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AURORA ENERGY

INDEPENDENT REVIEW OF ELECTRICITY NETWORKS

FINAL REPORT

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Independent review of electricity networks
Final report

Aurora Energy

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ABBREVIATIONS

ABS	Air Brake Switch
ACR	Automatic Circuit Recloser
ACSR	Aluminium Conductor Steel Reinforced
AHI	Asset Health Indicator
AL	Aluminium
AMP	Asset Management Plan
CB	Circuit Breaker
CU	Copper
DDO	Drop-Out fuse
DGA	Dissolved Gas Analysis
EEA	Electricity Engineers Association
GIS	Geographical Information System
GPD	Group Peak Demand
GXP	Grid Exit Point
HV	High voltage
LDC	Load Duration Curve
LV	Low voltage
L&C	Long and Crawford
NZECP	New Zealand Electrical Code of Practice
OEM	Original Equipment Manufacturer
OH	Overhead
OMS	Outage Management System
PILC	Paper Insulated Lead Covered cable
POI	Points of Interest
RMU	Ring Main Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAP	Systems, Applications and Products in data processing. A software company
SCADA	Supervisory Control and Data Acquisition
SLD	Single Line Diagram

SME	Subject Matter Expert
UG	Underground
VCR	Value of Customer Reliability
VOLL	Value of Lost Load
XLPE	Cross Linked Polyethylene
ZSS	Zone Substation

EXECUTIVE SUMMARY

PROJECT CONTEXT

WSP has been engaged by Aurora Energy (Aurora) to undertake an independent review to determine the state of the electricity networks in Dunedin and Central Otago, identifying any critical assets at significant risk of failure. This will allow interested stakeholders to better assess the appropriateness of the planned interventions and investments Aurora proposes to make. The two key tasks for the review, which reflects a consumer focus, are to:

Establish an accurate and reliable assessment of the current state of the Aurora networks with particular focus on identified critical assets

Having established the state of the network, determine the resulting prioritised risk to consumers.

REVIEW APPROACH

To meet the terms of reference for the review, WSP developed an approach based on assessing the Aurora network from several perspectives:

- **Resilience**: the ability of the network to withstand or recover from high impact, but very low frequency, events such as earthquakes
- **Security**: whether the electricity network topology provides appropriate capabilities, such as capacity, redundancy and switching capability, to maintain normal supply to consumers
- **Performance**: an indication of which assets and areas of the network pose the greatest risk to public safety, reliability of supply and the environment based on historical rates and durations of asset outages
- **Network risk**: the combination of the probability that assets may fail and the consequence of the impact to public safety, reliability of supply or the environment.

Examining security and performance allowed us to focus our review of network risk on key matters. Each of these perspectives is discussed in detail below. The key outcome of the review is the prioritised list of network risk that Aurora needs to consider in their future network management plans and investments.

The project was managed in two stages. The first stage of this project involved an assessment/gap analysis of the extent, reliability and suitability of existing asset data (i.e. age, condition, defect, failure data) that could be used to undertake a risk assessment of the network. Based on the data gaps identified, the second stage then involved scheduling of additional testing and inspection programs in order to close the data / knowledge gaps and enable a risk assessment to be undertaken.

The key tasks undertaken across the two stages were:

1. An investigation into the asset data available
2. Targeted and/or random testing of the asset fleets to validate existing data and to generate new data where gaps were identified
3. Desktop investigation/analysis of all compiled asset data, including both existing data sets and new data gathered
4. Creation and population of asset risk profiles for each asset class.

It should be noted that this report is aimed at providing the current state of the Aurora network. It does not include consideration on the interventions and future strategies planned by Aurora. In addition, any matters relating to Aurora's performance against quality standards are excluded from the review scope. The review does not include benchmarking or commenting on improvement actions.

SUITABILITY OF ASSET DATA

WSP undertook an assessment of Aurora's data through a series of interviews with Subject Matter Experts (SMEs) and analysis of the data sets provided. We validated that the information was suitable for use and obtained additional information through site inspections and testing. Each asset class was given a ranking against the data requirements and then assigned an overall data quality score of High, Medium or Low. We identified gaps in some of the asset data and initiated actions to validate or improve the data for this review through on-site inspection.

The table below shows that adequate data and information was available for the review following our inspections and validation. The ranking of Low for distribution cables is caused by the lack of condition data available, however, it is common in industry to have limited data on these assets due to their nature of being buried underground and, therefore, not able to be inspected. The following table shows an overview of the asset data summarised into key asset categories.

ASSET	FROM AURORA	ACTION TAKEN	RESULT
Support structures	Medium	Site inspections to validate Field testing undertaken	High
Overhead lines – Sub transmission	Medium	Drone survey undertaken Field measurements	Medium
Overhead lines – Distribution	Medium	Drone survey undertaken	Medium
Underground cables – Sub transmission	Medium	No action possible	Medium
Underground cables – Distribution	Low	No action possible	Low
Circuit breakers	Medium	Site inspections to validate	Medium
Distribution switchgear	Medium	Site inspections to validate	Medium
ZSS transformers	High	Inspection results to validate	High
Distribution transformers	Medium	Inspection results to validate	Medium
Protection systems	Medium	Site inspections to validate	Medium

KEY FINDINGS

WSP's review investigated Aurora Energy's electricity network to assess the risks as they relate to network resilience, network security, network performance, and each asset class.

NETWORK RESILIENCE

Network resilience relates to how well the network is designed, from the perspective of the supply chain, to ensure continued supply following very high impact but very low frequency events, natural disasters in particular. Our investigation identified that Aurora's network is subject to several very high impact events, most notably earthquakes and the resultant liquefaction of the ground.

WSP found that most key assets have been installed clear of earthquake fault lines, flood zones, landslide risk zones and tsunamis risk areas. However, it is not possible to avoid these altogether as customers occupy these areas and require electricity.

A review of the most recent earthquakes in Christchurch found that liquefaction of the ground had the biggest impact to network supply as it severely damaged underground cables. Overhead lines are a lower risk as damage can be identified and repaired more rapidly. Dunedin is in an area that has a moderate to high liquefaction risk, and eight of the nineteen zone substations are supplied by radial underground sub transmission cables. Although these are dual circuits, which provides redundancy, they are located in the same trench and, hence, can be expected to be impacted equally by a major event. The cable type, ages, deteriorated condition, and installation methods means that these are the highest risk with respect to network resilience.

Maintaining network operations and control is also key to maintaining a resilient network. Aurora currently has two control centres which normally operate separately and provide limited back up for the other. This poses a risk that a major event disabling one will significantly impact operational control of part of the network. This risk is being mitigated through Aurora's 'one network' initiative which involved upgrading the SCADA system to enable each control room to control the entire network.

NETWORK SECURITY

Network security relates to how well the topology and design of Aurora's network can maintain supply to consumers. There are two key aspects to security:

- The ability of Aurora to isolate a faulted part of the network and resupply customers by operating switches to reconfigure the network. Sufficient interconnection will minimise the number of customers experiencing long outage times and, hence, improve performance.
- The ability to take assets out of service in order to undertake maintenance, without creating a large outage area affecting more customers than necessary. Inability to do this means that maintenance of critical assets may be deferred and result in assets not being sufficiently maintained, leading to shortened serviceable life or in-service failure.

WSP found that:

- Zone substations are generally supplied radially from the Grid Exit Points, but by double circuits, so there is an adequate level of redundancy.
- Urban feeders generally have good levels of interconnection with adjacent feeders to be able to transfer load, however, some parts are radial with no interconnection. These arrangements do not appear different to most other electricity businesses.
- Long rural feeders normally have limited ability to enable resupply via switching, and this is reflected in the security and performance standards set for those feeders. We found that the topology of Aurora's network was appropriate for its geographical location and distribution of customers. To mitigate the risk of a prolonged outage should a single transformer zone substation fail, Aurora has a mobile transformer that can be deployed to restore supply quickly.

NETWORK PERFORMANCE

The long-term network performance was analysed to identify any assets that are displaying an increasing trend in the number of outages. Our assessment was not against performance standards but to identify where risk to the network was materialising.

We found that overhead conductors, poles and crossarm assets were causing more than 50% of the network outages that were attributed to asset deterioration. There was an upward failure trend evident, although it has ameliorated in the most recent year, likely as a result of the accelerated pole program.

The analysis identified the following critical assets:

- **Poles:** an accelerated pole program has slowed a declining performance trend that started in 2013. The current state of poles still appears to be in poor condition, indicating there is an elevated level of risk with this fleet
- **Pole top structures:** highly related to pole performance with respect to reliability

- **Overhead conductor (all voltages):** demonstrated to have declining performance based on defects relative to other assets and can pose a high risk to the public when it fails if protection systems do not operate as intended
- **Protection systems:** our analysis of outages demonstrated instances when protection systems did not operate and, therefore, did not mitigate the public safety risk as intended.

Safety performance of the network was generally found to be appropriate, except for risks associated with protection systems. Data obtained from the safety registers identified 35 incidents in the period 2015 – 2018 where a conductor fell to the ground and remained live. We identified that:

- some were on the LV network, with protection by a fuse that did not react to the fault
- some were due to a high impedance HV fault, where a back feed from the energised network circumvents the proper operation of the protection relays
- an estimated 15 faults should have been detected by the protection relays.

Our detailed review of the protection systems supports that there is an issue with appropriate functioning of the older fleet of electromechanical protection relays.

NETWORK RISK

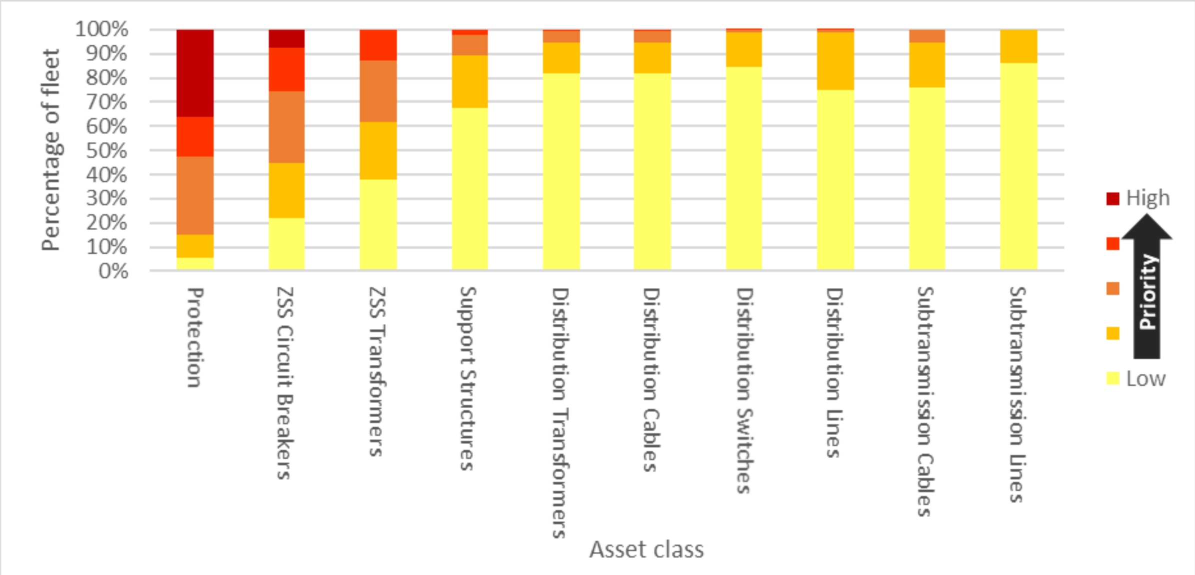
Overall, most assets pose a small risk to public safety, reliability or the environment. The risks posed by these assets are no greater than WSP has observed in other networks in New Zealand and internationally.

WSP found some exceptions:

- **Protection system assets**: these assets are used to detect a failure that results in a flow of electrical current that is larger than normal or a flow to ground (earth faults). Many of these assets are beyond their nominal life, employ obsolete technology and maintenance is incomplete. Five types of electromechanical relays are now an obsolete technology and are consistently losing calibration between maintenance cycles. These relays are used for earth fault and over-current detection. The failure of these relays to operate as intended has resulted in live conductors on the ground not being detected and de-energised. Most observed instances, where earth faults were not isolated, were found to involve the identified relay types or older electromechanical relays more generally. This supports they are at the end of their serviceable lives. Protection system assets pose a significant safety risk and should be prioritised.
- **Zone substation circuit breakers:** these assets are used to switch the network and are opened by protection systems to isolate faults on the network. The inspection, testing and maintenance of these assets is incomplete. The technology and specific models installed also pose an increased risk. Some oil insulated zone substation circuit breakers were found to present an elevated risk to the network with respect to network reliability and the safety of field crews due to their potential failure mode through arc fault and fire. Many of the specific types of circuit breaker in-service on the Aurora network have been identified in the electricity industry as having an elevated risk of failure
- **Zone substation transformers**: these assets are located at bulk supply points (zone substations) and used to transform voltage from the high voltage used on the sub transmission network to the medium voltages used on the distribution network. The transformers at two zone substations are in poor condition, although we note that one is currently in the process of being decommissioned. Additionally, transformer tap changers are showing signs of deterioration and some are behind their maintenance schedule, increasing risk of an outage on the associated transformers.
- **Support structures**: these assets consist of the poles, crossarms and insulators that are used to support conductors. The pole inspection program has recently been improved but has not identified all poles that are in poor condition as it has not yet covered the whole network. Crossarms are not inspected adequately and many are in poor condition. Some are categorised as high risk due to their location relative to population and probability of failure. Note that while our analysis focuses on a whole of fleet assessment and will identify expected quantities, individual assets requiring remediation will be identified through Aurora's normal inspection and testing program.

— **Distribution switchgear**: these assets are used to switch the distribution network. A significant number are defective and inhibit normal operation of the network, which can lengthen outages experienced by customers and impact the reliability performance of the network. Some models have identified issues which present a safety risk, predominately for field crews. A significant portion of the ring main unit type switchgear inspected (40%) have oil leaks. Batteries in circuit reclosers do not have a regular replacement scheme. This poses risk that the reclosers may not operate when required.

We used Aurora's risk management approach to classify the identified risks. The chart below shows the result.



Overall, we found a high number of risks in the "Red" category, indicating network risk has not been reduced to as low as reasonably practical.

A prioritised list of risks has been developed to provide guidance on where Aurora should focus their attention in maintaining the safety and reliability of the network.

1 PROJECT CONTEXT

WSP has been engaged by Aurora Energy (Aurora) to determine the state of their electricity distribution networks in Dunedin and Central Otago. The purpose of this engagement is to identify the levels of risk on the network and specifically identify any critical network assets that are at significant risk of failure.

WSP entered a tripartite agreement with the Commerce Commission and Aurora to ensure an independent review and to assist the Commission on matters relevant to the review within WSP's area of expertise. The Commission reviewed the scope of work and commented on the draft and final reports.

To provide the project context, this section sets out the background that led to the initiation of this project, the objective and scope of the project, the methodology and approach undertaken, and the structure of this report.

1.1 OBJECTIVE

The objective of the project is to undertake an independent risk assessment of the Dunedin and Central Otago electricity distribution networks owned and operated by Aurora Energy. The risk assessment is to be undertaken with a consumer focus, with explicit regard given to:

- public safety
- reliability
- resilience
- environmental risk
- post-fault restoration times.

The output of the project is to establish an accurate and reliable risk profile for the current state of the Aurora networks, within the bounds of accuracy of the sampling method, and with a particular focus on the identified critical assets. The resulting prioritised risk to consumers will then be determined from this assessment.

Based on the agreed approach which includes the use of asset inspection by sampling a portion of the population and extrapolation across the remainder of the fleet, it is probable that specific assets in poor condition may not be identified. The intent of this assessment is to understand the situation of the entire fleet of assets in an efficient manner to enable Aurora to most efficiently prioritise their maintenance and replacement activities where needed. The purpose is not to necessarily identify each individual asset – that is the role of the recurrent inspection and testing tasks of the field crews in business as usual operations.

1.2 PROJECT SCOPE

Key aspects of the review include:

- identifying Aurora's critical assets and their underlying physical condition
- assessment of Aurora's understanding of the performance and health of its assets (in the absence of hard evidence what assumptions / judgment is being applied)
- identification of potential and probable failure modes, and the underlying potential consequences of failure
- assessment of the extent to which the network assets are constructed to appropriate design standards, taking into account:
    - the past and current design standards applied by Aurora

  - the specific location and environment of the assets
  - the impact of asset deterioration.
- consideration of the extent to which network topology mitigates (or otherwise) the risk of service failure in significant urban areas of the network, and in rural zones:
  - underlying security of supply standard
  - areas where security of supply standard is exceeded
  - areas where security of supply standard is not being met
  - emerging capacity constraints
  - locations where changing land use is driving a need to convert infrastructure historically designed for rural use, to urban levels of resilience and reliability.
- estimate the overall risk profile for the Aurora networks.

The two key deliverables of the review are:

- establishment of an accurate and reliable assessment of the current state of the Aurora networks with a particular focus on identified critical assets
- having established the state of the network, determine the resulting prioritised risk to consumers.

This risk assessment is undertaken within the context of a consumer focus as described in section 1.1.

1.3 EXCLUSIONS FROM SCOPE

Not all of Aurora's assets were included in the scope for the review. Assets excluded comprise non-network assets (such as vehicles), capacitor banks, ripple control, disconnector/earth switch, surge arrestors, and buildings

It should be noted that this report is aimed at providing an assessment of the current state of the Aurora electricity network. It does not include consideration on the interventions and future strategies planned by Aurora. In addition, any matters relating to Aurora's historical performance against quality standards, benchmarking against other network service providers or the performance of individuals, are excluded from the scope. Indirect matters, such as Aurora's engineering capability are also excluded.

1.4 APPROACH AND METHODOLOGY

This project has been undertaken in two stages. The first stage undertook a high-level review of the asset data held by Aurora. The second stage validated the data, undertook field inspections and testing to fill identified gaps, and used the available data to assess the network risk.

WSP used the following high-level approach:

Task 1: Data Review

For the assessment of asset data, WSP reviewed the following to determine data gaps:

- format/availability of data (i.e. paper records or data base), including the usability of data in its current format
- completeness of data in databases, accuracy and consistency of the data (i.e. check for obvious errors, which may include some limited visual inspections of nearby assets as sample testing for data accuracy)
- maintenance records availability, again with check for accuracy and completeness.

We also undertook interviews with staff to assess their understanding of the asset data and how it was collected. The interviews focused on discussing asset attribute data, condition data and performance information, as well as the process used to gather and validate the information. The combination of the data assessment and staff interviews allowed us to identify missing information. Further description on the data review approach is set out in section 3.

Task 2: Asset testing / data validation

This involved the development of an inspection and testing program to gather new data to fill gaps or to validate the practices undertaken by the field crews. This validation was to ensure procedures were followed and the data gathered from site was accurately sent back to Aurora (via mobile device or paper records). Further description on the data validation approach is set out in section 3.5 and then in the individual asset classes later in the report.

Task 3: Analysis of compiled asset data

The desktop analysis of asset data was done at two levels, firstly from a whole of network viewpoint to look for trends in network performance, including reliability trends and defects trends and also to assess any particular areas of concern related to the overall network resilience. Following this network viewpoint, each individual asset class was analysed to assess failure modes, performance, inspection / testing regimes and condition.

Task 4: Considerations of asset and network design

As well as looking at the asset data and asset condition, WSP considered the design standards that had been applied by Aurora in the context of the location and environment of the assets and the impact of asset deterioration. In addition, WSP considered the extent to which network topology mitigates the risk of service failure in significant urban areas of the network and in rural zones. This was done through assessment against Aurora's security of supply standard, specifically identifying areas where this standard is not being met or has emerging capacity constraints.

Task 5: Development of risk profile

The final task involved using the asset data to create the risk profile for the individual asset categories. This involved consideration of public safety, reliability and the environment to identify the risks associated with each asset class and each area of the network. Not every asset was inspected or reviewed, but sufficient data collected to enable a risk profile to be developed for each asset category.

Where possible, we have undertaken quantitative analysis to quantify the risk as a financial value or as an index to enable ranking of risk at a more granular level (whereas a qualitative or matrix approach could allocate the same risk value to a multitude of assets reducing the ability to prioritise and target risk). However, for some analysis, the risk assessment is qualitative due to either the availability of data, or the type of risk being discussed.

1.5 STRUCTURE OF THE REPORT

This report is structured to provide a view of the network from a high level before discussing individual asset risk. The report sets out the definitions used in the report, our analysis and findings, and the prioritised risk to consumers.

Section 2: Overview of Aurora's network

Section 3: Asset data

Section 4: Network risk

Section 5: Network resilience

Section 6: Network security

Section 7: Network performance

Section 8: Support structures

Section 9: Distribution switchgear

Section 10: Distribution transformers

Section 11: Overhead lines – sub transmission

Section 12: Overhead lines – distribution

Section 13: Underground cables – sub transmission

Section 14: Underground cables – distribution

Section 15: ZSS Transformers

Section 16: ZSS Circuit breakers

Section 17: Protection systems

Section 18: Conclusions

2 OVERVIEW OF AURORA’S NETWORK

Aurora Energy, 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 for two large separate regions of the South Island – Dunedin and Central Otago.

Central: predominantly rural, lower population density

Dunedin: predominantly urban, higher population density

Source: Aurora AMP 2018

Aurora’s network is fed from Grid Exit Points from Transpower’s transmission network. Aurora Energy’s network is hierarchical in nature, with lines and cables operating at three distinct voltage ranges:

- Sub transmission – mostly 33kV but also 66kV
- Distribution – mostly 11kV in Central Otago and 6.6kV in Dunedin
- Low Voltage (LV) – 230V single phase or 400V three phase.

Electricity from high voltage circuits (lines and cables) is transformed, at numerous zone substations, to lower voltage circuits that each serve anywhere between one and a few hundred customers. Often the transformation in voltage is 33kV to 11kV; although in Wanaka, the conversion is from 66kV to 11kV, and then to the 400/230 volts used in homes and businesses.

The key asset classes considered in this review are:

- Support structures, including poles and the crossarms and insulators that are affixed to poles
- Overhead lines and underground cables
- Switchgear and circuit breakers that are used to switch and isolate parts of the network
- Transformers that are used to transform voltages from a high voltage to a lower voltage
- Protection systems that detect a failure of the network that results in a flow of electrical current that is larger than normal or a flow to ground.

3 ASSET DATA

Reliable and complete asset data is required to effectively manage a large asset fleet. Asset data enables asset managers to understand the composition of an asset fleet, how it is performing against performance indicators, to identify emerging trends and risks, and how they can be mitigated.

The data required falls into three categories:

- **Asset attributes:** this includes basic asset information including the make, model, materials, ratings, age and location. This data provides understanding of the segments of the asset fleet and allows monitoring of similar asset classes.
- **Condition and defect data:** this includes the testing and inspection results of assets, a history of the types and numbers of defects identified, and any failures to operate as intended for the asset type.
- **Performance data:** this includes how well the asset is performing its intended function against established criteria. Commonly this includes reliability metrics (SAIDI, SAIFI, customer minutes off supply), public safety and environmental requirements.

The use of these data sets enables asset managers to assess the probability and consequence of an asset failure using a range of techniques. Unreliable or incomplete data reduces the insight that can be gained and limits the analytical techniques that can be applied.

WSP undertook an assessment of Aurora's data through a series of interviews with SMEs and analysis of the data sets provided. We identified several areas where asset data was not available, not as complete or where data was not reliably collected or stored in a useful format. Our assessment considered the level of data accuracy and completeness that would be expected for each asset class based on how they are managed by Aurora and common industry practice.

The following sections describe the key elements of the asset data and systems used to gather and store the data.

3.1 ASSET DATA SYSTEMS

The key systems used by Aurora for managing and storing asset data are set out in Table 3.1:

Table 3.1 Asset data systems used by Aurora

SYSTEM	TYPE OF INFORMATION
ARC FM/ArcGIS (ESRI Software)	Geo-spatial information
SAP	Financial data (not used for asset data)
Outage Management System (OMS)	Outage data
Internal business network folders	Scanned PDF reports and defect data
Power BI	Data analysis tool
Protection Settings Database	Protection relay makes and models, settings and dates
Structured Lines	Data collection application for poles inspections
Survey 123	Mobile app development platform
Xivic	Legacy database for asset inspection
AMData database	SQL Server based asset data repository (developed in-house)

The process that has been established for managing the Structured Lines data provides good functionality for recording data, analysing the information and enabling asset management decisions to be undertaken.

Data analysis tools (such as PowerBI) are being used to good effect to obtain useful insights into the assets. The development and maintenance of the system is reliant on only one or two people in the business which introduces a key person risk for ongoing asset management processes.

3.2 ASSET ATTRIBUTES

Asset attributes have in general been captured in GIS. While this has been made to work for many assets, there is no link to financial data and or any functional workflow and maintenance management systems incorporated into the software. This limits the functionality of the asset management system.

The accuracy of the information was found to vary dependant on the asset type. Refer to Table 3.3 for our assessment on the accuracy of attribute information against each asset class.

Our assessment of the reliability of the data included assessing the completeness of the attributes for the fleet, how well and consistently the entries were made in each column and consistency of data between different data sources. We found that a consistent unique identifier per asset is not implemented, making it difficult to work with and manage the data efficiently and creating uncertainty that all assets have been accounted for.

In general, WSP would have expected better data for some of the asset types such as zone substation assets that have low volumes on the network. However, the data on the distribution assets was not too dissimilar in accuracy and completeness when compared to other electricity distribution providers. In some cases, it was of lower quality, such as for distribution switchgear, and in others it was more complete, such as for poles.

3.3 CONDITION AND DEFECT DATA

Similar to the asset attributes data, the quality and reliability of the condition and defect data depends on the asset class. On a general level it was found that defects have not been captured well, with reports not well organised and difficult to extract useful information for trending the fleet performance.

Issues included inconsistency of formats for capturing defects data over time, inconsistent naming conventions and different groupings of reports, both within folders and within individual scanned PDFs (i.e. a mixture of general site inspection, battery testing and circuit breaker maintenance compiled into one document). This made it difficult to find defect data and to identify systemic issues.

The dates on the inspection and testing sheets indicated the inspections were not undertaken on a consistent periodic basis. The time between inspections varied within asset classes.

The condition data collection process has historically been very manual, although we note that Aurora is currently in the process of developing a suite of mobile applications that they are rolling out into the field rapidly. This will enable – and enforce – consistent collection of data that can be automatically transferred into the asset databases to improve reports. This is a good example of how Aurora is engaging with modern technology to improve management of their network.

3.4 PERFORMANCE DATA

Network performance data was predominately captured in the outage management system. Data entry into the database was a manual process and only quality reviewed consistently in Dunedin. However, the process is audited annually and there are a low number of outages each day which minimises any problems with manual data entry errors. It is also acknowledged that the practices have improved with the establishment of the new SCADA system using General

Electric's PowerOn Fusion, where the data capture will be automatic for all telemetered and HV in-field switchable devices.

The process of reporting outages is to allocate the outage location to the nearest distribution transformer. This has the effect of reducing visibility of locational issues, such as from vegetation, or being able to consistently identify a specific asset type that is causing outages.

3.5 DATA GATHERING AND VALIDATION

WSP has undertaken data validation activities in field to gain confidence in the accuracy of the information and data captured by Aurora. The level of field validation undertaken was dependent on our initial assessment of the asset data quality as described in section 3 and the criticality of the asset in regard to its potential impact on safety, reliability and the environment.

Based on the initial data assessment, the activities reflected in Table 3.2 were undertaken.

Table 3.2 Field validation approaches

DATA QUALITY	FIELD VALIDATION	CHECKS MADE	APPLICABLE ASSETS
High / Medium	Audits of Aurora led tests / maintenance procedures Independent visual inspection	Testing in accordance with testing procedures and training provided. Consistency in testing across different testing staff or crews. Correct capture of data.	Supporting structures - poles Zone substations – all subclasses Overhead lines – sub transmission
Medium / Low	Independent inspections of assets	Condition assessment of critical components / features	Supporting structures – crossarms and related hardware Distribution switchgear – ACR and ABS Overhead lines – distribution
Any	Limited field validation	Ad hoc checks made during other inspection activities	Underground cables Distribution Transformers

Limitations of field validation work:

For some asset classes, such as underground cables and metal enclosed switchgear, inspections were unable to be performed due to inaccessibility of the assets, as inspections or tests would require significant network outages. Additionally, for some asset classes, the ability to witness asset tests or inspections was restricted by Aurora's maintenance programme. This was the case for the zone substation inspections which are only carried out once every four years per substation and can require significant planned outages on the network, limiting flexibility with timing and zone substations inspected.

The specific limitations of the field validation work undertaken on each asset class is set out in the specific asset sections presented later in this report.

Approach to sampling

In undertaking field work validation, WSP applied a sampling approach to gathering the asset information for those assets with a large population (poles, distribution switchgear, etc). A sampling approach was required due to the costs and timeframes that would be required to view all the network assets. The sampling approach allowed for an efficient process to be undertaken to improve confidence in asset information, whilst ensuring sufficient effort is allocated to the assets, based on their risk profiles.

The sampling approach uses statistical analysis to calculate a sample size based on the 'Confidence Level' and the 'Margin of Error' required. For details on the sampling calculation, refer to Appendix A. As part of the calculation to determine the suitable sample size, asset classes were broken into segments. As an example, those assets in more critical areas (i.e. where there is a high risk to public safety) were segmented from those in less critical areas. For other assets, segments may have been based on the location of the assets to account for different environmental conditions (e.g. Dunedin inland vs Dunedin coastal). By segmenting the assets, we were able to improve the targeting of our sampling and focus on those areas of highest concern to safety, reliability or the environment.

For those assets with small populations, such as zone substations and protection systems, WSP's approach to sampling was not based on a statistical sampling approach. Instead we verified data in areas where there have been particular issues or where assets are in known growth areas or likely to have changed network conditions such as fault levels. The specific approach taken to sampling is described under each asset class as presented later in this report.

3.6 SUMMARY OF DATA ASSESSMENT

Table 3.3 provides a summary of the assessment of asset data against the three data requirements of attributes, condition and performance data for each asset class.

Rankings are shown as:

🟢 High: the data is sufficiently complete and can be relied upon. It is suitable for the management of the asset type.

🟡 Medium: there are gaps in the data but it may be appropriate for use, likely validation is required

🔴 Low: the data is materially incomplete and limits the analysis that can be undertake or creates uncertainty in the results

Each criteria was ranked with the 'overall' data quality result reflecting the predominant assessment for the asset class. This was a semi-qualitative assessment based on discussions with the subject matter expert, analysis of data sets provided and our experience in the industry. The amount and reliability of the data was considered with respect to each type of asset and normal approaches to asset management for that asset.

Table 3.3 Summary of initial data quality by asset class

ASSET CLASS	SUB CLASS	ATTRIBUTES	CONDITION	PERFORMANCE	OVERALL DATA QUALITY
Support structures – Poles	Structured Lines inspection approach	🟡	🟢	🟢	🟢
	Historical inspection approaches	🟡	🔴	🟢	🔴
Support structures – Other	Crossarms and insulators	🔴	🟡	🟢	🟡
Distribution switchgear – Ground-mounted	RMU	🔴	🟡	🟡	🔴
	Switches	🔴	🟡	🟡	🔴

ASSET CLASS	SUB CLASS	ATTRIBUTES	CONDITION	PERFORMANCE	OVERALL DATA QUALITY
Distribution switchgear - Pole-mounted	Fuses	Red	Yellow	Yellow	Red
	Switches	Red	Yellow	Yellow	Red
	Reclosers	Yellow	Yellow	Yellow	Yellow
	Sectionalisers	Yellow	Yellow	Yellow	Yellow
Distribution transformers	Ground-mounted	Green	Yellow	Yellow	Yellow
	Pole-mounted	Green	Yellow	Yellow	Yellow
	Voltage Regulators	Green	Yellow	Yellow	Yellow
Overhead lines – Sub transmission	All types	Green	Green	Yellow	Green
Overhead lines – Distribution	HV	Green	Red	Red	Red
	LV	Yellow	Red	Red	Red
Underground cables – Sub transmission	PILC	Green	Red	Yellow	Red
	Oil insulated	Green	Yellow	Yellow	Yellow
	Gas insulated	Green	Yellow	Yellow	Yellow
	XLPE	Green	Red	Yellow	Red
Underground cables – Distribution	HV cables[1]	Green	Red	Yellow	Yellow
	LV cables[1]	Yellow	Red	Red	Yellow
	Cast Iron Potheads	Yellow	Yellow	Yellow	Yellow
Zone substation – Transformers	Transformers	Yellow	Yellow	Green	Yellow
	Tap changers	Yellow	Yellow	Green	Yellow
	Bushings	Red	Yellow	Green	Red
	Bunding	Green	Green	Green	Green
Zone substation – Circuit breakers	All types	Yellow	Yellow	Green	Yellow
Zone substation – Protection	Protection relays	Yellow	Green	Green	Yellow
	Setting information	Yellow	not applicable	not applicable	Yellow
	Battery banks and chargers	Yellow	Yellow	Green	Yellow
	Instrument transformers	Red	Red	Red	Red
	SCADA	Yellow	Yellow	Yellow	Yellow

(1) Although the condition and/or performance data is assessed as a ‘red’, the overall data quality is a ‘yellow’ as condition and performance data is not generally kept on these assets in the electricity industry.

Where data was found to be insufficient for this review, WSP sought to improve it through site inspection, examination of records etc. The final assessment of data quality for each key asset class is shown in Table 3.4.

Table 3.4 Final data quality for key assets

ASSET	FROM AURORA	ACTION TAKEN	RESULT
Support structures	Medium	Site inspections to validate Field testing undertaken	High
Overhead lines – Sub transmission	Medium	Drone survey undertaken Field measurements	Medium
Overhead lines – Distribution	Medium	Drone survey undertaken	Medium
Underground cables – Sub transmission	Medium	No action possible	Medium
Underground cables – Distribution	Low	No action possible	Low
Circuit breakers	Medium	Site inspections to validate	Medium
Distribution switchgear	Medium	Site inspections to validate	Medium
ZSS transformers	High	Inspection results to validate	High
Distribution transformers	Medium	Inspection results to validate	Medium
Protection systems	Medium	Site inspections to validate	Medium

All data was found to be suitable for our review, except for Underground Cables – Distribution, where attribute data is held in paper drawing records and, hence, not readily accessible and condition data was not available. We note that this is not uncommon across the industry, given that the asset is buried. This is discussed further in section 14.1.

4 NETWORK RISK

The key output of this independent assessment is a prioritised list of risks on the network. To enable this to be done, WSP was required to assess the relative risks of the different assets classes. This section defines what is meant by network risk and then sets out the approach taken for calculating the network risk to enable comparison across fleets and prioritisation. The specific details of the approach taken for each asset class are set out in the individual asset class sections 8 to 17.

It should be noted that the network resilience, or in other words the networks ability to recover from significant events such as earthquakes and severe storms, has been dealt with separately from the asset risk and is detailed in section 5.

4.1 OVERVIEW

Our assessment is required to consider the risk posed by each asset class to identify where Aurora should focus their efforts for mitigating the network risk to ensure network safety and reliability and to minimise the impact of network assets on the environment.

4.1.1 DEFINITION OF RISK

Risk is defined as the probability of an event multiplied by the consequence of that event for each failure mode. This can be written as a formula:

$$Risk = \sum_{All\ failure\ modes} Probability\ of\ failure\ x\ Consequence\ of\ failure$$

Where:

- probability of failure is either a calculated quantitative probability or an assessment of asset condition as a proxy for probability when the data does not enable a quantitative assessment.
- consequence of failure is either the calculated value of the asset failure or the criticality of the asset based on the importance of the asset to network safety or operation.

4.1.2 OUR APPROACH TO RISK ASSESSMENT

All risks assessed in our review are associated with the failure of an asset. Our assessment of the asset risk, according to the consequence of failure and quantified probability of failure, was based on the asset type, our assessment of existing data and the additional data we gathered. We have applied the most appropriate approach to assessing asset risk for each asset class and type of risk. The reasoning for these choices is discussed below. We also outline our approach to any existing operational controls.

PROBABILITY OF FAILURE

For most assets, the probability of failure can be quantified using data from asset failures as well as the data on assets that have been replaced due to assessment as being at the end of their serviceable life (prior to failure). Analysis of the data enables calculation of the probability of failure based on asset attributes and condition information.

Where data is not available to calculate quantified risk, an asset health index has been used as a proxy for probability. The health of the asset is a good indicator of how well it is likely to perform its function. The calculation of the health index has been determined with consideration to the method set out in the EEA Asset Health Indicator guide[1]. The asset health risk approach was used for 1 of the 11 asset classes we reviewed.

[1] Electricity Engineers' Association, Asset Health Indicator (AHI) Guide, Revision 1, January 2016

CONSEQUENCE OF FAILURE

The consequence of failure is a quantitative assessment of the outcome of an asset failure.

In order to establish a prioritised list of asset risks, we have considered the potential impact of each asset failure. This involves assigning the highest consequence that could occur, given the failure mode of the specific asset class, so that it can be allocated an appropriate ranking relative to other assets. This approach provides comparability across asset classes. We note that this approach is different to establishing risk at a network level, as summing individual risks does not allow for the diversity in consequences that may occur when considering multiple asset failures.

WSP has considered three main consequences of asset failure – public safety, reliability (calculated as energy at risk) and environment. The approach taken to assess the consequence of failure of an asset is influenced by the nature of the asset, and whether it is above ground, underground or in a secure compound.

We have used a quantitative approach to assessing the consequences relating to reliability (based on value of lost load) and public safety (based on a safety index). A qualitative approach has been used for consequences relating to environment (based on historical information).

EXISTING RISK MITIGATION CONTROLS

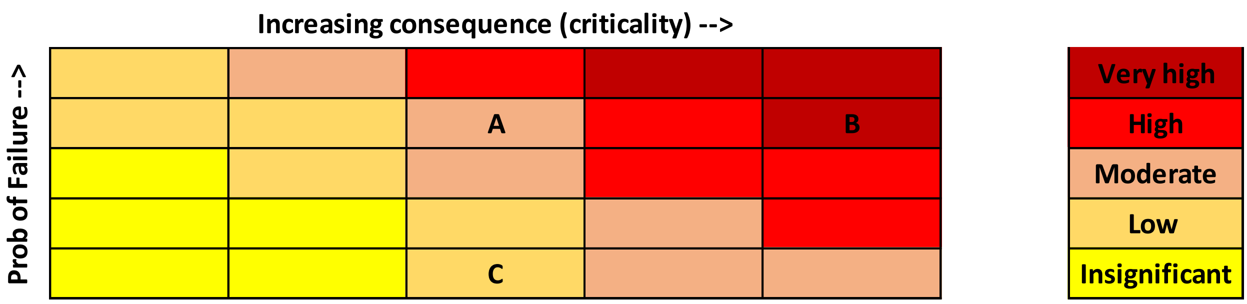
It is important to note we have taken an asset focused approach to assessing the safety risk. This means we have not considered any operational controls that have been, or could be, put in place to mitigate the risk. While this approach may overstate risk in some instances, it enables Aurora to assess whether these can be mitigated or reduced through current or new risk control measures. We have not undertaken a review of the effectiveness or consistency of implementation of operational controls.

4.1.3 VISUALISING RISK

To display the level of risk for different types of assets, both high-volume assets such as poles and low-volume assets such as ZSS transformers across different risk types, we have used a standard form of risk assessment as described in AS/NZS 31000. It provides a simple view of relative scales of risk and it is the approach used by Aurora, hence it can be easily understood and applied in their normal business practices.

Table 4.1shows an example of the risk matrix approach as set out in AS/NZS 31000, with the overall risk ranking based on the probability of asset failure and the consequence/criticality. Five categories are used for both probability of failure and consequence/criticality with the ultimate result being a ranking of risk as depicted by the coloured boxes from insignificant to very high. The values A, B and C are the number of assets with that risk category, i.e. 'A' assets have a moderate risk and 'B' assets have a very high risk. Further detail on how the probability of failure and consequence are mapped to the matrix is provided in sections 4.2.3 and 4.3.4 respectively. These sections describe how the approach to ranking provides a suitable comparison between risk types and asset fleets.

Table 4.1 Aurora's risk matrix



4.1.4 INTERPRETING THE MATRICES

The risk matrices we have developed in our approach are intended to only provide the comparative risk between the different asset classes, and not an absolute risk. The method used to identify risk has been undertaken on a consistent basis across all asset classes so that the outcomes would be comparative and enable Aurora to most effectively manage the network.

As an example, Table 4.1 shows items A, B and C in different risk categories. In interpreting these categories, it should be read:

- that item A has a comparatively higher probability of failure compared to item C, but the same consequence when it fails
- that item B has a comparatively higher consequence when it fails compared to item A, but the same probability of failure.

Item B has a very high risk. Where this is a safety risk, it should not be interpreted that item B will result in serious public injury as there are several events that must align for the risk to materialise. Broadly, the events that must occur include a) the failure of an asset, b) for the failure mode to be one which poses a risk to the public, and c) for a member of the public or staff to be present at the time of failure. To assess each of these events in a deterministic manner requires a number of assumptions to be made, which can result in the assessments not being comparable between asset classes and difficulty in extrapolation across an entire fleet of assets. Further, it generally results in low probabilities with the effect of grouping all assets into the same risk category, which does not enable differentiation between assets for the purpose of prioritisation.

Item B should be interpreted as the failure of this asset has the potential to cause a serious public safety or reliability of supply risk. As each asset with this level of potential could result in a serious consequence, each asset is assigned the same serious consequence. In practice, not all assets will fail in a manner that has the potential to cause the highest consequence and, hence, the asset risk represented by item B cannot be summed with other asset risks to obtain a network wide risk.

Importantly, we have considered Aurora's normal working practices when assessing the consequences but have not considered the operation of safety on the network, or specific safety practices employed by Aurora staff and contractors in response to the known risks.

The approach we have adopted, of using a comparative or relative ranking for the consequence, means that we can provide a prioritised list of asset risks that has reasonable granularity. We can use and rely on the available asset data that we have gathered and / or verified and minimise the assumptions made. All asset classes across both network regions can be treated with the same method of assessment and using the same relative risk scoring approach. This ensures that the results are comparable between the asset classes.

4.2 ASSESSING PROBABILITY OF FAILURE

This section describes the methods used to calculate the probability of failure.

4.2.1 QUANTITATIVE MODELLING APPROACH

The quantitative modelling techniques are summarised below and further details of these techniques are provided in Appendix D.

Weibull survivor curve: The Weibull distribution is commonly used in asset management in the electricity industry for forecasting the replacement needs of assets. It provides a distribution of probability of failure (or Weibull probability) against the asset age. The distribution curve (or chart shape) reflects low failure rates during the early stages of an assets life which then increases as the assets age. The distribution curve is derived based on historical replacement data for a particular asset class or sub asset class where data is available. The two key parameters in describing the Weibull distribution are the characteristic age (also called the scale factor) and the shape factor. The conditional probability is calculated to provide the incremental probability of an asset reaching its end of life from year to year. This enables us to identify the volumes expected to fail and determine network risk at a fleet level based on asset ages.

Advanced techniques: Advanced techniques use statistical and machine learning models, such as linear regression and neural networks, to examine relationships between different asset characteristics to determine the probability of failure of an asset and provide a predicative forecast. It involves assessment of multiple variables (for example, timber strength of poles, age, location) to ultimately determine a relationship from the characteristic to the remaining life of the asset or the degree of degradation. Machine learning techniques require large data sets to establish the algorithm before it can be applied for forecasting.

Pro-rata/statistical allocation of condition based on recent test data: This approach uses a pro-rata allocation based on the known asset condition determined by the inspection process which is then extrapolated across the fleet. The statistical basis identifies the margin of error of the data sample and is used to determine if the data sample provides a reasonably accurate representation of the fleet. It is used where there is accurate and up to date information on a number of assets in a population, or where field testing has been undertaken to gathering new data (rather than validating existing data). It cannot identify the expected risk on an individual asset but can provide an estimate of the percentage of the population expected to be within a condition category.

Where field validation work undertaken by WSP was found to be in general agreement with data captured by Aurora, the data captured by Aurora was used in the probability of failure assessment. In the case that field validation work picked up on inconsistencies of asset information or provided new asset information, then the new information was incorporated into the probability of failure assessment. The approach to incorporating field work into risk assessments is described in the individual asset class sections presented later in this report.

Once calculated, the probability of failure was grouped into five categories as set out in Table 4.2.

4.2.2 QUALITATIVE ASSESSMEMT

The qualitative assessment approach to determining the probability of failure assesses defects and failures that have occurred on the network and takes into account the individual assets age, make and model, and experiences from other businesses with the same or similar assets. As part of the qualitative assessment, the asset health index, as determined by the asset age relative to its expected nominal life, has been considered.

Following detailed assessment of all asset data available to establish patterns in the asset performance and any other information, such as issues with maintenance and industry wide type issues, WSP formed a view about the likely condition of the asset type and determined a probability of failure based on the five categories set out in Table 4.2.

4.2.3 MAPPING PROBABILITY TO THE MATRIX

To ensure comparability with the Aurora risk approach, we have adopted the same rankings as used by Aurora as detailed in its 2018 AMP. Table 4.2 sets out how WSP has mapped a quantitative assessment of the probability of failure to align with the categories set out in Aurora’s matrix.

Table 4.2 WSP Probability of Failure Ranking

RANKING	DESCRIPTION	QUALITATIVE	ASSET HEALTH INDEX	QUANTITATIVE
5	Almost certain	Happened in last year in location	>100% nominal life	40% to 100%
4	Likely	Happened in last year in company	90% to 100% nominal life	10% to 40%
3	Possible	Happened in last year in industry	80% to 90% nominal life	1% to 10%
2	Unlikely	Heard of in industry	50% to 80% nominal life	0.2% to 1%

RANKING	DESCRIPTION	QUALITATIVE	ASSET HEALTH INDEX	QUANTITATIVE
1	Rare	Unheard of in industry	0% to 50% nominal life	0% to 0.2%

4.3 ASSESSING CONSEQUENCE OF FAILURE

The following sections discuss our general approach to assessing the three types of consequence considered – public safety, reliability and environment.

4.3.1 SAFETY

When assessing public safety risk, we have used asset criticality as a relative measure of risk rather than using an absolute measure of risk. The application of this approach for distribution assets and for ZSS assets is set out below.

DISTRIBUTION ASSETS

Assets that are above ground in publicly accessible locations can pose a risk to public safety. The assets that fall into this category include:

- support structures (poles, crossarms, insulators and the top section of poles)
- overhead conductors
- distribution switches and distribution transformers
- other pole and ground mounted assets.

Protection systems are located in zone substations but their impact is on public safety in the distribution network. Therefore, their risk has been modelled based on the same approach as distribution assets.

Sub transmission support structures and overhead conductors are also located in publicly accessible locations and can pose a risk to public safety. Therefore, their risk has been modelled based on the same approach as distribution assets.

Population density

The physical location of the assets is a significant contributor to the criticality of an asset to public safety. Assets that are located in areas with a higher population density will have a higher probability of a person being in close proximity when it fails. Hence, the population density at an asset's location is an appropriate proxy for the criticality of an asset and is a consistent and independent measure across all asset types.

Our assessment considered population density based on population data obtained from the 2013 census. The data provides the usually resident number of people down to the level of residential dwellings. The data is used as a GIS layer that provided a contour map of population density as shown in Figure 4.1. Increases in population due to tourism have not been explicitly taken into account due to a lack of available information, although such increases should mirror local population to some extent. We also acknowledge that some residential growth areas will not be fully reflected in the 2013 data set, however, we consider that those areas are not material in area of the network and are likely to have newer assets if they have been established since 2013 and, therefore, their exclusion from the analysis will not have a material impact on the outcome.

As the population density is used as a criticality factor/index rather than as an absolute measure, use of population density from the 2013 census is sufficient for the purposes of this review to prioritise assets risks.

Calculating the public risk index

The index is based on the area that would be impacted should the asset fail in a high consequence manner. To calculate the risk index, the following steps were taken:

- The density of population in the vicinity of an asset was assigned to the asset based on the asset location and the GIS population density layer.
- The impact area of an asset when it fails was calculated. The area was based on physical attributes such as the height of a pole or evidence from other failures at Aurora or in the electricity industry.
- The population density of the area was multiplied against the impact area to calculate the impact on population density.

The public safety consequence is, therefore:

$$Public\ Safety\ Index = \ Size\ of\ impact\ area \times Population\ density$$

Limitations

This assessment of safety risk is not an absolute measure but intended to be comparative between assets to enable prioritisation between asset fleets. The method is only applicable to distribution assets, i.e. those that are installed outside of zone substations, and protection relays.

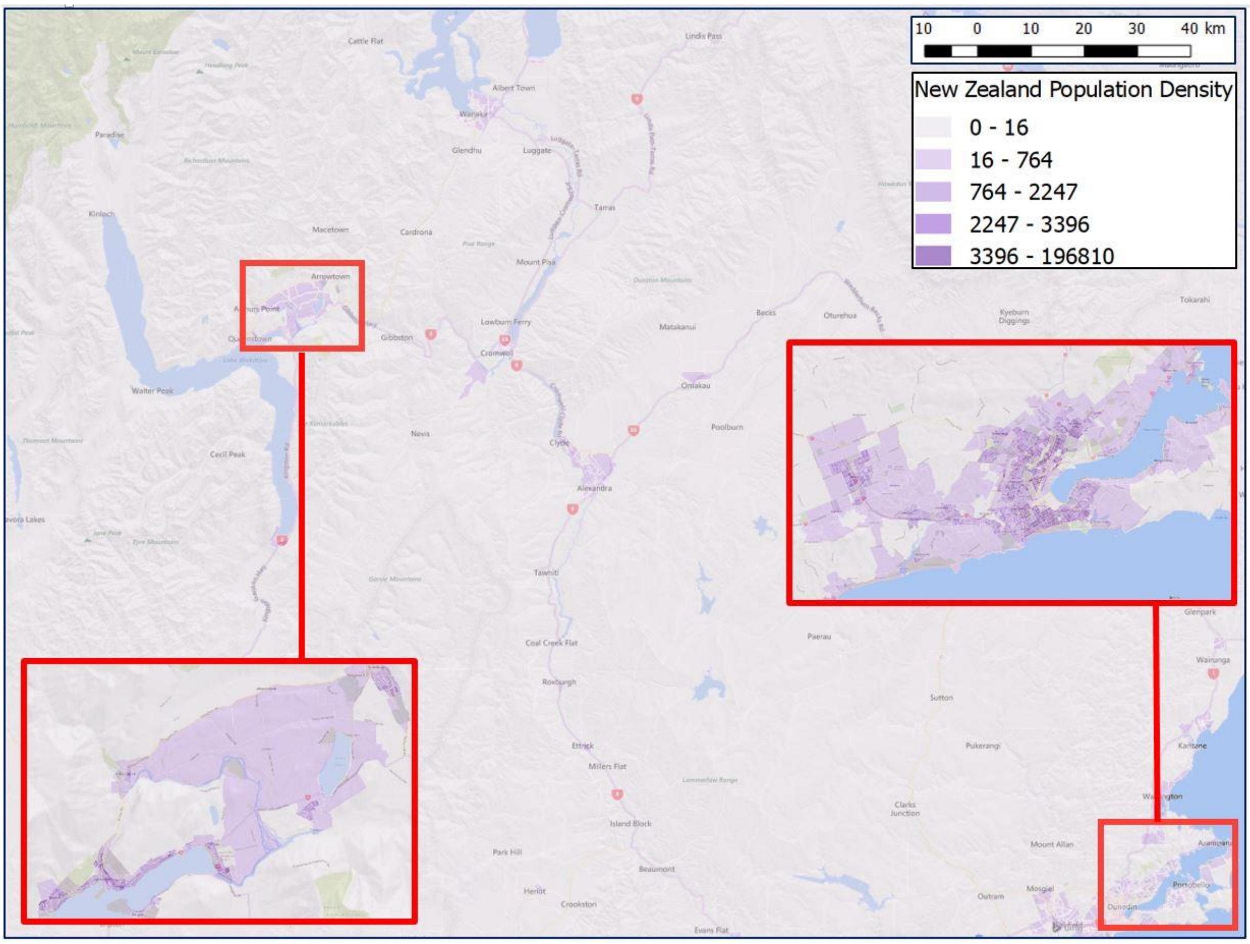


Figure 4.1 Population density derived from the 2013 Census data[2]

[2] Population data sourced from https://koordinates.com/layer/7322-new-zealand-population-density-by-meshblock/

ZONE SUBSTATION ASSETS

Assets that are located within zone substations pose a safety risk to field crews rather than the public. These assets are most likely to fail when being operated so the likelihood of field crew being present at the time of failure is increased, compared to public proximity to assets in the distribution network.

The key assets assessed that fall into this category include:

- zone substation circuit breakers
- zone substation transformers.

For these assets, analysis of the asset type, calculation of parameters such as arc fault boundary, experience and knowledge from recent events in the electricity industry, and engineering judgement is used to assess the criticality.

We note that Aurora implements a number of practices and procedures to safeguard personnel working within a zone substation, however, as discussed in section 4.1.2, our review is of the asset risk. The effectiveness and consistent implementation of the safety process have not been considered or assessed as part of this review. Hence, our assessment does not consider the safety practices in assessing the asset criticality.

4.3.2 RELIABILITY (ENERGY AT RISK)

The risk to network reliability is the loss of supply to consumers. An economic cost of the loss of supply can be calculated and is comparable across asset types, hence it can be used to prioritise network risk. The economic impact of loss of supply can be calculated based on the value customers place on reliability, so energy at risk is then a function of:

- the demand supplied by an asset (the amount of energy that would be interrupted if the asset was to fail)
- the duration of the expected asset outage prior to restoration of supply
- the value of customer reliability (VCR) also called the value of lost load (VoLL), typically expressed as $'000/MWh.

The energy at risk is, therefore:

$$Energy\ at\ risk = Load\ lost \times Value\ of\ consumer\ reliability$$

VALUE OF CONSUMER RELIABILITY

The VCR or VoLL is an economic cost of the amount of electricity that is prevented from being supplied to consumers due to the outage caused by electricity assets.

A number of studies have been undertaken to determine the value consumers place on electricity supply based on stratification by metrics such as load type (e.g. residential, commercial or industrial) and geographic location. WSP has used the VoLL used by Aurora for the assessment as set in Table 4.3. This sets out a different VoLL for the two networks.

As a way of checking the VoLL used, WSP has compared the values used by Aurora against the values published by the Electricity Authority (EA) on the 23 July 2013[3] . From the EA study, the VoLL for Christchurch has been used as the closest equivalent to Dunedin and escalated to 2018 dollars. It is noted that the Aurora VoLL for Dunedin is similar to the average EA VoLL when adjusted to 2018 dollars, and the VoLL applied in Central is similar to the large non-residential VoLL from the EA study which is reflective of the types of customers on that network. This indicates the Aurora VoLL is suitable for use in this review.

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[3] Electricity Authority, Investigation into the Value of Lost Load in New Zealand – Report on methodology and key findings, 23 July 2013

Table 4.3 Value of Lost Load ($/MWh)

CONSUMER TYPE	EA VOLL ($'2013)	EA VOLL ($'2018)	AURORA VOLL CENTRAL ($'2018)	AURORA VOLL DUNEDIN ($'2018)
Residential	$14,818	$15,988	$12,000	$20,000
Small non-residential	$69,761	$75,268	$12,000	$20,000
Medium non-residential	$46,686	$50,372	$12,000	$20,000
Large non-residential	$10,940	$11,804	$12,000	$20,000
Weighted average	**$18,690**	**$20,166**	**$12,000**	**$20,000**

The approach to calculating the energy at risk has been undertaken using one of two methods based on the asset type and the data available for the asset type.

DISTRIBUTION ASSETS

Distribution assets have a lower impact on unserved energy and can typically be replaced in a short period of time. Aurora provided us with unserved energy values by using its GIS to calculate the impact of an asset failure for each distribution asset. The approach found the nearest isolation point upstream of the asset being assessed and calculated the SAIDI impact based on all customers downstream of that isolation point losing supply for a period of four hours to represent an indicative outage duration. This calculated a SAIDI value that reflected the number of customers and duration of time they would be affected. The assumption of four hours for each outage is appropriate based on their historical performance and suitable when considering a fleet wide analysis.

WSP leveraged this analysis to convert the SAIDI value back to customer minutes off supply, then using the average demand per customer calculated the unserved energy. This was then multiplied by the VoLL to derive an economic cost of each asset failing.

ZONE SUBSTATIONS

Energy at risk is assessed at a zone substation level using demand data available from SCADA, transfer capacity available at each individual zone substation, redundancy and nameplate capacity. The key information sources and how they are used include:

- substation demand: extracted from SCADA and used to develop a load duration curve (LDC) for the substation. The LDC is the arrangement of the hourly demand data from highest to lowest to show the proportion of time throughout the year that a specific level of demand is experienced
- asset capacities: extracted from asset databases these include the nameplate rating, and redundancies (i.e. N-1 capacity if relevant)
- transfer capacity: based on engineering assessment of the substation and feeder configuration, this specifies the amount of load that can be supplied from an adjacent substation
- time to restore supply: this was based on engineering judgement and Aurora's plans for specific substations
- forecast load growth: growth forecasts provided by Aurora.

The amount of energy that would not be supplied in the event of an outage is calculated using the LDC and the N, N-1 or N-2 capacity of the substation as appropriate, allowing for the transfer capacity. The energy multiplied by the VoLL to calculate an economic cost of the outage.

SUB TRANSMISSION ASSETS

Energy at risk for sub transmission assets is based on the demand at the relevant substation including allowance for load transfers, and uses the expected duration for restoration of the sub transmission supply. The analysis considered the difference in restoration times based on the asset type of overhead conductor or underground cable, and the N or N-1 redundancy of the sub transmission circuit.

4.3.3 ENVIRONMENT

The Resource Management Act 1991 (RMA) sets out the requirements Aurora must meet with respect to environmental management. The RMA also sets out penalties for failure to comply or meet the requirements The Penalties are separated into three grades of severity and infringement notices. These are described below:[4]

- Grade 1 offences carry a maximum penalty for a person of imprisonment for up to 2 years or a fine up to $300,000. Entities are subject to a fine of up to $600,000 and there is provision for an additional penalty of up to $10,000 for every day during which the offence continues. These offences relate to activities that make use of land or undertake activities on land without consent or in contravention of a district plan
- Grade 2 offences carry a maximum penalty of $10,000 and, if the offence is a continuing one, a further fine up to $1,000 for every day during which the offence continues. These offences relate to contravention of an order made by the Environmental Court, particularly regarding protection of sensitive information and noise
- Grade 3 offences carry a maximum penalty of $1500. These offences related to wilful obstruction of people exercising powers under the Act or contravention of a summons or an order to provide information
- As an alternative to criminal proceedings a Council may serve an infringement notice where an infringement offence has been committed. The person culpable will required to pay an infringement fee of up to $1000.

CALCULATION OF ENVIRONMENTAL RISK

Historical data on environmental incidents is used to assess the risk posed by each asset class. In addition, the type of asset and potential to cause an incident even if not observed historically, is considered. This includes, for example, consideration of oil containing assets, their locations and mitigating designs, as well as equipment containing SF6 gas.

4.3.4 MAPPING CONSEQUENCE TO THE MATRIX

To ensure comparability with the Aurora risk approach, we have adopted rankings for the economic consequence that align with Aurora's approach as detailed in its 2018 AMP. Table 4.4sets out how WSP has mapped the assessment of the criticality to align with the economic consequence.

Table 4.4 WSP Consequence of Failure Ranking

CONSEQUENCE / CRITICALITY RANKING	SAFETY INDEX (ZONE SUBSTATION ASSETS)	SAFETY INDEX (DISTRIBUTION, SUBTRANSMISSION AND PROTECTION ASSETS)	ECONOMIC CONSEQUENCE (ENERGY AT RISK, ENVIRONMENT)
5	Fatality of more than 3 workers	N/A	>$50m
4	Fatality of between 1 to 3 workers	Fatality of between 1 to 3 people	$10m to $50m
3	Serious injuries	Serious injuries	$2m to $10m

4 Information regarding environmental penalties was provided by Aurora.

CONSEQUENCE / CRITICALITY RANKING	SAFETY INDEX (ZONE SUBSTATION ASSETS)	SAFETY INDEX (DISTRIBUTION, SUBTRANSMISSION AND PROTECTION ASSETS)	ECONOMIC CONSEQUENCE (ENERGY AT RISK, ENVIRONMENT)
2	Minor injury	Minor injury	$150k to $2m
1	No impact	No impact	≤$150k

5 NETWORK RESILIENCE

This section considers network resilience with specific regard to the unique location of Aurora's network and lessons learnt from recent high impact events.

5.1 DEFINITION OF NETWORK RESILIENCE

Network resilience refers to the ability of the network to withstand or recover from high impact events. The performance of each asset in the supply chain is important to achieving good performance, but it is the way that the supply chain as a whole reacts to events that determines resilience. Hence, in this report, the emphasis of resilience is placed on the impact on the system as a whole rather than on individual components.

When discussing resilience, the events referred to are very low frequency but with very high impact and, typically, include events such as earthquakes, floods and other natural hazards. These events are often referred to by time periods (e.g. a 1 in 100-year flood, or earthquakes expected once every 1000 years) rather than the number of events per day or per year.

Common failures due to asset condition, vegetation or localised events (i.e. storms) that only impact a small number of assets or group of customers are discussed under network reliability in section 7 at the network level and in the specific asset sections for each asset class presented later in this report, as required.

5.2 RESILIENCE RISK MAPS

The Dunedin and Central networks are located in inherently risky regions with respect to natural hazards. Due to the terrain, proximity to the coast and being in seismically active locations, the resilience of the Dunedin and Central Otago networks needs to be considered with regard to a number of different risk factors. The main natural hazards based on the historical data include:

- Earthquake fault lines
- Tsunami affected areas
- Seismic liquefaction potential
- Landslides
- Flood areas.

Additionally, hoar frost and ice occur frequently in the inland regions and can occasionally impact the network to a significant degree.

Our approach to assessment of resilience is based on a GIS view of the assets and the natural hazards to which they are subject. These hazards are shown in Figure 5.1 with the two largest population centres, Dunedin and Queenstown, shown as inserts to provide more detail.

Figure 5.2 shows a close up of the Dunedin city area to provide additional detail on the sub transmission cables that are located in the area and the natural hazards. The figures highlight the number of assets that are located in each risk area and the number of different risks that exist in the Dunedin and Central Otago regions[5]. Dunedin supplies 56.5% of

[5] The data used for the GIS risk layers was sourced from Otago Regional Council https://www.orc.govt.nz/managing-our-environment/maps-and-data.

customers on the network and 38.6% of all customers are located in the Dunedin city area. Detailed views of maps are provided in Appendix C.

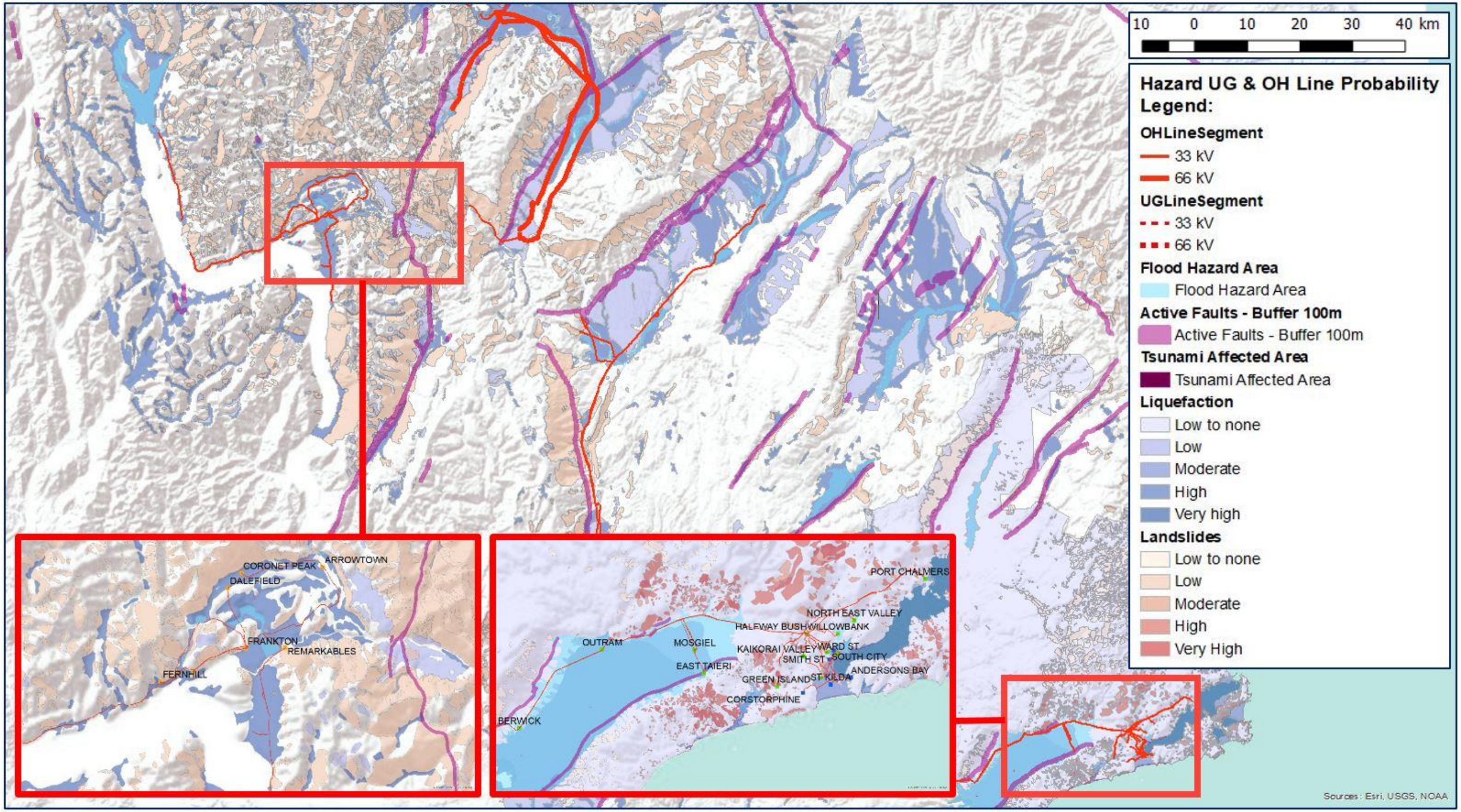

Figure 5.1 Overview of natural hazards in Aurora's network areas

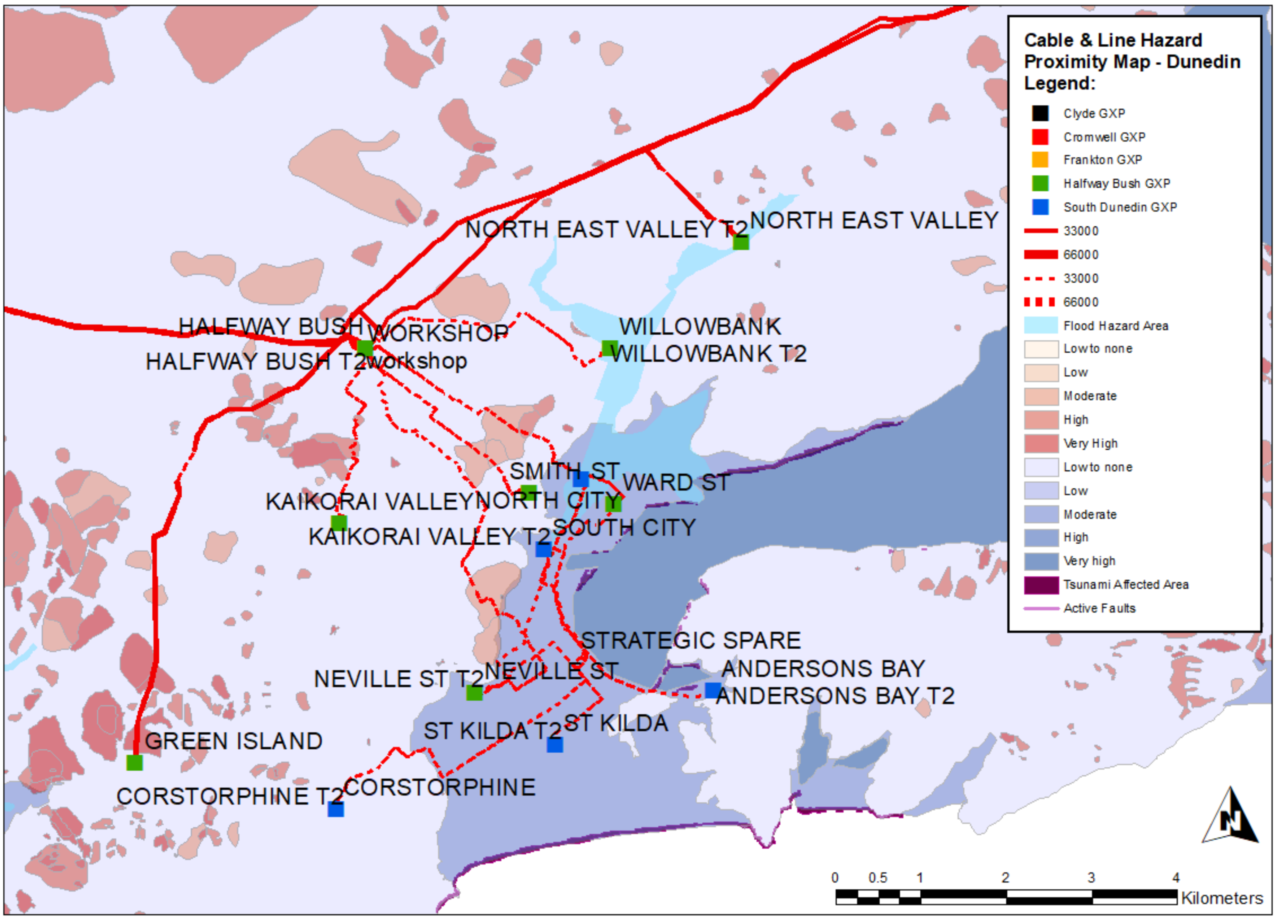

Figure 5.2 Dunedin network region hazard map

To demonstrate the significance of these hazards, a summary of major events has been provided in Table 5.1 and Table 5.2. Table 5.1 shows there have been 43 significant natural events in New Zealand in the past 155 years with 12 affecting the South Island and in the proximity of the Otago region. Table 5.2 shows the annual average number and frequency of earthquakes in New Zealand.

Table 5.1 Number of natural hazard events in New Zealand since 1843 (excluding earthquakes)

NATURAL HAZARD	ALL NEW ZEALAND	SOUTH ISLAND
Weather	13	2
Landslide	9	4
Flooding	8	1
Tsunami	8	4
Volcanic	3	0
Wildfire	2	1
Total	43	12

Source: Wikipedia https://en.wikipedia.org/wiki/List_of_natural_disasters_in_New_Zealand

Table 5.2 Earthquake frequency in New Zealand

EARTHQUAKES	ANNUAL AVERAGE	FREQUENCY
4.0 – 4.9	352	1 per day
5.0 – 5.9	27.3	2 per month
6.0 – 6.9	1.6	3 per 2 years
7.0 – 7.9	0.3	1 per 4 years
8.0 or over	0	1 per century

Source: https://www.geonet.org.nz/about/earthquake/statistics

Of the hazards considered, Earthquakes, Landslide and Tsunami represent the greatest hazards. Of these, tsunamis and landslides occur infrequently and have caused only minor damage in the Aurora network area. For example, the 9.5 Richter scale Chilean earthquake of 1960 resulted in a tsunami of 2.7 metres above the tide level of the time at the Port of Lyttelton (near Christchurch) in the South Island, damaging boats and electrical gear. A hotel and several houses were flooded, and 200 sheep drowned.[6] To achieve resilience, key network assets and critical spares should not be located in tsunami affected areas, or where landslides are possible.

Conversely, earthquakes occur frequently, with damaging earthquakes every 4 years on average. Network resilience will be impacted by assets close to fault lines and the susceptibility of key assets, such as substations, to damage from earth movement and vibration.

5.3 RECENT EVENTS

To further consider the resilience on the Aurora network, we have done some studies into recent major events that had impacts on electricity network infrastructure. The purpose of this study is to understand the impact on the network in terms of asset failures, costs, reliability and to consider the lessons learnt and any potential mitigating actions that could be recommended as a result of these events. The events we have looked at relate to the specific risks identified in the Aurora network region – specifically earthquakes / liquefaction.

5.3.1 CHRISTCHURCH EARTHQUAKES 2010 AND 2011

The Orion network in Christchurch was impacted by earthquake events in 2010 and 2011 – the main event being in September 2010 (7.1 magnitude), followed by an aftershock in February 2011 (6.3 magnitude). The aftershock had the more significant impact on the Orion network, taking 10 days to restore electricity to 90% of customers, with direct costs of over $40m and loss of 630 million customer minutes. Some of the key findings relevant to Aurora from post-earthquake studies into the Christchurch earthquakes are described below:

- Much of the damage was a result of a result of liquefaction and lateral spreading around watercourses rather than peak ground accelerations[7]. Liquefaction occurs predominantly where geologically young soil (<10,000 years old), consist of loose sediments that are fine grained and non-cohesive (coarse silts and fine sands) and are saturated (below the water table). Areas in the Aurora network that are prone to liquefaction are shown in Section 5.2.

6 https://teara.govt.nz/en/tsunamis/page-3

7 K. Group, "Resilience Lessons: Orion's 2010 and 2011 Earthquake Experience, Independent Report," September 2011.

- Damage through liquefaction included loss of one zone substation (out of 51), one primary substation (out of 300), 50% of 66kV cables and 10% of 11kV cables. In the majority of cases, cable failures were for older cables (40-50 years).
- Breaks in cables included failure of couplings in tension, failure of cables in compression and damage resulting from failure of concrete slabs used to support cables[8]. It was found that ducted cables survived these conditions better than exposed cables, with the duct providing some level of protection, so while the duct itself was damaged the cable remained undamaged. Installation and joining faults dominated buried electrical cables, some of which could be a result of poor insulation practices.
- In the 11kV system modern cables with PE sheathing had lower break rates than older cables with PILC sheathing. This indicates that in the long term there will be benefits from replacing older cables with newer cable types which are more resilient.

5.3.2 SNOW FALLS SEPTEMBER 2018

Heavy snow falls in the area of Queenstown caused damage to Aurora's overhead lines resulting in electricity outages in Arrowtown, Frankton, Dalefield, Queenstown and Glenorchy. According to the Otago Daily News, it took days to restore power to many of the properties as line crews faced treacherous off-road conditions. Early indications are most related to trees falling on overhead lines. Aurora has an active programme of vegetation management, but it is thought that most of the trees that caused disruptions were outside of the regulated cutting zone.

This incident raises issues about Aurora's lack of authority to manage trees that present risks to a resilient network. It is also evident that aging assets are likely to fail during extreme natural events.

5.4 RESILIENCE OF HEAD OFFICE AND CONTROL CENTRES FUNCTIONS

The Aurora head office is located in Dunedin with the main control room located in the same building. The control room has primary responsibility for control of the Dunedin network. A second control room is located in Cromwell which has the primary responsibility of control of the Central network.

There is a 'one network' project underway that has involved upgrading the SCADA and control systems and software to enable each control room to also provide back up control of the other network. The new system is expected to be commissioned at the end of October 2018.[9]

Table 5.3 shows a summary of risks for each location. It highlights that Cromwell is in an earthquake prone area and Dunedin is subject to earthquakes and liquefaction. The implications are:

- An earthquake affecting the Dunedin area could result in liquefaction of the ground that could make the Head Office and main Dunedin control room inaccessible. This would:
  - impact the ability to manage the network and coordinate network restoration
  - impact control of the network to manage the network restoration process and ensure public safety
  - potentially cause the loss of some asset or network information (note that electronic data is backed up on servers located in Wellington).

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[8] Opus, "Technical Note 05 - Response of Buried Assets other than Water Pipelines (Part of Underground Utilities - Seismic Assessment and Design Guidelines)," November 2016.

[9] Aurora advise that the new system has now been commissioned.

- An earthquake affecting the Cromwell control room would impact the ability to control the network to ensure public safety and to enable restoration works to be undertaken. We note that the control room is located in a valley that may have restricted access following an earthquake event, impacting staff access.

Table 5.3 Summary of risks for control rooms and head office

ASSET	FLOOD	LIQUIFECTION	EARTHQUAKE	LANDSLIDE	TSUNAMI
Dunedin (Head office)		Moderate			
Cromwell		Low	<2km		

A very small possibility exists that ground liquefaction could impact both control centres, but it is likely that such an event would require the entire area to be evacuated and, hence, is not an unreasonable risk to take.

5.5 RESILIENCE OF KEY ASSETS

Key assets are those that form the upstream portions of the supply chain and include the sub transmission network and zone substations. Other assets distribute electricity and, hence, are located to suit customers' needs rather than to avoid the risk of damage during an extreme event.

5.5.1 GRID EXIT POINTS

There are five supply points from Transpower's transmission assets to Aurora, called Grid Exit Points (GXPs), and a number of small hydropower stations in the Central network. Each of the GXPs supply a number of substations and form three separate network islands in Central and two in Dunedin. There is no interconnection between the substations from the islands in Central with only limited transfer capacity available at the 6.6kV distribution voltage level in Dunedin. Permission is required from Transpower for each tie made between GXPs. Once the new Carisbrooke zone substation is commissioned, there will be one sub transmission inter tie between GXPs available in Dunedin.

The network configuration means that there is no way to quickly recover from the loss of a GXP through network switching. As a result, the loss of any GXP will result in loss of the set of substations supplied by it. Dunedin Control Room has prepared and checked contingency switching for offloading zone substations for the Dunedin city area. We note that significant new infrastructure would be required to create interconnections between islands, and even then, the interconnections would be subject to the same natural hazards.

The future Carisbrook tie could enable a degree of mitigation of this risk. However, as shown by the risk areas in the Dunedin map, the South Dunedin GXP, downstream substations and consumers are all located in the same flood and liquefaction risk zone. Hence, a major event is likely to impact all assets and consumers.

5.5.2 SUB TRANSMISSION LINES

Resilience of the sub transmission lines has been assessed based on GIS layers for a number of natural hazards. The GIS results show that the most severe hazards are from liquefaction. This is also a finding from the review of the Christchurch earthquakes. Some sub transmission lines cross fault lines and are located in flood prone areas as this is unavoidable when connecting zone substations to GXPs. We generally found that overhead lines were constructed to minimise the volume of assets installed rather than to avoid fault lines.

5.5.3 SUB TRANSMISSION CABLES

Resilience of the sub transmission cables has been assessed based on GIS layers for a number of natural hazards. The GIS results show that the most severe hazards are for cables in Dunedin that are exposed to liquefaction, flooding and earthquakes. A finding from the Christchurch earthquakes was that liquefaction had the greatest impact with respect to damaging cables. Conduits were found to provide the best protection to all cables and XLPE was found to have a better rate of survival compared to PILC.

The underground network supplying Dunedin is all located on a moderate to high liquefaction risk area. This presents a common mode of failure across all the sub transmission cables. Wide spread damage to these cables would have a significant impact on the network and would take time to replace and restore power.

5.5.4 ZONE SUBSTATIONS

Resilience of the zone substations has been assessed based on GIS layers for a number of natural hazards. Table 5.4 shows an overview of the risks posed to each of the zone substations, while the customer numbers and maximum demand columns provide an indication of the impact that would be caused by an outage.

This analysis has not considered accessibility issues for each of the substations.

Table 5.4 Summary of risks by zone substation

Asset	# CUST	MAX DEMAND (MVA)	FLOOD	LIQUEFACTION	EARTHQUAKE	LANDSLIDE
Alexandra	3,989	11.1	<500m	High		
Andersons Bay	4,458	15		Moderate		
Arrowtown	2,671	8.5				<1km
Berwick	403	1.4	YES	Moderate	<5km	
Camp Hill	1,327	5.3	<100m	High	<5km	
Cardrona	168	4.1	<100m	High	<5km	<500m
Clyde-Earnscleugh	1,274	3.8	<500m	High	<5km	
Commonage	2,810	12.2				<500m
Coronet Peak	16	5.3		High		<500m
Corstorphine	3,911	12.8		Low to none		<500m
Cromwell	4,266	11.2		Low	<5km	
Dalefield	347	2.4				
Earnscleugh	na	na	<500m	High	<5km	
East Taieri	5,072	16	YES	Moderate	<200m	<1km
Ettrick	453	1.9	<500m	High	<5km	
Fernhill	1,634	6.7		High		<300m
Frankton	3,952	14.6		High		<500m
Green Island	3,834	13.3		Low to none	<5km	<200m
Halfway Bush	3,990	14.5		Low to none		<500m
Kaikorai Valley	2,561	10.2		Low to none		<500m
Lauder Flat	198	0.7	<500m	High		
Lindis Crossing	201	5.9		High	<5km	
Mosgiel	1,674	6.9	YES	Moderate	<5km	

Asset	# CUST	MAX DEMAND (MVA)	FLOOD	LIQUEFACTION	EARTHQUAKE	LANDSLIDE
Neville St	2,933	11.5		Moderate		<500m
North City	585	18.2	YES	Moderate		<1km
North East Valley	3,322	10.8	YES	Low to none		<500m
Omakau	662	2.8	YES	High		
Outram	1,030	2.8	YES	Moderate	<5km	
Port Chalmers	2,752	6.5		Low to none		<300m
Queensberry	425	2.8	<100m	High	<600m	<1km
Queenstown	2,437	14	<500m	High		<300m
Remarkables	1	2.4	<500m			<200m
Roxburgh	848	1.8	<100m		<5km	<300m
Smith St	1,466	14	<500m	Low to none		<200m
South City	654	15.3	<500m	Moderate		<500m
St Kilda	3,373	14.8		Moderate		
Wanaka	6,880	19.8		High	<5km	<1km
Ward St	1,143	10.7	<500m	Moderate		<1km
Willowbank	1,886	12.6	YES	Low to none		<300m

The table shows that Flood, Liquefaction and Earthquake are the greatest risks to the zone substations:

- For flood risk, we found that those zone substations that are in flood prone areas were located close to customers and, hence, no reasonable alternative location was possible. We note that no precautions against possible flood are evident at these substations.
- For liquefaction, we note that no additional precautions other than those required by building codes have been undertaken.
- For Earthquake risk, we note that only two zone substations are affected (close to fault lines) and that these are located close to customers and, hence, no reasonable alternative location was possible.

Severe damage to a substation could result in an extended outage. The typical lead time for a power transformer is around 9 months and the typical time from design to commissioning is close to 2 years. Although the process could be expedited, the common risks amongst the zone situations means there is likely to be multiple zone substations damaged and, therefore, there could be further constraints due to asset lead time or labour resources.

Other events can also occur, such as hoar frost where sustained low temperatures can cause the build-up of ice on conductors, and the weight of ice can exceed the capacity of the conductor to support the additional strain resulting in broken poles and/or conductors. Typically, such events have a low impact on safety and reliability when compared to other events and, as such, have not been considered in our risk assessments.

5.6 KEY FINDINGS

WSP found that most key assets have been installed clear of earthquake fault lines, flood zones, landslide risk zones and tsunamis risk areas. However, it is not possible to avoid these altogether as customers occupy these areas and require electricity.

A review of the most recent earthquakes in Christchurch found that liquefaction of the ground had the biggest impact to network supply as it severely damaged underground cables. Overhead lines are a lower risk as damage can be identified and repaired more rapidly. Dunedin is in an area that has a moderate to high liquefaction risk, and eight of the nineteen zone substations are supplied by radial underground sub transmission cables. Although these are dual circuits, which provides redundancy, they are located in the same trench and, hence, can be expected to be impacted equally by a major event. The cable type, ages, deteriorated condition, and installation methods means that these are the highest risk with respect to network resilience.

Maintaining network operations and control is also key to maintaining a resilient network. Aurora currently has two control centres which normally operate separately and provide limited back up for the other. This poses a risk that a major event disabling one will significantly impact operational control of part of the network. This risk is being mitigated through Aurora’s ‘one network’ initiative which involved upgrading the SCADA system to enable each control room to control the entire network.

WSP concludes that the resilience of the network could be improved by replacing the oil and gas insulated underground cables in the Dunedin area with XLPE type as these are less likely to suffer damage due to liquefaction of the ground following an earthquake.

6 NETWORK SECURITY

Security of supply refers to the electricity network topology providing appropriate capabilities, such as capacity, redundancy and switching capability, to maintain normal supply to consumers.

This section discusses:

- how the network topology is likely to impact the ability of the network to respond to asset failures
- the impact of the network topology on planned works
- identified capacity constraints
- assessment of how well Aurora is meeting their security of supply criteria guidelines.

This section is not a full review of the security of supply arrangements implemented by Aurora. It is only intended to inform how the network topology mitigates, or otherwise, the impact of asset failure and how that affects the consequence of asset failure and, hence, the risk posed by each asset class.

6.1 SECURITY OF SUPPLY REQUIREMENTS

Table 6.1 sets out the Aurora's security of supply requirements for its urban and rural networks.[10] We note that most electricity network businesses have similar requirements and that those adopted by Aurora do not appear inappropriate for the Aurora network.

Table 6.1 Security of supply requirements

CLASS OF SUPPLY	GROUP PEAK DEMAND (GPD) IN MVA	MINIMUM DEMAND TO BE MET AFTER:		
		FIRST OUTAGE	SECOND OUTAGE	BUS-BAR FAULT
Urban				
U1	0 to 1	Initially – nil 100% GPD within 4 hrs	Initially – nil 100% GPD within 4 hrs	NA
U2	1 to 3 (6.6kVA), or 1 to 5 (11kVA)	Initially – nil 100% GPD within switching time	Initially – nil 100% GPD within 4 hrs	NA
U3	3 or 5 up to10	Initially – nil 100% GPD within switching time	Initially – nil 100% GPD within 4 hrs	Initially – nil 100% GPD within switching time
U4	Over 10	Defined firm capacity	Initially – nil 100% GPD within 4 hrs	Initially – nil 100% GPD within switching time
Rural				
R1	All	Initially – nil 100% GPD within 6 hours		
R2	0 to 3 (6.6kVA), or 0 to 5 (11kVA)	Initially – nil 100% GPD within 6 hours		
R3	0 to 5MVA	Initially – nil 100% GPD within 6 hours		

10 Aurora is proposing and seeking feedback on a new Security of Supply standard in the 2018 Asset Management Pan. The new standard was not available in sufficient time for this report. Note that a changed standard may impact our findings.

6.2 NETWORK TOPOLOGY

This section considers the sub transmission and distribution network topologies and how these are likely to impact security of supply.

6.2.1 SUB TRANSMISSION

SUB TRANSMISSION NETWORK

Aurora operates sub transmission at 33kV and 66kV. The two network areas contain 5 GXPs that supply a total of 39 Zone Substations, as shown in Table 6.2.

Although there are five GXPs within the two networks, there is currently no ability to transfer a substation to an alternate GXP via network switching. In Central, this is a result of the distance and geography between the zone substations and GXPs. In Dunedin, the GXPs and zone substations are in close proximity but there is no switching arrangement to enable network reconfiguration. This arrangement is not uncommon in electricity business as the technical arrangements required to allow multiple supplies can be complex and costly. Hence, the five GXPs are essentially five islanded networks at sub transmission level, but at distribution level load transfers are possible in the Dunedin area.

Table 6.2 GXP supply points

NETWORK	GXP	TOTAL
Central	Clyde GXP	7
	Cromwell GXP	6
	Frankton GXP	8
Dunedin	Halfway Bush GXP	13
	South Dunedin GXP	5
Total		**39**

The sub transmission network in Dunedin is typically underground cable in the urban areas and overhead lines in the rural areas. The sub transmission network in Central is typically overhead lines. This reflects the population density and geography of the network areas.

The following items that impact on network security were identified:

- Most of the network is arranged in a dual radial line configuration to each substation. However, some of the smaller zone substations are supplied by only a single radial sub transmission line, although all have some load transfer capability via interconnections with adjacent feeders. These include:
  - Omakau and Lauder Flat ZSS
  - Ettrick ZSS
  - Camp Hill ZSS
  - Cardrona ZSS
  - Coronet Peak is connected by an underground cable spur line
  - Dalefield ZSS is connected to the sub transmission line with a fuse.

The following items have been identified that impact the security of supply:

- Berwick, Outram, Mosgiel and East Taieri are all connected to the A Line, B Line and C Line feeders that run between Waipori and Halfway Bush GXP. There appears to be sufficient redundancy provided, given:
  - Mosgiel ZSS has three connections from the three lines. Two of the overhead lines then run parallel to each other with a separation of approximately 10m between the circuits for the majority of the route. This could provide a common point of failure for the two circuits which reduces the security of both Mosgiel and East Taieri. The third line is separated and is routed down an adjacent road
  - East Taieri ZSS is connected via cable from Mosgiel ZSS, hence it is reliant on reliability/security of Mosgiel ZSS and is not directly connected radially to Halfway Bush GXP
  - Berwick ZSS and Outram ZSS have connections to all three lines.

  We note that the A, B and C Lines are in poor condition, but Aurora has plans in place for remediation. Implications to the protection scheme due to the complex feeder arrangement are discussed in section 17.
- The new Carisbrook ZSS will be supplied from South Dunedin GXP, whereas Neville St ZSS which it is replacing, was supplied from Halfway Bush GXP. The existing interconnector from Ward Street (which is fed from Halfway Bush GXP) will be reconnected to the new Carisbrooke ZSS. This arrangement will improve the ability of the network to transfer load should one of the GXPs experience an outage.
- North East Valley is a HV spur line comprised of sections of overhead line and underground cable connected to the Port Chalmers feeder originating from Halfway Bush GXP. The connection point is controlled by IRW-955 manual switches. Hence, a fault at either North East Valley or Port Chalmers, upstream from the 33kV ZSS circuit breakers, will reduce the security of supply to the other substation until manual switching can be undertaken.
- Sub transmission cable faults are difficult to locate and take time to repair or replace. Therefore, the condition of these cables is important for ensuring that they provide the expected level of redundancy and each cable is capable of supplying the full capacity of all connected zone substations. Sub transmission cable condition is discussed in section 13. Additionally, some underground cables forming dual circuits are installed in the same trench and pose a risk of suffering damage from a common event, such as excavation.
- Ettrick ZSS is supplied by a single radial line from Roxburgh ZSS and Omakau ZSS and Lauder Flat ZSS are supplied by a single radial line from Alexandra ZSS.
- Both circuits of the Wanaka to Queensberry line are located in relatively close proximity for a short section along Wanaka Luggate Hwy.
- The transfer capacities within the Dunedin area (Neville St (will become Carisbrook), Smith St, Mosgiel, Kaikorai Valley and Ward St) are, or greater than, the demand on those substations. As a result, even though some have high probabilities of failure, such as Neville St, there is no impact if there is a transformer failure as the demand can be completely transferred away via the distribution network.
- Aurora has plans to restore supply to a single transformer ZSS in the case of a transformer failure by a mobile transformer that can be used for this purpose (where it is technically compatible and if not already deployed). We note that Aurora also has a spare 5 MVA transformer on order and the transformers from currently planned substation rebuilds will be retained as spares, facilitating the restoration of supply following an outage.

The sub transmission network would relate to outages that would be classed as U3, U4, R2 and R3 based on Table 6.1. In general, the topology of the network at sub transmission level should provide sufficient redundancy to enable Aurora to meet the security requirements. Ettrick, Omakau and Lauder Flat are radially supplied by a single sub transmission line, however, these are small rural zone substations with peak loads of 1.9 MVA, 2.8 MVA and 0.7 MVA respectively supplied by 33kV overhead lines so it is likely supply could be restored within the required 6 hour period.

EMBEDDED GENERATION

There is approximately 128 MVA of embedded generation connected to the Aurora network, 98% of which is from hydropower stations. Domestic solar PV makes up only 1.2% of embedded generation.

A significant proportion of this is connected to the Clyde GXP network, supplying the demand at those zone substations and injecting excess generation back into the transmission network.

Most of the generation is connected at 33kV. Although embedded generation is connected to the sub transmission network, it does not provide security to the network because when a sub transmission line outage occurs, the generation must be disconnected.

6.2.2 DISTRIBUTION

Security of supply at the distribution level is driven by the redundancy of transformers at the zone substations and the degree at which the distribution feeders are interconnected and able to switch to transfer load to other feeders. These attributes are discussed in the following sections.

ZONE SUBSTATIONS

Review of the current load data and forecast growth rates indicate there are no capacity constraints currently on the network that are resulting in demand not being supplied. All Aurora owned zone substation assets currently have sufficient capacity to supply all connected load in normal circumstances and high growth areas have sufficient capacity to meet future demand (based on current forecasts). The only substation where there is an approaching capacity constraint is Remarkables: however, that is a customer connection point and is dependent on the customer requesting more capacity.

Table 6.3 shows the number of zone substations that have N-1 redundancy. All urban substations have two transformers so that an outage on one transformer should not cause a long interruption to supply.

Almost all rural substations only have one transformer. This appears appropriate when considering the relatively small number of customers supplied from these substations. Often the decision to install a sub transmission line and substation is made for technical reasons (voltage drop and transfer capability) rather than for reasons of reliability of supply and, hence, providing redundancy is not economic. We did not find any single transformer substations that should have been provided with an N-1 redundancy (see energy at risk assessment in section 15.5). We note that Queensberry ZSS and Lindis Crossing ZSS are located close together and Aurora considers them as one 2 transformer substation in terms of demand security.

Table 6.3 Substation redundancy

NETWORK	NETWORK TYPE	N-1	N	TOTAL
Central	RURAL	5	13	18
Central	URBAN	3	-	3
Dunedin	RURAL	-	2	2
Dunedin	URBAN	16	-	16
Total		**24**	**15**	**39**

We note, however, the peak demand at a number of zone substations with two transformers has exceeded or is approaching the substation’s firm capacity (N-1 capacity plus load transfer capacity). These substations are shown in Table 6.4. Only two have exceeded their firm capacity rating: Arrowtown ZSS and Cromwell ZSS. Peak demand at the zone substations not listed is at 60% or less of firm capacity.

Table 6.4 Zone substations approaching N-1 capacity

ZONE SUBSTATION	PEAK DEMAND AS PERCENTAGE OF FIRM CAPACITY
Arrowtown	155%
Cromwell	140%
Frankton	81%
Wanaka	80%
Alexandra	79%
Anderson's Bay	71%

The zone substation asset that limits the capacity of the substation is shown in Table 6.5. In the majority of cases, it is the transformer that is limiting capacity.

Table 6.5 Zone substation constraints

CONSTRAINT	NUMBER OF ZONE SUBSTATIONS
Protection: 85% of overcurrent pickup	4
Incomer CB rating	4
Transformer capacity	25
Transformer/85% Overcurrent pickup	6
Total	**39**

Note: Riverbank ZSS and Carisbrook ZSS are not yet commissioned so are excluded from the list above

In summary, the network appears to be designed appropriately to meet the type and magnitude of demand at a zone substation level. Arrowtown and Cromwell has exceeded their firm capacity, however we note that Aurora has work underway to address these in 2018 and 2019 respectively.

The security of supply requirement for rural areas set a single requirement for all contingencies, which is to restore supply within 6 hours following an outage. Although Aurora has a mobile substation to respond to transformer outages, their ability to restore supply within the required timeframe may be limited should an outage occur while the mobile substation is deployed elsewhere.

DISTRIBUTION FEEDERS

Designing the network with flexibility to transfer load onto adjacent feeders is important for managing supply and facilitating the maintenance and inspection of distribution assets.

In the Aurora network, most distribution feeders in urban areas have good levels of interconnection with adjacent feeders. Some parts of urban feeders are radial with no interconnection and rural feeders are predominately radial with no or limited interconnections to other feeders. This means that there is no or limited possibility of switching to improve the speed of resupply of customers. These arrangements do not appear different to most other electrical line utility businesses.

Specific findings for the main distribution areas are set out in Table 6.6.

Table 6.6 Assessment of distribution feeder flexibility

AREA	COMMENT
Arrowtown 11kV	— The 11kV is arranged as interconnected ring distribution network, however some parts are fed radially and do not have any redundant feeders or supply.
Fernhill substation	— Complicated ring distribution arrangement, with some parts fed radially. — The network is interconnecting with other areas, which makes it flexible during outages.
Frankton Substation 11kV	— The 11kV is arranged as interconnected ring distribution network, however some parts are fed radially.
Glenorchy – Oxburn 11kV	— The network is radially fed. Although Air Break Switches are connected along the lines, it will not be possible to isolate part of the line for any reason (faults or maintenance) without loss of supply to some parts of the line.
Queenstown and Commonage 11kV	— Each zone substation is supplied by two sub transmission line originating from Frankton GXP, each supplying different sections of the 11kV bus bar. This provides N-1 redundancy at each station. — There is no specific approach to how the 11kV network is configured. This will make it difficult during network operations and upgrades to account for all scenarios to ensure feeders are able to provide backup feed for certain areas during outages.
Alexandra 11kV	— The distribution network is based on interconnected ring arrangement, however some of the parts are radial. With this arrangement, network parameters knowledge and database is essential to assess the backup feeding arrangement during equipment or feeder outages.
Clyde-Earnscleugh 6.6kV	— Most of the network is radial, therefore outage of any equipment or feeder section will result in outage of parts of the feeder. Part of the network is connected through an Auto transformer to Galloway-Crawford Hill 11kV network, this may provide supply to that part of the feeder in case of an outage.
Ettrick (ETTR) 11kV	— The system is fed from a single transformer at Ettrick and interconnected with Roxburgh substation, Parts of the network are radial and outages of section of the line will mean losing supply from that section.
Galloway, Omakau Roxburgh, Single Creek-Fruitlands, Roxburgh Hydro	— The network is interconnected which will allow feeding from different parts of the network to provide backup during outages. However, some parts are fed radially, therefore sections of the 11kV lines will be isolated during outages.

The main implications of the identified level of network flexibility are:

- In general, the design of the network is likely to enable Aurora to meet the security of supply requirements by using network switching at the 6.6kV distribution level in Dunedin. This would enable more rapid resupply of load in the event of a zone substation level outage event.
- The ability to transfer load between feeders at the distribution level in central is more limited due to the geography of the network. Switching between feeders from the same substation is possible, however, transferring load from one substation to another via the distribution level is typically limited to the Queenstown area.

- Where there is limited switching to enable assets to be removed from service for maintenance, the assets may not be maintained with sufficient frequency to ensure they remain in appropriate condition and identified for replacement prior to failure.

6.3 PERFORMANCE AGAINST SECURITY GUIDELINES

In this section we assess the network performance against the security of supply standard. We have interpreted the Group Peak Demand to be the peak demand as applied to the group of customers experiencing the outage. The following approach was used to assess the security of supply performance:

- the peak demand was calculated as the average peak demand per customer based on the zone substation peak demand divided by the total number of customers supplied by that substation
- the number of customers affected by an outage was multiplied by the customer peak demand for that group of customers, based on the feeder, number and summed together. If the feeder number was not known, the network average peak customer demand was applied
- the feeder number was used also used to classify the outage as either urban or rural
- the group peak demand and urban or rural classification was used to allocate the outage to a security of supply category as set out in Table 6.1
- To be categorised as U4, the Asset affected had to be identified as a zone substation, otherwise it was allocated to U3. This was considered to align more closely to the definitions in Table 6.1. All other categories were based on the Group Peak Demand of the customers affected by the outage and does not consider the type of asset that caused the outage.

The distribution of the outages was calculated and plotted. The distributions were found to be exponential with high occurrences of low duration outages and fewer occurrences of high duration outages. Figure 6.1 shows an example of the results for the U1 category.

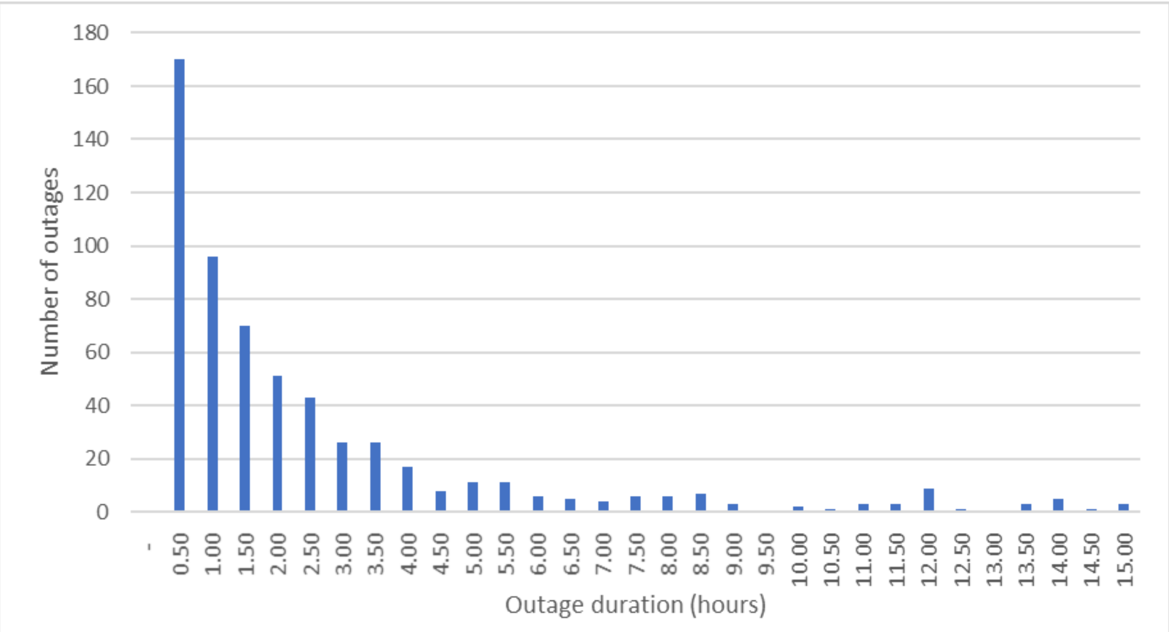

Figure 6.1 Example of the frequency distribution for the U1 category of outages (4 years to 30 June 2018)

Table 6.7 shows the performance per security of supply category. Since the outage data does not specify if the outage is the first or second in an event, and major events such as storms have not been excluded, the assessment has been undertaken against 4 hours' restoration for categories U2 to U4 to allow for any of the outages that may have been second outages in an event.

The results show that, on average, across all categories, 86% of the outages are restored within the required time and, on average, all categories, aside from U1 are within the required time period.

Table 6.7 Summary of security of supply performance

CATEGORY	REQUIREMENT (HOURS)	PERCENTAGE OF OUTAGES WITHIN LIMIT	AVERAGE (HOURS)
U1	4	79%	4.8
U2	4	83%	3.0
U3	4	82%	2.7
U4	4	93%	0.6
R1	6	90%	3.2
R2	6	84%	4.4
R3	6	88%	2.9

The 'Unknown' cause code is the most frequent category, followed by equipment deterioration and weather and vegetation. Fuses and overhead line are the two most frequent asset classes affected followed by 'Unknown' and poles.

This prominence of 'Unknown' in the analysis of this data indicates that there is uncertainty and difficulty in accurately identifying the cause and recording the data, but also identifies where improved data collection might add valuable insight into assets and failure modes that should be prioritised to improve network security. It would be a difficult task to improve security without first reducing the Unknown category.

The performance against the criteria is a combination of the response of the field crews to an outage as well as the flexibility of the network to be able to enable quick restoration of supply through switching. Improvements can be made through investment in network flexibility or via improved field crew response.

6.4 CHANGING LAND USE

Significant demand growth through residential development has been identified on Aurora's network, predominately in the Central region. A significant proportion of this is in the Queenstown area and, as a result, is supplied from zone substations that are predominately designed with N-1 capacity. However, there has also been significant growth around Wanaka which has resulted in the establishment of Camp Hill ZSS and Riverbank ZSS (currently under construction).

Increasing demand means the topology and security of supply needs to be considered. Currently Aurora only designs zone substations with capacity of greater than 7.5 MVA to have two transformers. In addition, there are eight power transformers across seven substations that are protected by fuses on the primary (33kV) side of the transformer. Using fuses for the primary protection of the transformer at these substations impacts the ability to remove faults quickly and to effectively coordinate protection across the system. The result is a potential for more damage to occur when a fault does occur.

An example of the impact of changing land use is the new Lauder Flat zone substation, which was constructed to provide additional capacity to the area to supply a predominately agricultural load (irrigation). It is supplied via a single radial sub transmission line and the total peak demand at risk if the line fails is 3.5 MVA. Although some load can be resupplied via the 11kV distribution system, the main contingency response is deployment of the mobile transformer, however, that is only a solution for a zone substation based fault and will not improve security of supply with respect to a sub transmission fault, although overhead line faults can be repaired relatively quickly.

6.5 KEY FINDINGS

An analysis of network performance shows that the network is in most cases able to effectively manage outages and provide sufficient security of supply. Key findings are:

- Most distribution feeders in urban areas have good levels of interconnection with adjacent feeders. Some parts of urban feeders are radial with no interconnection and rural feeders are predominately radial with no or limited interconnections to other feeders. This means that there is no or limited possibility of switching to improve the speed of resupply to customers. These arrangements do not appear different to most other electrical line utility businesses.
- Although embedded generation is connected to the sub transmission network, it does not provide security to the network because when a sub transmission line outage occurs, the generation must be disconnected.
- There is no interconnection between ZSS's supplied from different GXPs. If a GXP was lost, then it would affect all connected ZSS's. In the Dunedin area there is one sub transmission connection between GXPs and an ability to transfer load at the distribution level for some feeders, but generally, there is geographical separation between ZSS's supplied by each GXP, making interconnection difficult.
- ZSS's are supplied radially from the GXPs, but by double circuits, so there is a level of redundancy.
- Wanaka Cromwell line has a section where the two circuits are relatively close so could both be impacted by a significant storm event.
- ZSS's supplied by oil insulated cables are likely to be at higher risk due to the condition of the cables and higher probability of a second contingency event (both cables out of service).
- 12 ZSSs are single transformer sites and do not have sufficient transfer capacity to off-load all load. However, Aurora has a mobile transformer that can be deployed to mitigate the risk of a transformer failure.
- There are no emerging capacity constraints for Aurora owned ZSS's when operating under normal (N) conditions.
- There are two substations, Arrowtown and Cromwell, with peak demand currently above their firm (N-1) capacity rating.
- There are four substations approaching their firm (N-1) capacity at 70% to 81%. Of these, Frankton and Wanaka have significant growth forecast, while Alexandra has slight growth forecast and Anderson's Bay has a flat growth forecast.
- The network is meeting its security of supply requirements between 79% and 93% of the time across the 7 security of supply categories.

WSP concludes that the security of supply appears to be appropriate for the size and topography of the load supplied. Security of supply could be significantly improved by adding more interconnections between ZSSs and HV distribution feeders, but this is unlikely to be economic with the present network size.

7 NETWORK PERFORMANCE

Historical network performance provides an indication of which assets and areas of the network pose the greatest risk to public safety, reliability and the environment. This is identified through analysis to show the frequency of asset failures and where performance is declining, as observed through an increasing number of outages or rising number of defects.

In this assessment, only outages that were caused by assets in poor condition, and not external events such as vandalism or collisions by vehicles or animals, were considered.

Weather is only considered in the assessment where specifically stated. Additional stress on the asset caused by high winds (which it should be designed to withstand) could cause the asset to fail. In this scenario, the asset would have survived had it been in better condition and, hence, its deteriorated state is contributing to an increased network risk of that asset class.

As noted in section 3.4, there are limitations with the completeness or granularity of data which limits our analysis to asset class level.

The purpose of this section is not to assess network performance, but to assess the suitability of the performance data for assessing performance of individual asset classes and to identify which asset classes are causing deterioration in performance. This will inform the assessment of which assets classes pose a risk to the reliability of the network and the prioritised network risk assessment.

7.1 RELIABILITY DATA

Network performance data was predominately captured in the outage management system (OMS). Data entry into the OMS database was a manual process and only quality reviewed consistently in Dunedin. However, the process is audited annually and there are a low number of outages each day which minimises any problems with manual data entry errors.

We note that while the data provides accurate outage information, the completeness of some data fields limits the analysis that can be undertaken to assess trends in asset performance. Some of this is due to the recording practice in the field while some of it is due to the nature of particular faults that limit the information that can be recorded.

Key findings on reliability data are:

- The data is only recorded to the nearest distribution transformer. This has the effect of reducing visibility of any locational issues, such as from vegetation, and limits the ability to consistently identify a specific asset type that is causing outages.
- 28% of outages have a cause code of “Cause Unknown” allocated and 17% of outages have an asset type code of “Equipment Unknown” allocated. The cause of some types of faults and the initiating asset type, such as those caused by conductor clashing or vegetation contacting conductors, are not always able to be identified.
- Description and comment fields are free text resulting in multiple variations of text for the same issue. This makes it more difficult to analyse the data consistently. We note that recording outage information in free text fields (unstructured data) is not a practice unique to Aurora, it is common with electricity distributors across Australia and New Zealand.
- There is inconsistent recording of the feeder ID where the fault occurred. This makes it more difficult to analyse the data consistently.

Despite the limitations of the asset data, we found that the outage data available was suitable overall and appropriate to allow our analysis of the network risk. The data limitations highlighted above did however limit the insight that could be gained.

7.2 RELIABILITY TRENDS

This section provides a high-level overview of the recent performance of the Aurora network. It identifies specific asset classes that have a higher impact on network risk by assessing performance trends and significant contributions to network reliability performance.

7.2.1 REGULATORY PERFORMANCE

Reliability of supply data provided by Aurora to the Commerce Commission provides a good view of the overall performance of the network. While the granularity of the data is limited, overall trends are clear and assist in identifying those assets that are contributing to supply interruptions.

Figure 7.1 shows the performance of Aurora's networks (Dunedin and Central combined) in terms of System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) and the trend line. The data displayed includes both unplanned and planned outages and is not normalised for major weather events[11].

The charts demonstrate that there has been an increasing trend for both metrics for unplanned outages. This is supported by the fit of the trend line indicated by the R^2 value (the R^2 value is a measure of how well the trend fits the data, a value of 1 indicates a perfect fit while a value of 0 indicates there is no fit). The chart indicates that there has either been an improvement in unplanned outage performance in 2017, or potentially just a return to trend after a departure in 2016.

The charts also show an increase in the number and duration of planned outages, starting in the 2017 financial year. The contribution of planned outages increased from an average of 22% between 2013 and 2016 to 37% for SAIDI and an average of 10% between 2013 and 2016 to 20% for SAIFI. This reflects Aurora's implementation of the accelerated pole program and increased focus on asset replacement.

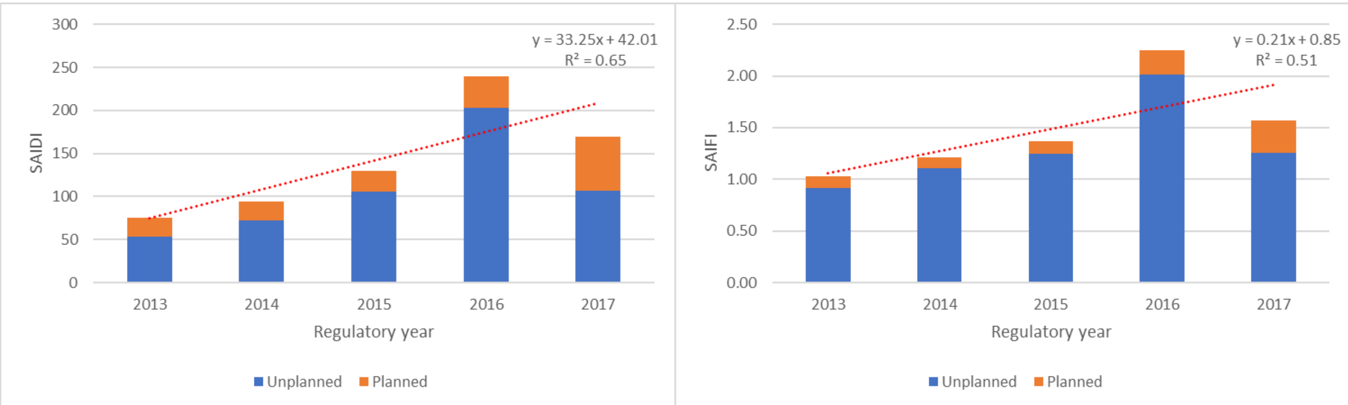

Figure 7.1 SAIDI and SAIFI as reported to the Commerce Commission

A summary of the outages by equipment type, as reported to the Commerce Commission, is set out in Figure 7.2. The charts highlight that the outages have been predominately caused by distribution lines, distribution cable and distribution other. Sub transmission lines and sub transmission other have also caused unplanned outages.

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11 The data for these charts was obtained from the Commerce Commission website: https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance/information-disclosed-by-electricity-distributors. The reliability data included up to 2017. Data for 2018 was not available.

Figure 7.2 Planned and unplanned SAIFI by asset type, all outage causes

Based on SAIFI, which reflects the number of incidents, an average of 23% of outages between 2013 and 2017 are identified to be the direct result of defective equipment based on the data reported to the Commerce Commission. As shown in Figure 7.3, this has risen linearly from 16% of outages in 2013 to 28% in 2017. The high R^2 value indicates the trend is well supported by the data. However, the data available from the published outage data on the Commission website does not provide detail of the asset classes or asset types that are included in the defective equipment category.

The following sections further assess the historical performance of the network using the outage data recorded by Aurora which provides a more granular level of detail for each outage.

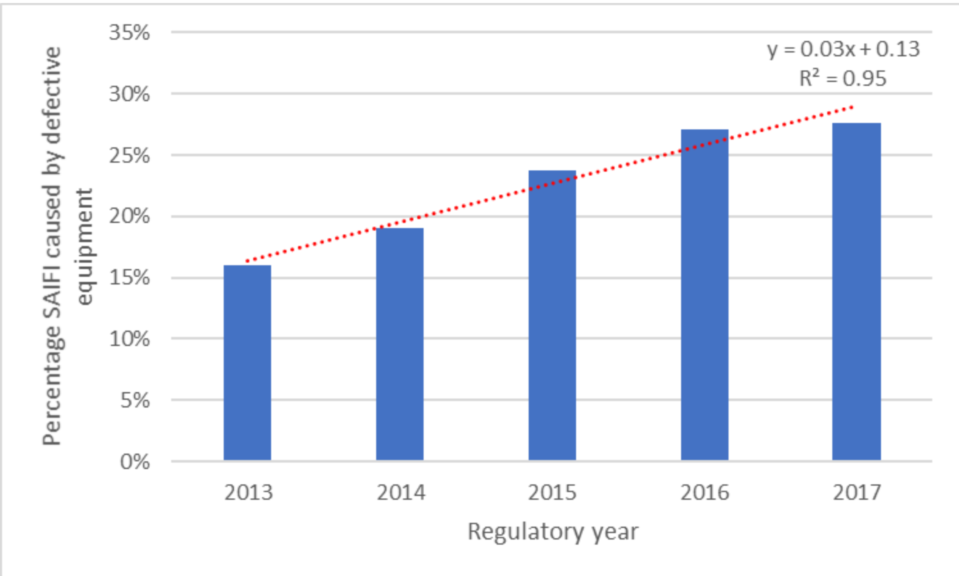

Figure 7.3 Trend of outages caused by defective equipment

7.2.2 OUTAGE MANAGEMENT SYSTEM DATA

This section examines the raw outage data available from Aurora's OMS with the intention of identifying the relationship between asset condition and the historical performance and trends. Our assessment in this section is based on outage events and is not intended to consider performance in terms of SAIDI and SAIFI on the same basis as the regulatory reliability scheme. The data presented in this section is likely to include outages which are excluded from regulatory reporting, such as low voltage assets, and, therefore, may demonstrate a different trend or numbers of outages.

UNPLANNED OUTAGES DUE TO ASSET DETERIORATION

Figure 7.4 shows the total number of outages for all assets caused by deterioration covering the same time period as the data available from the Commerce Commission. It excludes outages caused by vegetation, unknown causes, wind and weather, or external impacts on assets. Fuses as a cause have also been excluded from this analysis where the cause indicated it operated properly. However, fuses that were identified as not having operated as intended were retained in the data set. While large weather events may cause accelerated asset deterioration, these are regular occurrences and the impact on certain assets increase the risk those assets pose to network performance.

The data shows an increasing trend in the outages experienced on the network. The high R^2 value of 0.95 indicates a good fit of the trend line to the data. The underlying data suggests that the dominant contribution to outages is from overhead lines, but it also indicates that overhead lines have a consistent contribution from year to year. The increasing trend is driven by outages caused by support structures and distribution switchgear.

We also note that Aurora has identified some changed work practices over this period that could have an impact on increasing both SAIDI and SAIFI. One change relates to the operation of some problematic fuse types, where the HV feeder is de-energised while fuses are removed and replaced, and results in additional short outages when fuses are changed. Another change inhibits auto reclose of circuit reclosers during the summer months which WSP understands is to reduce fire risk. This has the impact on prolonging outages once the switch is operated.

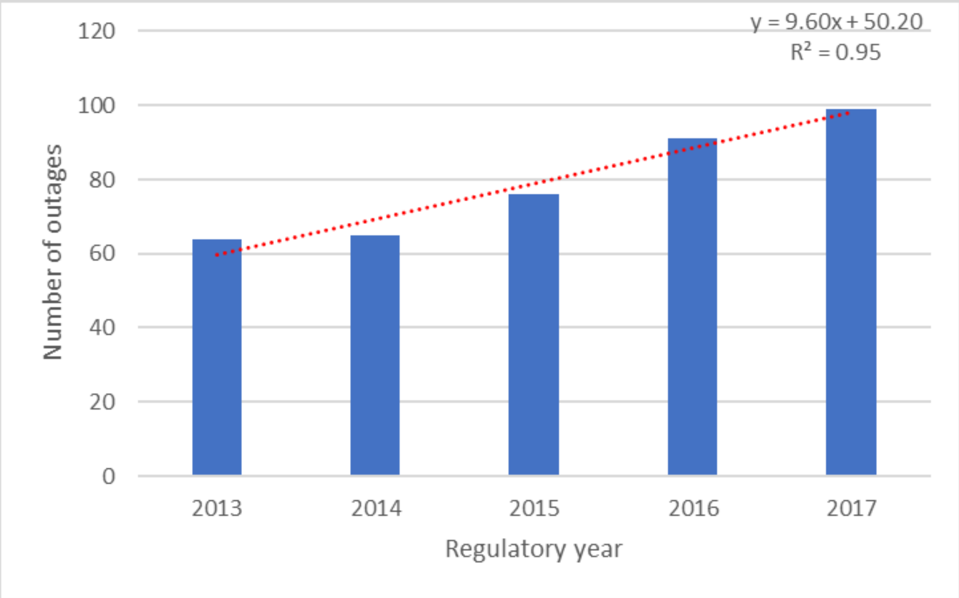

Figure 7.4 Count of unplanned outages from all assets due to deterioration

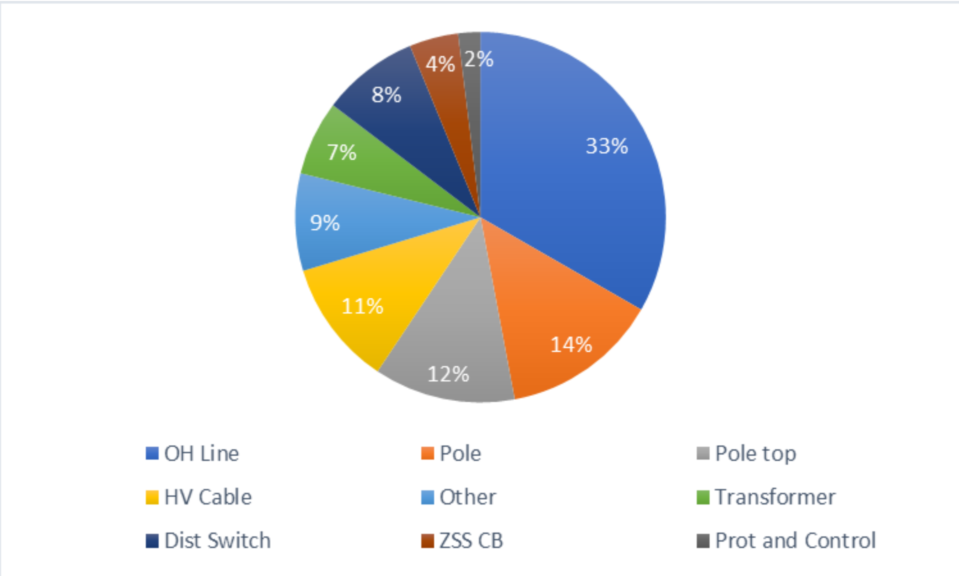

Figure 7.5 Unplanned outages by asset type

Figure 7.5 shows a breakdown of all asset classes that have been identified as causing an outage. The percentages are based on the average number of outages caused by each asset class from 2013 to 2017 inclusive, so it is calculated on the same basis as the data above.

Further information regarding the trends of individual asset types, if available, will be provided in sections 8 to 17 where we discuss individual assets.

UNPLANNED OUTAGES DUE TO VEGETATION AND WEATHER

Approximately 25% of unplanned outages (in the full outage data provided from 2000 through to 2018) are caused by vegetation or weather. Of these, 70.2% are the result of vegetation or weather impacting on overhead conductors and 8.6% due to vegetation or weather impacts on poles.

The impact of vegetation on overhead conductors causes damage and can often cause the line to break. This results in additional joints in the line when it is returned to service and, in general, has an adverse impact on overhead conductor condition.

7.3 DEFECT TRENDS

As discussed in section 3.3, asset defect data (i.e. a problem with an asset that has not yet resulted in a fault or outage) recorded by Aurora is stored in PDF documents and is not in a format that can be used for trending and analysis of historical performance.

We investigated using available financial data (stored in SAP) relating to defects to determine if the data was useful in identifying specific asset types that are experiencing increasing defects as a sign of deterioration of the fleet.

The SAP data is expected to be complete and up to date as there are controls in place that require Delta to obtain work orders, which are generated through SAP and linked to financial settlements. We found the data in SAP has maintained consistent naming conventions across the time period reviewed, however, the granularity of the data was not sufficient to enable identification of specific asset types.

Further, Aurora identified that the activities included in the expenditure categories is likely to have changed over time and there have been significant increases in costs for some asset classes that may skew the results. Therefore, we were unable to identify a suitable data source for a top down assessment of asset defect trends that would provide a high-level view of which asset classes are posing an elevated risk to network risk.

7.4 ENVIRONMENT

As set out in section 4.3.3 the RMA sets out requirements on Aurora with respect to environmental management. Incidents that relate to assets in the last four years are:

Table 7.1 Environmental incidents relating to assets

ASSET	INCIDENT	RESPONSE
Distribution substation – Fruitlands – Rural – remote – 2017	It appeared that the distribution substation had been struck by a vehicle causing oil spillage.	Aurora's spill response protocol deployed, and clean-up of the site was undertaken. Otago Regional Council informed of the incident.
Pole top distribution substation struck by a car – Mosgiel 2018	The pole was knocked down and oil escaped from the transformer.	Aurora's spill response protocol deployed, and clean-up of the site was undertaken. Otago Regional Council informed of the incident.
Pole top transformer hit by truck – 2018	An unidentified high sided vehicle has made contact with a pole mounted transformer, resulting in damage to the transformer which resulted in the release of the contents (Oil) to ground.	Delta replaced the transformer. Fulton Hogan cleaned up the spill
North City Underground Oil Filled Cable – 2015	Detection of loss of oil pressure which suggested that oil was leaking from the cable.	Contact was made with the Otago Regional Council and they were advised of the issue. A programme of testing was instigated to discover the location of the leak. This included thermal imaging.

Based on historical performance, Aurora appears to be managing the network assets to pose a low risk to the environment. The environmental issues reported are limited to cables and distribution transformers but have not resulted in any financial penalties.

7.5 SAFETY INCIDENTS

Public safety is an important consideration for electricity networks. Safety can be managed through:

- controls put in place to prevent an incident such as design standards, inspection and replacement programs
- control to mitigate the impact of an incident once it has occurred such as appropriate protection systems to de-energise the assets and ensuring suitable response times by field crews.

Historically, the number, cause and impact of safety incidents has not been recorded consistently. In 2013 an issue notification register was created and used for reporting of network issues, including public safety items. Based on discussion with Aurora staff and review of the data, the register was actively used during 2014 and 2015, but ceased to be used consistently during 2016 and early 2017 with significantly fewer incidents recorded. The register was re-established in July 2017 and has been used consistently since with one person responsible for the data entry and reporting.

Although this database has deficiencies and does not reflect recent works undertaken by Aurora such as the recent pole inspection and replacement program, it is the best data available for assessing safety impacts.

Table 7.2 Summary of public hazards 2015 to 2018

ASSET CLASS	EQUIPMENT DEFECT		OTHER CAUSE	ALL CAUSES
	SERIOUS HAZARD	HAZARD	SERIOUS HAZARD	
Cable	-	1	-	20
Crossarms	2	12	-	16
Conductor	27	35	26	225
Miscellaneous	-	3	2	63
Pole	6	46	-	88
Service box/Pillar	-	147	-	152
Shock	--	-	-	2
Streetlight	-	2	-	6
Total	**35**	**243**	**28**	**548**

Table 7.2 sets out how many of these incidents were caused by equipment defects and failures. The total data set indicates that 225 hazards relate to conductors, 88 to poles and 16 to crossarms. Serious hazards are categorised based on where the text field indicated that there was an elevated risk to the public such as conductors remaining live on the ground or starting a fire (protection failed to trip or was delayed) or poles falling on roads or footpaths. Descriptions that stated the conductor was on the ground but did not specify the conductor was live or had caused a fire were excluded from the serious hazards in Table 7.3 as it was considered more likely that the conductor would have been deenergised.

Table 7.3 Summary of public hazards

ASSET CLASS	EQUIPMENT DEFECT		OTHER CAUSE	ALL CAUSES
	SERIOUS HAZARD	HAZARD	SERIOUS HAZARD	
Cable	-	1	-	20
Crossarms	2	12	-	16
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Shock	--	-	-	2
Streetlight	-	2	-	6
Total	**35**	**243**	**28**	**548**

The table identifies 35 incidents in the period 2015 – 2018 where a conductor fell to the ground and remained live. We identified that:

— some were on the LV network, with protection by a fuse that did not react to the fault

- some were due to a high impedance HV fault, where a back feed from the energised network circumvents the proper operation of the protection relays
- an estimated 15 faults should have been detected by the protection relays.

The analysis also identifies that an average of 11 poles per year have failed and fallen over as a result of asset deterioration. This aligns with the data recorded in GIS and the outage data regarding poles that have failed in service.

7.6 KEY FINDINGS

WSP's analysis found that the reliability data is of appropriate quality for the purpose of this review and is audited and reported to the Commerce Commission annually. We identified some data issues that limit the ability to analysis the data to determine trends in individual asset classes:

- 28% of outages have a cause code of "Cause Unknown" allocated.
- 17% of outages have an asset type code of "Equipment Unknown" allocated.
- Outages are allocated to the nearest distribution transformer.
- There is inconsistent data entry into some fields, particularly free text fields.

The network is showing an upward trend in the number of outages being experienced. This trend is evident in reliability metrics of SAIDI and SAIFI reported to the Commerce Commission as well as when considering the number of asset outages. The number and duration of planned outages increased in the 2017 financial year, from an average of 22% to 37% for SAIDI and an average of 10% to 20% for SAIFI. This reflects Aurora's implementation of the accelerated pole program and increased focus on asset replacement. We also note that Aurora has identified some changed work practices relating to the operation of some fuse types and inhibiting auto reclose during summer that could have an impact of increasing both SAIDI and SAIFI.

The outage data showed that there is an increasing trend in the outages caused by deterioration of support structures and distribution switches and there is a large but steady contribution from overhead lines. In addition, review of the public safety registers found that there have been 35 instances of live conductors on the ground that have not been deenergised by fuses (LV) or protection (HV), although some were identified as high impedance faults that cannot always be detected.

The analysis identified the following critical assets:

- Protection systems: our analysis of outages demonstrated multiple instances when protection systems did not operate and, therefore, did not mitigate the public safety risk as intended.
- Support structures: including both poles and the pole top structures (i.e. crossarms and insulators) have demonstrated a period of declining performance and have posed a high risk to public safety due to the number of pole failures. The recent accelerated pole program appears to have slowed this declining trend.
- Overhead conductor (all voltages): demonstrated to have a steady performance based on asset deterioration driven failures but is the most significant contribution to reliability performance based on defects relative to other asset classes. It poses a high level of risk to the public when it fails and relies on the protection systems to detect the failures and deenergise the section of the feeder.
- Distribution switches (all voltages): these have recently demonstrated an increasing trend in the number of asset failures driven by deterioration.

Aurora's network does not appear to pose as significant risk to the environment. Only four instances of environmental impacts were identified during the last four years and all were minor with no financial penalty.

8 SUPPORT STRUCTURES

This section discusses the current state of the support structures asset fleet, its recent performance and WSP's assessment of the risk it presents to Aurora's network in terms of impacts to safety, reliability and the environment.

The support structures asset class includes:

- poles
- crossarms
- insulators.

These assets are discussed below.

8.1 ASSET DATA

8.1.1 AVAILABILITY AND QUALITY

To assess the risk of the supporting structures, WSP reviewed the following information:

- pole data from GIS, Structured Lines, Xivic and older records
- raw data produced by the Deuar testing system
- performance data including outage data and the public hazards database
- discussion with Aurora SMEs.

The poles data was split into three main spreadsheets. One for Structure Lines data, one for Xivic data and one for poles not tested under Xivic or Structured Lines. Overall the attribute data for the poles inspected by Structured Lines was good and mostly complete, but the level of completeness varied with the other two data sources. Crossarm and insulator data was also found to be quite complete but did not appear to have been kept up to date. The key findings were:

Attributes (poles):

- 2.5% of poles were missing the location identifiers (i.e. Pole ID, Global ID, Facility ID, Object ID) were not recorded, did not match across all data sets and there were some that were not unique
- 2.5% of poles did not have a material type, height or configuration recorded
- 83% did not have pole strength recorded
- 56% did not have a foundation type recorded
- 15% did not have a usage type/pole arrangement recorded
- The status (in service or out of service) was not recorded for 2.0% of poles
- Where pole installation dates were not known, the data had been inferred based on assumptions, including the age of associated plant. This is common practice in the industry and is considered an appropriate approach to fill in data gaps for this asset class.

Attributes (crossarms):

- Crossarm data had fairly complete locational information but inconsistent use of inputs for attribute data and the inputs did not always match the column heading which made it difficult to use
- Crossarms did not have an installation date recorded

Condition:

- Data on pole condition was available in all data sets but only considered reliable from the Structured Lines data source due to the inspection and testing techniques applied prior to Structured Lines being more subjective and based on the inspector's experience
- The majority (73%) of condition data for crossarms was collected between 2010 and 2013 so was not up to date information.

Performance:

- Performance data was available for all assets from the outage data and in the public hazards register.

A summary of our findings in regard to data quality is reflected in Table 8.1.

Table 8.1 Summary of data quality

ASSET CLASS	SUB CLASS	ATTRIBUTES	CONDITION	PERFORMANCE	OVERALL DATA QUALITY
Poles	Structured Lines inspection approach	🟡	🟢	🟢	🟢
Poles	Historical inspection approaches	🟡	🔴	🟢	🔴
Crossarms	All	🔴	🟡	🟢	🟡

8.1.2 ASSET CLASS SEGMENTATION

In order to improve targeting of data validation and sampling in the field, segmentation has been used to allow us to target assets that pose the highest risk to safety, reliability or environment (refer to section 3). Asset segmentation was applied to the poles and their associated pole top structures. As they are essentially one asset group, the poles characteristics were used to perform the segmentation for all the assets discussed in this section. The following segmentation has been applied:

- Pole material (softwood, hardwood, concrete or steel)
- Testing type (refer section 8.2.3)
- Location (Dunedin / Central)
- Criticality (Critical / Non-critical).

Criticality is used to describe the consequence of an asset failing in service. The criticality segmentation for poles has been based on safety to public as the assets are above ground, in close proximity to the public and have failure modes that can result in unsafe situations. The consequence of failure on reliability is considered less as only a small number of consumers are typically impacted. For the initial analysis WSP used the locations of Points in Interest (POI) provided by Aurora. The POIs define a spatial location such as a school, social infrastructure, emergency services, or shopping centres and are used as a proxy for volumes of foot traffic or population density. Aurora has used GIS to identify the proximity of assets to approximately 18,000 POI's.

8.2 DESCRIPTION OF THE ASSET CLASS

8.2.1 FLEET COMPOSITION

POLES

This asset class covers all distribution and sub transmission poles on Aurora's network. The fleet is comprised of the pole material types and criticality as shown in Table 8.2. The fleet has been broken down into the pole materials as the testing / inspection regime differs for the pole types and also the consequence of failure is different for each pole type, therefore, the risks are different depending on pole material.

The table demonstrates that Dunedin network has 28% more poles than the Central network. The geographical area of the Dunedin network is also smaller than Central, highlighting the higher asset density in Dunedin. The main difference between the size of the asset fleets is the number of concrete poles on each network with double the number of concrete poles in the Dunedin area, with the volumes of other pole types being approximately equal. The critical and non-critical split shows that Dunedin has about 74% more critical poles (11% compared to 8%) based on Auroras POI methodology.

Table 8.2 Pole fleet summary by type and location

MATERIAL	CENTRAL		DUNEDIN		TOTAL
	CRITICAL	NON-CRITICAL	CRITICAL	NON-CRITICAL	
Hardwood	816	10,932	1,352	9,253	22,353
Softwood	349	3,557	279	2,254	6,439
Concrete	696	7,606	1,460	14,663	24,425
Steel	32	601	24	175	832
Total	**1,893**	**22,696**	**3,115**	**26,345**	**54,049**

POLE TOPS

The distribution of the pole top fleet is shown in Table 8.3.This table shows the breakdown of the crossarms into the material type. It shows that the majority of crossarms are hardwood, with only 1.7% steel. Typically, steel crossarms are only installed on steel poles, although there are a few exceptions.

Table 8.3 Crossarm fleet

LINE	CENTRAL	DUNEDIN	TOTAL
Hardwood	36,146	55,793	91,939
Steel	976	677	1,653
Total	**37,122**	**56,470**	**93,592**

There have been different types of hardwoods used on the network but predominantly Australian hardwood and Malaysian hardwood. The Malaysian hardwood has been found to be of lower durability and is often found to have a specific type of fungal growth on it. It is also smaller cross-sectional dimension of 75mm rather than the standard 100mm. There are approximately 3,620 Malaysian hardwood crossarms on the network based on the GIS data (extrapolating for the unknown proportion) which agrees with the numbers identified by staff during interviews.

The crossarms asset data shows that 60% of the crossarms are located in Dunedin and 40% are located in Central. Comparing this to the percentages of pole in each location, we found that Dunedin has 1.9 crossarm levels per pole and

Central has 1.5 crossarm levels per pole, with an average of 1.7 across the networks. This aligns with Dunedin being a denser urban environment, with more complex pole tops required to navigate the streets.

A crossarm level can be used for different voltages and also to enable tee-offs or to support other pole top equipment. Each level can have one or two crossarms, but our analysis has considered them as one crossarm as that is how they would typically be treated for replacement. The frequency of poles with multiple crossarms is shown in Figure 8.1.

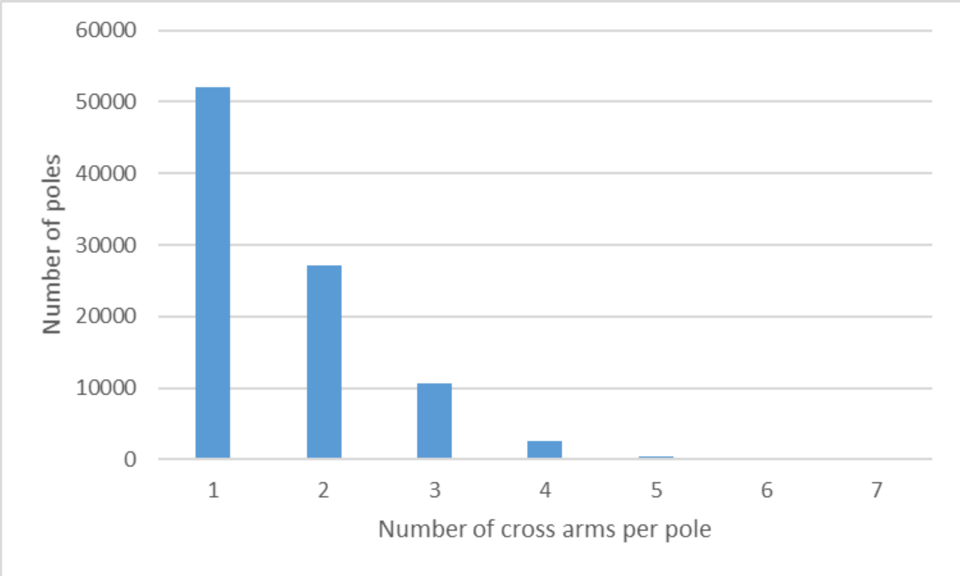

Figure 8.1 Number of crossarms per pole

Insulators generally have a life that is longer than the crossarm and are replaced when the crossarm is replaced. Some are damaged and replaced early but, for the purpose of this analysis, we consider the crossarms and insulators as a single group when assessing performance, risk and drivers for replacement.

Table 8.4 shows the breakdown of the insulator fleet. It shows that 31% of the insulator types are not recorded in GIS. It also shows that 45% of the fleet uses pin type insulators. This type is known to enable water ingress where the insulator is attached to the crossarm and, therefore, enable deterioration of the crossarm.

Table 8.4 Insulator fleet

TYPE	TOTAL	PERCENTAGE
Bobbin	9,743	10%
Pin	41,759	45%
Post	360	0%
Shackles	1,628	2%
Strain	11,137	12%
Unknown	28,964	31%
Total	**93,591**	**100%**

AGE PROFILES

The age profile in Figure 8.2 shows the relative age of the pole assets and material types. The age profile provides an indication of the volumes of assets approaching the end of their expected lives. The pole profile has three large spikes in 1960, 1965 and 1970 and several smaller ones in five year increments from 1975 to 1990. Although the total volumes installed each year are not excessive or unrealistic, the pattern indicates it is likely that default or calculated dates have been allocated to some of these assets. This is a common data issue across many electricity networks and is primarily caused by the long lives of these assets and changes in asset data recording technology over time. As there is no alternative data source, the age profile is considered to be fit for the purpose of this assessment.

In general, the overall profile aligns with the historical development of the network and the reduced volumes installed prior to 1954 aligns with the historical replacement data and expected life of assets derived from our analysis.

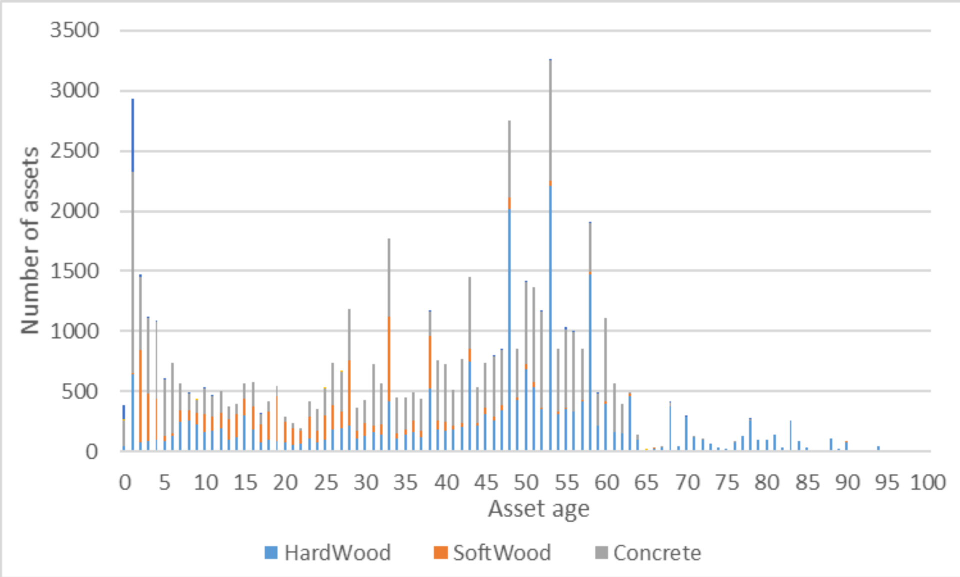

Figure 8.2 Poles age profile by material type

Similarly, Figure 8.3 shows the age of the crossarms assets by material type. The crossarm data did not contain an age for the crossarms. We note that Aurora has a reconductoring program that was completed in 2004 which resulted in crossarm replacements and there is evidence of ad hoc crossarm replacements, however, there has not been a dedicated program to address crossarm condition. To address the uncertainty in the age data for crossarms, WSP assumed the crossarm was the same age as the pole as there was no other more reliable data.

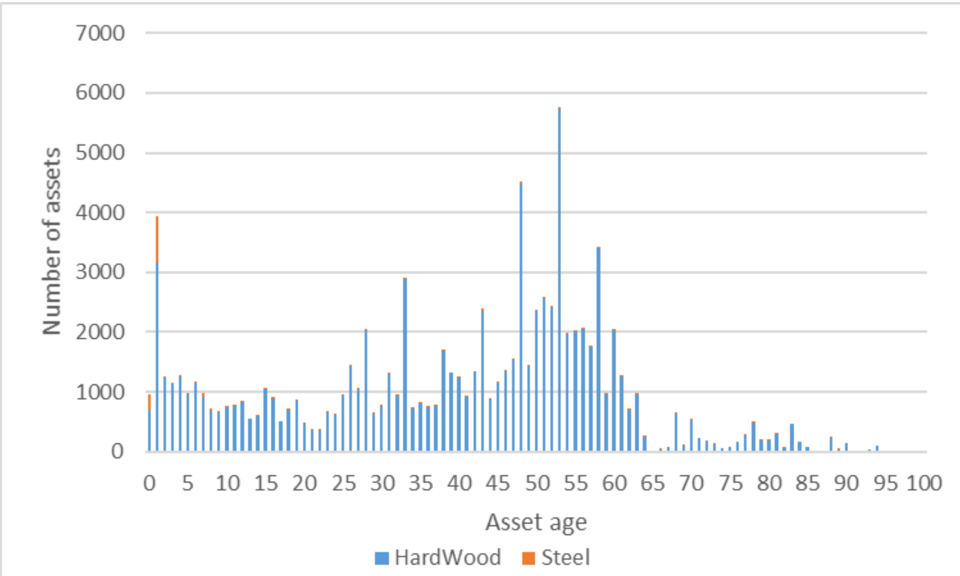

Figure 8.3 Approximated crossarm age profile by line voltage

EXPECTED LIFE

Table 8.5 shows the fleet statistics in relation to expected asset life of the poles, and average remaining life for the different pole types. The expected life is the number of years that a pole is expected to remain in serviceable condition following installation. The expected life of hardwood poles has been calculated from the ages of poles at the time of replacement where the cause of replacement was deterioration. There was insufficient historical data on softwood pole replacements to calculate an expected age, hence the expected life has been estimated as 45 years based on discussion with Aurora and general industry experience. For concrete and steel poles the expected life is based on engineering assessment.

The table indicates that a large number of hardwood poles are now approaching the end of their expected life of 55 years, with a considerable number (6,220 poles) that already exceed the expected asset life.

The table shows that the fleet of softwood poles is relatively young with an average of 18 year of life remaining.

Table 8.5 Fleet statistics - Poles

	EXPECTED LIFE	WEIGHTED AVERAGE AGE	WEIGHTED AVERAGE REMAINING LIFE	NUMBER EXCEEDING EXPECTED AGE
Hardwood	55	45.2	9.8	6,220
Softwood	45	26.6	18.4	439
Concrete	80	34.1	45.9	0
Steel	75	3.9	71.1	1

Table 8.6 shows the fleet statistics in relation to the expected life of the crossarms. It highlights that the fleet is quite old with 44,244 crossarms are exceeding their expected age. Note, this analysis is based on the calculated age profile for crossarms, so can only be viewed as an indication of the fleet status. It is likely that a number of crossarms have been replaced and the fleet has fewer assets exceeding their expected lives.

Table 8.6 Fleet statistics – Crossarms

	EXPECTED LIFE	WEIGHTED AVERAGE AGE	WEIGHTED AVERAGE REMAINING LIFE	NUMBER EXCEEDING EXPECTED AGE
Hardwood	45	39.2	5.8	44,244
Steel	75	14.9	60.1	18

These tables provide an initial view of the potential risk to the network as it demonstrates that there is an expectation of a need to address assets that are reaching or have exceeded their expected life. However, some assets can remain in good condition well beyond their life, so condition assessment and examination of historical trends of the asset performance is necessary to refine the view of risk and properly understand the network risk.

8.2.2 FAILURE MODES AND CONSEQUENCES

This section discusses the failure modes and consequences as they relate to this asset class. This is not intended to be a detailed failure mode assessment, it is only intended to inform how we approached our risk analysis and reflect the key deterioration modes that we identified during the review.

The primary failure mode for poles is loss of structural strength due to deterioration through decay or corrosion. The following list sets out the key failure modes for each of the assets considered in this section:

- Wood poles deteriorate through decay (rot) at the base and at the top of the pole where moisture is able to be absorbed. Fungi can also grow in the wood also causing deterioration:
  - At the base, just below ground level, the rot occurs from the inside and spreads upwards and outwards, so it is difficult to detect. The poles also rot from the outside inwards, but this can be easily observed and measured. The result is loss of strength of the pole until the forces it is subjected to (tensions and weight of the conductors, wind) cause it to break
  - At the top of the pole the rot spreads downwards and outwards. It can be seen when observed from above but is generally not visible from the ground. It can result in weakening of the crossarm attachment point and splitting of the pole.
- Concrete poles deteriorate due to corrosion of the steel reinforcement. As it corrodes, it expands which increases the amount of moisture that can enter and accelerate the corrosion. An effect of this is spalling, which refers to lumps of concrete falling off the pole and results in loss of structural strength.
- Steel poles deteriorate through corrosion at the base of the pole below ground level making it hard to detect. Once sufficiently weak the forces it is subjected to (tensions and weight of the conductors, wind) can cause it to break.
- Crossarms typically rot due to moisture and fungi causing the wood to rot. Often this occurs from the top of the crossarm where water can pool. It is also common to occur at the point where insulators are attached to the crossarm, especially in the case of pin type insulators where increased deterioration as water can more easily enter the attachment point. In particular, the Malaysian hardwood crossarms are thought to be a potential environmental risk due to fungal growth and their lower durability than other types posing an increased risk of failure.
- Insulators are typically damaged through mechanical stress, such as being hit by objects or vibration. They normally have longer lives than the crossarms and are replaced with the crossarm or pole. For sub transmission voltages, deterioration of the insulators can be detected through the presence of corona.

Another key failure mode is external impact. This is typically the result of cars crashing into poles that are located adjacent to roads. Since this is not a condition based risk, it has been excluded from this analysis.

In general, for poles in good condition, there is a low probability of failure and the risk of failure increases over time as the poles age and are exposed to environmental conditions. The main consequences of failure are:

- the pole failure can result in a safety hazard as it can fall over and damage property or injure people
- as a consequence of a pole falling, the conductors can break and fall to the ground or remain suspended in the air but low enough for people or vehicles to make contact with them
- the pole could result in an interruption to supply
- the pole could start to lean over or break at the base but still be held upright by the conductors
- a crossarm failure can result in an outage due to a fault caused by the conductor falling onto the crossarm
- a crossarm failure can also result in a safety hazard if the conductor falls off the crossarm it will remain suspended by the adjacent poles but at a lower height that may be low enough for people or vehicles to contact them.

As can be seen from the above statements, the majority of the consequences of a pole or crossarm failure are related to public safety. There are no environmental impacts associated with a pole failure.

8.2.3 INSPECTION AND TESTING

There have been various testing regimes for poles applied by Aurora over the years, demonstrating continual development in their approach to asset management and maturity of their systems over time. The changes in their approach also demonstrate the willingness to implement new testing methodologies and technologies for reporting.

These regimes have varied from fairly basic approaches that were reliant on inspector judgement and experience (pre-October 2014), to more formulaic and less subjective approaches. In 2014, Aurora started to introduce a new testing practice for wooden poles that used Deuar Testing techniques. The Deuar testing uses a mechanical device to test characteristics of the pole in a purely quantitative manner and a calculation is then undertaken to determine the remaining strength of the pole. When undertaking the Deuar testing, the above ground parts of the pole and attachments (including crossarms and insulators) are assessed using a visual assessment based on a set of criteria and categorisations so that it is not subjective. The Deuar test method can fail a pole through either the results of the strength test obtained using the mechanical device or through the visual inspection component of the method.

In September 2017, the Deuar testing became part of a fully revised testing and inspection practice for poles. The new approach is referred to as Structure Lines after the mobile application used to collect the data.

STRUCTURED LINES APPROACH

The Structured Lines approach combines Deuar testing with a revised visual inspection technique (known as Traditional testing). The Traditional testing involves visual inspection of all defects above the ground, including pole and crossarm condition and condition of insulators. It also involves some digging around the base of the pole. It is based on a set of criteria and categorisations so that it is not subjective. Deuar testing is applied to all wooden poles (unless there is an access issue) and the Traditional testing is applied to all other poles, including concrete and steel. The test data from these two inspection methods is recorded using the Structured Lines mobile application which then transfers the files for validation and included in the analysis process. This new regime led to more accurate, complete and reliable data sets as reflected in our data assessment (refer Section 8.1). However, one limitation of the Structured Line approach is the ability to accurately assess the condition of the pole tops with observation being ground based and, therefore, unable to get a clear view on the condition of crossarms or the tops of poles. To resolve this limitation, Aurora is investigating the use of a camera attached to a hot stick (electrically insulated pole) to take photos from above.

At the time of writing this report 6,644 wooden poles out of a total population of 30,278 (22%) and 928 concrete poles out of 24,271 had been subjected to this regime of testing (4%). The lower number of concrete poles is due to the concrete pole testing being put on hold. This occurred due to a lack of information on the strength rating for locally made concrete poles which was resulting in more poles being flagged for replacement than necessary due to the need to make a conservative strength assumption. The rate of condemning concrete poles did not fit with the low rate of pole failure experienced on the network which indicated more information was required to ensure appropriate poles were addressed. Aurora are undertaking forensic testing / break testing in order to verify the testing techniques. This will ensure that the right poles are replaced to most effectively manage the network risk.

In general, the wooden poles are considered higher risk due to their shorter expected life and the experience of the number of failures on the network in recent years.

POLE TAGGING

Following testing of a pole by the Structured Line approach, a pole is tagged to identify its condition:

- a blue tag indicates that the pole is in an acceptable condition, but the associated assets (crossarms, insulators) or other attached assets (distribution assets) are showing signs of defects. The severity of the defect is recorded in Structured Lines
- an orange tag indicates that the condition of the pole is deteriorated and it is suspected to be incapable of supporting structural design loads. It also is used as a cautionary warning for field crews not to climb. Orange tagged poles are required to be remediated within 12 months
- a red tagged pole is in a more deteriorated state than an orange pole, is at risk of failure under normal design loads, and is required to be remediated within 3 months. The red tag also requires an assessment of the probability of the pole to cause damage to property or injury to a person.

In or around late 2014, Aurora's approach to tagging poles changed. The change was to tag poles with a limited life (less than 12 months) as well as those at end of life. Aurora decided to also tag poles with limited life as red as there was no alternative process at the time. During the period of late 2014 to 2017, there was inconsistent application of red tag assessment and it resulted in a lot of red tagged poles on the network. In 2017, Aurora introduced the orange tag for the limited life poles. The red tagged poles are progressively being retested under the Structured Lines approach and the tag is either updated or the pole scheduled for replacement.

POLE REPLACEMENTS

In 2017, Aurora implemented its Accelerated Pole Replacement (APR) Program which remediated approximately 2,800 poles over the course of a year. The program aimed to reduce network risk as quickly as possible and targeted poles with known defects, older poles and new discoveries during scoping and investigation phases.

Aurora is also planning a testing program that will use a variety of inspection and testing techniques and technologies, then testing the actual breaking strength of the poles to assess the accuracy of each method and applicability to Aurora's network.

The inspection and testing program being run by Aurora focused on the areas of the network that had high criticality scores (close to POIs) and old poles. This was appropriate for most effectively managing risk. However, it meant that some areas of the network had not been subjected to testing under the new regime.

8.3 DATA VALIDATION

The data provided through the Structured Lines inspection approach appeared complete. However, it did not cover all areas of the network. WSP initiated programs to ensure the gaps in coverage of the network were closed (on a sampling basis) and the processes undertaken in the field were robust and would lead to consistent and reliable data being returned to the asset management team at Aurora.

Field work involved a variety of activities due the variation in asset data quality, the high criticality of assets, and the large number of assets in the asset fleet. This included:

- allocation of specific poles to be tested for coverage of the network
- observation of Structured Line approach testing
- drone based high-resolution photography of crossarms (and other pole top assets) and overhead conductors with associated assessment of imagery
- sampling of Red Tag poles.

ADDITIONAL POLE TESTING

Approach:

To ensure analysis covered all areas of the network, we identified a selection of poles that were required to be tested for the purpose of this review in addition to Aurora's planned program. To ensure broad coverage of the network, the selection was based on:

- poles that were not tested and were separated from the nearest tested pole by 500m to 1000m
- criticality of the poles
- material type (hardwood, softwood or concrete)
- separation between the selected poles to avoid grouping of selected poles.

Field work undertaken:

Dedicated teams of Aurora's pole inspectors were assigned to test these poles. The number of poles selected were:

- Dunedin: 248
- Central: 339.

STRUCTURED LINE AUDITS

Approach:

With high data quality for the support structures tested by Deuar and Tradition Testing methods, WSP used auditing of processes used in the field as a way of validating the asset data. The audits covered the Dunedin and Central networks, focusing on the processes used and correct application of the Deuar and Traditional testing methods:

- correct application of the Traditional test, in particular, the aspects of the assessment that can be subjective
- the consistency of each crew as they applied tests using Deuar and Traditional methods across wood and concrete poles
- the consistency across the different field crews in Dunedin and Central
- correct capture of data and information into Aurora's systems.

Field work undertaken:

The audits were undertaken by an experienced engineer and lines inspector with strong backgrounds in distribution networks including pole fleet management and condition assessment. The following audits were undertaken:

- **Dunedin:** Four two-person Delta inspection teams were observed carrying out inspections over the period 13 – 17 August. 25 pole sites were inspected; 23 timber, 2 concrete. This included both Deuar and Traditional testing procedures
- **Central:** Four one-person Delta inspection teams were observed carrying out inspections over the period 27-31 August. 14 pole sites were inspected; 9 timber, 5 concrete. This included both Deuar and Traditional testing procedures.

DRONE BASED INSPECTIONS

Approach:

Due to the limitation of the Structured Lines approach to test the condition of crossarms and pole tops, WSP carried out drone inspections of these assets, as well as conductors and insulators. The drone survey involved flying over a large number of poles and conductors for a random selection of pole types, line voltages and locations. High resolution imagery was taken of the assets which was later subjected to a desk-based review to look for a range of defect conditions.

Field work undertaken:

210 sites were selected for the review with approximately 4 poles per site location i.e. a total of 759 poles (401 poles in Central and 358 in Dunedin). This included 1,198 crossarms. The drone flights were undertaken in August and September.

RED TAGGED POLE AUDIT

Approach:

To gain confidence in the red tag approach for poles, WSP carried out an independent check of poles that have been tagged as red. It was understood that poles had been tagged as red in the past when the foundation type was installed in concrete and could not be inspected. This had resulted in incorrect tagging of poles and an overstated impression on the risk of the pole assets. The poles were selected based on:

- not having been tested by Structured Lines
- identified as red tagged
- wood poles.

Field work undertaken:

A selection of red tagged poles were checked to confirm that the condition of the poles was appropriate to be red tagged. The condition was assessed using the same scoring system as used by Aurora.

- Dunedin area: 31 poles were checked
- Central: 28 poles were checked.

8.4 ASSET PERFORMANCE

This section considers the historical performance of the assets to understand how the network has changed over time, evaluating the outages per year, number of defects and historical replacements. It then discusses the findings from our field work and draws conclusion based on the analysis of all the data.

8.4.1 HISTORICAL PERFORMANCE

SUPPLY OUTAGES DUE TO POLE FAILURES

The number of annual failures is an indicator of the trends in asset condition on the network. The two figures below show the number of poles that failed while in service. The first data set is from the outage data and the second is from GIS. The differences between the data sets identifies discrepancies in the reporting or recording of data in the two systems.

The two data sets contain different asset information that is useful for different purposes. Since the outage data is audited annually and reported to the Commerce Commission, we accept that the outage data is more appropriate for assessing trends as it would be reliable and up to date.

Figure 8.4 below shows the annual outages per year caused by pole failures as recorded in the outage data. The data was filtered to only include poles that had failed in service due to defective equipment and where the description was a broken pole (ie it failed in service). The data shows a slightly increasing trend but with a low fit (indicated by the R^2 value of 0.5) as there is volatility from year to year. The data for 2018 is only data for half a year for January to July.

Although there is an increasing trend, the data shows that there may be some recent improvement in the performance of the fleet, likely because of the accelerated pole replacement program.

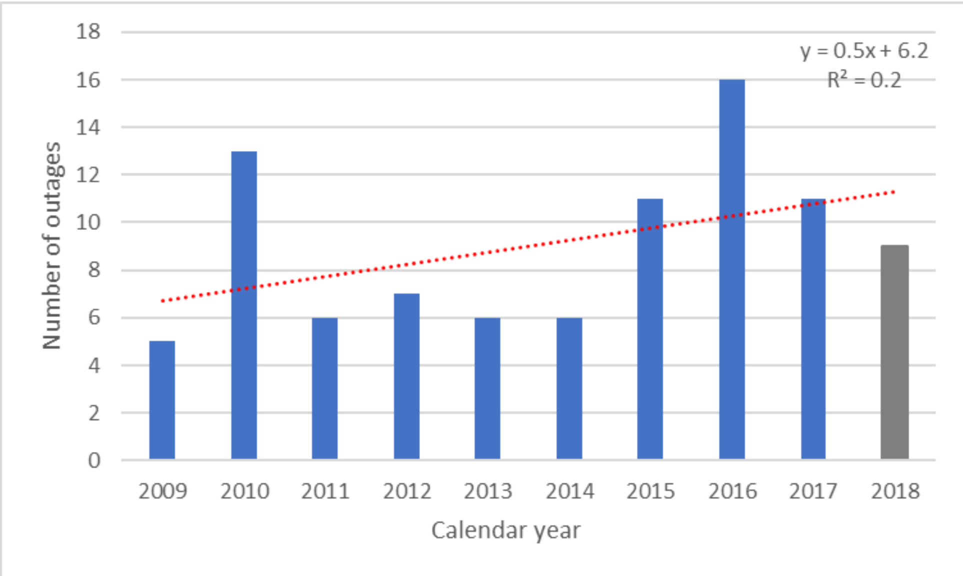

Figure 8.4 Historical outages caused by pole failures

Figure 8.5 shows the pole failure data as recorded in GIS. Only the poles identified as having failed in service have been included in the chart. The data shows that GIS indicates that more poles have failed in service than reflected by the outage records prior to 2015, but fewer than the outage records since 2015. This indicates that there may have been a change in the data recording process in GIS.

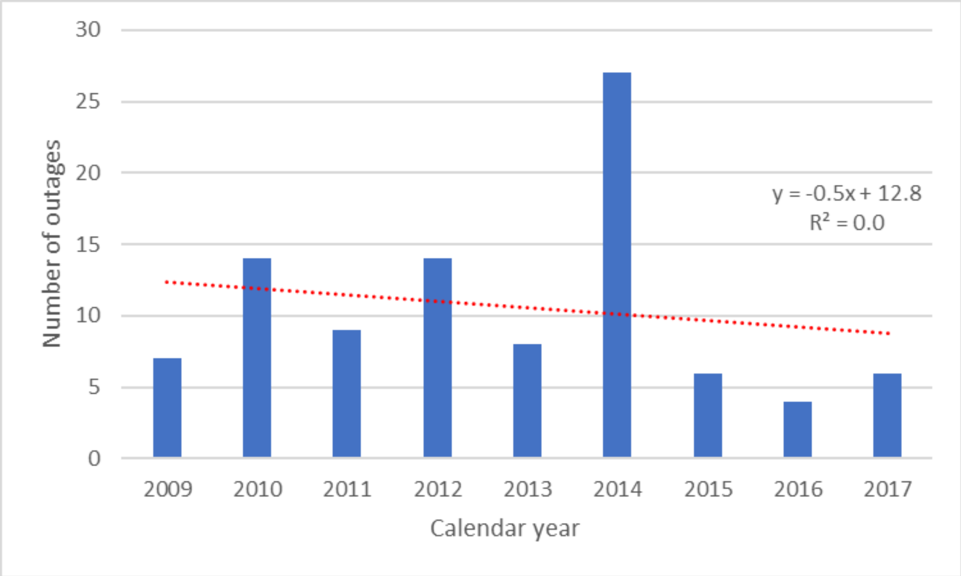

Figure 8.5 All in service pole failures without causing outages

The GIS data may not be up to date or may have some mis-allocation of the reason for pole replacement, however it contains the age of the pole when it was replaced so it can be used for analysis of the pole survival rate.

Both data sets indicate a long-term average of 10 poles failing in-service each year as caused by asset deterioration. This excludes any poles that fail with the cause being identified as due to weather.

SUPPLY OUTAGES DUE TO POLE TOP FAILURES

Figure 8.6 shows the number of pole tops that failed while in service as a result of asset deterioration. The data includes cross arms and associated hardware such as insulators. It shows a slight downward trend since 2009, however, the trend has been relatively flat since 2012.

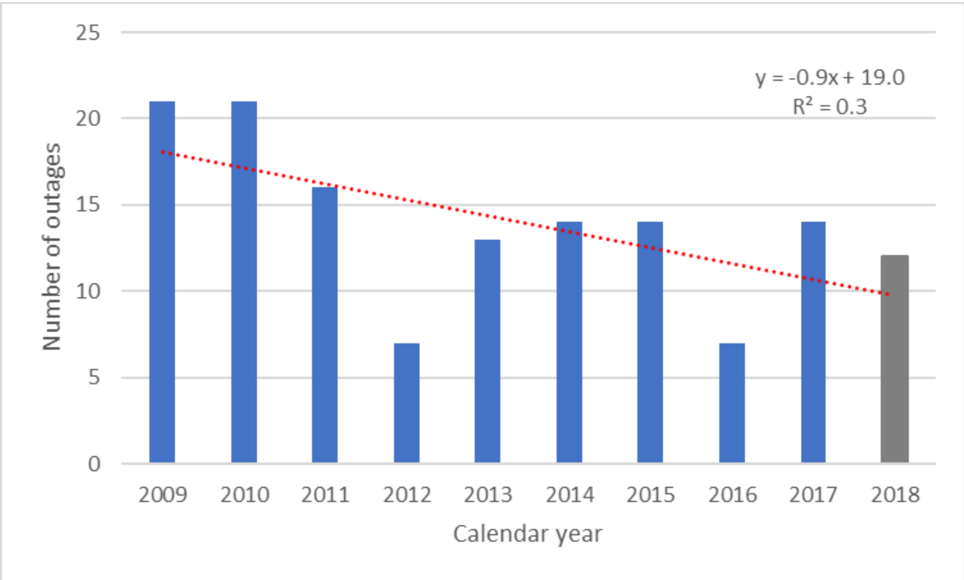

Figure 8.6 Historical outages caused by pole top failure

HISTORICAL POLE REPLACEMENTS

Understanding the ages when poles fail is important for forecasting replacement volumes and assessing the risk of the poles currently installed on the network. Using the abandoned poles data from GIS, we were able to assess the distribution of the age of poles when they fail. Figure 8.7 shows the distribution of the ages of poles when replaced in planned circumstances prior to failing and Figure 8.8 shows the distribution of the ages of poles when replaced after they have failed.

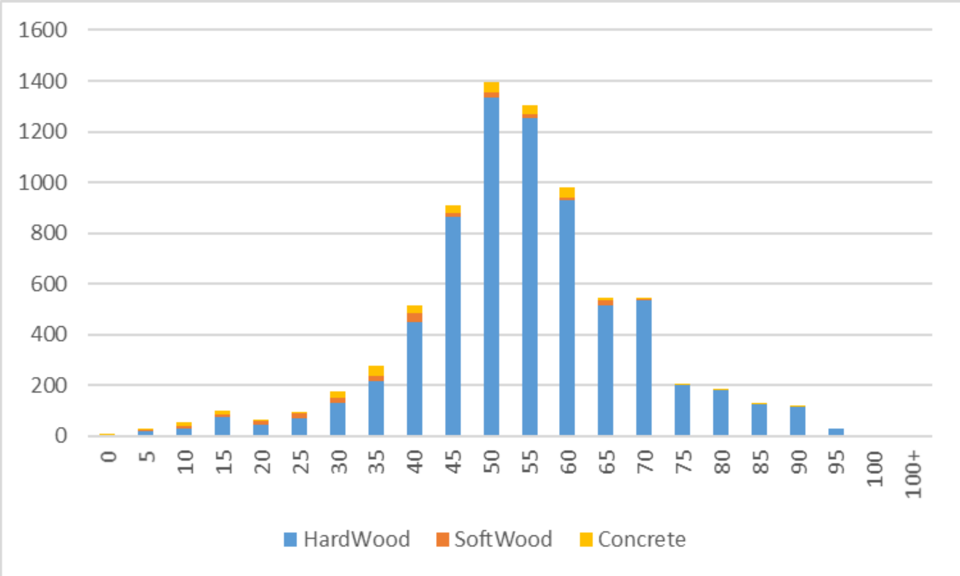

Figure 8.7 Frequency of age at replacement by material type

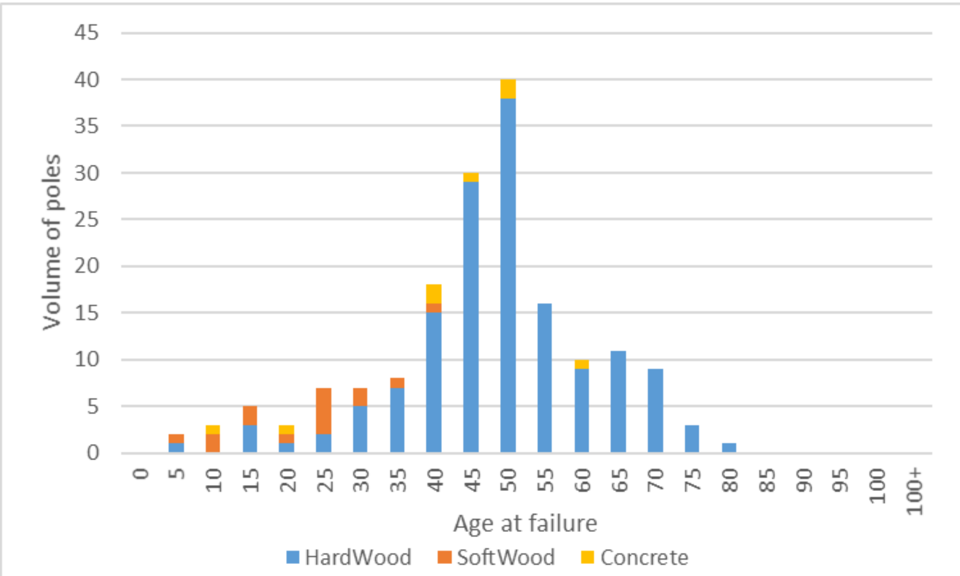

Figure 8.8 Frequency of age at failure by material type

The distributions of asset failures were analysed to determine a suitable probability distribution to model the asset failure rates and to calculate the parameters of those probability distributions. In both cases a Weibull function was found to fit the curves well. The characteristic age of a Weibull distribution is where 63.2% of all assets have failed. The shape factor sets how flat or peaky (and skewed) the distribution is. Weibull distributions are commonly used across Australia and New Zealand in the electricity industry for asset end of life analysis.

The characteristics derived are shown in Table 8.7.

Table 8.7 Pole failure distribution curve characteristics

POLE TYPE	DATA SET	SAMPLE SIZE	CHARACTERISTIC AGE	SHAPE FACTOR
Hardwood	Replaced prior to failure	7,636	55.6 years	3.9
	In service failure	148	52.8 years	3.8
Softwood	Replaced prior to failure	516	32.7 years	2.2
	In service failure	Insufficient data	NA	NA
Concrete	Replaced prior to failure	279	49.6 years	4.0
	In service failure	Insufficient data	NA	NA
Steel	Replaced prior to failure	Insufficient data	NA	NA
	In service failure	Insufficient data	NA	NA

We note that for concrete poles the expected life was unexpectedly short. Based on discussions with Aurora, we identified that historical replacements may have been undertaken earlier in the poles life than necessary due to the previous methods applied for assessing pole condition. Based on revised assessment criteria and discussions with Aurora, we applied a characteristic age of 80 years for concrete poles and 75 years for steel poles with a shape factor of 4.

8.4.2 STRUCTURED LINES

This section analyses the data from Structured Lines which includes the condition assessments based on Deuar and Traditional Testing for wood and concrete poles, as well as data related to crossarms.

Structured Lines captures the defects on the pole as well as the pole (strength) assessment. The worst case defect or strength rating is applied to the pole and drives the need for remediation or replacement. Since the concrete pole inspections were put on hold, this section focuses on the outcomes for wood poles only. Poles with an unknown type are also excluded.

DEFECTS IDENTIFIED

Table 8.8 shows a summary of the number of defects found on wooden poles that have been inspected using the Structured Lines app (Deuar or Traditional testing). The percentage of poles with each defect tag is reflected as proportion of the total poles inspected. The defect rating is based on the worst defect identified on the pole. All defects, regardless of ranking, are allocated a blue tag.

Table 8.8 Number of wood poles found with defects by defect class

DEFECT TAG	ACTION	NUMBER	PERCENT
D1	Critical safety hazard – Requires immediate attention	297	4.6%
D2	High safety hazard – Does not require immediate action.	533	8.2%
D3	Medium Hazard – May affect length of service	618	9.5%
D4	Low Hazard – Will not affect length of service	611	9.4%
No defect tag	No action	4423	68.2%
Total inspected		**6482**	**100%**

Table 8.9 shows a breakdown of components that are considered in the defecting process and the percentage of poles identified with those defects. Depending on the severity of the defect and the component that has the defect, this can be a driver for pole replacement. This decision is based on an economic assessment of the cost to replace the pole (and associated assets) or to rectify the defect. Some components (such as the pole top) cannot be replaced independently of the pole. The sum of the percentages below does not equal the percentages in Table 8.9 as there can be a many to one allocation, i.e. one pole could have a high severity defect on the crossarm as well as the pole top.

Table 8.9 Severity of defects by component identified during inspection (shown as percentage of poles inspected)

COMPONENT	D1	D2	D3	D4	NO TAG
Crossarm	4.6%	8.2%	8.4%	4.7%	74.1%
Pole top	1.7%	4.8%	6.3%	9.4%	77.8%
Pole top bolt	0.0%	0.2%	0.3%	0.3%	99.2%
Above ground decay	0.0%	0.0%	0.3%	0.2%	99.5%

The very top of a wood pole can allow water to be absorbed into the pole and cause rotting and deterioration. Pole caps can be installed to help prevent this occurring. Table 8.10 sets out the number of poles that have and don't have pole caps. The table shows that 53% of poles did not have pole caps, and that without pole caps, poles are more likely to suffer significant deterioration.

Table 8.10 Wood pole deterioration with and without pole caps

POLE CAP	TOTAL	NO/LOW ISSUES	MAJOR ISSUES	% WITH ISSUES
Null	548	548	0	0%
No pole cap	4304	2043	2261	53%
Present and sound	1592	1384	208	13%
Present but deteriorated	38	28	10	26%

Further analysis shows that of all the defects categorised as D1, 38% are on poles tagged as either red or orange. This means that 38% of poles with defects identified on the pole tops will be addressed due to other pole integrity issues. However, there are 62% of poles with D1 graded defects that will remain on the network with an elevated level of risk unless specifically addressed by Aurora.

LEANING POLES

Inspection of the network identified a large number of leaning poles. This was supported by analysis of the Structured Lines data, as shown in Table 8.11. Poles that are leaning can indicate an issue with the footing of the pole and can result in conductor sags being greater than designed reducing clearance to ground or adjacent structures. However, it does not generally indicate an elevated risk of pole failure and is predominately aesthetic. There is no regulation that requires poles leaning beyond a specific angle to be rectified and EDBs set their own thresholds.

All the poles that are identified to be leaning greater than 10 degrees were recorded as red tagged in the Structured Lines data which indicates that Aurora is addressing this defect.

Table 8.11 Leaning poles

ANGLE	NUMBER	PERCENT OF FLEET	MARGIN OF ERROR
>10 Degrees	12	0.16%	0.07%

ANGLE	NUMBER	PERCENT OF FLEET	MARGIN OF ERROR
6-10 Degrees	149	1.97%	0.25%
2-5 Degrees	933	12.32%	0.60%
None	6479	85.55%	0.64%

GENERAL POLE TAGGING

Table 8.12 shows the breakdown of the number of poles tagged with each colour. The cause of tagging includes pole strength as well as any defects identified on the pole. It shows that testing by the Deuar method results in a lower rate of defecting poles, with 34% of poles being tagged (red, orange or blue) compared to 52% when tested using the Traditional method. Part of this is due to the Traditional method that required poles to be downgraded in strength at certain ages, whereas Deuar calculates the remaining strength by testing.

Table 8.12 Number of poles tag by colour and method

TEST REGIME	RED	ORANGE	BLUE	NA	TOTAL
Deuar	151	258	867	2,479	3,755
Traditional	538	523	353	1,313	2,727
Total	**689**	**781**	**1,220**	**3,792**	**6,482**

REPLACEMENTS

As discussed in section 8.2.3, poles can fail testing and be tagged for replacement through three mechanisms:

- failing the Traditional Testing method (Traditional)
- failing the strength component of the Deuar testing process (Deuar), or
- failing the visual component of the Deuar testing process (Visual).

Table 8.13 shows how many poles were replaced as a result of each of the methods. 'Multiple' indicates where more than one of the inspection mechanisms resulted in a requirement for replacement.

Table 8.13 Driver for replacement

REPLACEMENT DRIVER	WOOD POLES		CONCRETE POLES	
	NUMBER	PERCENTAGE OF FLEET	NUMBER	PERCENTAGE OF FLEET
Traditional	410	6%	113	12%
Visual	150	2%	5	1%
Deuar	69	1%	0	0%
Multiple	60	1%	1	0%
Total	**689**	**10%**	**119**	**13%**

The table shows that there are a number of drivers for pole replacement and that the structural strength calculated by Deuar testing is only one aspect. Further, poles have been more likely to be replaced due to above ground deterioration or deterioration of the poles components than due to insufficient poles strength.

Assessment of the sample of tested poles shows that the test sample is representative of the fleet. The tested sample had a slightly older average age as Aurora has purposefully avoided testing young poles. Using the sample size and fleet size we can determine the confidence interval for how many poles are expected to be on the network and at the end of their serviceable life.

For wood poles, the confidence interval, based on a 95% confidence level, is between 9.4% and 10.6%. That can be restated as we are 95% sure that the number of poles on the network that currently have reached their end of life as a result of deterioration of the pole or pole top components is between 2,846 and 3,210. This is approximately half of the number predicted just based on a discrete age basis. Refer to Appendix A for details on the confidence level and margin of error calculation for the tested sample size.

We note that the required replacement rate of concrete poles shown in Table 8.13 is likely to be overstated. During testing, Aurora indicated that there was an excessively high number of concrete poles being condemned compared to their experience of failures on the network. Historically only a few concrete poles had been replaced per year, whereas the replacement number increased to 113 in a few months of the revised inspection program. Upon investigation, Aurora found that the driver for replacement was the need to make a conservative assumption regarding the strength of the ‘home made’ council concrete poles that did not have a certified strength rating. Due to this, the inspection of concrete poles was stopped until the actual strength of the poles could be determined by testing in a controlled environment. Hence, we are not relying on the results shown in Table 8.13 for concrete poles.

8.4.3 WSP FIELD WORK AND INSPECTIONS

This section analyses the findings of the field work undertaken by WSP.

ADDITIONAL POLE TESTING

The additional testing was undertaken by Aurora staff and reported via structured lines, hence it was included in the data set provided by Aurora as the output from structured lines and included in the analysis in section 8.4.2 above.

STRUCTURED LINE AUDITS

The findings from our audit of the Structured Lines approach for support structure assessment are as follows:

- The Deuar testing procedures were consistently applied by all teams both in Dunedin and Central for setup, testing and process, with correct adherence to the training provided, except for one case in Dunedin. In this case, the lineman used an alternative approach that is common in the electricity industry but is not according to Auroras procedures. It is noted that the experience level of the teams carrying out assessments varied but was not thought to affect the testing results.
- 8% of poles were tested using a non-standard procedure: 1 out of 25 the poles in the Dunedin area (4%) was tested using a process that, although it is common in the electricity industry, was not in accordance with Aurora’s procedures and 1 out of 25 poles (4%) had unknown issues with data inputs into the Deuar device.
- Inefficiencies were identified with the testing process that limited the number of poles tested per day, including mobile reception so the Deuar device could operate, and did not take full advantage of reporting other defects observed on the network, such as defects on nearby poles, while in the field which limits the potential effectiveness of the inspections. However, the inefficiencies did not impact the procedure followed or create uncertainty with the results of the testing and inspection.
- When crews were able to carry out the Deuar testing, no normal inspections were carried out post-test in the Dunedin area, such as excavating around the pole to check for decay. This means potentially beneficial information is not being opportunistically gathered, limiting the potential effectiveness of the inspections.
- An observation was made at one pole that the placement (orientation) of the Deuar testing device relative to the pole had an impact on the results. We found that the initial test results were close to the threshold between Medium and High priority and retesting from a different orientation produced a small change to the results which caused it to fall

into a different priority category. This indicates that the underlying results need to be considered when prioritising remediation works as well as the high level category.

Our on-site audit of the testing process found that overall the inspectors applied the correct procedures and carried out the tests correctly, although the inspectors only focused in the specific test being carried and specific asset and did not record and report other defects observed on the network.

REG TAGGING OF POLES

The audit of 59 poles across the Dunedin and Central network identified that most of the poles were still serviceable and were likely to have two or more years of serviceability remaining prior to being replaced. The assessment was undertaken by an experienced pole inspector and used Aurora's Traditional Inspection assessment criteria.

These results are consistent with the period of time from 2014 to 2017 when poles were tagged red rather than orange to indicate a safety hazard to field crews and comply with new obligations to tag poles with limited remaining life. It supports the expectation that as these poles are tested, the tag will be revised if appropriate at the time and the perception of excessive red tagged poles on the network is misleading due to the tagging process applied between 2014 and 2017 in the past.

DRONE BASED INSPECTIONS OF POLE TOPS

The drone survey inspected 759 poles with 1,198 crossarms, equating to an average of 1.6 crossarms per pole. This is between the average for Central (1.5) and Dunedin (1.8) with a slight bias towards Central which reflects the slightly higher number of poles surveyed in that network region.

The survey identified a total of 877 crossarms with defects, although multiple crossarms could be on a single pole. The defects included associated assets such as switches, DSDO and distribution transformers. 876 of these defects related to supporting structures as reflected in Table 8.14. The defects were assessed in terms of the severity of the defect as well as by applying the Aurora Defect Tagging rules which account for the consequence of the issue as well. Assets with no defects were not identified.

Table 8.14 Defects by asset type and Defect Tag type

ASSET TYPE	D1	D2	D3	D4	TOTAL
Cross-arm	35	63	58	5	161
Cross-arm double HV	6	52	51	1	110
Cross-arm double LV	4	29	43	0	76
Cross-arm single HV	10	144	97	3	254
Cross-arm single LV	12	53	59	0	124
Pole Cap	0	1	4	2	7
Pole Top	20	32	62	27	141
Pole Top Bracket	1	0	2	0	3
Total	**88**	**374**	**376**	**38**	**876**

The defect rate by tag type as a percentage of the number of crossarms inspected is shown in Table 8.15. The analysis shows that there is a high defect rate in categories D2 and D3 which indicates poor condition but no immediate action required.

Table 8.15 Number of pole tops found with defects by defect class

DEFECT TAG	ACTION	NUMBER	PERCENT	ERROR
D1	Critical hazard – Requires immediate attention	88	7.3%	±1.2%
D2	High hazard – Does not require immediate action.	374	31.2%	±2.2%
D3	Medium Hazard – May affect LoS	376	31.4%	±2.2%
D4	Low Hazard – Will not affect LoS	38	3.2%	±0.8%
No Tag		322	26.9%	±2.1%
Total		**876**		

Given the size of the sample observed compared to the size of the total asset fleet and the percentage of defects identified, we can provide a confidence interval on a statistical basis. This provides a margin of error around the identified percentage with a confidence level of 90% that the actual number of defects is within that error band.

Table 8.16 compares the results from the Structured Lines data to the results from the aerial survey. It shows that there is a much higher defect rate identified from the aerial survey. This is likely to be due to most of the deterioration mechanisms working from the top of the assets and would, therefore, not be visible from the ground. This result is consistent with the experience of other electricity business that have changed from a ground-based assessment to using aerial photography to assess the pole top condition.

We note that Aurora is investigating the use of pole mounted cameras for rollout and become part of the standard inspection procedures.

Table 8.16 High level comparison between Structured Lines and Drone survey

DEFECT TAG	STRUCTURED LINES	DRONE SURVEY	DIFFERENCE
D1	4.6%	7.3%	2.7%
D2	8.2%	31.2%	23.0%
D3	9.5%	31.4%	21.9%
D4	9.4%	3.2%	-6.2%
No defect tag	68.2%	26.9%	-41.3%
Total inspected	**100%**	**100%**	

8.5 APPROACH TO RISK ASSESSMENT

We have taken a quantitative approach to the risk assessment for support structures that relies on the use of parameters identified in our analysis above. We apply two assessment method to determine the risk of poles and apply field test results to determine the risk of crossarms.

The two methods applied to poles are:

- multivariate regression using machine learning to derive insights into the data
- conditional probability of failure using the Weibull parameters from Table 8.7

The historical replacement rates (Table 8.13) and volumes exceeding their expected lives (Table 8.5) were used as a verification to check on the model results were reasonable.

Due to incomplete age data for the crossarms, the results of the drone survey were used to determine the risk of crossarm failure based on the percentage of defects across the fleet. The low margin of error of the survey, calculated using statistical methods, supports this as a valid assumption.

For both poles and crossarms, the consequence of failure was calculated based on the population density of the asset location to determine an index for the impact on public safety and the expected energy unserved due to the asset failure to determine the impact on reliability. The method for calculation of consequence is described in section 4.3.

The two methods for determining the probability of pole failure are discussed below.

MULTIVARIATE REGRESSION AND ADVANCED TECHNIQUES

WSP undertook advanced statistical analysis to predict the degree of degradation and remaining serviceable life for poles that had not been tested under the Structured Lines regime. The model used the pole test results, augmented by additional data gathered from public sources related to terrain and weather, to determine the most important parameters driving deterioration of the poles and predict pole condition.

The multivariate approach derived a moderate fit to the data, however, the results had a large standard deviation (indicating uncertainty) and were not appropriate for forecasting condition. Further details of this approach are provided in Appendix D.

Due to the moderate fit and the resulting large standard deviation, we were not able to apply this model to determine the risk. However, this analysis was valuable in identifying the key predictors of pole deterioration, with the most important finding through this technique was that the age of the pole was consistently found to be the most significant factor in determining the pole condition. As a result, the Weibull distribution approach to modelling the risk on the network is currently considered to be the best approach for determining a risk assessment of the network that includes both a quantitative probability of failure and consequence of failure.

WEIBULL SURVIVOR CURVE MODELLING

We applied the conditional probability of failure as derived using a Weibull probability distribution based on historical asset failure and replacement data. The conditional probability derived established the risk of failure, while the consequence was assessed by considering both the impact to safety (using the technique described in section Appendix D) and the impact to network reliability.

The Weibull parameters used were those identified in Table 8.7 that were calculated from actual historical network performance data and, therefore, provide the best representation of the fleet.

Where there was insufficient historical performance data to calculate parameters, appropriate parameters were applied based on experience with this modelling technique for these asset types in the electricity industry.

8.6 RISK ASSESSMENT

Table 8.17 to Table 8.20 set out our assessment of network risk as a result of support structures. This assessment accounts for the age, materials and historical performance of the support structures fleet, as well as incorporating the results of the field inspections undertaken.

Although there are 6,660 poles that have exceeded their expected lives (refer to Table 8.5), the Weibull modelling found that there are expected to be 1,630 poles that will reach the end of their serviceable life and require remediation. In addition, defects of the crossarms and pole top assets are expected to drive some replacement. The drone survey identified that 7.3% of the fleet has a D1 graded pole top defect, and based on the Structured Lines data it is expected that 62% of those are not on poles already tagged orange or red. Therefore, there is up to an additional 2,490 poles that may need replacement or other remediation due to associated defects and currently pose an elevated level of risk to the network.

The total number of pole and crossarm asset expected to be at end of life is lower than, but in line with, the historical average replacement percentages during the Structured Lines inspection regime (10.9%) and is also lower than the upper limiting value of the 6,660 poles exceeding their expected life. These outcomes validate that our forecasting approach is deriving appropriate numbers that align with past experience. This supports our allocation of the probability of failure to each support structure asset.

Our analysis takes a fleet management approach to assessing risk and is not intended to identify individual support structures that require remediation, that will be done through normal business inspection and testing. Our analysis provides guidance to the priority of the replacements and a guide to the quantum of the expected risk on the network.

The matrices below are separated out for Central and Dunedin for both poles and crossarms as the risk profile of each area is quite different due to the population density of the regions. The risk has been assessed for both energy at risk and public safety, with the matrix displaying the highest of the two risks for each asset.

As expected, the risks predominantly in the insignificant to low categories, with a few becoming moderate and some high risk.

Table 8.17 Support structures risk matrix for Dunedin

Increasing consequence (criticality) -->

Prob of Failure -->					
	0	0	0	0	0
	1409	641	391	155	0
	7951	4815	2940	1137	0
	3155	1333	758	272	0
	1766	1111	1034	592	0

Table 8.18 Support structures risk matrix for Central

Increasing consequence (criticality) -->

Prob of Failure -->					
	0	0	0	0	0
	148	44	5	2	0
	10981	2419	254	103	0
	2429	607	47	13	0
	5886	1410	154	87	0

Table 8.19 Crossarm risk matrix Dunedin

Increasing consequence (criticality) -->

Prob of Failure -->					
	0	0	0	0	0
	1831	1096	817	378	0
	7824	4684	3493	1617	0
	7874	4714	3515	1628	0
	7548	4519	3370	1560	0

Table 8.20 Crossarm risk matrix Central

Increasing consequence (criticality) -->

Prob of Failure -->					
	0	0	0	0	0
	2067	550	65	28	0
	8833	2352	277	119	0
	8890	2368	279	120	0
	8522	2270	267	115	0

8.7 KEY FINDINGS

The key components of support structures are poles, crossarms and insulators. Information on insulator defects and condition is not separately recorded but they are generally replaced with the crossarm; hence, the review assessed insulators and crossarms together. We found:

- The asset data available from Aurora's systems and augmented by our field inspections was suitable for the purpose of this review. We note that the data is not complete and improvements to consistency of the data recorded can be made. Incomplete asset data presents a risk to effective asset management.
- There are 6,660 poles (12%) in service that exceed their expected life and there are 44,260 crossarms (47%) in service that are estimated to exceed their expected life based on the age of the pole they are installed on. Crossarm installation date information is not recorded by Aurora. The large number of support structures that exceed their expected lives indicates an elevated risk of failure of these assets. Further modelling was undertaken to refine the assessment of network risk and to identify quantities of high risk poles (2.6%) and crossarms (2.3%).
- A rising trend in supply outages from failed poles prior to 2016 has been arrested in 2017-2018, likely because of the accelerated pole replacement program.
- The pole inspection program has recently been improved but has not identified all poles that are in poor condition as it has not yet covered the whole network.
- Crossarms are not inspected adequately and many are in poor condition. Some are categorised as high risk due to their location relative to population and the probability of failure. Probability of failure was based on results from our field inspections.
- Malaysian Hardwood crossarms (3.8%) have a shorten life due to fungal growth and need to be replaced.

Note that our analysis focuses on a whole of fleet assessment and identifies expected quantities. Individual assets requiring remediation will be identified through Aurora's inspection and testing program.

WSP concludes that support structure poses a moderate to high risk to network reliability and specific assets pose a high risk to public safety due to their location in populated areas.

Table 8.21 summarises the risks for the support structures fleet and indicates the priority for remediation. The risks shown in the table cannot be allocated to individual assets and provide an indication of the scale of the risk only. For instance, the locations and volumes of the Malaysian Hardwood crossarms are not known and the testing to ensure accurate assessment of pole strength is a fleet wide risk.

Table 8.21 Summary of general risks for the support structures fleet

ITEM	NUMBER	RISK TYPE	DESCRIPTION
Remediation of poles	1,397	Safety	Expected number of high risk poles on the network. These are predominately termination and Tee-Off poles in high population areas. Individual assets to be identified through normal inspection process.
Remediation of crossarms	2,142	Safety	Modelled volume of high risk crossarms based on Drone inspections. Individual assets to be identified through normal inspection process.
Malaysian hardwood crossarms	~3,600	Safety	Hazard posed by Malaysian hardwood cross arms. Estimated volume based on interviews and available data. Individual assets to be identified through normal inspection process.
Improvement to testing and inspection processes	Fleet wide	Safety	Assessment of pole strength, particularly concrete poles, to enable improved condition assessment accuracy.

9 DISTRIBUTION SWITCHGEAR

This section discusses the current state of the distribution switchgear asset fleet, its recent performance and WSP's assessment of the risk it presents to Aurora's network in terms of impacts to safety, reliability and the environment.

9.1 ASSET DATA

9.1.1 AVAILABILITY AND QUALITY

To assess the risk of the distribution switchgear, WSP reviewed the information available from the following activities:

- on-site inspection of assets
- analysis of distribution switchgear attributes such as type and age
- review of Aurora's inspection and test results
- review of outage data
- discussion with Aurora SMEs to understand any data gaps.

We assessed the data availability of this asset class. In undertaking this assessment, we have considered all the information we obtained from Aurora over the course of the project. Table 9.1 is the data quality summary of the available information where we took into consideration the ease of available and accessibility of the information.

We found that the available data for distribution switchgear was adequate for the purpose of this review, however, the accessibility of the data is not straight forward as it is spread over many separate documents and systems including GIS, spreadsheets and PDF site inspection reports. Items to note are:

- an overall average of 77% of ground-mounted RMUs and switches attribute data was recorded
- an overall average of 65% of pole-mounted switches attribute data was recorded
- no attribute data was available for pole-mounted fuses (i.e. manufacturer, configuration and switch type). Note that WSP identified the fuse type through inspection for a sample of assets as part of our data validation (see section 9.3)
- across both ground-mounted and pole-mounted switchgear, switchgear type was unknown for 86% of the fleet noting that approximately 21% of those switches were installed during that last 10 years
- 93% of all attribute data is recorded for reclosers, with 89% of reclosers having the manufacturer recorded and 66% having the switch type recorded.
- there is inconsistency in the terminology used in the asset data making data harder to use effectively.

This missing information identified could be readily included in the asset register. This would enable improved recording of fault and outage information as well as enabling Aurora to locate each asset type on the network. Having this information would allow asset type issues that may emerge to be more easily identified and ensure appropriate maintenance is undertaken.

In general, while we identified deficiencies in the data which pose a risk to effective asset management, we found that there was sufficient information available to undertake this review based on a modelling approach.

Table 9.1 Summary of data quality

TYPE	SUB TYPE	ATTRIBUTES	CONDITION	PERFORMANCE	DATA QUALITY
Reclosers and sectionalisers	Reclosers	🟡	🟡	🟡	🟡
	Sectionalisers	🟡	🟡	🟡	🟡
Ground-mounted switchgear	RMU	🔴	🟡	🟡	🔴
	Switches	🔴	🟡	🟡	🔴
Pole-mounted switchgear	Fuses	🔴	🟡	🟡	🔴
	Switches	🔴	🟡	🟡	🔴

9.1.2 ASSET CLASS SEGMENTATION

Distribution switchgear was segmented into pole-mounted and ground-mounted groups for field inspections to enable validation of data.

9.2 DESCRIPTION OF THE ASSET CLASS

This section provides an overview of the asset fleet and the characteristics that are indicators of risk.

9.2.1 FLEET COMPOSITION

Distribution switchgear includes:

- Pole mounted switchgear, including fuses and air break switches (ABS)
- Ground mounted switchgear, including ring main units (RMU)
- Automatic circuit reclosers (ACRs) and sectionalisers.

Table 9.2 shows the fleet summary classified by switchgear type for each network. There is a total of 7,896 distribution switchgear units installed on the network. Due to the larger geographical area, the Central network has 39% more distribution switchgear compared to the Dunedin network.

Table 9.2 Fleet summary by type

TYPE	SUB TYPE	CENTRAL	DUNEDIN	TOTAL
Reclosers and sectionalisers	Reclosers	44	16	60
	Sectionalisers	3	0	3
Ground-mounted switchgear	RMUs and Switches	627	727	1,354
Pole-mounted switchgear	Fuses	3,502	2,096	5,598
	Switches	447	492	939
Total		**4,623**	**3,331**	**7,954**

AGE PROFILE

Figure 9.1 and Figure 9.2 show the age profile of assets by switchgear type, which provides an indication of the volumes of assets approaching the end of their expected lives. The fuses are shown on a separate chart due to the difference in volume of assets compared to the switchgear. The chart shows that 60% of air break switches, 77% of RMUs, 82% of fuses and all reclosers are within the industry standard asset life of 40 years.

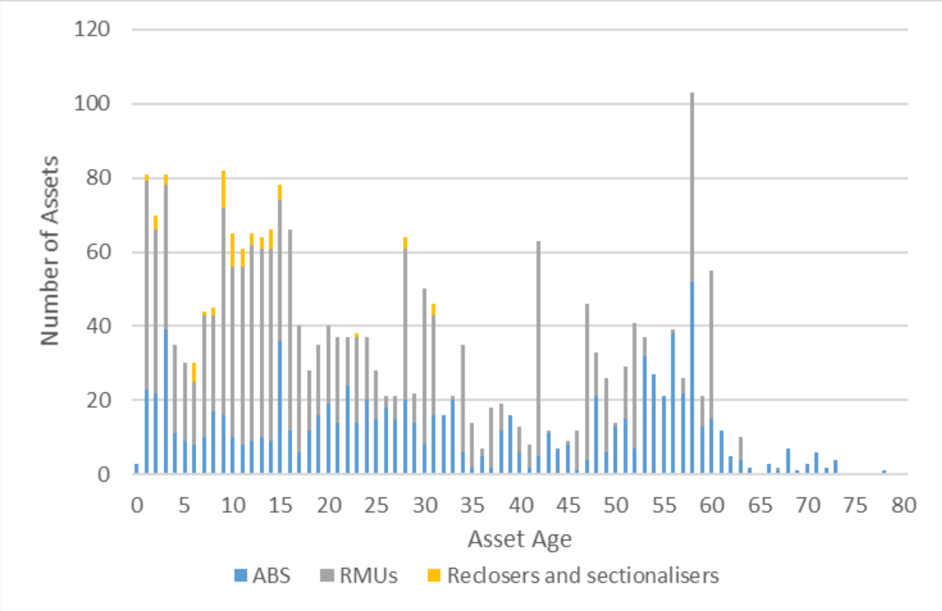

Figure 9.1 Distribution switchgear age profile by asset type

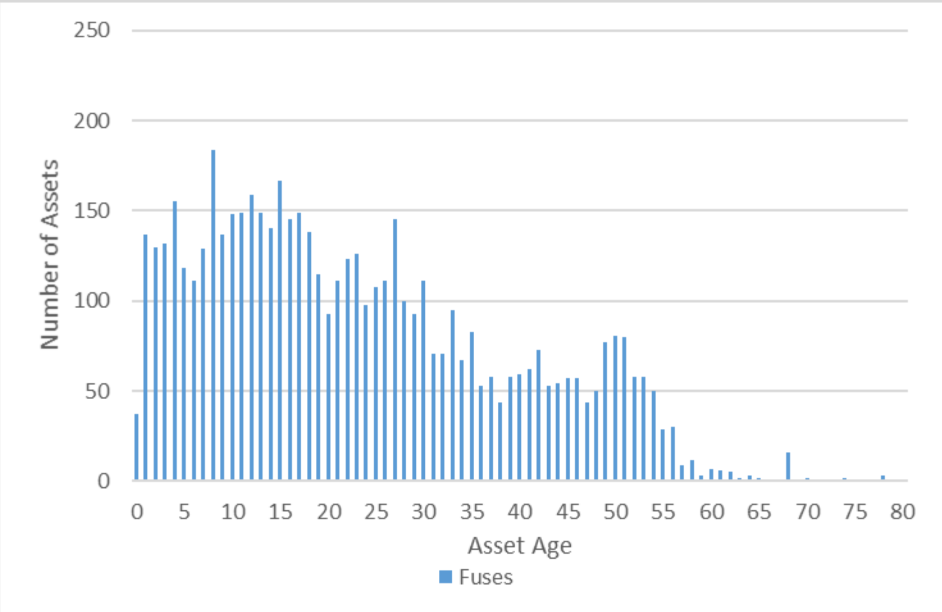

Figure 9.2 Distribution fuses age profile

EXPECTED LIVES

Table 9.3 shows the fleet statistics in relation to expected asset life of the distribution switchgear, and average remaining life for the different switchgear types. While we have provided the general expected life for the assets, the life achieved depends on the specific installation location, with a longer life expected for switchgear located inside a building compared to those located outdoor.

Table 9.3 Fleet statistics

TYPE	WEIGHTED EXPECTED LIFE	WEIGHTED AVERAGE AGE	WEIGHTED AVERAGE REMAINING LIFE	NUMBER EXCEEDING EXPECTED AGE
Pole-mounted Air Break Switches	40	33.1	6.9	371
Pole-mounted Fuses	40	23.2	16.8	991
Ground-mounted switches	40	23.8	16.2	316
Reclosers and sectionalisers	40	11.3	28.7	0

9.2.2 FAILURE MODES AND CONSEQUENCES

This section discusses the failure modes and consequences as they relate to this asset class. It is only intended to inform how we approached our risk analysis and reflect the key failure modes that we identified during the review.

Under normal operating environments, there are three common distribution switchgear failure modes: the first is due to a failure in operating mechanism, which is generally not evident until the switchgear is operated; the second is wear of the contacts leading to arcing and eventual failure; and, the third is the failure of the associated connections to conductors, i.e., failure of cable terminations that damage the switch. Regardless of switch type, the consequence could lead to electrical failure in both events. We note the following:

- It is common for pole-mounted switchgear to fail due to rust, mechanical failure, missing bolts and nuts and loose parts. Due to the failure modes, the risk of failure increases over time due to age and/or if they are not operated for long periods. Insufficient or inadequate maintenance will also likely result in a higher probability of failure. WSP has not seen any evidence to suggest that pole mounted switchgear experience catastrophic or explosive failures on Aurora’s network. The most common failure mode identified is failure to operate due to seized mechanisms.
- For ground-mounted switchgear, including RMUs, oil-filled switchgear is most common. It is common for this type of switchgear to fail due to oil leaks, aged fuses, oil ingress and internal arcing which could lead to a catastrophic failure and has been recently experienced in the industry with specific types of switchgear, Long & Crawford (L&C) and Statter in particular. In addition, other switchgear of similar vintages that are in the Aurora network have been known to fail on other networks, including:
  - Andelect
  - ABB SD
  - Reyrolle ROKSS

The main consequence of switchgear failure is typically loss of electricity supply to an area. If the mechanism is seized or cannot be operated, then the next switch upstream must be operated which will result in a larger outage than necessary.

However, oil type RMUs have recently experienced explosive failures in Australia and New Zealand. The Long & Crawford type switch contains a fuse that is housed in an oil filled container. Failure of the container can result in an explosion. This has resulted in fatalities of field crews, but WSP is not aware of any in injury to the public as a result.

On Aurora’s network, the majority of the L&C and Statter type distribution switches are installed indoors. This provides an improved safety outcome particularly with respect to the explosive failure mode as it provides a physical barrier for protection of the public.

9.2.3 INSPECTION, TESTING AND REPLACEMENT

We found that historically maintenance on distribution switchgear has not been undertaken consistently and there was no regular inspection program in place. The maintenance strategy was to run these assets to failure. However, an inspection was undertaken whenever a problem arose with any individual switchgear unit or when Aurora performed replacements on other assets related to the switchgear, such as pole replacements. We note that Aurora has recently changed their approach to a periodic inspection and testing cycle and are implementing mobile apps to capture data. This has not yet been rolled out across the fleet.

9.3 DATA VALIDATION

As part of our data validation, WSP undertook a review of the inspection and test sheets and carried out on-site inspections. The on-site inspections were a visual inspection on a selected sample of both the pole-mounted and ground-mounted switchgear to look at the general condition of the assets, as well as specific checks such as earthing connections, accessibility, and oil levels or leaks as applicable.

Inspection of pole-mounted switchgear was limited to what could be seen from the ground. There were also some limitations for ground-mounted switchgear inspections due to access issues (for example with switchgear being on Kiwi-rail sites). We did not conduct switchgear testing as this requires certain parts of the network to be isolated and taken offline.

As part of the on-site inspections, a total of 25 ground-mounted switchgear and approximately 60 pole-mounted switchgear were visually inspected. The findings from the field work are set out in section 9.4.

9.4 PERFORMANCE AND CONDITION

This section considers the historical performance to understand how the network has changed over time. This provides a leading indicator on likely future network performance and probability of asset failure or need for remediation.

RELIABILITY PERFORMANCE TRENDS

Figure 9.3 show the annual outages per calendar year for distribution switchgear, excluding fuses, and Table 9.4 shows the number of outages by cause. The data was filtered to only include distribution switchgear that failed in service due to defective equipment and planned replacements where the description was to replace a faulty transformer. The R^2 is 0.7 which shows a good fit to the data.

The chart shows there is an increasing trend of distribution switchgear failures which indicates these assets pose a risk to the network reliability and operator safety. Note that the data for 2018 is for half a year from January to July.

Asset deterioration contributed 48 (74%) of the 65 outages and a further 5 (8%) were attributed to operating the switchgear outside operating parameters. For asset deterioration, pole-mounted air break switchgear (ABS) contributes to 32 of the outages and ground-mounted switchgear contribute 14 of the outages.

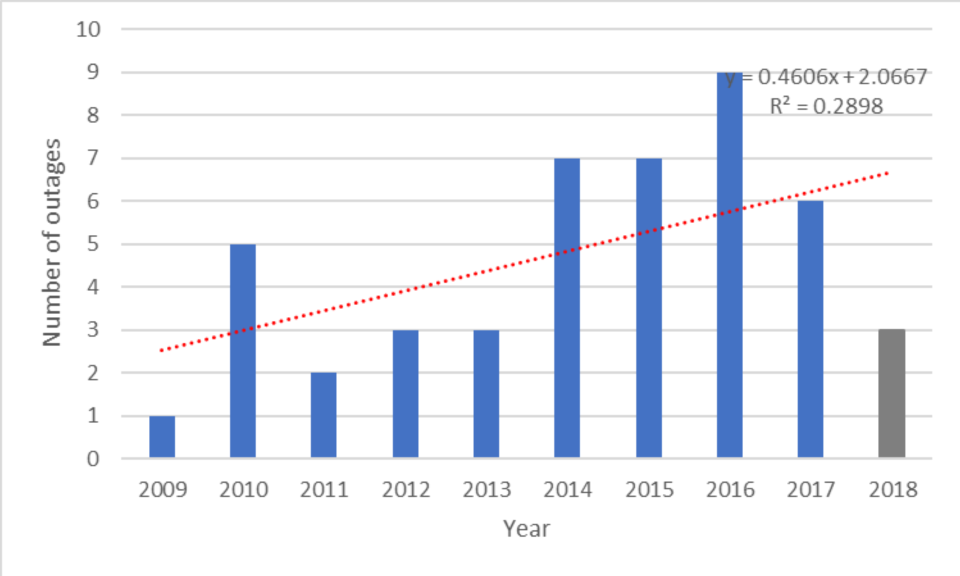

Figure 9.3 Historical outages caused by distribution switchgear failure, excluding fuses

Table 9.4 Cause of outages for distribution switchgear, excluding fuses

CAUSE DESCRIPTION	NUMBER OF OUTAGES	PERCENTAGES	ABS	ACR	CB	GROUND-MOUNTED
Equipment Deterioration	36	78%	23	2	0	11
Equipment Imminent Failure	3	7%	2	1	0	
Unknown	3	7%	2	0	0	1
Weather Winds	2	4%	1	0	0	1
Equipment Faulty Manufacture	1	2%	1	0	0	0
Weather Rain	1	2%	0	0	1	0
Total	**46**	**100%**	**29**	**3**	**1**	**13**

Figure 9.4 and Table 9.5 show the historical outages caused by fuses that were identified to have not operated correctly. Fuses that were recorded as having operated as intended to stop the fault are excluded. For example, a cause description of a 'Blown fuse' was excluded as that is the intended operation, however, a cause description of 'Faulty fuse' or 'Burnt fuse' was included as it indicates the fuse did not operate as intended and is therefore a failure of the asset.

The chart and table show that there is a consistent number of fuses that fail to act as intended each year, with an average of 20 per year, but displaying a decreasing trend. The data available does not have sufficient detail to undertake further investigation to determine if there is a relationship between the fuses that fail and fuse attributes such as type or age, although EDO type fuses make up 77% of fuses that fail in service.

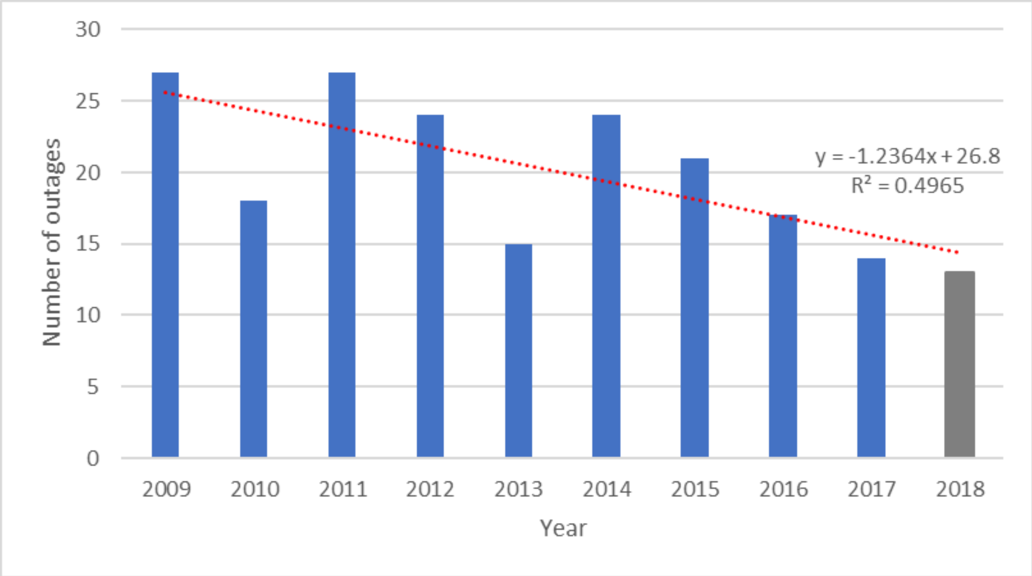

Figure 9.4 Historical outages caused by distribution fuse failure

Table 9.5 Cause of outages for distribution fuses

CAUSE DESCRIPTION	NUMBER OF OUTAGES	PERCENT	DDO	GLASS	HRC	LV FUSE UNIT
Equipment Deterioration	183	92%	141	3	23	16
Unknown	10	5%	7	2	1	0
Weather Rain	2	1%	2	0	0	0
Weather Winds	2	1%	1	0	1	0
Environment Fire	1	1%	1	0	0	0
Environment Salt Spray	1	1%	1	0	0	0
Equipment Imminent Failure	1	1%	1	0	0	0
Total	**200**	**100%**	**154**	**5**	**25**	**16**

HISTORICAL REPLACEMENT

Figure 9.5 shows the age of distribution switchgear, excluding fuses, at end of life replacement and at failure (replaced once it has already failed in service). The chart shows that most distribution switchgear is replaced prior to failure (indicated in the chart as “End of Life”). The in-service failure rate is approximately two distribution switchgear units in every five-year period. We note that there is a backlog of ABS distribution switches that are tagged as ‘Do not operate’ that are not included in this list.

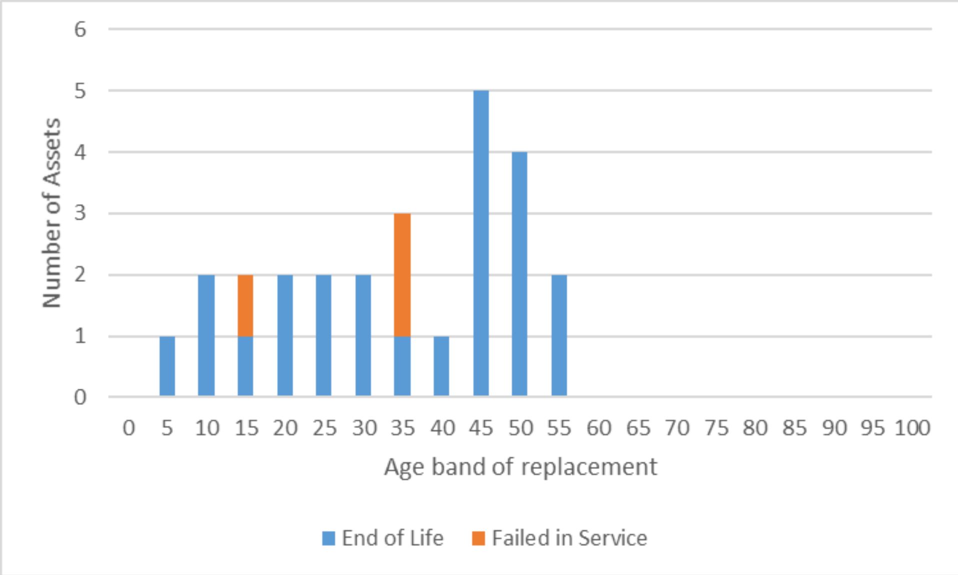

Figure 9.5 Frequency of age at replacement by cause (excluding fuses)

Although this is a small data set, it was used in the calculation of the survival curve characteristics. The calculated characteristics were then reviewed against electricity industry experience of these asset types to confirm they were appropriate for use.

SWITCHGEAR CONDITION

Historically there has not been a regular dedicated inspection and testing program for distribution switches. However some adhoc testing has been undertaken and a specific program was undertaken in 2017 that inspected 155 RMUs. A review of the inspection data, available test sheets and the public hazard register found:

- During testing in the last month, Aurora found approximately 50 additional distribution switchgear units that are not operational. The large number of inoperable switches complicates network operations as it would result in an outage of a larger area when the next operational upstream switch is opened and poses a risk to network reliability.
- Recloser batteries are built into the recloser and maintained or swapped out based on a programmed time slot. WSP reviewed the recloser battery list and found 10 reclosers have yet to have their battery replaced as part of the replacement programme. This poses a risk that the reclosers may not operate when required.
- We identified some evidence of auto-reclosers detecting faults, tripping lines and auto-reclosing, but then failing to re-trip when the fault remained which can lead to a severe hazard. This was identified in the public safety hazard register as a high impedance fault scenario that can be difficult for protection devices to detect.
- Inspection results were available for 87 ABB SD type distribution switches. No temperature stress was found, but three units indicated partial discharge. One switch unit was found to be severely corroded and the external condition of eight units was found to be moderately deteriorated.
- Inspection results were only available for 1 out of 26 Reyrolle type switches. The inspection results indicated that there were no signs of partial discharge or problems with high temperatures and the external condition was only moderately deteriorated. In addition, 23 of the switches have not yet exceeded their expected serviceable life.
- Inspection results were only available for 13 out of 208 L&C type switches. The inspection results indicated that while there were no signs of partial discharge or problems with high temperatures, one unit had a severe oil leak and most had low oil levels. The external condition was moderately deteriorated.
- No inspection or test information was available for Statter type switches.

The findings above and incomplete inspection and test data related to the L&C, Statter and Reyrolle ROKSS type switches indicates an elevated risk on the network with respect to distribution switchgear.

DISTRIBUTION EARTHING

WSP reviewed a number of test and remediation reports for distribution assets. The reports indicate that Aurora has undertaken earthing testing and remediation across distribution asset fleets in both the Dunedin and Central networks since 2013, with evidence of a large program of works (testing and remediation) from 2014 to 2016.

WSP examined details of distribution earthing during its site inspections around the network. All inspected transformers have intact earthing but there is a need for the earth conductor to be fixed to the pole. This is a similar issue with pole-mounted switchgear. No other issues were identified.

DISTRIBUTION FUSES

Aurora is aware of some type issues and deterioration of HV fuses and a number of fuses that have been identified as unsafe for field crew to operate or remove from service unless de-energised. These fuses are:

- HRC fuses in the Dunedin network on FD-A mounts have been identified as having a type issue where the mount can break when operated
- Low voltage JW Wedge and Lucy fuses have been identified to pose an elevated risk to worker safety and are subject to operational controls specifying they cannot be operated while the line/asset is energised.

The failure of an individual fuse has a low consequence comparative to the other asset classes, posing a small risk to reliability and safety.

LONG & CRAWFORD SWITCHGEAR

L&C switchgear is an old switchgear technology that was installed on Aurora's electricity networks in the 1970's and 1980's. The switchgear construction uses a fuse assembly that is immersed in oil and contained in a cast iron housing. From a safety perspective, the L&C switchgear pre-dates arc-fault containment design and has demonstrated an explosive failure mode in some instances. Two recent examples are noted below, although it is thought that operator error may have also been a contributing factor in these cases:

- Galleria shopping centre, Morley, Western Australia: An explosion occurred which was associated with the private electricity distribution network within the shopping centre. Several persons were injured and two died from their injuries.
- Vector, Auckland: Due to ingress of oil, the L&C fuse switch exploded and oil and internal parts from inside the switch were spread over 25 meters from the switch. No persons were harm in this event.

WSP note that ageing oil-filled non-arc fault rated distribution switchgear (where arc-fault rating is defined by IEC 62271) is considered to have potential safety impacts. We note that there are industry safety advice notices against this asset type and recommendations for replacement of oil filled distribution switchgear from a number of industry sources, including:

- Queensland Government, Mines Safety – Ageing electrical switchgear, September 2016
- UK Power Engineering Improvement Initiative[12]
- Scottish Power[13]
- Electricity Networks Association (UK)[14]
- EEA (NZ), and

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[12] http://www.hse.gov.uk/foi/internalops/ocs/400-499/oc483_27.htm

[13] Scottish Power Express, refence EXP-11-180 – Operational restriction (Oil sludging) L&C t3GF3/T4GF3 and Scottish Power Express, reference EXP-11-189 SOP 383 Long and Crawford GF3F et al

[14] ENA, Autumn 2012 ENA SHE Managers – Review of past asset related incidents

— Order from Energy Safety (Western Australia)[15]

The weight of evidence from in service failures across the electricity industry, and general industry practice, indicates that this switchgear type is at or approaching its end of life.

Figure 9.6 shows Aurora has 208 L&C units, which is 18% of the RMU fleet

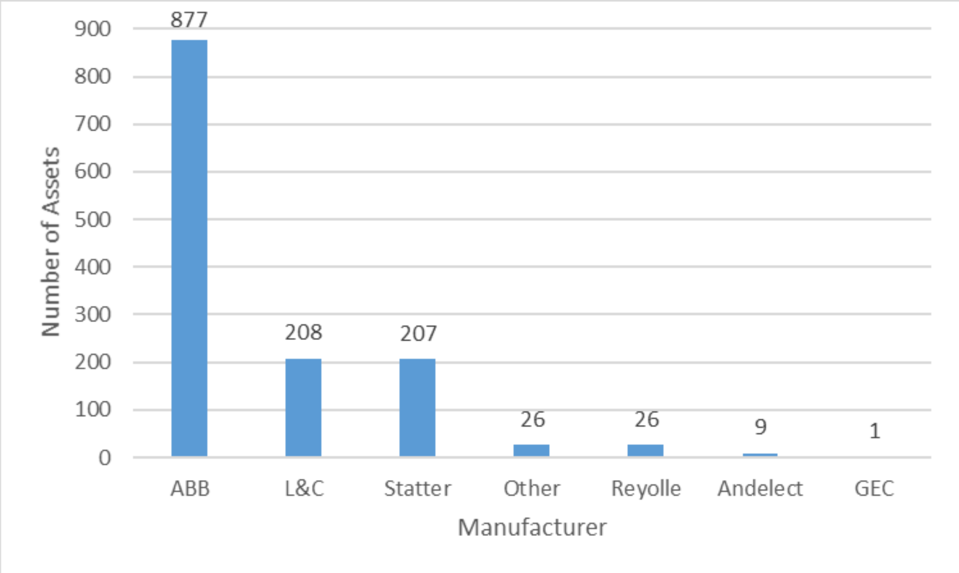

Figure 9.6 Quantity of RMU by manufacturer

The Statter type switchgear has a similar construction to the L&C type switchgear of oil filled fuse units with cast iron lids/casing. It is also of a similar age to the L&C units so are found to have the same risk profile. Aurora is aware of the risk and have put in place a risk mitigation program to mitigate this risk.

INSPECTION FINDINGS

The visual assessment checked 73 units of distribution switchgear in Dunedin and Central Otago. Key findings from the assessment include:

Ground-mounted distribution switchgear and RMUs:

- Seven ABB RMUs of the 23 inspected have signs of oil leakage with two units having oil below the level mark. we identified that two of the seven RMUs were not recorded in Aurora's GIS (used as the asset master data register).
- Some sites show subsidence on the foundation due to movement of soil, cracking in foundations and gaps occurring between the foundation and the switchgear.
- For external earthing, there is no cable riser protection on the earthing cable which poses a safety hazard should the earth be damaged. For internal earthing, WSP saw no evidence of improperly earthed equipment.
- Some switchgear that is in poor condition with signs of oil leakage was tagged for a partial-discharge test[16].
- We were unable to inspect an L&C unit, however, we inspected two Statter units which are an early modular design of RMU. They incorporate oil filled fuse compartments enclosed by a cast iron lid/casing which are similar to the L&C unit. The two units 2 units were age in their mid-50s and had poor physical appearance even though they were both installed inside a building which provide protection from the environment.

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15 Urgent Attention Bulletin, Western Power, 6/2/2015 Operational restriction (L&C /GEC/ALSTOM)

16 We note that in 2017 there were 155 RMUs inspected, included partial discharge testing. Aurora has indicated that the partial discharge tags may be a historical process and require assessment and removal. The current process requires all RMUs to be tested for partial discharge prior to operation.

Pole-mounted distribution switchgear:

- 25 of the 50 switchgear units inspected have moderate to bad rust on the operating mechanism, especially at the U-bolt connection on the operating pipe. If not addressed, this can result in the mechanism seizing and resulting in the switch not operating correctly or becoming inoperable.
- Only 30% of switchgear have dual earthing conductor while the rest are single earthing. Although there is no requirement for double earthing, it is now common practice for redundancy as broken earth connections have safety consequences for the field crews. Our site inspection identified 2 locations out of the 50 inspected where the earthing conductor was a smaller gauge compared to the sizes commonly used at the other locations. Smaller conductors are not as mechanically strong and there is a slightly elevated risk that they may break, resulting in loss of the earth connection.

Our inspection identified additional uncertainty regarding the completeness of Aurora's asset data for this asset class, as demonstrated by the discovery of two assets installed on the network that were not in Aurora's asset systems. We also found that, in general, the fleet appears to be worn and exhibiting end of life signs through the types of defects identified. Our findings align with the information provided by Aurora that there has not been an established and periodic maintenance program for this asset class.

In general, this fleet is considered to have an elevated risk of failure of failure, and the L&C and Statter types are found to have an elevated consequence to safety and reliability when they fail, however, this is mitigated where these assets are installed indoors which provides a physical barrier that protects the public.

Our site inspections did not identify any obvious deficiencies or faults with fuses and found they correctly installed at appropriate locations such at distribution transformers and spur lines.

9.5 APPROACH TO RISK ASSESSMENT

We have taken a quantitative approach to the risk assessment of Distribution Switchgear that relies on the use of parameters identified in our analysis above. We develop a survival cure based on the conditional probability of failure using the Weibull distribution derived from historical asset failure and replacement data. The conditional probability established the risk of failure, while the consequence was assessed by considering both the impact to safety and the impact to network reliability.

9.6 RISK ASSESSMENT

Analysis of the distribution switchgear fleet data identified 1,678 switchgear units have exceeded their expected life of 40 years, compared to the fleet size of 7,954 switchgear units (including fuses). This indicates that there is an elevated probability of failure of these assets and provides an indication of the magnitude of risk on the network.

The modes of deterioration and types of defects identified through the field inspections were predominately age related, such as rusting components and cracking foundations. This demonstrated that age has a strong relationship to condition, and it is, therefore, a strong indicator of a risk on the network and suitable for use in modelling.

Application of the Weibull model takes a probabilistic view of the fleet. Historical records of removed distribution switchgear included the age of switchgear at failure or replacement and this data was used to create a probability of failure (survival) curve which determines the probability of asset failure for each asset. We calculated an additional 74 units of switchgear would reach end of life during the next year

The failure of oil insulated distribution switchgear as discussed in the previous sections can pose a risk to the public and field crews. Since these assets are distributed around the network, there is the potential for the public to be in close proximity to the switches. Switchgear installed inside enclosures has a better safety outcome as it provides a physical barrier.

The dominant consequence from the failure of distribution switchgear is loss of supply to customers, or the need to operate an upstream switch to enable network operations or isolate a fault and, therefore, create a larger outage.

Oil-filled distribution switchgear are small in capacity and only hold small amounts of oil, hence, as a fleet they pose a low environmental risk. As such, as we would not expect oil leakage or an oil spill to have no long-term effect on ecosystem functions or incur a penalty as set out in section 4.3.3.

The tables below show that the distribution switchgear generally have a low or moderate risk due to their locations on the network and installation of oil insulated switchgear in enclosures. Only 20 are classed as having a high risk. These are the L&C type assets in highly populated locations. In general, Dunedin has a slightly higher risk than Central.

Table 9.6 Distribution switchgear risk matrix for Dunedin

Increasing consequence (criticality) -->

Prob of Failure -->

0	0	0	0	0
99	155	12	5	0
1754	686	55	15	0
276	49	3	0	0
157	73	0	0	0

Table 9.7 Distribution switchgear risk matrix for Central

Increasing consequence (criticality) -->

Prob of Failure -->

0	0	0	0	0
70	1	0	0	0
2543	148	0	0	0
1174	57	0	0	0
625	7	0	0	0

9.7 KEY FINDINGS

The key assets in the distribution switchgear fleet are pole mounted air break switches, pole mounted auto reclosers, ground mounted switchgear and RMUs. We found:

- The asset data available from Aurora's systems and augmented by our field inspections was suitable for the purpose of this review. We note that the data is not complete and improvements to consistency of the data recorded can be made. Incomplete asset data presents a risk to effective asset management.
- The distribution switchgear fleet has 1,678 units (21%) exceeding their expected life. This indicates that there is an elevated probability of failure of these assets and provides an indication of the magnitude of risk on the network. Further modelling was undertaken to refine the assessment of network risk and to identify quantities of high risk assets.
- Distribution switchgear has only contributed 8% to the average number of outages on the network between 2013 and 2017 but is displaying an increasing trend.

- A significant number of distribution switchgear units are defective and inhibit normal operation of the network, which can lengthen outages experienced by customers or expand the number of customers affected as an upstream switch must be operated instead. This can impact the reliability performance of the network.
- A significant portion of the RMU type switchgear inspected (40%) have oil leaks, indicating a deteriorated condition.
- The L&C type switchgear are at or approaching their end of life and are found to have a high probability of failure. They have been found to have an explosive failure mode and, hence, can pose a risk to safety. There are a number of industry safety advice notices related to this asset type. The Statter type switchgear has a similar construction to the L&C type switchgear of oil filled fuse units with cast iron lids/casing. It is also of a similar age to the L&C units so are found to have the same risk profile.
- There are three types of fuses: HV HRC fuses, and LV JW Wedge and Lucy fuses, that have identified type issues, but pose a low risk to reliability and safety. The need to deenergise the LV fuses prior to operation is a risk to reliability, however, as LV fuses only impact a small number of people the risk is low.
- 77% of fuse failures are caused by DDO type fuses, indicating a possible type failure. However, the impact of reliability and safety is immaterial
- Batteries in circuit reclosers do not have a regular replacement scheme. This poses risk that the reclosers may not operate when required.

WSP concludes that distribution switchgear poses a low to moderate but increasing risk to network reliability and specific assets pose a high risk to worker safety. Table 9.8 summarises the risks for the distribution switchgear fleet and indicates the priority for remediation.

Table 9.8 Summary of general risks for the distribution switchgear fleet

ITEM	NUMBER	RISK TYPE	DESCRIPTION
Statter distribution switchgear	28	Reliability and Safety	Statter switchgear units with high and moderate risk.
Long and Crawford distribution switchgear	59	Reliability and Safety	Long and Crawford switchgear units with high and moderate risk.
ABB RMUs	3	Reliability and Safety	ABB RMU’s with high and moderate risk.

10 DISTRIBUTION TRANSFORMERS

This section discusses the current state of the distribution transformer asset fleet, its recent performance and WSP's assessment of the risk it presents to Aurora's network in terms of impacts to safety, reliability and the environment.

10.1 ASSET DATA

10.1.1 ASSET DATA AVAILABILITY

To assess the risk of the distribution transformer, WSP reviewed the information available from the following activities:

- on-site inspection of a random selection of assets
- analysis of transformer attributes such as type, age and operating voltage
- discussion with Aurora SMEs to understand any data gaps.

In undertaking this assessment, we have considered all the information we obtained from Aurora over the course of the project. Table 10.1 is the data quality summary of the available information where we took into consideration the ease of available and accessibility of the information.

We found that the available data for distribution transformers was generally good, however, the accessibility of the data is not straight forward as it is spread over many separate documents and systems including GIS, spreadsheet and PDF site inspection reports. Items to note are:

- key attributes (service date and ratings) are well populated but 21% of transformers have an unknown manufacturer associated with them
- condition information is available but spread over a combination of spreadsheets and PDF hand written site inspection reports making it difficult to use and analyse
- there is inconsistency in the terminology used in the asset data making data harder to use effectively.

This missing information identified could be readily included in the asset register. This would enable improved recording of fault and outage information as well as enabling Aurora to locate each asset type on the network. Having this information would allow asset type issues that may emerge to be more easily identified and ensure appropriate maintenance is undertaken.

In general, we found that there was sufficient information available to undertake this review, although there is opportunity for improvement that would facilitate good asset management practices.

Table 10.1 Summary of data quality

TYPE	ATTRIBUTES	CONDITION	PERFORMANCE	DATA QUALITY
Ground-mounted Transformer	●	●	●	●
Pole-mounted Transformer	●	●	●	●
Voltage Regulators	●	●	●	●

10.1.2 ASSET CLASS SEGMENTATION

Distribution transformers were segmented into pole-mounted and ground-mounted groups for field inspection.

10.2 DESCRIPTION OF THE ASSET CLASS

This section provides an overview of the asset fleet and the characteristics that are indicators of risk.

10.2.1 *FLEET COMPOSITION*

This asset class comprises of:

- ground-mounted transformers
- pole-mounted transformers
- voltage regulators.

Aurora's network comprises of 7,029 distribution transformers and 13 voltage regulators. Due to the larger geographical area, the Central network has 65% more distribution transformers compared to the Dunedin network, which has a smaller number of larger capacity transformers to supply a higher population density. Table 10.2 shows the fleet summary classified by transformer type for each network. These figures were based on currently in-service distribution transformers.

Table 10.2 Fleet summary by type and location

TYPE	CENTRAL	DUNEDIN	TOTAL
Ground-mounted transformer	2,062	960	3,022
Pole-mounted transformer	2,308	1,686	3,994
Voltage regulators	8	5	13
Total	4,378	2,651	7,029

AGE PROFILE

Figure 10.1 shows the age profile of the transformers and voltage regulators by type and it provides an indication of the number of assets approaching the end of the expected life.

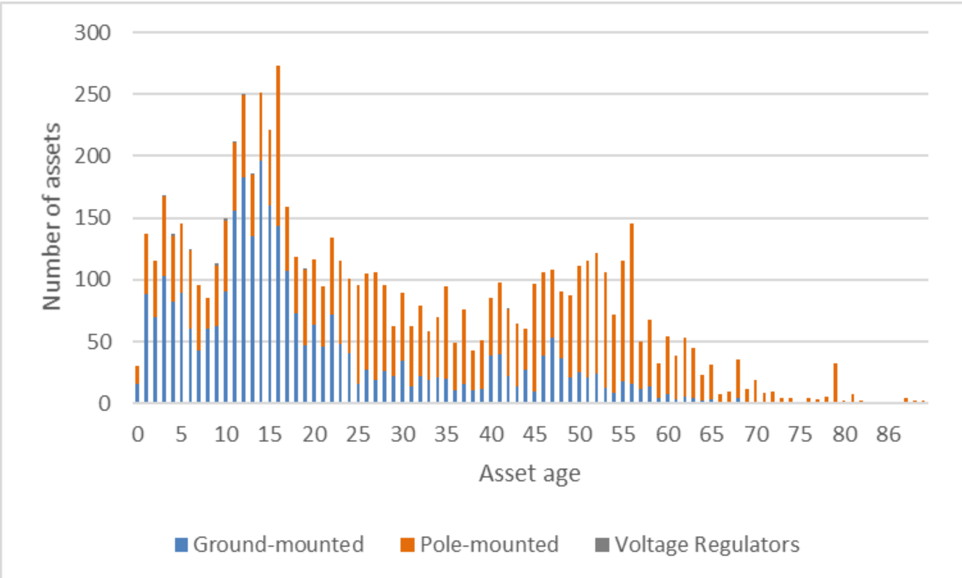

Figure 10.1 Distribution transformer age profile by type

EXPECTED LIFE

Table 10.3 show the weighted average age of the distribution transformers by type. The expected life for distribution transformers depends on the installation, installation condition and whether the unit is enclosed or located inside or outside a building.

- For ground-mounted distribution the expected OEM life is typically 35 years and operate at 40% capacity, however the life of the transformers can be extended with oil maintenance and refurbishment at 40 years and we can expect an asset life ranging from 55 to 60 years. For our analysis, we would assume an asset life of 55 years.
- With pole-mounted transformers, they are usually much smaller and typically feed farms and smaller local installations. They are usually operated from 60% to 80% capacity and seldom maintained and are normally replaced after failure. We expect this type of transformer to have an asset life between 45 to 60 years. For our analysis, we would assume an asset life of 55 years.
- For voltage regulators, the life is dependent on the technology and the original manufacturer. The life span can be variable as it may have moving parts (e.g. voltage taps) and the capacitors have a finite life. Typically, they have an expected life between 35 to 40 years. For our analysis, we would assume an asset life of 35 years.

Table 10.3 Fleet statistics

TYPE	WEIGHTED EXPECTED LIFE	WEIGHTED AVERAGE AGE	WEIGHTED AVERAGE REMAINING LIFE	NUMBER EXCEEDING EXPECTED AGE
Ground Mounted Transformer	55	19.9	35.1	79
Pole Mounted Transformer	55	34.8	20.2	647
Voltage Regulators	35	11.7	23.3	1

10.2.2 FAILURE MODES AND CONSEQUENCES

This section discusses the failure modes and consequences as they relate to this asset class. This is not intended to be a detailed risk assessment; it is only intended to inform how we approached our risk analysis and reflect the key failure modes that we identified during the review.

Under normal operating environment, distribution transformers are generally robust and, in most instances, the industry would adopt a “run-to-failure” strategy as part of their maintenance strategy. The exception is large distribution transformers which are usually monitored. We note the following:

- For ground-mounted transformers, the common failure mode is usually insulation failure or external factors e.g. falling debris, ground subsidence or damaged foundation.
- For pole-mounted transformers, the common failure mode is usually insulation failure or external factors e.g. vehicle collision into the pole, ground subsidence or damaged pole foundations.
- For voltage regulator, it is common for corrosion to occur on contacts.

Although distribution transformers are robust, the consequence of failure could potentially lead to

- oil spillage
- permanent disability to people in the public, employees or contractors. Distribution transformers are not expected to explode and internal faults are typically contained within the transformer tank

- short term supply interruption which have a low impact on customers, as a failure impacts a relatively small number of customers and is readily replaced.

10.2.3 INSPECTION, TESTING AND REPLACEMENT

We found that maintenance on distribution transformers under 100 kVA is not consistently undertaken and there is no regular inspection program in place. This is common industry practice and the adopted maintenance strategy is to run these assets to failure. However, visual inspections are undertaken as and when required for example when there is a known issue in industry with a make and model or when Aurora is performing replacements on other assets surrounding the transformer.

With distribution transformers above 100 kVA and for regulators, Aurora has in place a maintenance programme to perform inspections on a routine basis.

REPLACEMENT HISTORY

Distribution transformers are replaced at failure and at occasions, depending on condition, aged-transformers are replaced at the time when the poles are replaced.

The findings from the review of inspection and our on-site inspections are discussed in the following sections.

10.3 DATA VALIDATION

As part of data validation, WSP undertook on-site inspection on a selected sample of both the pole-mounted and ground-mounted transformers.

Approach:

The on-site inspections were a visual inspection on a selected sample of both the pole-mounted and ground-mounted transformers. Specifically looking for oil leaks, unusual sounds and overheating, ground subsidence, access to the unit and to ensure the transformer is not covered or a hole dug underneath it.

Inspection of pole-mounted transformers was limited to what could be seen from the ground. We did not conduct transformer testing as this requires certain parts of the network to be isolated and customers to be interrupted.

Field work undertaken:

A total of 25 distribution transformers were sampled and inspected visually inspected. The findings from the field work are set out in section 10.4.

10.4 PERFORMANCE AND CONDITION

This section considers the historical performance to understand how the network has changed over time. This provides a leading indicator on likely future network performance and probability of asset failure or need for remediation.

RELIABILITY PERFORMANCE TRENDS

Figure 10.2 shows the annual outages per year. The data was filtered to only include distribution transformers that had failed in service due to defective equipment and planned replacement where the description was to replace a faulty transformer. The R^2 is 0.09 which shows outages caused by distribution transformers fluctuates from year to year. The data for 2018 is an estimate based on half a year of data for January to July.

The chart shows a flat trend of transformer failures with a low fit to the data. There is an average of 10 outage per year which indicates these assets pose a risk to network reliability and safety.

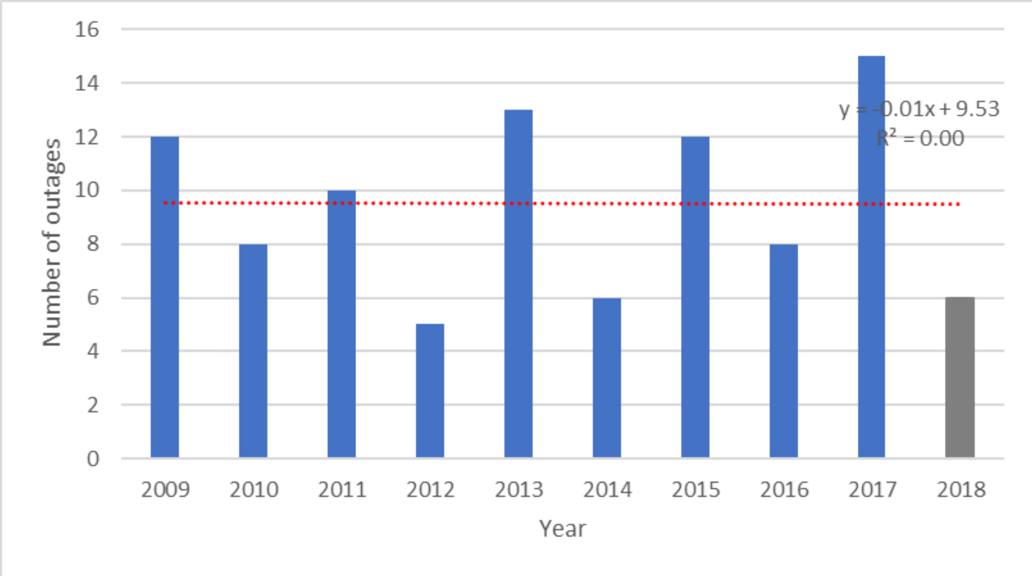

Figure 10.2 Historical outages caused by distribution transformers failure[17]

Table 10.4 shows the number of outages for each cause since 2009. Asset deterioration contributes 59 (62%) of the 95 outages and a further 9 (9%) were attributed to an imminent failure in the transformer.

Table 10.4 Cause of outages

CAUSE DESCRIPTION	NUMBER OF OUTAGES	PERCENTAGES
Equipment Deterioration	59	62%
Unknown	14	15%
Equipment Imminent Failure	9	9%
Equipment Outside Operating Parameters	4	4%
Weather Winds	3	3%
Environment Fire	2	2%
Environment Flooding	2	2%
Equipment Faulty Manufacture	1	1%
Weather Rain	1	1%
Total	**95**	**100%**

UNDERGROUND SUBSTATION

Underground substation assets are often installed in public places and as such can pose a public safety risk. There is also a safety risk for field crews due to the confined spaces and the older asset types installed, as well as a general risk of minor flooding because they are located underground.

Calibre Consulting conducted an inspection on 18 underground substations and assigned a condition grade to each substation between 1 (excellent) to 5 (very poor). Table 10.5 is a summary of the underground substation condition scores assigned.

17 Note that the data for 2018 is an estimate based on half a year of data for January to July.

Table 10.5 Summary condition assessment for underground substation

CONDITION	EXCELLENT	GOOD	REASONABLE	POOR	VERY POOR
Number of Substation	0	14	4	0	0

In March 2018, AECOM[18] completed a report with the purpose of assessing the design and cost of replacing the underground substations. The report referenced the assessments undertaken by Calibre and expanded on those findings to include a condition assessment of the main electrical equipment of the underground substations. The condition assessment focused on the age of the equipment but also identified some visual defects including rust, evidence of flooding and oil leaks. No electrical test results were included. The overall assessment of the electrical equipment indicated the substations were in good to reasonable condition.

Based on this review, all of the underground substations are perceived to be in good or reasonable condition. For the four underground substations that are in reasonable condition, there is deterioration evident, however, failure is considered unlikely in the near future. We note the dissolved gas analysis testing of the transformers in 2017 shows no abnormal gas generation in these transformers which provides some validation of the inspection.

Aurora has established a program to replace the underground substations to remove the field crew risk caused by confined spaces which is in line with actions being undertaken by other EDBs in New Zealand.

DISTRIBUTION EARTHING

WSP reviewed a number of test and remediation reports for distribution assets. The reports indicate the that Aurora has undertaken earthing testing and remediation across distribution asset fleets in both the Dunedin and Central networks since 2013, with evidence of a large program of works (testing and remediation) from 2014 to 2016.

WSP examined details of distribution earthing during its site inspections around the network. All inspected transformers have earthing but there is a need for the earth conductor to be fixed to the pole. This is a similar issue with pole-mounted switchgear. No other issues were identified.

INSPECTION FINDINGS

Distribution transformers are not considered high risk and are generally robust. The visual assessment has checked at random 25 distribution transformers in Dunedin and Central Otago. Most transformers in rural areas are rated at less than 100 kVA. Higher rating transformers are found in Dunedin and occasionally, mounted on a platform supported by two poles.

Key findings from the assessment include:

Ground-mounted transformers:

- While some of the inspected transformers have some minor damage to cooling fins, they are generally in good condition with not much rust.
- Some of the transformers have evidence of oil leakage and it is advisable to monitor them.
- There were no issues with temperature or unusual sounds on the transformers inspected.

Pole-mounted transformers:

- Some of the transformers have oil leakage and it is advisable to monitor them.

[18] AECOM, Dunedin underground substation, Preliminary design report, 2018

10.5 APPROACH TO RISK ASSESSMENT

We have taken a quantitative approach to the risk assessment of Distribution Transformers that relies on the use of parameters identified in our analysis above. We apply conditional probability of failure using the Weibull distribution based on historical asset failure and replacement data. The conditional probability derived established the risk of failure, while the consequence was assessed by considering both the impact to safety and the impact to network reliability.

Distribution transformers are robust in nature; however, they can still pose a public safety risk since they are located in public spaces.

10.6 RISK ASSESSMENT

Analysis of the distribution transformer fleet data identified 726 transformers have exceeded their expected life of 55 years, compared to the fleet size of 7,013 transformers. This indicates that there is an elevated probability of failure of these assets and provides an indication of the magnitude of risk on the network.

Application of the Weibull model takes a probabilistic view of the fleet. Historical records of removed distribution transformers included the age at failure or replacement. This data was used to create a probability of failure (survival) curve and was used in conjunction with the age profile of the fleet to determine the volume of transformers currently likely to have reach end of life. We calculated an additional 115 units of transformers would reach end of life during the next year.

The table and charts below show the risk on the network in the matrix format to identify the quantity of distribution transformers at risk. The risk matrices are separated by network and are based on the probability of failure as derived by the Weibull distribution analysis. The consequence is based on both the public safety risk and energy at risk (refer to section 4.3for details).

The failure of distribution transformer as discussed in the previous sections may pose a public safety risk since they are found in densely populated areas. The maximum consequence is higher in Dunedin compared to Central, largely due to population density.

When considered on a fleet basis, distribution transformers pose a minor environmental risk, as they only hold small amounts of oil. As such, as we would not expect oil leakage or an oil spill to have no long-term effect on ecosystem functions or incur a penalty as set out in section 4.3.3.

Table 10.6 shows the risk for distribution transformers in the Dunedin network. 57 pole mounted transformers are considered high safety risk due to their age and proximity to the public.

Table 10.6 Distribution transformer risk matrix for Dunedin network

Increasing consequence (criticality) -->

Prob of Failure -->

0	0	0	0	0
0	0	0	0	0
987	577	297	57	0
304	99	26	2	0
171	90	32	6	0

Table 10.7 shows the risk for distribution transformers in the Central network. Two distribution transformers are considered a high risk to safety due to their age and proximity to the public. There are no transformers in the Central network that are a high risk to reliability.

Table 10.7 Distribution transformer risk matrix for Central

Prob of Failure --> / Increasing consequence (criticality) -->				
0	0	0	0	0
10	0	0	0	0
1447	195	20	2	0
1509	393	39	3	0
694	69	4	0	0

10.7 KEY FINDINGS

The distribution transformer fleet is segmented based on being pole or ground mounted and having a capacity of less than or greater than 50kVA. We found:

- The asset data available from Aurora's systems and augmented by our field inspections was suitable for the purpose of this review. We note that these are predominantly run to failure assets so less data is expected to be captured on asset condition.
- There are 727 distribution transformers (10%) that have exceeded their expected life and, therefore, pose an elevated risk to the network. Further modelling was undertaken to refine the assessment of network risk and to identify quantities of high risk assets.
- About 10 distribution transformers (0.1%) fail in-service each year. There is a gradual increasing trend of transformer failures, which indicates these assets pose an increasing risk to network reliability and safety.
- With some exceptions, distribution transformers are a run to failure asset and present small risks to safety, reliability or the environment.
- There are 57 distribution transformers in the Dunedin network considered to have a high safety risk due to their age (as a proxy for condition), capacity and proximity to the public. In the Central network, two distribution transformers are considered a high risk to safety. There are no transformers in either the Dunedin or Central networks that are a high risk to reliability.
- There are 328 distribution transformers (4.7%) with a moderate level of risk.

Note that while our analysis focuses on a whole of fleet assessment and identifies expected quantities, individual assets requiring remediation will be identified through Aurora's normal inspection and testing program.

WSP concludes that distribution transformers pose a low to moderate risk to network reliability and safety, except for a few aged transformers in the Dunedin network that pose a high risk. Table 10.8 summarises the risks for the distribution transformer fleet and indicates the priority for remediation.

Table 10.8 Summary of general risks for the distribution switchgear fleet

ITEM	NUMBER	RISK TYPE	DESCRIPTION
Ground mounted distribution transformers	34	Safety	Distribution transformers with high safety risk. Modelled volume based on historical data to develop survivor curve. Individual assets to be identified through normal inspection process.

ITEM	NUMBER	RISK TYPE	DESCRIPTION
Pole mounted distribution transformers	25	Safety	Distribution transformers with high safety risk. Modelled volume based on historical data to develop survivor curve. Individual assets to be identified through normal inspection process.
Ground mounted distribution transformers	168	Safety	Distribution transformers with medium safety risk. Modelled volume based on historical data to develop survivor curve. Individual assets to be identified through normal inspection process.
Pole mounted distribution transformers	160	Safety	Distribution transformers with medium safety risk. Modelled volume based on historical data to develop survivor curve. Individual assets to be identified through normal inspection process.

11 OVERHEAD LINES - SUB TRANSMISSION

This section discusses the current state of the overhead sub transmission lines asset fleet, its recent performance and WSP's assessment of the risk it presents to Aurora's network in terms of impacts to safety, reliability and the environment.

11.1 ASSET DATA

11.1.1 AVAILABILITY AND QUALITY

To assess the risk of the overhead lines - sub transmission, WSP reviewed the information available from the following activities:

- past investigation reports into the sub transmission lines
- asset data from GIS, network schematics and route diagrams
- outage data base
- on-site inspection through visual surveys using a camera equipped drone
- on-site survey using surveying equipment.

A summary of our findings in regard to data quality is reflected in Table 11.1.

The main comments on our findings are:

- Attributes: We found that the quality of the attribute information for sub transmission lines was good overall. Over 99% of conductor types were recorded in GIS.
- Condition: There were few investigation reports or periodic surveys, but this is not inconsistent with Aurora asset management approach of 5 yearly detailed inspections and does not indicate poor data.
- Performance: Up to date performance information was available where outages had occurred, however, the sub transmission line availability records (database of sub transmission lines that had been taken out of service but without causing an interruption to supply) data was less consistently recorded. Availability data was available from 2000 to 2003 and 2012 to 2017 for Dunedin and 2003, 2012 and 2013 for Central.

Table 11.1 Summary of data quality

ASSET CLASS	SUB CLASS	ATTRIBUTES	CONDITION	PERFORMANCE	OVERALL DATA QUALITY
Overhead lines	Sub transmission	● (green)	● (green)	● (amber)	● (green)

11.1.2 ASSET CLASS SEGMENTATION

In order to improve targeting of data validation and sampling in the field, the asset fleet was split into segments based on the following attributes:

- Material type (ACSR, Aluminium, Copper and Steel)
- Voltage level (low voltage, high voltage, sub transmission)

- Location (Dunedin / Central)
- Criticality (Critical / Non-critical based on Aurora's Points of Interest information).

Criticality is used to describe the consequence of an asset failing in service. The criticality segmentation for sub transmission lines has been based on safety to public (and linked to that of the nearest pole) as the assets are above ground, in close proximity to the public and have failure modes that can result in unsafe situations. The consequence of failure on reliability is considered less due to redundancy on most sub transmission circuits, customers are not affected by a single incident.

WSP has used a GIS layer for POI provided by Aurora to determine the criticality. The POIs define a spatial location such as a school, social infrastructure, emergency services, or shopping centres and are used as a proxy for volumes of foot traffic or population density. Aurora has used GIS to identify the proximity of assets to approximately 18,000 POI's identified on their network (residential areas are not included in the analysis).

11.2 DESCRIPTION OF THE ASSET CLASS

The sub transmission line fleet includes the voltages of 33kV and 66kV and is comprised of three main materials:

- copper (CU)
- aluminium conductor steel reinforced (ACSR)
- aluminium (AL)

The composition of the asset fleet is discussed below.

11.2.1 FLEET COMPOSITION

The fleet is comprised of 525.7 km of sub transmission lines, with 27% located in Dunedin and 73% located in Central. This reflects the geography and population density of the two networks. Table 11.2 shows the composition of the networks by conductor type, voltage and length.

Most of the sub transmission network is built to have N-1 redundancy, so each substation is supplied radially by two circuits from the upstream GXP. Both circuits are rated to take the full load of the zone substation should one of the circuits fail. Both circuits are normally operated concurrently, with each supplying half the substation load. There are only a few smaller substations that are supplied radially by a single sub transmission line.

The two networks are comprised of different types of conductor materials. Dunedin is 81% copper and 18% ACSR, while Central is 3% copper and 96% ACSR. The different types of material may reflect the age of the construction of the network, with Central being much younger, or a choice based on Dunedin's proximity to the coast as the steel reinforcement may corrode in marine environments.

Table 11.2 Sub transmission line fleet summary by material type and voltage (length, m)

MATERIAL	VOLTAGE	CENTRAL	DUNEDIN	TOTAL
ACSR	66kV	108.1	0.0	108.1
AL	66kV	0.1	0.0	0.1
ACSR	33kV	258.0	26.2	284.2
AL	33kV	3.9	1.1	5.0
CU	33kV	11.9	116.4	128.3
Total		**382.1**	**143.7**	**525.7**

AGE PROFILE

The age profile of assets in Figure 11.1 shows the relative age of conductors by type and the year of installation. The peak of copper shown at 111 years of age is the A Line and B Line[19] that connect Halfway Bush GXP to Waipori and are two of three separate circuits that run parallel to each other for approximately 31 km (to Berwick, the Aurora owned section of the line).

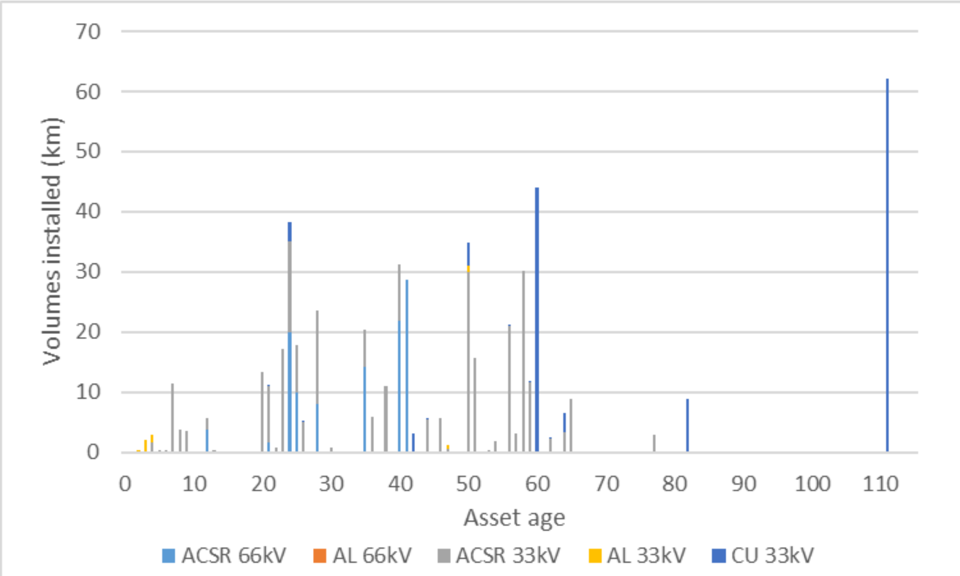

Figure 11.1 Overhead lines sub transmission age profile by conductor type

EXPECTED LIFE

Table 11.3 shows the weighted average age of the sub transmission lines by type. The expected life of the conductor varies depending on the material type, the cross-sectional area and distance from the coast line. Table 11.3 shows the weighted average life and ages summarised by the conductor material type and voltage.

It shows that 33kV copper has the greatest volume exceeding its expected life, driven by 74 km related to the A, B and C Lines and the remainder predominantly the Port Chalmers/North Valley lines. The ACSR is only slightly older than its expected life - a third located in Central and two thirds in Dunedin where it is predominately related to the Green Island and Port Chalmers/North Valley lines. Since many condition deterioration drivers are age related, this provides an initial view on the risk associated with each asset.

Table 11.3 Fleet statistics

CONDUCTOR TYPE	WEIGHTED EXPECTED LIFE	WEIGHTED AVERAGE AGE	WEIGHTED AVERAGE REMAINING LIFE	NUMBER EXCEEDING EXPECTED AGE
ACSR 66kV	74	33.1	40.9	0.0
AL 66kV	120	3.0	117.0	0.0
ACSR 33kV	68	39.9	27.6	32.2
AL 33kV	115	18.9	96.2	0.0
CU 33kV	71	84.7	-13.7	95.4

19 The data provided had an age of 111 years for A Line and B Line. This was considered a data error and updated to the same age as C Line.

11.2.2 FAILURE MODES AND CONSEQUENCES

Failures modes in sub transmission systems can be caused by abnormal weather conditions placing a high physical loading on poles, wires, crossarms, stays etc that exceed design loadings. This becomes more of a risk as the asset ages (pole tops and crossarms cracking, insulators reaching the end of their design life, pole base/foundation failure). Coastal locations can induce wire corrosion issues in the steel core of ACSR conductor.

Ice and snow loading that build up on the conductor (there can be an accompanying wind loading as well) can stick to the conductor adding significant weight to the asset, hoar frost in the Central region is possibly the most severe weather pattern than can induce this failure mode. Conversely in the summer period, smoke from scrub fires around the lines can cause a short to ground/between conductor phases.

High wind conductor clashing situations can cause a phase to phase short which will trip the line protection. Conductor spacing are typically such to avoid this issue occurring. Wind induced vibration can cause conductor fretting at insulator fixing points. Over the long term, reduced conductor life or breakage is possible if not corrected but is typically managed with the correct installation of vibration dampers and good installation practice.

Insulators that are used to insulate and support the live conductor can fail when at end of life.

Consequences of any of these installation requirements failing can result in the tripping of the affected circuit, which then needs to be checked/repaired before re livening. If the affected circuit has n-1 redundancy, this back up point of connection will provide higher security/continuity of supply to avoid an outage.

This section discusses the failure modes and consequences as they relate to this asset class. This is not intended to be a detailed failure mode assessment, it is only intended to inform how we approached our risk analysis and reflect the key deterioration modes that we identified during the review.

11.2.3 INSPECTION AND TESTING

Aurora has historically undertaken periodic surveys from the ground and more recently via helicopter to inspect the sub transmission lines. We reviewed the reports from two of the inspections that were undertaken in 2016 and 2017. In addition, there are visual inspections undertaken as part of other maintenance tasks.

Aurora has identified plans for physical testing of samples of aged and deteriorated conductor to improve their understanding of the residual strength and risk of failure.

Other electricity distribution businesses undertake similar type of inspection for this asset class. Historically there has been little testing that could be done due to the nature of the asset and condition is generally inferred from the performance of types of conductor across the network over time.

11.3 DATA VALIDATION

DRONE SURVEY

WSP undertook a program of work to inspect the overhead sub transmission conductors for visual signs of deterioration, such as fraying strands of the conductor, external corrosion, signs of internal corrosion and other visible forms of damage. The inspections were undertaken by using a drone based high-resolution camera to fly along the conductor span and take photos that could later be examined. This enabled viewing of the images at high resolution close up on a computer rather than using binoculars. The inspection program was combined with the pole top inspections to improve efficiency of the exercise.

210 sites across the Dunedin and Central networks were selected and the drone inspected four poles and three spans. The site selections were made based on:

- conductor material
- conductor size

- age of conductors
- separation between locations to ensure a random sample across the network.

The first program was general for all overhead ones and included some sub transmission lines. A second program was set up to focus on the sub transmission lines for which 20 locations, covering approximately 70 poles, were selected in Central where the majority of sub transmission overhead lines are located.

In total, approximately 759 poles and approximately 660 spans were inspected.

VERTICAL HEIGHT AND SEPARATION SURVEY

A further survey was taken out on the 66kV and 33kV lines to check compliance with design standards. This survey measured the vertical separation between the 66kV and 33kV strung along the top of the pole and the 11kV strung underneath as well as the clearance of the 66kV line from the ground. The current minimum design standard separation between 66kV and 11kV circuits is required to be 2m and the minimum separation between 33kV and 11 / 6.6kV circuits is 1.2m [20]. Clearance from the ground is required to be 5.5m where there is no vehicle access and 6.5m where there is vehicle access.

Our survey team took measurements of line separation at 8 locations on the 66kV circuits in Central. At each location, the separation between all lines was measured on two poles, resulting in a total of 65 measurements. The 66kV lines were selected for measurement of the separation as they were the subject of an uprating project from 33kV to 66kV. In those situations, there is risk that the separation between circuits will not be adjusted to meet the new code requirement. The measurements were taken at the crossarms between the attachment point of the conductors to the top of the insulators.

The team took measurements of line height from ground at 10 locations along the UC66 -1 line.

The surveyor used a Sokkia 3030R theodolite which is a 3 second instrument that is accurate to +/- 2mm per 100 meters.

CORONA SURVEY

Corona surveys were undertaken in Dunedin in 2016 and in Central in 2017 by TransNet. The surveys focused on the detection of corona discharge. Corona is an indication of deterioration of assets and can cause radio frequency interference, audible noise and can create corrosive substances when in humid conditions, further damaging the insulators and conductors. The results from two corona surveys were reviewed by WSP[21,22,23].

11.4 PERFORMANCE AND CONDITION

This section provides an overview of the key findings from the field based surveys combined with our investigation into existing data and documentation.

RELIABILITY PERFORMANCE

The sub transmission network is in most cases designed to an N-1 level of security, meaning the there are two separate lines that supply most zone substations. As a result, the network is highly reliable and there are not too many failures attributed to the asset class. Figure 11.2 shows the performance of Aurora’s fleet. It shows that Dunedin has had one outage on the sub transmission network that resulted in loss of supply since 2009. For Central, the outages are infrequent with an increase to 16 outages in 2017.

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[20] Vertical separations defined in Electrical Code of Practice (ECP34), an appendix to NZS3000

[21] TransNet, Corona Inspection – Delta Utility Services Dunedin Report ID: 159, January 2017

[22] TransNet, Corona Inspection – Delta Utility Services Central Otago Report ID: 160, May 2017

[23] High Voltage Solutions, Thermographic Inspection Survey – Central Otago, September 2017

In total, there have been 34 outages caused by the sub transmission network, of these 74% had an unknown cause and were successfully reclosed, indicating that it was likely a transient fault such as conductor clashing or spurious trips by protection. The outages were mostly attributed to Omakau ZSS and Ettrick ZSS which are both connected by single sub transmission lines.

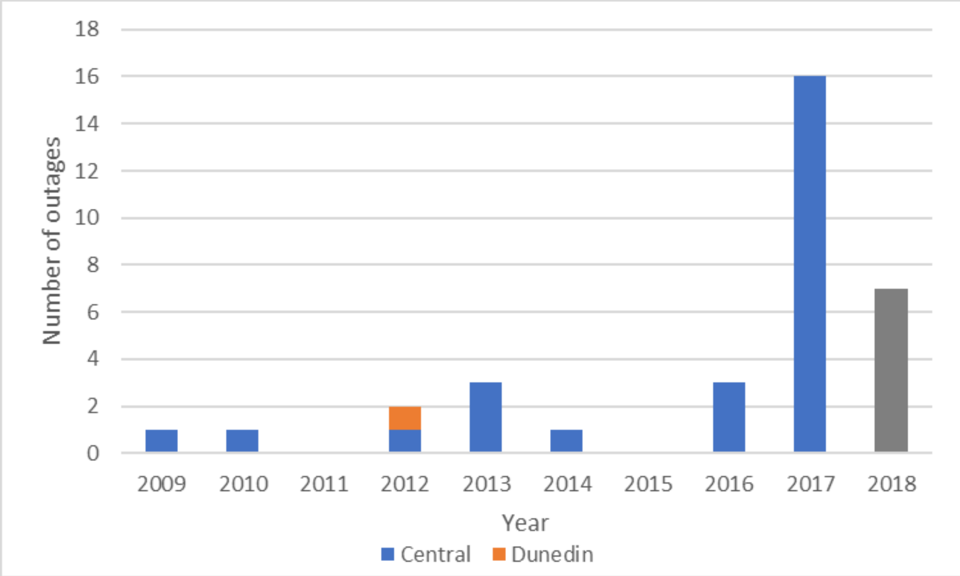

Figure 11.2 Sub transmission line performance

Note that the value for 2018 is only half a year of outage data from January to July.

AVAILABILITY

While reliability performance examines the number of outages that result in a fault, availability provides insight on how much time of the year the network is available for supplying energy. The higher the availability the more secure the network, but networks are typically not 100% available as maintenance must be carried out.

Due to the N-1 arrangement of the sub transmission conductor, a fault on a conductor does not necessarily result in an outage as the load is transferred to the other conductor and supply is maintained. Therefore, sub transmission conductor faults are not contained in the outage data records. Availability data was available for 2000 to 2003 and 2012 to 2017 for Dunedin and 2003, 2012 and 2013 for Central. This provides some insight into the risk of both circuits being out of service at the same time.

The Dunedin overhead sub transmission had an average availability of 99% with the lowest average being 82% for one of the lines to Mosgiel ZSS due to a fault in 2001 and extended maintenance in 2014. However, since there are three lines supplying Mossgiel ZSS there was no outage.

The Central overhead sub transmission lines had an availability of over 99% with the lowest being 97% for the Cromwell – Wanaka No 1 line due to the upgrade to 66kV.

The data showed that the typical duration required to rectify a fault on the overhead sub transmission network ranges between a few hours and up to 4 days.

SAFETY

There was a total of 11 instances where the sub transmission lines caused either a safety incident by falling to the ground or were reported in the public hazard register. These all occurred between 2006 and 2017.

- six instances in the outage data (from 2000 to 2018) regarding lines falling to the ground and causing an outage
- five instances in the public safety register (from 2015 to 2016 and mid-2017 to mid-2018) involving 33kV lines causing fires.

This indicates that although these assets can pose a risk to public safety, the events are infrequent, with one outage every three years and one safety incident ever year on average. The information available indicates that the protection operated for these incidents where the conductor made contact with the ground, mitigating the risk.

ASSET CONDITION AND CONSTRUCTION

Based on our review of available asset reports undertaken by Aurora, on-site surveys undertaken by WSP and review of network diagrams, we have identified the issues listed below. Overall, the sub transmission network is performing well, so although a number of issues are identified, they are not yet adversely affecting network performance.

VERTICAL SEPARATION

The survey results from the vertical separation survey described in section 11.3 are shown in Table 11.4

Table 11.4 Sub transmission circuit separation distance

CIRCUIT	VOLTAGE	MAXIMUM (M)	MINIMUM (M)	AVERAGE (M)
Wanaka – Cromwell Line No. 1 (UC66-1)	66kV	1.92	1.73	1.83
Alexandra 33kV Lines	33kV	2.3	1.35	1.82
Dalefield 33 (DA33)	33kV	1.45	1.41	1.43
FK7784/WC33	33kV	1.36	1.31	1.34

NZECP 34:2001 requires the separation between 11kV and 66kV circuits to be a minimum of 2 metres. It also allows for circuit separations to be lower than the specified minimum if a detailed engineering study of the maximum over voltages and conductor motion establishes that there will be no adverse effect from an installation with less clearance.

Table 11.4 shows that the 66kV line does not comply with the current minimum requirement of 2m and an engineering study to support the reduced separation was not available from Aurora. It is noted that Circuit UC66 was originally a 33kV circuit that was uprated to 66kV. The 33kV circuits comply with the requirement of minimum 1.2m clearance.

GROUND CLEARANCE

As part of the inspection the height above ground of the lowest point of 10 spans on the UC66-1 sub transmission line were measured. The measurements were to the 66kV line, but no measurement was taken for the 11kV line strung underneath the 66kV line.

The assessment found that the 66kV line height varied from 8.0m to 10.3m. We note that the vertical separation of the 66kV and 11kV lines at the crossarm is 1.8m, so it is likely the lowest point of the 11kV line is 6m above ground. The locations measured to be 8m were not accessible by a vehicle, so they are likely to comply with the minimum height requirements of 5.5m in this situation.

However, upon review of the pole heights on the sub transmission line support structures, we found that 3.9% have a height above ground of 8m or less. This data indicates it is likely the sag in the span between poles will result in the line having a clearance of less than 6.5m and possibly less than 5.5m in some cases. This was not quantified through surveys as part of this review.

In the area, changing land use has meant that land previously used for farming animals is now being converted to other forms of agriculture that utilise different types of larger machinery. Hence, the height of conductors above ground may present a risk.

CONSTRUCTION ISSUES

The Cromwell to Wanaka 66kV lines (UC66-1 and UC66-2) both have construction issues from when they were upgraded from 33kV to 66kV lines. For example, the pins are not centred in the insulator, hole bores may not be vertical (possibly due to being bored on site), the base of the insulator is wider than the crossarm, and crossarms are not square. This has resulted in insulators leaning over which is likely to reduce their serviceable life. This issue is known to Aurora.

The A, B and C Lines in Dunedin are in poor condition and they use a complex design with the connections to the tee-offs to Mosgiel, Outram and Berwick zone substations. Aurora is aware of the condition of this line and has plans in place to address the issues.

CORONA

The TransNet Corona survey identified that 27% of sub transmission poles across the network had corona present:

- 89% of poles showed corona present, and 9% have strong corona present in Central
- 10% of poles showed corona present, and 1.5% showed strong corona present in Dunedin
- no corona was identified in Port Chalmers or Green Island
- deterioration mode identified as Aeolian vibration of Line Guard/Armour Rods, and Hand Ties at connection to insulators
- pin insulators identified in both networks as performing poorly
- there are not any low spans currently identified.

The survey shows general deterioration of parts of the sub transmission network. The rate of deterioration is not identified.

VEGETATION MANAGEMENT

Evidence was provided to support active identification, notification and action taken to address situations where trees infringe on sub transmission line clearance zones. This included a sample of first cut notices as well as follow up notices of the hazard posed by the customers’ vegetation. The dates of notices sighted ranged from 2006 to 2018 and covered both Central and Dunedin. The notices identified a range of clearances of the trees from touching the conductor in some cases up to encroaching in the clearance zone.

DRONE SURVEY / VISUAL INSPECTION

The drone survey found some evidence of minor corrosion and minor damage. The damage was most commonly observed at the connection to the insulator. The inspections did not identify any new or significant damage or failure modes and found the conductors sampled to be in acceptable condition.

Table 11.5 below shows a summary of the common conductor related defects identified, the percentage of the sample and the calculated error margin.

Table 11.5 Conductor defect summary from the drone survey

DEFECT TYPE	TOTAL	PERCENTAGE	MARGIN OF ERROR
Insulator pins leaning	37	3%	0.8%
Conductor rusty	11	1%	0.5%
Insulator broken	3	0%	0.2%
Binder broken	2	0%	0.2%
Crossarm bolt/shackle loose	9	1%	0.4%
Insulator Pins Rusty	48	4%	0.9%
Conductor strands broken	1	0%	0.1%
66kV Insulators leaning	3	0%	0.2%
Conductor frayed	1	0%	0.1%

The results show that the drone survey didn't identify major defects. The small margin of error indicates that this sample is representative of the fleet and a good indicator of visible modes of conductor failure.

Rusty and leaning pins were the most common issues identified in the survey. These issues are generally age related as the assets corrode over time or the crossarm deteriorates enabling the insulator to lean.

11.5 APPROACH TO RISK ASSESSMENT

Due to the type of information available, a semi quantitative approach was taken to the risk assessment for this asset class. This combined assessment of the probability of failure with the consequence of failure using the information described in section 11.4. The risk assessment has been undertaken in two parts:

The probability of failure was calculated by deriving the survival curve based on the type of conductor, its age and proximity to the ocean. The onsite inspections and previous inspections identified defects that are typically age-related deterioration and, hence, will be appropriately accounted for in the survival curse modelling.

The issues discussed regarding the vertical separation and ground height clearances are compliance issues and do not impact the heath of the asset or its probability of failure. We were not able to quantify these risks, so they are not included in the risk matrices, but are included in the prioritisation of risks.

ENERGY AT RISK

Sub transmission lines are generally configured in an N-1 arrangement, so loss of a single line will not result in loss of supply. The probability of a dual contingency, where both sub transmission lines are lost concurrently, is very low, as seen in the outage data and availability data.

The availability data shows that the fault restauration times for overhead sub transmission lines has typically required a duration of several hours to restore supply with a maximum of 4 days. Hence, the consequence of a dual supply outage is very low due to the quick restoration.

SAFETY

Ensuring network safety is an important driver for the sub transmission lines. Overhead lines are located in publicly accessible places and there is evidence of sub transmission lines falling to the ground. However, the overhead sub transmission network is predominately located in rural areas in the Central network, which reduces the possible safety impact of the line.

Due to the limitations of the data available, the safety risk for overhead conductors was determine based on the average population density of the feeder to determine a relative risk index.

ENVIRONMENT

Overhead sub transmission lines do not pose a risk to the environment. The risk was not assessed.

11.6 RISK ASSESSMENT

The overhead sub transmission line risk is split by network and displayed in matrix format showing the number of kilometres of line in each risk category. The analysis shows that although there is a high probability of failure on some of the Dunedin sub transmission lines (the A and B Lines that are in closer proximity to the coast), the safety consequence is very low due to the sub transmission lines being located away from highly populated areas, although we note that fences run beneath some sections of the lines, which has the effect of extending the hazardous zone.

Due to the N-1 redundancy, high availability and quick restoration times the reliability consequence is very low and not included in the risk matrices below.

Table 11.6 Sub transmission lines risk matrix for Dunedin

Prob of Failure --> / Increasing consequence (criticality) -->				
23	0	0	0	0
48	0	0	0	0
67	0	0	0	0
6	0	0	0	0
0	0	0	0	0

Table 11.7 Sub transmission lines risk matrix for Central

Prob of Failure --> / Increasing consequence (criticality) -->				
0	0	0	0	0
3	0	0	0	0
147	0	0	0	0
115	0	0	0	0
117	0	0	0	0

11.7 KEY FINDINGS

The key components of overhead sub transmission lines are conductors and connectors. They operate predominantly at 33kV, with two circuits operating at 66kV. Overall, the sub transmission network is performing well. Several issues are identified, but they are not yet adversely affecting network performance. We found:

- The asset data available from Aurora's systems and augmented by our field inspections was suitable for the purpose of this review. Only performance data was found to be incomplete, i.e. sub transmission line availability is not recorded.
- On average, one sub transmission line per year causes either a safety incident by falling to the ground or is reported in the public hazard register. This indicates that, although these assets can pose a risk to public safety, the events are infrequent and the information available indicates that the protection operated for the incidents where the conductor made contact with the ground.
- The A, B and C sub transmission lines in Dunedin are in poor condition and there is a higher probability of failure on some sections (the A and B Lines that are in closer proximity to the coast and 111 years old). However, the consequence of failure is low due to the redundancy in the network and because the sub transmission lines are located away from highly populated areas.
- The Cromwell to Wanaka lines have a number of issues including vertical separation between the 11kV and 66kV circuits of 1.8 m compared to the requirement for separation of 2m. In addition, there are a number of issues relating to its construction.
- It is likely there are spans of the sub transmission lines that do not comply with the minimum height requirements. This was not quantified as part of this review but is indicated by the asset data.

WSP concludes that sub transmission lines pose a low risk to network reliability and safety. Table 11.8 summarises the sub transmission line risks and indicates the priority for remediation.

Table 11.8 Summary of sub transmission line risk

CIRCUIT/ITEM	NUMBER	RISK TYPE	DESCRIPTION
Address risk posed by A, B, C Line	93km	Reliability	The section of line owned by Aurora from Halfway Bush GXP to Berwick zone substation. This is a low risk.
Vertical separation and construction issues on Cromwell – Wanaka No 1 and No 2 Lines	101km	Regulatory	The complete No. 1 and No. 2 lines have identified issues with vertical separation and construction. The level of risk was not quantified as part of this review.
Height above ground of sub transmission lines	N/A	Regulatory/Safety	It is likely there are spans of the sub transmission lines that do not comply with the minimum height requirements. The level of risk was not quantified as part of this review.

12 OVERHEAD LINES - DISTRIBUTION

This section discusses the current state of the distribution overhead lines, its recent performance and WSP's assessment of the risk it presents to Aurora's network in terms of impact to safety and reliability.

12.1 ASSET DATA

12.1.1 AVAILABILITY AND QUALITY

To assess the risk of the distribution overhead lines, WSP reviewed the information available from the following activities:

- Past investigation reports into the distribution overhead line
- Asset data from GIS, network schematics and route diagrams
- Outage database
- On-site inspection through visual surveys using camera equipped drone
- On-site survey using surveying equipment.

In undertaking this assessment, we have considered all the information we obtained from Aurora over the course of the project. Table 12.1 is the data quality summary of the available information where we took into consideration the ease of available and accessibility of the information.

We found that there is generally good information regarding the distribution line attributes and information from GIS, however:

- There is no condition data available for this asset class as there is no dedicated inspection or testing program
- Performance data is captured in the outage management system, however, the fault locations are allocated to the nearest distribution transformer and feeder numbers are not consistently recorded. This limits the ability to use the performance data to identify the risk on the network by different conductor types. Important items to note are:
  - key attributes for both distribution line and LV lines are largely populated with 0.2% (17) and 5.8% (2,076) entries without a conductor type respectively

To assess the risk of this asset we applied a modelling approach to utilise the data available. By taking this approach, we found that there was sufficient information available to undertake this review.

Table 12.1 Summary of data quality

ASSET CLASS	SUB CLASS	ATTRIBUTES	CONDITION	PERFORMANCE	OVERALL DATA QUALITY
Overhead lines	6.6kV and 11kV	🟢	🔴	🔴	🔴
	LV Line	🟡	🔴	🔴	🔴

12.1.2 ASSET CLASS SEGMENTATION

In order to improve targeting of data validation and sampling in the field, the asset fleet was split into segments based on the following attributes:

- Material type (ACSR, Aluminium, Copper and Steel)
- Voltage level (low voltage, high voltage, sub transmission)
- Location (Dunedin / Central)
- Criticality (Critical / Non-critical based on Aurora's Points of Interest information).

Criticality is used to describe the consequence of an asset failing in service. The criticality segmentation for distribution overhead lines has been based on safety to public (and linked to that of the nearest pole) as the assets are above ground, in close proximity to the public and have failure modes that can result in unsafe situations. The consequence of failure on reliability is considered less with only a small number of consumers typically impacted for LV and HV circuits. Due to redundancy on most sub transmission circuits, customers are not affected by a single incident.

WSP has used a GIS layer for POI provided by Aurora to determine the criticality. The POIs define a spatial location such as a school, social infrastructure, emergency services, or shopping centres and are used as a proxy for volumes of foot traffic or population density. Aurora has used GIS to identify the proximity of assets to approximately 18,000 POI's identified on their network (residential areas are not included in the analysis).

12.2 DESCRIPTION OF THE ASSET CLASS

This section provides an overview of the asset fleet and the characteristics that are indicators of risk.

12.2.1 FLEET COMPOSITION

This asset class includes the low voltage and the 6.6kV and 11kV conductors and comprised of four main materials:

- Aluminium conductor steel reinforced (ACSR)
- Aluminium (AL)
- Copper (CU)
- Steel (ST).

The fleet comprised of 49% (2,313 km) distribution lines, 22% (1,045 km) LV lines and 28% (1,326 km) LV street lighting. Majority of distribution lines are made from ACSR whereas Aluminium is predominantly found in LV line. Table 12.212 shows the composition of the network by conductor type and length.

Table 12.212. Fleet summary (length, km)

MATERIAL	HV LINE	LV LINE	LV STREET LIGHTING	TOTAL
ACSR	1,513	12	-	1,524
Copper	527	732	1,318	2,578
Steel	239	0	-	239
Aluminium	34	301	2	337
TOTAL	**2,313**	**1,045**	**1,320**	**4,678**

For HV line, the network is comprised of 2,313 km of distribution line, with 68% located in Central and 32% located in Dunedin. This reflects the geography and population density of the two networks. The two networks are comprised of different types of conductor materials. Central is predominantly ACSR while Dunedin has two-third ACSR and one-third copper. The different types of material may reflect the age of the construction of the network, with Central being much younger, or a choice based on Dunedin's proximity to the coast as the steel reinforcement in an ACSR conductor may corrode in marine environments.

Table 12.3 Fleet summary (length, km) for HV and LV distribution line by material and network

MATERIAL	CENTRAL	DUNEDIN	TOTAL
ACSR	1,263	262	1,524
Copper	666	1,912	2,578
Steel	234	4	239
Aluminium	100	237	337
Total	**2,263**	**2,416**	**4,678**

AGE PROFILE

Figure 12.1 shows the age profile for distribution lines and LV with the majority of the conductors within their expected life of 60 years, which is common in the industry. The expected life is dependent on the installation condition and the location of the cable from marine environments.

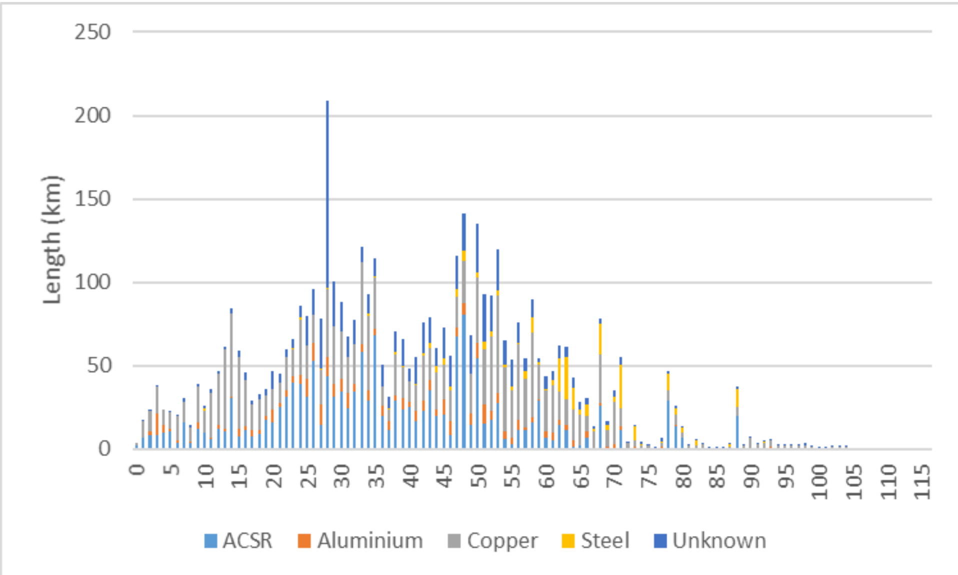

Figure 12.1 Overhead lines distribution age profile by conductor type

EXPECTED LIFE

Table 12.4 shows the weighted average age of the distribution lines by material type. The expected life of the conductor varies depending on the material type, the cross-sectional area and distance from the coast line.

It shows that copper conductors have the greatest volume exceeding its expected life, driven predominantly by conductors located in the Dunedin network with a total length of 309 km. ACSR also has a large proportion, 162km, that is exceeding its expected life. Approximately 15% of the steel conductor fleet has exceeded its expected life.

Table 12.4 Fleet statistics for overhead distribution line (HV and LV)

CONDUCTOR TYPE	WEIGHTED AVERAGE EXPECTED LIFE	WEIGHTED AVERAGE AGE	WEIGHTED AVERAGE REMAINING LIFE	LENGTH EXCEEDING EXPECTED LIFE (KM)
ACSR	63	37.7	25.0	161.7
Aluminium	103	37.6	65.5	2.4
Copper	68	40.1	27.7	308.8
Steel	75	62.8	12.1	34.6

12.2.2 FAILURE MODES AND CONSEQUENCES

Failures modes in distribution overhead lines can be caused by abnormal weather conditions placing a high physical loading on poles, wires, crossarms and stays that exceed design loadings. The probability of failure increases as the asset ages (pole tops and crossarms splitting, insulators reaching the end of their design life, pole base/foundation failure). Coastal locations can lead to wire corrosion issues in the steel core of ACSR conductor.

The common mode of failure for ACSR is the steel core in the conductor corrodes; as it corrodes it expands which lets water enter between the outer aluminium strands and accelerates corrosion. Eventually the strength of the steel will be insufficient to support the conductor span and the conductor will break.

Copper has a different failure mechanism. Movement of the conductor at the supporting points causes bend strengthening of the copper and it can become brittle and eventually break. In addition, the conductor heats up and cools down as customer loads increase and decrease daily. This can cause annealing of the copper, which softens the metal, eventually causing increased sags and failure.

Aluminium conductors most often fail due to external damage such as lightning strikes or tree impact. These conductors will corrode through oxidation of the surface.

Conductor creep[24] can also be a problem if not correctly allowed for when the conductor is installed. Incorrect allowance or installation can result in additional sag that can infringe on required minimum clearances, require the conductor to be de-rated (used at a lower capacity), and possibly cause vibration that can cause the conductor to fatigue and eventually break.

Steel conductors deteriorate as the galvanized coating breaks down, eventually leading to corrosion, loss of cross-sectional area and eventual failure.

This section discusses the failure modes and consequences as they relate to this asset class. This is not intended to be a detailed failure mode assessment, it is only intended to inform how we approached our risk analysis and reflect the key deterioration modes that we identified during the review.

12.2.3 INSPECTION, TESTING AND REPLACEMENT

Aurora does not have a dedicated inspection and testing program for overhead conductors but undertakes visual inspection on an opportunistic basis when inspecting other assets as part of other maintenance tasks.

Historically there has been little testing that could be done due to the nature of the asset and condition is generally inferred from the performance of types of conductor across the network over time. However, due to the location of the outage being identified as the location of the nearest distribution transformer, this is a modelled approach and the resulting rates of failure per conductor type has some uncertainty.

24 The permanent elongation of the conductor caused by the tension it experiences due to its installation.

12.3 DATA VALIDATION

DRONE SURVEY

WSP undertook a program of work to inspect the overhead distribution conductors for visual signs of deterioration, such as fraying strands of the conductor, external corrosion, signs of internal corrosion and other visible forms of damage.

The inspections were undertaken by using a drone based high-resolution camera to fly along the conductor span and take photos that could later be examined. This enabled viewing of the images at high resolution close up on a computer rather than using binoculars. The inspection program was combined with the pole top inspections to improve efficiency of the exercise.

210 sites across the Dunedin and Central networks were selected and the drone inspected four poles and three spans. The site selections were made based on:

- conductor material
- conductor size
- age of conductors
- separation between locations to ensure a random sample across the network.

In total, approximately 759 poles and approximately 660 spans were inspected.

12.4 PERFORMANCE AND CONDITION

This section provides an overview of the key findings from the field-based surveys combines with our investigation into the existing data and documentation.

RELIABILITY PERFORMANCE

Figure 12.2 shows the historical outages caused by the failure of overhead distribution lines. The data shows an increasing trend in outages caused by overhead distribution conductor. The trend line has a reasonable fit to the data.

The overhead distribution conductor class has the largest impact to network performance, contributing an average of 33% of the outages from 2013 to 2017. The outage data shows evidence of an increasing trend in the number of outages caused by this asset class. This indicates that modelling the asset based on a metric related to reliability is appropriate for assessing the risk of this asset class.

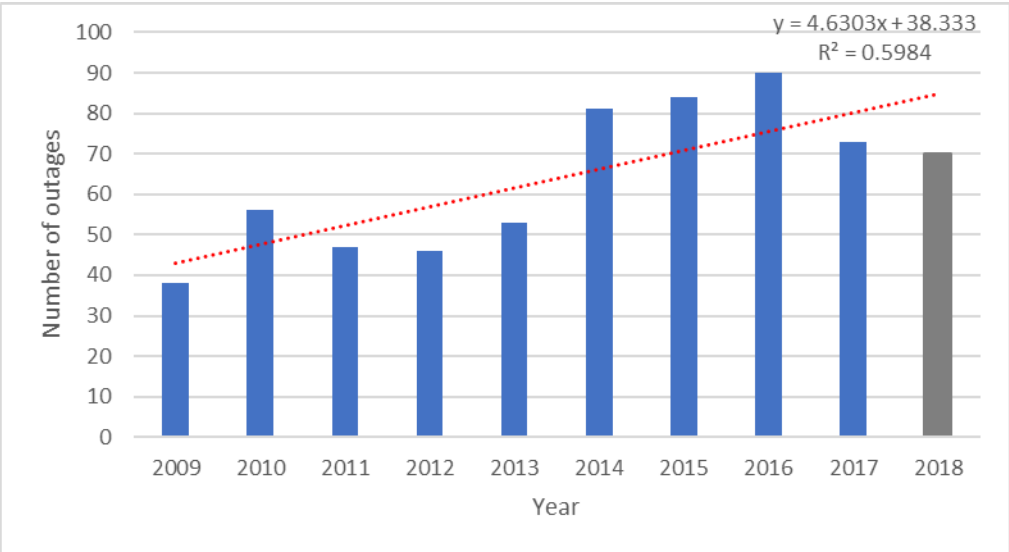

Figure 12.2 Historical outages caused by overhead distribution lines failure

There were 166 incidents recorded in the outage records where a conductor was identified as having fallen to the ground because of deterioration. When the impacts of weather and vegetation are included, the number increases to 404. This is an average of between 10 and 25 incidents per year. The public safety register, that was in use consistently from 2014 to 2015 and then re-established in mid-2017, also identified as similar number of incidents annually.

VERTICAL HEIGHT AND SEPARATION

Clearance from the ground varies by conductor voltage, insulation type and vehicle accessibility and is set out in NZECP 34:2001. Aurora records low conductors and has identified 225 conductors do not meet the minimum safe vertical distance requirements.

Table 12.5 Low span conductors by insulation

INSULATION	11KV	6.6KV	400V	230V	TOTAL
Bare	3	2	2	12	**19**
Ins	1	0	0	1	**2**
Unknown	0	2	53	68	**123**
PVC	0	0	25	56	**81**
Total	**4**	**4**	**80**	**137**	**225**

VEGETATION MANAGEMENT

The trend analysis in Figure 12.2 only shows the impact of asset deterioration on the asset performance. However, vegetation causes the majority of outages related to overhead distribution line. Evidence was provided to support active identification, notification and action taken to address situations where trees infringe on distribution line clearance zones. This included a sample of first cut notices as well as follow up notices of the hazard posed by the customers' vegetation. The dates of notices sighted ranged from 2006 to 2018 and covered both Central and Dunedin. The notices identified a range of clearances of the trees from touching the conductor in some cases up to encroaching in the clearance zone.

CONDUCTOR TYPE ANALYSIS

Aurora has undertaken some analysis regarding the type of conductors failing. Outages due to conductor failures are recorded against the nearest upstream distribution transformer so there is some uncertainty in determining which conductor type failed. Figure 12.3 shows the frequency of the types of conductor that have failed based on best available information.

In general, there is a higher failure rate of light (<100mm^2 cross section) ACSR in Central and light copper in Dunedin. This is reflective of their dominant conductor types in the regions, Central is 74% ACSR and Dunedin is 71% copper. These failures occurred between 2003 and 2018. It demonstrates that light copper and light ACSR have the highest failure rates, at approximately four times the number of failures of the next nearest type.

Table 12.6 shows the volume of conductor type by size that are exceeding their expected lives.

Table 12.6 Breakdown of asset types that are exceeding their expected life

MATERIAL	WEIGHT	LENGTH (KM)	PERCENT
ACSR	Heavy	7.9	2%
ACSR	Light	150.1	31%
AL	Heavy	0.2	0%
AL	Light	2.1	0%

MATERIAL	WEIGHT	LENGTH (KM)	PERCENT
CU	Heavy	0.8	0%
CU	Light	290.6	60%
ST	Light	34.6	7%
Total		**486.2**	**100%**

The failure rates observed also align with the sub class of conductors that are make up the volume of conductor exceeding its expected life, with the dominant types of conductor that exceed their expected lives are light copper (60%) and light ACSR (31%). This supports an age-based modelling approach by asset material type and weight for assessing risk of failure.

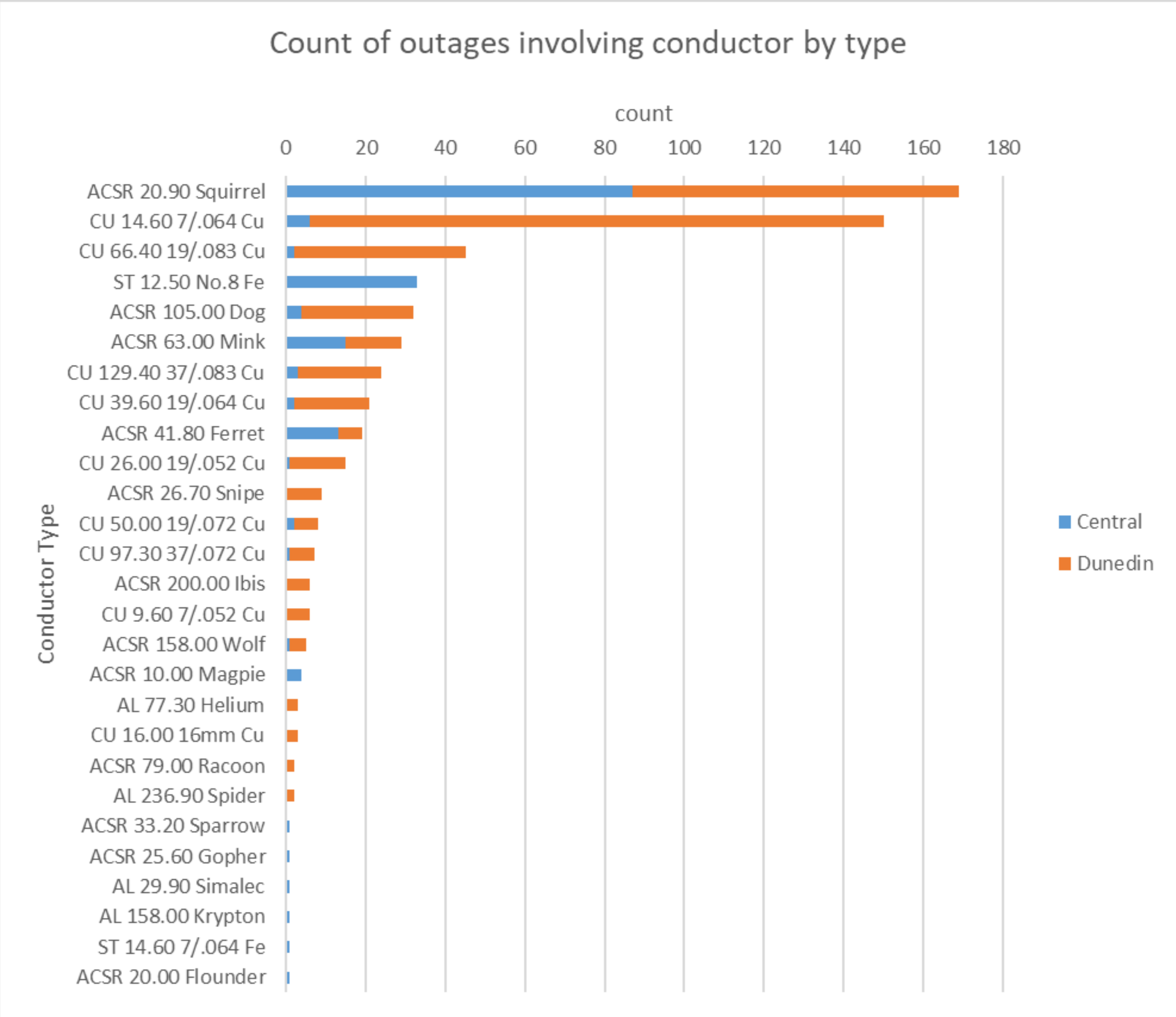

Figure 12.3 Aurora's analysis of conductor type failures

DRONE SURVEY

Our drone survey was undertaken to assess for any excessive damage that would indicate high risk of failure and external visible deterioration. The results of the drone survey demonstrated that there were no major external/visible defects on the conductors. Some signs of external rusting were observed and some minor damage to conductors at the attachment point to the insulator was observed.

Table 12.7 Conductor defects found with drone

DETERIORATION MODE	NUMBER OF LOCATIONS
Minor rust	9
Deteriorated connector	4
Incorrect use of equipment	1
Weathering on conductor	1
No defect found	197

12.5 APPROACH TO RISK ASSESSMENT

Due to the inherent difficulties with identifying deterioration of conductors through inspection, we applied a modelling approach to assess the likely risk given the conductor type, conductor size, its age and location.

We applied a Weibull methodology to calculate the probability of failure and the consequence was calculated based on the conductor's location and the population density and using the value of energy not supplied.

12.6 RISK ASSESSMENT

The risk profile of overhead conductors is shown below as the volume of assets (km) in each category. The matrices display the maximum risk of either reliability or safety. It identifies that there are some conductors located in Dunedin with a high risk. This aligns with the higher population density of Dunedin.

Table 12.8 Distribution overhead line risk matrix for Dunedin

Increasing consequence (criticality) -->

Prob of Failure -->

2	3	0	0	0
72	108	2	2	0
512	689	13	7	0
289	308	14	11	0
182	195	4	4	0

Table 12.9 Distribution overhead line risk matrix for Central

Increasing consequence (criticality) -->

Prob of Failure -->

0	0	0	0	0
43	27	0	0	0
769	159	0	0	0
541	163	0	0	0
397	163	0	0	0

12.7 KEY FINDINGS

The key components of overhead distribution lines are conductors and connectors. They operated at 6.6kV and 11kV. We found:

- The asset data available from Aurora's systems and augmented by our field inspections was suitable for the purpose of this review and the assessment approach undertaken. We note that the data is not complete as inspections are not undertaken consistently and outage data does not capture specific conductor material types. Incomplete asset data presents a risk to effective asset management.
- There are 10 to 25 public safety incidents per year related to distribution overhead line conductors. This asset class also contributes the largest impact to network performance, with an annual average of 33% of the outages from 2013 to 2017. The outage data indicates an increasing trend in the number of outages caused by this asset class.
- The HV network consists of mainly ACSR conductor while the LV network consists mainly of copper conductor. There are 309 km (12%) of copper conductor, 162 km (11%) of ACSR conductors and 35 km (15%) of steel conductor that are currently exceeding their expected life.
- A common failure mode for this asset class is failure of the conductor by way of corrosion or fatigue, both of which are related to age. Aurora does not have a dedicated inspection and testing program for overhead conductors but undertakes visual inspection on an opportunistic basis when inspecting other assets as part of other maintenance tasks. The evidence examined suggests that ACSR and copper conductor with a cross sectional area of less than 100 mm^2 have the highest failure rates.
- Aurora has recorded 225 instances where conductors did not meet the minimum safe heights above ground outlined in NZECP 34:2001.

WSP concludes that distribution overhead lines pose a moderate risk to network reliability and safety, mostly due to their relatively high failure rate but low consequences to public safety when they fail. There are some conductors located in Dunedin with a higher consequence due to their location in densely populated areas. Table 12.10 summarises the distribution overhead line risks and indicates the priority for remediation.

Table 12.10 Summary of distribution overhead line risk

ITEM	NUMBER	RISK TYPE	DESCRIPTION
Aged light ACSR conductor	2.6km	Safety/Reliability	Aged light ACSR conductor on distribution lines (HV) close to the coast. Modelled volume based on survival curve. Individual assets to be identified through normal inspection process.
Aged light copper conductor	9.7km	HSE/Operations	Aged light copper conductor in distribution lines (HV and LV) 500m to 5km to the coast. Volumes have been modelled based on survival curve, but individual assets to be identified through normal inspection process.

ITEM	NUMBER	RISK TYPE	DESCRIPTION
Copper, ACSR and Aluminium conductor	28.6km	Safety/Reliability	Copper, ACSR and Aluminium conductor on distribution lines (HV and LV) 500m to 5km to the coast. Modelled volume based on survival curve. Individual assets to be identified through normal inspection process.
Rectification of low spans	225	Safety	225 conductor spans have been identified to not comply with required minimum height.

13 UNDERGROUND CABLES – SUB TRANSMISSION

This section discusses the current state of the underground cable asset, its recent performance and WSP's assessment of the risk it presents to Aurora's network in terms of impacts to safety, reliability and the environment.

13.1 ASSET DATA

13.1.1 AVAILABILITY AND QUALITY

To assess the risk of the sub transmission cables, WSP reviewed the information available from the following activities:

- on-site inspection of assets (where possible)
- review of inspection and testing sheets
- analysis of cable type, age and network topology
- review of outage data
- discussion with Aurora SMEs.

We found that the quality of the information varied depending on the source. The GIS data contained cable attribute information for all cables and was found to be complete. However, the inspection and testing data did not contain a comprehensive set of cable test results or records of oil leaks. The performance of the cables was not captured in the outage data due to the redundancy of the network, so outage and fault records were not available.

Important data deficiencies:

- **Condition:** there were no testing records for Neville Street, Willowbank or Smith St zone substations. Inspection records were completed
- **Condition:** there were no testing records for XPLE or PILC cables
- **Condition:** all historical test and inspection data is only available in scanned pdf format and it is not well organised in a structured manner. This makes it difficult to identify issues or trends across the fleet
- **Performance:** there were no inspection or issue investigation records available for faults or specific failure modes that have been identified by Aurora. Data has been captured at a high level in some reports such as the AMP. Due to the N-1 configuration, a cable outage does not necessarily result in an outage and, hence, the fault data is not captured in the outage records
- **Performance:** circuit availability data was not complete or up to date. Data was available from 2000 to 2003 and 2012 to 2017 for Dunedin and 2003, 2012 and 2013 for Central.

A summary of our findings in regard to data quality is reflected in Table 13.1

Table 13.1 Summary of data quality – Underground cables, sub transmission

ASSET CLASS	SUB CLASS	ATTRIBUTES	CONDITION	PERFORMANCE	OVERALL
Zone substation	PILC	🟢	🔴	🟡	🔴
	Oil insulated	🟢	🟡	🟡	🟡
	Gas insulated	🟢	🟡	🟡	🟡
	XLPE	🟢	🔴	🟡	🔴

13.1.2 ASSET CLASS SEGMENTATION

Asset class segmentation was not relevant for field inspection work for this asset type as we did not undertake a sampling approach.

13.2 DESCRIPTION OF THE ASSET CLASS

The sub transmission cable fleet includes the voltages of 33kV and 66kV and is comprised of four main technologies:

- oil insulated cables
- gas insulated cables
- Paper Insulated Lead Covered cable (PILC), and
- Cross Linked Polyethylene (XLPE).

The older oil and gas insulted cables reflect the technology of the day and require fluid pressure to ensure insulation properties are maintained. Leaks can result in loss of insulation performance and can lead to failure. PILC is a proven technology that has been commonly used in electricity networks since around the 1950’s and XLPE is a more modern design of cable. Neither PILC or XLPE use fluid to maintain insulation properties.

While oil insulated and gas insulated cables are a type of PILC cable, the need to maintain fluid pressure separates the type of construction, failure modes and expected serviceable life. For clarify, we refer to them as Oil and Gas insulated cables to clearly separate them from PILC cables which do not require fluid pressure.

13.2.1 FLEET COMPOSITION

The fleet is comprised of 93 km of sub transmission cable, with 82% located in Dunedin and 65% being oil or gas insulated. Table 13.2 shows the total length of installed cable by type and location. The volumes of cable in each location reflect the geography and topology of the networks, with Dunedin being predominately urban and Central being predominately rural and, hence, relying more on overhead conductors.

The sub transmission network is built to have N-1 redundancy, so each substation is supplied radially by two circuits from the upstream GXP. Both circuits are rated to take the full load of the zone substation should one of the circuits fail. Both circuits are normally operated concurrently, with each supplying half the substation load.

Table 13.2 Fleet cable summary (km)

ASSET CATEGORY	DUNEDIN	CENTRAL	TOTAL
66kV XLPE		1.1	1.1
33kV gas pressurised	35.8		35.8
33kV oil pressurised	25.0		25.0
33kV PILC	11.2	0.1	11.3
33kV XLPE	4.0	15.4	19.4
Unknown	0.2		0.2
Total	**76.2**	**16.7**	**93.0**[25]

Table 13.3 shows the location (zone substation) of the each of the gas and oil insulated cables by type and length.

Table 13.3 Gas and oil insulated cables by zone substation

ZONE SUBSTATION	INSULATION TYPE	LENGTH (KM)
Corstorphine	Oil	8.8
East Taieri	Oil	5.1
North City	Oil	5.0
South City	Oil	3.1
St Kilda	Oil	3.1
Neville St	Gas	13.4
Ward St	Gas	8.3
Willowbank	Gas	7.8
Smith St	Gas	6.2
Total		**60.8**

AGE PROFILE

The age profile of assets in Figure 13.1 shows the relative age of cable by type and the periods of time where each technology was dominant. It highlights the large volume of gas and oil cables compared to PILC and XPLE.

PILC cables generally have a long life. The cables installed to supply Kaikorai Valley ZSS and Ward St ZSS make up 80% of all PILC cables and are the oldest cables on the network. The younger PILC cables are predominantly short sections installed to replace deteriorated or faulted parts of these circuits.

[25] Note: total may not appear to add up due to rounding

The gas insulated cables supply four zone substations, of which Neville St makes up 38% by volume. Neville St ZSS is expected to be decommissioned during FY19 and will, therefore, remove a significant risk from the network. Oil insulated cables supply five zone substations.

It is important to note that, although there are two circuits supplying each zone substation, in all cases, they are both of the same technology, were originally established during the same year with the same construction techniques, and installed in the same trench. Hence, the age-related failure modes are likely to be common between the two circuits resulting in a higher probability for a second contingency (loss of both circuits during the same period of time) than expected.

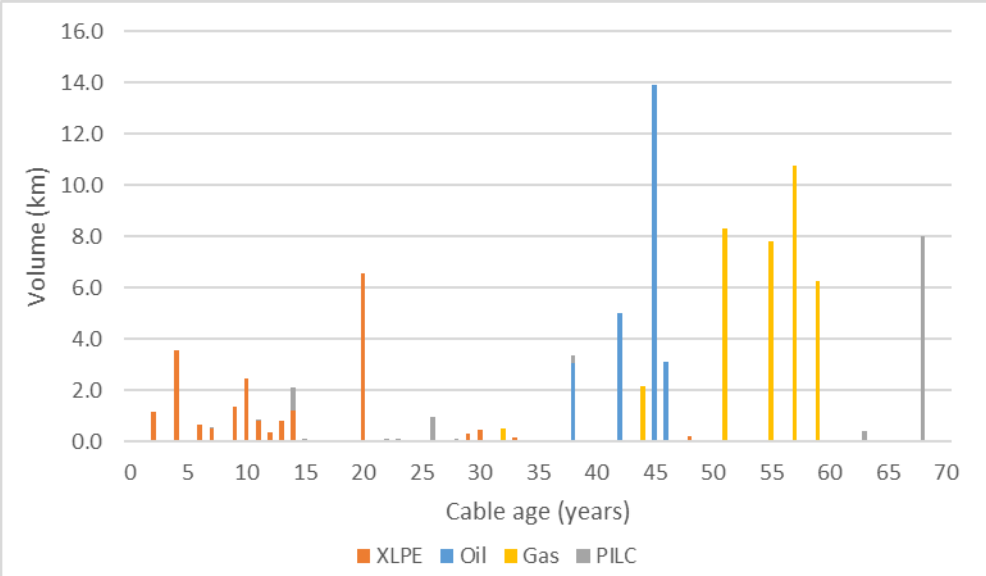

Figure 13.1 Sub transmission cable age profile

EXPECTED LIFE

Table 13.4 shows the weighted average age of the sub transmission fleet by cable type. The expected life is based on nominal design life and Aurora's current expectations.

Table 13.4 Cable fleet statistics

MATERIAL TYPE	EXPECTED LIFE	WEIGHTED AVERAGE AGE	WEIGHTED AVERAGE REMAINING LIFE	LENGTH (KM) EXCEEDING EXPECTED AGE
33kV Gas	80	54.4	25.6	0
33kV Oil	80	43.7	36.3	0
33kV PILC	80	56.2	23.8	0
33kV XPLE	60	13.1	46.9	0

13.2.2 FAILURE MODES AND CONSEQUENCES

This section discusses the failure modes and consequences as they relate to this asset class. This is not intended to be a detailed failure mode assessment. It is only intended to inform how we approached our risk analysis and reflect the key deterioration modes that we identified during the review.

The primary failure mode is the loss of insulation of the cable which results in a fault. Depending on the cable type, the loss of insulation manifests in different ways:

- XLPE: water ingress into the cable at points of electrical stress and where the external sheath has been damaged causes ‘treeing’ of the insulation. The treeing extends along the cable and damages the insulation until it is insufficient and results in a failure
- Oil and Gas insulated cables: damage to the external sheath allows the insulating medium to leak out which reduces the cable insulation and enabling the cable to fault. The damaged sheath also allows water ingress which can cause further deterioration
- Gas insulated: water ingress at joints causes the bronze tape to corrode and exposing the lead sheathing to high pressures. The lead eventually punctures allowing the gas or oil to escape, with the potential for moisture to be absorbed into the cable. Eventually the insulation will deteriorate and result in failure
- PILC: PILC uses oil (wax) impregnated paper as insulation. This is different to oil insulated cables that require oil to be pumped in under pressure. Aurora has identified a failure mode where oil drains from the paper insulation of PILC cables where the cables have been installed on steep hills. This reduces the insulation properties and has led to fault on the sub transmission cables to Kaikorai Valley.
- Joints (including terminations): these are a common location of failure for cables and there are multiple causes of failure including: ground movement exerting physical stress on a joint; moisture ingress damaging insulation; poor workmanship when installing the joint; overheating due to overloading or the joint conductor connection becoming loose. The failure can be a phase to phase or a phase to ground fault which in some circumstances can result in fire.

An alternative driver is cause by a sudden electrical shock to the cable when it is already in a deteriorated state. This can occur when a cable experiences a fault current or when there is a sudden increase in load, such as when a second circuit is taken out of service. Aurora has identified this to be the cause of damage to joints of gas cables. The implication of this is that the probability of a second contingency event, where both cables suffer an outage at the same time and supply is lost, could be higher than expected due to this failure mode being triggered by the outage of the first circuit.

The third main failure mode is external impact. This is typically the result of cables being dug up due to excavation works and is normally mitigated through separate cable routes. However, the sub transmission cables in Aurora’s network have both cables installed in the same trench with concrete slabs on top for mechanical protection. This arrangement results in a slightly elevated risk of both cables being taken out of service at the same time. In this case, cables are primarily vulnerable to common mode failure due to soil liquefaction during earthquakes.

In general, for cables in good condition, there is a very low probability of both circuits losing supply at the same time. The main consequences are:

- possible momentary loss of supply during changeover/switching if the primary bus of the zone substation is run as two separate sections
- should a second contingency occur, there could be loss of supply for extended periods of time. This is mitigated through load transfers at the distribution voltage level
- minor environmental risk from leaking oil. The insulating oil used is not classified as hazardous, it is insoluble in water and is biodegradable.

13.2.3 INSPECTION AND TESTING

Aurora runs a periodic inspection and testing program for its sub transmission cables. The program only applies to oil and gas insulated cables. PILC and XLPE are normally only tested prior to being returned to service after an associated asset has been maintained or if there is an apparent issue being investigated.

The inspection and testing program involves two components:

- visual inspection and monitoring of the gas and oil pressure of cables and condition of alarms. Evidence was provided to support a consistent program with a cycle of approximately 6 weeks

- a sheath testing program that measures the sheath integrity and provides an evaluation of the cable that could lead to failure. Evidence was provided to support a period testing program that has run every two years (approximately) since 2013.

We note that Ward St was the only gas insulated cable to have been tested. Test results were not available for Neville St, Willow Bank or Smith St. No evidence of insulation resistance testing was provided.

Oil consumption and gas consumption volumes are not well documented or recorded in a systematic manner. Only oil consumption for North City No 2 was well recorded due to the significant and long-term leak identified on that circuit.

13.3 DATA VALIDATION

Our approach to data validation is set out in section 3. We note that for some asset classes, such as underground cables, inspections were unable to be performed due to inaccessibility of the assets, as they are direct buried in the ground, and inspections or tests would require significant network outages.

For these assets we relied on existing inspection and test reports and data available from Aurora’s GIS and other data bases. The data available from these data sources was considered sufficient for the purpose of this review.

13.4 PERFORMANCE AND CONDITION

This section discusses the performance of the sub transmission network in terms of availability and historical testing results.

AVAILABILITY

While reliability performance examines the number of outages that result in a fault, availability provides insight on how much time of the year the network is available for supplying energy. The higher the availability the more secure the network, but networks are typically not 100% available as maintenance must be carried out.

Due to the N-1 arrangement of the sub transmission cables, a fault on a cable does not necessarily result in an outage as the load is transferred to the other cable and supply is maintained. Therefore, sub transmission cable faults are not contained in the outage data records. Availability data was available for 2000 to 2003 and 2012 to 2017 for Dunedin and 2003, 2012 and 2013 for Central. This provides some insight into the risk of both circuits being out of service at the same time.

The Dunedin underground sub transmission had an average availability of 98% across all circuits from 2000 to 2003 and 2012 to 2017. There was volatility in the annual availability per circuit, but no distinct trend was identified. The predominant reason for unavailability was maintenance and testing. There were 29 faults recorded between 2000 and 2003 and two faults recorded in 2012 and 2013. The N-1 arrangement means there has not been any outages attributed to the sub transmission cables.

The Central sub transmission network has predominantly overhead lines with only small sections of underground cable. The performance of the underground cable sections was not separable from the overall circuit information and, therefore, the availability of these asset could not be assessed.

The restoration times for faults were an average of 5 days with a maximum time of 33 days.

TESTING RESULTS

WSP undertook a review of the inspection and testing records available for the sub transmission cables. In total, 14 out of 66 (21%) of the cable test records identified some level of defect with the cables. Of these some were major defects, including severe oil leaks at North City No 2 cable and failed sheath tests, and minor defects such as minor items requiring replacement. Table 13.5 sets out the defects identified in the sub transmission cable fleet.

Table 13.5 Sub transmission cable defects

ASSET	YEAR	TYPE	DEFECT IDENTIFIED
Alarms and gauges	Multiple		Minor defects requiring minor asset maintenance or replacement
Gas cable joints	Multiple	Gas	Corrosion of bronze tapes used for the joints of gas insulated cables as a result of moisture ingress. This has resulted in annual failure of gas pressure cables during the past 20 years.
North City No 2	Multiple	Oil	Oil leak identified at rate of 57 litres per month, total of 4,274 over the 6 year period 2009 to 2015. The leak has stopped, however, the location and cause of the leak were not found or identified.
Kaikorai Valley	Multiple	PILC	Oil draining from paper, decreasing insulation and resulting in a fault (identified by Aurora)
Kaikorai Valley	Multiple	PILC	Evidence of 10 defects which required replacement of a cable segment on KV No 1 and 12 defects on KV No 2 over a long period of time.
Ward St No 1 and 2	2013	Gas	Failed sheath testing
Corstorphine No. 1	2013	Oil	Failed sheath testing
East Taieri No.1	2013	Oil	Failed sheath testing
North City No.1	2013	Oil	Failed sheath testing
St Kilda No 1 and 2	2013	Oil	Required 5 minute ‘dry out’ before passing sheath test
St Kilda No 1 and 2	2018	Oil	Required 15 minute ‘dry out’ before passing sheath test.
East Taieri	2017	Oil	Low oil identified, indicating an oil leak in the cable
North City No.1	2015	Oil	Failed sheath testing
Ward St No 2	2018	Gas	Failed sheath testing

There were no defects identified for XLPE cable.

The defects identify the known risks on the network with respect to the sub transmission cables. There is also unknown risk due to no testing results being available for Willow Bank ZSS and Smith St ZSS. There are no results for Neville St ZSS, however, Neville St will be decommissioned and replaced by Carisbrook ZSS (expected end of 2018) so the risk of these cables will be removed.

In support of the PILC issue at Kaikorai Valley identified by Aurora, the data shows that there are sections of the No 1 cable with 10 different ages and No 2 cable with 12 different ages. These sections range in length from 7.7m to 112m, indicating that faulted sections may have been replaced. These circuits have a much larger number of sections with different ages than any other circuit, which mostly have 1 or 2 sections of different ages.

The testing identifies a number of recurrent sheath integrity failures and the deterioration in the condition of the St Kilda No 2 cable over a 5 year period, demonstrated by the increased time required for it to ‘dry out’ prior to passing the sheath test in 2018 compared to 2013.

It is also understood gas leaks have proven to be difficult to identify and locate. Nitrogen is used as the insulation gas of the cable but is an odourless gas. Therefore, an additive is added to the gas to enable field crew to detect it. This can take significant time resulting in the faulted cable being out of service for a prolonged period of time.

Based on this evidence and interviews with staff, there are indications that the gas and oil insulated cables are reaching the end of their serviceable lives.

13.5 APPROACH TO RISK ASSESSMENT

Due to the type of information available, a qualitative approach was taken to the risk assessment for this asset class.

SAFETY RISK

These cables are buried underground and not accessible to the public. There have not been any identified instances of the sub transmission cables causing a public safety hazard, nor of excavators digging up the sub transmission cables.

The safety risk is found to be Insignificant.

ENERGY AT RISK

The consequence of a cable failure has been determined by the energy at risk. The energy at risk was calculated using the load characteristics for the zone substation and calculating the energy that would not be supplied to customers if both sub transmission cables failed at the same time and required one month to be repaired, based on maximum repair time identified in the availability data. The total energy was then multiplied by the VoLL. The analysis took into account the zone substation load and transfer capability.

Five of the Dunedin zone substations are located in areas where there is sufficient capacity to transfer load away via the distribution (6.6kV) network to restore supply and mitigate the extent of the outage experienced. The transfer capacities for those substations is equal to, or greater than, the demand on those substations. This reduces the consequence of failure of these circuits which reduces the total risk and, therefore, reduces the priority for remediation. These substations are: Neville St, Smith St, Mosgiel, Kaikorai Valley and Ward St.

The probability of failure is a quantitative assessment based on the cable type and age using a survival curve based on the Weibull probability distribution. Due to history of defects and recent performance of these cables, the expected life was reduced to reflect that these cables are exhibiting end of life signs through sheath test failures, leaking of oil and problems with joints. The expected life for PILC, Oil and Gas type cables was reduced to 70 years, based on experience in other electricity businesses and evidence obtained from the investigation into the asset defects. The issues associated with individual cables were considered when assessing the prioritisation of the risks

Since the network is built with N-1 redundancy, a second contingency event is required to cause any actual loss of supply. However, as noted in section 13.2.2, experiencing a fault current or the full load of the substation can cause damage to the aged cables, particularly those with gas or oil insulation. This results in the probability of a second contingency being increased as a result of the initial event.

Table 13.6 Unweighted energy at risk assessment by cable

ZONE SUBSTATION	TYPE	VOLTAGE	LENGTH (KM)	AGE	ENERGY AT RISK ($'M, 2018)
North City	Oil	33kV	5.0	42	3.4
Corstorphine	Oil	33kV	8.8	45	1.5
East Taieri	Oil	33kV	5.1	45	0.8
South City	Oil	33kV	3.1	46	0.3
St Kilda	Oil	33kV	3.1	38	0.3
Neville St	Gas	33kV	13.4	55	0
Ward St	Gas	33kV	8.3	51	0
Willowbank	Gas	33kV	7.8	55	0
Smith St	Gas	33kV	6.2	59	0

ZONE SUBSTATION	TYPE	VOLTAGE	LENGTH (KM)	AGE	ENERGY AT RISK ($'M, 2018)
Kaikorai Valley	PILC	33kV	5.7	7 - 68	0
Other	PILC	33kV	5.7	11 - 68	NA
Other	XLPE	33kV & 66kV	20.6	2 - 33	NA

NA: not assessed due to low expected risk
Note: the energy at risk is not probability weighted so it does not include consideration of the probability of failure.

ENVIRONMENTAL RISK

The environmental impact of these cables is caused by oil leaking through damaged sections of the sheath or at joints and terminations. Examination of the inspection and test records identified that a significant amount of oil can leak out of the cable and into the environment. Between 2009 and 2015 4,274 litres leaked from North City No. 2 cable. Currently this cable is not leaking.

Although only one oil leak event was identified by Aurora as having been deemed an environmental incident, the response to the incident as descried in Table 13.7 highlights the significance of the impact and how seriously it is taken. Any financial penalties of the incident have not been provided to WSP.

We note that the current type of insulating oil used is not classified as hazardous, it is insoluble in water and is biodegradable, hence minimising the environmental impact. However, there is no information regarding the types of oil that have previously been used and that may still be contained within the cables.

Table 13.7 Environmental incidents

ASSET	INCIDENT	RESPONSE
North City Underground Oil Filled Cable - 2015	Detection of loss of oil pressure which suggested that oil was leaking from the cable.	Contact was made with the Otago Regional Council and they were advised of the issue. A programme of testing was instigated to discover the location of the leak. This included thermal imagining. The leak stopped by itself, however the location or cause of the leak were not identified.

13.6 RISK ASSESSMENT

Table 13.8 and Table 13.9 below show the outcome of our risk assessment. They show the highest risk ranking for each of the risk categories identified and displayed as kilometres of cable per category.

As described above, the reliability risk considered the energy at risk (the value of energy that would go unserved) at the zone substation should supply be lost at the sub transmission level. This accounts for all available load transfers.

The 17 km of cable that has a higher risk of failure is the connection to Neville St (10.7km) and Smith Street (6.2km) zone substations. As part of the Neville St decommissioning project, the associated cables will be decommissioned, removing this risk.

North City cables pose a moderate risk due to the limited load transfer available and the condition of the cable increasing risk of failure.

We note that Kaikorai Valley cables have evidence of a number of faults and a failure maybe caused by its location in steep terrain. However, due to the ability to transfer load to restore supply and N-1 configuration, it is not identified to be a priority for remediation.

Table 13.8 Sub transmission underground cable risk matrix for Dunedin

Increasing consequence (criticality) -->

Prob of Failure -->

0	0	0	0	0
0	0	0	0	0
44	17	5	0	0
2	3	0	0	0
5	0	0	0	0

Table 13.9 Sub transmission underground cable risk matrix for Central

Increasing consequence (criticality) -->

Prob of Failure -->

0	0	0	0	0
0	0	0	0	0
0	0	0	0	0
7	0	0	0	0
9	0	0	0	0

13.7 KEY FINDINGS

The sub transmission underground cables fleet is comprised of largely oil and gas insulated cables, followed by XLPE and PILC. Overall, the sub transmission underground cable fleet is performing well but there are some condition issues that have emerged during the past few years. We found:

- The asset data available from Aurora's systems was suitable for the purpose of this review and the assessment approach undertaken. We note that underground cables are not routinely inspected as they are directly buried in the ground, but testing has been undertaken on the oil and gas cables on a regular basis. There were no test records for XLPE and PILC cables.
- No loss of supply has been attributed to a failure of a sub transmission underground cable. Since the sub transmission underground cable network is built with N-1 redundancy, a second contingency event is required to cause any actual loss of supply. Average availability of the cables is 98%, with the predominant reason for unavailability being maintenance and testing.
- There have not been any identified instances of the sub transmission underground cables causing a public safety hazard.
- The available test records identified a number of recurrent sheath integrity failures, indicating a deteriorated condition.
- 17 km of cable that has been assessed as having a higher risk of failure is comprised of the connection to Neville St (10.7 km) and Smith Street (6.2 km) zone substations. As part of the Neville St decommissioning project, the associated cables (10.7 km) will be decommissioned, removing this risk.
- North City cables pose a moderate risk due to the limited load transfer available and the condition of the cable increasing risk of failure. There was a significant oil leak on the North City No. 2 cable, however, the leak stopped in 2015.

— There is a low risk of environmental damage through oil leaks, although the type of oil used limits the damage caused.

We note that replacement of a sub transmission underground cable can be a lengthy process and the lack of good condition information poses a risk that a cable needing replacement may not be identified with sufficient lead time. The impact is a potential reduction in network security while cables are replaced.

WSP concludes that sub transmission underground cables pose a low to moderate risk to network reliability and an insignificant risk to public safety. Oil leaks can pose a risk to the environment, but none were identified currently. Table 13.10 summarises the sub transmission underground cable risks and indicates the priority for remediation.

Table 13.10 Summary of sub transmission underground cable risk

ITEM	NUMBER	RISK TYPE	DESCRIPTION
North City (oil insulated cable)	5.0km	Reliability	Oil insulated cable with significant historical leaks. This is a Moderate risk.
Corstorphine (oil insulated cable)	8.8km	Reliability	Oil insulated cable with second highest energy at risk should both circuits fail. This is a Low risk.
Kaikorai Valley (PILC with history of faults)	5.7km	Reliability	PILC cable with evidence of a high number of historical failures. This is a Low risk.
Failed sheath tests	25.3km	Reliability	A number of circuits: Ward St No 1 and No 2, Corstorphine No 1, East Taieri No 1, St Kilda No 1 and No 2. This is an Insignificant to Low risk.

14 UNDERGROUND CABLES – DISTRIBUTION

This section discusses the current state of the underground distribution cables asset fleet, its recent performance and WSP's assessment of the risk it presents to Aurora's network in terms of impacts to reliability.

This asset class comprises:

- Underground distribution HV cables.
- Underground distribution LV cables.

14.1 ASSET DATA

14.1.1 AVAILABILITY AND QUALITY

To assess the risk of the distribution cables, WSP reviewed the information available from the following activities:

- defect data
- analysis of cable type, age and network topology
- review of outage data
- discussion with Aurora SMEs.

In undertaking this assessment, we have considered all the information we obtained from Aurora over the course of the project. Table 14.1 is the data quality summary of the available information where we took into consideration the ease of available and accessibility of the information.

We found the attribute data for underground distribution cables was generally quite good, however the accessibility of the data is not straight forward as it is spread over many separate documents and systems including GIS and spreadsheets. Important items to note are:

- key attributes for both HV and LV underground cables are largely populated with 0.2% (16) and 8.2% (2,262) entries without an insulation type respectively
- no assessment is made of LV cables and their performance is not separately tracked
- there is no age data available for cast iron pothead, including installation and removal dates, but they all have GIS coordinates and 70% of them also have the street name recorded.

Distribution cables are not considered a critical asset for this review. As a result, we found that there was sufficient information available to undertake this risk assessment based on a modelling approach.

Table 14.1 Summary of data quality

ASSET CLASS	SUB CLASS	ATTRIBUTES	CONDITION	PERFORMANCE	OVERALL DATA QUALITY
Underground cables	HV cables[1]	🟢	🔴	🟡	🟡
	LV cables[1]	🟡	🔴	🔴	🟡
	Cast Iron Potheads	🟡	🟡	🟡	🟡

(1) Although the condition and/or performance data is assessed as a 'red', the overall data quality is a 'yellow' as condition and performance data is not generally kept on these assets in the electricity industry.

14.1.2 ASSET CLASS SEGMENTATION

Asset class segmentation was not relevant for field inspection work for underground distribution cables as we did not undertake a sampling approach.

14.2 DESCRIPTION OF THE ASSET CLASS

This section provides an overview of the asset fleet and the characteristics that are indicators of risk.

14.2.1 FLEET COMPOSITION

The fleet comprised of 52% (1,046 km) HV cables and 48% (956 km) LV cables. Table 14.2 shows the composition of the network by conductor type and length.

Table 14.2 Fleet cable summary

ASSET GROUP	ASSET CLASS	ASSET CATEGORY	UNITS	DUNEDIN	CENTRAL	TOTAL
UG cables - distribution	HV cable	11/6.6kV PILC	km	279.5	147.9	427.4
		11/6.6kV XLPE or PVC	km	36.2	580.4	616.6
		Submarine cable	km	1.4	-	1.4
	LV cable	400V XLPE or PVC	km	272.1	684.2	956.3

The asset fleet also includes potheads, which are used where cables exit the ground and transition to overhead lines. They are located at the top of poles. Cast iron potheads are a sub category of the pothead fleet. There are 455 cast iron potheads on the network, 385 high voltage and 70 low voltage, and are all located on the Dunedin network.

The age profile of assets in Figure 14.1 shows the relative age of assets and cable types. It provides an indication of the volumes of assets approaching the end of their expected lives.

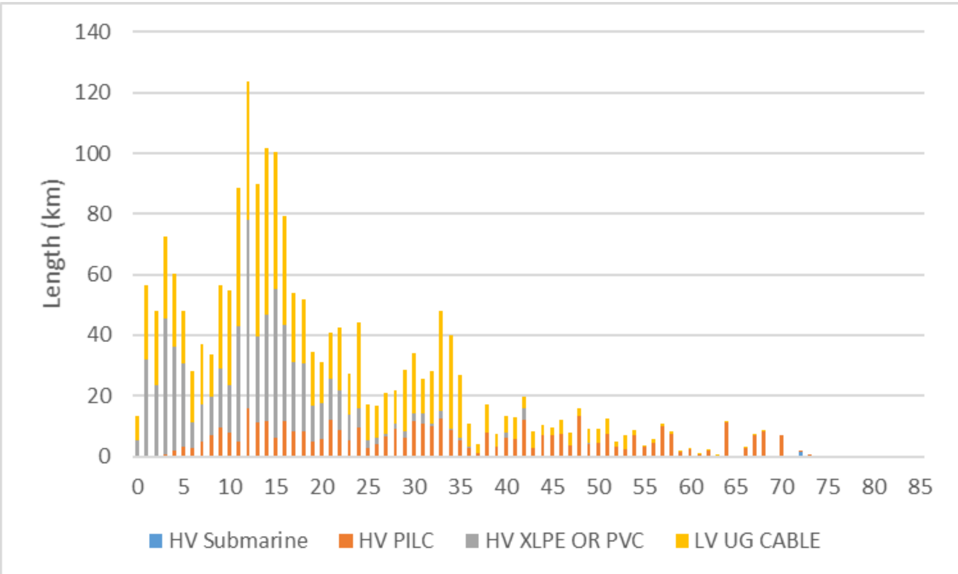

Figure 14.1 Cable age profile by material type

EXPECTED LIFE

The age profiles are shown below for and summary statistics are shown in Table 14.3 shows the weighted average age of the underground distribution cables. The expected life is similar across insulation material.

Table 14.3 Cable fleet statistics

	EXPECTED LIFE	WEIGHTED AVERAGE AGE	WEIGHTED AVERAGE REMAINING LIFE	LENGTH EXCEEDING EXPECTED LIFE (KM)
HV 11/6.6kV PILC	60	33.6	26.4	42.6
HV Submarine (PILC)	60	72.0	-12.0	1.4
HV 11/6.6kV XLPE or PVC	45	11.9	33.1	0.3
LV 400V XLPE or PVC	45	19.2	25.8	41.3

Table 14.3 shows that 9.5% of the PILC type HV cable and the entire section of HV submarine cable exceed their expected lives, indicating an elevated risk of failure of this asset type. There is also 4% of LV cable that has exceeded its expected life.

14.2.2 FAILURE MODES AND CONSEQUENCES

This section discusses the failure modes and consequences as they relate to this asset class to inform our approach to risk analysis for this asset fleet.

The primary failure mode is the loss of insulation of the cable which result in a fault. Depending on the cable type, the loss of insulation manifests in different ways. Both of these failure modes are age related as the other sheath deteriorates but can be accelerated by damage from external impacts or installation practices.

- XLPE: water ingress into the cable at points of electrical stress and where the external sheath has been damaged causes ‘treeing’. The treeing extends along the cable and damages the insulation until it is insufficient and results in a failure
- PILC: PILC uses oil (wax) impregnated paper as insulation. This is different to oil insulated cables that require oil to be pumped in under pressure. Aurora has identified a failure mode where oil drains from the paper insulation of PILC cables where the cables have been installed on steep hills.
- Joints (including terminations): these are a common location of failure for cables and there are multiple causes of failure including: ground movement exerting physical stress on a joint; moisture ingress damaging insulation; poor workmanship when installing the joint; overheating due to overloading or the joint conductor connection becoming loose. The failure can be a phase to phase or a phase to ground fault which in some circumstances can result in fire.

The second main failure mode is external impact. This is typically the result of cables being dug up due to excavation works and is normally mitigated through separate cable routes and mechanical protection or identification.

The main consequences of distribution cable failures are loss of supply until the cable is repaired. In urban areas, supply may be able to be restored through network switch in some cases.

Where cables are dug up during excavation, there is the risk of electrocution if the excavation equipment penetrates or damages the external sheath and insulation.

Cast iron potheads have been identified to have an explosive failure mode that can result in parts of the cast iron housing falling to the ground, posing a safety risk to the public. The failure mode is age related and caused by moisture ingress into the unit following planned outages. We note that Aurora has an established program to remove cast iron pothead from the network.

14.2.3 INSPECTION AND TESTING

There is no regular inspection program in place. This is common industry practice and the adopted maintenance strategy is to run these assets to failure. However, this means that there is no condition data available for this asset class.

14.3 DATA VALIDATION

Our approach to data validation is set out in section 3. We note that for some asset classes, such as underground cables, inspections were unable to be performed due to inaccessibility of the assets, as they are direct buried in the ground, and inspections or tests would require significant network outages.

For these assets we relied on existing inspection and test reports and data available from Aurora's GIS and other data bases. Due to the asset type and modelling approach undertaken, the data available from these data sources was considered sufficient for the purpose of this review.

14.4 PERFORMANCE AND CONDITION

This section provides an overview of the key findings from our investigation into the existing data and documentation.

RELIABILITY PERFORMANCE

Figure 14.2 shows the number of historical outages caused by the failure of underground distribution lines. The data was filtered to only include underground distribution lines that had failed in service due to defective equipment, including both cables and potheads. The chart shows that there is very volatile performance and there is no clear trend. However, the HV cables asset class was identified to make the fourth highest contribution to network performance.

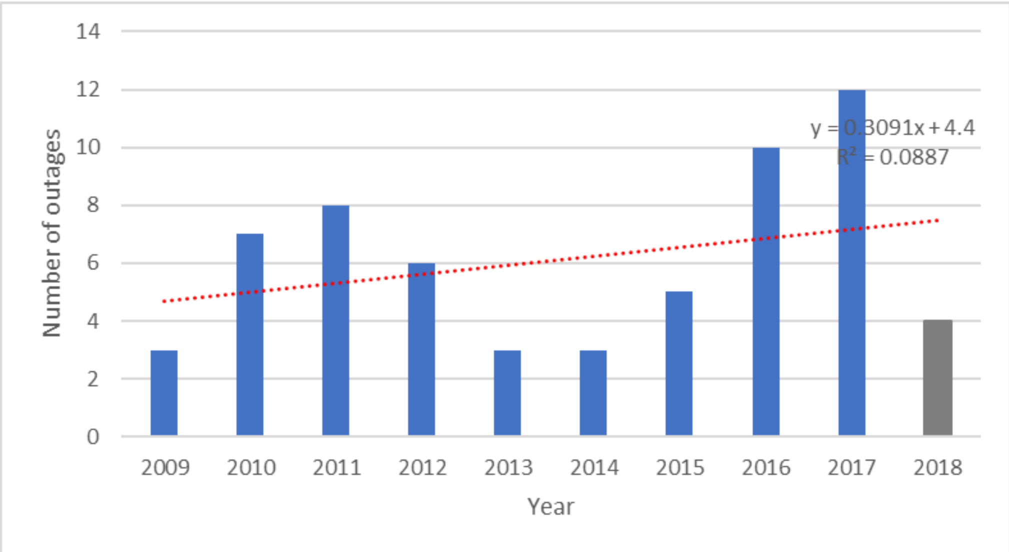

Figure 14.2 Historical outages caused by underground distribution lines failure[26]

Figure 14.3 shows the performance of the pothead fleet. It demonstrates that there isn't a strong trend of outages, but there is a long-term average of 2 outages per year. Only one of the faults was specifically attributed to a cast iron pothead and only one was due to a cause other than defective equipment.

[26] Note that the data for 2018 is an estimate based on half a year of data for January to July

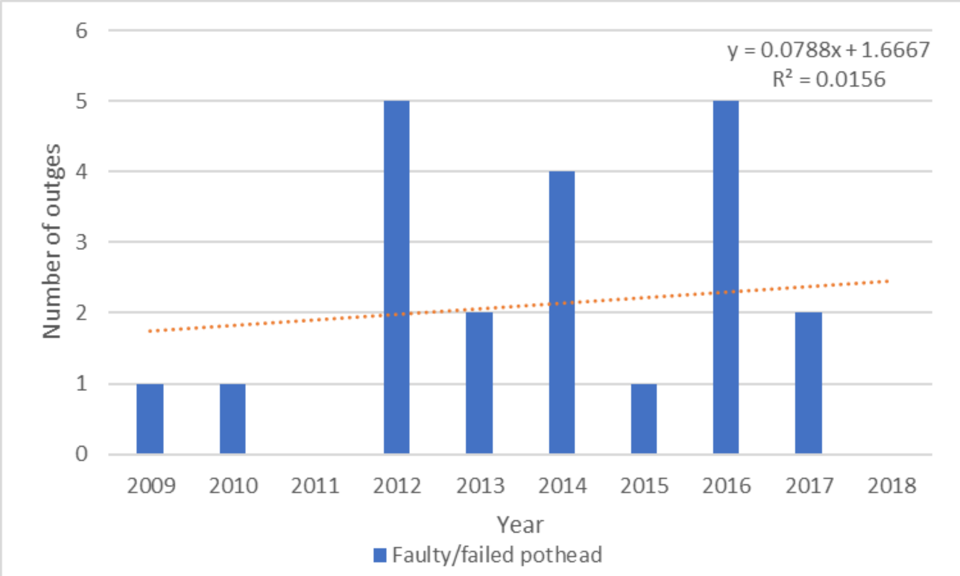

Figure 14.3 Trend of outages caused by pothead

Table 14.4 shows the number of outages for each cause since 2009. Equipment deterioration contributes 89 (85%) of the 105 outages and a further 5 (5%) were attributed to equipment imminent failure. Potheads are included in this outage data

Table 14.4 Cause of outages

CAUSE DESCRIPTION	NUMBER OF OUTAGES	PERCENTAGES
Equipment Deterioration	89	85%
Unknown	7	7%
Equipment Imminent Failure	5	5%
Equipment Faulty Manufacture	2	2%
Environment Flooding	1	1%
Environment Vibration	1	1%

14.5 APPROACH TO RISK ASSESSMENT

We have taken a quantitative approach to modelling the risk posed by distribution cables. Since the cables are underground, they do not present a safety risk. The asset class contributes significantly to network reliability performance, hence using energy unserved as the primary metric for risk is appropriate.

Since there is limited data available regarding the condition of the asset fleet, the risk assessment has taken a modelling approach that focused on the reliability risk calculated from the energy that would not be supplied if there is an outage of a cable.

We applied a survival curve based on the Weibull distribution using the expected life of the cable type. The survival curve determined the risk of failure, while the consequence was assessed by considering the impact to network reliability.

The risk of potheads was assessed using a qualitative approach. We note that due to the failure mode of these assets they can present a safety risk on the network. The consequence assessment was based on their location on the network using the population density, as for other distribution assets. The probability of failure was assessed based on engineering judgement and past performance. Historically there have been two pothead failures on average per year, the risk assessment framework indicates failure is likely to occur. Aurora currently has an established program to remove cast iron potheads from the network, but while they are on the network they are included in the current state assessment.

14.6 RISK ASSESSMENT

The consequence score based on Aurora's risk matrix for operations and systems risk is minor. The impact could lead to a supply interruption which can be restored within 3 days and within normal operating outcomes. The impact of SAIDI and SAIFI would be within normal operating parameters.

Table 14.5 and Table 14.6 show the risk that underground distribution cables pose to the network, showing the length of cable aligned with Aurora's risk matrix in the Dunedin and Central network. Table 14.7 shows the risk matrix for cast iron potheads in Dunedin, there are no known cast iron potheads on the Central network.

Table 14.5 Distribution underground cables risk matrix for Dunedin

Increasing consequence (criticality) -->

Prob of Failure -->					
	0	0	0	0	0
	3	0	0	0	0
	234	31	0	0	0
	100	16	0	0	0
	166	40	0	0	0

Table 14.6 Distribution underground cables risk matrix for Central

Increasing consequence (criticality) -->

Prob of Failure -->					
	0	0	0	0	0
	0	0	0	0	0
	68	7	0	0	0
	227	53	0	0	0
	754	304	0	0	0

Table 14.7 Distribution cable cast iron pothead risk matrix for Dunedin

Increasing consequence (criticality) -->

Prob of Failure -->					
	0	0	0	0	0
	127	55	127	145	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0

14.7 KEY FINDINGS

The distribution underground cables fleet is comprised of largely XLPE and PILC type cables. Overall, the underground cable fleet is performing well but there are some condition issues that have emerged during the past few years. We found:

- The asset data available from Aurora's systems was suitable for the purpose of this review and the assessment approach undertaken. No regular testing or maintenance program exists for distribution underground cables and, therefore, there is very little asset health information, specifically in the areas of condition and performance data. A modelling approach was applied to assess the probability of failure using the best asset data available.
- HV distribution cables asset class causes 11% of the network outages, the fourth highest contribution out of the asset classes. Most outages in this asset class are recorded as being caused by asset deterioration.
- Approximately 10% of PILC cables and the entire section of HV submarine cables exceed their expected life and, therefore, represent an elevated risk of failure for this asset type.
- Cast iron potheads were identified to present a public safety risk because they are installed on poles and is it possible for their failure mode to affect public safety. Aurora has a program in place to remove these from the network.
- The dominant risk posed by distribution cables is related to network reliability. However, each cable generally supplies a small number of customers so the impact of each individual cable failure is low.

WSP concludes that distribution underground cables pose a low risk to network reliability and an insignificant risk to public safety and the environment. However, cable terminations in the form of cast iron potheads pose a moderate to high risk to public safety in the Dunedin network area. Table 14.8 summarises the distribution underground cable risks and indicates the priority for remediation.

Table 14.8 Summary of distribution underground cable risk

ITEM	NUMBER	RISK TYPE	DESCRIPTION
Cast iron potheads	455	HSE	455 cast iron potheads are installed on the Dunedin network. These have an elevated risk to safety, ranging from low to high dependant on their location.

15 ZSS TRANSFORMERS

This section discusses the current state of the transformer assets, its recent performance and WSP's assessment of the risk it presents to Aurora's network in terms of impacts to safety, reliability and the environment.

15.1 ASSET DATA

15.1.1 AVAILABILITY AND QUALITY

In undertaking this assessment, WSP has considered all the information we obtained from Aurora over the course of the project. In our assessment, we took into consideration the ease of availability and accessibility of the information.

To assess the risk of the Zone Substation (ZSS) Transformers, WSP reviewed the information available from the following activities:

- on-site inspection of assets
- analysis of transformer attributes such as type and age
- review of capacity and redundancy
- review of inspection and test results from Aurora's maintenance program
- discussion with Aurora SMEs to understand any data gaps.

We found that the data held by Aurora for transformers is good. However, the accessibility of the data is not straight forward as it is spread over many separate documents and systems including GIS, spreadsheets and PDF site inspection reports. Important items to note are:

- only 90% of the tap changer attribute data was recorded
- transformer attributes are all known, but spread over several data sources
- condition information is available, but spread over a combination of spreadsheets and PDF hand written site inspection reports
- the maintenance schedule does not include four tap changers (two zone substations)
- Bushing attributes are not recorded, making the identification of any systemic issues difficult (issues being oil seal failure in 33kV solid core bushings, base condition reference for 66kV bushings). Considered a low to modest risk.
- load duration data was not available for all zone substations due to the recent change of system. We do not consider this a significant issue as it is a temporary result of changing systems. The data will become available with the new system
- attribute and condition information about the bushings was not recorded.

Overall, we found the information for transformers to be appropriate for the analysis undertaken and to allow us to identify and prioritise the areas of risk on the network. Table 15.1 summarises the data quality.

Table 15.1 Summary of data quality

ASSET CLASS	SUB CLASS	ATTRIBUTES	CONDITION	PERFORMANCE	OVERALL
Zone substation	Transformers	🟡	🟡	🟢	🟡
	Tap changers	🟡	🟡	🟢	🟡
	Bushings	🔴	🟡	🟢	🔴
	Bunding	🟢	🟢	🟢	🟢

15.1.2 ASSET CLASS SEGMENTATION

Asset class segmentation was not relevant for field inspection work for this asset type as we did not undertake a sampling approach.

15.2 DESCRIPTION OF THE ASSET CLASS

This section provides an overview of the asset fleet and the characteristics that are indicators of risk. This asset class comprised of:

- the power transformer
- tap changer
- bushings
- bunding.

The impact on network risk of each of these components are discussed below.

15.2.1 FLEET COMPOSITION

Aurora’s network has 39 existing zone substations which are comprised of 15 single transformer zone substations and 24 two transformer zone substations. As shown in Table 15.2, the capacities of the transformers range from 2 MVA to 25 MVA.

There are two substations currently under construction: Riverbank ZSS will be a new substation (switching station) with longer term plans to install a transformer and take load from Wanaka ZSS, and Carisbrook ZSS will replace Neville St ZSS. Transformers at these two substations have been excluded from the analysis in this section unless otherwise specifically mentioned.

The geographical distribution of customers in the Central network lends itself to a larger number of small single transformer zone substations. Many of these are legacy designs when they were owned by local councils, prior to Aurora ownership. In these cases, the transformers are typically located in small fenced enclosures with the switchgear mounted on top.

Table 15.2 Transformer fleet summary

		TRANSFORMER CAPACITY (MVA)						
NETWORK	REDUNDANCY	0-5	5-10	10-15	15-20	20-25	TOTAL ZSS	TOTAL TF'S
Central	N	11	2	-	-	-	13	13
Central	N-1	1	2	2	1	2	8	16
Dunedin	N	2	-	-	-	-	2	2
Dunedin	N-1	-	2	4	2	8	16	32
Total		**14**	**6**	**6**	**3**	**10**	**39**	**63**

AGE PROFILES

Age is generally a good proxy for asset condition and, therefore, risk of failure. Transformers are highly reliable assets and have long lives if well maintained. The expected life of a transformer is typically around 60 years for most distribution businesses. If transformers are loaded above their rated capacity for extended periods of time, or are operated in hot and humid environments, then the heat generated accelerates their aging process. However, the transformers on Aurora's network are not heavily loaded and are in a temperate environment which will help their longevity.

Figure 15.1 shows the age profile for Aurora's transformer fleet. It shows a number of transformers are at or approaching their expected life and this is an indication of increasing risk on the network. It demonstrates that a large proportion of the transformer fleet will be approaching its expected serviceable life over the next 10 years and is likely to result in increasing risk to reliable supply and appropriate planning for mitigation of the risk is required.

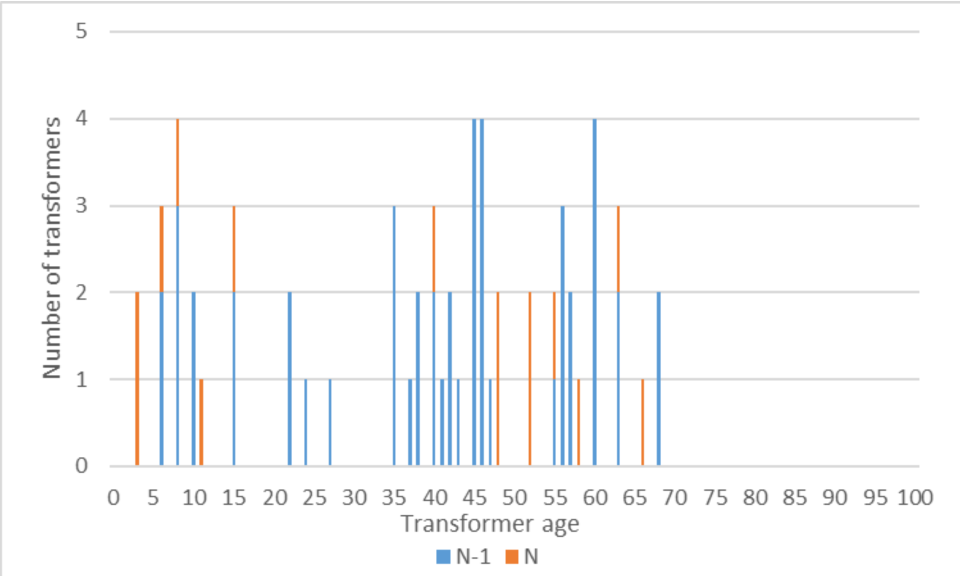

Figure 15.1 Transformer age profile by zone substation and distribution type

EXPECTED LIFE

Table 15.3 shows a summary of the asset fleet, comparing the average age to the expected life by capacity. This provides a view on which segment of the fleet is likely to pose higher risk to the network. The table shows that 10 transformers have already exceeded their expected life.

While age is a useful proxy for condition, actual condition assessments, historical performance, redundancy in the network and other mitigation plans need to be considered as well to assess which assets are likely to pose the highest risk to the network. These are discussed in the following sections.

Table 15.3 Transformer fleet statistics (60 years is current estimate by WSP)

RATINGS (MVA)	EXPECTED LIFE	QUANTITY	WEIGHTED AVERAGE AGE	WEIGHTED AVERAGE REMAINING LIFE	NUMBER EXCEEDING EXPECTED AGE
0-5	60	10	46.8	13.2	2
5-10	60	11	32.3	27.7	2
10-15	60	7	33.3	26.7	0
15-20	60	26	40.8	19.2	4
20-25	60	9	34.3	25.7	2
Total	**60**	**63**	**38.5**	**21.5**	**10**

15.2.2 FAILURE MODES AND CONSEQUENCES

In addition to age related insulation failure, transformer failure modes applicable to Aurora's assets are oil leaks, tap changer mechanism defects, possible absorption of moisture and internal winding restraint/robustness to sustain a fault. Overheating (winding hot spot) and bushing risks are considered low providing all ZSS remain in service, a structured maintenance programme is in place to address these risks.

On load tap changers provide automatic voltage regulation, with the continual switching causing arcing within its chamber and resultant contamination of its oil and mechanism wear. Whilst modern transformers have separate tap changer oil reservoirs for this purpose, the gasses generated can pollute the main winding oil if a link is provided via a sharing of conservator tank oil (communicating tap changer) as is found in some Aurora transformers. Planned tap changer maintenance is key to maintaining reliability.

Outages will shift load onto neighbouring transformers and this would have to be managed, as short term overload ratings need to be monitored to keep within peak load transfer capacity. Winding over heating will accelerate the aging process and any failure can have catastrophic consequences (failures can present themselves months/years after the initial event). Bushing failures are a risk at higher voltages but this is only a concern at 66kV installations (these transformers are relatively new in the Aurora network and thus unlikely).

15.2.3 INSPECTION AND TESTING

Aurora undertakes four yearly cyclic inspections of the zone substations, during which they inspect the transformers. All zone substation transformers have evidence of inspection and testing being undertaken on a frequent basis:

- oil sampling has been done on a one or two-year cycle for all transformers
- visual zone substation checks have been undertaken frequently including all assets, including specific checks on the transformers
- tap changers are inspected monthly as part of the zone substation checks but the schedule to meet overhaul maintenance requirements has not been maintained.

WSP reviewed the inspection and testing results to assess the risk that these assets pose to the network.

15.3 DATA VALIDATION

All zone substations (except Remarkables) were inspected visually. Testing undertaken by Delta was observed at two substations, one in Dunedin and one in Central, which were schedule for their four-yearly maintenance during the time of this review.

ZSS transformers were visually inspected for:

- Confirmation of manufacturer, age, type
- Physical appearance – oil leaks, corrosion, paint
- Oil bunding containment and fire walls / separation from other assets
- General observations around seismic restraint
- Access for maintenance.

The audits were undertaken by an experienced engineer with strong background in transmission and distribution networks including asset management and condition assessment.

Much of this information was available from the Aurora asset data and provided us with a high degree of confidence for our assessment of asset condition and the risks associated with ZSS transformers.

15.4 PERFORMANCE AND CONDITION

This section assesses the performance and condition of the transformer fleet.

15.4.1.1 TRANSFORMER EXTERNAL CONDITION

The zone substation inspections identified that the external condition of all transformers is satisfactory aside from three zone substations where transformers have minor oil leaks. These two substations are:

- North City zone substation in Dunedin where the transformer radiators are suffering from spot rusting in several locations with a slow leak of oil on the radiators of T2. Temporary repairs are evident in several locations on T1 and T2 indicating this is an ongoing issue
- Fernhill zone substation in Central has sign of oil leakage, identified by a light coating of oil around the transformer controls enclosure, however the source is suspected to be the tank sensor cable glands.
- Arrowtown T1 OLTC gasket has a minor leak which has a temporary patch repair. Minor transformer leaks are common across electricity businesses.

15.4.1.2 TRANSFORMER INTERNAL CONDITION

Aurora undertakes periodic oil sampling for analysis from the transformers to assess the internal condition of the transformers. These include for dissolved gas analysis (DGA) and Furan analysis.

DGA are undertaken to indirectly detect transformer internal faults or insipient faults. Furan analysis is used to indirectly estimate the degree of polymerisation (DP) of the paper insulation mechanical strength (these results do appear optimistically high for the 50 to 60 year old units and an actual paper sample would be required for a definitive figure). Taking DGA analysis is good industry practice and most business use it as a key indicator of remaining transformer life.

A complicating factor in the DGA and DP results is that the oil has been filtered at various times throughout the life of the transformers. Filtering removes the trace chemicals from the oil and effectively resets the base line, hence it is necessary to adjust the oil results to account for oil filtering to ensure a result that reflects the transformers condition. It is not evident that this has been done, and it is possible that the results overstate the transformers remaining life as some of the very old transformers still have abnormally high DP results. For example, the transformers that have estimated DP in their 400 and 500's are:

- Remarkables T1 with DP of 480 (52 yrs old)
- Outram T2 – DP 517 (66 yrs old)
- Outram T1 – DP 544 (66 yrs old)
- Cromwell T2 – DP 581 (46 yrs old).

Remarkables and Outram transformers data indicate it is indicative of reaching the end of their service life, followed by Cromwell. It is noted that a plan is in place to upgrade parts of the Outram substation.

Eight zone substations shown in Table 15.4 do not have DP results. This does not appear to be an issue for most of the transformers as they are quite young and the paper strength deteriorates with age and heat. However, Port Chalmers has two old transformers which would be considered to have a higher risk of failure due to being past their expected lives.

Table 15.4 Transformers without estimated DP test results

ZONE SUBSTATION	NUMBER OF TRANSFORMERS	AGE (YEARS)
Camphill	1	3
Cardrona	1	8
Commonage	2	10
Lindis Crossing	1	3
Port Chalmers	2	63
Queensberry	1	15
Wanaka	2	15
Ward St	2	8

The results indicate that all zone substation transformers currently in service have satisfactory internal condition and are suitable for normal operation, although some are shown to be at or near the end of their service life. As the general condition of transformers is satisfactory, we have used transformer age as a proxy for future condition in the risk analysis.

15.4.1.3 TAP CHANGERS

Each transformer has a tap changer to regulate the output voltage, so it remains within specified upper and lower limits. Tap changers are important for the correct functioning of the transformer and maintaining quality of supply on the network. The outage data showed only eight outages recorded that are attributed to failure of the tap changer at a zone substation transformer, the most recent being in 2011, and only two identified as being due to equipment condition. Hence, this review has focused on their condition and how this affects the risk of the transformer fleet.

Out of the 63 zone substation transformers, 65% of transformers had test reports available for review. Three OLTC failures occurred in the last year at East Taieri, Green Island and Willowbank. In general, the fleet was shown to be in acceptable condition with only five tap changers identified to be in poor condition:

— Willowbank ZSS, Transformers 1 and 2

— East Taieri ZSS, Transformers 1 and 2

— Port Chalmers T1 (failed in 2016).

Most of the inspection and test reports were from a period between 2014 and 2017, however there some from 2010 and 2002. Each tap changer type has its own maintenance cycle based on the number of operation or the time elapsed since the last inspection. Table 15.5 shows a summary of the tap changers that are behind on their required maintenance schedule. It shows that half the switches overdue based on the time requirement are also overdue based on the number of operations since the overhaul. A complete list is shown in Appendix E.

The maintenance schedule did not contain Willowbank ZSS or Earnscleugh ZSS.

Table 15.5 Tap changers behind maintenance schedule

YEARS OVERDUE	NUMBER BASED ON TIME	NUMBER BASED ON OPERATIONS
More than 5 years	3	2
4 to 5	1	1
3 to 4	1	1
2 to 3	12	4
1 to 2	7	
Based on switching		8
Total	**24**	**16**

15.4.1.4 BUSHINGS

Information about the type and condition of bushings is not recorded by Aurora. Evidence was found in the inspection and test sheets of inspections identifying issues and resulting in the asset being repaired with a defect repair report. This indicates that defects are likely to be found as part of routine inspections of the zone substations and raise for appropriate action.

However, since Aurora only records asset data in PDF inspection sheets, identifying issues or trends across the fleet is difficult. Understanding the type of assets that are installed on the network is important for effective asset management.

15.4.1.5 SURGE ARRESTORS

Observations of the earth connection at the base of surge arrestors in Alexandra zone substation, Mosgiel zone substation and Wanaka zone substation found used a solid copper bar. This may impede the operation of the surge arrestor and consideration needs to be given to using a flexible earth strap connection. The protection of some transformer and cables from surges is not clear.

15.4.1.6 ZSS EARTHING

WSP reviewed a number of ZSS earth grid test reports and studies. The reports and studies indicate that Aurora has undertaken consistent earthing testing and remediation across the zone substations in both the Dunedin and Central networks. The dates of the test reports show testing has been undertaken in Dunedin ZSS every 5 to 10 years from the early 1990’s, with the Central ZSS data available for all sites within the last 3 years.

WSP examined details of ZSS earthing mats during its site inspection of zone substations. No issues were identified.

15.4.1.7 BUNDING

Transformers are located in bunds which contain oil if there is a leak. Inspection of the zone substations identified that 34 of the zone substations have appropriately bunded transformers with bunds that have satisfactory capacities and are in good condition. We note that many bunds require manual drainage of water and thus need to be subject to regular inspection visits (presently two weekly).

Bunding was not present at a number of small zone substations in the Central network which were all established prior to 1980 and contain transformers with capacities 5 MVA and below, namely:

- Arrowtown ZSS
- Clyde Earnscleugh ZSS
- Dalefield ZSS
- Earnscleugh ZSS
- Ettrick ZSS
- Omakau ZSS.

Cromwell is a substantial ZSS and has no transformer bunding. A catastrophic event has the potential to spill oil into the adjacent main road stormwater system.

Of these unbunded sites, Omakau was located close to a small stream in the Manuherikia catchment which is a sensitive catchment. This presents a possible environmental risk should a significant leak develop in this transformer. We note that the transformer is currently assessed to be in acceptable condition (viewed externally) and no leaks or significant rust was identified.

Plastic drainage pipework is satisfactory for oil containment but not suitable if a fire is burning within the transformer bund. This is considered a particular issue at Fernhill (bunds interconnected and no flame trap).

15.4.1.8 MOBILE SUBSTATION

Aurora have a trailer mounted mobile substation to provide an alternative point of connection to their sub transmission supply, for when taking out a single transformer ZSS for maintenance. This requires site infrastructure around its connection into the network, something which is still to be completed for a number of sites.

This is considered a valuable asset, offering improved security of supply during maintenance outages, though completion of facilities to temporarily connect to all single transformer ZSS is necessary to fully take advantage of this facility.

15.4.1.9 PROXIMITY TO THE PUBLIC

The review identified that, in many areas, residential housing had encroached on zone substation sites. In most cases, there appeared to be sufficient clearances and protection. However, one exception was the East Taieri zone substation. This zone substation is located adjacent a petrol station and the transformers are positioned against the bordering wall. There is a fire wall between the transformers, but their reservoir tanks extend above the wall. There is no fire wall located between the transformers and the petrol station (a recent addition). This is shown in Figure 15.2.

Figure 15.2 East Taieri zone substation transformer adjacent a petrol station

15.4.1.10 BUILDINGS AND GROUNDS

WSP made the following observations during its site inspections:

- Drawing records at most ZSS include construction red mark-up prints in their folders and some Single Line Diagrams were still showing decommissioned assets. These records need to be brought up to date at all sites, to reduce the risk of operational error.
- Fire detection in all ZSS building should be reviewed from the perspective of risk. Typically, smoke detectors are only found in the main switchgear room and no fire detection in adjoining rooms. There is no evidence of any testing of the alarm system.
- North City ZSS has been fitted with an Inergen gas flood fire protection system. Room air tightness needs to be reviewed for this system to be effective.
- Intruder security at Mosgiel ZSS control building is compromised from the fact it is outside the switchyard security fence and glass louver windows into the switchgear room are easily accessed. The building is next to a main rural road.
- Roxburgh ZSS appears to have incomplete construction works, with unidentified control cable cores in a switchyard CB mechanism cabinet and a duplicate 110 V DC battery in a switchyard hut.

The deficiencies identified during onsite inspections at the zone substations are of a minor nature and pose an insignificant risk to safety, reliability and the environment.

15.4.1.11 FIRE WALLS BETWEEN TRANSFORMERS

Fire walls between transformers are not provided in all zone substations[27]. Depending on separation between the transformers (assumed here to be less than approximately 3m), this increases the risk of a fire propagating from one transformer to the second transformer and resulting in a second contingency incident.

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[27] Fire walls between transformers are not installed at Arrowtown, Clyde-Earnscleugh (though one unit not in service), Cromwell. Queenstown has a modest separation between transformers, but the T2 fire risk is the adjoining outdoor feeder switchgear. Should a fire occur, all these transformers are located under significant overhead busbar / switchgear assemblies, which would be significantly compromised during a catastrophic event.

15.5 APPROACH TO RISK ASSESSMENT

The approach undertaken to assess the risk posed by zone substation transformers has been undertaken in three parts as described below.

SAFETY RISK

This is based on a qualitative assessment of the zone substation transformers.

ENERGY AT RISK

This is a quantitative assessment of the value of energy that would not be supplied should either one or both of the transformers (in a two transformer station) experience an outage. In undertaking this assessment, we considered the following:

- The conditional probability of failure was calculated (the probability of failing in year t+1 given that it has survived to year t). The probabilities of only one transformer failing and the probability of both transformers failing together was considered. The probability was based on a Weibull distribution with parameters set appropriately for the age characteristics of Aurora's fleet.
- The time to restore supply has been based on Aurora's mitigation plans, which include the use of the mobile transformer in rural areas and the use of a spare transformer, or relocation of a transformer from another substation, for urban areas.
- In the inner part of Dunedin, there is sufficient transfer capacities to fully offload a substation using switching of the 6.6kV network. As a result, even though some transformers have relatively high probabilities of failure, such as Neville St, there is minimal impact as the demand can be completely transferred away via the distribution network. These substations are: Neville St, Smith St, Mosgiel, Kaikorai Valley and Ward St. Once commissioned, Carisbrook will also have this ability.
- The Value of Lost Load (VoLL) has been used as \$12/kWh for Central and \$20/kWh for Dunedin to reflect the different customer demographics.
- The model incorporates the cost to restore supply. This means that there is an expected cost due to the probability of failure and need to repair that failure, even though the energy can be transferred away. This indicates an increasing risk, even though there is redundancy for the supply through load transfers.

The probability of failure was adjusted to reflect the lack of maintenance and identified deteriorated condition of the tap changers by increasing the probability of a minor transformer outage.

The energy at risk was calculated for one year as we are only assessing the current state of the network and not forecasting forward to assess future scenarios.

ENVIRONMENTAL RISK

This is based on a qualitative assessment of the locations and physical protection provided at each zone substation.

15.6 RISK ASSESSMENT

This section sets out WSP's risk assessment for Aurora's transformer fleet.

SAFETY

East Taieri is the only substation identified to have a public safety risk due to its location adjacent to a petrol station and no physical barrier or fire protection between the transformers and the petrol station. However, the DP value of the transformers are close to 700 indicating it is in satisfactory internal condition, the external inspection did not reveal any significant deterioration that would indicate end of life, and the tap changer is due for an overhaul this year, but otherwise has been maintained. An oil leak from the main transformer into its tap changer was corrected within the last 12 months. As a result, the risk of an incident initiated by the transformers at East Taieri or their components is assessed as Medium.

Earth potential rise from zone substation ground faults has been investigated by Aurora/specialist consultant and was found to pose low risk to people.

ENERGY AT RISK

Figure 15.3 shows the energy at risk. Substations in Capital letters are located in the Dunedin network and lower case names are located in the Central network. The figure shows a snapshot of the current risk for a single year at each substation. It does not consider how the risk will change over time as a result of deterioration of assets, load growth or planned asset replacements. Additional detail for each substation is provided in Appendix E.

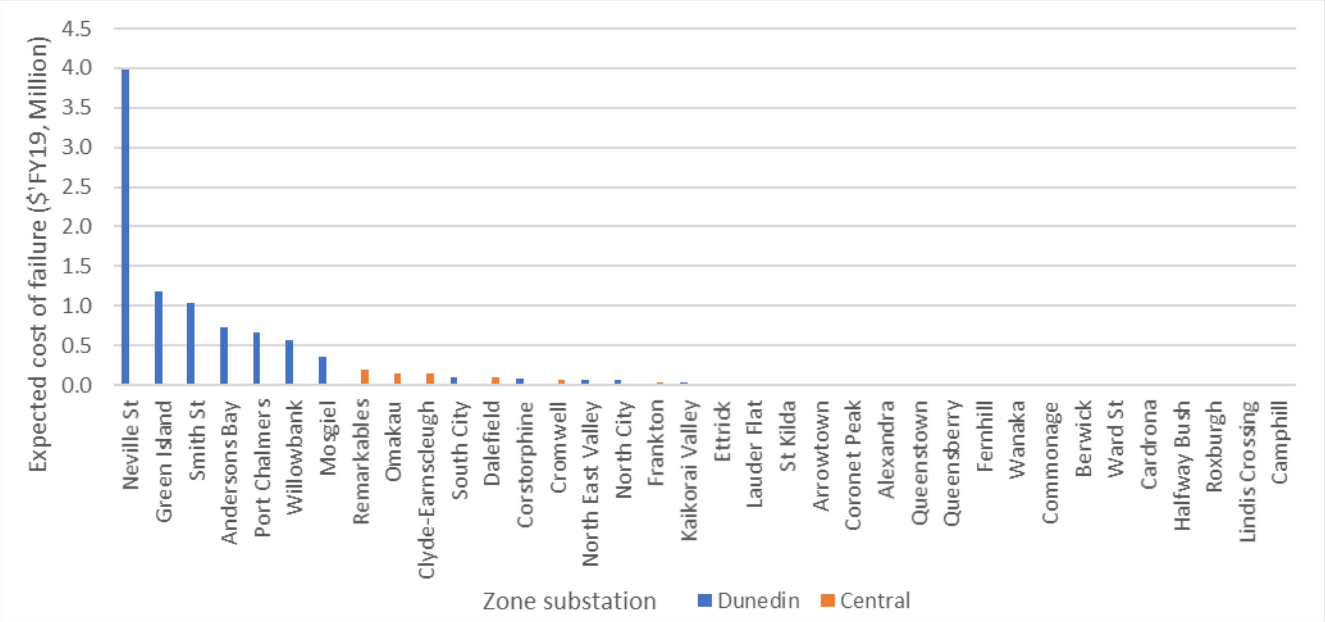

Figure 15.3 Energy at risk by substation for one year

We note that there is a project in progress to construct Carisbrook ZSS to replace Neville St ZSS, which is addressing the greatest risk on the network posed by zone substation transformers.

The energy at risk values in Figure 15.3 are probability weighted based on the condition of the transformer and tap changers. Therefore, the values are different to the consequence rank of the risk matrix which is based on the unweighted consequence.

ENVIRONMENT

There were six zone substation transformers identified to not have any bunding for oil containment. Omakau ZSS was the only one to be located adjacent to a water way. Omakau is an old transformer and, hence, presents an elevated risk of oil leaks. We note that there is a stop bank in place that may contain the oil, however, this zone substation transformer is considered a Moderate environmental risk.

The remaining five transformers are located away from waterways, hence, the consequence is lower and the risk score is insignificant.

Table 15.6 shows the risk matrix for the transformer fleet. It identifies a number of transformers with elevated risk of failure, predominately as a result of the tap changer condition. The transformer with the highest risk of failure is Outram as it is old, past test and inspection reports for the tap changer identify condition issues, and the tap changer is outside its required inspection schedule.

Table 15.6 Zone substation transformer risk matrix

Increasing consequence (criticality) -->

Prob of Failure -->

1	0	0	0	0
7	0	4	1	0
6	0	2	4	2
7	2	4	2	1
6	3	3	3	5

15.7 KEY FINDINGS

The zone substation transformer fleet is comprised of power transformers and their associated tap changers and bushings. Most zone substation transformers are in good condition. They are inspected regularly and appear to be appropriately managed. We found:

- The asset data available from Aurora's systems and augmented by our field inspections was suitable for the purpose of this review. We note that the data on tap changers and bushings is not complete and improvements to consistency of the data recorded can be made. Incomplete asset data presents a risk to effective asset management.
- External deterioration that has resulted in minor oil leaks was identified on three transformers (4.7%).
- Internal condition is assessed by analysis of the oil which is common industry practice. This shows the transformers to be in serviceable condition. However, we note that the oil has been filtered and there has not been a physical sample taken from inside the transformers to provide a baseline for the oil tests. This presents a risk that the oil test results may indicate a better than actual internal condition.
- Test reports showed that the tap changer fleet was in acceptable condition, except for five tap changers (7.9%). There have also been three tap changer failures during the past year indicating an elevated level of risk from this transformer component. There are 24 tap changers that are overdue for maintenance by between 1 and 7 years.
- Bunding around each transformer to contain oil leaks was established at all but 6 substations. The main risk related to a lack of bunding was at Omakau, which is located adjacent a small waterway. The environmental risk was classified as Moderate.
- Aurora has a mobile substation with connection points at most of the single transformer substations to provide support in case of a transformer failure.
- East Taieri was the only zone substation identified to pose a safety risk, classified as Moderate. It is located adjacent to a petrol station but does not have any physical protection in place to protect the petrol station in case of a serious failure and/or fire.
- The transformers at two zone substations are in poor condition, although we note that one is currently in the process of being decommissioned. Additionally, transformer tap changers are showing signs of deterioration and some are behind their maintenance schedule, increasing risk of an outage on the associated transformers.
- There were 8 transformers (12.7%) identified as high risk to reliability, predominately due to the transformer internal condition and tap changers.

WSP concludes that ZSS transformers currently pose a moderate risk to network reliability and a low risk to public safety, except for East Taieri where no physical protection is in place to protect the adjacent petrol station in case of an explosive failure or fire. Transformers at Omakau are not bunded and pose a small risk of environment damage from an oil leak. Table 15.7 summarises the ZSS transformer risks and indicates the priority for remediation.

Table 15.7 Summary of ZSS transformer risk

ZONE SUBSTATION/ITEM	NUMBER	RISK TYPE	DESCRIPTION
Green Island T1	1	Reliability	Transformer condition modelled to be poor. Tap changer has not been maintained within the required schedule resulting in high risk.
Cromwell T1 and T2	2	Reliability	Tap changer has not been maintained within the required schedule. Demand is exceeding substation N-1 capacity. This is a high risk.
Andersons Bay T1 and T2	2	Reliability	Transformer condition modelled to have elevated probability of failure. This is a high risk.
Green Island T2	1	Reliability	Transformer condition modelled to be poor. This is a high risk.
North East Valley T1	1	Reliability	Tap changer has not been maintained within the required schedule resulting in elevated risk. This is a high risk.
Wanaka T2	1	Reliability	Tap changer has not been maintained within the required schedule resulting in elevated risk. This is a high risk.
Arrowtown T1 and T2	2	Reliability	Low probability of failure but high consequence. Demand is exceeding substation N-1 capacity. This is a moderate risk.
Port Chalmers T1 and T2	2	Reliability	Transformer condition modelled to be poor. Tap changer on T2 has not been maintained within the required schedule resulting in elevated risk. No DGA results, so no internal condition data. This is a moderate risk.
Tap changer maintenance	12	Reliability	Elevated risk of 12 transformers due to tap changers not being maintained according to schedule and recent tap changer failures on network indicating elevated risk. The risk ranges from low to moderate depending on the transformer.
East Taieri	2	Safety	Located adjacent to a petrol station without firewalls/protection. This is a Medium risk.
Omakau	1	Environment	No bunding and located adjacent to a waterway. This is a Medium risk.

16 ZSS CIRCUIT BREAKERS

This section discusses the current state of the zone substation circuit breaker assets, its recent performance and WSP's assessment of the risk it presents to Aurora's network in terms of impacts to safety, reliability and the environment.

16.1 ASSET DATA

16.1.1 AVAILABILITY AND QUALITY

To assess the risk of the zone substation indoor and outdoor circuit breakers, WSP reviewed the information available from the asset data sources:

- on-site inspection of assets and witnessing testing of assets
- analysis of circuit breaker type, age, and location
- review of inspection and test records and the maintenance schedule
- review of a sample of switchboard arrangements
- review of outage data
- discussion with Aurora SMEs to understand any data gaps.

We assessed the data availability of this asset class. In undertaking this assessment, we have considered all the information obtained from Aurora over the course of the project. In our assessment, we took into consideration the ease of availability and accessibility of the information.

We found that the data available for zone substation circuit breakers was generally quite good. Two key data sources were GIS and the maintenance schedule spreadsheet. There was a net difference of two circuit breakers between these two data sources, however, GIS contained three circuit breakers that were not in the maintenance schedule (WK2758, LF6576, SC) and the maintenance schedule contained five that were not in GIS (AB6, PC2, NS9, OT2 (twice))

The number of operations and condition was well documented, although using site inspection sheets in pdf form made assessment difficult. The performance data for circuit breakers was recorded in the outage database, although not all zone substation circuit breaker outages had the feeder identified. Important data deficiencies:

- the manufacturer and model were not complete in either the GIS system or maintenance schedule, 87% and 91% complete respectively, and 8% had neither the manufacturer nor model recorded
- 83% of circuit breakers had the zone substation location or feeder ID recorded. We used the latitude and longitude coordinates to fill in the missing zone substation information
- some vacuum circuit breakers were identified to be older than 60 years which was identified to be an error, however, no other information is available to update the installation date.

This missing information would be easy to update in GIS and would enable improved recording of fault and outage information as well as enabling Aurora to locate each asset type on the network to identify any asset type issues that may emerge and ensure appropriate maintenance is undertaken.

In general, we found that there was sufficient information available to undertake this review.

Table 16.1 Summary of data quality

ASSET CLASS	SUB CLASS	ATTRIBUTES	CONDITION	PERFORMANCE	OVERALL DATA QUALITY
Zone substation	Zone circuit breakers	● (amber)	● (amber)	● (green)	● (amber)

16.1.2 ASSET CLASS SEGMENTATION

Asset class segmentation was not relevant for field inspection work for this asset type as we did not undertake a sampling approach.

16.2 DESCRIPTION OF THE ASSET CLASS

This section describes the ZSS circuit breaker fleet. The circuit breaker assets are comprised of several parts that are often referred to interchangeably. These are:

- circuit breakers: these are the actual switches that turn on and off supply to a feeder
- switchboard: the frame/housing for the circuit breakers that enables circuit breakers to be inserted or extracted and provides protection to the field crews from live high voltage components
- switchgear: commonly used to refer to a complete switchboard or group of circuit breakers in one location.

For this section, we refer to circuit breakers in a broad sense, unless specifically discussing the switchboard.

16.2.1 FLEET COMPOSITION

There are 411 zone substation circuit breakers across the Dunedin and Central networks. These are located within 39 zone substations of which 21 are in Central and 18 are in Dunedin. The fleet composition is shown in Table 16.2.

Table 16.2 Zone substation circuit breaker fleet summary

VOLTAGE (KV)	TYPE*	DUNEDIN	CENTRAL	TOTAL
6.6	OIL	158	16	174
	SF6	13	-	13
	VAC	35	4	39
11	OIL	11	18	29
	SF6	-	6	6
	VAC	30	64	94
33	OIL	7	11	18
	SF6	6	2	8
	VAC	9	15	24
66	SF6	-	6	6
Total		**269**	**142**	**411**

(1) OIL – minimum oil insulation (also referred to as OCB), SF6 – sulphur hexafluoride insulation, VAC – vacuum insulation.

(2) Excludes assets at the future Riverbank and Carisbrook zone substations that are not yet commissioned. Includes assets at Neville St ZSS assets that are still in service.

The circuit breakers cover four voltages; 33kV and 66kV circuit breakers connect the sub transmission network to the primary side of zone substation transformers, while the 6.6kV and 11kV circuit breakers connect from the secondary side of the zone substation transformers to the bus and from the bus to the distribution feeders.

The circuit breakers can be located indoors or outdoors and have three different insulating mediums, as shown in Table 16.3. The combination of indoor or outdoor type and the insulation medium creates a different risk profile for each installation. Information on failure modes and consequences is set out in section 16.2.2.

Table 16.3 Installation types of circuit breakers

INSULATION MEDIUM	TYPE	CENTRAL	DUNEDIN	TOTAL
OIL	Indoor	12	193	205
OIL	Outdoor	9	9	18
SF6	Indoor	12	13	25
SF6	Outdoor	7		7
VAC	Indoor	75	54	129
VAC	Outdoor	15	9	24
Total		**130**	**278**	**408**

Note: the difference between the data sources has resulted in three circuit breakers not being captured in the analysis for this table.

Circuit breakers are highly reliable assets and have long lives. The expected life of a circuit breakers is typically around 50 years for most distribution businesses. The actual life achieved is impacted by the operational conditions, including the number of switching operations experienced, the fault currents it is subjected to, and the environment it is housed in including heat and humidity.

However, the circuit breakers on Aurora's network are not heavily loaded, generally have fairly low fault levels compared to the switchgear nameplate ratings and are located in a cool environment which will help their longevity. In such circumstances, age is generally a good proxy for asset condition and, therefore, risk of failure.

Figure 16.1 shows the age profile for Aurora's circuit breakers fleet. It shows several circuit breakers are at or approaching their expected life and this is an indication of increasing risk on the network. The figure demonstrates that a large proportion of ZSS circuit breakers are likely to have an elevated risk with respect to reliable supply and appropriate planning for mitigation of the risk is required. The data showing recently installed oil circuit breakers and vacuum circuit breakers older than 45 years demonstrate likely data errors in the asset data base.

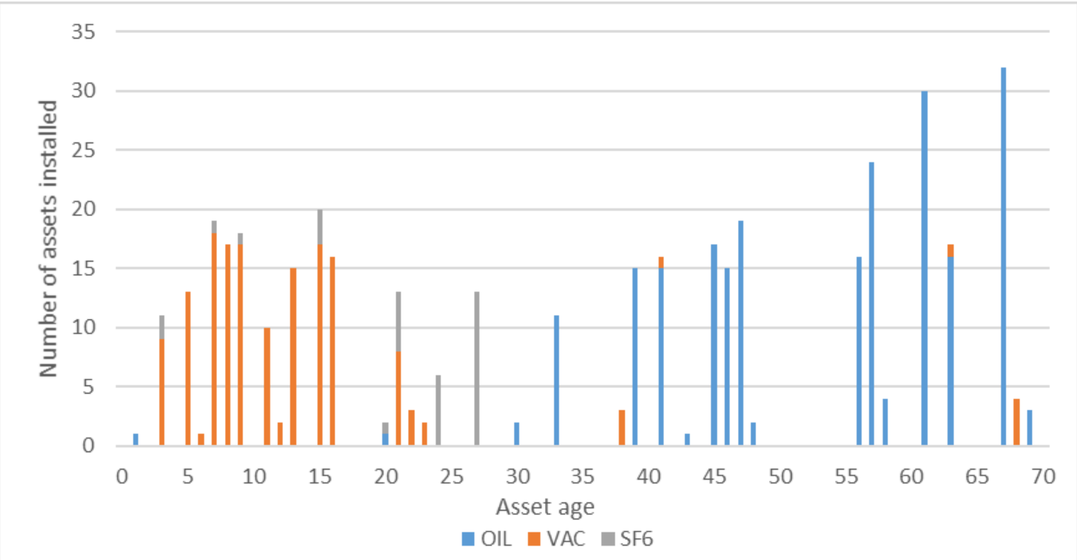

Figure 16.1 Circuit breaker age profile by insulation type

Table 16.4 shows a summary of the asset fleet, comparing the average age to the expected life by capacity. This provides a view on which segment of the fleet is likely to pose higher risk to the network. The table shows that 129 circuit breakers (31% of the fleet) have exceeded their expected life, of which 117 are indoor type and oil insulated.

Table 16.4 Weighted average remaining life of the circuit breaker fleet

CIRCUIT BREAKER TYPE	AVERAGE EXPECTED LIFE	WEIGHTED AVERAGE LIFE	REMAINING LIFE	NUMBER EXCEEDING EXPECTED LIFE
INDOOR				
OIL	50	53.3	-3.3	116
VAC	50	11.0	39.0	1
SF6	50	24.8	25.2	0
OUTDOOR				
OIL	50	45.9	4.1	8
VAC	50	26.4	23.6	4
SF6	50	9.6	40.4	0

Oil insulated circuit breakers (OCBs) are an older technology and have a higher risk associated with them. When circuit breakers fail, they can cause an arc which can be an ignition source for a fire. Since OCBs use oil as the insulating medium, there is a risk that the oil will catch alight and the fire could propagate through the switchboard. This failure mode can destroy the entire switchboard and the associated devices and cabling attached to it.

The zone substations where the circuit breakers that have exceeded their expected life are located are shown in Table 16.5. Note, Neville St ZSS is about to be decommissioned and replaced by Carisbrook ZSS. This will remove 34 OCBs from the network.

Table 16.5 Circuit breakers exceeding their expected life

ZONE SUBSTATION	INSULATION TYPE	NUMBER
Neville Street	OIL	34
Halfway Bush	OIL	16
Green Island	OIL	15
Smith Street	OIL	15
Willowbank	OIL	15
Andersons Bay	OIL	14
Outram	OIL/VAC	8/2
Alexandra	OIL	3
Ettrick	OIL	1
Clyde-Earnscleugh	OIL	1
Roxburgh	VAC	4
Queenstown[1]	VAC	5
Wanaka[1]	VAC	3
Total		**129**

(1) These substations have VWVE type circuit breakers that have exceeded their serviceable life, but are shown in the asset database as between 21 and 23 years old.

When assessing risk, age is a useful proxy for condition, but actual condition assessments, historical performance, redundancy in the network, and other mitigation plans need to be considered as well to assess which assets are likely to pose the highest risk to the network. These are discussed in the following sections.

16.2.2 FAILURE MODES AND CONSEQUENCES

This section discusses the failure modes and consequences as they relate to this asset class. This is not intended to be a detailed risk assessment, it is only intended to inform how we approached our risk analysis and reflect the key deterioration modes that we identified during the review.

Deterioration modes are typically insulation medium breakdown at the circuit breaker contacts for both indoor and outdoor circuit breakers.

- For vacuum circuit breakers, occasionally a loss of vacuum can occur at its contact bottle but is uncommon. For Viper and NOVA brand vacuum CBs, there is no combustible material to ignite should the vacuum contact bottle fail - this type of breaker is considered robust. However, some CBs use a combination of vacuum bottle contacts immersed within an oil filled tank (type VWVE, KFME, KFE, KF). Should the vacuum bottle fail in and allow the ingress of oil into the vacuum chamber, the CB will fail catastrophically when the oil ignites from the switching arc. An additional issue was the modification of the VWVE CBs when retrofitting CTs around their bushings, which has been reported that the modified imperfect seal can allowed moisture into the oil. These circuit breakers are considered have a low to modest risk of failure.
- Oil circuit breakers: older traditional technology and requires additional maintenance with inspection of load carrying contacts, filtration of the oil insulation medium and removal of carbon contamination within the arc chamber.
- SF6 circuit breakers are considered maintenance free, although periodic testing of the SF6 gas should be analysed for contamination. It is understood that Aurora have not tested their SF6 and it is assumption that the SF6 gas had no contamination at the time of installation. However, other EDBs in have found that the manufacturer supplied SF6 CBs were filled with impure gas. This could lead to early failure.

Oil insulated circuit breakers have the potential to fail catastrophically, and the resultant fire could propagate through an indoor /outdoor switchboard assembly as the circuit breakers are adjacent to each other. In outdoor situations where CBs are discrete assemblies, there is a large distance between each circuit breaker and consequential damage beyond the faulted breaker is potentially low.

Circuit breakers can fail through an arc flash fault[28] which creates a pressure wave that propagates outwards from the switchgear. Indoor switchboards should be arc fault rated to safely vent this energy. It can occur for all type of circuit breakers.

Insulator flash over within indoor circuit breakers is possible where the busbars are not continuously insulated and dust ingress has accumulated over time across busbar insulator supports. This would typically apply to older oil switchgear as we found no evidence of internal inspection and cleaning. Early failure detection is possible from insulation resistance and partial discharge tests.

An additional source of failure can arise from the interface with the cable termination. This failure can be caused through mechanisms such as overheating or deterioration of the cable joint/termination and the failure can damage the circuit breaker and result in a fire.

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[28] Arc flash fault – energy released when an arc is generated whilst opening a circuit breaker/isolator

Should any issues exist around the non-operation of protection systems, this could severely impact on the circuit breakers capacity to sustain the through fault until such time as backup protection would operate. These risks reflect more onerously on the older minimum oil circuit breakers. As an awareness safety measure, Aurora has undertaken an assessment of the prospective energy released should a fault occur whilst operating the switchgear and stipulation of the minimum personal protective equipment to be warn when standing at a given distance from the switchgear.

Aurora has stated that any oil contaminated with PCBs has been disposed of, however this was not validated through testing as part of this review.

16.2.3 INSPECTION AND TESTING

Circuit breaker maintenance is typically undertaken based on a maximum time period or maximum number of switching operations, whichever occurs first. Lack of maintenance can result failure of parts, spurious tripping, or failure to trip when require and, therefore, increases the level of risk that the asset will not perform its intended function. It can also result in a reduced serviceable life.

Vacuum Circuit Breakers (VAC) and Gas (SF6) Insulated Circuit Breakers (GIS) can typically undergo in the order of 100’s of fault cycles prior to triggering maintenance, whereas OCBs typically are in the order of 5 to 10 operations in fault conditions before maintenance is required.

Aurora undertakes a planned four yearly maintenance cycle for zone substations for major maintenance on all assets, with 39 zone substations this equates to approximately one per month.

The findings from the review of inspection and test results and our on-site inspections are discussed in the following sections.

16.3 DATA VALIDATION

As part of the assessment, WSP also undertook a review of inspection and test sheets and on-site inspection. The on-site inspection had two parts:

- observing the maintenance crews undertake a zone substation inspection at Green Island (Dunedin) and Alexandra (Central) zone substations. Testing was only observed at two substations due to the maintenance cycle being followed by Aurora and the duration required for the testing
- a visual inspection of all zone substations.

It was not possible to observe any more as substation testing requires taking a zone substation out of service and can involve significant load transfers or outages and require a long lead time for planning.

The on-site inspection identified consistent inspection practices and found no issues with the data provided by Aurora, however, the test sheets used by the Delta contractor were not the latest version as issued by Aurora. Testing observed at Green Island was satisfactory, however at Alexandra all the tasks were not completed due to lack of time, resources and spare parts.

16.4 PERFORMANCE AND CONDITION

This section assesses the performance and condition of the circuit breaker fleet.

16.4.1 RELIABILITY PERFORMANCE TRENDS

Zone substation circuit breakers are highly reliable assets so typically there are not too many failures attributed to the asset class. Figure 16.2 shows the performance of Aurora’s fleet. It identifies an increasing trend of outages which indicates that there is an underlying issue.

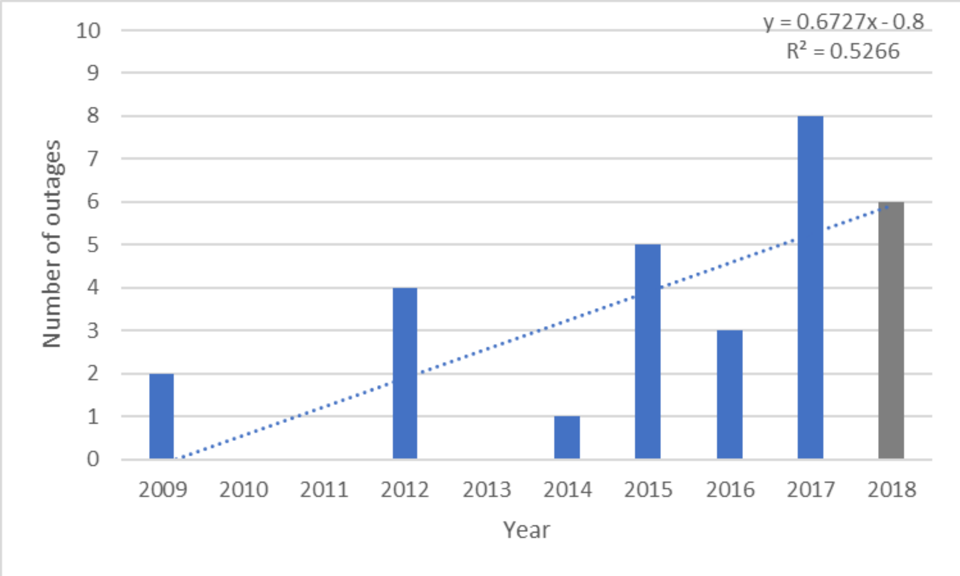


Figure 16.2 Historical outages caused by subzone circuit breakers failure

Further analysis into the cause of the failures shows that 11 of the 26 (42%) were attributed to asset deterioration. A further 12 (46%) were attributed to human error. Of the human error related outages, 6 (23%) were identified as operator error in what appears to be a response to a single instance of a sub transmission line tripping in 2017, while the other 6 had no further information. The high rate of human error, particularly human switching error, indicates that there is a higher probability that field crews will be present at the switchgear at the time of the fault. As stated in section 16.2.2, the highest probability of an arc fault is when racking in or out circuit breakers or when switching. We note that Aurora has safety procedures in place for field crews, including protective clothing and a requirement for non-essential crew to exit the room, However, as stated in section 4, operational controls have not been considered in the assessment of risk.

Table 16.6 Cause of outages

CAUSE DESCRIPTION	NUMBER OF OUTAGES
Equipment Deterioration	11
Human Switching Error	9
Unknown	2
Human Incorrect Protection	1
Equipment Incorrect Maintenance	1
Foreign Interference Animals	1
Human Excessive Paralleling Currents	1
Total	**26**

Table 16.7 examines the location and type of circuit breaker that has caused and outage. It shows the prevalence of indoor oil insulated circuit breakers involved in these outages, in particular the outages identified as caused by equipment deterioration.

The human switching error outages involving oil insulated indoor circuit breakers indicate an elevated risk due to the failure mode of these assets. This is increased as none of the switchboards are rated to contain arc faults like modern switchboards.

While no arc fault failures have been recorded on Aurora's network, some have occurred recently on the same type of circuit breaker installed in other electricity businesses networks and some been identified as end of life and at higher risk of failure.

Table 16.7 Location and type of circuit breaker faults

CAUSE	ZONESUB	TYPE	INSULATION	OUTAGES
Equipment Deterioration	Queenstown	Indoor/Outdoor	VAC/SF6	1
Equipment Deterioration	Roxburgh	Outdoor	Oil	2
Equipment Deterioration	Arrowtown	Outdoor	Oil	2
Equipment Deterioration	Alexandra	Indoor/Outdoor	Oil	1
Equipment Deterioration	Ettrick	HV Fuse	N/A	1
Equipment Deterioration	Roxburgh	Outdoor	Oil	2
Equipment Deterioration	Unknown	Unknown	Unknown	1
Equipment Deterioration	Willowbank	Indoor	Oil	1
Human Switching Error	Berwick	Indoor	OIL	1
Human Switching Error	Willowbank	Indoor	OIL	1
Human Switching Error	Cromwell	Indoor/Outdoor	VAC	1
Unknown	North East Valley	Indoor/Outdoor	VAC/SF6	1
Unknown	Queenstown	Indoor/Outdoor	VAC/SF6	1
Human Incorrect Protection	Wanaka	Indoor	VAC	1
Incorrect Maintenance	Kaikorai Valley	Indoor	OIL	1
Foreign Interference Animals	Frankton	Indoor	VAC	1
Human Switching Error	Smith Street	Indoor	OIL	1
Total				**20**

16.4.2 MAINTENANCE SCHEDULE

Circuit breaker maintenance is typically undertaken based on a maximum time period or maximum number of switching operations, whichever occurs first. Lack of maintenance can result in failure of parts, spurious tripping, or failure to trip when require and, therefore, increases the level of risk that the asset will not perform its intended function. It can also result in a reduced serviceable life.

Vacuum Circuit Breakers (VAC) and Gas (SF6) Insulated Circuit Breakers (GIS) can typically undergo in the order of 100's of fault cycles prior to triggering maintenance, whereas OCBs typically are in the order of 5 to 10 operations in fault conditions before maintenance is required.

Aurora undertakes a planned four yearly maintenance cycle for zone substations for major maintenance on all assets, with 39 zone substations this equates to approximately one substation per month. Review of the past maintenance dates showed that some substations had not been maintained within the previous four years. No evidence was found for inspection of the 33kV outdoor oil ASEA OCB contacts and cleaning of their arc chamber (located in the Central Otago region, age of these CBs is typically 30 to 50 yrs).

Analysis of the maintenance data provided showed that 45 (11%) of circuit breakers have operated more than three times under fault conditions but have not been maintained within the standard four yearly cyclic maintenance period. Some of these are identified as being up to 13 years without maintenance. However, it is evident that 4 OCBs have undergone a relatively high number of fault operations and have not been maintained with in the 4-year cyclic period. This increase the risk posed by those circuit breakers.

Table 16.8 shows the substations with a high number of operations since the most recent maintenance and where the most recent maintenance is outside of the four-yearly cyclic period. Circuit breakers in these substations are assessed as high risk assets. The number of operations shown is the sum for all the circuit breakers at that zone substation since that year.

Table 16.8 Circuit Breakers and number of fault operations since year of last maintenance

ZONE SUBSTATION	TYPE	NUMBER OF CBs	YEAR OF LAST MAINTENACE	FAULT OPS SINCE MAINTENACE
Arrowtown	VAC	5	2008	176
Clyde Earnscleugh	VAC	4	2013	31
Mosgiel	VAC	4	2005	80
Roxburgh	VAC	1	2007	19
Queenstown	VAC	2	2014	23
Fernhill	VAC	2	2005	39
Port Chalmers	VAC	3	2014	26
Green Island	OCB	2	2014	12
Ettrick	OCB	1	2013	10
Omakau	OCB	1	2014	4

16.4.3 LEGACY INSTALLATIONS

Due to the history of how the network developed, Aurora has acquired a number of assets that were built by previous asset owners, typically local councils (ref Central Electric Power Board). This has resulted in a number of non-standard zone substation layouts. These include single transformer zone substations with the switchgear mounted on top of the transformer in a metal enclosure and indoor switchgear that has been installed outdoors in a metal-clad enclosure. The zone substations affected by these legacy construction approaches include:

- Arrowtown
- Clyde-Earnscleugh
- Dalefield
- Earnscleugh
- Ettrick
- Omakau
- Remarkables

These substations all contain ASEA 11kV CBs, which are under the same maintenance programme WSP observed at Alexandra, but lack of access means that their contact condition and cleaning of the arc chamber has not been undertaken. WSP would advise Aurora to consider this matter further.

In addition, the VWVE type circuit breakers are vacuum bottles immersed in oil and, hence, there is the possibility of fire when they fail. These CBs were modified when installed on the network with the result of enabling moisture ingress which is causing condition issues. These CBs have been rotated through different There are 14 of these CBs installed on the network at:

- Mosgiel (2)
- Outram (2)
- Queenstown (5)
- Roxburgh (4)
- Wanaka (3).

A further legacy concern at Alexandra ZSS is that the outdoor 33kV busbar clearance to ground does not meet industry practice. WSP would advise Aurora to consider this matter further.

16.4.4 EMBEDDED GENERATION

The Alexandra 33kV bus has approximately 28 MW of local generation injected at this point. This will impact on the energy at risk of an Alexandra 33kV circuit breaker failure. The WSP energy at risk model does not take this into account as the operational model for this generation was not available at the time of our assessment.

16.4.5 INSPECTION AND TEST RESULTS

We reviewed a sample of test and inspection reports to assess the accuracy of the dates in the maintenance schedule and identify any significant trends.

We found that in general the dates aligned with the maintenance schedule, however, some inspections had been carried out that were not recorded as completed in the schedule. These included East Taieri and some circuit breakers at Fernhill ZSS and Wanaka ZSS.

A number of the older circuit breakers across the fleet were displaying evidence of deterioration including:

- minor parts that required replacement (including Andersons Bay ZSS and Berwick ZSS)
- significant amounts of carbon in the oil that indicates high load or fault clearances (including East Taieri which is approaching its expected serviceable life and Corstorphine)
- slow operating times or phases operating at significantly different speeds (including Andersons Bay ZSS and some of the old circuit breakers at Mosgiel ZSS).

These findings support our analysis of risk based on the asset age, type and frequency of operations.

16.4.6 FINDINGS FROM ON-SITE INSPECTION

Key findings from the on-site assessment include:

- Bulk oil 11kV CBs (Brush, Cooke & Ferguson, Reyrolle, South Wales) have records that indicate that satisfactory maintenance procedures have been undertaken with the exception of their protection CTs (refer protection section of this report) which have not been tested as part of past maintenance and inspection practices. This elevates the risk that the CTs are not functioning as expected.

- Circuit breakers ASEA 33kV HLC (Alexandra) and 11kV HKK (Alexandra, Arrowtown, Clyde-Earnscleugh, Earnscleugh, Ettrick, Omakau) have undergone regular tests, however their contacts and arc chamber have never been inspected for wear or carbon contamination because of the lack of oil seal spares.
- Green Island 6.6kV indoor ZSS switchgear (over the two days on-site inspection observation was made of only two CBs):
  - CB contacts were being disassembled for inspection, oil filtered, all parts cleaned of carbon contamination. Test records were being completed
  - CB protection relays functional tests undertaken and results recorded. New testing requirements of the CT protection circuit identified a failed CT secondary circuit (this test had never been previously undertaken) and had the potential to negate the operation of the CB under fault conditions and possibly cause a fire at the CT. Following CB checks identified a second similar fault. Repairs undertaken, but this highlights the risks around old (60 yrs plus) switchgear.
  - Inspection and test sheets used by Delta were not the latest version published by Aurora.
- Alexandra 11kV ZSS switchgear (visits over two days provided test observation of one CB and associated transformer tests):
  - Alexandra outdoor 11kV ASEA CBs. Four yearly test procedures were being undertaken using outdated test sheets. The contacts of the minimum oil CB and arc chamber were not inspected for carbon contamination. This aspect has not been inspected since installation in the 1980's. These CBs are an indoor breaker installed in a locally build outdoor enclosure. This type of CB is installed in outdoor shelters mounted on top of the transformer at Clyde-Earnscleugh, Ettrick and Omakau ZSS. It is likely these substations will have same issues.
  - Alexandra outdoor 33kV minimum oil CBs were not part of the observed tests, but it is understood that their contacts and arc chamber have not been inspected since installation (1950's and 1980's) for the same reason of not having a replacement seal available to return the unit to service.
  - Alexandra's 33kV outdoor overhead busbar (legacy asset) is very low with current design clearances not met.

Due to the age in installation arrangement, it is likely that there will be dust contamination across bushings in the indoor busbar chamber and possible degradation of older pitch filled cable terminations. This is particularly important for the 40 to 60 year old oil CB switchgear.

16.5 APPROACH TO RISK ASSESSMENT

The approach undertaken to assess the risk posed by zone substation circuit breakers has been undertaken in three parts as described below.

SAFETY RISK

This is based on a qualitative assessment of the likely number of field crew present at the time of maintenance, calculated arc fault boundaries, type of circuit breakers, types of enclosures and fault current.

ENERGY AT RISK

This is a quantitative assessment of the value of energy that would not be supplied should the switchgear fail and the probability of it failing in a catastrophic manner that would cause a zone substation outage. In undertaking this assessment, we considered the following:

- The energy at risk based on an N-1 or N-2 event at a zone substation as the worst-case scenario. The scenario was selected based on the layout of the substation and ability of a circuit breaker failure to result in the loss of either one or both switchboards. Oil insulated circuit breakers have a higher ability for this to occur due to the risk of fire.

- The time to restore supply has been based on the ability for Aurora's mitigation plans, which include transfer of load to other substations and the use of the mobile transformer (which includes distribution switchgear) to supply load.
- In the inner part of Dunedin, there is sufficient transfer capacities to fully offload a substation using switching of the 6.6kV network. As a result, even though some zone substations have relatively high likelihood of failure, there is minimal impact as the demand can be completely transferred away via the distribution network. These substations are: Neville St, Smith St, Mosgiel, Kaikorai Valley and Ward St. Once commissioned, Carisbrook will also have this ability.
- The Value of Lost Load (VoLL) has been used as $12/kWh for Central and $20/kWh for Dunedin to reflect the different customer demographics.
- The model incorporates the cost to restore supply. This means that there is an expected cost due to the probability of failure and need to repair that failure, even though the energy can be transferred away. This indicates an increasing risk, even though there is redundancy for the supply through load transfers.

The unweighted energy at risk was calculated based on a three month time to repair. The analysis does not consider load growth or future deterioration of asset condition as we are only assessing the current state of the network and not forecasting forward to assess future scenarios.

In addition to the energy at risk, specific findings from the onsite audits have been accounted for by adjusting the risk ranking of certain circuit breaker types. The identified types were given an increased likelihood of failure to reflect unknown/poor internal condition of the assets and industry experience with the same or similar circuit breaker types.

ENVIRONMENTAL RISK

This is based on a qualitative assessment of the locations and type of environmental impact at each zone substation.

16.6 RISK ASSESSMENT

SAFETY RISK

Zone substation circuit breakers are not considered to pose a risk to the public as they are located within secure compounds, hence the only risk to the safety of work crews.

We note that most switchboards do not have arc fault detection relays and are not rated to withstand an arc fault. The power transmitted by an arc fault is related to the fault current at each individual location. The impact is also affected by other factors, such as whether the explosion is contained within an indoor substation, therefore directing the explosion in a certain direction. Arc faults are a significant hazard and there are recent events that have occurred in New Zealand and Australia in recent years that have led to injury of staff and destruction of assets.

The safety consequence has been assessed based on the approach set out in section 4. The consequence is a function of the insulation type (contains oil) to enable the catastrophic event to occur, the switchboard type (indoor) and the fault current.

The probability of failure is a function of the age of the circuit breaker, the type and configuration (indoor, outdoor and insulating medium), its condition and number of operations under fault conditions.

Table 16.9 sets out the substations with the largest arc fault boundaries with the highest number of fault operations. We note that operational controls can be put in place to mitigate this risk but these have not been considered in this assessment as the purpose is to rank the risk of the circuit breakers.

Table 16.9 Safety risk based on arc fault boundary for indoor circuit breakers

ZONE SUBSTATION	FAULT OP'S	ARC FAULT BOUNDARY (M)
Smith Street	3	12.02
Halfway Bush	4	11.62

ZONE SUBSTATION	FAULT OP'S	ARC FAULT BOUNDARY (M)
Ward St	6	11.32
Green Island	15	10.89
Andersons Bay	3	10.69
Kaikorai Valley	2	9.33
Corstorphine	5	8.37
Alexandra	16	6.11
South City	1	6.10
Wanaka	4	5.16

(1) Note: arc fault boundary indicative only with simplified condition for ranking of risk. It is calculated as the distance where the energy is 1.2cal/cm2.

(2) The number of fault operations is the sum for all CBs at the zone substation since the last known maintenance was carried out

ENERGY AT RISK

From the analysis of the transformer fleet, we have identified that five of the substations in Dunedin have sufficient load transfer capacity to transfer away all load via the 6.6kV network. This means that if a single circuit breaker fails, the load at risk is low as load can be transferred away to restore supply. This does not apply in other areas, where a loss of supply would occur until the circuit breaker can be repaired or swapped out for a spare

However, the risk is with older OCB type arrangements where a failure can result in a fire and which can then propagate through the switchboard (for indoor types) and destroy the switchboard and all secondary wiring and associated equipment. This can be an N-2 event depending on the arrangement of the switchboards in the substation. In this case the rebuild time would be significantly longer.

The consequence is a function of the insulation type (oil) to enable the catastrophic event to occur, the switchboard type (indoor) to enable propagate of the fire, and the unsecured demand at the substation.

The probability of failure is a function of the age of the circuit breaker, the type and configuration (indoor, outdoor and insulating medium), its condition and number of operations under fault conditions.

The consequence shown in Table 16.10 below is the unmitigated total risk (the sum of N-1, N-2 and Minor) based on the energy at risk modelling approach. For this risk to materialise, it requires the circuit breaker to fail and the failure mode to initiate a fire. The zone substations listed only include where the insulation medium includes oil, the switchboards are indoor type which will enable the propagation of a fire, the expected life has been exceeded, and there have been three or more fault operations since the most recent recorded maintenance. Neville St is excluded as it is about to be decommissioned. This identifies Outram and Anderson Bay as the largest risks based on switchgear type.

Note that the table only shows the circuit breakers at the zone substation that have exceeded their serviceable life, it may not include all circuit breakers located at that substation.

We note that the zone substations in Table 16.10 below largely align to the same zone substations identified in Table 16.9.

Table 16.10 Unweighted reliability consequence at zone substations

ZONE SUBSTATION	TYPE	# OF OCBS	FAULT OP'S	AVERAGE AGE	UNWEIGHTED RISK
Outram (33kV and 11kV)	OIL	10	137	57	$551.00
Andersons Bay	OIL	14	81	57	$422.49

ZONE SUBSTATION	TYPE	# OF OCBS	FAULT OP'S	AVERAGE AGE	UNWEIGHTED RISK
Green Island	OIL	15	72	61	$385.53
Alexandra	OIL	3	33	57.3	$216.86
Halfway Bush	OIL	16	42	63	$146.61
Arrowtown	OIL	2	11	48	$126.96
South City	OIL	19	12	47	$20.70
Willowbank	OIL	15	35	56	$11.91
Smith Street	OIL	15	15	61	$11.25
Clyde-Earnscleugh	OIL	1	1	58	$1.01
Ettrick	OIL	1	34	58	$0.02
Wanaka	VAC	3	9	22	$428.51
Queenstown	VAC	5	0	25.2	$18.59
Roxburgh	VAC	4	54	68	$4.55

ENVIRONMENT RISK

The environmental risk associated with ZSS circuit breakers is predominantly due to:

— SF6 gas leaks (which is a high impact greenhouse gas and is also a toxic gas to people). Most switchgear will eventually leak small amounts into the atmosphere which has a negative impact on the environment, or

— oil leaks, however, each circuit breaker only contains a small quantity of oil and are not located in close proximity to water ways.

The risk is rated as Insignificant.

For zone substation circuit breakers, the risk in the risk matrix is shown as this highest risk out of safety and reliability based on the mapping set out in section 4.

Table 16.11 Zone substation circuit breaker risk matrix

Increasing consequence (criticality) -->

Prob of Failure -->

1	5	1	15	0
9	1	32	60	15
2	20	66	0	11
12	39	15	0	3
11	25	48	17	0

16.7 KEY FINDINGS

The zone substation circuit breaker fleet is comprised of indoor and outdoor circuit breakers that are insulated by using oil, vacuum and gas (SF6) technologies. We found:

- The asset data available from Aurora’s systems and augmented by our field inspections was suitable for the purpose of this review. We note that the data is not complete and improvements to consistency of the data recorded can be made. Incomplete asset data presents a risk to effective asset management.
- There are 129 circuit breakers (31%) have exceed their expected lives.
- The inspection, testing and maintenance of ZSS circuit breakers is incomplete with 25 circuit breakers not been maintained within the required maintenance schedule. In addition, the internal mechanisms of HLC and HKK type circuit breakers have not been maintained. This elevates the probability of these assets failing.
- Some oil insulated zone substation circuit breakers were found to present an elevated risk to the network with respect to network reliability and the safety of field crews due to their potential failure mode through arc fault and fire.
  - Some of the specific types of circuit breaker in-service on the Aurora network have been identified in the electricity industry as having an elevated risk of failure, in particular the HLC, HKK and LMT models.
  - The switchboards are not rated to contain an arc fault and, hence, pose an elevated risk to field crews.
  - The VWVE type switchgear was modified at installation which has enabled moisture ingress and deterioration of the assets.
- A number of indoor circuit breakers have been installed in custom built outdoor enclosures which, upon site inspection, did not appear to be fully sealed from the environment. This is likely to result in an increased rate of deterioration and an increased probability of failure.

WSP concludes that ZSS circuit breakers pose a moderate risk to network reliability and worker safety. They have no impact on public safety or the environment. Table 16.2 summarises the ZSS circuit breaker risks and indicates the priority for remediation.

Table 16.12 Summary of ZSS circuit breaker risk

ZONE SUBSTATION	NUMBER	RISK TYPE	DESCRIPTION
Alexandra ZSS	14	Reliability/Safety	HKK and HLC circuit breakers. Not maintained internally. This includes High and Very High asset risks.
Arrowtown ZSS	2	Reliability/Safety	HKK circuit breakers. Not maintained internally. This includes High and Very High asset risks.
Green Island ZSS	15	Reliability/Safety	61 year old Cooke and Ferguson oil circuit breakers exceeding the expected life of 50 years. Have not been maintained within the maintenance schedule. This includes High and Very High asset risks.
Outram ZSS	10	Reliability/Safety	57 year old circuit breakers are exceeding the expected life of 50 years, including 2 VWVE type which have an elevated risk due to modifications when installed. This includes High and Very High asset risks.
Andersons Bay ZSS	14	Reliability/Safety	57 year old Brush bulk oil circuit breakers exceeding their expected life. High risk due to age, type and untested associated current transformers.
Halfway Bush ZSS	16	Reliability/Safety	57 year old Cooke & Ferguson bulk oil circuit breakers exceeding their expected life. High risk due to age, type and untested associated current transformers.

ZONE SUBSTATION	NUMBER	RISK TYPE	DESCRIPTION
Smith Street ZSS	15	Reliability/Safety	61 year old Cooke & Ferguson bulk oil circuit breakers exceeding their expected life. High risk due to age, type and untested associated current transformers.
Willowbank ZSS	15	Reliability/Safety	56 year old Brush bulk oil circuit breakers exceeding their expected life. High risk due to age, type and untested associated current transformers.
Omakau ZSS	1	Reliability/Safety	HKK circuit breakers. Not maintained internally. This is a high risk.
Wanaka ZSS	3	Reliability/Safety	VWVE type circuit breakers with issues due to modification when installed. This is a high risk.
Neville Street ZSS	31	Reliability/Safety	Oil circuit breakers. About to be decommissioned. Moderate risk.
Queenstown ZSS	3	Reliability/Safety	VWVE type circuit breakers with issues due to modification when installed. Moderate risk.
Clyde-Earnscleugh ZSS	1	Reliability/Safety	HKK circuit breakers. Not maintained internally. Moderate risk.
Corstorphine ZSS	15	Reliability/Safety	46 year old LMT bulk oil circuit breakers. Moderate risk due to age and CTs.
Kaikorai Valley ZSS	15	Reliability/Safety	Oil insulated circuit breakers. Moderate risk.
Roxburgh ZSS	4	Reliability/Safety	VWVE type circuit breakers with issues due to modification when installed. Moderate risk.
South City ZSS	19	Reliability/Safety	47 year old LMT bulk oil circuit breakers. Moderate risk due to age and CTs.
St Kilda ZSS	15	Reliability/Safety	39 year old LMT bulk oil circuit breakers. Moderate risk due to age and CTs.

17 PROTECTION SYSTEMS

Our review of protection systems included the key components that make up the protection schemes this includes the protection relays, protection settings and schemes, instrument transformers, battery banks and battery chargers.

17.1 ASSET DATA

17.1.1 AVAILABILITY AND QUALITY

To assess the risk of the protection systems, WSP reviewed the information available from the asset data sources:

- on-site inspection of assets
- witnessing testing of assets
- analysis of relay type, age, settings and function information provided in the protection asset database
- review of protection setting calculation sheets
- analysis of protection schemes and co-ordination data from protection schematics and instrumentation diagrams
- review of outage data to assess the effectiveness of protection operation
- discussion with Aurora SMEs to understand any data gaps.

We assessed the data availability of this asset class. In undertaking this assessment, we have considered all the information we were able to obtain from Aurora over the course of the project. In our assessment, we took into consideration the ease of availability and accessibility of the information.

We found that there were significant data gaps in the information provided. The protection relay database contained information for all relays but varied greatly with between 19% and 100% complete depending on the field. For some attributes, this is not material and not uncommon for electricity business to not have the information. However, others such as the settings or reference to the calculation sheet were considered material. Settings not captured in the setting database were found to be captured in site based records (assessed by sample). Overall, the important fields were sufficiently complete and provided sufficient information for this review.

Important data deficiencies:

- 47 (4.1%) relays do not have a type and 52 (4.6%) do not have a location recorded
- CT current rating and winding ratios are only recorded for 64% of protection schemes
- Most of the battery and charger information is available for most zone substations and evidence is available of periodic inspection and testing. The information available regarding battery and charger alarms via SCADA is not up to date.

We also note that there were inconsistent naming conventions used throughout the data sets which makes analysis of the data more difficult and time consuming. In general, where information was available, we found that it was not always well organised and structured in a manner that would facilitate good asset management practices.

Table 17.1 Summary of data quality

ASSET CLASS	SUB CLASS	ATTRIBUTES	CONDITION	PERFORMANCE	OVERALL
Zone substation	Protection relays				
	Setting information		N/A	N/A	

ASSET CLASS	SUB CLASS	ATTRIBUTES	CONDITION	PERFORMANCE	OVERALL
	Battery banks and chargers	🟡	🟡	🟢	🟡
	Instrument transformers	🔴	🔴	🔴	🔴
	SCADA	🟡	🟡	🟡	🟡

17.1.2 ASSET CLASS SEGMENTATION

Asset class segmentation was not relevant for field inspection work for this asset type as we did not undertake a sampling approach. All zone substations were inspected visually and testing undertaken by Delta was observed at two substations, one in Dunedin and one in Central, which were scheduled for their periodic maintenance during the time of this review.

Testing was only observed at two substations due to the maintenance cycle being followed by Aurora and the duration required for the testing. It was not possible to do any more as substation testing can required significant load transfers or outages.

17.2 DESCRIPTION OF THE ASSET CLASS

This section provides an overview of the asset fleet and the characteristics that are indicators of risk.

17.2.1 FLEET COMPOSITION

The protection systems are comprised of three main assets:

- protection relays which have settings calculated and set to detect specific events and take appropriate action, such as trigger an alarm or open a circuit breaker
- instrument transformers provide a signal to the protection relay that is a scaled down representation of the current and voltage on the network at that location
- SCADA system to send substation information to the control room
- battery banks and chargers ensure reliable DC supply is maintained to the protection relays.

Each of these assets are described below.

17.2.1.1 PROTECTION RELAYS

The tables and graph below show the breakdown of the relay asset fleet by location, age and type. There are 1,138 in total, of which 693 (61%) are electromechanical type, 398 (35%) are electronic and 47 (4%) do not have a known type.

Electromechanical relays are an old technology with limited functionality. Each relay only has one protection function so multiple relays are required per asset. In addition, the communications and control capability available through SCADA is limited.

Digital relays cover the sub-classes of Static and Numerical. These types represent the evolution in technology over time and have progressively increased functionality. Generally digital relays have a shorter expected life than electromechanical relays due to the electronic components but can provide multiple protection functions per relay and integrate into the SCADA system. Approximately 44% of the Numerical relays and 8% of the Static relays have exceeded their expected life.

There are 857 located in Dunedin and 229 located in Central, highlighting the larger customer and asset base in Dunedin. There is no location recorded for 52 relays. Electro mechanical relays have an expected life of around 50 years, whereas modern digital relays have an expected life of around 20 years.

Electromechanical relays have moving parts and loose calibration over time. These relays can be recalibrated and parts replaced, if available. However, given the age of the assets replacement parts are becoming more scarce which can force the need for replacement rather than maintenance. Indications of end of life include more rapid loss of calibration, mechanical failure of parts and not passing functional testing.

Digital relays are solid state electronic devices and generally cannot be maintained. Software can be upgraded and the device tested and some modular types can have individual modules independently replaced.

Table 17.2 Relay type by network location

TYPE	CENTRAL	DUNEDIN	UNKNOWN LOCATION	TOTAL
Electromechanical	8	682	2	692
Numerical	124	101	1	226
Static	44	36	4	84
Microprocessor	17	6	41	64
Total	193	825	48	1066

Table 17.3 show a summary of the age of the asset fleet. It shows that approximately 382 (55%) of the electromechanical relays and 106 (28%) of the electronic relays have exceeded their expected life. This does not mean that those relays must be replaced but given age is often a good proxy for condition, and the old relays will not have vendor support and spares are not held in store and will become increasingly difficult to source elsewhere. For modern digital relays, firmware upgrades for security or compatibility purposes may no longer be available once they are out of vendor support.

Table 17.3 Relay age analysis

	EXPECTED LIFE	WEIGHTED AVERAGE AGE	AVERAGE REMAINING LIFE	EXCEEDING EXPECTED AGE
Electromechanical	50	52.8	-2.8	382
Numerical	20	10.5	9.5	23
Static	20	27.8	-7.8	75
Microprocessor	20	11.7	8.3	8
Total		**39.4**		**488**

Note: unknown relay types did not have an installation date recorded so data is not available for the table above.

Figure 17.1 demonstrates that there was a clear change in technology that occurred in the 1980's where electromechanical relays were superseded by digital relays. The age profile is reflective of relays being installed as large groups when substations are established or switchboards or protection schemes replaced. The high volumes of electromechanically relays compared to digital relays is reflective of the single function provided by elector mechanical relays meaning multiple electromechanically relays are required for each digital relay to provide the same protection.

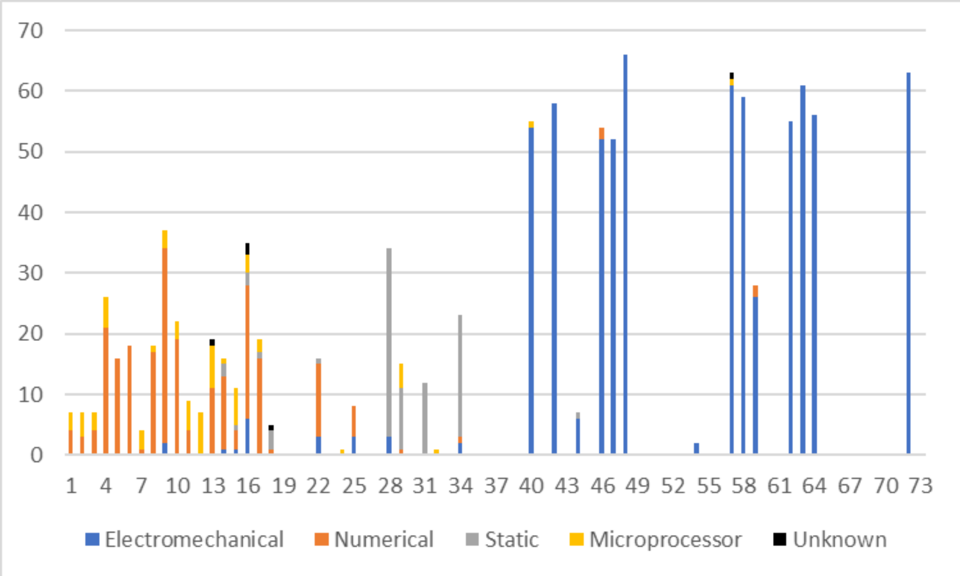


Figure 17.1 Relay age profile

17.2.1.2 INSTRUMENT TRANSFORMERS

Instrument transformers include Voltage Transformers and Current Transformers. They are typically installed at the same time as the circuit breakers to which they are connected. The asset records only had data available for current transformers.

Older protection schemes tended to use CTs which have a secondary winding rated to 5A whereas modern schemes have a preference for CTs rated to 1A. Impregnated cotton insulation types have also changed over time, adopting improved enamel and cellulose insulation with higher temperature and insulation resistance ratings. There are 405 CTs with unknown ages. Based on the relay types they are connected to, it is estimated that 306 of these are 5A rated CTs.

As CTs are typically installed as part of the circuit breaker bay, the age profile of the CTs has been assumed to be based on the ages of the circuit breakers. Table 17.4 shows an overview of the CT population. The predominate type of CT on the network is a 5A air or oil insulated CT with an average age of 53 years (based on the age of circuit breakers in Figure 16.1), with an estimated total volume of 713 or 63% of the fleet.

Failure of a CT will result in failure of the protection scheme. If the CT fault is an open or short circuit of the secondary winding, most commonly, if the CT fails, the protection device will operate to open the circuit breaker as a precaution. However, the different insulation has an impact on the failure modes and consequences. Aurora has a small number of oil insulated CTs with 5A secondary rating can generate a lot more heat during a sustained fault and, therefore, can result in a fire which will damage nearby assets and can lead to destruction of oil insulated switchgear if the fire propagates through the switchboard. This is less likely with air insulated CTs.

Table 17.4 CT population overview

RELAY TYPE	1A	5A	UNK	TOTAL
Electromechanical	53	406	233	692
Microprocessor	23		41	64
Numerical	158	17	51	226
Static	12	34	38	84
Total	**246**	**457**	**363**	**1066**

17.2.1.3 SCADA SYSTEM

The SCADA system enables remote monitoring and control of the network assets. It is comprised of the IT systems and software that are considered non-network assets and the operational technology (OT) assets that are located in the field. Aurora has recently upgraded its SCADA systems as part of its 'one network' initiative which enables both control rooms, one in Dunedin and one in Cromwell, to control the entire network. The project did not involve upgrading all the Remote Terminal Unit (RTU) assets which are located in the zone substations. Aurora has a fleet of 67 RTUs, the age profile of the RTUs in the two networks is shown in Figure 17.2.

RTUs typically have an expected life of 15 years. The RTUs in Dunedin are generally newer than in Central with the most common type being the SEL Axion. We found that there are 16 RTUs that have exceeded their expected life, 4 of which are located in Dunedin and are 29 years old and 12 in Central.

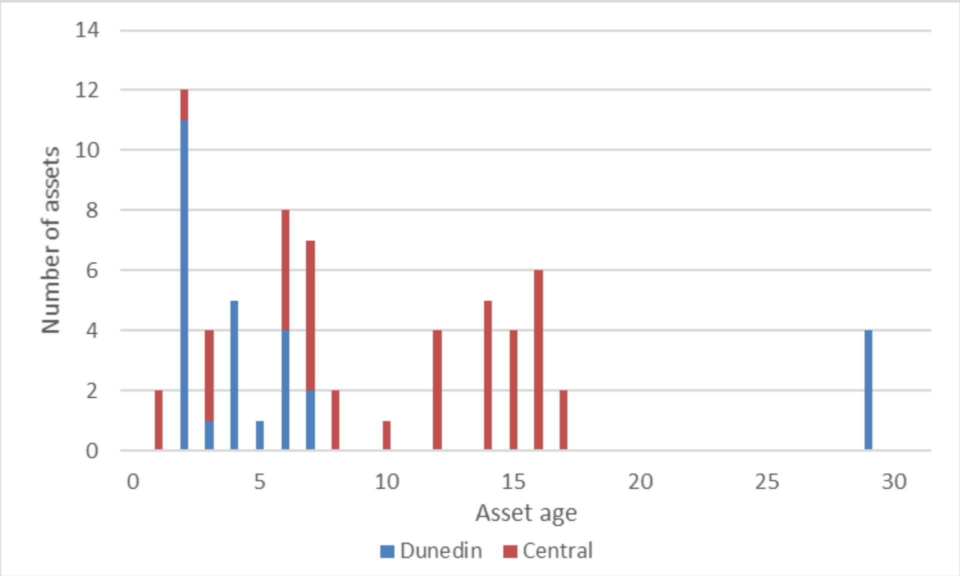


Figure 17.2 SCADA RTU age profile

17.2.2 FAILURE MODES AND CONSEQUENCES

This section discusses the failure modes and consequences as they relate to this asset class. This is not intended to be a detailed risk assessment; it is only intended to inform how we approached our risk analysis and reflect the key deterioration modes that we identified during the review.

Failure modes are diverse but can be summarised as follows: electromechanical relays – bearing and mechanism pivot points becoming stiff due to the lack of lubrication. Loose trip linkage assemblies. Microprocessor relays contain a significant number of electronic components that have a finite life, the more pertinent failure component being the drying out of their capacitors.

Consequences of these issues are possible fail to trip under fault conditions, trip without reason or setting drift over time. The impact of this may compromise public safety if faults are not cleared in a timely manner, damage to assets, spurious trips resulting in poor network performance.

The consequence of an RTU failure is loss of vision of the substation from the control room. The protection and other devices will continue to operate as normal, however, if there is an outage it may not be seen via SCADA. This is a risk to reliability as outages may be longer than necessary. RTUs are configured to notify the control room via SCADA if they fail so action can be take and the risk is low.

17.2.3 INSPECTION AND TESTING

Inspection and testing for the protection systems has been undertaken on a periodic basis. The time between inspection and maintenance for relays is set out as every four years with batteries and chargers inspected every month. Historically instrument transformers have not been inspected, however, a new inspection program was initiated this year but only includes current transformers.

From the data available, it appears that testing is undertaken approximately every four years. This aligns to the zone substation maintenance cycle, however, it also appears that the timing has not been strictly adhered to.

The results from protection inspection and test data has historically been captured through paper based forms that include tabulated data for specific data entry as well as hand written annotations as required. These sheets are then scanned and stored on Auroras network. Since these are hand written, they are not in a format that can be easily analysed to assess patterns or trends in data across time, relay types or different locations.

Furthermore, there are also historical paper-based data held by Delta which makes it more difficult to know of their availability and accessibility.

The findings from the review of inspection and test results and our on-site inspections are discussed in the following sections.

17.3 DATA VALIDATION

As part of the assessment, WSP also undertook a review of inspection and test sheets and on-site inspection. The on-site inspection had two parts: firstly, observing the maintenance crews undertake a zone substation inspection at Green Island (Dunedin) and Alexandra (Central) zone substations; secondly, a visual inspection of 38 of the 39 zone substations (Remarkables was not visited).

The findings from the site visits are that the protection systems are complete with most of the relays old but in a tidy condition. This gives a high level of confidence that the data provided by Aurora is suitable for our review.

17.4 PERFORMANCE AND CONDITION

This section discusses the historical performance of the protection system assets and data relating to the condition of specific asset types and the fleet in general.

17.4.1 PROTECTION SCHEME AND SETTINGS REVIEW

WSP undertook a review of the protection information. This included assessment of the data provided in the protection asset data base, calculation sheets and a detailed review of the protection schemes at five zone substations.

The review focused on assessing the protection schemes implemented, the set-up of coordination schemes (but not a detailed review of the calculations or the setting coordination of all relays), changes to the network such as increased load and fault currents that may impact protection settings, and where this may lead to risk on the network.

The assessment of the protection functions, operating time, age and type of the relays was carried out using the data provided for all Dunedin and Central relays. The review also looked for gaps in protection of the system, consideration of changes to network fault levels and loading at substations, and comparison with standard practice

A sampling approach was taken for assessment of the schemes and coordination to identify commonalities that indicate systemic issues and network risk. Five zone substations were selected based on condition observed during on-site inspection, fault current and known growth areas:

- Mosgiel Zone Substation
- Alexandra Zone substation
- Smith Street Zone Substation
- Queenstown Zone Substation
- Cromwell Substation.

In addition, protection schematics were used to form an overview of the protection system covering both areas networks. A summary of the key findings is provided:

- We could not define a common/specific protection scheme/strategy for the applied protection in the network. i.e. There are no specific criteria used to protect different assets. It was found that the protection of same assets at different locations have been implemented differently. Therefore, we did not have reference, standard or bench mark to assess against.
- The protection setting calculation documents show that that most of these settings were calculated during the 1980's and 1990's. Since then there has been significant growth and change in the network. It was observed that changes have been applied to the protection of some of the zone substations for various reasons, including to resolve nuisance tripping or address increased load. However, there was no evidence that these changes have been coordinated with overall protection scheme of the network. Therefore, a review of the overall network protection is considered critical for the safe and reliable operation of the network.
- The dates on the protection setting calculations sheets are old and there does not appear to have been a recent protection system study/review to ensure the protection schemes and settings are still appropriate given changes in the network since the original settings were calculated, including review of the protection settings and asset ratings (including distribution switches) against fault currents and loading present on the network now.
- We could not clearly verify the primary and secondary protection of the assets (feeders and transformers). Some locations have unit protection installed as primary and non-unit protection installed as secondary, however some locations have only one form of protection and some have used only fuses. Therefore, it was not possible to identify the reasoning behind selecting specific primary and secondary protection for feeders and transformers.

- Although the provided data include protection setting calculations for the above mentioned five zone substations, it was not possible to identify a full coordination assessment covering all the locations.
- Within the sample of substations reviewed, we noted that the incoming feeders at Mosgiel Zone substation do not have protection relays associated with them and they rely on distance protection relays located at the upstream of the feeder (Halfway Bush GXP). Further, there is no interlock associated with the three incomer scheme to prevent the circuit breaker on the third line (normally open) from closing onto a fault if the other two circuit breakers have been tripped. Similar arrangements that do not have a local protection relay and instead rely on the distance protection of the upstream feeder were also identified at Outram.
- Within the sample of substations reviewed, we noted that busbar protection schemes (differential or frame leakage protection) were not applied in all zone substations and flash arc protection was also only implemented in a few locations. We note that busbar protection is not always applied in distribution systems where the network conditions allow, for example if fault levels are low or when other adequate fast operating protections cover the bus bar. However, there does not appear to be a consistent approach applied at Aurora.
- We noted that the protection settings sheets at zone substations contained some hand-written mark ups identifying different settings in the relay than recorded on the sheet. There was no evidence provided to indicated why the settings were changed or reference to a calculation sheet. There were few instances of this identified.
- The earth fault protection of the feeders is either instantaneous or definite time, which could be difficult to coordinate without affecting the sensitivity of the protection. Faults that involve conductors that fall to the ground often have high fault impedance, which sometimes makes it difficult to detect if the setting is not sensitive enough. On the other hand, settings that are too sensitive can result in spurious tripping and impact on network reliability. WSP reviewed calculations to coordinate earth fault settings at two of the five zone substations that were reviewed in detail and found them to be adequate. The other three zone substations showed coordination between the settings, but the calculations were not provided in the protection setting calculation documents.
- Due to the age of the protection relays, availability of spares to enable quick change over for failed or defective relays could become a major issue as the relays reach end of life.
- The Alexandra to Clyde sub transmission line has areas not currently covered by a protection scheme. A new scheme is being implemented for the end of this year.

Additional findings with more detail specific to each of the substations reviewed are included in Appendix B.

17.4.2 FUSE PROTECTED TRANSFORMERS

Our review found that some of the small zone substation transformers are protected by HV fuses on the primary (33kV side). a full list is provided in table x, but the following important points were identified:

- Central includes eight 33kV to 11 or 6.6kV transformers that have capacities of 3 MVA and 5 MVA that are protected by fuses on the 33kV side. This is not a standard approach for this size of transformers. The use of fuses for this type of protection increases the difficulty of coordinating the protection scheme with downstream protection devices
- The Omakau transformer is protected by fuses and does not have a circuit breaker for protection. Any planned outage requires the line to be isolated first from Alexandra, which will also result in an outage at Lauder Flat, while the fuses are removed. This will increase the difficulty in removing the transformer from service for maintenance.

Table 17.5 Transformers protected by 33kV fuses

ZONE SUBSTATION TRANSFORMER	CAPACITY (MVA)
Arrowtown T1	5
Arrowtown T2	5
Clyde-Earnscleugh T2	5
Dalefield	3
Earnscleugh	3
Ettrick	3
Remarkables	3
Omakau	3

17.4.3 SPARE RELAYS

Aurora maintains a list of spare relays and their locations. Using this list and information from the protection relay database we assessed where there may be risk due to the types of spare relays available. The spare relay information categorised the relays as held as a spare (including the number and location), not held as a spare and unknown.

We found there are approximately 151 different types of relays on the network. This may be slightly overstated due to the inconsistent naming conventions and missing data. Our analysis showed that Aurora does not hold spare relays for 23% of the fleet, or 265 relays. Considering this by relay type, 62% or 94 of the different models of relay do not have spares.

However, not having a spare is not necessarily a risk as it also depends on the condition of that type of relay across the network. We considered the relays by type and average age, to get a better understanding of the risk that may bring to the network.

Table 17.6 Relays without spares

	NUMBER OF MODELS	NUMBER WITHOUT SPARES	MEAN AGE
Electromechanical	45	23	47.3
Static	35	20	32.4
Numerical	32	16	23.8
Unknown	20	19	16.0
Microprocessor	19	16	8.8

Table 17.6 shows that there are 23 types of electromechanical relays and 16 types of numerical relays that do not have spares and have an average age that is approximately their expected life. This increases network risk as it will not be possible to replace the relay quickly should it be found to have failed. Replacement requires significant design work to install a modern microprocessor-based relay. This will increase the duration that the feeder will need to be out of service.

17.4.4 SCADA

Since the SCADA IT and software system is new, our focus was on the assets in the field, namely the RTUs. We undertook the review by on site field inspections and review of historical inspection and test reports.

We reviewed inspection and test reports which demonstrated that the RTUs were working correctly. However, we found that the most recent test and inspection reports for the Central network were from 2014, putting them just outside of the four-yearly zone substation inspection schedule. The inspection and test reports in Dunedin were more recent.

During on-site inspections of the substations we undertook a visual inspection of the RTUs located in zone substations due to the substation maintenance schedule. All the RTUs were functioning and in adequate condition. No issues were identified.

There are 16 RTUs that have exceeded their expected life. There are four in Dunedin that are 29 years old which are being replaced or are scheduled for replacement. Excluding the four 29 year old RTUs, the average age of the Dunedin assets is less than four years old, with the maximum being 7 years.

The RTUs in Central are older with an average age of 11 years and 30% being 15 years old. There are 12 in Central that have exceeded their expected lives and are identified to be replaced as part of a communications infrastructure project. However, until they are replaced, there pose a risk to the network.

We find that 51 of the 67 RTUs pose an insignificant risk to the network as they have not yet exceeded their expected life and have been inspected periodically. However, for the 16 RTUs that are beyond their life we find they pose a slightly elevate risk to the network.

17.4.5 PROTECTION RELAYS

This section describes the condition of the protection systems as identified by on-site inspection and examination of the historical inspection and testing records.

To review the condition of the protection systems, WSP undertook on-site inspection of the assets and witnessing of testing, inspection and maintenance practices of Aurora's service provider was undertaken to validate the accuracy of data in the asset database and assess the robustness of the inspection and testing by identify any departures from the procedures. The on-site assessment also identified various installation methods and associated risks.

WSP reviewed a selection of 1100 testing sheets across 35 zone substations taken between 1999 and 2016, as well as on-site inspection and review of on-site documentation. The review identified the following general items as well as systemic issues that indicate the asset fleet of electromechanical relays is reaching the end of its serviceable life:

- The test records provided do not indicate that there is a specific maintenance plan (TMP) that has been followed. The dates of the testing show periodic inspection and testing has been undertaken but did not appear to be based on a fixed cycle or according to relay type and age. WSP has observed that other electricity businesses generally increase the frequently of inspection and testing as the relay ages. This is because Electromechanical relays lose calibration over time and more quickly when they are old and worn. Therefore, the maintenance frequency is expected to be higher for older electromechanical relays. However different cycles of inspection and testing was not evident in the data provided. While most relays have been inspected within the past four years, dates on the inspection sheets identify that some relays have not been inspected for much longer.
- Timing and pick up values consistently required adjustment. Recalibration was required on 513 test sheets covering 51 relays tested. The adjustments required ranged up to 65% for timing and 20% for pick-ups. The large adjustments required has implications for coordination of the protection schemes and the duration of faults on the system prior to being cleared, hence having a safety impact.
- Notation on the testing sheets identify that a range of electromechanical relays required cleaning to prevent contacts from sticking/not functioning, relay flags not operating, noisy components indicating that there was an internal mechanical problem and other condition related problems.
- The FGL earth fault, PBO overcurrent and AKA earth fault time delayed relays manufactured by AEI appear to consistently require more maintenance and recalibration, with larger percentage adjustments, than other relay types, notably at Anderson Bay and Green Island zone substations. There are 207 of these relays on the network. All of

these relays are significantly past their expected serviceable life of 50 years. The average age of PBO relays is 59 years and of FGL relays is 61 years.

Table 17.7 Relay types identified with systemic performance issues

SITE NAME	AKA	FGL	PBO	TCD5	TJM10	TOTAL
ANDERSONS BAY ZONE SUB	14	20	13			47
CORSTORPHINE ZONE SUB				14		14
EAST TAIERI ZONE SUB				8	8	16
GREEN ISLAND ZONE SUB	14	18	14			46
HALFWAY BUSH ZONE SUB	16	20	13			49
MOSGIEL ZONE SUB	2		2			4
NEVILLE ST ZONE SUB	12	13	13			38
OUTRAM ZONE SUB	5	8	6			19
SMITH ST ZONE SUB	14	20	14			48
SOUTH CITY ZONE SUB				18		18
ST KILDA ZONE SUB				14	14	28
WILLOWBANK ZONE SUB	14	18	14			46
Total	**91**	**117**	**89**	**54**	**22**	**373**

We note that Neville St is in the process of being decommissioned, which will result in 37 of these relays being removed from service.

WSP notes that earth fault detection on feeders is an issue due to the high impedance of conductor on ground faults. This may be compounded by relays that are not operating as intended as a result of settings drifting over time and without a regular inspection program to ensure the settings remain within tolerance.

The desktop analysis was supported by on-site inspection of the zone substation. WSP visited 38 of the 39 zone substations (Remarkables was not visited) to undertake a visual inspection and also witness inspection and testing at Green Island (Dunedin) and Alexandra (Central) zone substations. The key observations were:

- The inspection and testing identified that the relays and protection systems appeared functional but approaching end of life.
- Some relays were found with elements turned off, most likely due to incomplete procedures after testing the relays.
- The relays for all the feeder protection at Alexander ZSS were in one cubicle. This increases the risk that damage to the cubicle, e.g. from a fire, can cause outage to all the feeders. It is recommended that Aurora investigate splitting these protection relays into two panels to avoid a single point of failure.
- Some relays were not housed inside a building, though they are in an enclosed box mounted to the transformer. This subjects the relatively delicate protection relays to vibration, moisture and large temperature variations.

In summary, the protection relay fleet is aged and at end of life. Electromechanical relays are often out of specification and pose a risk of maloperation of the protection schemes. The maintenance program does not ensure that all relays are tested at appropriate intervals.

17.4.6 BATTERIES AND CHARGERS

Aurora have plans in place to standardise chargers and batteries which is progressively being implemented. Approximately half the ZSSs have a 'standard' charger, fewer have a 'standard' battery. Battery replacements are covered in the ZSS maintenance programme.

In generally the battery age indicate that they are in serviceable condition (exceptions indicated below). However, there does not appear to be a standard battery system design for the network and a number of different battery types were found during site inspections. It is understood Aurora are looking to standardise this which will include features such as voltage temperature compensation. We found evidence of recent battery testing (2017).

The chargers present a higher risk to the functionality of the protection systems. The following key risks were identified:

- There is no age data available for the charger, but in general about a third appeared old and at or approaching the end of their serviceable life.
- The attribute data for the chargers is incomplete and does not appear to be accurate, for example, there are only 19 substations listed with chargers that support protection scheme.
- Most substations only have one charger for protection, SCADA and communications, noting that the voltages required for each are different. Hence, there is a single point of failure and no redundancy.
- Aurora confirmed that all substations except Fernhill and Earnscleugh have battery and charger monitoring and alarms implemented via the SCADA system.
- Fernhill and Earnscleugh zone substations do not have battery and charger monitoring and alarms implemented via SCADA. This means that if the charger was to fail, then the control room will not know that they need to send a field crew to investigate and rectify the situation and the protection, communications or SCADA may cease to work when the battery voltage becomes too low without prior warning.
- Site inspection found some batteries thought to be past their used by date (East Taieri, North East Valley, North City.

17.4.7 INSTRUMENT TRANSFORMERS

Historically current and voltage transformers have not been tested so there is no test data available for review. During our site visit to Green Island a new testing regime was implemented that included testing current transformer secondary wiring. The two feeder circuits tested at Green Island 6.6kV switchgear failed insulation resistance tests and further tests to follow (four CTs failed to date). This is not a sample that can be used to extrapolate across the network but indicates there is an unknown risk associated with instrument transformers.

CTs which failed were part of 60 year old assets and successful repairs made as no spares were available. It is recommended that Aurora test all protection CTs on older metal clad switchgear as soon as possible to identify any common mode failures.

Voltage transformers were not included in the new inspection and testing procedure.

17.4.8 RELIABILITY PERFORMANCE

The protection systems can fail in two ways: firstly, they can fail or otherwise operate unintentionally and result in an outage; secondly, they can fail to operate when a fault occurs.

ASSET FAILURES CAUSING AN OUTAGE

The failure of the protection system could be the relay itself or the battery, instrument transformers or secondary wiring. However, they are highly reliable assets so typically there are not too many failures attributed to the asset class. Aurora has not historically undertaken root cause analysis of these failures.

The outage data shows only 19 outages since 2003 that are attributed to a component of the protection system. Of these 13 were attributed to the secondary wiring, four to the instrument transformers and two to the relays. The predominant cause of the outages was human error (which we observe is not uncommon due to the complexity of protection schemes), incorrect protection setting or incorrect maintenance/testing. Only one outage related to the deteriorating of a relay occurred during 2010. The relay that failed was located at Alexandra and, based on an inspection sheet from 2004, was most likely an ASEA RACIC type electromechanical relay.

The outage data results do not indicate a systemic problem with relay failures causing outage.

ASSET FAILURE TO STOP A FAULT

The failure of the protection system to detect and disconnect supply from a fault is an important measure of performance. Phase to ground faults can be difficult to detect due to their high impedance nature. Earth fault settings need to be sensitive enough to detect them, without causing spurious trips.

There were 166 incidents recorded in the outage records where a line was identified as having fallen to the ground as a result of equipment deterioration. When the impacts of weather and vegetation are included, the number increases to 404 events. This is an average of between 10 and 25 incidents per year. The public safety register that was maintained and used consistently by Aurora for two years from 2014 to 2015 and less consistently until 2017, identified a similar number of incidents annually. However, it also identified that 30 of these events resulted in a live conductor on the ground that was not cleared by the immediately upstream protection devices.

Out of these incidents:

- 15 were identified to be LV cables/conductors which are difficult to detect due to fault currents being not much different to normal supply currents.
- The remaining 20 were high voltage (6.6kV or 11kV) of which:
  - 4 were on feeders from Port Chalmers which has SEL 351S relays which should have cleared the fault
  - 2 were on Mosgiel feeders which had SEL751A relays which should have cleared the fault
  - 14 faults were found to be protected by electromechanical relays of which, from the information available, AEI FGL type, AEI PBO type and AEI AKA type were the predominate types. Form5 and Reyrolle B1 relays were also identified as having failed to operate.

Some of these incidents were due to a high impedance HV fault, where a back feed from the energised network circumvents the proper operation of the protection relays.

The failure of the Sensitive Earth Leakage (SEL) relays to operate may indicate that the Port Chalmers and Mosgiel distribution area have either changed characteristics and require a review of settings, have high impedance earth fault characteristics, or another component of the protection system failed such as the current transformers.

The failure of the electromechanical relays to operate aligns with the findings from our assessment of the test and inspection sheets showing that the settings are drifting and may no longer be suitable to detect the fault.

A non-functioning ASEA RI electromechanical relay at Clyde-Earnscleugh was identified during WSPs site visit and was subsequently replaced.

17.5 APPROACH TO RISK ASSESSMENT

Due to the type of information available, a qualitative approach was taken to the risk assessment for this asset class. The approach to assess risk on the network has been undertaken in three parts as described below and is based on the evidence set out in section 17.4.

ENERGY AT RISK

Managing energy at risk is not the primary function of relays, but supply outages can be extended by the failure of the primary protection scheme. The risk was not assessed as there is insufficient evidence regarding the number of spurious trips occurring on the network that this calculation would rely on.

SAFETY

Ensuring network safety is a key objective of protection systems. They function to stop faults on the network to ensure the network remains in a safe condition. The safety assessment has taken into consideration:

- the types of relays consistently loosing calibration
- the functionality of those relays, for example, earth fault and over current are more critical to public safety than transformer unit protection
- the location, including population density and load growth/network configuration changes
- voltage level and substation demand.

Based on the information available about these attributes, the assets were ranked and an assessment made on the risk.

ENVIRONMENT

Protection systems pose an insignificant risk to the environment.

17.6 RISK ASSESSMENT

The primary role of the protection systems is to ensure the safety of the electricity system and to prevent assets from being destroyed from excessive current or voltages.

The risk matrix below sets out the risk associated with the protection relays. The probability of failure is based on the assessment of the historical inspection and testing records where relays. The consequence was determined based on the criticality of the protection to the correct operation and continued safety of the electricity network and by using the customers supplied by the zone substation as a proxy for risk to public safety.

Table 17.8 Protection systems risk matrix

Increasing consequence (criticality) -->

Prob of Failure -->

0	**110**	**76**	**384**	**0**
0	**1**	**32**	**86**	**0**
0	**7**	**63**	**17**	**0**
0	**17**	**41**	**58**	**0**
0	**41**	**54**	**79**	**0**

17.7 KEY FINDINGS

The zone substation protection systems fleet is comprised of protection relays, batteries and chargers, and instrument transformers. We found:

- The asset data available from Aurora's systems and augmented by our field inspections was suitable for the purpose of this review. However, we note that the data is not complete and improvements to consistency of the data recorded can be made. Incomplete asset data presents a risk to effective asset management.
- There are 382 electromechanical relays (36% of the relay fleet) and 106 electronic relays (10% of the relay fleet) that are exceeding their expected life. This indicates an elevated risk of failure of these assets. Further modelling was undertaken to refine the assessment of network risk and quantities.
- In a four-year period, 20 faults on the HV network were not cleared by the immediately up-stream protection asset.

- We could not define a common/specific protection scheme/strategy for the applied protection in the network. The protection of similar assets at different locations have been implemented differently and there are no specific criteria used to protect different assets. This poses a risk that the protection scheme is not suitable for the current topology of the network.
- The dates on the protection setting calculations sheets are old and there does not appear to have been a recent protection system study/review to ensure the protection schemes and settings are still appropriate given changes in the network sine the original settings were calculated. This poses a risk that the settings are not appropriate for the current loading and fault current characteristics of the network.
- Five types of electromechanical relays are now an obsolete technology and are consistently losing calibration between maintenance cycles. These relays are used for earth fault and over-current detection. The failure of these relays to operate as intended has resulted in live conductors on the ground not being detected and de-energised. Most observed instances where earth faults were not isolated were found to involve the identified relay types or older electromechanical relays more generally. This supports they are at the end of their serviceable lives. Protection system assets pose a significant safety risk and their remediation should be assigned a high priority.
- Most substations only have a single battery and charger configuration resulting in a single point of failure that could impact the protection systems should they fail. Approximately half of these do not have an alarm via SCADA to alert the control room to a charger failure.
- Historically instrument transformers have not been tested during maintenance. Testing was implemented this year for current transformers (2018) and a high rate of failure was found. Voltage transformers are still not tested as part of the inspection and maintenance procedures. The high failure rate and incomplete testing indicates an elevated level of risk on the network. The extent of the risk was not quantified as part of this review as testing requires an outage of the associated protection system and substation.

Table 17.9 summarises the protection system risks and indicates the priority for remediation.

Table 17.9 Summary of protection system risk

ZONE SUBSTATION/ITEM	NUMBER	RISK TYPE	DESCRIPTION
Co-ordination of the protection system and schemes	1	Safety	Review and update of protection calculations, input variables (i.e. fault levels), coordination or protection schemes and use of fuses. This is a high risk.
Instrument transformers	39	Safety	Instrument transformers are in an unknown condition. Recent failure of testing at Green Island indicates igh level of risk with this asset class.
Battery and charger systems	39	Safety	There is typically only one battery bank and charger at each zone substation, there is no standard size, type or capacity. This is a high risk.
Alexandra zone sub	19	Safety	Performance issues with 'other' old electromechanical relays. This is a high risk.
Andersons Bay zone sub	58	Safety	Performance issues with AKA, PBO, FGL and other electromechanical relays. This is a high risk.
Corstorphine zone sub	54	Safety	Performance issues with TCD5 and other electromechanical relays. This is a high risk.
Green Island zone sub	55	Safety	Performance issues with AKA, PBO, FGL, other electromechanical relays. This is a high risk.
Halfway Bush GXP	7	Safety	4 high risk electromechanical relays.
Neville St zone sub	64	Safety	Performance issues with AKA, PBO, FGL, other electromechanical relays. Soon to be decommissioned. This is a high risk while still operational.
North City zone sub	29	Safety	2 high risk electromechanical relays. This is a high risk.
Queenstown zone sub	23	Safety	Other old numerical and electromechanical relays. This is a high risk.
Smith St zone sub	59	Safety	Performance issues with TCD5 and other electromechanical relays. This is a high risk.
South City zone sub	68	Safety	Performance issues with TCD5 and other electromechanical relays. This is a high risk.
St Kilda zone sub	52	Safety	Performance issues with TCD5 and TJM10 and other electromechanical relays. This is a high risk.
Ward St zone sub	25	Safety	2 high risk electromechanical relays. This is a high risk.
Willowbank zone sub	55	Safety	Performance issues with AKA, PBO, FGL, other electromechanical relays. This is a high risk.

18 CONCLUSIONS

This section sets out WSP's conclusions from the review and sets out a risk prioritised list of assets.

18.1 KEY RISKS

ASSET DATA

WSP undertook an assessment of Aurora's data through a series of interviews with Subject Matter Experts (SMEs) and analysis of the data sets provided. We validated that the information was suitable for use and obtained additional information through site inspections and testing. Each asset class was given a ranking against the data requirements and then assigned an overall data quality score of High, Medium or Low.

As evident from our data assessment, the data is not complete and improvements to consistency of the data recorded can be made. General observations are:

- Asset attributes have generally been captured in GIS. While this has been made to work for many assets, there is no link to financial data and or any functional workflow and maintenance management systems incorporated into the software. This limits the functionality applicable to asset management.
- Supply outage information is attributed to the nearest distribution transformer which limits the information that can be extracted from the data set. There is a reliance on free text fields which increases the difficulty of analysing the data.
- There was inconsistency in naming conventions across different data sources and no unique identifier for each asset which increased the difficulty in analysing data across different data sources.

The quality of the data varied across asset classes and was generally found to be better for the high value low volume assets, particularly zone substation assets, as well as for assets where there have been recent efforts to improve the asset management, in particular for support structures. We modified our approach to the risk assessment to make the best use of the data available for each asset class and to model the asset class in a manner that is reflective of its characteristics.

We conclude that despite data deficiencies adequate data and information was available for the review.

AURORA'S NETWORK RESILIENCE

Aurora's network is subject to risk from several natural hazards that could result in very high impact events, most notably earthquakes and the resultant liquefaction of the ground. WSP found that most key assets have been installed clear of earthquake fault lines, flood zones, landslide risk zones and tsunamis risk areas. However, it is not possible to avoid these altogether as customers occupy these areas and require electricity.

Dunedin is in an area that has a moderate to high liquefaction risk, and eight of the nineteen zone substations are supplied by radial underground sub transmission cables. Although these are dual circuits which provides redundancy, they are located in the same trench and, hence, can be expected to be impacted equally by a major event. The cable type, ages, deteriorated condition, and installation methods means that these are the highest risk with respect to network resilience.

WSP concludes that the resilience of the network could be improved by replacing older oil and gas insulated underground cables in the Dunedin area with modern XLPE type as these are less likely to suffer damage due to liquefaction of the ground following an earthquake.

NETWORK SECURITY

WSP found that the level of security in the network was similar to that observed in other electricity business. We note that:

- Zone substations are generally supplied radially from the Grid Exit Points, but by double circuits, so there is an adequate level of redundancy.
- Urban feeders generally have good levels of interconnection with adjacent feeders to be able to transfer load, however, some parts are radial with no interconnection. These arrangements do not appear different to most other electricity businesses.
- Long rural feeders normally have limited ability to enable resupply via switching, and this is reflected in the security and performance standards set for those feeders. We found that the topology of Aurora's network was appropriate for its geographical location and distribution of customers. To mitigate the risk of a prolonged outage should a single transformer zone substation fail, Aurora has a mobile transformer that can be deployed to restore supply quickly.

WSP concludes that the security of supply appears to be appropriate for the size and topography of the load supplied. Security of supply could be improved by adding more interconnections between ZSSs and HV distribution feeders, but this is unlikely to be economic with the present network size.

NETWORK RISK

The long-term network performance was analysed to identify any assets that are displaying an increasing trend in the number of outages. We found that overhead conductors, poles and crossarm assets were causing more than 50% of the network outages that were attributed to asset deterioration.

We found that most assets pose a small risk to public safety, reliability or the environment. The risks posed by these assets are no greater than WSP has observed in other networks in New Zealand and internationally. WSP found some exceptions which are set out in the following conclusions by asset class:

Support structures

The key components of support structures are poles, crossarms and insulators. Information on insulator defects and condition is not separately recorded but they are generally replaced with the crossarm; hence, the review assessed insulators and crossarms together. We found:

- A rising trend in supply outages from failed poles prior to 2016 has been arrested in 2017-2018, likely because of the accelerated pole replacement program.
- A significant number of poles (12%) and crossarms (47%) exceed their expected lives. The large number of support structures that exceed their expected lives indicates an elevated risk of failure of these assets. Modelling indicates 2.6% of the pole fleet and 2.3% of the crossarm fleet are in poor condition and have a high risk of failure.
- The pole inspection program has recently been improved but has not identified all poles that are in poor condition as it has not yet covered the whole network.
- Crossarms are not inspected adequately and many are in poor condition. Some (2.3%) are categorised as high risk due to their location relative to population and the probability of failure. Probability of failure was based on results from our field inspections.
- Malaysian Hardwood crossarms (3.8%) have a shorten life due to fungal growth and need to be replaced.

WSP concludes that the support structures pose a moderate to high risk to network reliability and specific assets pose a high risk to public safety due to their location in populated areas.

Distribution switchgear

The key assets in the distribution switchgear fleet are pole mounted air break switches, pole mounted auto reclosers, ground mounted switchgear and RMUs.

Distribution switchgear has only contributed 8% to the average number of outages on the network between 2013 and 2017 but is displaying an increasing trend.

A significant number of distribution switchgear units are defective and inhibit normal operation of the network, which can lengthen outages experienced by customers or expand the number of customers affected as an upstream switch must be operated instead. This can impact the reliability performance of the network.

Additionally, a significant portion of the fleet is aged, with 21% exceeding their expected lives. In particular,

- Two types of switchgear (L&C and Statter) are at end of life and have a high risk of explosive failure.
- A significant portion of the RMU type switchgear inspected (40%) have oil leaks, indicating a deteriorated condition.

This indicates that there is an elevated probability of failure of these assets.

WSP concludes that distribution switchgear poses a low to moderate but increasing risk to network reliability and specific assets pose a high risk to worker safety. The exception to this are the L&C and Statter switchgear, a portion of which (20 units) represent a high risk to public safety.

Distribution transformers

Distribution transformers are a run to failure asset, with about 10 (0.1%) failing each year. Failures of distribution transformers present small risks to safety, reliability and to the environment. Due to their age and location, there are 328 distribution transformers (4.7%) with a moderate level of risk.

While only a small portion of the fleet is aged, with 10% exceeding their expected lives, there is a gradual increasing trend of transformer failures, which indicates these assets pose an increasing risk to network reliability and safety. In particular,

- There are 57 distribution transformers in the Dunedin network considered to have a high safety risk due to their age, capacity and proximity to the public. In the Central network, two distribution transformers are considered a high risk to safety. There are no transformers in either the Dunedin or Central networks that are a high risk to reliability.

WSP concludes that distribution transformers pose a low to moderate risk to network reliability and safety, except for a few aged transformers in the Dunedin network that pose a high risk.

Overhead Lines – sub transmission

The key components of overhead sub transmission lines are conductors and connectors.

Overall, the sub transmission network is performing well. Several issues are identified, but they are not yet adversely affecting network performance. We found:

- On average, one sub transmission line per year causes either a safety incident by falling to the ground or is reported in the public hazard register. This indicates that, although these assets can pose a risk to public safety, the events are infrequent and the information available indicates that the protection operated for the incidents where the conductor made contact with the ground.
- The A, B and C sub transmission lines in Dunedin are in poor condition and there is a high probability of failure on some sections (specifically the A and B Lines that are in closer proximity to the coast and 111 years old). However, the consequence of failure is low due to the redundancy in the network and because the sub transmission lines are located away from highly populated areas.
- The Cromwell to Wanaka lines have a number of issues, including vertical separation between the 11kV and 66kV circuits of 1.8 m compared to the requirement for separation of 2 m. In addition, there are a number of issues relating to its construction.
- It is likely there are spans of the sub transmission lines that do not comply with the minimum height requirements. This was not quantified as part of this review but is indicated by the asset data.

WSP concludes that sub transmission lines pose a low risk to network reliability and safety.

Overhead lines – distribution

The key components of overhead distribution lines are conductors and connectors. The HV network consists of mainly ACSR conductor while the LV network consists mainly of copper conductor. A small portion of the asset fleet currently exceeds their expected lives - 309 km (12%) of copper conductors, 162 km (11%) of ACSR conductors and 35 km (15%) of steel conductors.

There are 10 to 25 public safety incidents per year related to distribution overhead line conductors. This asset class also contributes the largest impact to network performance, with an annual average of 33% of the outages from 2013 to 2017. The outage data shows evidence of an increasing trend in the number of outages caused by this asset class.

A common failure mode for this asset class is failure of the conductor by way of corrosion or fatigue, both of which are related to age. Aurora does not have a dedicated inspection and testing program for overhead conductors but undertakes visual inspection on an opportunistic basis when inspecting other assets as part of other maintenance tasks. The evidence examined suggests that ACSR and copper conductor with a cross sectional area of less than 100 mm2 have the highest failure rates.

WSP concludes that distribution overhead lines pose a moderate risk to network reliability and safety, mostly due to their relatively high failure rate but low consequences to public safety when they fail. There are some conductors located in Dunedin with a higher consequence due to their location in densely populated areas.

Underground cables – sub transmission

The underground sub transmission cables fleet is comprised of largely oil and gas insulated cables, with some XLPE and PILC types. Overall, the sub transmission underground cable fleet is performing well but there are some condition issues that have emerged during the past few years. We found that no loss of supply has been attributed to a failure of a sub transmission underground cable and there have not been any identified instances of the sub transmission cables causing a public safety hazard.

Some issues were identified:

- The available test records identified a number of recurrent sheath integrity failures.
- 17 km of cable that has a higher risk of failure is comprised of the connection to Neville St and Smith Street zone substations. As part of the Neville St decommissioning project, the associated cables (10.7 km) will be decommissioned, removing this risk.
- North City cables pose a moderate risk due to the limited load transfer available and the condition of the cable increasing risk of failure. There was a significant oil leak on the North City No. 2 cable, however, the leak stopped in 2015.
- There is a low risk of environmental damage through oil leaks, although the type of oil used reduces this risk.

WSP concludes that sub transmission underground cables pose a low to moderate risk to network reliability and an insignificant risk to public safety. Oil leaks can pose a risk to the environment, but none were identified currently.

We note, however, that replacement of a sub transmission cable can be a lengthy process and the lack of good condition information poses a risk that a cable needing replacement may not be identified with sufficient lead time. The impact is a potential reduction in network security while cables are replaced.

Underground cables - Distribution

The distribution underground cables fleet is comprised of largely XLPE and PILC type cables. Overall, the underground cable fleet is performing well but there are some condition issues that have emerged during the past few years. We found:

- HV distribution cables asset class causes 11% of the network outages, the fourth highest contribution out of the asset classes. Most outages in this asset class are recorded as being caused by asset deterioration.
- Approximately 10% of PILC cables and the entire section of HV submarine cables exceed their expected life and, therefore, represent an elevated risk of failure for this asset type.

- Cast iron potheads were identified to present a public safety risk. Aurora has a program in place to remove these from the network.

WSP concludes that distribution underground cables pose a low risk to network reliability and an insignificant risk to public safety and the environment. However, cable terminations in the form of cast iron potheads pose a moderate to high risk to public safety in the Dunedin network area.

ZSS transformers

The zone substation transformer fleet is comprised of power transformers and their associated tap changers and bushings. Most zone substation transformers are in good condition. They are inspected regularly and appear to be appropriately managed. We found:

- The transformers at two zone substations are in poor condition, although we note that one is currently in the process of being decommissioned. Additionally, transformer tap changers are showing signs of deterioration and some are behind their maintenance schedule, increasing risk of an outage on the associated transformers.
- There were 8 transformers (12.7%) identified as high risk to reliability, predominately due to the transformer internal condition and tap changers.
- There are 24 tap changers that are overdue for maintenance by between 1 and 7 years.
- Bunding around each transformer to contain oil leaks was established at all but 6 substations. The main risk related to a lack of bunding was at Omakau, which is located adjacent a small waterway. The environmental risk was classified as Moderate.
- East Taieri was the only zone substation identified to pose a safety risk, classified as Moderate. It is located adjacent to a petrol station but does not have any physical protection in place to protect the petrol station in case of a serious failure and/or fire.

WSP concludes that ZSS transformers currently pose a moderate risk to network reliability and a low risk to public safety, except for East Taieri where no physical protection is in place to protect the adjacent petrol station in case of an explosive failure or fire. Transformers at Omakau are not bunded and pose a small risk of environment damage from an oil leak.

ZSS circuit breakers

The zone substation circuit breaker fleet is comprised of indoor and outdoor circuit breakers that are insulated by using oil, vacuum and gas (SF6) technologies.

Failures of zone substation circuit breakers occur infrequently and, hence, have a small impact on network reliability. As they are located within a ZSS, they have no impact on public safety.

We found:

- A significant portion (31%) of ZSS circuit breakers have exceeded their expected lives.
- The inspection, testing and maintenance of ZSS circuit breakers is incomplete. This elevates the probability of these assets failing.
- Some oil insulated zone substation circuit breakers were found to present an elevated risk to the network with respect to network reliability and the safety of field crews due to their potential failure mode through arc fault and fire:
  - Some of the specific types of circuit breaker in-service on the Aurora network have been identified in the electricity industry as having an elevated risk of failure, in particular the HLC, HKK and LMT models.
  - The switchboards are not rated to contain an arc fault and, hence, pose an elevated risk to field crews.
  - The VWVE type switchgear was modified at installation which has enabled moisture ingress and deterioration of the assets.

- A number of indoor circuit breakers have been installed in custom built outdoor enclosures which, upon site inspection, did not appear to be fully sealed from the environment. This is likely to result in an increased rate of deterioration and an increased probability of failure.

WSP concludes that ZSS circuit breakers pose a moderate risk to network reliability and worker safety. They have no impact on public safety or the environment.

Protection systems

The zone substation protection systems fleet is comprised of protection relays, batteries and chargers, and instrument transformers. Overall, we found that the protection relay fleet was performing poorly, with many aged and using obsolete technology. In a four-year period, 20 faults on the HV network were not cleared by the immediately up-stream protection asset.

We found:

- There are 382 electromechanical relays (36% of the relay fleet) and 106 electronic relays (10% of the relay fleet) that are exceeding their expected life. This indicates an elevated risk of failure of these assets.
- Five types of electromechanical relays are now an obsolete technology and are consistently losing calibration between maintenance cycles. These relays are used for earth fault and over-current detection. The failure of these relays to operate as intended has resulted in live conductors on the ground not being detected and de-energised. Most observed instances where earth faults were not isolated were found to involve the identified relay types or older electromechanical relays more generally. This supports they are at the end of their serviceable lives.
- Most substations only have a single battery and charger configuration resulting in a single point of failure that could impact the protection systems should they fail. Approximately half of these do not have an alarm via SCADA to alert the control room to a charger failure.
- Historically instrument transformers have not been tested during maintenance. Testing was implemented this year (2018) and a high rate of failure was found. This indicates an elevated level of risk on the network.

WSP concludes that ZSS protection systems are in poor condition and pose a high to very high risk to network reliability and public safety. Protection system assets pose a significant public safety risk and their remediation should be assigned a high priority.

SUMMARY OF RISKS

We used Aurora's risk management approach to classify the identified risks. The chart below shows a summary of the result.

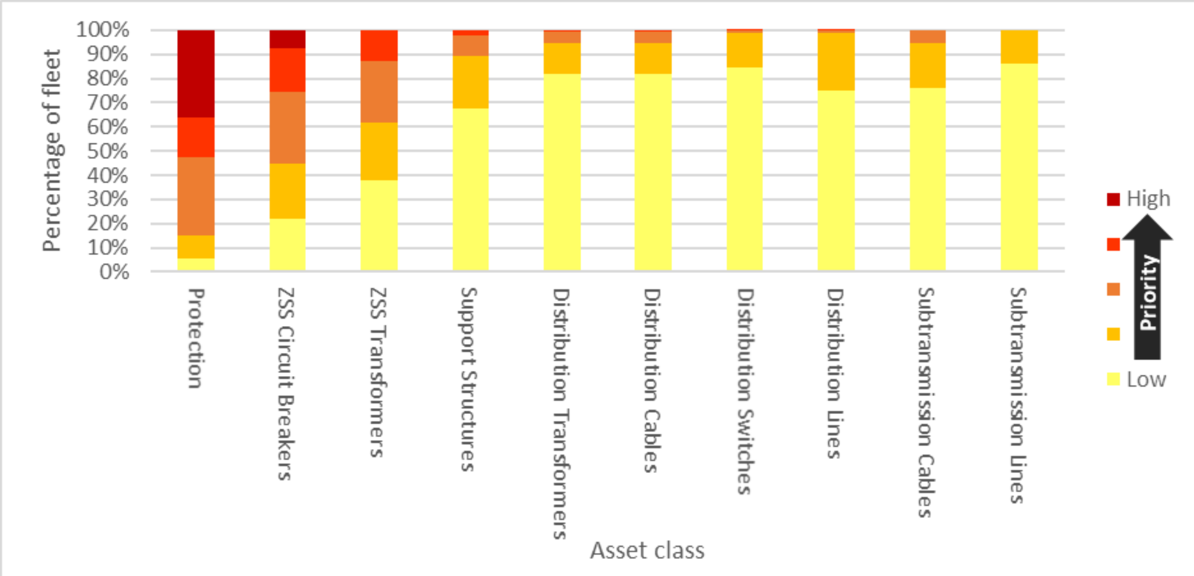


Figure 18.1 Summary of risk by asset class[29]

Overall, we found a high number of risks in the "Red" category, indicating network risk has not been reduced to as low as reasonably practical.

A prioritised list of risks has been developed to provide guidance on where Aurora should focus their attention in maintaining the safety and reliability of the network.

18.2 PRIORITISED LIST OF RISKS

The prioritisation list is provided in Appendix F. It sets out the preferred order to address the identified network risks based on information available and the network configuration at the time of issuing this report. We note that there are interdependencies between the network assets. Should new information become available or should the network be reconfigured, it may be necessary to reassess the prioritisation of the risks.

[29] For the purpose of this chart, the distribution cables have been calculated based on number of cables rather than length to enable addition of the cast iron potheads into the same category. This makes each cable and pothead a single unit and, therefore, can be added on a 'like for like' basis for the purpose of displaying risk.

APPENDIX A

ASSET SAMPLE SELECTION

A1 SEGMENTATION FOR SAMPLING

To ensure the best value for money from any sampling required, asset classes were segmented to enable different levels of confidence to be applied when calculating sample sizes. This was done to minimise costs while ensuring sufficient effort was allocated to assets with different risk profiles.

We used the asset criticality as the first segmentation to separate the asset fleets into high and low criticality sub-categories. Additional segmentation was applied to asset groups as relevant based on the data assessment and knowledge of the asset types. Where relevant, segmentations may have been applied based on:

- testing regimes applied to assets
- location of assets to account for public safety (i.e. proximity to points of interest or density of population)
- location of assets to account for environmental conditions (i.e. Central v Dunedin Inland v Dunedin Coastal)
- asset type or material type where it could result in sufficiently different deterioration rates or criticality assessment

Once the population had been segmented to improve the targeting of our sampling, an appropriate sample size was calculated as discussed below.

For assets with a large population (e.g. poles, distribution switchgear) WSP took a statistical approach to calculating the sample size based on the Confidence Level and Margin of Error required for each population segment criticality. The formulas used are shown below with the parameters defined in Table A.1.

$$Sample\ Size = \frac{Z^2 * p * (1-p)}{C^2}$$

Normalising for population size gives:

$$New\ Sample\ Size = \frac{Sample\ Size}{1 + \frac{Sample\ size - 1}{Population}}$$

Table A.1 Sample size calculation variable descriptions and values

VARIABLE	DESCRIPTION	LOW CRITICALITY	HIGH CRITICALITY
Z	The z value from the standard normal distribution for the Confidence Level required	1.28 (80% confidence level)	1.96 (95% confidence level)
p	Standard deviation of the condition of the population	0.5 assumed since not yet assessed	0.5 assumed since not yet assessed
C	Margin of error (Confidence Interval) of the result	±5%	±5%
Population	Number of assets in the fleet segment	Varied per asset class	Varied per asset class

APPENDIX B

SUBSTATION INSPECTIONS

B1 SITE INSPECTION FINDINGS BY SUBSTATION

This section lists the key findings per substation based on our on-site inspections.

GENERIC FINDING TO ALL ZSS

Following comments are applicable to all sites

- Switchgear: no evidence of any insulation resistance testing of protection CTs or indoor busbar. CT and busbar IR testing needs to be done to assess the condition of the protection circuits and the busbar chamber from the perspective of their integrity. The need for this was highlighted by the failure of protection CTs at Green Island.
- Surge arrestors: installation of SAs to protect cables, transformers from vacuum CB switching pulses, lightning etc seems to be patchy and a review is recommended. Many instances of rigid copper strap looking to block off SA arc vent.
- Bund gratings or metal trench covers are typically not earthed. Aurora should consider this under their earthing risk assessment requirements.
- Fire detection observation: one, sometime two smoke detectors are in the main switchgear room(s). No fire detectors in other building rooms. No evidence of any maintenance of the smoke detectors. Should a fire occur in any of the substations (the main risk is from within a control panel) its detection is uncertain. As the buildings are not occupied fire detection is not a NZBC requirement but very desirable from a risk perspective. Lack of complete building fire detection could be considered a fatal single point of failure within all substation buildings.
- Drawing folders: Most of the site drawing folders contain red pen mark-up prints. The accuracy and completeness of these drawing folders needs to be reviewed.
- Mercury switches within some transformer temperature relays have been identified as a false trip risk during a seismic event. It is also probable that these types of switch contact will exist within older Buchholz relays, something that has not been investigated.
- Arc flash assessment notification re PPE requirements if operating switchgear was not seen at all sites. Given the HV assets are existing (and not covered under AS/NZS 3000, EEA Guidelines 2011).
- Building signage: Bar a few sites, Health & safety notices re CPR/first aid are out of date, no first aid fire extinguisher.
- Seismic restraint: not formally considered, but a suitable qualified person should review this aspect independently of this report. As an observation, not all cells in battery banks are secured to their stands. Overhead gantry structure doesn’t appear to be braced in all directions.

DUNEDIN NETWORK

ANDERSONS BAY

Vegetation growing through security fence. No possum guards visible on the 33 kV bus structure posts.

BERWICK

Outdoor switchyard: four feeder cast iron cable potheads observed.

EAST TAIERI

Fire wall to adjacent petrol station (newer development). Transformer temperature relays use mercury switch contacts. Battery charger is original and batteries beyond end of life (dated 2005).

HALFWAY BUSH GXP

Old relay room battery end of life (new relay room under construction). Control panel doors removed from site leaving terminals accessible.

KAIKORAI VALLEY

It was observed new 33k V feeder and transformer Differential protection has been installed but not put into service /requires completion.

MOSGIEL

Substation building at approximately 60 years old and considered near end of life. Remedial works to reinforce its structure are evident, glass louvre windows facing the State highway are not considered secure and there is no security fence along this boundary. Some switchyard surge arrestor arc vents blocked by rigid copper earth strap.

NORTH CITY

Outdoor switchyard: The two power transformers radiators look to have had patch repairs over their life. Pressing issues are:

1. T2 radiators are rusting and an oil catch bottle and drip tray is placed under one leak. Several temporary leak repairs plus new rust areas are evident. All radiators require the thorough refurbishment.
2. Winding temperature relays use mercury switches. In an earthquake the transformers may spuriously trip losing the hospital and university loads.
3. It is suggested the Silica gel breathers are replaced with a nontoxic desiccant.

110 Vdc batteries look to be beyond their service life and their replacement needs to be investigated.

NORTH EAST VALLEY

Stored in the open switchyard were four 200 L drums of chemicals (same as was found inside Andersons Bay ZSS), collecting water in their lids. Two had their seals broken. Use by date was 17/3/2018.

Protection relays are first generation microprocessor type and due for end of life replacement.

110 Vdc charger: original charger considered to be end of life and replacement recommended. Battery is 17 years old and is well beyond end of life

OUTRAM

Facilities would be described end of life/very serviced aged and it is understood that replacement of all assets is underway. One transformer was not in service due to tap changer issues.

PORT CHALMERS

Switchyard security fence over grown in places. Transformers are 60+ yrs old and require a review of remaining service life. Review of spark gap (surge arrestor) performance recommended to validate protection of primary assets. 24 Vdc SCADA charger, protection, alarm unit installed but no battery.

SMITH ST

Transformers, switchgear are 60+ yrs old and require a review of remaining service life.

CENTRAL OTAGO NETWORK

ALEXANDRA

At 35 years, the substation has the appearance of being much older than it presents. very poor from the perspective height clearances to the 33kV bus. Its close proximity to ground is a concern (you could physically touch live 33 kV transformer bushing terminals at an estimated height of 2.1 m agl) and it is recommended immediate restricted entry zones are put in place whilst a permanent solution is planned. It is at significance variance to industry best practice.

33 kV ASEA type HLC CBs are minimum oil - four are newer at estimated 35 years old and three 58 years old (data base – Circuit Breakers.xls). Whilst the oil is replaced every four years, CB contacts and arc chamber have never been disassembled for inspection. Used oil colour has been reported as being mixed. Lack of seal spares was cited as being the reason for not undertaking this inspection. It is a significant concern contact inspection and removal of carbon deposits has never been undertaken from the contact chamber. It is recommended CB contact maintenance inspection work is undertaken as soon as possible as there is no degree of confidence around their condition. CB spring charge motors are AC, therefore, require a local service supply to recharge spring.

Surge arrestor performance details should be reviewed due to copper earth strap blocking their vent.

Some structure equipment stands have their foundation fixing studs secured with only half a nut (studs not long enough).

Transformer oil bund Petra oil barrier filters were being partially blocked with silt. This needs to be removed and the maintenance/life expectancy of these filters needs to be clarified (information details not clear).

11 kV ASEA type HKK outdoor switchgear - four yearly maintenance tests were witnessed. Tests were being undertake using a superseded procedure and not the new/revised procedures issues by Aurora. CBs Contractor on site competent but under resourced for the planned tasks, most of which will not have been undertaken. Contact oil is replaced on a four yearly interval but their contacts and arc chamber have never been inspected. The outdoor enclosure for these indoor rated CBs was designed by the original asset owner and is considered end of life. Internal pinex lining is disintegrating (fire hazard and not a suitable product for this application), partial discharge has been detected around internal busbar cubicle penetrations (report 2017) which needs to be addressed and can only be taken as a stop gap maintenance measure.

11 kV feeder protection relays all in one control panel – if there was to be a fire in this panel all feeder protection schemes would be compromised.

ARROWTOWN

Whilst this is listed as being n-1, one transformer does not have the capacity to take all the load. A third unit needs to be considered. T1 leaking oil from a temporary repair. No oil bunding.

11 kV ASEA HKK CBs atop the transformer require contact inspection.

Status of the original 110 Vdc battery charger should be reviewed.

CARDRONA

Switchgear building: Labelling of the SEL 787 protection relay required. No transformer differential protection seen – required confirmation. Water in the 11 kV switchgear cable trench observed and may have a long term effect of the switchgear?

CLYDE EARNSCLEUGH

Transformer T1: ASEA RI protection relay not working on one phase. Temperature relay uses mercury switch contacts. Cabinet door opens to eye level. No oil bunding.

11 kV ASEA HKK CBs atop the transformer require contact inspection.

CB192 cable screens not run back through CTs. Review Raychem BØ termination clearance to earthed metal. Insulation tape around screen disintegrating

CORONET PEAK

No surge arrestors or spark gaps seen – requires review. Cooling fans use three phase motors – with a single phase local service supply an electronic convertor has been used to provide three phase power. It is understood this requires manual resetting if power is lost.

No room at present to park the Aurora mobile substation should a failure occur.

CROMWELL

Transformers are adjacent to each other with no fire wall between. No oil bund with any oil leakage having the potential to drain onto the adjacent main road stormwater.

Surge arrestor performance details should be reviewed due to copper earth strap blocking their vents.

CROMWELL GXP

No surge arrestor protection observed. VTs earther via galvanised mild steel frame – should be earther direct to ground.

Whilst new 24 Vdc charger and batteries have been installed, the old units have not been removed.

DALEFIELD

Observations: 33 kV conductors into and out of Dalefield look to be of a small cross sectional area. Guy on last pole into ZSS does not has an insulator break or PVC sleeve. Dirty 11 kV insulators from birds roosting on the transformer.

EARNSCLEUGH

No oil bunding. 11 kV ASEA HKK CBs atop the transformer require contact inspection. CB cable screens not run back through CTs.

ETTRICK

Understand this sub has been on the refurbishment list for some years. No oil bunding. Broken sheds on 33 kV AIS. 11 kV ASEA HKK CBs atop the transformer require contact inspection. SA installed but copper strap blocking arc vent.

FERNHILL

A relatively new ZSS but has a number of aspects that require review:

1. T1 and T2 oil bunds are linked via a PVC pipe. This drainage system is good for rain water but not burning oil – no flame traps, PVC pipe is not fire rated, a fire in one bund could migrate to the second bund.
2. T1 VT fuse caps atop the transformer have not been fitted correctly and could potentially not be weather tight. Sensor cable gland on the side of the transformer are leaking oil.
3. No details on the 11 kV SF6 gas sited – purity should be verified.
4. 110 Vdc battery cell sized looked physically small. Capacity and age replacement (dated 2008) required verification.

Unusual that the oil filled local service transformer is inside the relay room from a fire hazard perspective.

FRANKTON

Transformer bunding – no flame trap to protect drainage into the oily separator. Connection via a PVC pipe will not be fire rated.

FRANKTON GXP

This was a Transpower structure that is now part of Aurora's assets. There are multiple 33 kV air break switches – it is not known if their insulators are of a two part construction, as their cement joint is known to fail.

LAUDER FLAT

Transformer bund drain fitted with SPI Petrochem oily water barriers. Sediment build up and a filter screen is missing – their maintenance arrangement need to be reviewed as they drain into an open road side sump/drain. Emergency trip buttons should have trip covers. Transformer panel cabinet doors not earthed.

QUEENSBERRY

Installation of SAs need reviewing. As an unfounded observation, the control cabinet has no forced cooling and will potentially get very hot during summer.

QUEENSTOWN

Both T1 and T2 are within a very compact switchyard, and a fire in either transformer would have a significant impact on the overhead 33 kV bus structure. A T2 fire would have a significant impact on the immediately adjacent 11 kV feeder CBs. No details on the 11 kV SF6 gas sited – purity should be verified.

Surge arrestor performance details should be reviewed due to copper earth strap blocking their vents. SAs on 11 kV cables required review.

110 Vdc batteries due for replacement 2017.

RIVERBANK RD

Switching station under construction. Relay room has heat detectors fitted which is fine, however, they will take a long time to respond to a fire event. As a suggestion, early warning would be better detected with smoke detectors.

ROXBURGH

33 kV ASEA CB contacts have not be maintained from the time it was placed into service (as per Alexandra) – these require inspection.

Construction activities in the switchyard look as if they have not been finished and it would be desirable loose ends are completed – outdoor CB control cabinet wiring has no wire/terminal numbers; a 110 Vdc battery in the switchyard looks as if it should have been decommissioned and its connected loads transferred to the 110 Vdc battery in the relay building.

WANAKA

Protection for T1 Differential protection earth fault element LED found not to be illuminated, indicating that this element has not been enabled (element enabled on T2).

Restricted one way access behind 11 kV indoor switchgear.

Outdoor surge arrestor requirements require review (rigid copper strap used, SAs at cable terminations etc). Deteriorating PVC tape on CB 3232 cable termination is unravelling and bridging its termination insulator.

Aurora ZSS photo summary

Photo 1: Alexandra ZSS – 33/11 kV T2; live 33 kV terminals approx. 2.1 m agl. ASEA CB type HPL on left

Photo 2: Alexandra ZSS – 11 kV feeder CBs; indoor ASEA HKK CBs in an outdoor enclosure; Flammable Pinex lined internally; 11 kV bus generating partial discharge

Photo 3: Clyde Earnscleugh ZSS – non-functioning protection relay (one phase) on right hand side of cabinet

Photo 3: Cromwell ZSS – T1 & T2 adjacent to each other; no fire wall between units (impractical because of overhead bus), no oil bund; main road adjacent

Photo 4: Queenstown ZSS – T2 directly adjacent to 11 kV feeder switchgear (indoor breakers in an outdoor enclosure); 33 kV bus structure directly above the transformer(s)

Photo 5: Fernhill ZSS: subject to verification, bund drainage from T1 looked to flow into T2 bund using a PVC drainage pipe; non fire retardant, no flame trap. Tee joint in T2 bund, connection T1 and the drainage sump

Photo 6: Fernhill ZSS T1 – oil leaking from sensor cable glands; VT fuse caps on to of transformer incorrectly fitted

Photo 7: Willowbank ZSS – observed encroachment of residential apartments looking directly into ZSS assets over the top of boundary wall

Photo 8: North City ZSS T2 – leaking radiator oil being caught in a 2L container; many radiator repairs evident

Photo 9: North City ZSS – transformer temperature relay mercury switch contacts (spurious trip risk in a seismic event)

Photo 10: Halfway Bush ZSS – typical suite of 1960's 6.6 kV feeder CBs, electromechanical protection relays, bulk oil CBs

B2 DETAILED REVIEW OF SUBSTATION PROTECTION SCHEMES

MOSGIEL ZONE SUBSTATION

Mosgiel Zone substation is fed by three circuits (Line 1, Line 2 and Line 3) which T-off from A Line, B Line and C Line (via three connections) from Half Way Bush GXP.

- None of the three lines have dedicated protection associated with them at Mosgiel substations. It is not recommended to rely on zone 2 of distance protection at the remote substation as primary protection for busbar faults.
- No busbar protection scheme is implemented for the 33kV busbars, therefore both Line 1 and Line 2 incomers as well as the busbar are protected by zone 2 distance protection between Waipori generation and Halfway Bush GXP. Any 33kV bus fault would operate the distance element.

- For a 33kV busbar fault, the upstream distance protection will operate and clear the fault by zone 2 protection (by opening the remote end CB), the automatic changeover will close Line 3 onto the faulted bus and this may create further damage. There is no interlock provided to prevent line 3 from closing, if both line 1 and 2 are tripped for a 33kV busbar fault.
- No busbar protection for the 11kV busbar
- No information provided regarding coordination between zone 2 protection of the incoming feeders and the downstream feeders and transformer protection.
- The latest updated calculation provided is 1992, this is significant amount of time, where many changes of the network loading, configuration and fault levels could have occurred. The setting file of the zone substations indicate that there are 2 calculations reference 88 and 170 dated 2004, to calculate backup earth fault for both transformer 11kV incomers in the substations 11kV busbar. These calculations are not included in the provided documents.
- The primary side of the two 10 MVA transformers is protected by Instantaneous Earth fault and IDMT overcurrent. The main protection for the secondary side is Restricted Earth Fault/leakage relay. Transformers of this size would typically have transformer differential protection as primary protection and IDMT overcurrent and earth fault to properly coordinate with the 11kV feeders.

ALEXANDRA ZONE SUBSTATION

Alexandra-Clyde 1 and Alexandra-Clyde 2, 33kV feeders connect Alexandra zone substation and Transpower 220kV/33kV Clyde Substation.

- Only distance protection covers Alexandra ZSS's two incoming feeders (the Rox-Alex lines). From Alexandra ZSS, a single line supplies Omakau ZSS and Lauder Flat ZSS. The Omakau-Lauder is protected by over current and earth fault protection is installed, but there is no distance protection, so there is no backup scheme for this line. This is not uncommon for distribution lines, but this is acting as a sub transmission line.
- There is no 33kV or 11kV busbar protection. There may be protection provided by overcurrent at Transpower-Clyde substation, but details of this were not available.
- The transformer is properly protected by differential protection as primary protection, and overcurrent and earth fault protection as a backup on the 11kV side. However, the 33kV side of the transformer was not provided with overcurrent or earth fault as a backup for faults on the 33kV side of the transformer. If the differential protection failed to clear faults on the 33kV of the transformer, then the supply will be lost for the whole zone substation as the second line of protection is overcurrent and earth fault at the main incomers. The setting file does not include setting for feeder the incomers CB 3142 and CB 3122, also the protection coordination calculations does include these two feeders as part of the coordination study.
- No protection test records were provided.

SMITH STREET ZONE SUBSTATION

Smith Street Zone substation does not include 33kV switchgear. The substation receives two separate incoming feeders to the 33kV/6.6kV transformers from Transpower Halfway Bush GXP. Each line is fitted with differential protection to protect the line and transformer at Smith Street Zone substation.

The following high level comments are made regarding the protection scheme at the Smith St Zone substation:

- The 6.6kV panel incoming feeders are protected by over current and earth fault protection. This protection serves as a backup protection for the 6.6kV feeder and the restricted earth fault protection of the transformer secondary.

- The busbar is protected by bus zone frame leakage relay.
- The protection scheme at Smith Street zone substation seems adequate, however no protection coordination calculation was provided.
- The setting of the earth fault includes instantaneous setting and time delayed elements, for all incomers and feeders. It is not clear how coordination is achieved between the 6.6kV feeders and the incomers with such low setting currents. No protection calculation records were available for the substation, therefore it is not possible to assess the coordination.
- Only two test records were provided. Protection test records for all feeders and transformers were carried out in 2005 and only one feeder and one transformer in 2008. The records indicate that some adjustment was required for the earth fault protection pickup time.

CROMWELL SUBSTATION

Aurora distribution network around Cromwell receives power from Transpower through several 33kV connections at the Cromwell GXP. However, these Transpower connections seems to be omitted from the 'High Level Network Protection SLD - 20727'. This makes it difficult to follow the SLD. Generally, all connections to bus bars at all substations should be shown or referred to in the SLD, regardless of who owns those assets. The ownership boundaries, if any, should also be shown in these SLDs, which is also seen to be missing in the 20727 SLD.

As per the 'Aurora Energy Asset Management Plan 2006-2016', the power received from Transpower is used to supply the Cromwell Zone substation and the two stepup auto transformers at the Cromwell GXP, which supplies power to the Wanaka Area. All these supply connections and a high level description of the protection scheme adopted to protect these connections are shown in the SLD 20727 provided by Aurora. As part of this review, the protection arrangements at the Cromwell zone substation and its 33kV incomer connections only will be analysed.

Protection scheme applied for Cromwell Zone substation:

- Cromwell 11kV zone substation is supplied by two 33/11kV transformers that receives power from two Transpower 33kV connections (33kV incomers). one of these 33kV connections also connects to the Meg Generation. The two 33/11kV transformers are of unequal size - T1 is rated 5/10 MVA, while T2 is rated at 7.5 MVA.
- At the Cromwell GXP end, these two 33kV connections (CB 1032 and CB 1092) are protected by two old electromechanical over current and earth fault relays owned by Transpower. However, at the Cromwell zone substation end, the 33/11kV transformers and the 11kV feeders are all protected by numerical protection relays that are installed around 2003- 2006. The Meg generation feeder, which contains a 33/6.6kV, 4 MVA transformer seems to have no protection on the 33kV side as per the SLD 20727. There is also a ripple injection unit, a couple of step down transformers and a mobile substation connected on the 33kV side of the Cromwell zone substation. The step down transformers are seen to be protected by fuses, and the mobile substation seems to be protected by transformer differential protection (as per the setting data base). However, the protection equipment protecting the ripple injection unit is not clear.
- The protection scheme at Cromwell GXP is arranged so that if the CB 1032 or 1092 opened manually or due to a protection operation, the corresponding 33/11kV transformer downstream in the Cromwell zone substation is tripped out.
- At Cromwell zone substation, the transformer 1 is protected by a single SEL 351S relay, plus Buchholz, pressure relief and winding temperature protections. The SEL 351S relay contains over current, earth fault, switch on to fault, restricted earth fault (11kV winding) and circuit breaker failure. All these protections are provided on the 11kV side, and no protections are provided on the 33kV side other than the Transpower 33kV protections upstream.

- At transformer 2, an additional circuit breaker (CB 3822) is provided on the 33kV side, which is not seen at transformer 1. The transformer 2 has all the protections mentioned above for transformer 1, with an additional cooper form 6 recloser provided at the 3822 circuit breaker. This Cooper Form 6 relay contains over current and earth fault protections used to protect the 33kV winding of transformer 2. This is in addition to the Transpower 33kV protections upstream.
- Arc flash protection is provided at the 11kV bus bar and at the 11kV circuit breakers at the Cromwell zone substation, while SEL 351S relays are provided at all the 11kV feeders and the 11kV bus coupler. All feeders are provided with over current, earth fault, switch on to fault and circuit breaker fail protection functions together with single shot auto reclose.

Review summary:

The following high level comments can be made regarding the protection scheme at the Cromwell GXP and the Cromwell zone substation based on the evidence in the documents mentioned above:

- The protection single line diagrams do not describe all associated details in sufficient detail. Examples: the drawing 20727 do not show the Transpower network connections or ownership boundaries in detail, the drawing 3C/03E/047 do not adequately cross reference to related drawings.
- The over current protection setting at transformer 1 is set at 800 A at the 11kV incomer (15.3 MVA), while the same setting at transformer 2 incomer is 600 A (11.43 MVA). These numbers correspond to significantly high MVA ratings compared to each transformer's rated capacity, which are 10 MVA and 7.5 MVA respectively. The setting calculation provided seems to have considered the capacity of the 11kV feeder cables, however, it is not clear whether the transformer's over load capabilities are considered when selecting these settings. It is recommended that these setting calculations be revisited, as significant overloading of the transformers could affect the life of the transformers in the long term.
- From the information provided it is not clear whether the two 33kV incomers are paralleled through the isolators / switches 3837 and 3824 on the 33kV side. If these are operated in parallel, then there is a risk that both the 33kV incomers could trip (through the instantaneous setting at the Transpower 1032 and 1092 over current relays) for a fault, resulting in an outage at the Cromwell zone substation.
- At transformer 1, only the Transpower electromechanical relay is provided to protect the transformer against 33kV winding / side faults. If this relay is failed, then there is no dedicated protection on the transformer 33kV side, and the upstream Transpower protection at the Cromwell GXP (at feeder 1082 or 1042) will need to operate to clear the fault. However, this won't initiate the intertripping scheme at Transformer 1 and, hence, the 11kV circuit breaker at the Cromwell zone substation (CB 830) will remain closed. This could ultimately trip the other transformer also because of back feeding to the fault if the two transformers are operated in parallel from the 11kV side. Similar risk also exists for breaker failure conditions at the 1032 and 1092 circuit breakers also, since there is no breaker failure protection at the 1032 and 1092 circuit breakers.
- No dedicated protection is provided at the 33kV Meg generation feeder. This reduces the reliability of the Cromwell zone substation transformer 2 33kV incomer, as it can be lost due to a fault on the 33kV Meg generation transformer unnecessarily.
- The protection setting calculation 103 does not consider the protection coordination with the fuses and other protections installed at the ripple injection unit (connected to 33kV side through isolator 3827). It is recommended to analyse these settings also as there could be potential coordination issues with these protections and the upstream instantaneous Transpower over current protections at the 1032 and 1092 circuit breakers.
- The protection setting calculation no: 103 provided by Aurora dates back to 2006. Subsequently, there has been an arc flash protection retrofit at around 2011 at the Cromwell zone substation. Aurora has modified the protection

setting configuration files to accommodate the arc flash protection at the SEL 351S relays in 2011 (calculation no: 216), however, it’s not clear whether they have revisited the over current and earth fault setting calculations as part of this exercise. Therefore, the existing over current and earth fault settings at the Cromwell GXP and the Cromwell zone substation seems to be set about 12 years ago. Note that the NZ Electricity code requests each AC system asset owner to check the protection settings and coordination every 4 years (Schedule 8.3, Technical Code A, Appendix B).

- All Aurora owned protection relays at the Cromwell zone substation are numerical type. If these relays don’t have self-monitoring, they need to be tested every 4 years, however if they have self-monitoring, the testing only need to be carried out every 10 years (as per NZ electricity code - Schedule 8.3, Technical Code A, Appendix B). However, the measurement circuits of these relays need to be tested every 4 years as per the same code. From the evidence that Aurora provided, these maintenance tests seems not done in line with these time frames.
- The protection setting calculation discussed in calculation no: 103 seems to follow a nonstandard approach referring to fault MVA rather than the fault current. It should be noted that analysis with reference to fault current is the standard practice when analysing current based relays like over current and earth fault protections. The protection coordination analysis also seems to be based on bus fault levels rather than contributions through the individual circuits, which on some occasions can lead to misleading conclusions.

QUEENSTOWN ZONE SUBSTATION

The Queenstown zone substation consists of two 33/11kV, 10/20 MVA transformers feeding several 11kV feeders as per the drawing 3C/04E/073. However, Transpower connections are again omitted from this diagram. As mentioned under Cromwell, all connections to bus bars at all substations should be shown or referred to in the SLD, regardless of who owns those assets. The ownership boundaries, if any, should also be shown in these SLDs, which is also seen to be missing in this SLD.

However, as per the ‘Aurora Energy Asset Management Plan 2006-2016’, the Queenstown substation receives power from Transpower through three 33kV lines from Frankton GXP.

<u>Protection scheme applied for Queenstown Zone substation:</u>

Queenstown 33/11kV zone substation is supplied by two 33/11kV transformers that receives power from three Transpower 33kV connections (33kV incomers).

The transformer 1 is protected by SPAD 346C differential relay, RACID over current and instantaneous earth fault relay (11kV side) and a SEL 751A relay (11kV side). It also has Buchholz, pressure relief and winding temperature protections. The SPAD differential relay also contains 33kV earth fault and restricted earth fault (33kV winding). The RACID relay has over current and instantaneous earth fault protections for 11kV side. A SEL 751A relay is also provided at the 11kV side, which has over current, earth fault and circuit breaker fail protections. The transformer 1 11kV incomer, 11kV bus section (on the transformer 1 side) and the 11kV feeders connected to that bus section are also provided with arc flash protection, which seems to be retrofitted to the transformer 1 / bus 1 side in 2013. The SEL 751A relay, which is also retrofitted in 2013, is used to integrate the 11kV bus arc flash protection with the transformer incomer protection scheme.

At transformer 2, a protection scheme similar to the transformer 1 scheme is employed except for the SEL 751A relay and the 11kV arc flash protection.

Arc flash protection is provided at one section of the 11kV bus bar (transformer 1 side) and at the 11kV circuit breakers on that section only. SEL 751A relays are provided at all the 11kV feeders on transformer 1 side bus section and at the 11kV bus coupler. All feeders are provided with over current, earth fault and circuit breaker fail protection functions.

On all the 11kV feeders on the transformer 2 side bus section, the protection is provided through SPAJ 140C protection relays, which has over current, earth fault and sensitive earth fault protections.

Protection scheme review summary:

The following high level comments can be made regarding the protection scheme at the Queenstown zone substation based on the evidence in the documents mentioned above:

- As with Cromwell, the protection single line diagrams do not describe all associated details in sufficient detail. In SLD 3C/04E/073, the circuit breaker numbers are missing, and also the Transpower connections.
- As per the Access setting database, a number of static ASEA relays (overcurrent and earth fault) are in service at Queenstown zone substation (some of these ASEA relay settings seems not complete in setting data base). However, these relays are not seen in the SLD 3C/04E/073. As per the older setting calculation sheet provided (calculation no: 49), these settings seem to be associated with the three 33kV incoming feeds from Transpower upstream. On the other hand, the setting database does not seem to have the settings related to any of the transformer protection relays (RACID / SPAD 346C).
- As per the SLD 3C/04E/073, the current transformer ratios used with protection relays seems not selected in a logical manner. For example, the CT1 on the 33kV side of transformer 1 have a maximum ratio of 200/1A, while some of the 11kV feeders have CT ratios of 1200/1A. Note that the transformer 1 has a maximum rating of 20 MVA, which means the maximum load current on the 33kV side could be in the order of 350A. This means the CT1 may be overload by about 175% under normal operation even if the 200/1A ratio is used, which could cause damage to the CTs (There was no clear information to determine what is the maximum service load on the transformer based on the supplied data. However, the setting database shows that the over current function on the 11kV side of the same transformer is set at 1200A, which is approximately 120% of the 20 MVA rating of the transformer. This is seen to be about 400 A on the 33kV side of the transformer).
- The setting calculation sheets provided by Aurora dates back to 1994 – 2005. Nevertheless, the setting database shows that with the upgrade of protection systems on the transformer 1 side, a setting revision was also carried out on all the feeders with upgraded protection relays in 2013-14. However, the settings on the older protection relays seems to be still based on the calculations performed around 2005. Also, the protection calculation sheets provided doesn’t seem to verify the CT requirements as part of the setting calculation process. Considering that 5P10 CTs are used in some circuits with very low CT ratios compared to the fault level (As per the data provided, the 3ph fault level on the 33kV side is 5.14 kA in 2013 for example), it is recommended to revisit all the CT requirements at the substation to verify whether they are sufficiently sized to work with the protection relays. Note that the similar type of CTs are also used for restricted earth fault and transformer differential protections also.
- At transformer 1 and 2, only the SPAD346C relays are provided to monitor faults on the 33kV winding. Therefore, if this relay fails, then the transformer 33kV faults are only detected by the relays on the Transpower 33kV incoming feeders. The setting calculation 49 shows that all these three protection relays are set identically and, therefore, could trip at the same time under such a scenario. This could cause an outage at the Queenstown zone substation. It is recommended to have a separate relay on the 33kV side (an OC relay) to minimize the possibility of this occurring.
- Some of the protection settings and calculations at the Queenstown substation are old (>13 years). Note that the NZ Electricity code requests each AC system asset owner to check the protection settings and coordination every 4 years (Schedule 8.3, Technical Code A, Appendix B).
- All Aurora owned protection relays at the Queenstown zone substation are either numerical type or static type. Some of these relays seems to have self-monitoring as per the SCADA point list provided, however some relays (especially the static relays) seems to have no self-monitoring. The relays that don’t have self-monitoring, need to be tested every 4 years, however the ones that have self-monitoring, only need to be tested every 10 years (as per NZ electricity code - Schedule 8.3, Technical Code A, Appendix B). However, the measurement circuits of these relays

need to be tested every 4 years as per the same code. From the evidence that Aurora provided, these maintenance tests seems not done in line with these time frames.

B3 ASSESSMENT OF ENERGY AT RISK BY ZONE SUBSTATION

This section provides additional information for each substation to describe how the energy at risk in section 15 was calculated.

The approach taken calculated the load that would be lost in the case of a single and double transformer outage, adjusted for the probability of each scenario occurring. Table B.1 shows the outcomes of the assessment.

Each of the columns have the following meanings:

— **Year**: the year substation capacity will be exceeded based on current demand and growth forecasts. We note demand forecast are currently being revised.

— **N-1 and Pr(N-1):** the value of energy at risk should one transformer fail excluding and including application of probabilities of failure, respectively. Failure of a transformer is expected to result in a 1 month outage until supply is restored.

— **N-2 and Pr(N-2):** the value of energy at risk should two transformers fail excluding and including application of probabilities of failure, respectively. Failure of a transformer is expected to result in a 1 month outage until supply is restored.

— **Minor and Pr(Minor)**: the value of energy at risk of a minor repairable failure excluding and including application of probabilities of failure, respectively. A minor (repairable failure) outage is assumed to be 1 week.

— **Pr(Risk):** the sum of all probability weighted energy at risk

Table B.1 Zone substation energy at risk analysis ($'M, 2018)

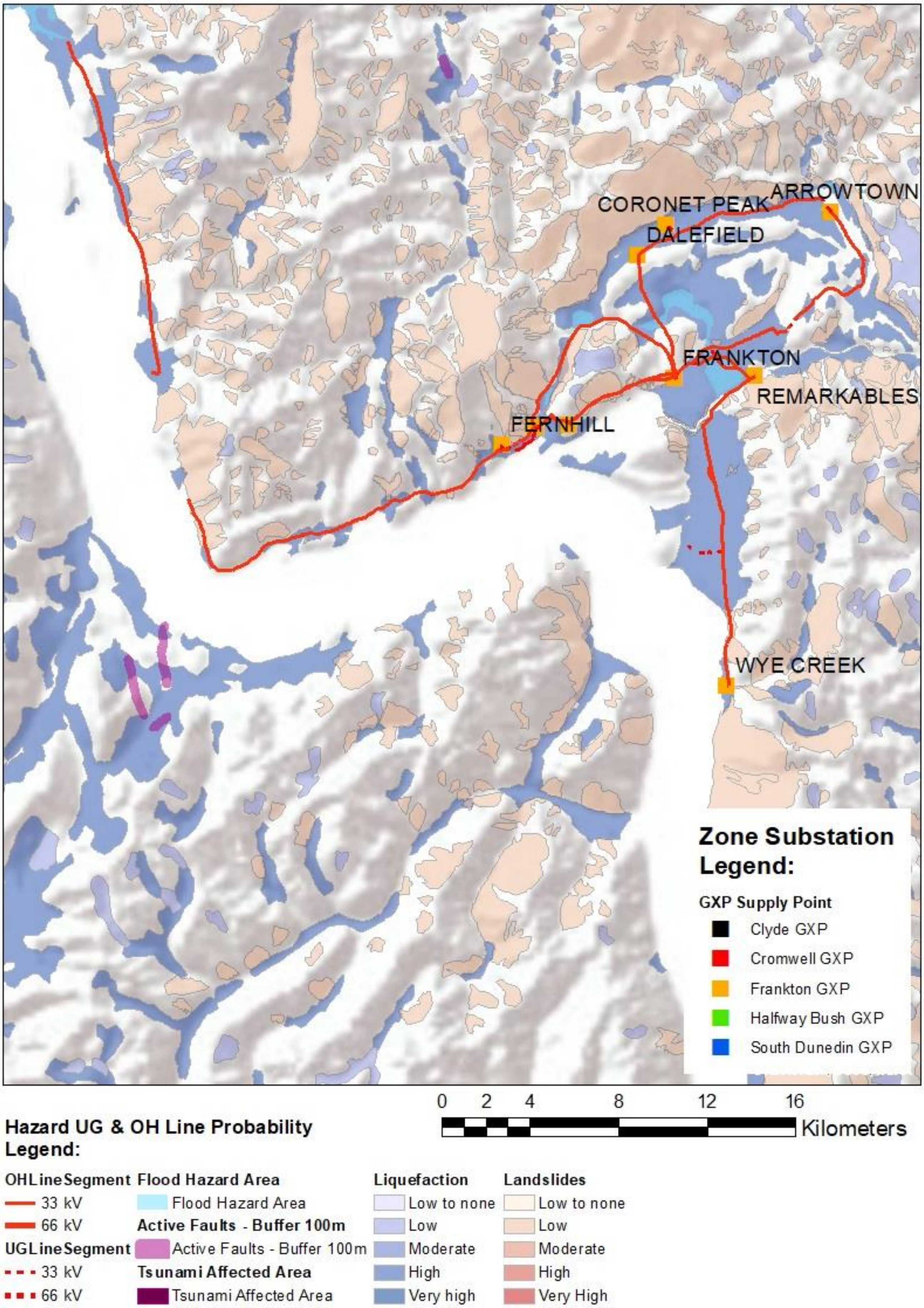
SUBSTATION	YEAR	N-1	N-2	MINOR	Pr(N-1)	Pr(N-2)	Pr(MINOR)	Pr(RISK)
Neville St	>2040	$-	$-	$-	$3.51	$0.38	$0.09	$3.98
Green Island	>2040	$-	$297.9	$6.2	$0.97	$0.15	$0.06	$1.18
Smith St	>2040	$-	$-	$-	$0.97	$0.03	$0.03	$1.04
Andersons Bay	>2040	$-	$351.3	$7.3	$0.63	$0.07	$0.03	$0.73
Port Chalmers	>2040	$-	$90.7	$1.9	$0.49	$0.11	$0.07	$0.66
Willowbank	>2040	$-	$0.5	$0.0	$0.54	$0.01	$0.02	$0.56
Mosgiel	>2040	$-	$0.0	$0.0	$0.33	$0.01	$0.02	$0.35
Remarkables	2020	$79.3	N/A	$3.3	$0.16	N/A	$0.04	$0.20
Omakau	2030	$52.9	N/A	$2.2	$0.12	N/A	$0.03	$0.15
Clyde-Earnscleugh	2045	$1.5	$1.5	$0.1	$0.13	$0.00	$0.02	$0.15
South City	>2040	$-	$4.1	$0.1	$0.09	$0.00	$0.00	$0.10
Dalefield	2042	$6.1	N/A	$0.3	$0.08	N/A	$0.01	$0.09
Corstorphine	>2040	$-	$18.3	$0.4	$0.08	$0.00	$0.00	$0.08

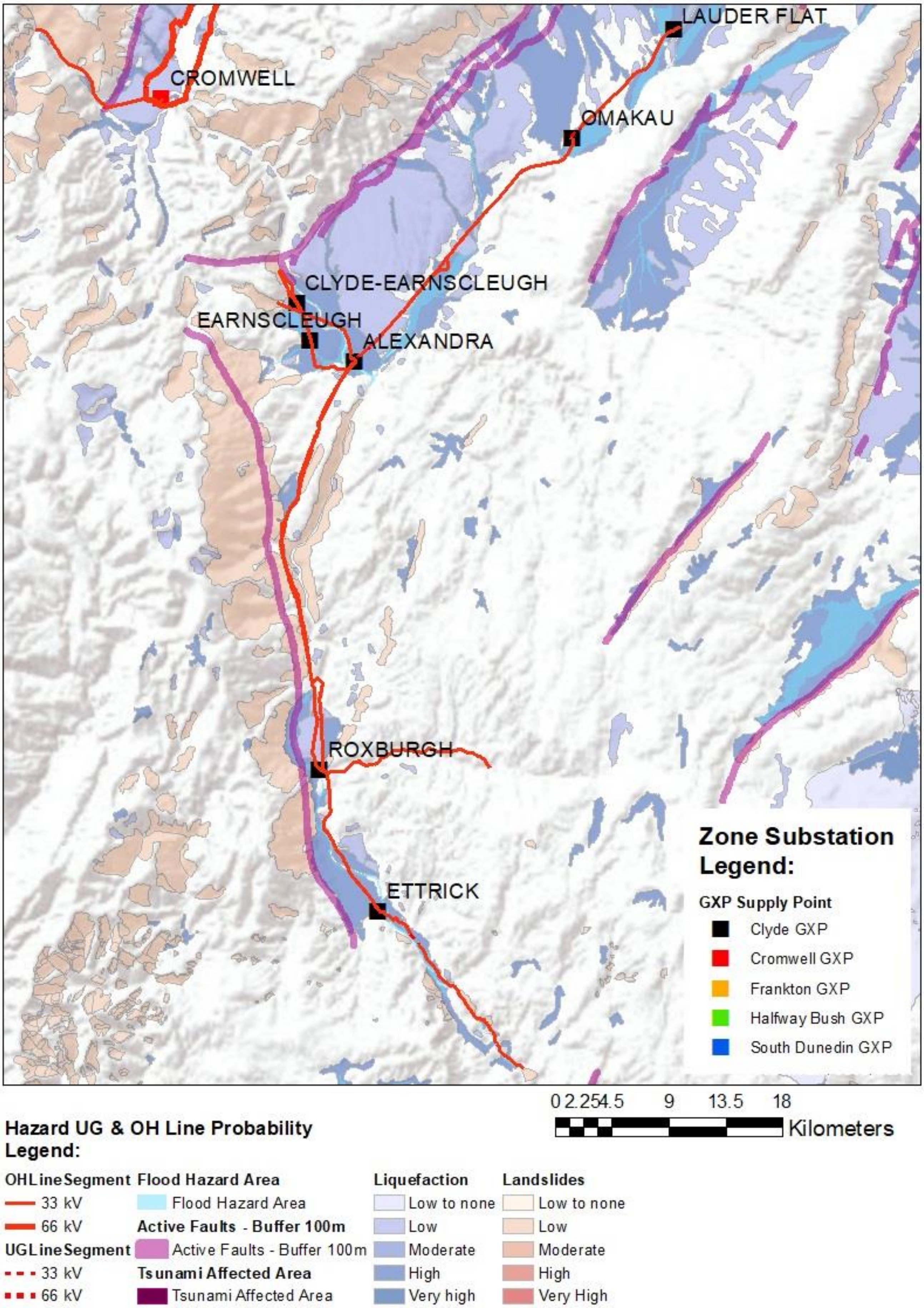
SUBSTATION	YEAR	N-1	N-2	MINOR	Pr(N-1)	Pr(N-2)	Pr(MINOR)	Pr(RISK)
Cromwell	2035	$23.8	$1,160.3	$24.7	$0.06	$0.00	$0.01	$0.07
NORTH EAST VALLEY	>2040	$-	$254.5	$5.3	$0.06	$0.00	$0.00	$0.06
NORTH CITY	>2040	$-	$40.8	$0.9	$0.05	$0.00	$0.00	$0.06
Frankton	2046	$-	$483.7	$10.1	$0.03	$0.00	$0.00	$0.03
KAIKORAI VALLEY	>2040	$-	$-	$-	$0.03	$0.00	$0.00	$0.03
Ettrick	>2040	$0.2	N/A	$0.0	$0.02	N/A	$0.00	$0.02
Lauder Flat	>2040	$0.1	N/A	$0.0	$0.02	N/A	$0.00	$0.02
ST KILDA	>2040	$-	$3.5	$0.1	$0.02	$0.00	$0.00	$0.02
Arrowtown	2027	$31.7	$717.1	$15.6	$0.01	$0.00	$0.00	$0.02
Coronet Peak	>2040	$23.4	N/A	$1.0	$0.01	N/A	$0.00	$0.01
Alexandra	>2040	$-	$854.0	$17.8	$0.01	$0.00	$0.00	$0.01
Queenstown	>2040	$-	$35.4	$0.7	$0.00	$0.00	$0.00	$0.00
Queensberry	2039	$45.5	$45.5	$1.9	$0.00	$0.00	$0.00	$0.00
Fernhill	>2040	$-	$5.1	$0.1	$0.00	$0.00	$0.00	$0.00
Wanaka	>2040	$-	$1,696.2	$35.3	$0.00	$0.00	$0.00	$0.00
Commonage	>2040	$-	$2.7	$0.1	$0.00	$0.00	$0.00	$0.00
BERWICK	>2040	$3.6	N/A	$0.2	$0.00	N/A	$0.00	$0.00
WARD ST	>2040	$-	$0.0	$0.0	$0.00	$0.00	$0.00	$0.00
Cardrona	2037	$17.8	N/A	$0.7	$0.00	N/A	$0.00	$0.00
HALFWAY BUSH	>2040	$-	$100.4	$2.1	$0.00	$0.00	$0.00	$0.00
Roxburgh	>2040	$13.7	N/A	$0.6	$0.00	N/A	$0.00	$0.00
Lindis Crossing	2030	$253.5	N/A	$10.6	$0.00	N/A	$0.00	$0.00
Camphill	>2040	$227.3	N/A	$9.5	$0.00	N/A	$0.00	$0.00

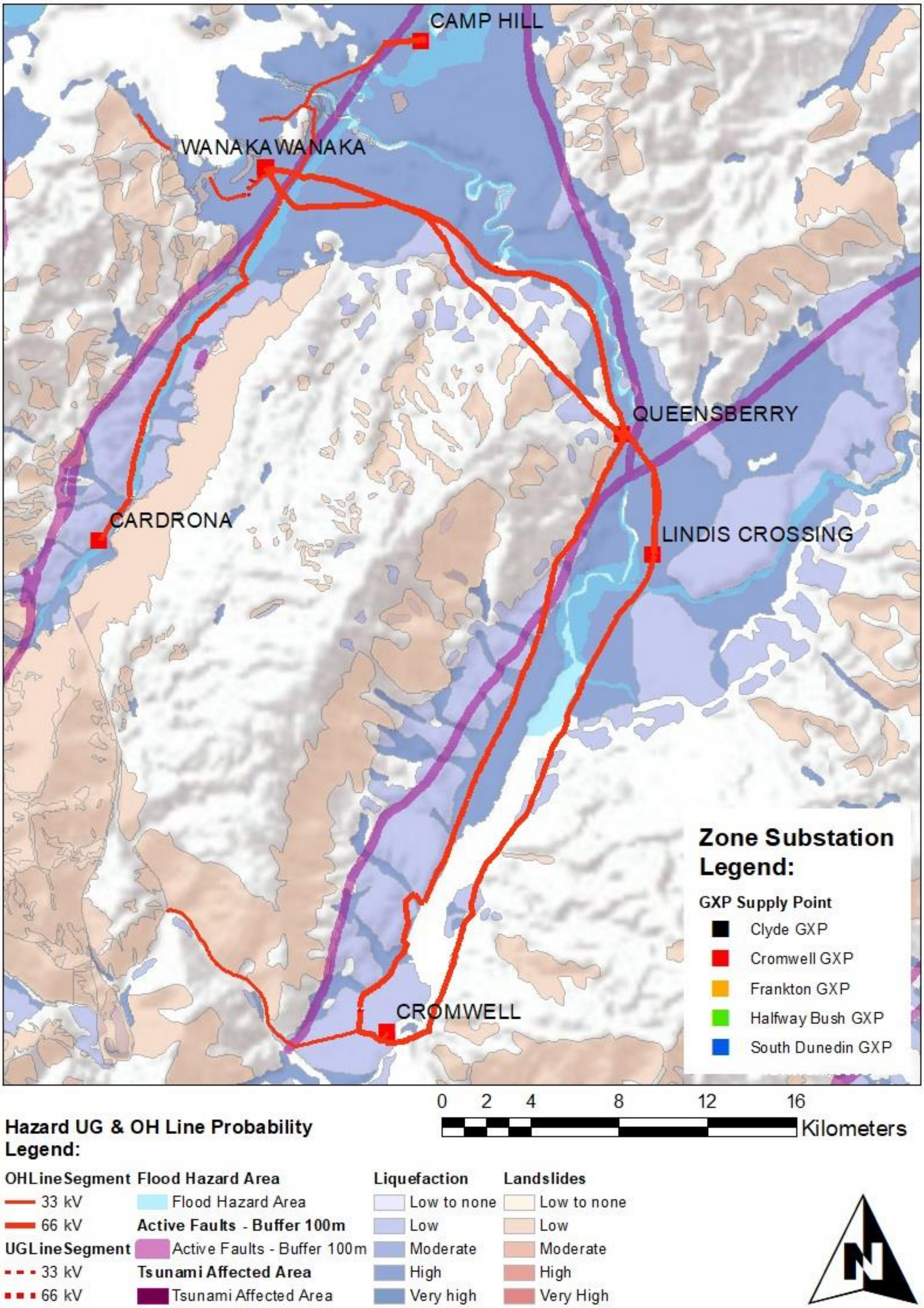
APPENDIX C

RESILIENCE MAPS

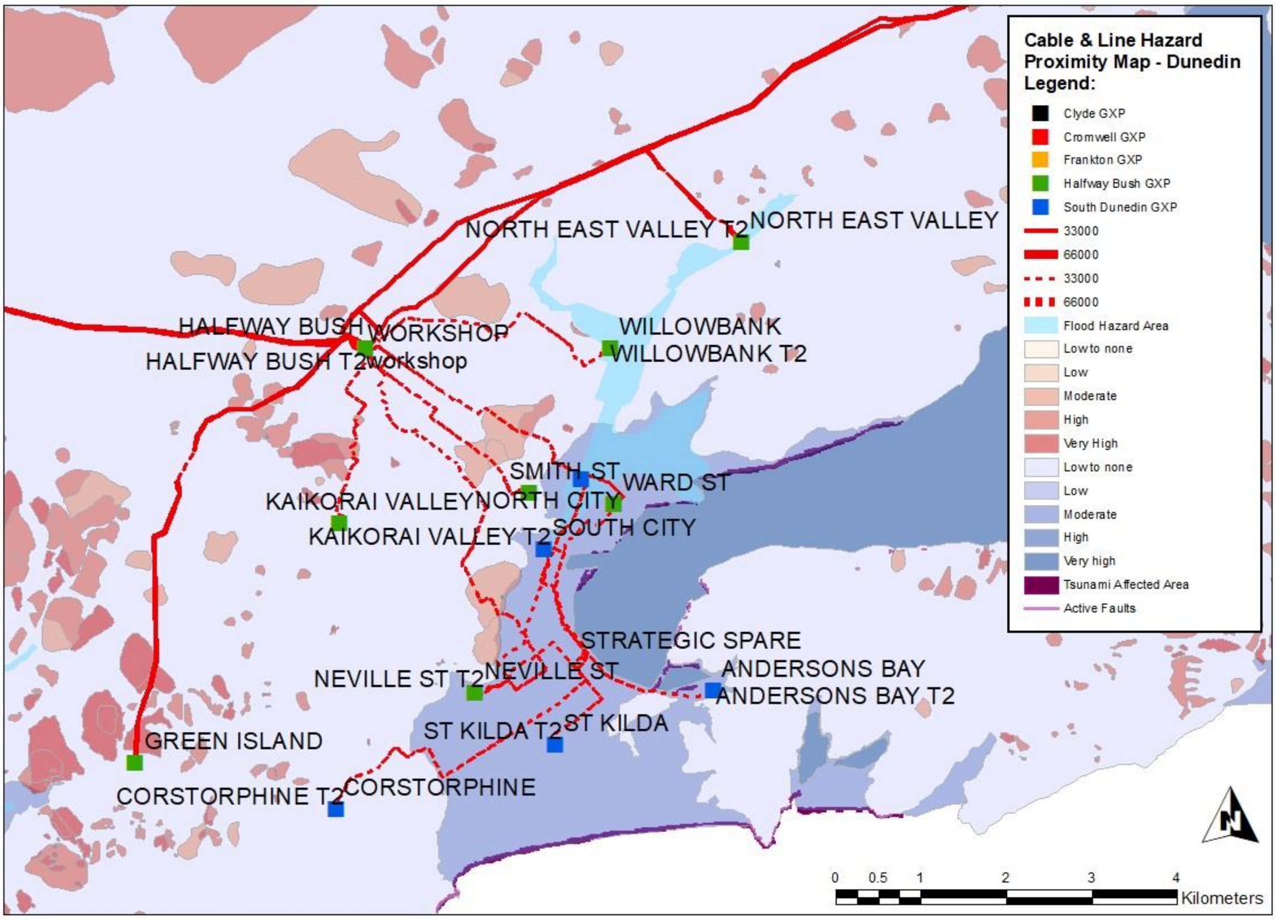
This appendix contains maps showing details of Aurora's key network assets and their proximity to Earthquake fault lines, Tsunami affected areas, Seismic liquefaction potential, Landslides, and Flood areas.

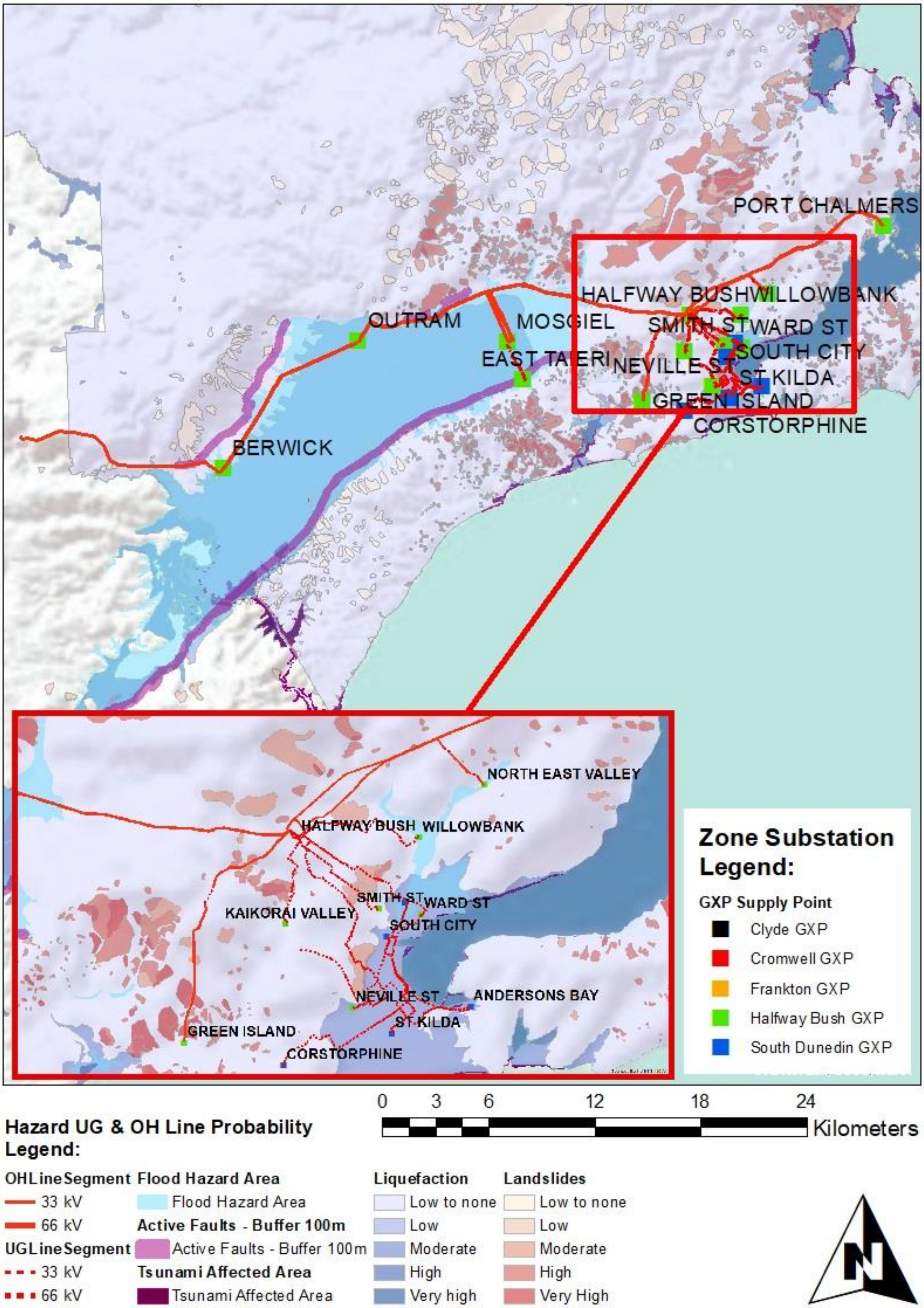

CORONET PEAK
ARROWTOWN
DALEFIELD
FRANKTON
REMARKABLES
FERNHILL
WYE CREEK
Zone Substation Legend:
GXP Supply Point
Clyde GXP
Cromwell GXP
Frankton GXP
Halfway Bush GXP
South Dunedin GXP
0 2 4 8 12 16
Kilometers
Hazard UG & OH Line Probability Legend:
OHLineSegment
33 kV
66 kV
UGLineSegment
33 kV
66 kV
Flood Hazard Area
Flood Hazard Area
Active Faults - Buffer 100m
Active Faults - Buffer 100m
Tsunami Affected Area
Tsunami Affected Area
Liquefaction
Low to none
Low
Moderate
High
Very high
Landslides
Low to none
Low
Moderate
High
Very High


LAUDER FLAT
CROMWELL
OMAKAU
CLYDE-EARNSCLEUGH
EARNSCLEUGH
ALEXANDRA
ROXBURGH
ETTRICK
Zone Substation Legend:
GXP Supply Point
Clyde GXP
Cromwell GXP
Frankton GXP
Halfway Bush GXP
South Dunedin GXP
0 2.25 4.5 9 13.5 18
Kilometers
Hazard UG & OH Line Probability Legend:
OHLineSegment
33 kV
66 kV
UGLineSegment
33 kV
66 kV
Flood Hazard Area
Flood Hazard Area
Active Faults - Buffer 100m
Active Faults - Buffer 100m
Tsunami Affected Area
Tsunami Affected Area
Liquefaction
Low to none
Low
Moderate
High
Very high
Landslides
Low to none
Low
Moderate
High
Very High


CAMP HILL
WANAKAWANAKA
QUEENSBERRY
CARDRONA
LINDIS CROSSING
CROMWELL
Zone Substation Legend:
GXP Supply Point
Clyde GXP
Cromwell GXP
Frankton GXP
Halfway Bush GXP
South Dunedin GXP
0 2 4 8 12 16
Kilometers
Hazard UG & OH Line Probability Legend:
OHLineSegment
33 kV
66 kV
UGLineSegment
33 kV
66 kV
Flood Hazard Area
Flood Hazard Area
Active Faults - Buffer 100m
Active Faults - Buffer 100m
Tsunami Affected Area
Tsunami Affected Area
Liquefaction
Low to none
Low
Moderate
High
Very high
Landslides
Low to none
Low
Moderate
High
Very High
N


NORTH EAST VALLEY
HALFWAY BUSH
WILLOWBANK
SMITH ST
WARD ST
KAIKORAI VALLEY
SOUTH CITY
NEVILLE ST
ANDERSONS BAY
ST KILDA
GREEN ISLAND
CORSTORPHINE
Sources: Esri, USGS, NOAA


Cable & Line Hazard Proximity Map - Dunedin
Legend:
Clyde GXP
Cromwell GXP
Frankton GXP
Halfway Bush GXP
South Dunedin GXP
33000
66000
33000
66000
Flood Hazard Area
Low to none
Low
Moderate
High
Very High
Low to none
Low
Moderate
High
Very high
Tsunami Affected Area
Active Faults
NORTH EAST VALLEY T2
NORTH EAST VALLEY
HALFWAY BUSH
WORKSHOP
HALFWAY BUSH T2
workshop
WILLOWBANK
WILLOWBANK T2
SMITH ST
WARD ST
KAIKORAI VALLEY
NORTH CITY
KAIKORAI VALLEY T2
SOUTH CITY
STRATEGIC SPARE
NEVILLE ST T2
NEVILLE ST
ANDERSONS BAY
ANDERSONS BAY T2
GREEN ISLAND
ST KILDA T2
ST KILDA
CORSTORPHINE T2
CORSTORPHINE
0 0.5 1 2 3 4
Kilometers


PORT CHALMERS
HALFWAY BUSH
WILLOWBANK
OUTRAM
MOSGIEL
SMITH ST
WARD ST
EAST TAIERI
NEVILLE ST
SOUTH CITY
ST KILDA
GREEN ISLAND
CORSTORPHINE
BERWICK
NORTH EAST VALLEY
KAIKORAI VALLEY
ANDERSONS BAY
Zone Substation Legend:
GXP Supply Point
Clyde GXP
Cromwell GXP
Frankton GXP
Halfway Bush GXP
South Dunedin GXP
0 3 6 12 18 24
Kilometers
Hazard UG & OH Line Probability Legend:
OHLineSegment
33 kV
66 kV
UGLineSegment
33 kV
66 kV
Flood Hazard Area
Flood Hazard Area
Active Faults - Buffer 100m
Active Faults - Buffer 100m
Tsunami Affected Area
Tsunami Affected Area
Liquefaction
Low to none
Low
Moderate
High
Very high
Landslides
Low to none
Low
Moderate
High
Very High
N

APPENDIX D

QUANTITATIVE MODELLING APPROACH DETAILS

D1 MODELLING PROBABILITY OF FAILURE

This section sets out the risk assessment modelling approach used by WSP in its analysis. It uses poles as an example.

WEIBULL MODEL

Weibull survivor curve analysis has been undertaken based on historical replacement data and the current asset age profile. This approach used historical replacement data to calculate a Weibull distribution function. The Weibull distribution parameters are then used to calculate the cumulative distribution function and subsequently the conditional probability of failure, that is, the probability of failing in year (t+1) given that it has survived until year (t).

The calculation of the Weibull curve was undertaken using historical asset failure data to calculate a probability density function that is then applied to calculate the conditional probability of an assets failure in a given year. The Weibull curve is used as it is accepted and commonly used in industry to model asset failures.

Figure D.1 shows the calculated Weibull distribution plotted against the corresponding asset failure data set. A goodness of fit test is undertaken to ensure the distribution is appropriate for use.

Where historical asset data isn't available, we use the expected life of the asset and set the shape factor to provide a reasonable probability of failure based on engineering judgement. If historical replacement volumes are known, we use them to calibrate the curve.

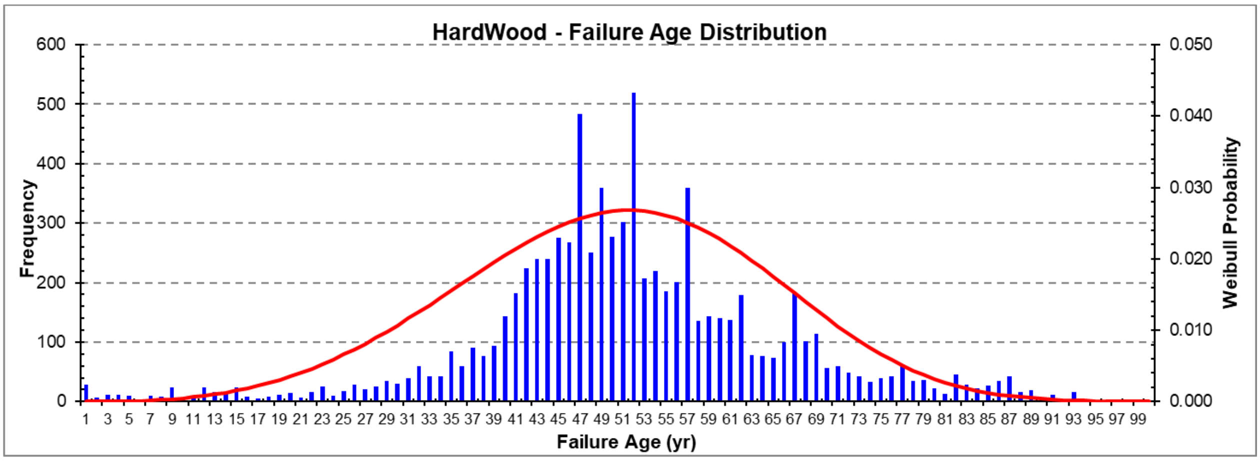


Figure D.1 Weibull distribution plotted against the data sample – Hardwood poles

The conditional probability (shown as the failure rate in the curve below) was then applied to assess the Probability of Failure for each asset.

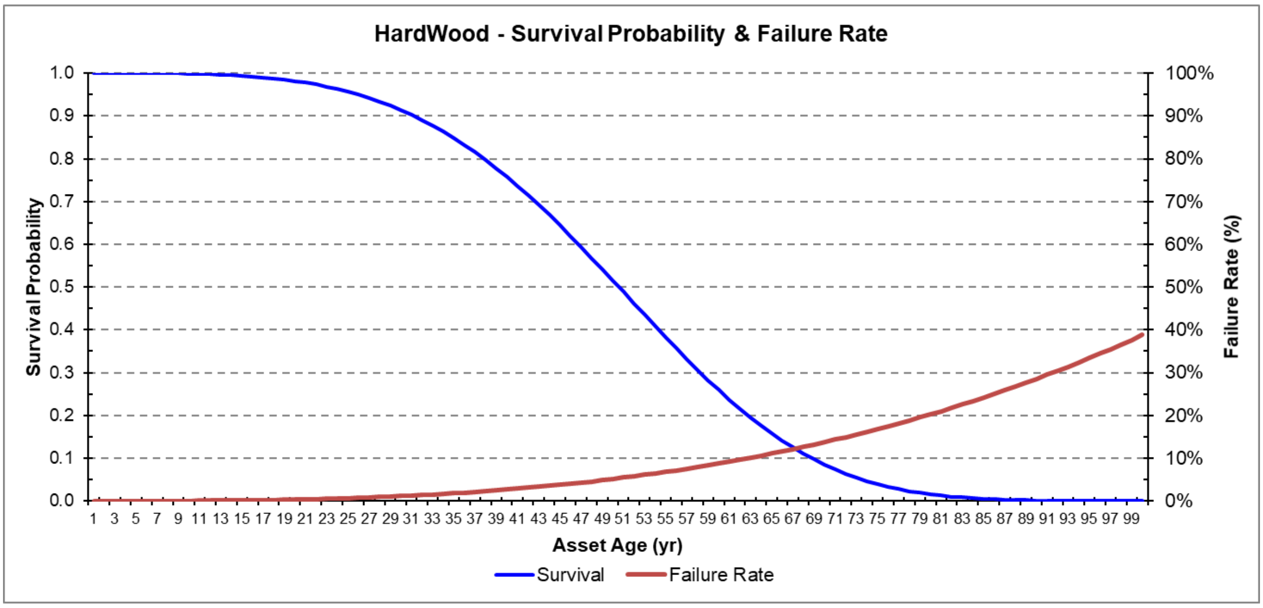


Figure D.2 Conditional probability of failure survival curve – Hardwood poles

Use and limitations of this approach:

The conditional probability of failure survival curve was used to assign a Probability of Failure to each asset on the network based on its age. When combined with the Consequence of Failure, this can then quantify the risk across the network.

The curve was also applied to the whole of network age profile to calculate the expected volume of assets that would need to be replaced in the during the next year. This allowed us to make a comparison of this approach to other alternative approaches that may have been available for the asset class.

KEY ASSUMPTIONS IN OUR MODELLING

Key assumptions used in this analysis are:

- The end of life assessment undertaken by Aurora was reasonably accurate and resulted in replacement of appropriately deteriorated assets that had reached their end of life. The Weibull parameters that were derived (characteristic age and shape factor) are reasonable when compared to industry guidelines and common practice in electricity businesses in Australia and New Zealand.
- The age of assets is reasonably accurate. Most businesses have some uncertainty in the age of assets.
- The analysis results derived for assets are not affected by past decisions. Past decision to undertake targeted replacement programs can skew the calculation of the Weibull parameters.
- The asset data is sufficiently complete to provide a reasonable estimate within the limitation of the accuracy of our report.

ADVANCED TECHNIQUES

Exploratory descriptive data analysis was the first step of the process in which relationships between key variables were examined. Based on the initial steps, it was evident that the data was noisy, and that pole age alone would not be able to explain all the variance in the data. This process was repeated with several variables such as pole diameter and timber strength.

Linear regression and neural network models were used to examine the data and develop a greater understand the effect of different variables on remaining pole life. The fitting process involved splitting the data into training and test data sets with the model being fit on the training data set and then tested on the test data set to avoid over fitting. Over fitting occurs when the model predicts the results of the training data set extremely well but does not predict very well for data outside of the training data set and, therefore, is not useful as a general predictive tool.

Neural networks were found to overfit the data, whereas linear regression performed better and provided greater insight into which variables were significant.

Regression involves fitting a straight line to the variables in the data with dummy variables added for categorical features such as timber strength. In short, the process aims to find the coefficients (β_n) to an equation like the one shown below such that it reduces the error between predicted and actual values. The output is the predicted value for the remaining pole life or the degree of degradation.

$$Output = \beta_0 + \beta_1 \times Pole\ age + \beta_2 \times Pole\ age^2 + \beta_3 \times Timber\ Strength - S1 + \cdots .. + \beta_n x_n$$

An initial fit was found, and statistical tests were performed on the coefficients to determine whether they were significant. This tested the probability that the relationship was between the variables was simply random or had a significant impact on the output.

The initial model found the following factors to be significant in determining both the remaining pole life and degree of degradation:

- Pole Diameter (larger diameter indicated longer life)
- Pole Age (younger poles had a longer life ahead of them)
- Timber Species strength group (S1 and S2 timbers performed better than the others)
- Network (Dunedin poles performed better)
- Pole Area (cross sectional area of each pole)

For predicting the remaining pole life, the model had an r-squared = 0.41, and a mean absolute error (MAE) of 15 years on the test data which the model had never seen before.

For predicting the degree of degradation, the model had an r-squared = 0.21, and a mean absolute error (MAE) of 17 degree of degradation percentages on the test data which the model had never seen before.

To improve the fit of the model additional variables were needed which would also be available for poles that had not been tested. Using the location data of the poles, environmental data from the NZ Land Resource Information Centre was spatially joined to the poles. The following pieces of additional information was added to the poles.

- 2013 annual rainfall
- Mean annual temperature
- Slope
- Mean annual solar radiation
- October Vapor Pressure Deficit
- Mean minimum temperature of the coldest month
- New Zealand Fundamental Soil Layer All Attributes.

The regression model was then refit using the new attributes. Interaction variables were also added to account for certain variables increasing the rate of decay e.g. $Pole\ Age \times Pole\ Diameter$ was found to be a significant variable.

The addition of spatial data reduced the mean absolute error of our predictions, however many of the GIS datasets were too coarse to explain a significant amount of variance. For example, the entirety of Dunedin was classed as having the same soil type in the NZ Fundamental Soil Layer. Nevertheless, both mean minimum temperature of the coldest month and mean annual solar radiation were found to have some significance on the results, albeit minor.

The improved model for remaining life had a MAE of 13 years on unseen data and an R-squared of 0.41, and the improved model for degree of degradation had a MAE of 15 degree of degradation percent on unseen data and an R-squared of 0.21.

Considering the highly variable nature of natural timbers the initial results were promising. It is expected that the addition of further explanatory variables will improve the fit.

APPENDIX E

TRANSFORMER DATA TABLES

TRANSFORMER DISOLVED GAS ANALYSIS RESULTS

The transformer DGA test results were analysed for trends and indications of end of life. One of the key indicators for transformer condition is the DP value which indicates the strength of the internal paper insulation and is a primary determinant for when a transformer has reached end of life. A DP value of 1000 is considered new and a DP value of 200 is considered end of life.

The lowest test result for each transformer is shown in Table E.1. It indicates that Roxburgh ZSS (a new transformer has been installed so the result tabulated is probably related to its predecessor) and Remarkables ZSS have the lowest DP values, but these are still above 400 and indicate there is still a reasonable amount of remaining life under normal operating condition. However, for the age of these transformers, the DP results look optimistically high and they should be treated as an indicative result.

Table E.1 Transformer DGA results

ZONE SUBSTATION	T1	T2
Alexandra	807	934
Andersons Bay	747	815
Arrowtown	924	968
Berwick	953	
Clyde-Earnscleugh	746	701
Coronet Peak	739	
Corstorphine	783	831
Cromwell	876	581
Dalefield	743	
Earnscleugh	663	
East Taieri	694	699
Ettrick	731	
Fernhill		777
Frankton	682	966
Green Island	716	668
Halfway Bush	797	843
Kaikorai Valley	762	893
Mosgiel	813	675
Neville St	545	543
North City	831	789
North East Valley	936	892
Omakau	695	
Outram	544	517
Queenstown	835	583

ZONE SUBSTATION	T1	T2
Remarkables	480	
Roxburgh		413
Smith St	773	757
South City	771	788
St Kilda	912	887
Willowbank	762	797
Grand Total	480	413

TAP CHANGER MAINTENANCE BACKLOG

Most of the inspection and test reports were from a period between 2014 and 2017, however there some from 2010 and 2002. Each tap changer type has its own maintenance cycle based on the number of operation or the time elapsed since the last inspection.

Table E.2 shows a s complete list of the tap changers that are behind on their required maintenance schedule. It shows that half the switches overdue based on the time requirement are also overdue based on the number of operations since the overhaul.

The maintenance schedule did not contain Willowbank ZSS or Earnscleugh ZSS.

Table E.2 Tap changer maintenance and overhaul backlog

TRANSFORMER	YEARS UNTIL OVERHAUL	PAST OPERATIONS THRESHOLD
Remarkables T1 New (Ex Omakau)	-6.4	1
Omakau T1 New	-6.4	
Cromwell T1	-5.4	1
Cromwell T2	-4.8	1
Dalefield T1	-3.4	1
Lindis Crossing T1	-2.9	
Outram T2	-2.9	1
Clyde-Earnscleugh T2	-2.9	1
St Kilda T1	-2.5	
Fernhill T1	-2.5	
Fernhill T2	-2.5	
Outram T1	-2.4	
Kaikorai Valley T1	-2.4	
Kaikorai Valley T2	-2.4	
North City T1	-2.3	1

TRANSFORMER	YEARS UNTIL OVERHAUL	PAST OPERATIONS THRESHOLD
North East Valley T1	-2.3	1
North City T2	-2.2	
Green Island T1	-1.9	
Queenstown T2	-1.7	
Mosgiel T1	-1.7	
Mosgiel T2	-1.7	
Wanaka T2	-1.7	
Queensberry T1	-1.6	
Port Chalmers T2	-1.5	
Green Island T2	-0.9	1
Arrowtown T1	-0.9	
Arrowtown T2	-0.9	1
Coronet Peak T1	-0.8	
East Taieri T1	-0.7	
Port Chalmers T1	-0.7	1
East Taieri T2	-0.6	1
Wanaka T1	-0.6	
Neville St Tx 3 Auto (Reactor)	-0.5	1
Neville St Tx 4 Auto (Reactor)	-0.4	1
Neville St T2	-0.4	
Andersons Bay T1	-0.4	1
Cardrona T1	-0.4	
Andersons Bay T2	-0.4	
Corstorphine T1	-0.1	
Corstorphine T2	-0.1	
Smith St T1	0.0	
Ettrick T1	0.2	
Frankton T1	0.3	1
North East Valley T2	0.4	
Smith St T2	0.4	
South City T1	0.4	
South City T3	0.5	
Queenstown T1	1.3	

TRANSFORMER	YEARS UNTIL OVERHAUL	PAST OPERATIONS THRESHOLD
Alexandra T1	1.3	
Alexandra T2	1.3	
Neville St T1	1.5	
Lauder T1 (Ex Maungawera)	2.0	
Commonage T1	6.1	
Commonage T2	6.1	
Frankton T2	7.8	
Berwick T1	8.4	
Halfway Bush T1	8.6	
Ward St T1	8.6	
Halfway Bush T2	9.2	
Roxburgh T1	9.7	
Camphill T1	12.1	

ENERGY AT RISK INFORMATION

This section provides additional information for each substation to describe how the energy at risk in section 15 was calculated. Note, that the calculation only considers the transformers. The risk from the switchgear is discussed in section 16.

The approach taken calculated the load that would be lost in the case of a single and double transformer outage, adjusted for the probability of each scenario occurring.

Table E.3 shows the outcomes of the assessment.

Each of the columns have the following meanings:

- **Year**: the year substation capacity will be exceeded based on current demand and growth forecasts. We note demand forecast are currently being revised
- **N-1 and Pr(N-1):** the value of energy at risk should one transformer fail excluding and including application of probabilities of failure, respectively. Failure of a transformer is expected to result in a 1 month outage until supply is restored
- **N-2 and Pr(N-2):** the value of energy at risk should two transformers fail excluding and including application of probabilities of failure, respectively. Failure of a transformer is expected to result in a 1 month outage until supply is restored
- **Minor and Pr(Minor)**: the value of energy at risk of a minor repairable failure excluding and including application of probabilities of failure, respectively. A minor (repairable failure) outage is assumed to be 1 week
- **Pr(Risk):** the sum of all probability weighted energy at risk.

Table E.3 Zone substation energy at risk analysis ($'M, 2018)

SUBSTATION	YEAR	N-1	N-2	MINOR	Pr(N-1)	Pr(N-2)	Pr(MINOR)	Pr(RISK)
Neville St	>2040	$-	$-	$-	$3.51	$0.38	$0.09	$3.98
Green Island	>2040	$-	$297.9	$6.2	$0.97	$0.15	$0.06	$1.18
Smith St	>2040	$-	$-	$-	$0.97	$0.03	$0.03	$1.04
Andersons Bay	>2040	$-	$351.3	$7.3	$0.63	$0.07	$0.03	$0.73
Port Chalmers	>2040	$-	$90.7	$1.9	$0.49	$0.11	$0.07	$0.66
Willowbank	>2040	$-	$0.5	$0.0	$0.54	$0.01	$0.02	$0.56
Mosgiel	>2040	$-	$0.0	$0.0	$0.33	$0.01	$0.02	$0.35
Remarkables	2020	$79.3	N/A	$3.3	$0.16	N/A	$0.04	$0.20
Omakau	2030	$52.9	N/A	$2.2	$0.12	N/A	$0.03	$0.15
Clyde-Earnscleugh	2045	$1.5	$1.5	$0.1	$0.13	$0.00	$0.02	$0.15
South City	>2040	$-	$4.1	$0.1	$0.09	$0.00	$0.00	$0.10
Dalefield	2042	$6.1	N/A	$0.3	$0.08	N/A	$0.01	$0.09
Corstorphine	>2040	$-	$18.3	$0.4	$0.08	$0.00	$0.00	$0.08
Cromwell	2035	$23.8	$1,160.3	$24.7	$0.06	$0.00	$0.01	$0.07
North East Valley	>2040	$-	$254.5	$5.3	$0.06	$0.00	$0.00	$0.06
North City	>2040	$-	$40.8	$0.9	$0.05	$0.00	$0.00	$0.06
Frankton	2046	$-	$483.7	$10.1	$0.03	$0.00	$0.00	$0.03
Kaikorai Valley	>2040	$-	$-	$-	$0.03	$0.00	$0.00	$0.03
Ettrick	>2040	$0.2	N/A	$0.0	$0.02	N/A	$0.00	$0.02
Lauder Flat	>2040	$0.1	N/A	$0.0	$0.02	N/A	$0.00	$0.02
St Kilda	>2040	$-	$3.5	$0.1	$0.02	$0.00	$0.00	$0.02
Arrowtown	2027	$31.7	$717.1	$15.6	$0.01	$0.00	$0.00	$0.02
Coronet Peak	>2040	$23.4	N/A	$1.0	$0.01	N/A	$0.00	$0.01
Alexandra	>2040	$-	$854.0	$17.8	$0.01	$0.00	$0.00	$0.01
Queenstown	>2040	$-	$35.4	$0.7	$0.00	$0.00	$0.00	$0.00
Queensberry	2039	$45.5	$45.5	$1.9	$0.00	$0.00	$0.00	$0.00
Fernhill	>2040	$-	$5.1	$0.1	$0.00	$0.00	$0.00	$0.00
Wanaka	>2040	$-	$1,696.2	$35.3	$0.00	$0.00	$0.00	$0.00
Commonage	>2040	$-	$2.7	$0.1	$0.00	$0.00	$0.00	$0.00
Berwick	>2040	$3.6	N/A	$0.2	$0.00	N/A	$0.00	$0.00
Ward St	>2040	$-	$0.0	$0.0	$0.00	$0.00	$0.00	$0.00
Cardrona	2037	$17.8	N/A	$0.7	$0.00	N/A	$0.00	$0.00

SUBSTATION	YEAR	N-1	N-2	MINOR	Pr(N-1)	Pr(N-2)	Pr(MINOR)	Pr(RISK)
Halfway Bush	>2040	$-	$100.4	$2.1	$0.00	$0.00	$0.00	$0.00
Roxburgh	>2040	$13.7	N/A	$0.6	$0.00	N/A	$0.00	$0.00
Lindis Crossing	2030	$253.5	N/A	$10.6	$0.00	N/A	$0.00	$0.00
Camphill	>2040	$227.3	N/A	$9.5	$0.00	N/A	$0.00	$0.00

APPENDIX F

PRIORITISED LIST OF RISKS

F1 RISK PRIORITISATION

The results from the risk assessment for each asset class, as set out in sections 8 to 17, were used to determine the prioritised list of risks to be addressed. Table F.1 sets out WSPs prioritised list of assets. The prioritisation levels used in the tables can be interpreted as reflected in Figure D.1, which indicates the prioritisation levels against the risk matrix set out in section 4.1.3. Only the critical risks were considered as the objective is to manage risk to the moderate risk category which is considered acceptable.

Figure F.1 Prioritisation level against risk matrix

	Increasing consequence (criticality) -->				
Prob of Failure -->		8	4	2	1
			7	3	2
			8	5	4
				7	5
				8	7

The prioritisation list in Table F.1 sets out the preferred approach based on information available and the network configuration at the time of issuing this report. Should new information become available or should an outage force reconfiguration of the network, it may be necessary to reassess the prioritisation of the risks.

When considering the prioritisation, we note that there are interdependencies between the options. For example, accepting the risk of sub transmission cables, means that the risk resulting from a transformer failure needs to be reassessed as the assumption regarding available spare capacity in the network may not be valid.

A further prioritised list for Distribution Switchgear and specifically the risk around L&C and Statter RMU's is provided in Table F.2. Refer section 9 of this report for details on this risk area.

Table F.1 Prioritised list of assets

ASSET CLASS	POLE/ITEM	DESCRIPTION	NUMBER	RISK TYPE	PRIORITY
Protection systems	Alexandra zone sub	Performance issues with 'other' old electromechanical relays.	19	SAFETY	2
Protection systems	Andersons Bay zone sub	Performance issues with AKA, PBO, FGL and other electromechanical relays. Soon to be decommissioned.	58	SAFETY	2
Protection systems	Battery and charger systems	There is typically only one battery bank and charger at each zone substation, there is no standard size, type or capacity.	39	SAFETY	2
Protection systems	Co-ordination of the protection system and schemes	Review and update of protection calculations, input variables (i.e. fault levels), coordination or protection schemes and use of fuses	1	SAFETY	2
Protection systems	Corstorphine zone sub	Performance issues with TCD5 and other electromechanical relays.	54	SAFETY	2
Protection systems	Green Island zone sub	Performance issues with AKA, PBO, FGL, other electromechanical relays. Soon to be decommissioned.	55	SAFETY	2
Protection systems	Halfway Bush GXP	4 high risk electromechanical relays.	7	SAFETY	2
Protection systems	Instrument transformers	Instrument transformers are in an unknown condition. Recent failure of testing at Green Island indicate elevated level of risk with this asset class.	39	SAFETY	2
Protection systems	Neville St zone sub	Performance issues with AKA, PBO, FGL, other electromechanical relays. Soon to be decommissioned.	64	SAFETY	2
Protection systems	North City zone sub	2 high risk electromechanical relays.	29	SAFETY	2

ASSET CLASS	POLE/ITEM	DESCRIPTION	NUMBER	RISK TYPE	PRIORITY
Protection systems	Queenstown zone sub	Performance issues with 'other' old numerical and electromechanical relays.	23	SAFETY	2
Protection systems	Smith St zone sub	Performance issues with TCD5 and other electromechanical relays.	59	SAFETY	2
Protection systems	South City zone sub	Performance issues with TCD5 and other electromechanical relays.	68	SAFETY	2
Protection systems	St Kilda zone sub	Performance issues with TCD5 and TJM10 and other electromechanical relays.	52	SAFETY	2
Protection systems	Ward St zone sub	2 high risk electromechanical relays.	25	SAFETY	2
Protection systems	Willowbank zone sub	Performance issues with AKA, PBO, FGL, other electromechanical relays. Soon to be decommissioned.	55	SAFETY	2
Zone substation circuit breakers	Alexandra ZSS Circuit Breakers	HKK and HLC circuit breakers are not maintained internally.	14	RELIABILITY/ SAFETY	2
Zone substation circuit breakers	Arrowtown ZSS Circuit Breakers	HKK circuit breakers are not maintained internally.	2	RELIABILITY/ SAFETY	2
Zone substation circuit breakers	Green Island ZSS Circuit Breakers	61 year old Cooke and Ferguson oil circuit breakers exceeding the expected life of 50 years. Have not been maintained within the maintenance schedule.	15	RELIABILITY/ SAFETY	2
Zone substation circuit breakers	Outram ZSS Circuit Breakers	57 year old circuit breakers are exceeding the expected life of 50 years, including 2 VWVE type which have an elevated risk due to modifications when installed.	10	RELIABILITY/ SAFETY	2

ASSET CLASS	POLE/ITEM	DESCRIPTION	NUMBER	RISK TYPE	PRIORITY
Distribution cables	Cast iron potheads	455 cast iron potheads are installed on the Dunedin network. These have an elevated risk to safety. 145 have priority 3, 127 have priority 7 and the remainder are low risks.	455	SAFETY	3
Distribution switchgear	Statter distribution switchgear	List provided	5	RELIABILITY/ SAFETY	3
Overhead distribution lines	Aged light copper conductor	Aged light copper conductor in distribution lines (HV and LV) 500m to 5km to the coast. Volumes hae been modelled based on survival curve, but individual assets to be identified through normal inspection process.	9.7km	SAFETY/RELI ABILITY	3
Support structures	Malaysian hardwood crossarms	Hazard posed by Malaysion hardwood cross arms. Estimated volume based on interviews and available data. Individual assets to be identified through normal inspection process.	~3,600	SAFETY	3
Support structures	Improvement to testing and inspection processes	Assessment of pole strength, particularly concrete poles, to enable improved condition assessment accuracy.	Fleet wide	SAFETY	3
Support structures	Remediation of high risk crossarms	Modelled volume of high risk crossarms based on Drone inspections. Individual assets to be identified through normal inspection process.	2142	SAFETY	3

ASSET CLASS	POLE/ITEM	DESCRIPTION	NUMBER	RISK TYPE	PRIORITY
Support structures	Remediation of high risk poles	Expected number of high risk poles on the network. These are predominately termination and Tee-Off poles in high population areas. Individual assets to be identified through normal inspection process.	1397	SAFETY	3
Zone substation circuit breakers	Andersons Bay ZSS Circuit Breakers	57 year old Brush bulk oil circuit breakers exceeding thier expected life. Elevated risk due to age, type and untested associated current transformers.	14	RELIABILITY/ SAFETY	3
Zone substation circuit breakers	Halfway Bush ZSS Circuit Breakers	57 year old Cooke & Ferguson bulk oil circuit breakers abexceeding their expected life. Elevated risk due to age, type and untested associated current transformers.	16	RELIABILITY/ SAFETY	3
Zone substation circuit breakers	Smith Street ZSS Circuit Breakers	61 year old Cooke & Ferguson bulk oil circuit breakers exceeding thier expected life. Elevated risk due to age, type and untested associated current transformers.	15	RELIABILITY/ SAFETY	3
Zone substation circuit breakers	Willowbank ZSS Circuit Breakers	56 year old Brush bulk oil circuit breakers exceeding their expected life. Elevated risk due to age, type and untested associated current transformers.	15	RELIABILITY/ SAFETY	3
Zone substation transformers	Green Island T1	Transformer condition modelled to be poor. Tap changer has not been maintained within the required schedule resulting in elevated risk.	1	RELIABILITY	3
Zone substation circuit breakers	Omakau ZSS Circuit Breakers	HKK circuit breakers not maintained internally.	1	RELIABILITY/ SAFETY	4

ASSET CLASS	POLE/ITEM	DESCRIPTION	NUMBER	RISK TYPE	PRIORITY
Zone substation transformers	Cromwell T1 and T2	Tap changer has not been maintained within the required schedule. Demand is exceeding substation N-1 capacity.	2	RELIABILITY	4
Distribution switchgear	Long and Crawford distribution switchgear	List provided	15	RELIABILITY/ SAFETY	5
Distribution transformers	Ground mounted distribution transformers	Distribution transformers with high safety risk. Modelled volume based on historical data to develop survivor curve. Individual assets to be identified through normal inspection process.	34	RELIABILITY	5
Distribution transformers	Pole mounted distribution transformers	Distribution transformers with high safety risk. Modelled volume based on historical data to develop survivor curve. Individual assets to be identified through normal inspection process.	25	RELIABILITY	5
Zone substation circuit breakers	Wanaka ZSS Circuit Breakers	VWVE type circuit breakers with issues due to modification when installed.	3	RELIABILITY/ SAFETY	5
Zone substation transformers	Andersons Bay T1 and T2	Transformer condition modelled to have elevated probability of failure.	2	RELIABILITY	5
Zone substation transformers	Green Island T2	Transformer condition modelled to be poor.	1	RELIABILITY	5
Zone substation transformers	North East valley T1	Tap changer has not been maintained within the required schedule resulting in elevated risk.	1	RELIABILITY	5
Zone substation transformers	Wanaka T2	Tap changer has not been maintained within the required schedule resulting in elevated risk.	1	RELIABILITY	5

ASSET CLASS	POLE/ITEM	DESCRIPTION	NUMBER	RISK TYPE	PRIORITY
Distribution switchgear	Statter distribution switchgear	List provided	23	RELIABILITY/ SAFETY	7
Overhead distribution lines	Aged light ACSR conductor	Aged light ACSR conductor on distribution lines (HV) close to the coast. Modelled volume based on survival curve. Individual assets to be identified through normal inspection process.	2.6km	SAFETY/RELI ABILITY	7
Overhead distribution lines	Copper, ACSR and Aluminium conductor	Copper, ACSR and Aluminium conductor on distribution lines (HV and LV) 500m to 5km to the coast. Modelled volume based on survival curve. Individual assets to be identified through normal inspection process.	28.6km	SAFETY/RELI ABILITY	7
Overhead distribution lines	Rectification of low spans	225 conductor spans have been identifed to not comply with required minimum height.	225	SAFETY	7
Zone substation circuit breakers	Neville Street ZSS Circuit Breakers	Oil circuit breakers. About to be decommissioned	31	RELIABILITY/ SAFETY	7
Zone substation circuit breakers	Queenstown ZSS Circuit Breakers	VWVE type circuit breakers with issues due to modification when installed.	3	RELIABILITY/ SAFETY	7
Zone substation transformers	Arrowtown T1 and T2	Transformers with low probability of failure but high consequence. Demand is exceeding substation N-1 capacity.	2	RELIABILITY	7
Zone substation transformers	Port Chalmers T1 and T2	Transformer condition modelled to be poor. Tap changer on T2 has not been maintained within the required schedule resulting in elevated risk. No DGA results, so no internal condition data.	2	RELIABILITY	7

ASSET CLASS	POLE/ITEM	DESCRIPTION	NUMBER	RISK TYPE	PRIORITY
Zone substation transformers	Tap changer maintenance	Elevated risk of 12 transformers due to tap changers not being maintained according to schedule and recent tap changer failures on network indicating elevated risk.	12	RELIABILITY	7
Distribution switchgear	ABB RMUs	List provided	3	RELIABILITY/ SAFETY	8
Distribution switchgear	Long and Crawford distribution switchgear	List provided	44	RELIABILITY/ SAFETY	8
Distribution transformers	Ground mounted distribution transformers	Distribution transformers with medium safety risk.Modelled volume based on historical data to develop survivor curve. Individual assets to be identified through normal inspection process.	168	RELIABILITY	8
Distribution transformers	Pole mounted distribution transformers	Distribution transformers with medium safety risk. Modelled volume based on historical data to develop survivor curve. Individual assets to be identified through normal inspection process.	160	RELIABILITY	8
Subtransmission underground cable	North City (oil insulated cable)	Oil insulated cable with significant historical leaks	5.0km	RELIABILITY	8
Zone substation circuit breakers	Clyde-Earnscleugh ZSS Circuit Breakers	HKK circuit breakers are not maintained internally.	1	RELIABILITY/ SAFETY	8
Zone substation circuit breakers	Corstorphine ZSS Circuit Breakers	46 year old LMT bulk oil circuit breakers. Elevated risk due to age and CTs.	15	RELIABILITY/ SAFETY	8
Zone substation circuit breakers	Kaikorai Valley ZSS Circuit Breakers	Oil insulated circuit breakers that are approaching their expected life.	15	RELIABILITY/ SAFETY	8

ASSET CLASS	POLE/ITEM	DESCRIPTION	NUMBER	RISK TYPE	PRIORITY
Zone substation circuit breakers	Roxburgh ZSS Circuit Breakers	VWVE type circuit breakers with issues due to modification when installed.	4	RELIABILITY/ SAFETY	8
Zone substation circuit breakers	South City ZSS Circuit Breakers	47 year old LMT bulk oil circuit breakers. Elevated risk due to age and CTs.	19	RELIABILITY/ SAFETY	8
Zone substation circuit breakers	St Kilda ZSS Circuit Breakers	39 year old LMT bulk oil circuit breakers. Elevated risk due to age and CTs.	15	RELIABILITY/ SAFETY	8
Zone substation transformers	East Taieri	Located adjacent to a petrol station without firewalls/protection.	2	SAFETY	8
Zone substation transformers	Omakau	No bunding and located adjacent to a waterway.	1	SAFETY	8

Table F.2 Prioritised list of Distribution Switchgear assets

GLOBAL ID	ASSET CLASS	NETWORK	REGULATORY	MANUFACTURER	PRIORITY
C83B3638-A2E2-4AEE-8E6F-9BF41C045200	3.3/6.6/11/22kV RMU	Dunedin	1961	STATTER	3
F2519C81-DB7C-4911-841F-A62EF2450066	3.3/6.6/11/22kV RMU	Dunedin	1961	STATTER	3
8297B7FA-A450-47F1-9030-95AAA0264B31	3.3/6.6/11/22kV RMU	Dunedin	1961	STATTER	3
82A0FB5F-A0AA-4860-ACDD-9F2AC528300B	3.3/6.6/11/22kV RMU	Dunedin	1961	STATTER	3
AFADEA10-77CD-4422-8B9A-4428EBE1C55E	3.3/6.6/11/22kV RMU	Dunedin	1961	STATTER	3
080D7827-F384-429B-82DC-286B3FF88164	3.3/6.6/11/22kV RMU	Dunedin	1973	L&C	5

GLOBAL ID	ASSET CLASS	NETWORK	REGULATORY	MANUFACTURER	PRIORITY
B343FE68-7453-4AB5-8738-3DDB8D2A76DE	3.3/6.6/11/22kV RMU	Dunedin	1973	L&C	5
23AE15CF-A5C3-4095-991B-0E6A2619F4FD	3.3/6.6/11/22kV RMU	Dunedin	1973	L&C	5
8CF4331D-B954-4A7D-A81E-13BFEA5CF7FA	3.3/6.6/11/22kV RMU	Dunedin	1976	L&C	5
05E61AAA-73DD-4731-820D-FE02C30B5E80	3.3/6.6/11/22kV RMU	Dunedin	1976	L&C	5
336B1A9C-EDC4-4A8E-BF31-0A7164706666	3.3/6.6/11/22kV RMU	Dunedin	1982	L&C	5
BAD70A40-FAE2-4104-A48B-33E48B423DB6	3.3/6.6/11/22kV RMU	Dunedin	1982	L&C	5
644B02BB-C58B-4BE4-9FAD-2DC96769B8B2	3.3/6.6/11/22kV RMU	Dunedin	1987	L&C	5
6B2F2342-BD41-4BFE-834A-E64CFEEA17BC	3.3/6.6/11/22kV RMU	Dunedin	1987	L&C	5
60C61DD5-0ACC-4808-9901-6636E7B75670	3.3/6.6/11/22kV RMU	Dunedin	1988	L&C	5
56B8CBFF-7530-4F68-A42C-11579C297572	3.3/6.6/11/22kV RMU	Dunedin	1988	L&C	5
2BDB6944-DD2B-4FA5-8F79-BE4B6AD0E1C9	3.3/6.6/11/22kV RMU	Dunedin	1989	L&C	5
1B3D6B6C-5333-41E9-94D7-FA646976951A	3.3/6.6/11/22kV RMU	Dunedin	1988	L&C	5

GLOBAL ID	ASSET CLASS	NETWORK	REGULATORY	MANUFACTURER	PRIORITY
C62456A5-BE25-4F89-8A24-2809771C6C99	3.3/6.6/11/22kV RMU	Dunedin	2000	L&C	5
0DFF9BB7-5BEF-48EE-B6BC-1EA1E72C2E2D	3.3/6.6/11/22kV RMU	Dunedin	2004	L&C	5
2C530302-18DD-4277-87E6-FA90556D35F2	3.3/6.6/11/22kV RMU	Dunedin	1959	STATTER	7
D9655233-47A4-4A4C-B939-79B1AA565337	3.3/6.6/11/22kV RMU	Dunedin	1959	STATTER	7
70816C72-E91B-42E5-B354-1360ED0E5EEB	3.3/6.6/11/22kV RMU	Dunedin	1959	STATTER	7
C10E7C5F-5DB4-49CF-817E-984561829302	3.3/6.6/11/22kV RMU	Dunedin	1959	STATTER	7
B9679D65-2A0B-47EA-BB7D-9BAB6CE20320	3.3/6.6/11/22kV RMU	Dunedin	1959	STATTER	7
C521CCE0-6C3E-40AE-98F0-3C4E73EE7EAB	3.3/6.6/11/22kV RMU	Dunedin	1959	STATTER	7
8012C580-ADA0-4DD3-A13B-6F45CE38DF66	3.3/6.6/11/22kV RMU	Dunedin	1959	STATTER	7
9FEC5228-D020-4232-B1E4-19E951775C9A	3.3/6.6/11/22kV RMU	Dunedin	1959	STATTER	7
6A77D9D0-E689-4A93-94A8-CD2B750FA9B0	3.3/6.6/11/22kV RMU	Dunedin	1959	STATTER	7
DE0141C4-0DF2-4EBE-98A0-1127BC461EBA	3.3/6.6/11/22kV RMU	Dunedin	1961	STATTER	7

GLOBAL ID	ASSET CLASS	NETWORK	REGULATORY	MANUFACTURER	PRIORITY
F82EA162-AA5C-4468-9DFC-18CE66267BCF	3.3/6.6/11/22kV RMU	Dunedin	1961	STATTER	7
AA6F196B-40AF-496B-9D53-9F82E12783A8	3.3/6.6/11/22kV RMU	Dunedin	1961	STATTER	7
C12D36FD-745F-4536-898C-F7FD1C4133FD	3.3/6.6/11/22kV RMU	Dunedin	1967	STATTER	8
31F44D0B-8A24-418E-8182-73BD9A44E943	3.3/6.6/11/22kV RMU	Dunedin	1967	STATTER	8
431DFF79-6E80-4424-B3D8-5D3FA007928C	3.3/6.6/11/22kV RMU	Dunedin	1967	STATTER	8
3D0A65C9-929A-42E5-B4AF-32BCF4630AEE	3.3/6.6/11/22kV RMU	Dunedin	1967	STATTER	8
D129DA1A-0AA3-488B-A903-6DE6061BED4B	3.3/6.6/11/22kV RMU	Dunedin	1967	STATTER	8
5F02A4FE-45C7-4068-9E4E-77F9D5B1C317	3.3/6.6/11/22kV RMU	Dunedin	1967	STATTER	8
8BA33168-45D0-40CE-A774-6582BA7872D1	3.3/6.6/11/22kV RMU	Dunedin	1967	STATTER	8
B885425B-7B12-4B22-8295-F42EB33C7E8D	3.3/6.6/11/22kV RMU	Dunedin	1967	STATTER	8
6C7B4BEC-69D8-4FF9-ACFD-BC12F247D45B	3.3/6.6/11/22kV RMU	Dunedin	1967	STATTER	8
E814D1CF-69DB-43D2-8FEC-750509CBF721	3.3/6.6/11/22kV RMU	Dunedin	1968	STATTER	8

GLOBAL ID	ASSET CLASS	NETWORK	REGULATORY	MANUFACTURER	PRIORITY
7039439B-5856-44B2-85A5-1BA95F56EF22	3.3/6.6/11/22kV RMU	Dunedin	1968	STATTER	8
5DB506F8-D7DD-42DE-89EC-C87256373E05	3.3/6.6/11/22kV RMU	Dunedin	1971	L&C	8
2BCC42CC-521A-404E-8567-3F723F932A1B	3.3/6.6/11/22kV RMU	Dunedin	1972	L&C	8
34F05AB6-0692-4625-A61D-82FAF1B1AA09	3.3/6.6/11/22kV RMU	Dunedin	1972	L&C	8
CD606C65-8DE2-4CC2-B72A-D79E73CF58D6	3.3/6.6/11/22kV RMU	Dunedin	1972	L&C	8
13750305-70B5-4CD0-982A-BC42A2959E08	3.3/6.6/11/22kV RMU	Dunedin	1972	L&C	8
9E24EAB2-8C3F-47EB-8E70-1509D688A233	3.3/6.6/11/22kV RMU	Dunedin	1972	L&C	8
5448A46A-2C26-403A-BA03-7CCBAA5E647E	3.3/6.6/11/22kV RMU	Dunedin	1972	L&C	8
E13FADD5-E001-4F7D-B8BA-DA5AFB6C3BC9	3.3/6.6/11/22kV RMU	Dunedin	1973	L&C	8
19EA21CE-8B7B-4FE4-A114-39109BB0F279	3.3/6.6/11/22kV RMU	Dunedin	1976	L&C	8
FD32DC34-ADDC-4413-83DB-E558F3970309	3.3/6.6/11/22kV RMU	Dunedin	1977	L&C	8
10EC2FDF-59F9-4E5B-A366-61619D9D8A44	3.3/6.6/11/22kV RMU	Dunedin	1977	L&C	8

GLOBAL ID	ASSET CLASS	NETWORK	REGULATORY	MANUFACTURER	PRIORITY
C8A8D633-BECA-4BDC-BC83-DA16A438257E	3.3/6.6/11/22kV RMU	Dunedin	1977	L&C	8
AB9C755C-7E98-42DE-8DA7-BA22E5BB362B	3.3/6.6/11/22kV RMU	Dunedin	1976	L&C	8
23D864BF-16C4-4CEE-8903-E896C153C6D3	3.3/6.6/11/22kV RMU	Dunedin	1977	L&C	8
12CB3FC3-CA51-4691-882A-32486C666B73	3.3/6.6/11/22kV RMU	Dunedin	1976	L&C	8
35A1F352-CBC9-407D-8BD1-A6AE2EB22FFD	3.3/6.6/11/22kV RMU	Dunedin	1977	L&C	8
35F01376-30BF-4209-A56A-35AC65CFC0BC	3.3/6.6/11/22kV RMU	Dunedin	1976	L&C	8
D3A37958-DEBC-489B-A1C9-6BFE47DF2605	3.3/6.6/11/22kV RMU	Dunedin	1977	L&C	8
F1DDDDE6-E497-4453-AB01-63A198C221F7	3.3/6.6/11/22kV RMU	Dunedin	1977	L&C	8
A8715E14-65C0-4626-9C50-4749BBDDBF8C	3.3/6.6/11/22kV RMU	Dunedin	1977	L&C	8
126DB235-98C0-46CA-ADCC-8B06372CBE92	3.3/6.6/11/22kV RMU	Dunedin	1977	L&C	8
78361FD1-0A5F-47FD-91A0-9A70C9B32F1E	3.3/6.6/11/22kV RMU	Dunedin	1978	L&C	8
349537A9-6307-40E8-9546-6B03DCAAFF3D	3.3/6.6/11/22kV RMU	Dunedin	1979	L&C	8

GLOBAL ID	ASSET CLASS	NETWORK	REGULATORY	MANUFACTURER	PRIORITY
30D2C132-0FBB-4B3F-A5C2-C22CBA30A193	3.3/6.6/11/22kV RMU	Dunedin	1979	L&C	8
0E8DBBF9-0EB5-4FA7-961A-B0FA05C3B508	3.3/6.6/11/22kV RMU	Dunedin	1980	L&C	8
C046D345-2EF6-4AC6-9D7E-AECC141E5A9B	3.3/6.6/11/22kV RMU	Dunedin	1980	L&C	8
689F8031-03D3-4707-8B4E-5A7EE66587C9	3.3/6.6/11/22kV RMU	Dunedin	1980	L&C	8
15135BF1-31D0-47D7-9618-90C4FBAE9FAF	3.3/6.6/11/22kV RMU	Dunedin	1982	L&C	8
BED939B4-5D41-4797-AA51-712A5D2AD8B6	3.3/6.6/11/22kV RMU	Dunedin	1983	L&C	8
238BD63F-1868-4E60-90A3-B545315608C1	3.3/6.6/11/22kV RMU	Dunedin	1983	L&C	8
BFB00732-21F4-4E99-8C12-D5CE69140AA2	3.3/6.6/11/22kV RMU	Dunedin	1983	L&C	8
319FBC86-4218-4825-9AC4-54432C67CCCA	3.3/6.6/11/22kV RMU	Dunedin	1985	L&C	8
8A6FA777-4AE2-4DE1-BE2C-6518B902524F	3.3/6.6/11/22kV RMU	Dunedin	1985	L&C	8
E82B9B54-5336-4EB2-B909-DDDB9DEB4A7C	3.3/6.6/11/22kV RMU	Dunedin	1984	L&C	8
47FE385A-9EB7-42E7-AFD1-D97874D147B6	3.3/6.6/11/22kV RMU	Dunedin	1984	L&C	8

GLOBAL ID	ASSET CLASS	NETWORK	REGULATORY	MANUFACTURER	PRIORITY
50FF8644-87BB-4D7A-B4CE-88088F358542	3.3/6.6/11/22kV RMU	Dunedin	1984	L&C	8
F2E9BBCB-E552-4CAA-9960-A8EC282F1D44	3.3/6.6/11/22kV RMU	Dunedin	1984	L&C	8
9E8A74FF-E508-41DE-871D-11996334B545	3.3/6.6/11/22kV RMU	Dunedin	1985	L&C	8
ABE3D0D2-77FD-47F6-8049-47ECBCE9FEBE	3.3/6.6/11/22kV RMU	Dunedin	1988	L&C	8
BE67C427-DCAB-4D9E-9AD3-A82A9B67B0D2	3.3/6.6/11/22kV RMU	Dunedin	1987	L&C	8
D6EB1BD4-2BF6-444F-A8DD-46238CE1CFD0	3.3/6.6/11/22kV RMU	Dunedin	1989	L&C	8
10B4BD9B-ED87-4060-8515-BF9DE58F4D9C	3.3/6.6/11/22kV RMU	Dunedin	1988	L&C	8
E5DBE9D2-79A1-4A3F-8C8E-2F5A60C9009B	3.3/6.6/11/22kV RMU	Dunedin	1989	L&C	8
96CE12FE-4876-4762-918A-52FA62DAA6ED	3.3/6.6/11/22kV RMU	Dunedin	2005	L&C	8
F8A44BF5-AFD8-4952-B6DC-CFB733A7D396	3.3/6.6/11/22kV RMU	Dunedin	2007	ABB	8
4F7FC46F-0231-4E98-8A10-7EC4084AA64B	3.3/6.6/11/22kV RMU	Dunedin	2007	ABB	8
E84BF420-B5C6-415B-9E2C-9FD0BC2935D8	3.3/6.6/11/22kV RMU	Dunedin	2007	ABB	8

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