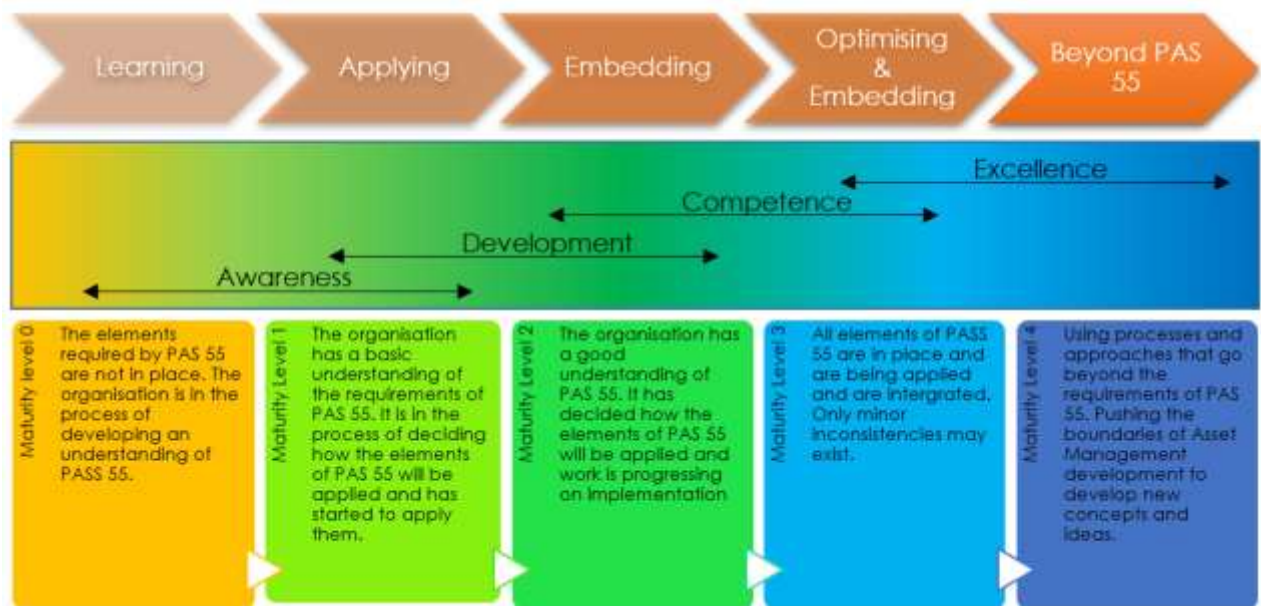


Figure 8-1 Pass55:2008 Maturity Scale

## **8.3 The Current Level of Asset Management Practice**

### **8.3.1 Asset Management Maturity Assessment**

The FY2016 Asset Management work plan provided for an independent assessment of the maturity of Aurora asset management practice to be completed prior to the conclusion of the regulatory year. The assessment was carried out by Energia Consulting using the Commerce Commission's AMMAT (Asset Management Maturity Assessment Tool).

The scope of the assessment included conduct of an audit using the AMMAT; preparation of recommendations for improvement aligned to stated asset management objectives and comparisons with previous assessments. The review was accomplished using staff and management interview sessions, compilation and review of documentary evidence against assessment criteria, with sufficient time for follow-up and clarification of the findings.

#### **8.3.1.1 AMMAT Assessment Results**

The AMMAT adopted by the Commerce Commission is focussed on the 31 functional areas of PAS55<sup>4</sup> that cover 'process', 'people' and 'metrics'. Key outcomes of the AMMAT assessment are:

- the overall maturity score has improved from 2.6 to 2.9, with material improvements being achieved in 9 of the 31 areas – see FIGURE 8-2;
- the gap to attaining Level 3 maturity across all functional areas is considered very small; and
- significant improvement has been made in key areas, and the Company is considered to be performing well compared to other businesses.

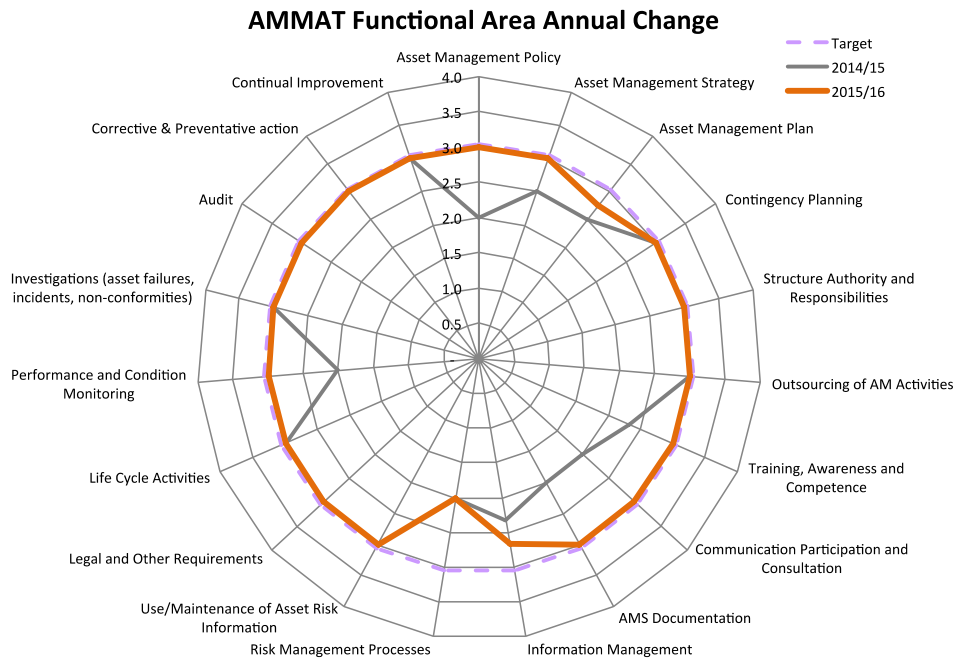
Areas of high performance and / or areas of significant improvement include:

- the development and adoption of an asset management policy and strategy that is clearly linked to the organisation's objectives and is appropriately influencing asset management activities;
- significant improvement in the level of meaningful customer engagement;
- significant improvement in the capture and utilisation of condition information which has enabled material improvements to the lifecycle section of the AMP over previous years;
- operation of a comprehensive performance management regime with the key aspects of asset management delivery being actively managed in a timely manner;
- clearly defined responsibilities for asset management and an organisational structure which continues to adapt to the needs of the assets; and
- material improvements in relation to competency management.

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<sup>4</sup> Publicly Available Specification for optimized management of physical assets (British Standards Institute PAS55:2008)



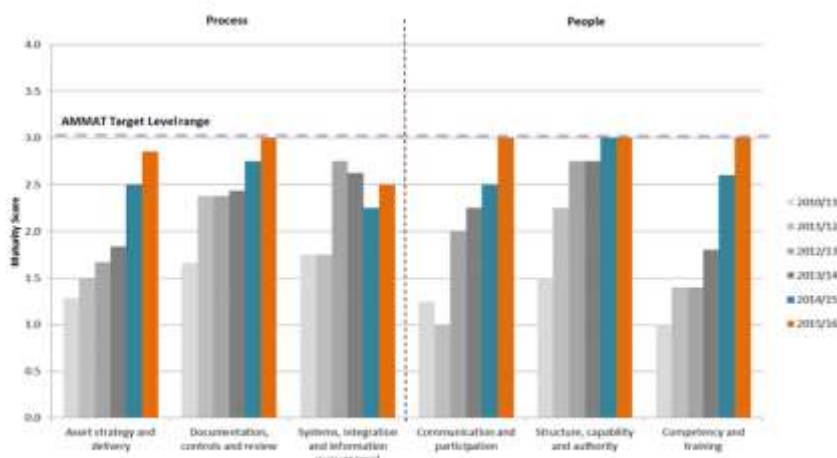


**Figure 8-2 AMMAT 2015/16 Functional Assessment**

### 8.3.1.2 Opportunities for Improvement

Figure 8-3 shows the Company has consistently improved over the past five years. However the audit has also highlighted some opportunities for improvement including:

- A need to increase the focus on cost effectiveness
- Completion of information system projects – we note the drop in maturity in relation to systems, integration and information management (between 2012/13 and 2014/15), which was due to recognised changes in condition information needs, and correction of an error in the assessment methodology
- Further work to formally document the risk assessments for all asset classes
- Further tidy-up of process documentation
- Determining the areas where “excellence” (level 4) is required.



**Figure 8-3 Summary Of Progress Between 2011 and 2016**



## 8.4 Asset Management Improvement Initiatives

The Asset Management Improvement Plan targets areas that provide a focus for action and contribute to meeting our asset management challenges over the next three years. These improvement streams were developed as an outcome of previous asset management Improvement plans and recommendations from the Energia Review of asset management practices (Feb 2015 and again in Feb 2016).

Asset Management Objective	Actions	Expected Results	When	Status
<b>Health Safety and Wellbeing</b> Nurturing the willingness to challenge	1. Implement the EEA Back to Basics Campaign	Shared safety culture, Improved safety performance and awareness	2017	
	2. Incorporate safety by design principles in all our detail designs		2017	
	3. Develop a critical control management plan and undertake a bow tie analysis for a range of fatal risk exposures –e.g. contact with live electricity		2016	<b>Complete</b>
	4. Create learning teams where lessons learned and safety initiatives are shared and improvements and recommendations actively followed up and Implemented		2017	
	5. Operationalise the Investigation Cause Analysis Method (ICAM) to investigate all Extreme and High Severity Incidents		2016	<b>Complete</b>
	6. Increase staff awareness of safety through targeted education, profile of incident statistics and performance, communication and consistent application of positive performance objectives		2016	<b>Complete</b>
	7. Implementation of appropriate Arc Flash protection procedures, rules and PPE	Improved awareness	2016	<b>Complete</b>
	8. Ensure that internal PSMS Audits are undertaken and actions arising from them are implemented	Recertification	2016	<b>Complete</b>
<b>Leadership</b> Developing a one team culture within Asset Management	9. An asset policy is adopted, approved and displayed	Attainment of Maturity level 3 and significant progress towards attainment of ISO55001 certification	2016	<b>Complete</b>
	10. Development of a Strategic Asset Management Plan (SAMP)		2016	<b>Complete</b>
	11. Review our structure in light of the current regulatory environment and the costs/benefits to determine if the status quo or an alternative model gives greatest shareholder value		2017	
	12. Implement an asset management governance group		2016	

Asset Management Objective	Actions	Expected Results	When	Status
<b>Network reliability and risk based prioritisation</b> Deliver "fit-for-purpose", cost effective operation, maintenance and replacement services that maximise the reliability of our distribution assets	13. Develop a criticality framework scope and methodology	Maintenance of all critical assets is optimised and Delta maintenance management practices are recognised as the benchmark in the distribution industry	2016	Progressing
	14. Move control operation to 24/7/365		2016	Progressing - Team selection is complete with staff undergoing training before moving to 24 X7
	15. Develop a formal prioritisation framework to inform O&M and Capital Programmes		2017	On track
	16. Spares are correctly identified, prioritised stored, maintained and replaced to ensure reliability when installed		2016	Progressing
	17. Implementation of pole reinforcement	Accelerated reduction in compliance network and public safety risk	2016	Complete
	18. Significantly Improve HV outage analysis and reporting	Improved understanding of causation and more timely accurate information	2016	Complete
	19. Develop and implement a standardisation policy for network equipment	Maximised compatibility interoperability, safety and minimisation of lifecycle cost	2018	
	20. Commissioning of 3 new substations (Camp Hill, Lindis Crossing and Riverbank Road in Wanaka)	Increased Network capacity in Central Otago	2017	On track
	21. Remove all Non-Compliant Condition 0 Poles from the Network	Reduced risk to the organisation	2020	On track
<b>New Technology, Systems and Processes</b> Integration of systems and processes that support the operational requirements of Asset Management	22. Preparation of an information strategy (to bring together the various projects)	Reduced risk to the organisation through delivery of business system deployed on a robust foundation	2016	Complete
	23. Consolidation of key business systems to better support end to end processing		2015-17	On track
	24. Formalisation of organisational data and information practices to ensure key data is robust and accurate		2016-17	On track
	25. Enable access to systems from anywhere that are flexible and scalable to support information sharing	Data is readily available in the form of relevant timely information	2018	
	26. Improve the organisations reporting capabilities for more accurate, relevant and timely information to support proactive decision making		2018	
	27. Leverage technology to prioritise,	Consolidated,	2016	Complete

Asset Management Objective	Actions	Expected Results	When	Status
	store, present and report on our 10 year program (AMP)	automated and better integrated systems to reduce complexity, improve decision making and improve ease of use		
	28. Develop and adopt an Enterprise Asset Management System (EAMS) architecture		2016	On track
	29. Implement an EAMS to store, analyse and manage the significant quantities of Asset data and transactions (including works management)		2017	
	30. Adoption of a Project Portfolio Management tool		2017	On track
	31. Deployment of smart Mobile device solutions (for all key asset classes)		2019	In Progress Vegetation & Poles are complete
	32. Deployment of the GE PowerOn advanced distribution management system to monitor, control and analyse the distribution network		2018	Underway
<b>Asset Knowledge</b> Improvements in asset performance by adopting an advanced asset management approach combined with detailed knowledge of asset condition	33. Enhance the measurement of asset condition for key asset classes and/or specific critical equipment	Changes in plant condition and the consequences of those changes on the reliability, and maintainability of the plant is understood and addressed in AMP	2016-2017	On track
	34. Implement HV lines condition inspection regime to inform conductor replacement program		2017	On track
	35. Develop and adopt condition assessment policy for major classes of assets and/or specific critical equipment		2017	
	36. Operationalise Devar Mechanical Pole Testing (MPT)		2015	Complete
	37. Failure modes identified for high risk and /or critical assets		2018	
	38. RCFA is carried out for all major faults		2019	
	39. Adoption of asset health indices for major asset classes		2018	
	40. Development of a reporting regime that efficiently and effectively communicates relevant equipment health condition information in a timely manner		2018	

Asset Management Objective	Actions	Expected Results	When	Status
<b>Communication and consultation</b> Enhance our customer understanding, deepen customer relationships and support customer retention and attraction	41. Analyse key stakeholders and customer groups and document their needs and expectations	Communication and consultation is demonstrably improved	2016	On track
	42. Implementation of Customer visits by senior executives who are not the account manager		2016	On track
	43. Increase communication with external stakeholders around the Asset Management Strategy		2016	On track
<b>Document, Records Management &amp; Assurance</b>	44. Lifecycle Strategies developed for all major classes of assets and /or critical assets e.g. Switchgear	Improved basis for the development of programs of work in the AMP	2017	
	45. Update Paper key based maintenance records into an electronic format		2016	Complete
	46. Update Emergency Management framework		2017	
	47. Determine the gap between our current asset management framework and ISO55000/1/2:2014 and develop a plan to bridge the gap		2015	Complete
	48. Achieve compliance of the asset management framework to ISO55001 by June 2019		2019	
	49. Review and update of all core BMS standards, procedures and forms		2017	
<b>People</b> Develop the skills and experience based on organisational needs and the aspirations of the individuals	50. Undertake a systematic review of competency and develop a plan to remediate gaps	The Asset Management team will have a complement of staff that is motivated, focused, and capable of managing the assets to meet the changing demands of the business	2016	Complete
	51. Development and Implementation of a competency framework that enables staff to identify gaps in their skills or competences		2017	Complete
	52. Succession plans for key positions within Asset management have been developed		2017	
	53. Learning and Development plans for every staff member are created which outlines how any skill gaps will be addressed in a timely manner		2017	
<b>Performance &amp; metrics</b> Develop and employ appropriate performance metrics to drive organisational and individual improvement	54. Establish a suite of performance metrics based on our value driver tree that support best practice and drive appropriate behaviours in our people	Performance metrics are used in effective and timely decision making	2016	Complete

## 9 APPENDIX

### 9.1 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)
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

## 9.2 Appendix B - Incident Quick Reference Guide

Incident Classification				
Phase	Description	Management Response	Response Plans	Notification / Escalation
	<b>Level 1 Minor Impact</b> <ul style="list-style-type: none"> <li>Incident is confined to a single workplace</li> <li>Incident can be managed using local resources</li> <li>Minimal or no disruption to public</li> </ul>	<b>Local</b> <ul style="list-style-type: none"> <li>Managed at the point of the incident</li> <li>Response plan based on site specific incident management plan or emergency response plans</li> <li>After managing initial response consider BCP activities that may be required</li> </ul>	<b>Local</b> <ul style="list-style-type: none"> <li>Business Continuity &amp; Disaster recovery plans</li> <li>Business Unit or site based incident management plans</li> </ul>	<b>Notify</b> <ul style="list-style-type: none"> <li>Business Unit Manager &amp; H&amp;S Advisor using Q-Pulse – See SM-5001</li> </ul> <b>Escalate If:</b> <ul style="list-style-type: none"> <li>Threat to life or safety persists</li> <li>Need assistance to manage</li> </ul>
	<b>Level 2 Medium Impact</b> <ul style="list-style-type: none"> <li>Incident is localized but external assistance may be required</li> <li>Potential minor disruption to public or local media interest</li> </ul>	<b>Regional or Business Group</b> <ul style="list-style-type: none"> <li>Managed within the affected business unit. Some national support may be required</li> <li>Response based on site incident management plan</li> <li>After managing initial response consider BCP activities that may be required</li> </ul>		<b>Notify</b> <ul style="list-style-type: none"> <li>Business Unit to Delta Incident Controller (for information and a second assessment on wider impacts)</li> <li>Brief executive as required</li> </ul> <b>Escalate If:</b> <ul style="list-style-type: none"> <li>Potential wider disruption incident management required</li> </ul>
	<b>Level 3 High Impact</b> <ul style="list-style-type: none"> <li>External assistance required</li> <li>Impact on wider business operations</li> <li>Significant disruption to public</li> <li>National Media interest</li> </ul>	<b>National</b> <ul style="list-style-type: none"> <li>Managed by Delta Incident management team</li> <li>Response based on Delta Incident Management Plan or Civil Defence</li> <li>Site emergency plans</li> <li>After managing initial response consider BCP activities that may be required</li> </ul>	<b>National</b> <ul style="list-style-type: none"> <li>Delta Incident Management Plan</li> <li>Civil Defence Management Plan</li> </ul>	<b>National</b> <ul style="list-style-type: none"> <li>Delta Incident Controller</li> <li>Delta Incident Management Team</li> <li>CEO / Board Briefed</li> </ul>

**Table 5.8 - Asset Categories and Quantities**

Asset Group	Asset Class	Asset Category	Units	Dunedin	Central	Te Anau	Total
<b>Support Structures</b>	Concrete poles / steel structure	Overhead line	Count	14,820	7,309	22,129	44,258
	Other pole types	Overhead line	Count	78	59	137	274
	Wood poles	Overhead line	Count	14,590	17,247	31,837	63,674
<b>Circuit Breakers</b>	Distribution switchgear	3.3/6.6/11/22kV CB (indoor)	Count	5			5
		3.3/6.6/11/22kV CB (pole mounted)	Count	1			1
		3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	Count	12	29	1	42
	Zone substation switchgear	22/33kV CB (Indoor)	Count		6		6
		22/33kV CB (Outdoor)	Count	23	30		53
		3.3/6.6/11/22kV CB (ground mounted)	Count	262	87		349
		3.3/6.6/11/22kV CB (pole mounted)	Count		19		19
		50/66/110kV CB (outdoor)	Count		5		5
<b>Switchgear</b>	Distribution switchgear	3.3/6.6/11/22kV RMU	Count	629	448	2	1,079
		3.3/6.6/11/22kV switch (ground mounted) - except RMU	Count	463	355	1	819
		3.3/6.6/11/22kV switches and fuses (pole mounted)	Count	2,559	3,962		6,521
	Zone substation switchgear	33kV switch (pole mounted)	Count	111	105		216



Asset Group	Asset Class	Asset Category	Units	Dunedin	Central	Te Anau	Total
Transformers & Voltage Regulators	Distribution Transformer	Ground mounted transformer	Count	911	1,817	5	2,733
		Pole mounted transformer	Count	1,710	2,435		4,145
		Voltage regulators	Count	11	30		41
	Zone Substation Transformer	Zone substation transformers	Count	35	33		68
Overhead Lines	Distribution Line	Distribution OH open wire conductor	km of OH line	731	1,576		2,308
		SWER conductor	km of OH line	8			8
	LV Line	LV OH conductor	km of OH line	824	225		1,049
	LV Street lighting	LV OH/UG streetlight circuit	km of OH line	714	575	8	1,297
	Subtransmission Line	Subtransmission OH up to 66kV conductor	km of OH line	144	382		526
Underground Cables	Distribution Cable	Distribution submarine cable	km of UG cable	1			1
		Distribution UG PILC	km of UG cable	281	148	1	429
		Distribution UG XLPE or PVC	km of UG cable	31	526	1	558
	LV Cable	LV UG cable	km of UG cable	255	630	6	890
	Subtransmission Cable	Subtransmission UG up to 66kV (gas pressurised)	km of UG cable	36			36
		Subtransmission UG up to 66kV (oil pressurised)	km of UG cable	25			25
		Subtransmission UG up to 66kV (PILC)	km of UG cable	11	0		11
		Subtransmission UG up to 66kV (XLPE)	km of UG cable	4	17		21

Asset Group	Asset Class	Asset Category	Units	Dunedin	Central	Te Anau	Total
<b>Communications Equipment</b>	SCADA and communications equipment operating as a single system		Count	25	78		103
	Centralised Plant		Count	21	3		24
	Ripple Control Relays		Count	1127	1083	5	2215
<b>Mobile Plant</b>	Mobile Power Transformer		Count		1		1
	Mobile Distribution Substations		Count	2	1		3
	Trojan Units		Count	1	1		2
<b>Generators</b>	Mobile generator		Count		1		1
	Emergency Generators		Count	1	2		3
<b>Protection Systems</b>	Protection relays (electromechanical, solid state and numeric)		Count	624	416		1040
<b>Buildings and Grounds</b>	Zone substation Buildings	Zone substations up to 66kV	Count	18	21		39
	Distribution Substations	Ground mounted substation housing	Count	911	1,817	5	2,733
<b>Other Primary equipment</b>	Connections	OH/UG consumer service connections	Count	54,815	31,631	82	86,528
	Civils	Cable tunnels	km	153.8	139.3		293.1
	Capacitor Banks	Capacitors including controls	Count	3			3
<b>Vegetation</b>	Touching	Kms of overhead line	Count	36.61	33.21		70
	Within Growth Limit Zone	Kms of overhead line	Count	6.26	18.28		25
	Within Notice Zone	Kms of overhead line	Count	4.59	8.54		13