Asset Management Plan 2015 - 2025

Publicly disclosed in March 2015

Contents

Enquiries

Enquiries, submissions or comments about this Asset Management Plan (AMP) can be directed to:

Chief Engineer
PowerNet Limited
PO Box 1642
Invercargill 9840

Phone (03) 211 1899
Fax (03) 211 1880
Email amp@powernet.co.nz

Liability disclaimer

The information and statements made in this AMP are prepared on assumptions, projections and forecasts made by Electricity Invercargill Limited and represent Electricity Invercargill's intentions and opinions at the date of issue (31 March 2015). Circumstances may change, assumptions and forecasts may prove to be wrong, events may occur that were not predicted, and Electricity Invercargill may, at a later date, decide to take different actions to those that it currently intends to take. Electricity Invercargill may also change any information in this document at any time.

Electricity Invercargill Limited accepts no liability for any action, inaction or failure to act taken on the basis of this AMP.

0. Summary[A3.1]

This section summarises some of the main points from the Asset Management Plan. Reference to the Electricity Distribution Information Disclosure Determination 2012 (EDIDD) is done with the superscript clause number in square brackets. i.e. [A3.1] refers to EDIDD Attachment A, clause 3.1.

0.1 Background and Objectives

The purpose of the AMP is to provide a governance and management framework that ensures that Electricity Invercargill Limited (EIL):

- Sets service levels for EIL's electricity network that will meet customer, community and regulatory requirements.
- Understands the network capacity, reliability and security of supply that will be required both now and in the future and the issues that drive these requirements.
- Have robust and transparent processes in place for managing all phases of the network life cycle from commissioning to disposal.
- Has adequately considered the classes of risk EIL's network business faces and that there are systematic processes in place to mitigate identified risks, with a focus on earthquakes in the short term.
- Has made adequate provision for funding all phases of the network lifecycle.
- Makes decisions within systematic and structured frameworks at each level within the business.
- Has an ever-increasing knowledge of EIL's asset locations, ages, conditions and the assets' likely future behaviour as they age and may be required to perform at different levels.

EIL works to the below strategies at the corporate and asset level:

Corporate Strategies

- Provide its customers with above average levels of service.
- Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.
- Understand and effectively manage appreciable business risk.
- Manage operations in a progressive and commercial manner.
- Strive to be an efficient but effective operation.

Asset Management Strategies	Strive to be an efficient but effective operation.	Manage operations in a progressive and commercial manner.	Understand and effectively manage appreciable business risk.	Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.	Provide its customers with above average levels of service.
Safety by design using the ALARP (as low as reasonably practicable) risk principle		✓	✓		✓
Minimise long term service delivery cost through condition monitoring and refurbishment	✓	✓			✓
Replace assets at their (risk considered) economic end of life	✓	✓	✓		✓
Facilitate network growth through timely implementation of customer driven projects		✓		✓	✓
Maintain supply quality and security with network upgrades to support forecast growth		✓	✓	✓	✓
Set performance targets for continuous improvement		✓			✓
Mitigate against potential effects of natural hazards; seismic, tidal, extreme weather			✓		✓
Utilise overall cost benefit at all investment levels including the "do nothing" option	✓	✓		✓	
Standardise and optimally resource to provide proficient and efficient service delivery	✓	✓			
Follow new technology trends and judiciously apply to improve service levels		✓			✓

Corporate Strategies

- Provide its customers with above average levels of service.
- Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.
- Understand and effectively manage appreciable business risk.
- Manage operations in a progressive and commercial manner.
- Strive to be an efficient but effective operation.

Asset Management Strategies

Asset Management Strategies	Strive to be an efficient but effective operation.	Manage operations in a progressive and commercial manner.	Understand and effectively manage appreciable business risk.	Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.	Provide its customers with above average levels of service.
Undertake initiatives to increase existing asset life or capacity	✓	✓			
Consider alternatives to status quo solutions	✓	✓			
Improve efficiency of electricity distribution for the net benefit of the customer	✓				✓
Achieve 100% regulatory compliance		✓	✓		✓
Minimise environmental harm		✓	✓		✓

This plan covers the period 1 April 2015 to 31 March 2025, and was approved by the EIL Board on 26 March 2015.

Management of the assets is undertaken by PowerNet Limited which uses internal field services staff for much of the operation, maintenance, renewal, upsizing and expansion of the network but makes use of external contractors as necessary for large capital projects.

The processes and systems used by PowerNet are described in section 9.

0.2 Details of the Assets

EIL supplies 17,199 customers in two electrically separate networks; Invercargill city and Bluff, with a total population of 34,965. The EIL network includes residential, commercial, light industrial and heavy industrial areas which have differing daily load profiles with peaks occurring at different times of the day due to, for example, migration of people from residential zones into the CBD area for their work day. These areas follow similar seasonal load variation peaking over the winter months.

There is:

- 1.4km of 33kV lines and 22.1km of 33kV cable.
- Four zone substations to transform High Voltage (HV) to Medium Voltage (MV).
- Two 11kV feeders supplying the Bluff network area from The Power Company Limited's Bluff Substation.
- 22.8km of 11kV lines and 159.0km of 11kV cables.
- 445 distribution transformers.
- The low voltage (230V) has 30.1km of overhead lines and 421.8km of cable supplying 17,199 customers.
- The age of the network is relatively young, 55% of standard life remaining, with most assets in good condition as an extensive undergrounding programme has renewed most parts of the city network.

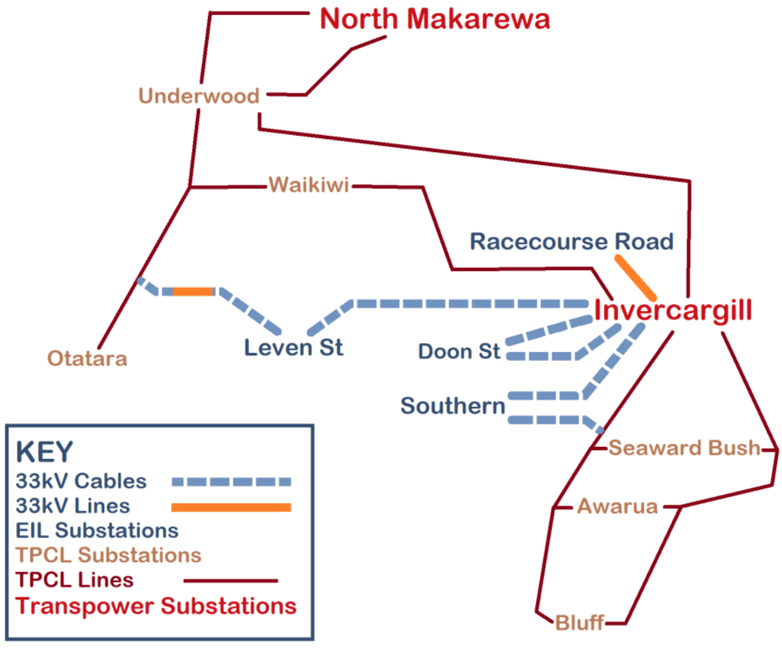


Figure 1: Overview of EIL Subtransmission Network 1 April 2013

0.3 Proposed Service Levels

Customers are content with the present level of service and no major changes in service levels are proposed. This was the outcome of customer consultation undertaken by a telephone survey.

The surveyed customers have indicated that they value continuity and then restoration most highly; therefore EIL's primary service levels are continuity and restoration. To measure performance in these areas two internationally accepted indices have been adopted:

- SAIDI – System Average Interruption Duration Index. This is a measure of how many system minutes of supply are interrupted per year per customer connected to the network.
- SAIFI – System Average Interruption Frequency Index. This is a measure of how many system interruptions occur per year per customer connected to the network.

EIL's targets for these measures for the next five years ending 31 March 2016 are set out in Table 1.

Table 1: EIL Reliability Projections

Measure	Class	2015/16	2016/17	2017/18	2018/19	2019/20	…	2024/25
SAIDI	B (Planned)	2.03	2.03	2.03	2.03	2.03	…	2.03
	C (Unplanned)	22.19	19.08	18.73	18.39	18.04	…	16.34
	Total	**24.22**	**21.11**	**20.76**	**20.41**	**20.07**	**…**	**18.34**
SAIFI	B (Planned)	0.01	0.01	0.01	0.01	0.01	…	0.01
	C (Unplanned)	0.59	0.58	0.58	0.57	0.57	…	0.54
	Total	**0.60**	**0.59**	**0.59**	**0.58**	**0.58**	**…**	**0.55**

Note this target is based on normalising extreme events to the following daily boundary values: SAIDI 3.24, SAIFI 0.08 i.e. cannot get more than 3.24 customer minutes of SAIDI occurring on a single day.

Target network efficiency measures are shown in Table 2.

Table 2: Energy Efficiency Measures

Measure	2015/16	2016/17	…	2023/25
Load Factor	50%	50%	…	50%
Loss Ratio	5.0%	5.0%	…	5.0%
Capacity Utilisation	45%	45%	…	45%

0.4 Development Plans

The maximum demand on the network has increased about 1.5% per annum over the last 20 years with energy increasing by about 0.5% per annum. Maximum Demand and Energy growth since 1950 are shown in Figure 2.

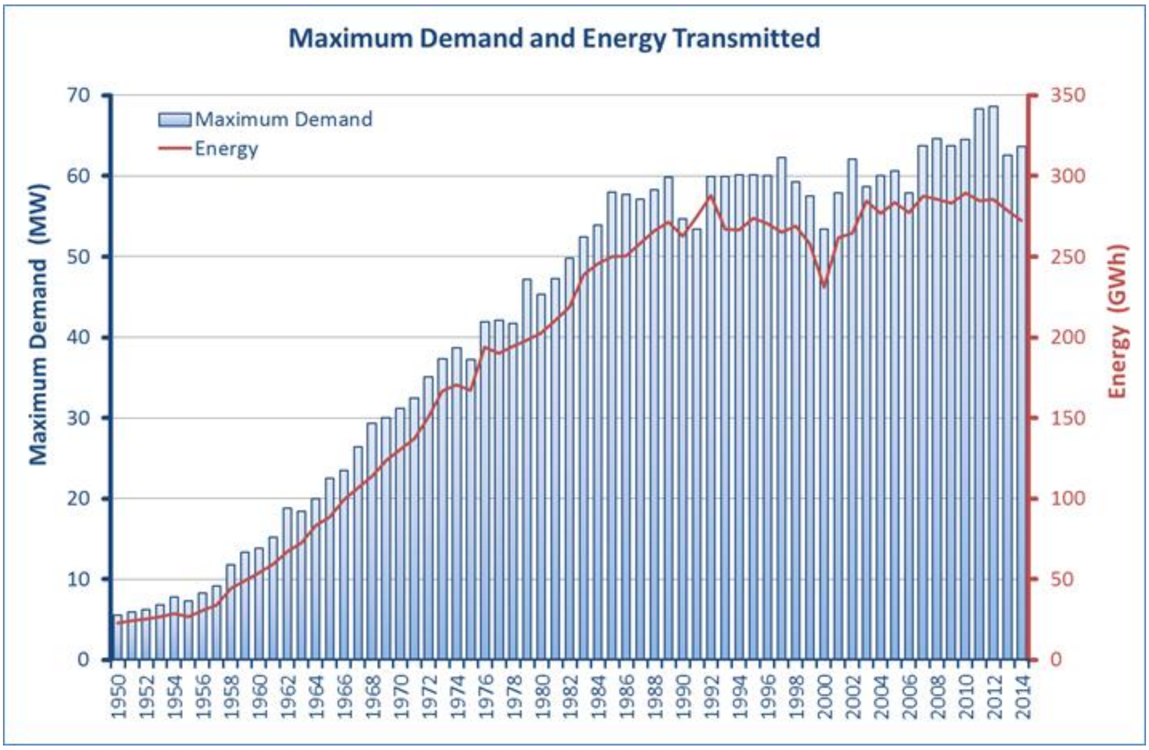


Figure 2: Maximum Demand and Energy Transmitted

The network will be upsized to meet this expected growth with reviews of loadings at zone substations used to trigger actual projects. The focus over the short to medium term is the completion of the following initiatives:

- New Spey Street substation (upsize and relocation of Doon Street substation).
- New 33kV XLPE cable to Spey Street.
- Paralleling, extension and condition assessment of 33kV oil-filled cables.
- Southern substation upgrades including new building housing new 33kV and 11kV switchboards, SCADA and control equipment and installation of relocated and refurbished ex-Doon Street transformer as second unit for firm supply.
- Renew underground substations in the Invercargill CBD.
- Seismic strengthening work at zone and distribution substations.
- Neutral earthing resistor (NER) installations {earthing safety}.

These projects will provide the additional capacity required and contribute to maintaining network reliability and safety. Additional work over the ten year planning period aimed at maintaining service levels will include:

- Improving safety at zone substations and on the distribution network.
- Upgrading areas to maintain acceptable voltages.
- Renewing unsafe and poorly performing assets.
- Meeting customer and distributed generator requests for new connections.
- Improving efficiency of the network by up-sizing of assets that have high losses and exchanging overloaded distribution transformers with currently installed under-utilised units.
- Extending remote monitoring and control to field devices.

Renewals of transformers, ring main units and pillar boxes are expected to have a significant on-going cost.

Capital expenditure each year varies with $5.47 million in 2015/16, then varying between $1.94 million and $3.95 million over the remainder of the ten year planning horizon.

Planned subtransmission network for 2025 is shown in Figure 3:

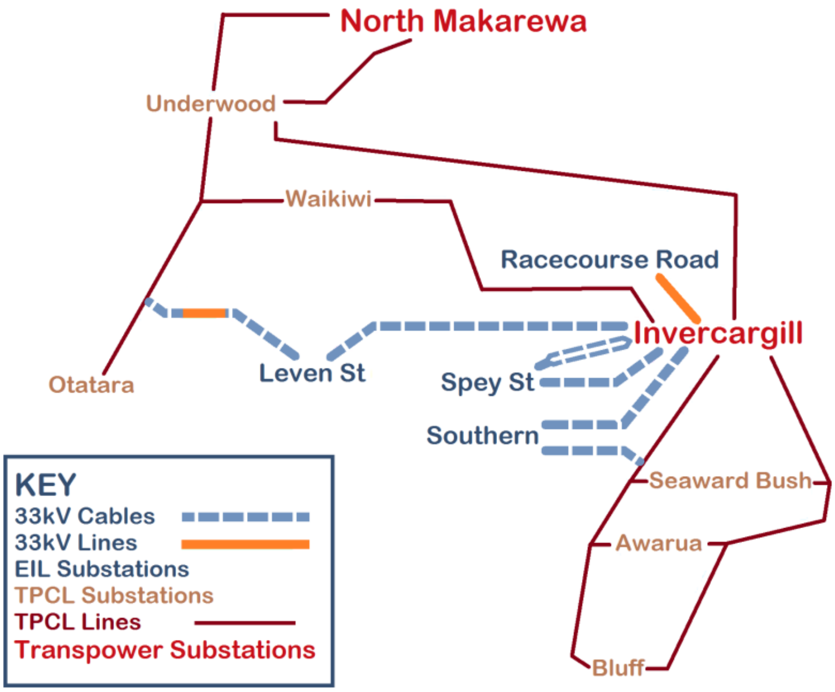


Figure 3: Proposed Network Configuration 2023

0.5 Managing the Asset's Lifecycle

The asset lifecycle used by EIL once assets are built, is: Operation, Maintenance, Renewal, Up-sizing, Extensions and Retirement. Analysis is done to review network operation to check if any trigger is exceeded and actions planned to maintain planned service levels. Replacement and renewal work aims to maintain average remaining life of assets at 50%.

- Asset replacement and renewal is expected to cost $0.10 million per annum.
- Vegetation Management is expected to cost only $1,400 per annum.

- Routine and Corrective Maintenance and Inspection of assets is budgeted for $0.80 million in 2015/16 and then expected to vary between $0.75 million and $0.78 million in future years.
- Service Interruptions and Emergencies is expected to cost $0.69 million per annum.

0.6 Capability to Deliver

EIL has robust processes and systems to help ensure efficient delivery of the objectives of the AMP and is adequately funded ultimately through the revenue from EIL's customers via their retailer.

Internal planning is done annually to ensure sufficient field services staff are available to complete the detailed works programme as part of the plan's development. Ensuring sufficient contracting resources for additional work involves working closely with EIL's contractors, carefully communicating the works plan and getting commitment that sufficient resources will be available for the year ahead.

0.7 Risk Management

The business is exposed to a wide range of risks. This section examines EIL's risk exposures, describes what it has done and will do about these exposures and what it will do when disaster strikes.

Risk management is used to bring risk within acceptable levels.

0.8 Funding the Business

EIL's revenue is primarily from retailers who pay for conveying energy over EIL's lines and from customer contributions for the uneconomic portion of new connections or upgrades.

Customer surveys found that only 12% would like to pay more for an improvement in service, so is insufficient to warrant a change in the rate of maintaining and renewing the network.

0.9 Processes and Systems

EIL's management company PowerNet uses a system based on ISO9000 quality system but has not maintained certification. Asset information resides in three key locations: Geographical Information System (GIS), Asset Management System (AMS), and Supervisory Control And Data Acquisition (SCADA). Some of this information is excellent but the accuracy of pole ages is poor with 63% having age estimated.

Condition information is planned to be better collected by use of a scanned form to collect the 20% of the network inspected each year. Planners can then use this data to plan work more efficiently.

0.10 Performance and Improvement

Performance against service reliability targets set in the 2013/14 AMP was achieved with results well under the target levels. Performance on EIL's network is typically very good.

Capital expenditure was 32.5% under budget and 18.3% over for maintenance.

Efficiency measures did not quite achieve targeted levels with load factor 1.1% below the minimum 50% target, losses 0.3% over the maximum 5% target and capacity utilisation

2.9% under the minimum 45% target. Load factor especially has been affected by the change in Transpower's pricing methodology and is difficult to influence.

Some strategies are planned to improve productivity.

0.11 Feedback and Comments

Comment on this plan is welcome and should be addressed to the Chief Engineer, PowerNet Ltd, PO Box 1642, Invercargill or email amp@powernet.co.nz. The next review of this AMP is planned for publishing in March 2014.

1. Background and Objectives[A3.2]

Electricity Invercargill Limited (EIL) is the electricity lines business that conveys electricity to the majority of Invercargill and to Bluff for approximately 17,199 customer connections on behalf of six energy retailers. The wider EIL entity also includes the following associations;

- A 50% stake in PowerNet, an electricity lines management company jointly owned with The Power Company Limited (TPCL). This is an unregulated entity and is therefore not subject to any disclosure requirements.
- A 24.9% stake in Electricity Southland Limited (ESL), which distributes electricity in the Frankton area of Central Otago. ESL is currently below the thresholds for disclosure.
- A 24.9% stake in OtagoNet. The entity for disclosure is OtagoNet Joint Venture (OJV), and its AMP is prepared and disclosed by PowerNet which manages the OJV assets along with those of TPCL, EIL and ESL.
- A 50% stake in Otago Power Services Ltd, an electrical contracting company based in Balclutha.

The interrelationship of these entities with the various holding companies and shareholders, along with the accounting treatment of results, is described in EIL's annual report.

This AMP deals solely with the EIL electricity network assets.

1.1 Purpose of the Asset Management Plan[A3.3.1]

The purpose of the AMP is to provide a governance and management framework that ensures EIL:

- Sets service levels of the electricity distribution services supplied by EIL that will meet customer, community and regulatory requirements.
- Understands the network capacity, reliability and security of supply that will be required both now and in the future and the issues that drive these requirements.
- Have robust and transparent processes in place for managing all phases of the network life cycle from commissioning to disposal.
- Has adequately considered the classes of risk EIL's network business faces and that there are systematic processes in place to mitigate identified risks.
- Has made adequate provision for funding all phases of the network lifecycle.
- Makes decisions within systematic and structured frameworks at each level within the business.
- Has an ever-increasing knowledge of EIL's asset locations, ages and conditions as well as the assets' likely future behaviour as they age and may be required to perform at different levels.

Disclosure of EIL's AMP in this format will also assist in meeting the requirements of Section 2.6, Attachment A and Schedules 11, 12 and 13 of the Electricity Distribution Information Disclosure Determination 2012.

This AMP is not intended to be a detailed description of EIL's assets (these lie in other parts of the business), but rather a description of the thinking, the policies, the strategies, the plans and the resources that EIL uses and will use to manage the assets.

1.2 Interaction with Other Goals and Drivers

All of the assets exist within a strategic context that is shaped by a wide range of issues including EIL's vision statement, asset strategy, the prevailing regulatory environment, government policy objectives, commercial and competitive pressures and technology trends. EIL's assets are also influenced by technical regulations, asset deterioration, the laws of physics and risk exposures independent of the strategic context.

1.2.1 Strategic Context

EIL's strategic context includes many issues that range from the state of the local economy to developing technologies. Issues that EIL considers include:

- The prevailing regulatory environment which guides prices, requires no material decline in SAIDI and requires EIL to compile and disclose performance and planning information.
- Government policy objectives, such as the promotion of distributed generation (particularly renewables).
- EIL's commercial goal which is primarily to deliver a sustainable earnings stream to EIL's owners that are the best use of their funds.
- Competitive pressures from other lines companies which might try to supply EIL customers.
- Pressure from substitute fuels both at end-user level (such as substituting electricity with coal or oil at a facility level) and at bulk generation level (wind farms).
- Advancing technologies such as gas-fired fuel cells that could strand conventional wire utilities.
- Local, national and global economic cycles which effect growth and development.
- Changes to the Southland climate that include more storms and hotter, drier summers.
- Interest rates which can influence the rate at which new customers connect to the network.
- Ensuring sufficient funds and skilled people are available long term to resource EIL's service requirements.

1.2.2 Independence from Strategic Context

It is also important to recognise that although EIL's assets must be shaped by the strategic issues identified in section 1.2.1 they will also be influenced (and even constrained) by issues that are independent of the strategic context.

These issues include:

- Technical regulations including such matters as limiting harmonics to specified levels.
- Asset configuration, condition and deterioration. These parameters will significantly limit the rate at which EIL can re-align 54km of lines, 600km of cables and 454 transformers to fit ever-changing strategic goals.
- The laws of physics which govern such fundamental issues as power flows, losses, insulation failure and faults.
- Physical risk exposures. Exposure to events such as flooding, wind, snow, earthquakes and vehicle impacts are generally independent of the strategic context.

Issues in which EIL's risk exposure might depend on the strategic context could be in regard to natural issues such as climate change (increasing severity and frequency of storms) or regulatory issues (say if LTNZ required all poles to be moved back from the carriage way).

- Safety requirements such as earthing of exposed metal and line clearances.

1.2.3 Annual Business Plan and Works Plans

Each year, the first year of the AMP is consolidated with any recent strategic, commercial, asset or operational issues into EIL's annual business plan. This defines the priorities and actions for the year ahead which will contribute to EIL's long-term alignment with the strategic context, fully understanding that this alignment process is very much one of "moving goal posts".

An important component of the Annual Business Plan is the Annual Works Programme which scopes and costs each individual activity or project that the company expects to undertake in the year ahead. A critical activity is to firstly ensure that this annual works program accurately reflects the current year's projects in the AMP and secondly ensures that each project is implemented according to the scope prescribed in the works program.

1.3 Key Planning Documents[A3.3.3, 3.3.4]

The key planning documents are expanded following, and the interactions of the key planning issues, processes and documents are shown in Figure 4:

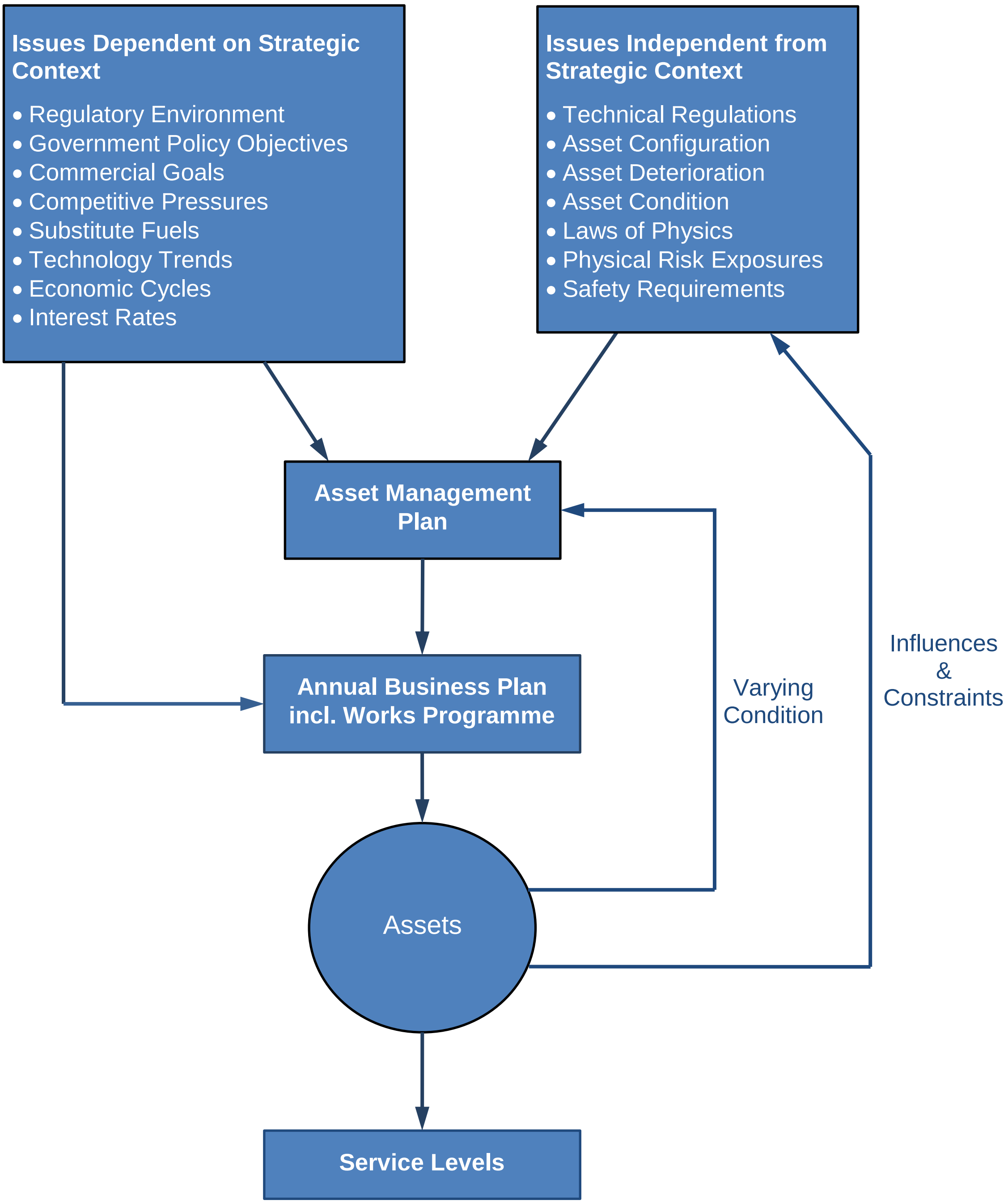


Figure 4: Interaction of Key Plans

1.3.1 Statement of Intent

EIL's Statement of Intent (SOI) is a requirement under the constitution of the company, and forms the principal accountability mechanism between EIL's board and the shareholder; Invercargill City Holdings. The SOI includes performance and reliability projections, which form the heart of the asset management activity and implicitly recognise the inherent trade-off between price and supply quality.

The SOI is available at http://www.powernet.co.nz on the Line Owners area under Company Information.

1.3.1.1 Performance Targets: Financial

EBIT% - Percentage Group Earnings Before Tax and Interest on Assets Employed

	2015/16	2016/17	2017/18
NPBT	7,331,919	8,726,350	8,775,204
Interest	2,358,907	2,748,932	2,845,310
NPBI&T	9,690,825	11,475,282	11,620,514
Total Assets	155,467,975	158,934,964	159,502,233
EBIT %	**6.23%**	**7.22%**	**7.29%**

NPAT% - Percentage Group Tax Paid Profit on Equity

	2015/16	2016/17	2017/18
NPAT	6,420,902	7,678,600	7,512,019
Equity	93,404,665	94,563,379	95,286,090
NPAT %	**6.87%**	**8.12%**	**7.88%**

Percentage of Consolidated Equity to Total Assets

	2015/16	2016/17	2017/18
Equity	93,404,665	94,563,379	95,286,090
Total Assets	155,467,975	158,934,965	159,502,233
% Equity/ Assets	**60.08%**	**59.50%**	**59.74%**

1.3.1.2 Performance Targets: Quality

SAIFI - System Average Interruption Frequency Index (the average number of times each customer connected to the network is without supply)

2015/16	2016/17	2017/18
0.60	0.59	0.59

SAIDI - System Average Interruption Duration Index (the average total time in minutes each customer connected to the network is without supply)

2015/16	2016/17	2017/18
24.2	21.1	20.8

The Commerce Commission Supply Quality Thresholds are:

SAIFI	0.772 times
SAIDI	31.13 minutes

1.3.2 Vision Statement[A3.3.2]

To be a top performing New Zealand Lines Company.

1.3.3 Strategic Plan

Key corporate drivers from EIL's Strategic Plan are:

- Provide its customers with above average levels of service.
- Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.
- Understand and effectively manage appreciable business risk.
- Manage operations in a progressive and commercial manner.
- Strive to be an efficient but effective operation.

1.3.4 Asset Management Strategy

EIL's asset strategy follows these guiding principles:

- Safety by design using the ALARP (as low as reasonable practicable) risk principle
- Minimise long term service delivery cost through condition monitoring and refurbishment
- Replace assets at their (risk considered) economic end of life
- Facilitate network growth through timely implementation of customer driven projects
- Maintain supply quality and security with network upgrades to support forecast growth
- Set performance targets for continuous improvement
- Mitigate against potential effects of natural hazards; seismic, tidal, extreme weather
- Utilise overall cost benefit at all investment levels including the "do nothing" option
- Standardise and optimally resource to provide proficient and efficient service delivery
- Follow new technology trends and judiciously apply to improve service levels
- Undertake initiatives to increase existing asset life or capacity
- Consider alternatives to status quo solutions
- Improve efficiency of electricity distribution for the net benefit of the customer
- Achieve 100% regulatory compliance
- Minimise environmental harm

1.3.5 Prevailing Regulatory Environment

EIL's assets are subject to a price and quality regulation established under Part 4 of the Commerce Act 1986. EIL is subject to information disclosure requirements (including the requirement to publish an AMP) along with other structural regulations such as restrictions on generating and retailing energy, and the requirement to connect embedded generation.

1.3.6 Government Policy Objectives

Electricity lines businesses are being increasingly required to give effect to many aspects of government policy, namely:

- Facilitating the connection of distributed generation on a regulated basis.
- Improving the already high levels of public safety around power lines and transformers.
- Offering increasingly variable tariffs to promote demand reduction despite the most economically efficient tariff structure for a lines business being a fixed cost.

1.3.7 Annual Business Plan

An Annual Business Plan (ABP) is produced by PowerNet and contains the following:

- Core Business, Vision Statement and Critical Success Factors.
- Commercial Objectives, The Nature and Scope of Commercial Activity and Company Polices.

- Annual Capital Works Programme and the Annual Works Plan (AWP) for the following four years.
- Business Plan Financials and Business Unit Reports.

1.3.8 Annual Works Plan

The AWP is produced by PowerNet that details the works to be undertaken for each financial year, and is incorporated into the ABP. All of next year's works, listed in the AMP, are included in the AWP.

1.4 Interaction of Goals/Strategies

Table 3 shows the linkage between the Corporate and Asset Management Strategies.

Table 3: Corporate and Asset Management Strategy Linkage

Corporate Strategies

Asset Management Strategies	Strive to be an efficient but effective operation.	Manage operations in a progressive and commercial manner.	Understand and effectively manage appreciable business risk.	Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.	Provide its customers with above average levels of service.
Safety by design using the ALARP (as low as reasonably practicable) risk principle		✓	✓		✓
Minimise long term service delivery cost through condition monitoring and refurbishment	✓	✓			✓
Replace assets at their (risk considered) economic end of life	✓	✓	✓		✓
Facilitate network growth through timely implementation of customer driven projects		✓		✓	✓
Maintain supply quality and security with network upgrades to support forecast growth		✓	✓	✓	✓
Set performance targets for continuous improvement		✓			✓
Mitigate against potential effects of natural hazards; seismic, tidal, extreme weather			✓		✓
Utilise overall cost benefit at all investment levels including the "do nothing" option	✓	✓		✓	
Standardise and optimally resource to provide proficient and efficient service delivery	✓	✓			
Follow new technology trends and judiciously apply to improve service levels		✓			✓
Undertake initiatives to increase existing asset life or capacity	✓	✓			
Consider alternatives to status quo solutions	✓	✓			
Improve efficiency of electricity distribution for the net benefit of the customer	✓				✓
Achieve 100% regulatory compliance		✓	✓		✓
Minimise environmental harm		✓	✓		✓

1.5 Period Covered by the Asset Management Plan[A3.4, 3.5]

[Addresses the Handbook requirement 4.5.2(c)]

This edition of EIL's AMP covers the period 1 April 2015 to 31 March 2025. It was prepared during August 2014 to March 2015, approved by EIL's Board on 26 March 2015 and publicly disclosed at the end of March 2015.

There is a degree of uncertainty in any predictions of the future, and accordingly the AMP is uncertain. Customer demand driven by turbulent commodity markets, public policy trends and possible generation opportunities within EIL's demand profile means the future is perhaps less certain than many other infrastructure businesses that have greater scale. Accordingly EIL has attached certainties to the timeframes of the AMP as summarised in Table 4.

Table 4: Certainty for AMP Planning Period

Timeframe	Residential & Commercial	Large Industrial	Intending Generators
Year 1	Very certain	Reasonable certainty	Reasonable certainty
Years 2 to 5	Certain	Little if any certainty	Little if any certainty
Years 6 to 10	Little if any certainty	Little if any certainty	Little if any certainty

1.6 Stakeholder Interests[A3.6]

1.6.1 Stakeholders[A3.6.1]

A stakeholder is defined as any person or class of persons who does or may do one or more of the following:

- Has a financial interest in EIL (be it equity or debt).
- Pays money to EIL (either directly or through an intermediary) for delivering service levels.
- Is physically connected to EIL's network.
- Uses EIL's network for conveying electricity.
- Supplies EIL with goods or services (includes labour).
- Is affected by the existence, nature or condition of the network (especially if it is in an unsafe condition).
- Has a statutory obligation to perform an activity in relation to the EIL network's existence or operation (such as request disclosure data, regulate prices, investigate accidents or District Plan requirements).

1.6.2 Stakeholder Interests[A3.6.2]

The interests of the stakeholders are defined in Table 5 below:

Table 5: Key stakeholder interests

	Interests				
	Viability	Price	Quality	Safety	Compliance
Shareholder – Invercargill City Holdings	✓	✓	✓	✓	✓
Bankers	✓	✓		✓	✓
Connected Customers	✓	✓	✓	✓	

	Interests				
	Viability	Price	Quality	Safety	Compliance
Contracted Manager (PowerNet)	✓	✓	✓	✓	✓
Energy Retailers	✓	✓	✓		
Mass-market Representative Groups	✓	✓	✓		
Industry Representative Groups	✓	✓	✓		
Staff and Contractors	✓			✓	✓
Suppliers of Goods and Services	✓				
Public (as distinct from customers)				✓	✓
Land owners				✓	✓
Councils (as regulators)				✓	✓
Transport Agency				✓	✓
Ministry of Economic Development		✓	✓	✓	✓
Energy Safety Service				✓	✓
Commerce Commission	✓	✓	✓		✓
Electricity Authority					✓
Electricity & Gas Complaints Commission			✓		✓
Ministry of Consumer Affairs			✓		✓

Table 6 below demonstrates how stakeholder's expectations and requirements are identified.

Table 6: How Stakeholder's Expectations are Identified

Stakeholder	How expectations are identified
Invercargill City Holdings	By their approval or required amendment of the SOI Regular meetings between the directors and executive
Bankers	Regular meetings between the bankers, PowerNet's Chief Executive and Chief Financial Officer. By adhering to EIL's treasury/borrowing policy By adhering to banking covenants
Connected Customers	Regular discussions with large industrial customers as part of their on-going development needs Annual customer surveys
Contracted Manager (PowerNet)	Board Chairman weekly meeting with the Chief Executive
Energy Retailers	Annual consultation with retailers
Mass-market Representative Groups	Informal contact with group representatives
Industry Representative Groups	Informal contact with group representatives
Staff & Contractors	Regular staff briefings Regular contractor meetings

Stakeholder	How expectations are identified
Suppliers of Goods & Services	Regular supply meetings Newsletters
Public (as distinct from customers)	Word of mouth around the city Feedback from public meetings
Land Owners	Individual discussions as required
Councils (as regulators)	Formally as necessary to discuss issues such as assets on Council land Formally as District Plans are reviewed
Transport Agency	Formally as required
Ministry of Economic Development	Regular bulletins on various matters Release of legislation, regulations and discussion papers Analysis of submissions on discussion papers
Energy Safety Service	Promulgated regulations and codes of practice Audits of EIL's activities Audit reports from other lines businesses
Commerce Commission	Regular bulletins on various matters Release of discussion papers Analysis of submissions on discussion papers Conferences following submission process
Electricity Authority	Weekly update Release of discussion papers Briefing sessions Analysis of submissions on discussion papers Conferences following submission process General information on their website
Electricity & Gas Complaints Commission	Reviewing their decisions in regard to other lines companies
Ministry of Consumer Affairs	Release of legislation, regulations and discussion papers General information on their website

1.6.3 Meeting Stakeholder's Interests[A3.6.3]

Table 7 provides a broad indication of how stakeholder's interests are accommodated in EIL's asset management practices:

Table 7: Meeting stakeholder interests

Interest	Description	How EIL meets interests
Viability	Viability is necessary to ensure that the shareholder and other providers of finance such as bankers have sufficient reason to keep investing in EIL.	Stakeholder's needs for long-term viability are accommodated by delivering earnings that are sustainable and reflect an appropriate risk-adjusted return on employed capital. In general terms this will need to be at least as good as the stakeholders could obtain from a term deposit at the bank plus a margin to reflect the ever-increasing risks to the capital in the business. Earnings are set by estimating the level of expenditure that will maintain Service Levels within targets and the revenue set to provide the required returns.
Price	Price is a key means of both gathering revenue	EIL's total revenue is constrained by the price path threshold regime. Prices will be restrained to within the limits

Interest	Description	How EIL meets interests
	and signalling underlying costs. Getting prices wrong could result in levels of supply reliability that are less than or greater than EIL's customers want.	prescribed by the price path threshold, unless it comprises safety or viability. Failure to gather sufficient revenue to fund reliable assets will interfere with customer's business activities, and conversely gathering too much revenue will result in an unjustified transfer of wealth from customers to shareholders. EIL's pricing methodology is expected to be cost-reflective, but issues such as the Low Fixed Charges requirements can distort this.
Supply quality	Emphasis on continuity, restoration of supply and reducing flicker is essential to minimising interruptions to customers' businesses.	Stakeholder's needs for supply quality will be accommodated by focusing resources on continuity and restoration of supply. The most recent mass-market survey indicated a general satisfaction with the present supply quality but also with many customers indicating a willingness to accept a reduction in supply quality in return for lower line charges.
Safety	Staff, contractors and the public at large must be able to move around and work on the network in total safety.	The public at large are kept safe by ensuring that all above-ground assets are structurally sound, live conductors are well out of reach, all enclosures are kept locked and all exposed metal is earthed. The safety of our staff and contractors is ensured by providing all necessary equipment, improving safe work practices and ensuring that they are stood down in unsafe conditions. Contractors will use all necessary safety equipment, improve their safe work practices and ensure that they stand down in unsafe conditions. Motorists will be kept safe by ensuring that above-ground structures are kept as far as possible from the carriage way within the constraints faced in regard to private land and road reserve.
Compliance	Compliance is necessary with many statutory requirements ranging from safety to disclosing information.	All safety issues will be adequately documented and available for inspection by authorised agencies. Performance information will be disclosed in a timely and compliant fashion.

1.6.4 Managing Conflicting Interests[A3.6.4]

Priorities for managing conflicting interests are:

- Conflict identified.
- Analysis of issues and options using the following priority hierarchy:
  1) Safety. Top priority is given to safety. The safety of staff, contractors and the public will not be compromised even if budgets are exceeded.
  2) Viability. Second priority is viability (as defined above), because without it EIL will cease to exist which makes supply quality and compliance pointless.
  3) Pricing. EIL will give third priority to pricing as a follow on from viability (noting that pricing is only one aspect of viability). EIL recognises the need to adequately fund its business to ensure that customers' businesses can operate successfully, whilst ensuring that there is not an unjustified transfer of wealth from its customers to its shareholders.
  4) Supply quality is the fourth priority. Good supply quality makes customers, and therefore EIL, successful.

5) Compliance. A lower priority is given to compliance that is not safety and supply quality related.

- Report with recommendation made to management.
- Decision made by Management Team, or escalated to EIL Board.

1.6.5 Customer Consultation

A face to face survey using a survey company was undertaken with seven key clients. It was found businesses had a very positive view of PowerNet as a professional company and were generally happy with the current level of reliability. Customers appreciate the notification of planned outages and the ability to negotiate timing to minimise impacts on their businesses. While most customers seemed happy with the restoration times after unplanned outages, there was a wide range of preferred timeframes indicated from six hours to ten minutes. On the whole communication with PowerNet regarding network issues or progress restoring supply during unexpected interruptions was seen positively however a couple of comments were received that this communication could have been more timely or more helpful and informative.

PowerNet is perceived to have a good public profile regarding community support. Some businesses expressed a desire for more proactive and regularly initiated contact from PowerNet staff to make them more aware of pricing and reliability options while others commented that they would prefer to initiate contact with PowerNet themselves.

Individual customers are also consulted as they undertake connection to the network. For example, the connection of the show grounds subdivision where options and negotiations occurred before the supply was agreed on.

1.7 Accountabilities for Asset Management[A3.7]

EIL's ownership, governance and management structure is depicted in **Figure 5**:

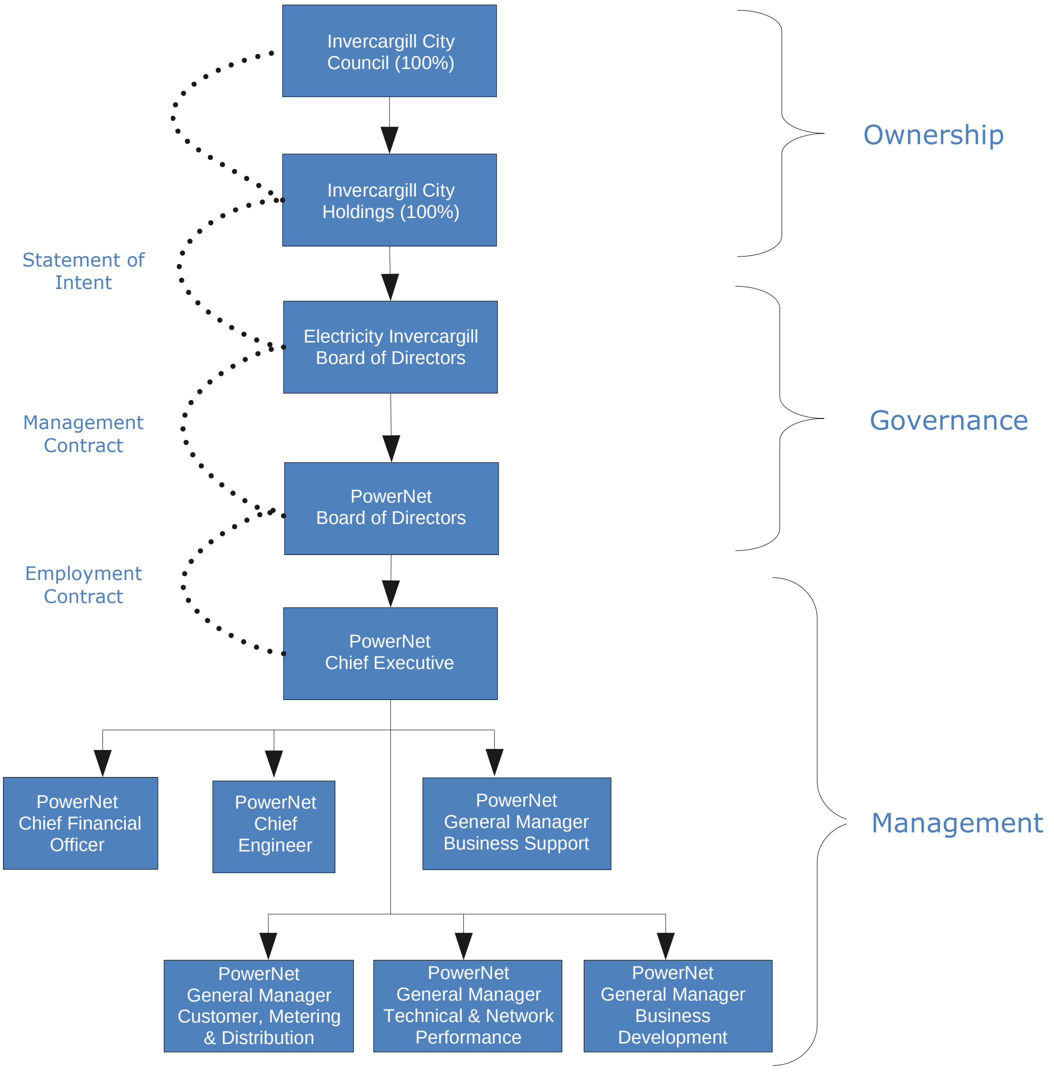


Figure 5: Governance and management accountabilities

1.7.1 Accountability at Ownership Level

EIL has a single shareholder – Invercargill City Holdings (Holdco) acting for Invercargill City Council as a CCTO (council controlled trading organisation). The CCTO currently has five directors;

- Grahame Sycamore (Chairman)
- Alan Dennis
- Cam McCulloch
- Tim Loan
- Lindsay Thomas

The CCTO is subject to the following accountability mechanisms;

- Directors are appointed to Holdco and subsidiary company directors are approved by Invercargill City Council.

1.7.2 Accountability at Governance Level[A3.7.1 (with AMP section 1.7.7)]

As EIL uses a contracted management company (PowerNet Limited) to manage the assets there is effectively a two-tier governance structure as follows:

The first tier of governance accountability is between EIL's Board and shareholder with the principal mechanism being the Statement of Intent (SOI). Inclusion of SAIDI and SAIFI targets in this statement makes EIL's Board intimately accountable to EIL's shareholder for these important asset management outcomes whilst the inclusion of financial targets in the statement makes EIL's Board additionally accountable for overseeing the price-quality trade-off inherent in projecting expenditure and SAIDI.

EIL currently has five directors:

- Neil Boniface (Chairman)
- Tom Campbell
- Ross Smith
- Darren Ludlow
- Sarah Brown

The second tier of governance accountability is between EIL's Board and the PowerNet Board with the principal mechanism being the management contract that specifies a range of strategic and operational outcomes to be achieved.

1.7.3 Accountability at Executive Level[A3.7.2 (with AMP section 1.7.4)]

Overall accountability for the performance of the electricity network rests with the Chief Executive of PowerNet. The principal accountability mechanism is the Chief Executive's employment agreement with the PowerNet Board which reflects the outcomes specified in the management contract between EIL's Board and PowerNet.

1.7.4 Accountability at Management Level[A3.7.2 (with AMP section 1.7.3)]

There are six level two managers reporting directly to PowerNet's Chief Executive with the principal accountability mechanisms being their respective employment agreements.

The individual manager who has the most influence over the long-term asset management outcomes will be the Chief Engineer through his preparation of the AMP which will guide the nature and direction of the other managers' work.

1.7.5 Accountability at Operational Level[A3.7.3 (with AMP section 1.7.6)]

PowerNet's Customer Metering and Distribution Services and Technical and Network Performance teams manage the work to achieve the outcomes in the Annual Works Plan. Data and information from inspections and checks are used to plan works for the following years.

Where additional external contractors are required, contracts will be utilised, structured on the following mechanisms:

- Purchase Order – generally only minor work
- Fixed Lump Sum Contract – generally on-going work

- Contract – specific project work

Each type details the work to be undertaken, the standards to be achieved, detail of information to be provided and payments.

1.7.6 Accountability at Work-face Level[A3.7.3 (with AMP section 1.7.5)]

With the recent amalgamation of Power Services with PowerNet (continuing under the name PowerNet) along with the attraction of additional technical staff the majority of field work is now done by internal field staff. The field staff are managed within PowerNet's Customer Metering and Distribution Services and Technical and Network Performance teams. External contractors are used when necessary to supplement workforce capacity or skillsets and include;

- DECOM Limited
- Transfield Services E & T NZ Limited
- Electrix Services Limited
- Otago Power Services Limited
- Local Electrical Inspectors (M Jarvis, I Sinclair, W Harper)
- Peak Power Services Limited
- Asplundh Tree Expert (NZ) Limited
- Cory's Limited
- Consultants (Mitton Electronet, Edison, Beca, SKM, S Sinclair, Millpower)

The principal accountability mechanism is through contracts that reflect the outcomes PowerNet must create for EIL.

1.7.7 Key Reporting Lines[A3.7.1 (with AMP section 1.7.2)]

The EIL board receives monthly commercial and network reports that cover the following items:

- Network reliability – this lists all outages over the last month, and trends regarding the SOI reliability targets
- Network Quality – detail of outstanding voltage complaints and annual statistics on them
- Network Connections – monthly and yearly details of connections to the network
- Use of Network – trend of the energy conveyed through the network
- Revenue – detail on the wheeling fees received
- Retailer activity – detail on volumes and numbers per energy retailer operating on the network
- Works Programme – monthly, year-to-date (YTD) and project life expenditure on each works programme item and percentage complete, with notes on major variations.

Each level of management has defined financial limits in the PowerNet Financial Authorities Policy. Generally most projects are approved by the Board in the Annual Works Programme as part of Annual Business Plan process. Any new project over $100,000 or variation to the approved Annual Works Plan by more than +10% or -30% will need to gain Board approval with capital projects over $1,000,000 being supported by a business case report.

1.8 Systems and Processes[A3.13]

Systems and processes are described in section 9 of this AMP.

2. Details of the Assets[A4]

This section summarises EIL's assets and asset configurations, but begins by describing EIL's geographical coverage, what sort of activities the underlying community uses electricity for, and the issues that are driving key asset parameters such as demand changes.

2.1 Distribution Area

2.1.1 Geographical Coverage[A4.1.1]

The distribution area includes:

- The part of Invercargill bounded by Racecourse Road to the east, the Waihopai Stream to the north and west (except for Invercargill Airport which is in EIL's area) and Elizabeth, Moulson and Brown Streets and Tramway Road to the south. Shown in Figure 6.
- The borough of Bluff extending as far west as the former Ocean Beach freezing works. Shown in Figure 7.

The topography is densely urban and built-up in both Invercargill and Bluff. Invercargill is almost totally flat (lying about 3m to 5m above sea level) whilst Bluff varies from flat to steep hills.

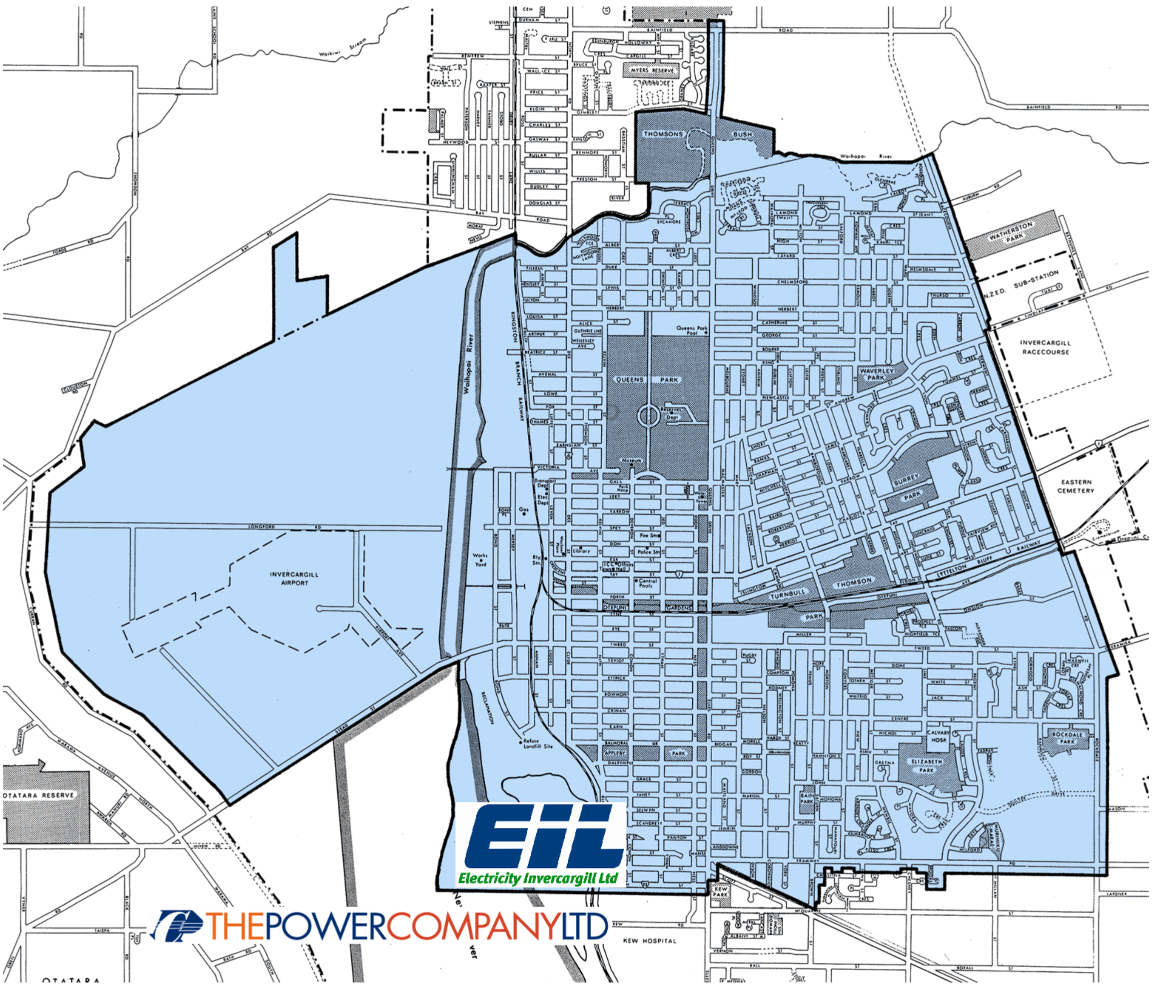


Figure 6: EIL Invercargill Distribution Area

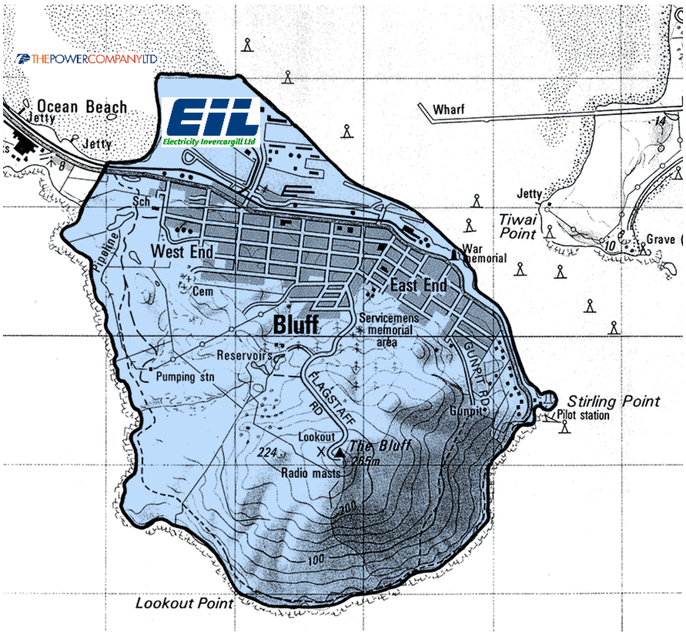


Figure 7: EIL Bluff Distribution Area

2.1.2 Demographics

The population of EIL's distribution area is approximately 34,965 of which the Bluff area accounts for approximately 5%. Census population projections for EIL's distribution area are shown in Figure 8:

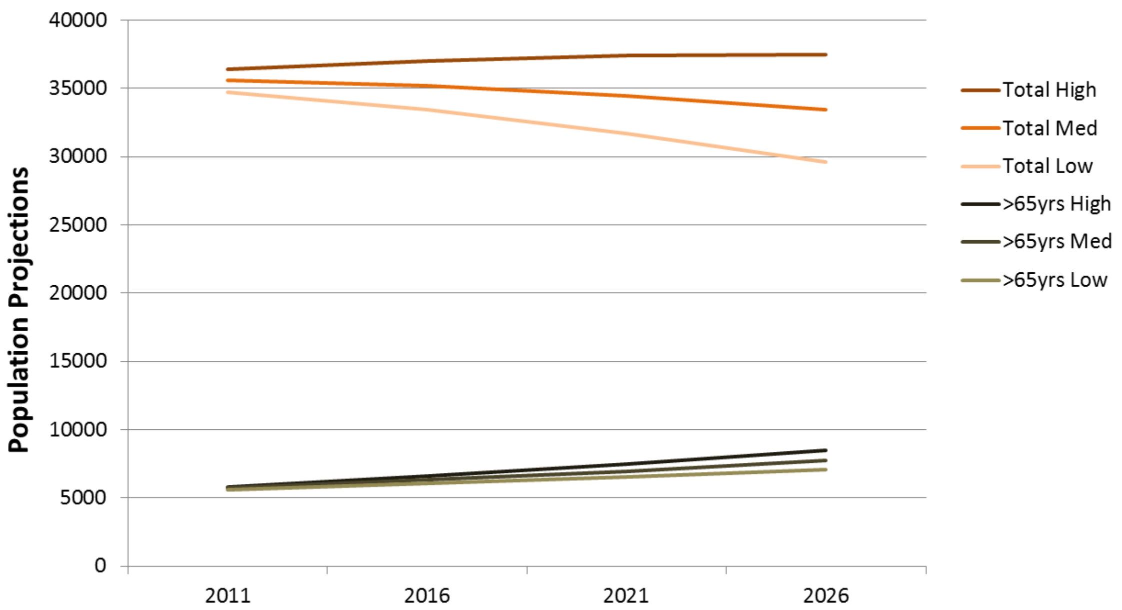


Figure 8: EIL Population Projections

The high projection shows population slightly increasing with medium and low projections showing a decline out to 2026. The number of people 65 years and older is projected to increase from about 15% to between 20% and 25% in 2026.

2.1.3 Key Industries[A4.1.2]

EIL's largest customer is a large port in the Bluff distribution area which regularly peaks at about 1.5MW and consumes approximately 5.8GWh per year.

No individual EIL customers are considered large enough to have any significant impact on network operations or asset management planning other than ensuring that adequate supply capacity is maintained.

Certain areas on the network have differing load densities and rates of growth which are more likely to influence asset management planning. Growth rates on the network however are relatively low and connections for new large customers are generally unpredictable so planning tends to be more reactive than proactive to avoid over investment.

The Bluff distribution area also includes port associated heavy industries as well as residential and commercial customers.

The Invercargill distribution area is predominantly residential but does include a medium-sized CBD, a heavy industrial area immediately west of the CBD and a light industrial area in the south east. The criticality of supply for the CBD as a whole is recognised with additional protection and automatic sectionalisation provided in this area.

2.1.4 Load Characteristics[A4.1.3]

Domestic: Standard household demand peaks in the morning (10:30am) and evening (6:30pm). The use of heat pumps is increasing electricity usage, with no noticeable impact over the summer hot period yet. Peaks normally occur in the winter months as heating requirements increase.

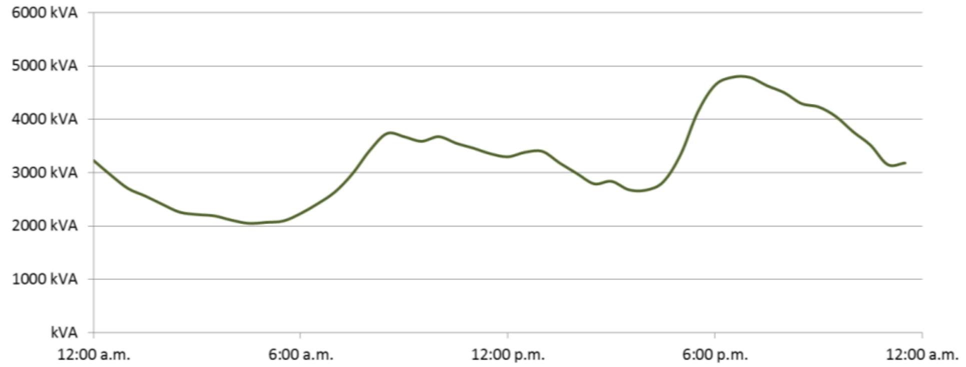


Figure 9: Typical Domestic Daily Load Profile (2 July 2011, Racecourse Road CB8)

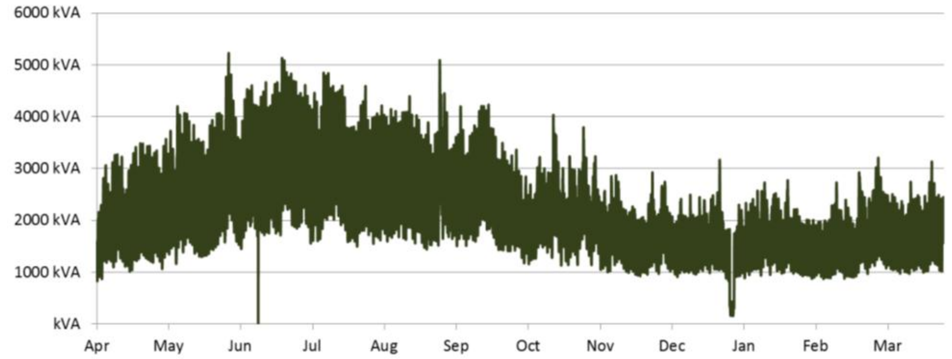


Figure 10: Typical Domestic Feeder Yearly Load Profile (Racecourse Road CB8)

CBD: Load peaks in the CBD later in the day (10:00-12:00am) as people migrate into the area for their work day. Week day loading is typically significantly higher than over the weekends corresponding to work patterns of the businesses in the CBD. Seasonal variation in the CBD load profile is similar to that of domestic loading with peak load occurring over the winter months. The CBD profiles shown in Figure 11 and Figure 12 include some industrial load which tends to follow similar consumption patterns.

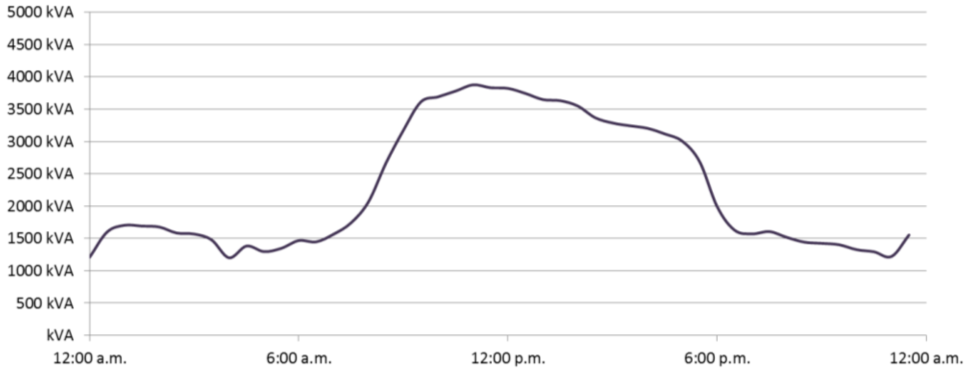


Figure 11: Typical CBD Feeder Daily Load Profile (2 July 2011, Leven Street CB10)

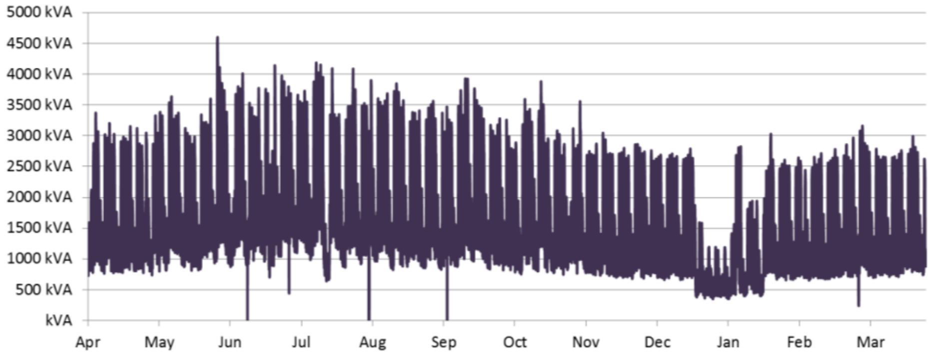


Figure 12: Typical CBD Feeder Yearly Load Profile (Leven Street CB10)

2.1.5 Other Drivers of Electricity Use

Other drivers of electricity use include:

- Heating associated with low temperatures during winter (-5°C frosts are not uncommon in the area). Increased electrical heating due to heat pump conversion is thought to be mostly offset by more efficient electrical heating replacing stand-alone electric heaters.
- The use of heat pumps as air conditioners is becoming more common especially in commercial buildings and often have poor power factor. Temperatures in the summer months occasionally reach 30°C.
- Improving home insulation due to the 'Warm Homes' project resulting in less energy required for heating.
- Proposed updates to the Regional Air Quality Plan have been advised and include prohibition of open fires from September 2015 and prohibition of non-approved burner/boilers installed;
    - before January 2001 from January 2016,

- between January 2001 and September 2005 from January 2021,
- between September 2005 and January 2010 from January 2025,
- after January 2010 from January 2029.

Approved boilers and burners are those which meet the national environmental Standards for emissions and thermal efficiency. This phase-out of inefficient heating will require replacement and some degree of conversion to electrical heating with heat pumps is to be expected.

- Increased energy efficiency due to government campaigns, for example gradual replacement of incandescent with compact fluorescent light bulbs and general energy conservation marketing.

2.1.6 Energy and Demand Characteristics[A4.1.4]

Key energy and demand figures for the year ending 31 March 2014 are as shown in Table 8.

Table 8: Energy and Demand

Parameter	Value	Long-term trend
Energy Conveyed	257.9 GWh	Variation around steady growth 0.5%
Maximum Demand[1]	63.64 MW	Large variation around steady growth 1.0%[2]
Load Factor	49%	Reasonably constant[2]
Losses	5.3%	Varying

It is particularly hard to extract underlying growth rates from historical data as both maximum demands and total energy conveyed, as recorded for any year, are heavily dependent on the weather. This variation tends to swamp the effect of the relatively low growth rates. Mathematical treatment such as “best fit” curve application yields completely different results when applied to different time periods i.e. previous 5 years, 10 years, 20 years etc. Shorter time periods giving meaningless results due to huge variation between inclusion and exclusion of a particular year (say between 4 years trend or 5 years trend) and longer time periods do not account for recent trends. Growth rates therefore tend to reflect “gut feel” more than anything and obviously certainty with the growth rates shown in Table 8 is low.

Note for the purposes of information disclosure Bluff is not considered a sub-network having less than 25km of distribution lines and less than 2000 ICPs connected and therefore values are inclusive of those for the Bluff area network.

Section 4.6.3 looks at the analysis, trending and forecast of growth for EIL.

2.2 Network Configuration

To supply EIL’s 17,199 customers EIL owns and operates two electrically separate networks that are both supplied by a single Grid Exit Point (GXP) at Invercargill. By way of explanation the Bluff network comprises two 11kV feeders supplied by TPCL’s zone substation situated just west of Bluff Township. EIL also owns interconnectors to TPCL’s

[1] This is different from the sum of the individual demands at each GXP, which will be greater than the coincident demand due to diversity.

[2] Step change in Maximum Demand occurred due to new Transpower Pricing Methodology, with individual GXP peaks now replaced by Lower South Island peaks across multiple GXP’s.

Otatara and Seaward Bush 33kV lines that provide alternative supplies to the Leven Street and Southern zone substations respectively.

2.2.1 Bulk Supply Assets and Embedded Generation[A4.2.1]

2.2.1.1 Invercargill GXP

Invercargill GXP comprises a strong point in the 220kV grid which is tied to Roxburgh and Manapouri power stations and to the North Makarewa GXP. Invercargill is also a major supply node for the Tiwai Point Smelter.

The 33kV supply arrangement at Invercargill comprises an indoor switchboard that is energised by two three-phase 120MVA 220/33kV transformers. There are eleven 33kV feeders each supplied through its own circuit breaker. EIL takes supply from seven of these feeders in normal operation including the two parallel TPCL feeders which supply Bluff. Back up supplies are available from other TPCL feeders and are used from time to time.

EIL owns the segments of 33kV line (but not the circuit breakers or bus) that run within the GXP land area and also accommodates a control room that oversees the operation of the network. EIL also owns one of the two 33kV 216⅔Hz ripple injection plants on the west side of the GXP site. The second plant is owned by TPCL with each providing backup capability to the other.

2.2.1.2 Bulk Supply Characteristics

Table 9: EIL Bulk Supply Characteristics

	Voltage	Rating	Firm Rating	Maximum Demand 2013/14	Coincident Demand 2013/14
Invercargill GXP	220/33kV	210MVA	105MVA	90.19MW (18:00 20/06/2013)	85.88MW (09:00 10/07/2013)
EIL	*(GXP assets shared with TPCL)*			63.64MW (20/06/2013 12:30)	58.60MW (09:00 10/07/2013)

2.2.1.3 Generation

There is no significant generation embedded within EIL's network. A small number of distributed generation connections exist but are only a few kW each in size so have negligible effect on GXP loading.

2.2.2 Subtransmission Network[A4.2.2 with AMP section 2.2.3]

EIL's subtransmission network is a single electrically connected 33kV network that takes supply from a single GXP at Invercargill and can take emergency supply from the North Makarewa GXP through TPCL's 33kV network as depicted in Figure 13.

Note that EIL's two Bluff 11kV feeders are supplied from TPCL's 33kV subtransmission network. EIL's subtransmission network comprises 1.4km of 33kV line and 22.1km of 33kV cable and has the following characteristics:

- Two points of interconnection with TPCL's 33kV network which provides alternative supplies to Leven Street and Southern zone substations.
- It is almost totally underground except for short lengths of overhead line between Invercargill GXP and Racecourse Road zone substation (about 200m long) and in the middle of the tie between Leven Street zone substation and TPCL's Otatara 33kV feeder.
- It is predominately a ring topology except for Racecourse Road which is a spur.

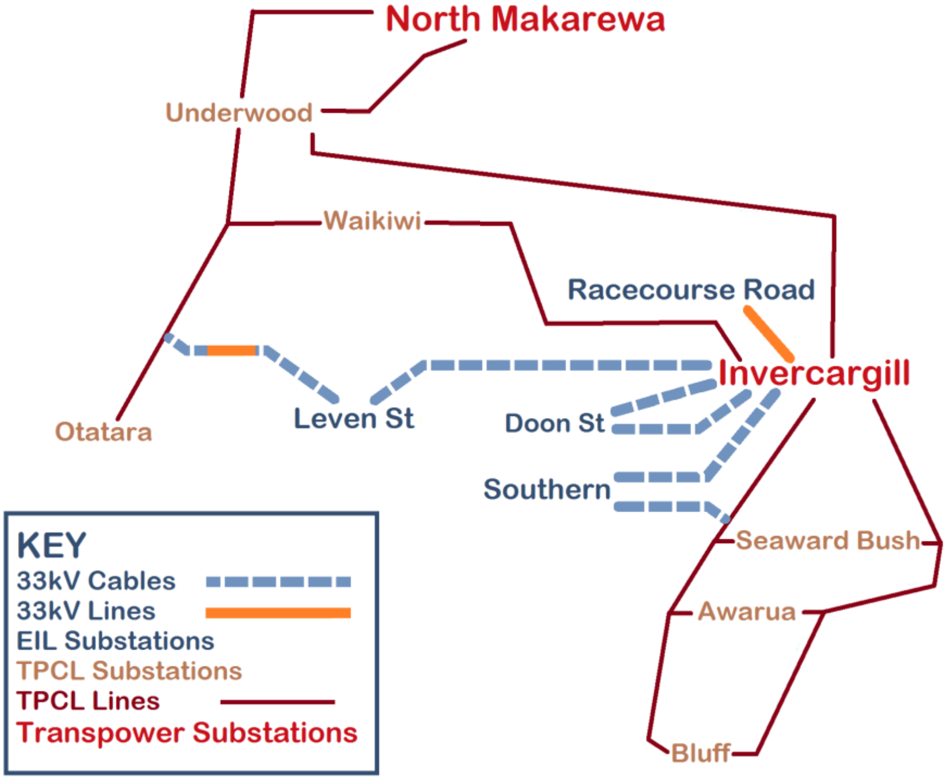


Figure 13: Subtransmission network

2.2.3 Zone Substations[A4.2.2 with AMP section 2.2.2]

EIL currently owns and operates four zone substations which have either AA or AAA security levels (see section 4.2.2.4 for security level definitions).

2.2.3.1 Doon Street

Doon Street is an urban AAA security substation having a dual-transformer arrangement with each transformer being supplied by a separate 33kV cable from Invercargill GXP. The substation supplies mainly residential customers but also supplies a large part of the Invercargill CBD. One transformer has a maximum rating of 23MVA with the other transformer being a larger 36MVA unit. This transformer mismatch is a temporary arrangement after one Doon Street transformer failed and was replaced. This arrangement provides a capacity of 59MVA with a firm capacity of 23MVA.

2.2.3.2 Leven Street

Leven Street is an urban AAA security substation having a dual-transformer arrangement being supplied by a single 33kV cable from Invercargill GXP. The substation supplies a large part of the CBD and Invercargill's heavy industrial area as well as some residential customers. An alternative 33kV supply via TPCL's Otatara 33kV feeder (which is supplied from an alternative GXP) is available which achieves the necessary AAA security for the substation. Due to the alternative supply being from another GXP the 33kV back-feed cannot be 'normally in service' and therefore a short interruption has to be accepted. Both transformers have a maximum rating of 23MVA providing a capacity of 46MVA and a firm supply of 23MVA.

2.2.3.3 Southern

Southern is an urban AA security substation having a single 23MVA transformer supplied by a single 33kV cable from Invercargill GXP. An alternative 33kV supply from TPCL's Seaward Bush 33kV feeder is available as backup if required. The substation supplies residential and some light industrial customers.

2.2.3.4 Racecourse Road

Racecourse Road is an urban AA security substation having a single 23MVA transformer supplied by a short 33kV overhead line from Invercargill GXP. The substation supplies predominantly residential areas but also has two metered feeders which supply a small semi-rural area of TPCL's network.

2.2.4 Distribution Network[A4.2.3]

2.2.4.1 Configuration

The 11kV distribution network is heavily meshed throughout the entire Invercargill area, with almost all distribution transformers being able to be supplied by two separate 11kV supplies. In the CBD most supplies to each transformer are protected by 'Solkor' unit protection.

Distribution in Bluff is mainly meshed except at feeder extremities.

2.2.4.2 Construction

The 11kV distribution network construction is as follows:

- All underground cable within the Invercargill CBD. Cable type (PILC or XLPE) depends on date of original installation or of repairs and renewals.
- Suburban areas of Invercargill are either XLPE cable or overhead line. A gradual overhead to underground (OHUG) program has been implemented over several decades leaving only 9.6km of overhead construction left.
- Bluff is almost totally overhead construction due to the shallow soil over rock substrata making undergrounding difficult. Originally the Bluff area was operated at 3.3kV distribution with conversion to 11kV occurring after EIL took over the assets.

2.2.4.3 Per Substation Basis

EIL's split of distribution network on a per substation basis is presented in Table 10. Safety and reliability are EIL's strongest drivers for allocation of resources, with customer density providing an indication of priority of other works.

Table 10: Distribution network per substation

Substation	Line Length (km)	Underground Cable Length (km)	Customers	Customer density
Doon Street	0.0	53.1	5,600	105.41 /km
Leven Street	4.9	31.0	2,109	58.66 /km
Racecourse Road	3.1	25.0	2,910	103.37/km
Southern	1.6	45.1	5,565	119.28 /km
Bluff – EIL feeders	13.2	4.7	1,015	56.62 /km
Total/average	**22.77**	**159.01**	**17,199**	**95.60 /km**

2.2.5 Distribution Substations[A4.2.4]

Just as zone substation transformers form the interface between the subtransmission and the 11kV distribution networks, distribution substations form the interface between the 11kV distribution and 400V distribution networks. The distribution substations range from a few remaining pole-mounted transformers to 3-phase 1,000kVA ground-mounted transformers supplied via circuit breaker ring main units with remote indication and control. These larger substations typically supply CBD customers or special customers, like the Stadium Southland event centre. There are a few underground sites located below pavements or road centre-plots, particularly in the CBD where land for ground mounted equipment was not available. Table 11 shows distribution transformer numbers by rating.

Table 11: Number of distribution substations

Rating	Pole	Ground
1-phase up to 15kVA	2	1
1-phase 30kVA	1	
3-phase up to 15kVA		1
3-phase 30kVA		3
3-phase 50kVA	2	2
3-phase 75kVA		1
3-phase 100kVA	3	17
3-phase 200kVA	4	62
3-phase 300kVA	1	250
3-phase 500kVA	1	57
3-phase 750kVA		30
3-phase 1,000kVA		8
Total	**13**	**432**

Each distribution transformer has medium voltage (MV) protection generally provided by fuses but some larger units by circuit breakers controlled by basic overcurrent and earth fault relays. This is generally applied as individual protection for each site though occasionally group protection is used where a single fuse is located at the take-off from the main feeder cable with up to five downstream units.

Low voltage protection is by DIN[3] standard HRC[4] fuses sized to protect overload of the distribution transformer or outgoing LV cables.

[3] Deutsches Institut für Normung e.V. (DIN; in English, the German Institute for Standardization) is the German national organization for standardization and is that country's ISO member body.

2.2.6 LV Network[A4.2.5]

2.2.6.1 Coverage

The 400V distribution network almost totally overlays the 11kV distribution network and is present on virtually every street. The coverage of each individual distribution transformer tends to be limited by volt-drop to about a 200m radius.

2.2.6.2 Configuration

The 400V distribution network has a moderate degree of interconnection that enables many customer connections to be supplied from "either end" in the event of a transformer failure. Transformer loading and volt drop tend to be the limiting factors in utilising these backups.

2.2.6.3 Construction

All of the Invercargill CBD and most of the suburban area reticulation is underground cable; mostly PVC with some older PILC cables. A couple of areas have overhead line remaining.

Bluff has overhead construction with underbuilt reticulation on most 11kV poles. Some undergrounding has occurred in a few locations using XPLE cable.

2.2.6.4 Per Substation Basis

On a per substation basis the split of LV network is as shown in Table 12.

Table 12: LV network per substation

Substation	Line Length (km)	Underground Cable Length (km)	Customers	Customer density
Doon Street	0.0	139.9	5,600	40.04 /km
Leven Street	3.4	55.8	2,109	35.66 /km
Racecourse Road	0.8	75.1	2,910	38.33 /km
Southern	1.4	147.7	5,565	37.33 /km
Bluff - EIL	24.5	3.3	1,015	36.50 /km
Total / average	**30.1**	**421.8**	**17,199**	**38.07 /km**

2.2.7 Customer Connection Assets

EIL has 17,199 customer connections - for which revenue is earned for providing a connection to the network via the ten retailers which convey electricity over the network. All of the "other assets" convey energy to these customer connections and essentially are a cost to EIL that has to be matched by the revenue derived from the customer

8 High Rupture Capacity.

connections. These customer connections generally involve assets ranging in size from a simple fuse on a pole or in a suburban distribution pillar to dedicated lines and transformer installations supplying single large customers. The number and changes over the year are shown in Table 13.

Table 13: Classes of customer connections

	Small (≤ 20kVA)				Medium (21 – 99kVA)			Large (≥100kVA)			
	8kVA 1ph	10% Fixed Option	20kVA 1ph	15kVA 1ph	30kVA 3ph	50kVA 3ph	75kVA 3ph	100kVA 3ph	Non ½hr Metered Individual	½hr Metered Individual	Total
Apr-13	343	3,915	11,438	77	711	378	123	72	50	126	**17,226**
May-13	339	4,018	11,322	76	710	379	124	72	50	126	**17,224**
Jun-13	339	4,028	11,321	75	711	378	125	71	50	126	**17,221**
Jul-13	341	4,031	11,337	75	711	377	125	71	51	126	**17,219**
Aug-13	342	4,007	11,341	74	713	377	125	71	51	126	**17,216**
Sep-13	345	3,981	11,337	74	712	374	127	72	51	126	**17,214**
Oct-13	346	3,988	11,321	75	709	373	127	72	51	126	**17,211**
Nov-13	346	3,995	11,316	76	707	376	127	72	51	125	**17,209**
Dec-13	346	4,045	11,251	76	705	376	130	72	51	125	**17,206**
Jan-14	343	4,049	11,237	76	705	376	130	72	52	125	**17,204**
Feb-14	340	4,091	11,205	75	708	376	129	72	52	125	**17,201**
Mar-14	340	4,136	11,182	75	707	376	128	71	52	125	**17,199**

In most cases the fuse forms the demarcation point between EIL's network and the customer's assets (the "service main") and this is usually located at or near the physical boundary of the customer's property.

2.2.8 Secondary Assets and Systems[A4.2.6]

2.2.8.1 Load Control Assets

EIL currently owns and operates a 33kV 216⅔Hz 125kVA ripple injection plant at Invercargill. Ripple relays at customer's premises respond to the injected ripple signal and switch controllable load (such as hot water cylinders and night-store heaters) providing effective load control for the network. The ripple injection plant is backed up from the adjacent TPCL plant and vice versa.

2.2.8.2 Protection and Control

(a) Key Protection Systems

EIL's network protection includes the following broad classifications of systems:

Circuit Breakers

Circuit breakers provide switching and isolation points on the network and generally work with protection relays, to provide automatic detection, operation and isolation of faults. They are usually charged spring or DC coil operated and able to break full load current as well as interruption of all faults.

Protection relays have always included over-current and earth-fault functions but more recent equipment also includes voltage, frequency, directional and circuit breaker fail functionality in addition to the basic functions. SOLKOR differential protection is also used extensively on 11kV cables in the Invercargill CBD.

Other relays or sensors may drive circuit breaker operation. Examples include transformer and tap changer temperature sensors, gas accumulation and surge relays, explosion vents or oil level sensors.

Fuses

Fuses provide fault current interruption of some faults and may be utilised by manual operation to provide isolation at low loading levels. As fuses are a simple over-current device they do not provide a reliable earth fault operation, or any other protection function.

Switches and Links

Switches provide no protection function but allow simple manual operation to provide control or isolation. Switches may be able to break considerable load (e.g. ring-main unit load break switches) but others such as air break switches may only be suitable for operation under low levels of load. Links generally require operation when de-energised so provide economic but less convenient switch points.

(b) DC Power Supplies

Batteries, battery chargers and battery monitors provide the direct current (DC) supply systems for circuit breaker control and protection functions and allow continued operation of plant throughout any power outage.

(c) Tap Changer Controls

Voltage Regulating Relays (VRR's) provide automatic control of the 'Tap Change On Load' (TCOL) equipment integral to power transformers and regulate the outgoing voltage to within set limits.

2.2.8.3 SCADA and Communications

SCADA is used for control and monitoring of zone substations and remote switching devices and for activating load control plant.

(a) Master Station

EIL's SCADA master station is located at PowerNet's System Control centre at the Findlay Road GXP, Invercargill. This system is based on the process industry standard 'iFIX' with a New Zealand developed add-on 'iPOWER' to provide full Power Industry functions.

(b) Communications Links

EIL currently owns and operates a multicore copper network between zone substations, CBD distribution substations and the SCADA master station at System Control from where control commands may be issued.

Data-radio links are also in service linking the System Control Data-radio to the Doon Street, Racecourse Road, and Southern zone substations and the Gore Street circuit breaker in Bluff.

(c) Remote Stations

Leven Street zone substation has one Harris D20M multiple rack RTU communicating with DNP3.0 protocol over 9600 baud Modem. Kingfisher RTUs are located at each of the Racecourse Road, Doon Street and Southern zone substations. Another Kingfisher RTU is located at a CBD distribution substation and there is also a Nulec controller for a field circuit breaker acting as an Intelligent Electronic Device (IED) in Bluff. The above RTUs all communicate with DNP3.0 protocol over 9600 baud Modem.

There are eight GPT mini RTUs located in other distribution substations in the CBD communicating with HDLC protocol over 1200 baud modem.

2.2.8.4 Other Assets

Generation

EIL do not own any mobile generation plant but may utilise three diesel generators owned by PowerNet. These are rated at 500kW, 350kW and at 275kW. There are no stand-by generators owned or able to be utilised by EIL.

Power Factor Correction
Customers are required to draw load from connection points with sufficiently good power factor so as to avoid the need for network scale power factor correction. As such EIL does not own any power factor correction assets.

Mobile Substations
EIL can utilise a TPCL owned trailer mounted 3MVA 11kV regulator and circuit breaker with cable connections though it is unlikely to be required due to the excellent backup capability of the 11kV network.

Metering
Most zone substations have time-of-use (TOU) meters on the incomers that provide details of energy flows and power factor. General integrating energy meters are provided to general customers with retailers providing TOU meters for larger customers, generally all over 100kVA capacity.

2.3 Age and Condition of EIL's Assets by Category

2.3.1 Bulk Supply Assets and Embedded Generation

The company owns assets within the GXP as detailed in Table 14.

Table 14: Injection Plants

Voltage	Location	Quantity	Manufactured	Condition
33kV	Invercargill 2	1	1988	Good, all gear is indoor

The injection plant at Invercargill was commissioned in 1989, with all plant enclosed within the building. This provides protection from the elements and therefore an expected greater extended life for the non-electronic components. The electronic components continue to provide good service with the power supply unit upgraded in 2005, after failures at other sites. While the plant has reached end of ODV standard life the condition and minor replacements mean the expected remaining life of this plant is at least 3 years by which time the injection plant will be redundant with the installation of smart meters.

2.3.2 Subtransmission Network

EILs subtransmission circuits are detailed in Table 15. All circuits are within their rating.

Table 15: Subtransmission Circuit Details

Voltage	Location	Quantity	Manufactured	Condition
33kV	Invercargill 2732 to Southern	Oil filled cable 5.0 km	1968 Remaining life 23yrs	Good, only lightly loaded*
33kV	Invercargill 2792 to Doon Street	Oil filled cable 3.5 km	1970 Remaining life 25yrs	Good, moderately loaded*
33kV	Invercargill 2872 to Doon Street	Oil filled cable 3.5 km	1975 Remaining life 30yrs	Good, moderately loaded*

Voltage	Location	Quantity	Manufactured	Condition
33kV	Invercargill 2862 to Leven Street	XLPE Cable 5.2 km	1983 Remaining life 13yrs	Good, only lightly loaded.
33kV	Seaward Bush Line to Southern	XLPE Cable 1.5 km	1999 Remaining life 39yrs	Good, not normally loaded.
33kV	Otatara Line to Leven	XLPE Cable 3.7 km & Overhead Line 1.1 km	2000 Remaining life 30yrs	Good, not normally loaded.
33kV	Invercargill 2772 to Racecourse Road	Overhead Line 0.3 km	1975 Remaining life 5yrs	Good, short cross country, concrete poles.

*However there has been some doubt raised recently over the understood ratings and reliability of these oil cables. This will be further investigated once the planned new 33kV XLPE cable is installed which will provide an alternative supply and reliable backup to the oil filled cables (see sections 4.8 and 5.5.1).

2.3.3 Zone Substations

2.3.3.1 Subtransmission Voltage Switchgear

The latest switchboard at Leven Street Substation is indoor and in good condition. The oldest circuit breaker is an outdoor unit located at Southern substation and is reaching end of life. A second outdoor circuit breaker at Southern substation has had a service life of 32 years and has some rusting due to the harsh coastal environment in Bluff from where it was relocated. Outdoor equipment at Southern Substation has been damaged by vandalism requiring the installation of protective barriers around critical equipment.

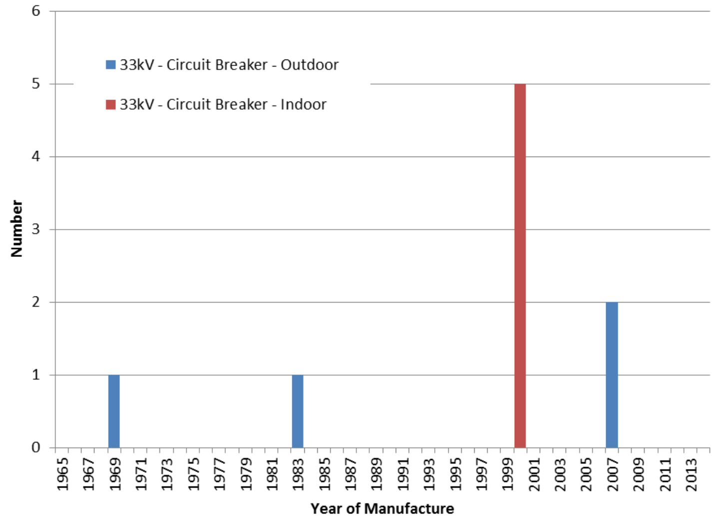


Figure 14: Subtransmission Voltage Circuit Breakers

2.3.3.2 Subtransmission Cables

EIL has three oil filled cables supplying the Doon St and Southern substations. The oldest of these cables has approximately a third of its expected life or 25 years remaining so should be in sound condition. However there are concerns with the rating of the cables and with the joints which have been found to be unreliable by other distribution companies.

The other cables are XLPE cables which are lightly loaded and in good condition. Some of these are unloaded cables used occasionally for backup. Earlier XLPE cables are understood to have a slightly shorter life expectancy however the oldest of these cables is still expected to have a remaining life beyond the 10 year planning horizon.

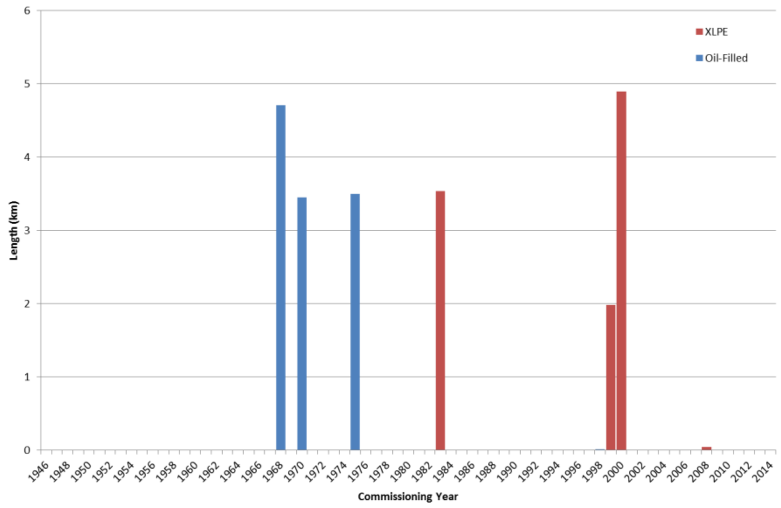


Figure 15: Subtransmission Cables

2.3.3.3 Power Transformers

The Power Transformers on the network were all rated to supply load up to 23MVA with forced cooling, based on an ambient temperature of 5ºC. Peak load in EIL generally occurs at the coldest times when heating requirements are greatest. Each unit is under the ONAN rating and Dissolved Gas Analysis monitoring shows each is in good condition.

Due to this condition assessment and the age of the units there are no transformer replacements expected within the next 10 years, however one of the two Doon St transformers unexpectedly failed in service recently and has been temporarily replaced with a 10MVA unit borrowed from TPCL. There is therefore less confidence in the condition of the remaining Doon St transformer which is of a similar manufacture, age and operational history. Power transformers beyond half their expected life are scheduled for refurbishment over the next few years and will include a detailed condition assessment.

A new larger 18/36MVA power transformer was purchased and installed as replacement for the failed Doon Street unit.

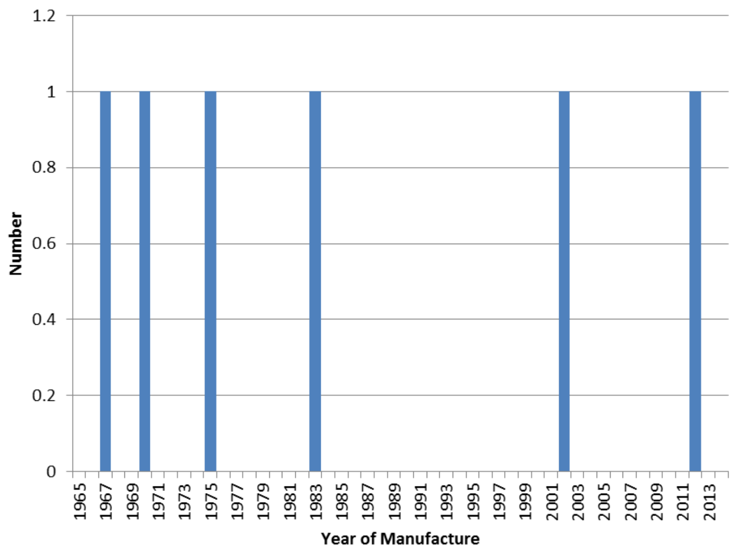


Figure 16: Power Transformers

2.3.3.4 Distribution Switchgear

Condition of the MV distribution switchgear is generally good however the oldest of this equipment is at end of life. Over half of the switchgear units make up 11kV switchboards at the zone substations with the rest generally installed in ring main unit configuration located in distribution substations in the city CBD, many are underground.

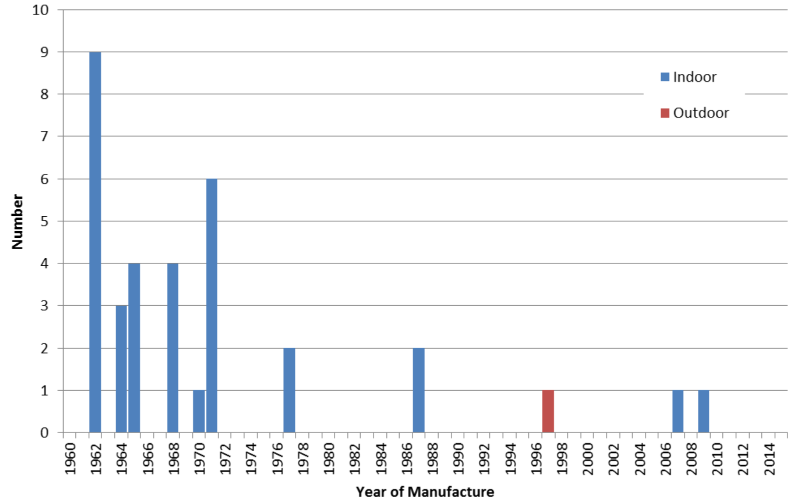


Figure 17: Distribution Voltage Circuit Breakers

2.3.4 Distribution Network

Figure 18 below displays the age of the MV cables on the network. Data on the exact material was not recorded and is now uneconomic to collect. Actual practical life for any cable is likely to be greater than the ODV standard life and on-going monitoring of actual performance will be utilised in planning. Most cables are lightly loaded and in sound condition however there have been termination and joint failures.

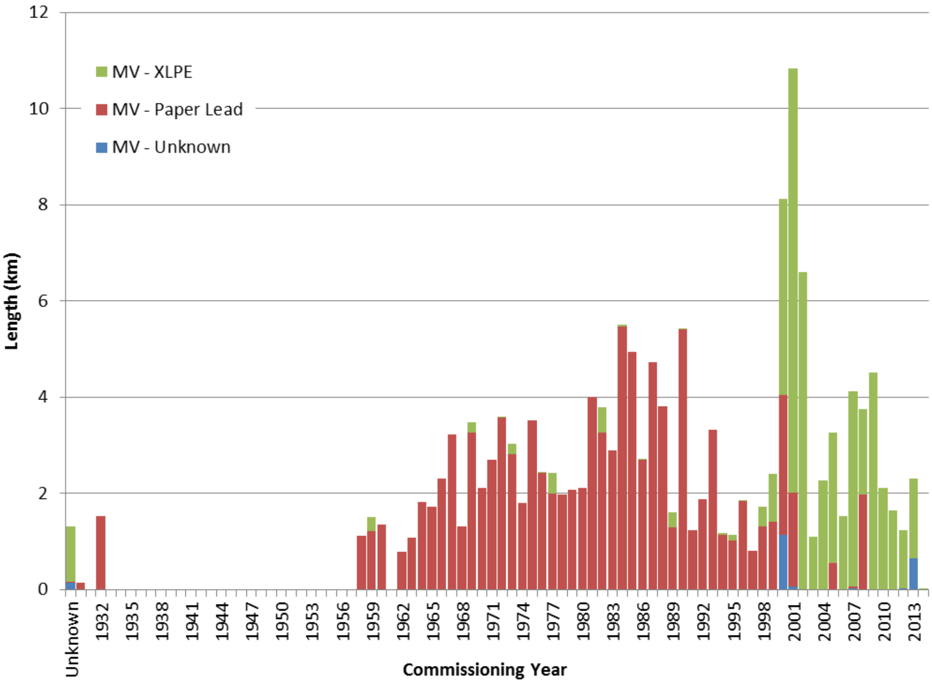


Figure 18: MV Cables

MV lines have gradually disappeared from the Invercargill network as the services have been undergrounded with only about 10km remaining. Most of the MV line length is in the Bluff area network where undergrounding is difficult due to the rocky subsurface.

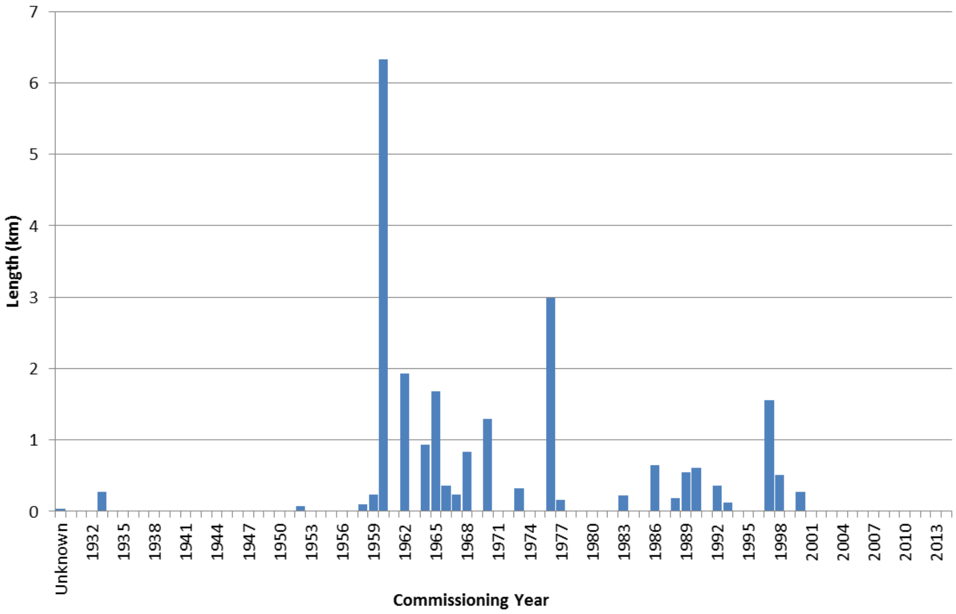


Figure 19: MV Lines

Figure 20 below displays the estimated age based remaining life of the MV poles on the network. The majority of these are in the Bluff region with most poles in Invercargill city having been removed as part of an extensive undergrounding programme.

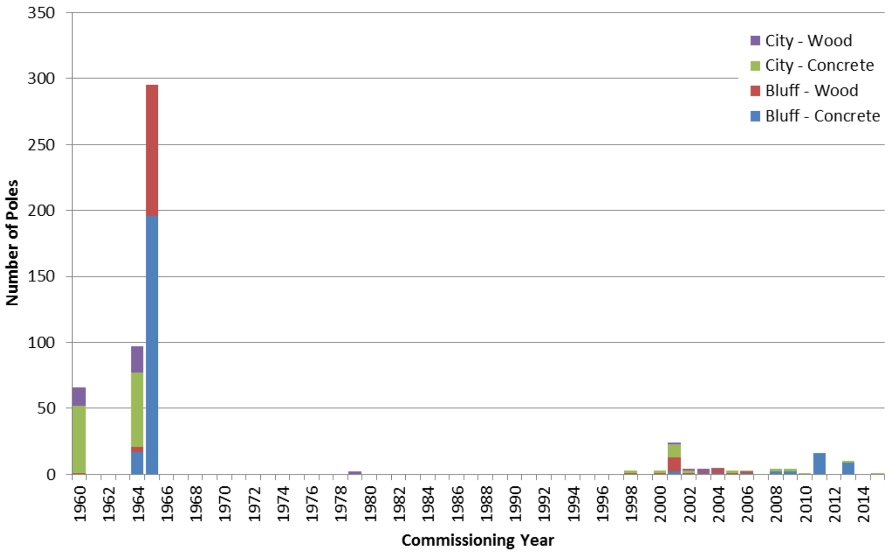
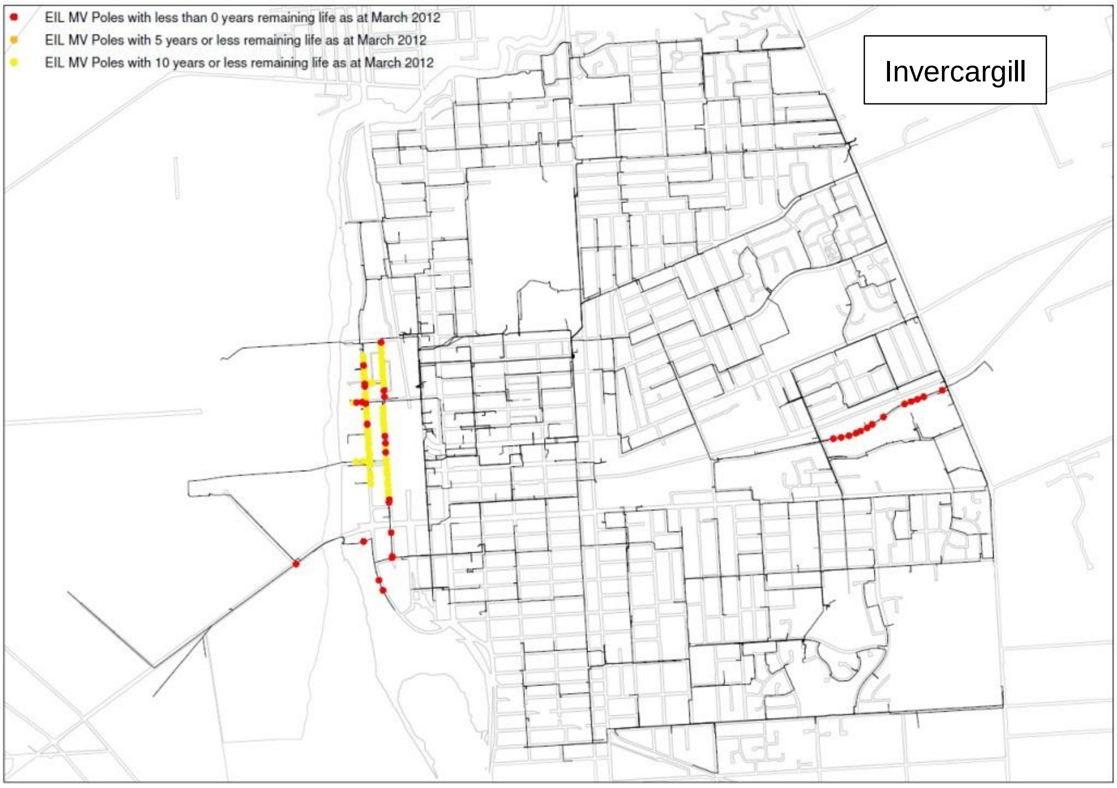


Figure 20: Distribution Poles

In theory for wooden poles, all lines built prior to 1970 should be replaced by the end of 2015 however five yearly condition assessment surveying is done on all MV lines with remedial repairs or renewal planned based on information obtained.

Maintenance of the few poles remaining in the Invercargill network area was deferred due to planned undergrounding of the Bond Street industrial area. This area will now remain as overhead construction therefore a slight focus in this area will now be required to catch up on this deferred maintenance. Figure 21 shows poles at or approaching typical end of life age, giving an indication of the MV pole replacements required over the ten year planning horizon.



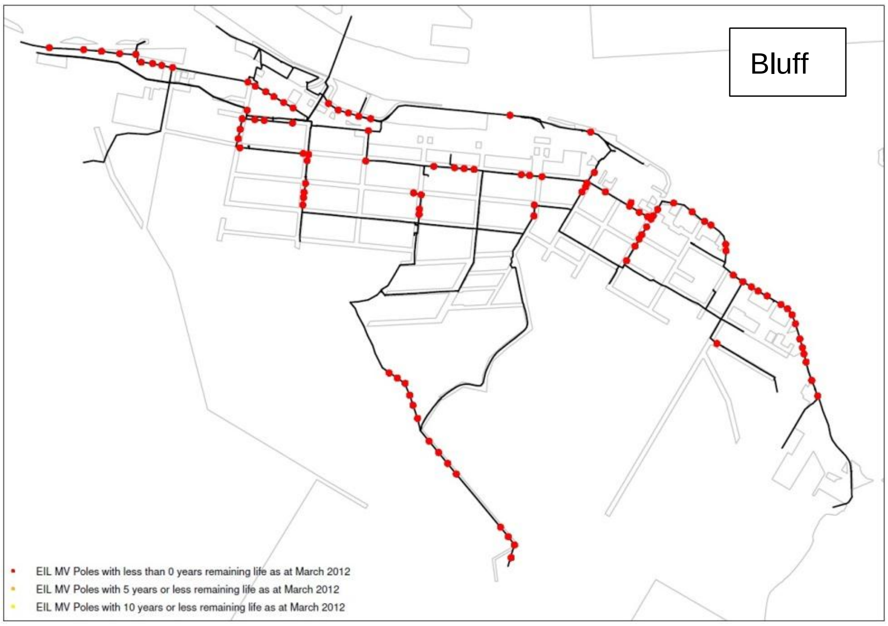


Figure 21: MV Poles with 10 years or less life remaining

2.3.5 Distribution Substations and Transformers

Figure 22 below displays the age profile of the distribution transformers on the network.

Most of EIL's transformers are ground mounted after the extensive undergrounding programme with only a few pole mounted transformers remaining.

Transformers found to be in poor condition after five yearly inspections may be replaced with units removed from service refurbished for reuse if economic. As ground mounted units are typically enclosed, the weather impact is reduced and the condition of these transformers is good.

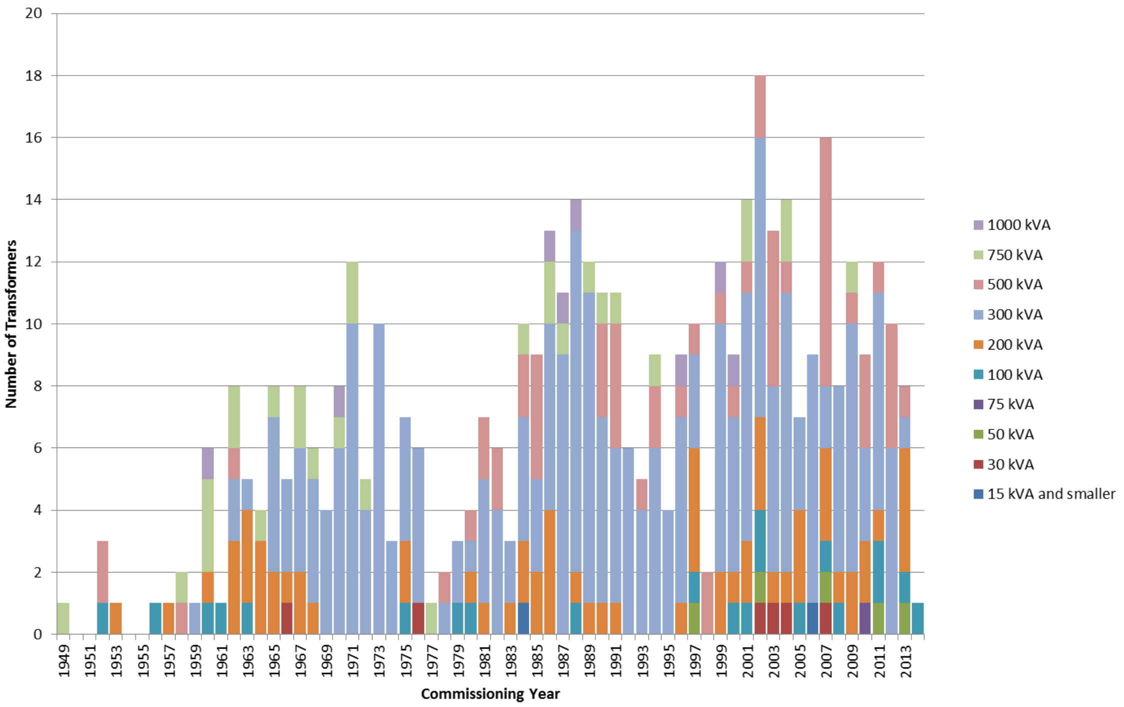


Figure 22: Distribution Transformers

2.3.6 LV Network

The LV cable commissioning year profile is shown in Figure 23 and highlights that based on age a number of assets should be renewed. In practice cables are left in service until performance deteriorates impacting on service levels.

Several 400V cables installed in the early 1970s are now reaching capacity due to in-build and greater demand per household. This is typically seen as an increase in voltage complaints received due to excessive volt drop during periods of peak loading.

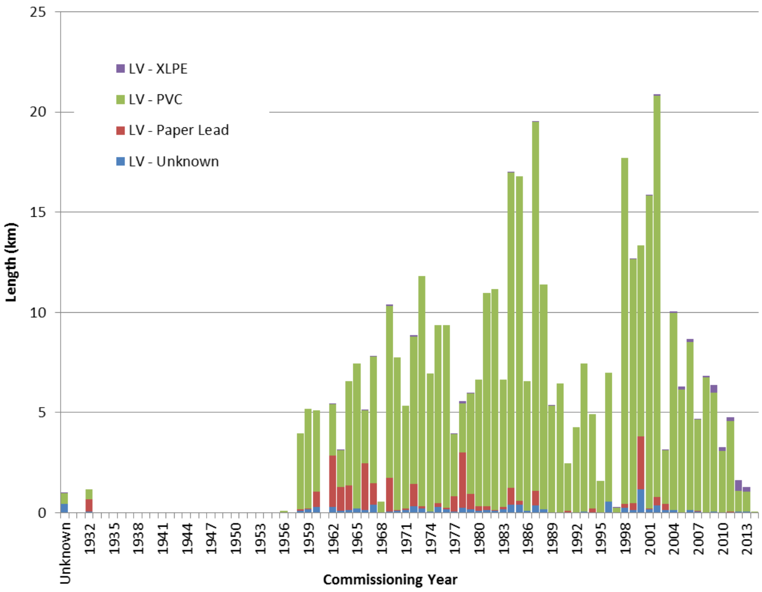


Figure 23: LV Cables

LV lines have gradually disappeared from the Invercargill network as the services have been undergrounded with less than 6km remaining. Most of the LV line length is on the Bluff area network where undergrounding is difficult due to the rocky subsurface.

New overhead line is being installed as ABC (Aerial Bundled Conductor) which does not require cross arms and insulators and has PVC insulation improving line safety.

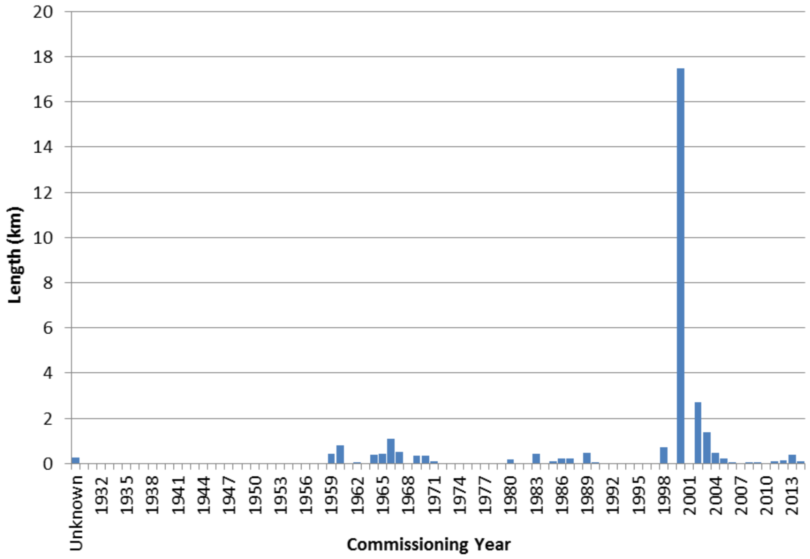


Figure 24: LV Lines

Almost all LV (400V) poles in the city have been removed as part of the undergrounding programme. Poles in Bluff and those remaining in Invercargill as shown in Figure 25 will be renewed as required being identified during the regular inspections of the network. A significant number of LV pole replacements have been completed recently as a result of these inspections.

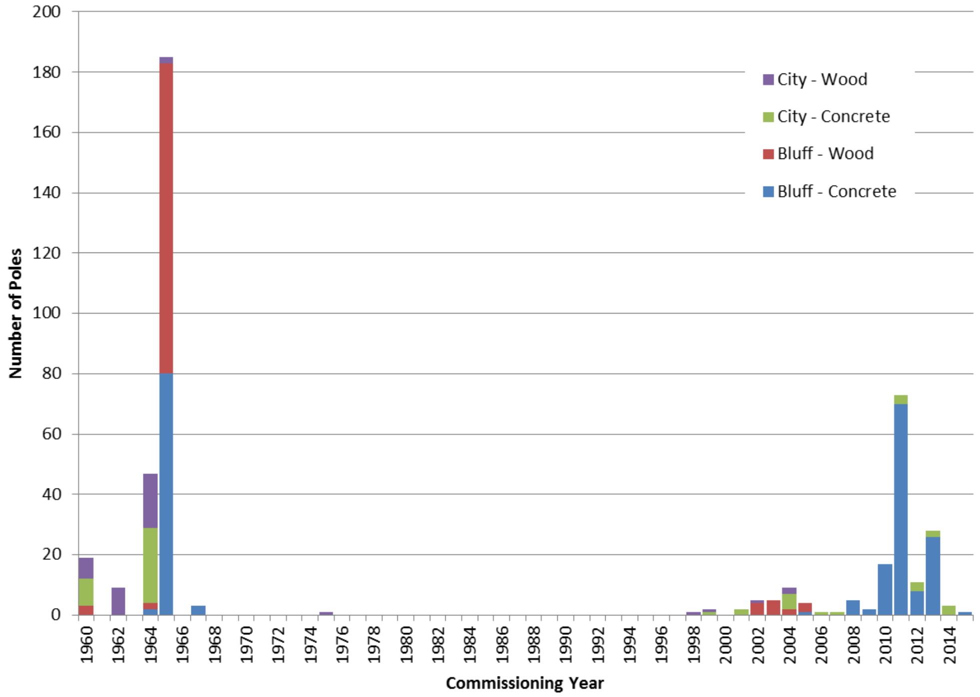
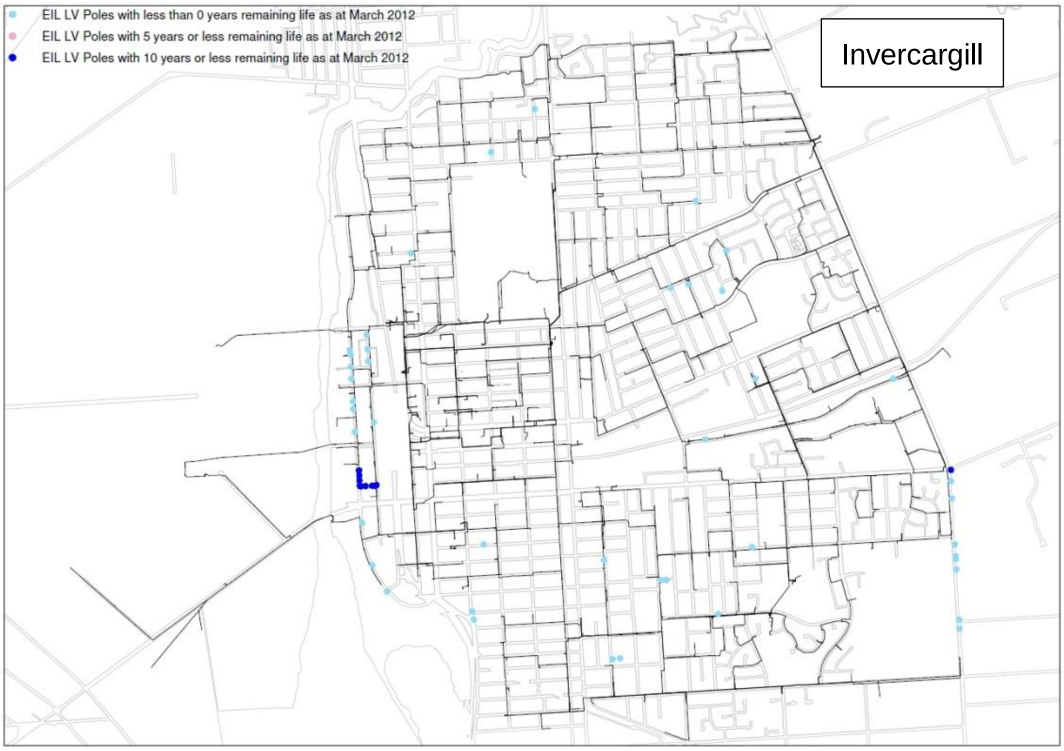


Figure 25: LV Poles

Figure 26 shows LV poles which are targeted for renewal over the 10 year planning period.



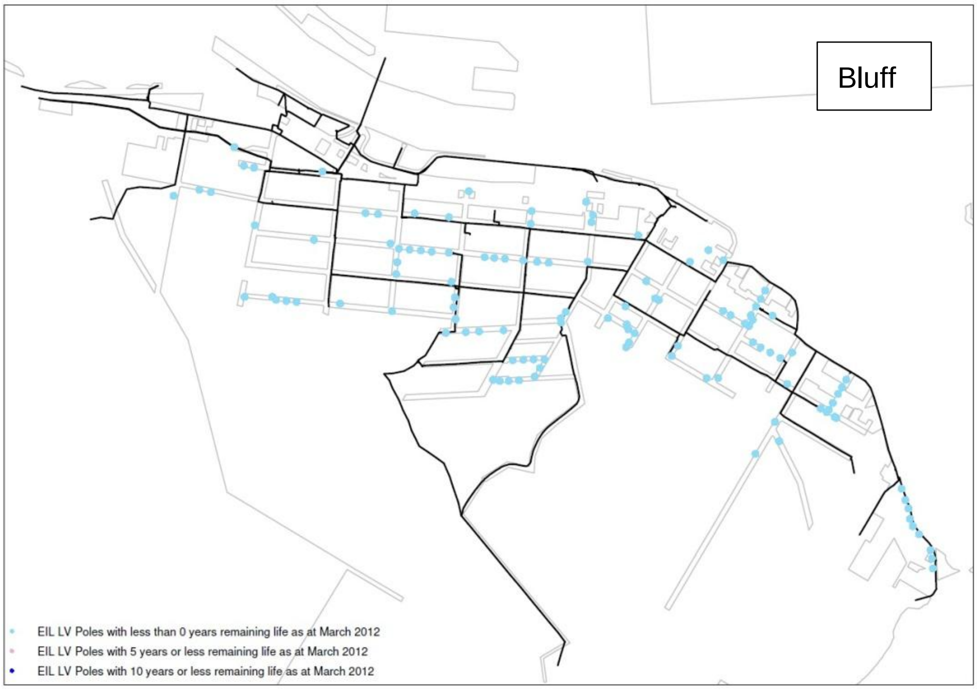


Figure 26: LV Poles with 10 years or less life remaining

2.3.7 Customer Connection Assets

No accurate age data exists for customer service cable or line assets and generally these are renewed as they fail or are augmented for increased customer requirements.

2.3.8 Load Control Assets

The installation of Load Control started with the injection plant at Invercargill in 1989 and finished at North Makarewa in 1994. Details are included with the GXP installed equipment. All 33kV plants are enclosed within buildings providing protection from the elements and therefore there is an expected greater extended life for the non-electronic components. The electronic components continue to provide good service with the power supply units upgraded in 2005 after failures at other sites.

These plants will be made redundant with the roll out of smart meters over the next few years.

2.3.9 Protection and Control

2.3.9.1 Key Protection Systems

The ground mount field circuit breakers are included with the 11kV zone substation circuit breakers, see section 2.3.3.4.

(a) Circuit Breakers

EIL has one 11kV pole mount field circuit breaker in service, located at Gore Street Bluff. It is a Nulec N24 reclosing circuit breaker manufactured in 1997 and is in average condition.

(b) Switches

Details on the age of air break switches (ABSs) are limited but most have been removed as part of the undergrounding programme with a small number remaining, mainly in Bluff.

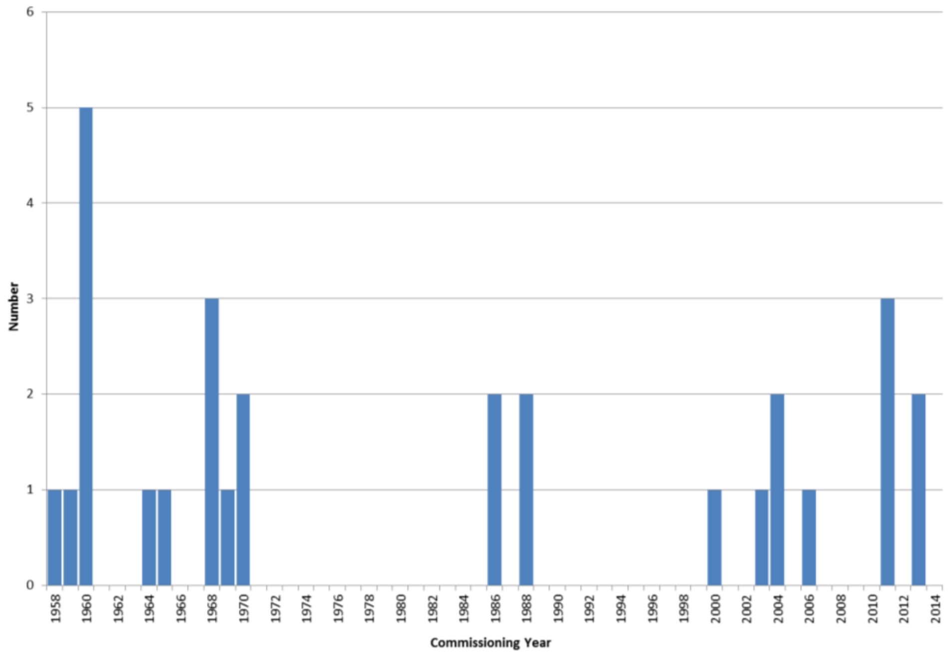


Figure 27: Air Break Switches

The age profile of RMU's below shows a number of units have reached their standard life of 45 years however these units are enclosed and are still providing good service. Some ages have been estimated.

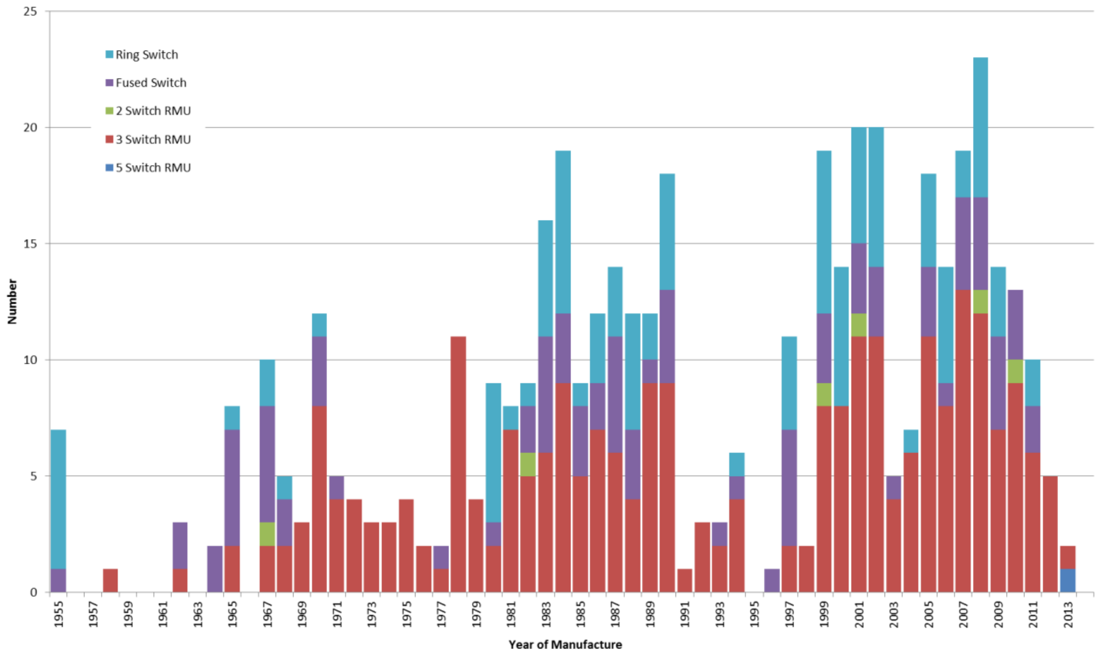


Figure 28: Ring Main Units

(c) Fuses

Most of the drop-out fuses on the network have been removed due to the undergrounding of services in the city, with a relatively small number remaining, mainly in Bluff. They are most often used where a transformer is supplied from overhead lines.

2.3.9.2 DC Power Supplies

As DC batteries are essential to the safe operation of protection devices, regular checks are carried out and each battery is replaced prior to the manufacturer's recommended life. No batteries are more than six years old.

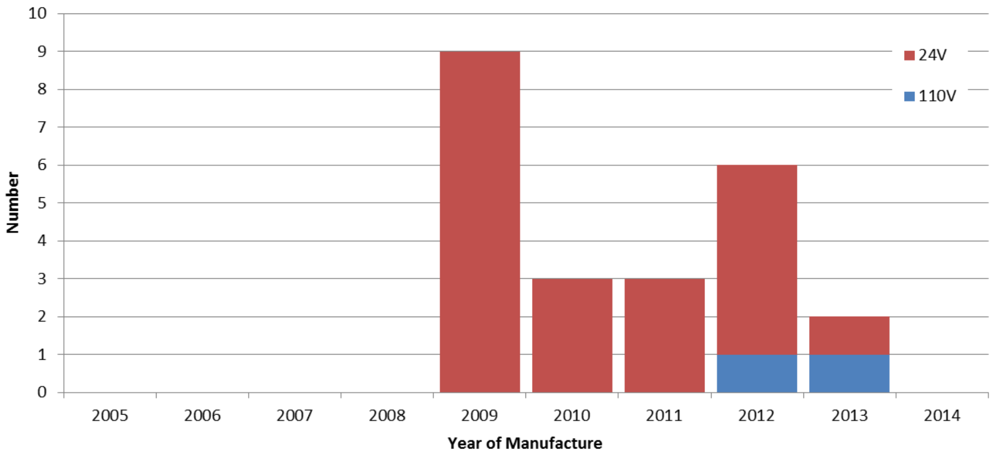


Figure 29: DC Batteries

2.3.9.3 Tap Changer Controls

Six voltage regulating relays are in operation with the associated transformer and are in good condition.

2.3.10 SCADA and Communications

2.3.10.1 Master Station

The initial system was commissioned in 1999 with a more recent upgrade of the Server PC's in 2005. The software has been developed with the latest version being implemented with the new servers in 2005. Both operator stations now have LCD screens.

2.3.10.2 Communications Links

The communications links have been upgraded in the last five years and the equipment is still in as-new condition.

2.3.10.3 Remote Stations

The early GPT mini RTU's were installed in 1995-98 to automate circuit breakers at distribution substations in the CBD. These units have continued to provide patchy service and are now due to be replaced. Two more modern RTUs are installed at distribution substations and larger RTUs with greater I/O are installed at each zone substation.

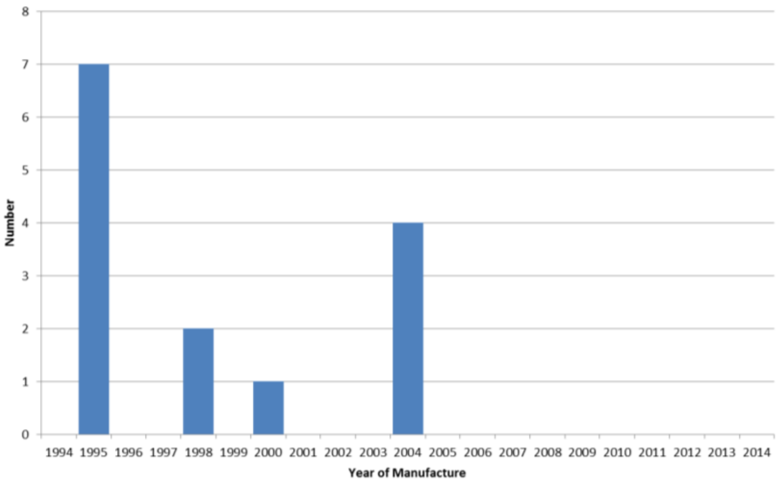


Figure 30: Remote Terminal Unit Assets

2.3.11 Other Assets

2.3.11.1 Mobile generation

None, but PowerNet own three mobile diesel generators rated at 500kW, 350kW and 275kW which EIL can utilise.

2.3.11.2 Stand-by Generators

None.

2.3.11.3 Power Factor Correction

None.

2.3.11.4 Mobile Substations

None.

2.3.11.5 Metering

EIL has 'Time Of Use' (TOU) meters on its incoming circuit breakers to provide accurate loading information on each zone substation. There are also TOU meters on some feeders to provide indicative load profiles for certain load groups. The age profile of these is shown in Figure 31.

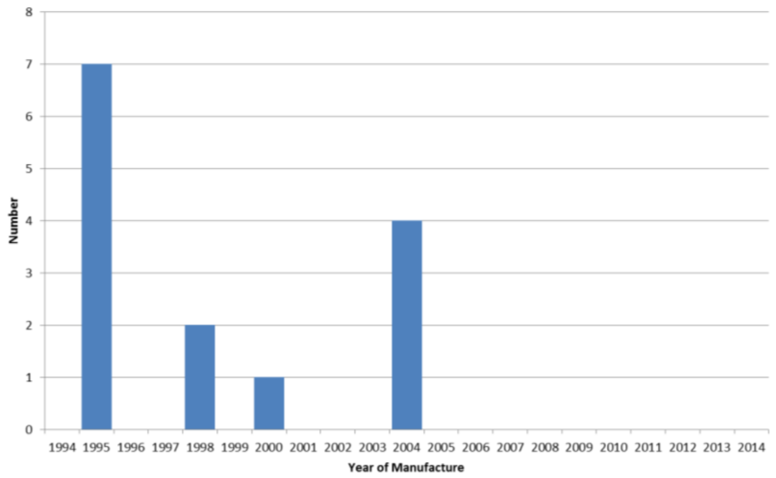


Figure 31: Metering Assets

2.4 Justifying the Assets

EIL creates stakeholder service levels by carrying out a number of activities (described in Section 5) on the assets, including the initial step of actually building assets such as lines and substations. Some of these assets need to deliver greater service levels than others e.g. the Leven Street substation supplying the Invercargill CBD has a higher capacity and security level than the Racecourse Road zone substation supplying the residential areas in north-east Invercargill. Hence a greater level of investment will be required than will generally reflect the magnitude and nature of the demand.

Matching the level of investment in assets to the expected service levels requires the following issues to be considered:

- It requires an intimate understanding of how asset ratings and configurations create service levels such as capacity, security, reliability and voltage stability.
- It requires the asymmetric nature of under-investment and over-investment to be clearly understood i.e. over-investing creates service levels before they are needed but under-investing can lead to service interruptions (which typically cost about 10 to 100 times as much as over-investing as was discovered in Auckland in June 2006).
- It requires the discrete "sizes" of many classes of components to be recognised e.g. a 220kVA load will require a 300kVA transformer that is only 73% loaded. In some cases capacity can be staged through use of modular components.
- Recognition that EIL's existing network has been built up over 80 years by a series of incremental investment decisions that were probably optimal at the time but when taken in aggregate at the present moment may well be sub-optimal.
- The need to accommodate future demand growth (noting that the Optimised Deprival Valuation (ODV) Handbook now prescribes the number of years ahead that such growth can be accommodated).

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

When last calculated in 2004, the ratio of EIL's Optimised Depreciated Replacement Cost (ODRC) to EIL's Depreciated Replacement Cost (DRC) was 0.9876 which with a ratio close to 1 indicates a high level of justification.

3. Proposed Service Levels[A5, 8]

This section describes how EIL set its various service levels according to the safety, viability, quality, compliance and price objectives that are most important to stakeholders (see section 1.6). It details how well EIL is meeting these objectives and what trade-off's exist between differing stakeholders. Considerations include; the desire for Return On Investment (ROI) vs desire for low price with good reliability, safety as first priority vs acceptable levels of risk and whether supply restoration should be prioritised ahead of compliance (e.g. South Canterbury snow storm).

3.1 Creating Service Levels

EIL creates a broad range of service levels for all stakeholders, ranging from those paid for (for their own benefit) by connected customers such as capacity, continuity and restoration to those subsidised by connected customers such as ground clearances, earthing, absence of interference, compliance with the District Plan and submitting regulatory disclosures, as shown in Figure 32. This section describes those service levels in detail and how EIL justifies the service levels delivered to its stakeholders.

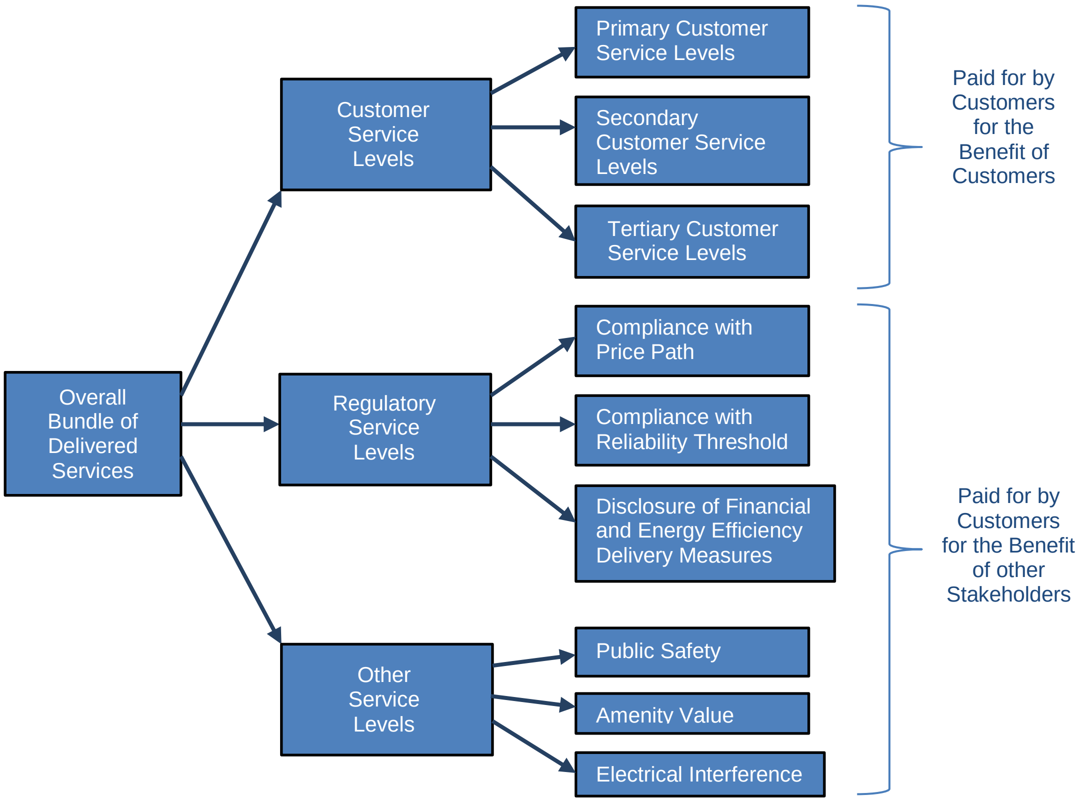


Figure 32: Types of Service Levels

3.2 Customer Oriented Service Levels[A7.1]

This section firstly describes the customer service levels EIL expects to create which are what the customers pay for and secondly the service levels EIL expects to create for other key stakeholder groups which the customers are expected to subsidise.

Research indicates that customers value continuity and restoration of supply more highly than other attributes such as answering the phone quickly, quick processing of new connection applications etc. It has also become apparent from EIL's research that there is an increasing value by customers placed on the absence of flicker, sags, surges and brown-outs although other research indicates that flicker is probably noticed more often than it is actually a problem.

The difficulty with these conclusions is that the service levels most valued by customers depend strongly on fixed assets to address and hence require capital expenditure solutions, as opposed to process solutions, which in itself raises the following three issues:

- Limited substitutability between service levels e.g. customers prefer EIL to keep the power on rather than answer the phone quickly.
- Averaging effect i.e. all customers connected to an asset will receive about the same level of service.
- Free-rider effect i.e. customers who choose not to pay for improved service levels would still receive improved service due to their common connection[5].

3.2.1 Primary Service Levels[A6]

The surveyed customers have indicated that they value continuity and then restoration most highly; therefore EIL's primary service levels are continuity and restoration. To measure performance in this area two internationally accepted indices have been adopted:

SAIFI (system average interruption frequency index) is a measure of how many system interruptions occur per year per customer connected to the network.

SAIDI (system average interruption duration index) is a measure of how many system minutes of supply are interrupted per year per customer connected to the network.

EIL's projections of these measures for the next ten years ending 31 March 2025 are shown in Table 16. These reliability projections take into account the new default price path calculation methodology including new (lower) extreme event normalising boundaries and a 50% weighting for unplanned outages.

Table 16: EIL Reliability Projections

Measure	Class	2015/16	2016/17	2017/18	2018/19	2019/20	…	2024/25
SAIDI	B (Planned)	2.03	2.03	2.03	2.03	2.03	…	2.03
	C (Unplanned)	22.19	19.08	18.73	18.39	18.04	…	16.34
	Total	**24.22**	**21.11**	**20.76**	**20.41**	**20.07**	**…**	**18.34**
SAIFI	B (Planned)	0.01	0.01	0.01	0.01	0.01	…	0.01
	C (Unplanned)	0.59	0.58	0.58	0.57	0.57	…	0.54
	Total	**0.60**	**0.59**	**0.59**	**0.58**	**0.58**	**…**	**0.55**

Table 17 shows the thresholds which apply to EIL's reliability performance. The boundary values represent the threshold for normalising extreme events where if SAIDI or SAIFI in any day exceeds the respective boundary the contribution to the overall annual SAIDI or SAIFI is capped at that boundary value. The limit represents the upper limits of acceptable reliability for network performance after normalising of extreme events.

Previous boundary values were set very high for EIL meaning extreme events would not be normalised and put EIL at risk of breaching the regulatory limits. The new

[5] This is the case with Invercargill and North Makarewa GXP's as they are more secure, due to the reliability required by the New Zealand Aluminium Smelter at Tiwai point.

normalisation boundaries should cater much better to EILs highly reliable network and assist in keeping SAIDI and SAIFI within the respective limits.

Table 17: EIL Reliability Thresholds

	Target	Collar	Cap	Limit	Boundary
SAIDI	24.08	17.03	31.13	31.13 (previously 45.65)	3.24 (previously 40.63)
SAIFI	0.594	0.415	0.772	0.772 (previously 1.13)	0.080 (previously 1.09)

The Cap, Target and Collar are used as part of a revenue incentive scheme for improving reliability on the network where cost effective. A total of $136,000 (equivalent to 1% of the starting price maximum allowable revenue for the regulatory period) is the “revenue at risk” split equally between SAIDI and SAIFI at $68,000 each. For performance at the Target level, which is calculated as EIL's average historical reliability levels, there is no adjustment to EILs revenue. Revenue losses a distributer faces when performing worse than the reliability target increases in direct proportion up to the SAIDI or SAIFI cap. Conversely distributor gains for performance better than the reliability target increase in proportion down to the collar. Performance beyond either cap or collar attracts no further respective losses or gains however the cap is also the limit of acceptable reliability.

In practical terms this means EIL's customers can broadly expect the reliability shown in Table 18:

Table 18: Expected fault frequency and restoration time

General location	Expected reliability	
Invercargill CBD 33kV Fault 11kV Fault	Frequency of faults ▪ One every 20 years ▪ One every 1.4 years	Estimated restoration[6]: ▪ 1 min ▪ 5 min
Invercargill other than CBD 33kV Fault 11kV Fault	Frequency of faults ▪ One every 7 years ▪ 4.5 every year	Estimated restoration[6]: ▪ 15 min ▪ 30 min
Bluff 33kV Fault 11kV Fault	Frequency of faults ▪ 3 every year ▪ 2.9 every year	Estimated restoration[6]: ▪ 1 min ▪ 45 min

Customers in all market segments surveyed indicated a preference for paying about the same line charges to receive about the same level of supply reliability.

3.2.2 Secondary Service Levels

Secondary service levels are the attributes of service that EIL customers have ranked below the first and second most important attributes of supply continuity and restoration. The key point to note is that some of these service levels are process driven which has two implications:

- They tend to be cheaper than fixed asset solutions e.g. staff could work a few hours overtime to process a back log of new connection applications and could divert an over-loaded phone, or EIL could improve the shut-down notification process.

[6] Except if supplied directly off the faulty section of line or cable.

- They are heterogeneous in nature i.e. they can be provided exclusively to customers who are willing to pay more in contrast to fixed asset solutions which will equally benefit all customers connected to an asset regardless of whether they pay.

These attributes include how satisfied customers are with communication regarding tree trimming, connections or faults, the time taken to respond to and remedy justified voltage complaints and the amount of notice before planned shutdowns.

Table 19 sets out the projections of these service levels for the next ten years (either as a percentage or on a scale of 1 to 5, where 1 is poor and 5 is excellent).

Table 19: Secondary service levels

Attribute	Measure	2015/16	2016/17	…	2024/25
Customer Satisfaction: New Connections	Phone: Friendliness and courtesy. {CSS: Q3(c)}[7]	>4[8]	>4	…	>4
	Phone: Time taken to answer call. {CSS: Q3(a)}	>4	>4	…	>4
	Overall level of service. {CSS: Q5}	>4	>4	…	>4
	Work done to a standard which met your expectations. {CSS: Q4(b)}	>4	>4	…	>4
Customer Satisfaction: Faults	Power restored in a reasonable amount of time. {CES: Q4(b)}	>80%	>80%	…	>80%
	Information supplied was satisfactory. {CES: Q8(b)}	>80%	>80%	…	>80%
	PowerNet first choice to contact for faults. {CES: Q6}	>30%	>35%	…	>50%
Voltage Complaints {Reported in Network report}	Number of customers who have made voltage complaints {NR}	<10	<10	…	<10
	Number of customers who have justified voltage complaints regarding power quality	<4	<3	…	<2
	Average days to complete investigation	<30	<30	…	<30
	Period taken to remedy justified complaints	<60	<60	…	<60
Planned Outages	Provide sufficient information. {CES: Q3(a)}	>80%	>80%	…	>80%
	Satisfaction regarding amount of notice. {CES: Q3(c)}	>80%	>80%	…	>80%
	Acceptance of maximum of three planned outages per year. {CES: Q1}	>50%	>50%	…	>50%
	Acceptance of planned outages lasting four hours on average. {CES: Q1}	>50%	>50%	…	>50%

{where the information is collected / reported from}

[7] CSS = Customer Satisfaction Survey undertaken by sending questionnaire to customers with invoices.

[8] Where 1 = poor and 5 = excellent

Targets are set based on the desired outcome of achieving positive customer experiences while accepting that targeting 100% satisfaction would be unrealistic. Trending of historical results has been considered for forecast the first year targets with future years reflecting slight improvements due to impact of future projects and improvement of internal process.

3.2.3 Other Service Levels

In addition to the service levels that are of primary and secondary importance to customers and which they pay for, there are a number of service levels that benefit other stakeholders such as safety, amenity value, absence of electrical interference and performance data. Some (in fact most) of these service levels are imposed on EIL by statute and while they are for the public good, i.e. necessary for the proper functioning of a safe and orderly community, EIL is expected to absorb the associated costs into its overall cost base.

3.2.3.1 Safety

Various legal requirements require EIL's assets (and customer's plant) to adhere to certain safety standards which include earthing exposed metal and maintaining specified line clearances from trees and from the ground:

- Health and Safety in Employment Act 1992.
- Electricity (Safety) Regulations 2010
- Electricity (Hazards from Trees) Regulations 2003.
- Maintaining safe clearances from live conductors (NZECP34:2001).
- EEA Guide to Power System Earthing Practice 2009 as a means of compliance with the Electricity (Safety) Regulations.

3.2.3.2 Amenity Value

There are a number of Acts and other requirements that limit where EIL can adopt overhead lines:

- The Resource Management Act 1991.
- The operative District Plans.
- Relevant parts of the operative Regional Plan.
- Land Transport requirements.
- Civil Aviation requirements.

3.2.3.3 Industry Performance

Various statues and regulations require EIL to compile and disclose prescribed information to specified standards. These include:

- Electricity Distribution Information Disclosure Determination 2012
- Commerce Act (Electricity Distribution Thresholds) Notice 2004

3.2.3.4 Electrical Interference

Under certain operational conditions EIL's assets can interfere with other utilities such as phone wires and railway signalling or with the correct operation of customer's plant or EIL's own equipment. The following two codes impose service levels on us.

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

3.3 Regulatory Service Levels

Various Acts and Regulations require EIL to deliver a range of outcomes within specified timeframes, such as the following;

- Ensure a wide degree of customer satisfaction with both pricing and reliability to avoid being placed under a restraining regime.
- Publicly disclose an AMP each year.
- Publicly disclose prescribed performance measures each year.

EIL is also required to disclose a range of internal performance and efficiency measures as required by the Electricity Distribution Information Disclosure Determination 2012. However previous disclosures were required under Electricity Distribution (Information Disclosure) Requirements 2008 with the complete listing of these measures included in EIL's disclosure to 31 March 2012 and with listing and analysis also on the Commerce Commission website http://www.comcom.govt.nz/electricity-information-disclosure-summary-and-analysis/.

3.3.1 Financial Efficiency Measures[A7.2 (with AMP section 3.3.2)]

EIL's targeted financial efficiency measures are shown in Table 20. These measures are:

- Ratio of OPEX to RC – [Operational Expenditure] / [Replacement cost of System Fixed Assets at year end]
- Indirect costs per ICP – [Indirect Costs (Business Support)] / [Number of Connection Points (at year end)].

Table 20: Targeted Financial Efficiency Measures

Measure	OPEX/RC	Indirect costs / ICP
2015/16	4.19%	$174.14
2016/17	4.37%	$187.84
2017/18	4.42%	$188.69
2018/19	4.41%	$188.50
2019/20	4.40%	$188.32
2020/21	4.37%	$188.13
2021/22	4.33%	$187.94
2022/23	4.31%	$187.75
2023/24	4.26%	$187.57
2024/25	4.23%	$187.38

3.3.2 Energy Delivery Efficiency Measures[A7.2 (with AMP section 3.3.1)]

Projected energy efficiency measures are shown in Table 21. These measures are:

- Load factor – [kWh entering EIL's network during the year] / [[max demand for the year] x [hours in the year]].
- Loss ratio – [kWh lost in EIL's network during the year] / [kWh entering EIL's network during the year].
- Capacity utilisation – [max demand for the year] / [installed transformer capacity].

Slight improvements are targeted but changes in peak management requirements have impacted the load factor. It may take a number of years for the Lower South Island (LSI) peak to settle down to a predictable level.

Loss ratio has varied due to reliance on annual sales quantities from retailers. As retailers are not reading the customers meter at midnight of the 31 December, some estimation methodology is required.

Table 21: Energy efficiency measures

Measure	2015/16	2016/17	…	2023/25
Load Factor	50%	50%	…	50%
Loss Ratio	5.5%	5.5%	…	5.5%
Capacity Utilisation	45%	45%	…	45%

3.4 Justifying the Service Levels

EIL's service levels are justified when:

- Improvements provide positive cost benefit within revenue capability.
- Customer contributions fund uneconomic portions of upgrade or alteration expenses to achieve a desired service level for an individual or group of customers.
- Skilled labour and technical shortages constrain what can be achieved.
- External agencies impose service levels either directly or indirectly where an unrelated condition or restriction manifests as a service level e.g. a requirement to place all new lines underground or a requirement to increase clearances.

Customer surveys over the last four years have indicated that customers' preferences for price and service levels are reasonably static – there is certainly no obvious widespread call for increased supply reliability. However EIL does note the following issues:

- The default price path methodology now includes a revenue incentive for improving reliability.
- The service level called "Safety" is continually under pressure to increase as regulations are updated to decrease industry related risk.
- Food and drink processing, storage and handling are subject to increasing scrutiny by overseas markets, and in particular interruptions to cooling and chilling are less acceptable. This requires EIL's cold storage customers to have higher levels of continuity and restoration.
- Economic downturn may increase the instance of theft of materials and energy.

3.4.1 Basis for Service Level Targets[A9, 10]

When setting EIL's service level targets the recent history of these service level measures are taken into account and it is recognised that these measures will be difficult and typically slow to change. Resulting measures for the Key reliability and energy efficiency service levels for which EIL sets service level targets are listed in Table 22 over the last five years. SAIDI and SAIFI for future years (starting with the 2015/16 disclosure year) will be calculated using a new methodology including new (lower) extreme event normalising boundaries and a 50% weighting for unplanned outages. Previously disclosed reliability results are shown however a recalculation of EIL's SAIDI and SAIFI using the new default price path method have been completed and are also shown as these are the more relevant figures used in EIL's trending and forecasting.

Table 22: Reliability and Energy Efficiency Results for the Past Five Years

Measure		2009/10	2010/11	2011/12	2012/13	2013/14
SAIDI	Previous Disclosure Method	27.2	44.7	63.6	31.8	25.1
	New DPP method	28.2	32.5	28.3	14.9	20.3
SAIFI	Previous Disclosure Method	0.83	1.18	1.30	0.33	0.52
	New DPP method	0.78	0.72	0.71	0.32	0.51
Load Factor		51%	48%	48%	51%	49%
Loss Ratio		5.1%	3.8%	6.1%	5.4%	5.3%
Capacity Utilisation		44.5%	46.4%	47.1%	41.7%	42.1%
OPEX/RC		4.10%	4.13%	4.41%	4.20%	3.76%
Indirect Cost / ICP		$108.91	$115.95	$130.02	$149.19	$99.76

In addition to trending of these results, benchmarking against other local distribution networks, as shown in Figure 33 to Figure 39, helps identify where EIL might look to improve from current service levels. Any year to year changes predicted are expected to be small and need to be backed up by planned projects or initiatives which would impact service levels.

SAIDI – available EDB reliability results since 2008 show EIL has been one of the leading networks in minimising the amount of time without supply that customers experience. EIL's position relative to other local EDBs suggests no significant improvement in SAIDI is warranted.

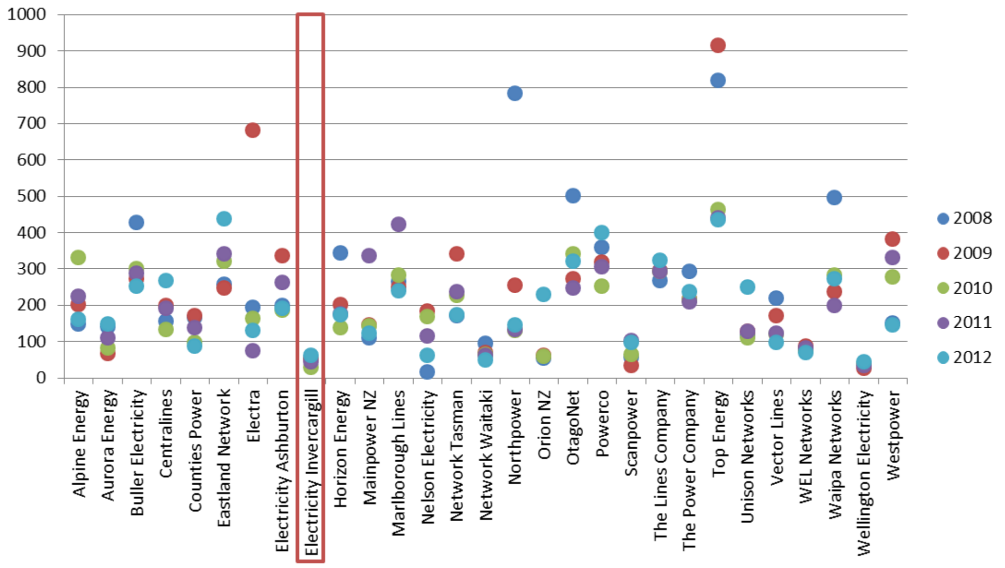


Figure 33: EIL SAIDI Comparison with Local EDBs

SAIFI - available EDB reliability results since 2008 show EIL has been one of the leading networks in minimising the number of supply interruptions that customers experience. EIL's position relative to other local EDBs suggests no significant improvement in SAIFI is warranted.

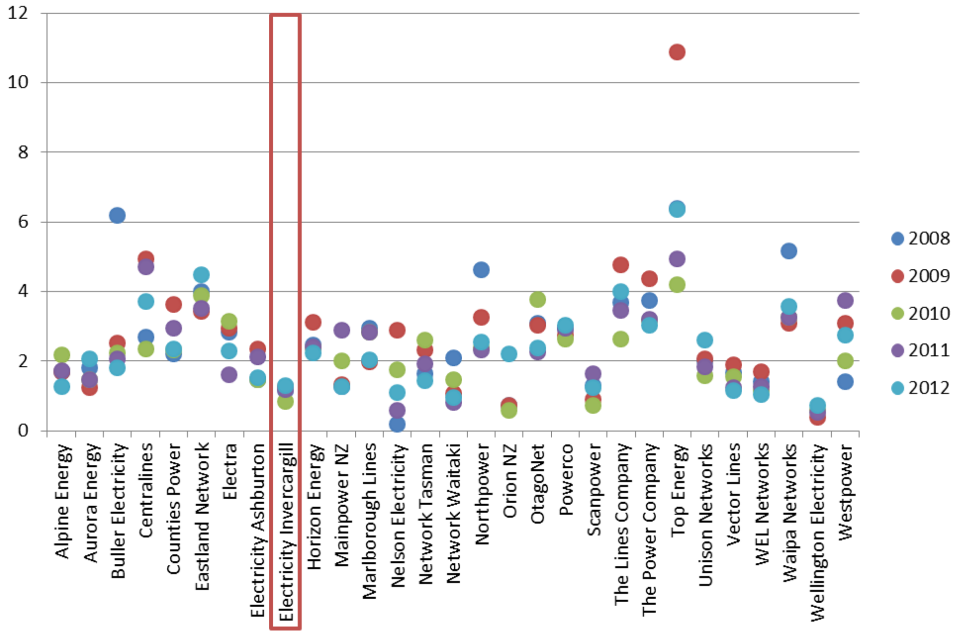


Figure 34: EIL SAIFI Comparison with Local EDBs

Load Factor - EIL's peak during winter months has not coincided with the LSI peak (tending to be late spring) over recent years. This meant that peak load control was not required in winter resulting in a higher peak with an adverse effect on load factor. There may also be less diversity in customer consumption across the network as the area supplied is completely urban.

Comparison with other networks shows that EIL's load factor is relatively low and is an area for improvement. However it is difficult to influence customer's consumption patterns since any line charge incentives offered are repackaged by retailers billing methodologies. Load factor is expected to remain at current levels in the short term.

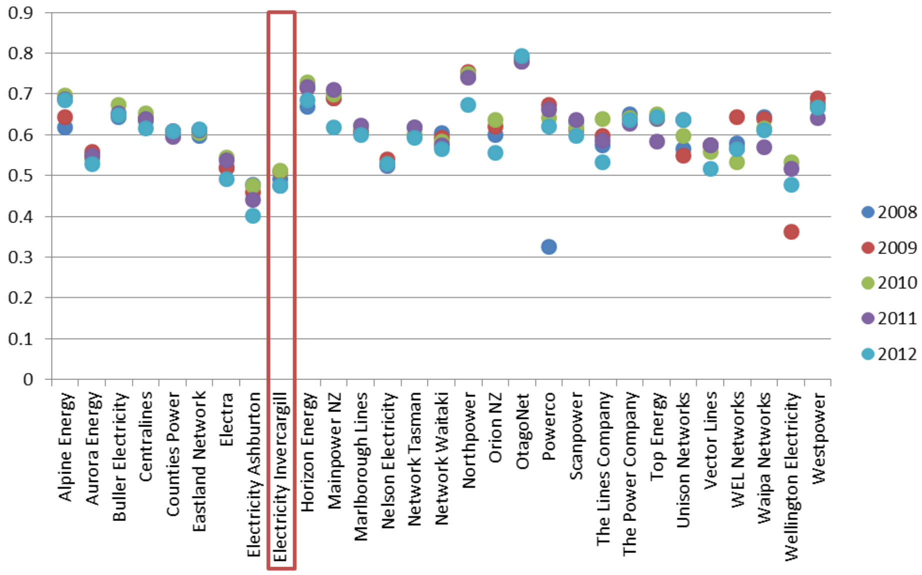


Figure 35: EIL Load Factor Comparison with Local EDBs

Loss Ratio - As losses are paid for by retailers, there is no financial incentive for the network company to reduce them apart from other technical issues such as poor voltage or current rating of equipment. Network equipment is generally upgraded as growth occurs which is expected to maintain losses at approximately present levels.

Comparison with other network companies shows EIL's network is among the more efficient. Trending over a five year period shows an increase in network losses however trending over most other time periods up to the last ten years shows a decrease. EIL can expect a long term average of about 4% to be maintained however year to year results can vary considerably due to retailer estimations and a slightly higher target has therefore been set.

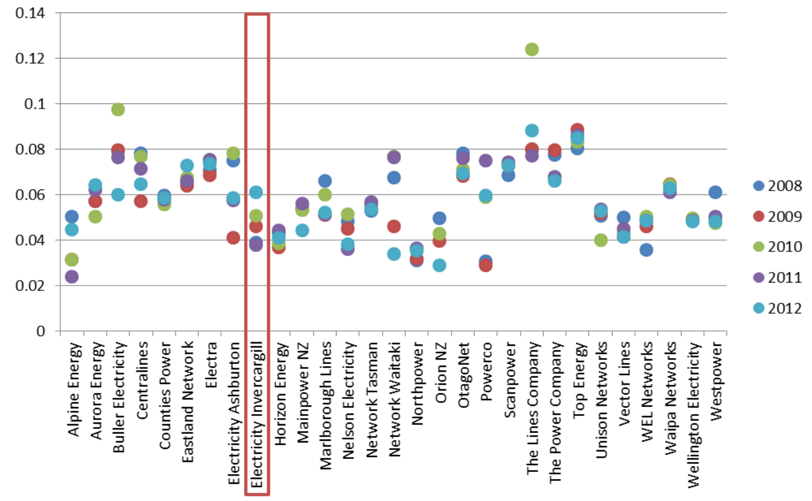


Figure 36: EIL Loss Ratio Comparison with Local EDBs

Capacity Utilisation - rationalisation[9] of transformers should improve capacity utilisation on the network but this will be offset somewhat by replacing overloaded transformers with appropriately sized units of standard ratings. Comparing EIL's capacity utilisation with other local EDBs highlights that EIL has the highest capacity utilisation factor therefore no strategies for improvement are warranted.

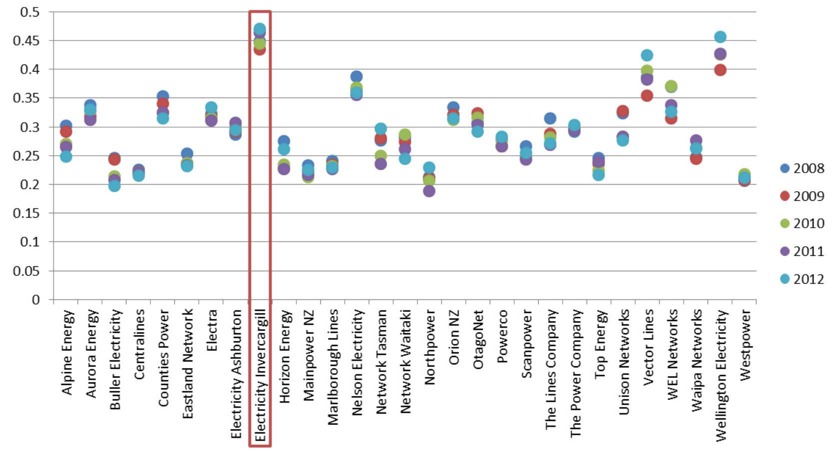


Figure 37: EIL Capacity Utilisation Comparison with Local EDBs

[9] Rationalisation is where one transformer is used to supply multiple customers, with peaks occurring at differing periods a smaller installed capacity usually results. e.g. dairy shed transformer of 50kVA can normally supply the farm house, but due to distances usually requires its own 15kVA transformer.

Financial service levels – Calculation and forecasting is carried out to project cost allocations for future years. Comparing ratio of OPEX to RC against other networks shows EIL is above average for this measure. The Business Support costs (a.k.a. Indirect.) per connection is shown below, with EIL being slightly above average. Some improvement is expected as greater degrees of planning are undertaken and resources are more effectively scheduled.

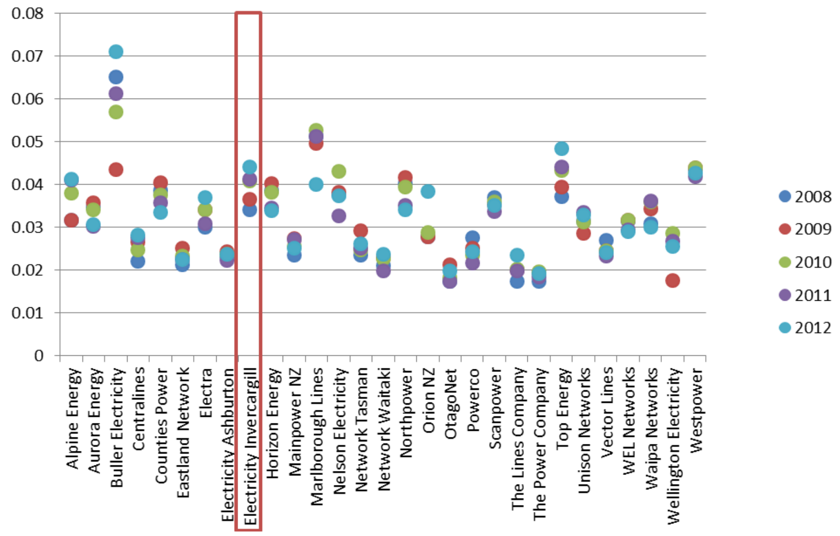


Figure 38: EIL OPEX/RC SAIFI Comparison with Local EDBs

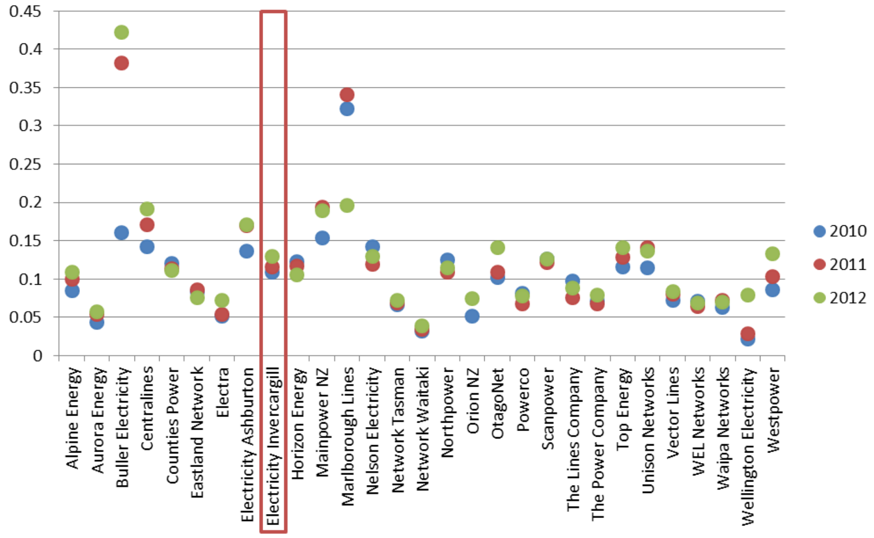


Figure 39: EIL Indirect Cost/ICP Comparison with Local EDBs

Customer Survey – targets are set based on historic trends and the anticipated impact of targeted improvement initiatives, for example, more Public Relations with newsletters, sponsorship and fridge-magnets should increase PowerNet as first point of contact for faults. Few justified voltage complaints are received by EIL, often none are received in any year, so targets are reducing to match the expectation that this will continue. Targeted improvement initiatives could result from dissatisfaction being expressed by customers; however survey results show that for the most part customers are happy with the current level of service.

4. Development Plans[A11]

Development plans are driven primarily by:

- Increasing customer demand due to growth or generation
- Asset renewal requirements
- Statutory requirements to improve service levels (security of supply, safety or environmental compliance)
- Internally generated initiatives to improve service levels

At its most fundamental level, demand is created by individual customers drawing (or injecting) energy through their individual connection points. The demand at each connection aggregates "up the network" through LV reticulation to the distribution transformer, then through the distribution network, the zone substation, the subtransmission network to the GXP and ultimately through the grid to the power stations. Load diversity tends to favour better load factor and capacity utilisation more and more with this aggregation of load up the network.

4.1 Planning Approach and Criteria[A11.1, 11.2]

4.1.1 Planning Unit

EIL has adopted the 11kV feeder as EIL's fundamental planning unit which typically represents one or perhaps two of the following combinations of customer connections:

- An aggregation of up to 2,000 urban domestic customer connections.
- An aggregation of up to 300 urban commercial customer connections.
- An aggregation of up to 20 or 30 urban light industrial customer connections.
- A cluster of large commercial customer connections such as a CBD tower block.
- A single large industrial customer especially if that customer is likely to create a lot of harmonics or flicker.

Physically this planning unit will usually be based around the individual lines or cables emanating from a zone substation. For a single load of more than 1MW (i.e. beyond what is considered incremental) EIL's planning principles and methods still apply, but the likely outcome is new assets at 11kV or higher.

4.1.2 Planning Approaches

EIL plans its assets in three different ways; strategically, tactically and operationally as shown in Table 23.

Table 23: Planning approaches

Attribute	Strategic	Tactical	Operational
Asset description	Assets within GXP. Subtransmission lines and cables. Major zone substation assets. Load control injection plant. Central SCADA and telemetry. Distribution configuration e.g. decision to upgrade to 22kV.	Minor zone substation assets. All individual distribution lines (11kV). All distribution line hardware. All on-network telemetry and SCADA components. All distribution transformers and associated switches. All HV customer connections.	All 400V lines and cables. All 400V customer connections. All customer metering and load control assets.
Number of customers supplied	Anywhere from 500 upwards.	Anywhere from one to about 500.	Anywhere from one to about 50.
Impact on balance sheet and asset valuation	Individual impact is low. Aggregate impact is moderate.	Individual impact is moderate. Aggregate impact is significant.	Individual impact is low. Aggregate impact is moderate.
Degree of specificity in plans	Likely to be included in very specific terms, probably accompanied by an extensive narrative.	Likely to be included in specific terms and accompanied by a paragraph or two.	Likely to be included in broad terms, with maybe a sentence describing each inclusion.
Level of approval required	Approved in principle in annual business plan. Individual approval by Board and possibly shareholder.	Approved in principle in annual business plan. Individual approval by Chief Executive.	Approved in principle in annual business plan. Individual approval by Chief Engineer.
Characteristics of analysis	Tends to use one-off models and analyses involving a significant number of parameters and extensive sensitivity analysis.	Tend to use established models with some depth, a moderate range of parameters and possibly one or two sensitivity scenarios.	Tends to use established models based on a few significant parameters that can often be embodied in a "rule of thumb".

EIL has developed the following "investment strategy matrix" shown in Figure 40, which broadly defines the nature and level of investment and the level of investment risk implicit in different circumstances of growth rates and location of growth.

Location of Demand Growth		Low	High
	Outside of existing network footprint	**Quadrant 3** • Capital Expenditure will be dominated by new assets that require both connection to the existing assets and possibly upstream reinforcement • Likely to absorb lots of cash – may need capital funding • Easily diverts attention away from legacy assets • Likely to result in low capacity utilisation unless modular construction can be adopted • May have high stranding risk	**Quadrant 4** • Capital Expenditure will be dominated by new assets that require both connection to existing assets and possibly upstream reinforcement • Likely to absorb lots of cash – may need capital funding • Easily diverts attention away from legacy assets • Need to confirm regulatory treatment of growth • May have a high commercial risk profile if a single consumer is involved
	Within existing network footprint	**Quadrant 1** • Capital Expenditure will be dominated by renewals (driven by condition) • Easy to manage by advancing or deferring straightforward Capital Expenditure projects • Possibility of stranding if demand contracts	**Quadrant 2** • Capital Expenditure will be dominated by enhancement rather than renewal (assets become too small rather than worn out) • Regulatory treatment of additional revenue arising from volume throughput as well as additional connections may be difficult

Prevailing Load Growth

Figure 40: Investment strategy matrix

Predominant CAPEX modes are:

- Large industrial loads such as a new factory which involves firstly extension and then usually up-sizing sit in Quadrant 4 which has desirable investment characteristics. This mode of investment does however carry the risk that if demand growth doesn't occur as planned, stranding can occur and the investment slips into Quadrant 3 which has less desirable investment characteristics.
- Dairy conversions involve extensions and then sometimes up-sizing but due to the lumpy nature of constructing line assets these may fall into Quadrant 3 which carries some risk of stranding or delayed recovery of investment.
- Declining cost of domestic heat pumps primarily requires urban up-sizing which fits mainly in Quadrant 2, which has reasonably desirable investment characteristics.
- Residential subdivisions around urban areas tend to have large up-front capital costs but recovery of costs through line charges often lags well behind. The size of the subdivision will dictate whether it falls in Quadrant 1 or 3, neither of which has particularly desirable investment characteristics. Hence some form of developer contribution is almost certain to be expected.

4.1.3 Trigger Points for Planning New Capacity

As new capacity has ODV, balance sheet, depreciation and ROI implications for EIL, endeavours will be made to meet demand by other, less investment-intensive means. This discussion also links strongly to EIL's discussion of asset life cycle in section 5.1.

The first step in meeting future demand is to determine if the projected demand will exceed any of EIL's defined trigger points for asset location, capacity, reliability, security or voltage. These points are outlined for each asset class in Table 24.

If a trigger point is exceeded EIL will then move to identify a range of options to bring the asset's operating parameters back to within the acceptable range of trigger points.

These options are described in section 4.2 which also embodies an overall preference for avoiding new capital expenditure.

Table 24: Summary of capacity "trigger points"

		Asset class		
Type	**Trigger**	**Zone substations**	**Subtransmission lines and cables**	**Network equipment within GXP**
Extension	Location	Load cannot be reasonably supplied by distribution configuration therefore requires new subtransmission lines or cables and zone substation.	Load cannot be reasonably supplied by distribution configuration therefore requires new subtransmission lines or cables and zone substation.	Load cannot be reasonably supplied by new or extended subtransmission or substation therefore requires new GXP equipment.
Up-sizing	Capacity	Max demand consistently exceeds 100% of nameplate rating.	Analysis calculates that the peak current exceeds the thermal rating of the circuit segment.	Max demand consistently exceeds 80% of nameplate rating.
	Reliability	Not applicable. Normally a Maintenance or Operational trigger, as no requirement for Up-sizing.		
	Security	Excursion beyond triggers specified in section 3.2.1.		
	Voltage	Voltage at MV terminals of transformer consistently drops below 10.45kV and cannot be compensated by OLTC.	Voltage at HV terminals of transformer consistently drops below 0.87pu and cannot be compensated by OLTC.	Not applicable.
Renewal	Condition	Asset deteriorated to an unsafe condition. Third party requests work.		

		Asset class		
Type	Trigger	LV lines and cables	Distribution substations	Distribution lines and cables
Extension	Location	Existing LV lines and cables don't reach the required location.	Load cannot be reasonably supplied by LV configuration therefore requires new distribution lines or cables and substation.	Load cannot be reasonably supplied by LV configuration therefore requires new distribution lines or cables and substation.
Up-sizing	Capacity	Tends to manifest as fuse blowing when current exceeds circuit rating.	Where fitted, MDI reading exceeds 90% of nameplate rating.	Analysis calculates that the peak current exceeds the thermal rating of the circuit segment.
	Reliability	Not applicable. Normally a Maintenance or Operational trigger, as no requirement for Up-sizing.		

Type	Trigger	Asset class: LV lines and cables	Asset class: Distribution substations	Asset class: Distribution lines and cables
	Security	Excursion beyond triggers specified in section 3.2.1.		
	Voltage	Voltage at customers' boundary consistently drops below 0.94pu.	Voltage at customers' boundary consistently drops below 0.94pu, which cannot be remedied by LV Up-sizing.	Voltage at MV terminals of transformer consistently drops below 10.45kV and cannot be compensated by local tap setting.
Renewal	Condition	Asset deteriorated to an unsafe condition. Third party requests work. Neighbouring assets being replaced.		

4.1.4 Quantifying New Capacity[A11.6]

The two major issues surrounding constructing new capacity are:

- How much capacity to build – this comes back to the trade-off between cost and building in extra capacity for security and risk-avoidance.
- When to build the new capacity – the obvious theoretical starting point for timing new capacity is to build just enough just in time, and then add a bit more over time.

EIL recognises the following practical issues which direct timeframes and mean that a certain degree of overbuild typically works out as the most economic option:

- The need to avoid risks associated with over-loading and catastrophic failure.
- The need to limit investment to what can be recovered under the price-path threshold and the ODV valuation methodology.
- The one-off costs of consenting, traffic management, access to land and reinstatement of sealed surfaces making it preferable to install large lumps of capacity to avoid multiple disruptions to a site.
- The standard size of many components which makes investment lumpy but allows efficient provision of spares.
- That while assets may be relocated, the often dominant construction and labour component of any installation cost cannot generally be recovered.

Selection of the right capacity to build is based on the following:

Cables

- Allow growth over expected life when known or otherwise 100% growth

Distribution transformers

- Individual customers, size to customer capacity.
- Domestic customers based on diversity as shown in Table 25.

Table 25: Customer Diversity and Distribution Transformer Size

Customers	Transformer Size
2	15kVA
6	30kVA
10	50kVA
20	100kVA
50	200kVA
80	300kVA
150	500kVA

Line equipment

- Use standard ratings (e.g. ABS 400A, field circuit breaker 400A)

Power transformers

- Allow expected area growth over 20 years

Substation equipment

- Use standard ratings

Subtransmission lines

- Allow expected area growth over life time of assets

New capacity is balanced to fit within EIL's guiding principle of minimising the long term cost in providing service of sufficient quality ahead of demand.

4.2 Prioritisation Methodology [A11.7 (with AMP section 4.3)]

4.2.1 Options for Meeting Demand

Table 24 defines the trigger points at which the capacity of each class of assets needs to be increased. In a broad order of preference, actions to increase the capacity of individual assets within these classes can take the following forms:

- Do nothing and simply accept that one or more parameters have exceeded a trigger point. In reality, do nothing options would only be adopted if the benefit-cost ratios of all other reasonable options were unacceptably low and if assurance was provided to the Chief Executive that the do nothing option did not represent an unacceptable increase in risk to EIL. An example of where a do nothing option might be adopted is where the voltage at the far end of a remote rural feeder is unacceptably low for a short period at the height of the holiday season – the benefits of correcting such a constraint are simply too low.
- Operational activities, in particular switching on the distribution network to shift load from heavily-loaded to lightly-loaded feeders to avoid new investment or winding up a tap changer to mitigate a voltage problem. The downside to this approach is that it may increase line losses, reduce security of supply or compromise protection settings.
- Influence customers to alter their consumption patterns so that assets perform at levels below the trigger points. Examples might be to shift demand to different time zones, negotiate interruptible tariffs with certain customers so that overloaded assets

can be relieved or assist a customer to adopt a substitute energy source to avoid new capacity. EIL notes that the effectiveness of line tariffs in influencing customer behaviour is dampened by the retailer's practice of repackaging fixed and variable charges.

- Construct distributed generation so that an adjacent asset's performance is restored to a level below its trigger points. Distributed generation would be particularly useful where additional capacity could eventually be stranded or where primary energy is going to waste e.g. waste steam from a process.
- Modify an asset so that the asset's trigger point will move to a level that is not exceeded e.g. by adding forced cooling. This approach is more suited to larger classes of assets such as power transformers.
- Retrofitting high-technology devices that can exploit the features of existing assets including the generous design margins of old equipment. An example might include using advanced software to thermally re-rate heavily-loaded lines, using remotely switched air-break switches to improve reliability or retrofit core temperature sensors on large transformers to allow them to operate closer to temperature limits.
- Install new assets with a greater capacity that will increase the assets trigger point to a level at which it is not exceeded. An example would be to replace a 200kVA distribution transformer with a 300kVA unit so that the capacity criterion is not exceeded.

In identifying solutions for meeting future demands for capacity, reliability, security and supply quality, EIL considers options that cover the above range of categories. The benefit-cost ratio of each option is considered including estimates of the benefits of environmental compliance and public safety and the option yielding the greatest benefit is adopted. EIL uses the model in Figure 41 to broadly guide adoption of various approaches.

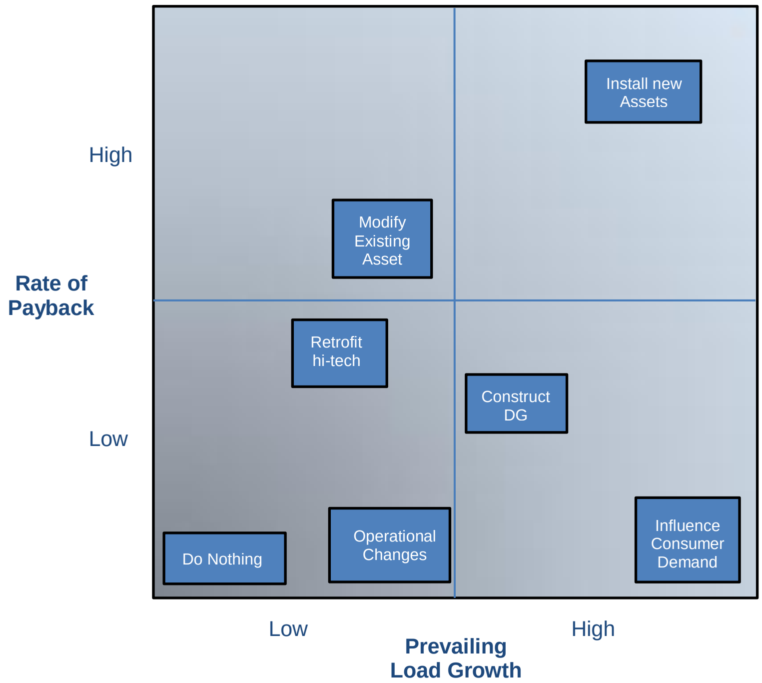


Figure 41: Options for Meeting Demand

4.2.2 Meeting Security Requirements

A key component of security is the level of redundancy that enables supply to be restored independently of repairing or replacing a faulty component. Typical approaches to providing security to a zone substation include:

- Provision of an alternative subtransmission circuit into the substation, preferably separated from the principal supply by a 33kV bus-tie.
- Provision to back-feed on the 11kV from adjacent substations where sufficient 11kV capacity and interconnection exists. This obviously requires those adjacent substations to maintain spare capacity.
- Use of local generation.
- Use of interruptible load (water heating).

The most pressing issue with security is that it involves a level of investment beyond what is obviously required to meet demand and it can be easy to let demand growth erode this surplus capacity. This was one of the key conclusions of the Electricity Distribution and Service Delivery Report into the blackouts following the storms in Queensland in 2004.

4.2.2.1 Prevailing Security Standards

The commonly adopted security standard in New Zealand is the EEA Guidelines which reflect the UK standard P2/5 that was developed by the Chief Engineers Council in the late 1970's. P2/5 is a strictly deterministic standard i.e. it states that "this amount and nature of load will have this level of security" with no consideration of individual circumstances.

Deterministic standards are now beginning to give way to probabilistic standards in which the value of lost load and the failure rate of supply components is estimated to determine an upper limit of investment to avoid interruption.

4.2.2.2 Issues with Deterministic Standards

A key characteristic of deterministic standards such as P2/5 and the EEA Guidelines is that rigid adherence generally results in at least some degree of over investment. Accordingly the EEA Guidelines recommend that individual circumstances be considered.

4.2.2.3 Contribution of Local Generation to Security

To be of any use from a security perspective, local generation would need to have close to 100% availability which is unlikely from a reliability perspective and even less likely from a primary energy perspective such as run-of-the-river hydro, wind or solar. For this reason, the emerging UK standard P2/6 provides for minimal contribution of such generation to security.

4.2.2.4 EIL Security Standards

Table 26 describes the security standards adopted by EIL, whilst section 2.2.3 lists the level of security at each zone substation and justifies any shortfall. In setting target security levels the following guiding principles are used:

- Where a substation is for the predominant benefit of a single customer, their wish for security will over-ride prevailing industry guidelines.
- The preferred means of providing security to urban zone substations will be by secondary subtransmission assets with any available back-feeding on the 11kV providing a third tier of security.

Table 26: Target security levels

Description	Load type	Security level
AAA	Greater than 12MW or 6,000 customers.	No loss of supply after the first contingent event.
AA	Between 4 and 12MW or 2,000 to 6,000 customers.	All load restored within 15 minutes of the first contingent event.
A(i)	Between 1 and 4MW	All load restored within 2 hours of a first contingent event by isolation and back-feeding.
A(ii)	Less than 1MW	All load restored in time to repair after the first contingent event.

4.2.3 Choosing the Best Option to Meet Demand [A11.3 (with AMP section 4.3.2)]

Each of the possible approaches to meeting demand that are outlined in section 4.2.1 will contribute to strategic objectives in different ways. EIL uses a number of decision tools to evaluate options depending on their cost as set out in Table 27.

Table 27: Decision Tools Used Based on Cost

Cost and nature of option	Decision tools	Organisational level of evaluation
Up to $50,000, commonly recurring, individual projects not tactically significant but collectively they do add up.	EIL standard rules. Industry rules of thumb. Manufacturer's tables and recommendations. Simple spreadsheet model based on a few parameters.	GM Network Operations
Up to $500,000, individual projects of tactical significance.	Spreadsheet model to calculate NPV that might consider 1 or 2 variation scenarios.	Chief Engineer
Over $1,000,000 occurs maybe once every few years, likely to be strategically significant.	Extensive spreadsheet model to calculate NPV, payback that will probably consider several variation scenarios.	Board Approval

4.2.4 Project prioritisation

Designers and planners use the 'decision tools' on projects to enable prioritisation and rationing of our resources. Consideration is also given to the Risk Profile of each option and this is also useful in selecting projects.

The Manager in each area prioritises the work based on their need to meet service standards. Level of budget is adjusted due to trends in service levels; therefore if service levels are steady, expenditure would remain the same. Some abnormal situations[10] do distort results and these are considered in setting targets and expenditure.

4.3 Network Development Options

4.3.1 Identifying Options

When faced with increased demand, reliability, security or safety requirements, EIL considers the broad range of options described in Section 4.2.1. The range of options for each issue varies due to:

Stakeholder interests

Section 1.6 lists stakeholder interests and the engineer considers these areas in planning and ranking an option.

Size of the project

Different issues have differing resource requirements. The level of analysis and the breadth of options vary with size. A simple issue like connecting a new customer next to an existing low voltage pillar box would only have a single option analysed, whereas a new industrial plant would have multiple options considered.

Creativity and knowledge of the Engineer

Breadth of options is also dependent on the Engineer undertaking the planning. Options are developed by the Engineer and critiqued by the Chief Engineer. Standard construction and existing designs are mainly used, but there is support for innovation.

Resource

Other higher priority projects may limit the resources available for each option. This could be a limitation of finances (uneconomic), workforce (to plan, design, manage, build or operate), materials (unavailability or long lead-time of equipment) or legal (need Resource Consent or easements).

Standardisation [A11.3, A11.4, 11.5]

Standards that apply to the network are given in the PowerNet Network Design Standard. Examples of standardisation are listed in Table 28:

Table 28: Equipment Standardisation

Component	Standard	Justification
Overhead Conductor	All Aluminium Alloy Conductor (AAAC): Chlorine, Helium, Iodine, Neon, Oxygen.	Low corrosion and improved impedance
Overhead Conductor	Aluminium Conductor Steel Reinforced (ACSR): Magpie, Squirrel, Flounder, Snipe.	Higher strength for long spans or snow loading
Low Voltage Overhead	Aerial Bundled Cable (ABC): 35, 50 & 95mm² Al / two & four core.	Safety, visual impact, lower cost.
Underground	Cross-linked Polyethylene (XLPE)	Rating, ease of use.

10 Abnormal situations: Major storms, significant planned outages, dry year rationing, external party major equipment failures.

Component	Standard	Justification
11kV Cable		
Underground Cable	Distribution and LV: 35, 95, 185 & 300mm^{2}Al	Common sizes easy to keep in stock, lower cost
Suppliers	Normally one or two suppliers for each component	Reduce spare requirements. Improved contractor familiarity.
Poles	Busck pre-stressed concrete	Long life, good strength
Crossarms	Solid hardwood	Long life, good strength

Standardised design is used for line construction with a Construction Manual and standard drawings in use by Contractors.

Standardised designs for projects may be used from time to time where projects with similarities occur within a short enough period of time. While these opportunities are rare on EIL's network, determination of the best available equipment (high quality, low cost) or design completed by PowerNet for other managed networks, may be utilised by EIL (and vice versa). Examples of equipment would be:

- Power Transformers
- 33kV & 11kV Switchboards
- Protection and Controls
- Distribution Substations and Switchgear

4.3.2 Identifying the Best Option [A11.3 (with AMP section 4.2.3)]

Once the best broad option has been identified using the principles embodied in Figure 41, EIL will use a range of analytical approaches to determine which option best meets EIL's investment criteria. As set out in Section 4.2.3, EIL uses increasingly detailed and comprehensive analytical methods for evaluating more expensive options.

- Simple Spreadsheet: Cost calculation with standardised economic benefit values.
- Risk analysis: More comprehensive and complexity for larger projects.
- Net Present Value (NPV) model: Time series model of future costs and benefits.
- Payback calculation: Financial calculation of the time estimated to recover cost of undertaking that option.
- Customer consultation: If solution impacts on a customer and changes the service level provided, the customer must be consulted to obtain their support.

4.3.3 Implementing the Best Option

Having determined that a fixed asset (CAPEX) solution best meets EIL's requirements and that EIL's investment criteria will be met (and if they won't be met, ensuring that a customer contribution or some other form of subsidy will be forthcoming), a project will proceed through the following broad steps:

- Perform detail costing and re-run cost-benefit analysis if detail costs exceed those used for investment analysis.
- Address resource consent, land owner and any Transpower issues.
- Perform detailed design and prepare drawings, construction specifications and if necessary tender documents.
- Tender out or Assign construction.

- Close out and de-brief project after construction.
- Ensure that contractors pass all necessary information back to EIL including as-builts and commissioning records.
- Ensure that learning experiences are examined, captured and embedded into PowerNet's knowledge base, standards or culture.

4.4 Policies for Distributed Generation[A11.11]

The value of distributed generation is clearly recognised in the following ways:

- Reduction of peak demand at the Transpower GXP.
- Reducing the effect of existing network constraints.
- Avoiding investment in additional network capacity.
- Making a very minor contribution to supply security where the customers are prepared to accept that local generation is not as secure as network investment.
- Making better use of local primary energy resources thereby avoiding line losses.
- Avoiding the environmental impact associated with large scale power generation.

It is also recognised that distributed generation can have the following undesirable effects:

- Increased fault levels, requiring protection and switchgear upgrades.
- Increased line losses if surplus energy is exported through a network constraint.
- Stranding of assets, or at least of part of an asset's capacity.

Despite the potential undesirable effects, the development of distributed generation that will benefit both the generator and EIL is actively encouraged.

The key requirements for those wishing to connect distributed generation to the network broadly fall under the following headings, with a guideline and application forms available on the web at http://www.powernet.co.nz/dg-guide.

4.4.1 Connection Terms and Conditions (Commercial)

- Connection of up to 10kW of distributed generation to an existing connection to the network will not incur any additional line charges. Connection of distributed generation greater than 10kW to an existing connection may incur additional costs to reflect network up-sizing.
- Distributed generation that requires a new connection to the network will be charged a standard connection fee as if it was a standard off-take customer.
- An annual administration fee will be payable by the connecting party.
- Installation of suitable metering (refer to technical standards below) shall be at the expense of the distributed generator and its associated energy retailer.
- Any benefits of distributed generation that arise from reducing EIL's costs, such as transmission costs or deferred investment in the network, and, provided the distributed generation is of sufficient size to provide real benefits, will be recognised and shared.
- Those wishing to connect distributed generation must have a contractual arrangement with a suitable party in place to consume all injected energy – generators will not be allowed to "lose" the energy in the network.

4.4.2 Safety Standards

- A party connecting distributed generation must comply with any and all safety requirements promulgated by EIL.
- EIL reserves the right to physically disconnect any distributed generation that does not comply with such requirements.

4.4.3 Technical Standards

- Metering capable of recording both imported and exported energy must be installed if the owner of the distributed generation wishes to share in any benefits accruing to EIL. Such metering may need to be half-hourly.
- EIL may require a distributed generator of greater than 10kW to demonstrate that operation of the distributed generation will not interfere with operational aspects of the network, particularly such aspects as protection and control.
- All connection assets must be designed and constructed to technical standards not dissimilar to EIL's own prevailing standards.

4.5 Use of Non-Asset Solutions [A11.12 (with AMP section 4.2.1)]

As discussed in section 4.2.1 the company routinely considers a range of non-asset solutions and indeed EIL's preference is for solutions that avoid or defer new investment.

Effectiveness of tariff incentives is lessened with Retailers repackaging line charges that sometimes removes the desired incentive. 'Use of System' agreements include lower tariffs for controlled, night-rate and other special channels.

Load control is utilised to control:

- the amount of Transpower charges by controlling the network load during the LSI peaks.
- load on individual GXP's when maximum demand reaches the capacity of that GXP.
- load on feeders during outage situations.

Load shedding is used by some customers where they accept a drop of their load instead of investing in additional network assets.

4.6 EIL's Demand Forecast

4.6.1 EIL's Current Demand

EIL's maximum demand (MD) of 63.64MW did not occur at the same time as the Lower South Island (LSI) peak which occurred at 09:00 on the 10th of July 2013. The EIL Bluff MD of 4.38MW occurred at a different time to both the overall EIL MD and the LSI peak. The EIL coincident demand at the time of the LSI peak was 58.60MW with 3.41MW of that load contributed by Bluff EIL. The individual maximum demands are shown in Figure 42.

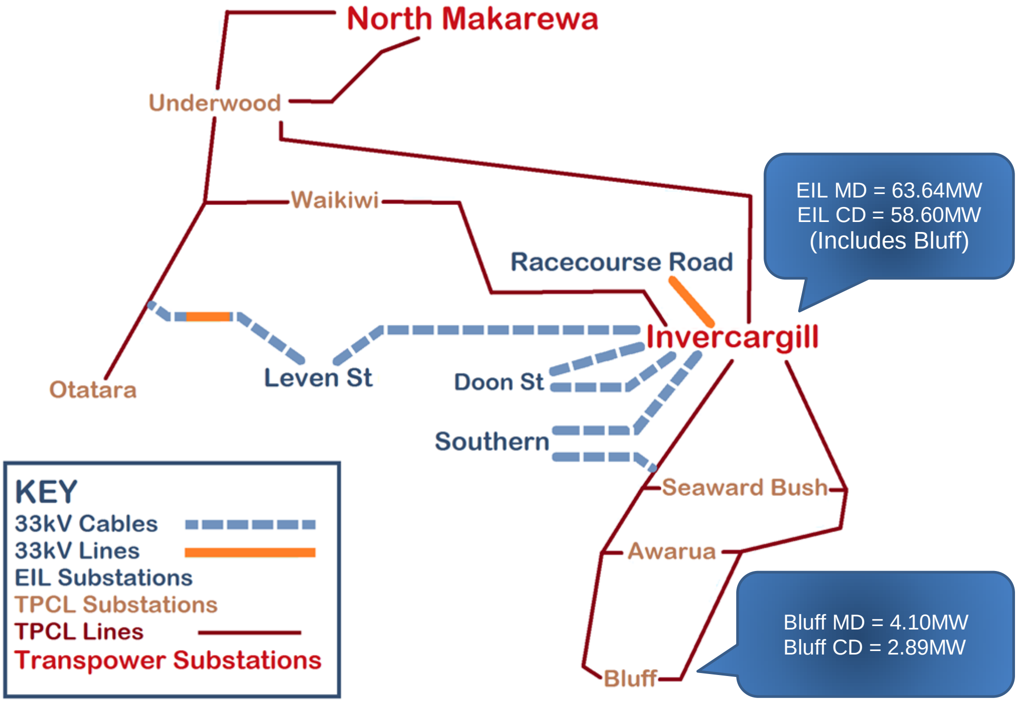


Figure 42: GXP and Generation Demands

Each zone substation recorded the maximum demands as listed in Table 29. The 99.9 percentile demand is given to remove any short term load transfers and is more indicative of actual area maximum demand.

Table 29: Substation Demand

	Installed Capacity	Max Demand (MVA)	99.9% Peak (MVA)						
Zone Substation	(MVA)	2013/14	2013/14	2012/13	2011/12	2010/11	2009/10	2008/09	2007/08
Doon St	59	21.0	17.2	14.5	13.6	22.7	22.8	22.0	23.7
Leven St	46	20.7	15.2	17.9	18.3	17.7	18.3	17.7	19.0
Racecourse Rd	23	13.9	9.4	12.7	12.7	9.7	10.1	9.4	10.1
Southern	23	16.0	13.5	14.3	14.2	12.5	12.5	11.7	12.4
Bluff (TPCL)	24	4.9	4.6	4.5	4.5	4.4	4.6	4.6	4.1

One 23MVA transformer failed at Doon St in 2010 and has been replaced with a 36MVA transformer in a temporary configuration until the new Spey Street substation is commissioned (see section 4.8.1). Load has been transferred to the other Invercargill substations to prevent the 23MVA firm capacity being exceeded.

4.6.2 Drivers of Future Demand

Key drivers of demand growth (and contraction) are likely to include the issues depicted in Figure 43.

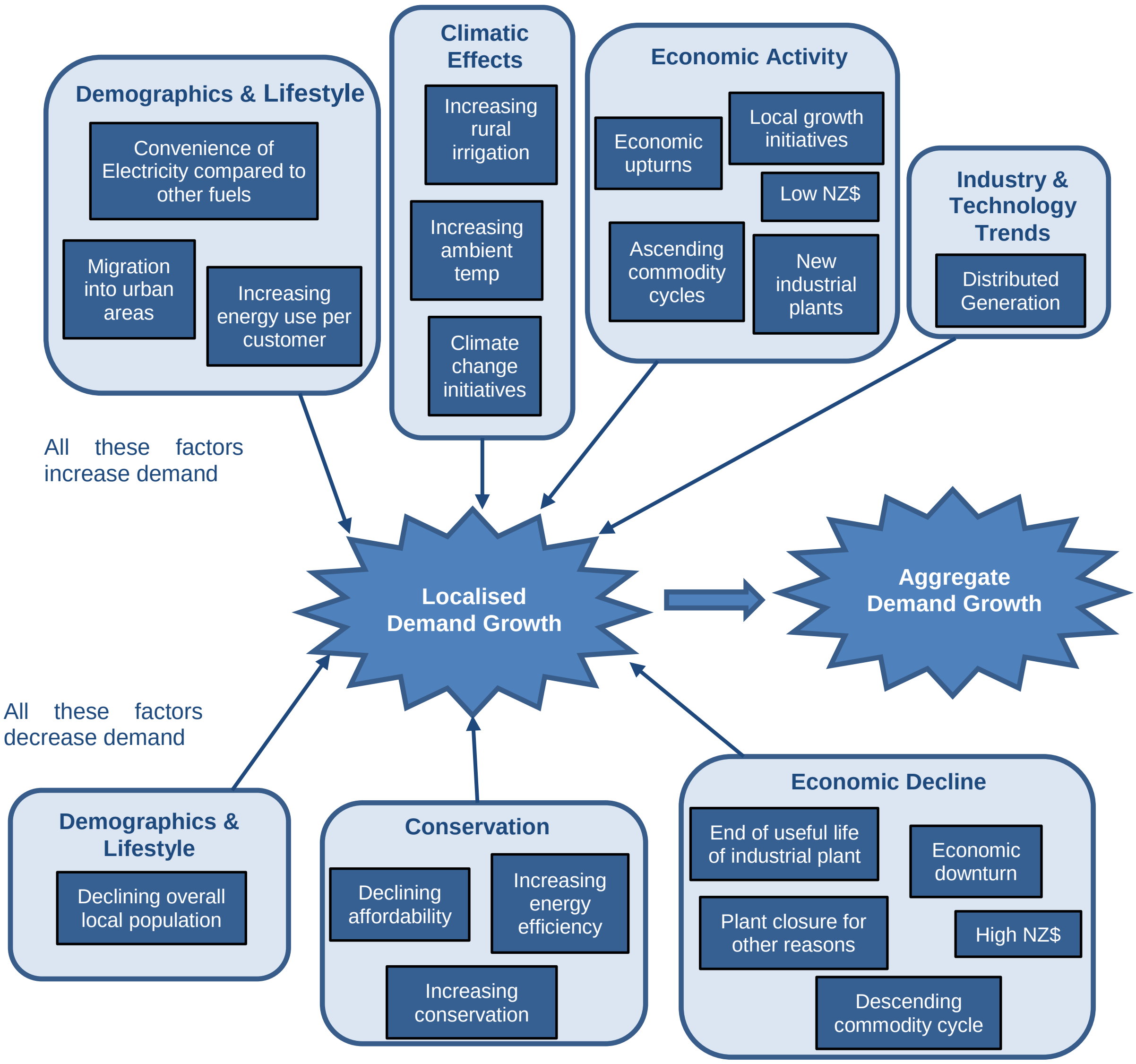


Figure 43: Drivers of Demand

At residential and light commercial feeder level, three or four of these issues may predominate and be predictable and manageable on a statistical basis, however experience shows that large customers give little if any warning of increases or decreases in demand. The residential and light commercial demand projections can be aggregated into a reasonably reliable zone substation demand forecast but heavy industrial demand will always remain more unpredictable. EIL's estimates of future demand are described in section 4.6.4.

Historically, EIL has experienced an average annual demand growth of about 1.5% for the last 20 years. This growth has been distorted with Transpower's introduction of TPM[11] where individual ELB peaks have been replaced by a regional grouping. This has allowed EIL to relax load control during the year due to the increased summer loading due to Dairying (on the TPCL network supplied from the Invercargill GXP). Whilst the company expects this average rate not to continue and to influence the revenue aspects

[11] Transmission Pricing Methodology: Allocation of Transpower costs are based on the share of the average of the top 100 peaks for all loads in the Lower South Island (LSI) region. See http://www.electricitycommission.govt.nz/rulesandregs/rules Part F, Section IV for more details.

of EIL's business, such as pricing, it must be acknowledged that actual demand growth at localised levels (which will influence costs) can vary anywhere from negative to highly positive. No reductions are foreseen due to the removal of the requirement to supply in 2013, as there is only one lateral that could be considered uneconomic. The following sections examine in detail the most significant drivers of the network demand over the next 10 to 15 years.

4.6.2.1 Rural Money Coming to Town

The impact of farmers retiring to the city increases demand for townhouses in desirable locations. This is not a new effect and therefore there is no increase in growth expected above trending of previous years.

4.6.2.2 Removal of Coal as a Heating Fuel

Solid Energy had previously advised it would withdraw from supplying coal to the household market by the beginning of 2013 in line with the National Environmental Standards for air quality but has since been revised to 2016. This would likely result in an increase in use of alternative sources of heating including heat pumps with resulting growth expected to affect residential areas.

Heat pump usage has naturally continued to increase as a convenient and efficient form of heating and the impact on demand has been less than earlier anticipated, therefore existing growth has been assumed to continue.

4.6.2.3 Continuance of Major Industries

There has been recent concern over the viability of Tiwai Point Aluminium Smelter having been put up for sale and recent Tiwai staff redundancies occurring. Tiwai takes supply directly from the transmission grid however it helps support many businesses and individuals both directly and indirectly and loss of this business could have a major impact on the local economy and therefore growth on EIL's network in Invercargill and Bluff. The impact that would be seen is difficult to predict as other industry may take advantage of the site or surplus energy that may result.

EIL's assumption is that Tiwai will continue to be viable in the short to medium term at least and therefore no change to growth forecasts has been made. No projects currently in progress would become unnecessary as a result of the loss of this industry and the timing of future projects could be altered as necessary if required, however most planned work involves replacements or maintenance which will be needed regardless.

4.6.2.4 Electric Vehicles

With significant penetration into the transport sector, electric vehicles have the potential to have a large impact on network demand. It is expected that the majority of this load should be able to be managed so that it is consumed at off-peak times (especially overnight) and therefore would have much less impact on peak demand and even improve load factor. Some demand increase is expected in the long term but is likely to be beyond the ten year planning horizon so has not been included in growth forecasts.

4.6.2.5 Discovery of Major Petrochemical Deposit

Exploration in the Great South Basin has been awarded to two companies, with the possible flow on effects if a deposit is developed. The likelihood and level of growth from this effect is unknown and has therefore not been included in forecasted growth.

4.6.2.6 Increased Environmental Concern

Consideration of energy efficiency in consumer appliances is more popular due to government or local council drivers and marketing leading to a reduction in consumption.

This is counteracted by conversion to electricity as a 'clean' fuel for heating. The overall effect is predicted to be minimal effect on growth.

4.6.2.7 Economic Crisis Impact

Economic downturn and recovery affects investment by customers and therefore the rate of growth. The recent economic crisis has affected the rate of new connections causing a reduction in growth. A gradual recovery with growth increasing slowly is expected.

4.6.3 Load Forecast Trend[A11.8.1 (with AMP section 4.6.4)]

Growth trends are difficult to establish as there is somewhat random variation on top of underlying growth. Generally the trend taken over the latest ten year period will be quite different year to year as the most recent years' data is included and data beyond ten years is excluded. This is again quite different to a 20 year trend. Longer term trends tend to "average" out the random variations but lose sight of recent changes to underlying growth. Some causes may be identified with hindsight but are typically difficult to predict e.g. a drought initiating increasing irrigation load. Growth is plotted and trend lines over various time periods are considered along with known events effecting consumption patterns before arriving at a reasonable estimate of growth which can be used for forecasting future demand and consumption.

Figure 44 shows the overall EIL data since 1950 and highlights the flattening out since the late '80s. Recent increases in maximum demand have been affected by changes in Transpower's pricing methodology; these changes are not apparent in energy growth.

Analysis of historic demand and energy usage over the last 10 years or so gives maximum demand growth of about 1.0% and energy consumption growth of about 0.5%. The overall effect of drivers of future demand mentioned in section 4.6.2 is not expected to significantly alter these growth trends in future years.

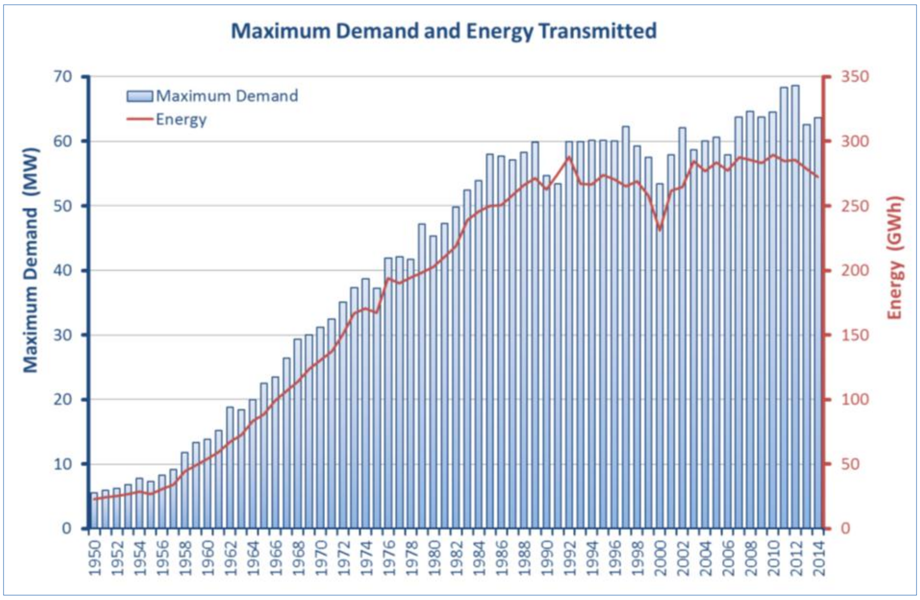


Figure 44: Maximum Demand and Energy Transmitted

4.6.4 Zone Substation Demand Forecast[A11.8.1 (with AMP section 4.6.3), 11.8.2]

Demand of the overall EIL network can be divided between the individual network areas and the zone substations that service them based on similar plotting and trending analysis for each zone substation along with knowledge of connection rates in certain areas. Demand for these areas and zone substations are expected to vary from that described in Section 4.6.1 as follows:

- Expansion of Commercial/Retail/Light Industrial in west Invercargill area impacting Leven and Doon Streets Substations at 2.0% per annum.
- Otherwise standard natural growth in Invercargill of 1.0% per annum, includes some infill of sections.
- Standard natural growth in Bluff of 1.0% per annum.
- Expansion of Commercial/Retail/Light Industrial in Bluff impacting Bluff Substation at 1.0% per annum.
- Load transfers between substations to keep under trigger levels.

Experience strongly indicates that it would be rare to ever get more than a few months confirmation, sufficient to justify significant investment, of definite changes in an existing or a new major customer's demand. This is because most of these customers operate in fast-moving customer markets and often make capital investment decisions quickly themselves and they generally keep such decisions confidential until the latest possible moment. Probably the best that EIL can do is to identify in advance where EIL's network has sufficient surplus capacity to supply a new large load but, as experience shows, industrial siting decisions rarely, if ever, consider the location of energy supply – they tend to be driven more by land-use restrictions, raw material supply and transport infrastructure. Table 30 identifies the rate of growth projected to zone substation level for a 10 year horizon, along with the provision expected to be made for future growth. This assumes no unforeseen changes in growth rates, as estimated from demand graph trends, or step changes due to connection or loss of large customers. Expanded data is included in Appendix B. Heavily loaded sites will be monitored more closely if data indicates capacity will be exceeded in the short term. Annual preparation of this data will highlight sites that vary from the above model and the planned works adapted for each situation, with some upgrades delayed or brought forward.

Table 30: Substation Demand Growth Rates

Substation	Rate and nature of growth	2015/16 Demand	2024/25 Demand
Doon Street / Spey Street	**2.0%** per annum, CBD, light industrial and residential.	**29.8**	**35.6**
	Provision for growth to 2023 • Doon Street provides a capacity of 59MVA and firm capacity of 23MVA. The replacement Spey Street substation will increase capacity to 72MVA and firm capacity to 36MVA. A new 33kV XLPE cable will be installed to supply one transformer at Spey Street with the existing 33kV oil filled cables to be paralleled and extended to provide another feeder to supply the second transformer and maintain security. • Transfer of 11kV load between substations has been utilised to avoid exceeding the firm capacity security threshold short term and in response to the temporary down rating of 33kV oil filled cables. With the additional firm capacity available once Spey Street is complete this new substation will take additional load to manage load below security triggers at the other Invercargill substations.		
Leven Street	**2.0%** per annum, CBD or medium-light industrial. Expansion within old show grounds subdivision.	**18.5**	**22.1**
	Provision for growth to 2023 • Load transferred to Spey Street after the new substation is completed will be used to avoid the 23MVA firm capacity being exceeded at Leven Street which would otherwise be reached in about 2017.		
Southern	**1.0%** per annum, residential. Potential for future subdivision in area enclosed by Rockdale Rd, Tramway Rd, Regent St & Centre St.	**16.7**	**18.3**
	Provision for growth to 2023 • The spare ex-Doon Street 23MVA unit will be installed at Southern in 2018 as		

Substation	Rate and nature of growth	2015/16 Demand	2024/25 Demand
	part of the substation upgrade to a dual transformer site with a firm capacity of 23MVA. • Load transfers were being used to delay the 12MVA security trigger being exceeded however a temporary de-rating of the 33kV oil cables have required load be shifted off Doon Street substation. • The Southern 12 MVA security trigger will be exceeded for brief periods during the winter until the new Spey Street and Southern substations projects are complete increasing overall network capacity and allowing load to be balanced between substations.		
Racecourse Road	**1.0%** per annum, residential.	16.7	11.4
	Provision for growth to 2023 • Load transfers were being used to delay the 12MVA security trigger being exceeded however a temporary de-rating of the 33kV oil cables have required load be shifted off Doon Street substation. • The Southern 12 MVA security trigger will be exceeded for brief periods during the winter until the new Spey Street and Southern substations projects are complete increasing overall network capacity and allowing load to be balanced between substations. • Racecourse Road will be the only Invercargill network substation with a single transformer and the lower AA security level remaining once Southern substation has been upgraded. Load transfers can be used to manage the substation load so that it remains below the 12MVA AAA security trigger out to about 2030.		
Bluff (TPCL)	**1.0%** per annum, industrial growth at the Port.	5.1	5.5
	Provision for growth to 2023 • New transformers installed recently provide a firm capacity of 13MVA with the spare capacity allowing growth well beyond the planning period.		

4.6.4.1 Demand Model Assumptions[A11.8.4]

The impact of Distributed Generation (DG) has been ignored due to the estimated low connection rate of DG and the probability that only a small percentage of the capacity will be available during peaks, e.g. White Hill (connected to the TPCL network) has 58MW generation capacity but had zero output during the LSI peak.

Load Management is used when substation equipment is nearing overload, and during load transfers for maintenance, and hasn't been considered in the projected demands above except to say that historical demand records have included these effects. Load shifting can also be done at the Retailer's request or during Dry-year rationing.

4.6.5 Estimated Demand Aggregated to GXP Level

Table 31 shows the aggregated effect of substation demand growth for a 10 year horizon at the Invercargill GXP.

Table 31: GXP Demand Growth

GXP	Rate and nature of growth	Provision for growth to 2025
Invercargill	0.0% Maximum Demand Load will be controlled using load management to stay at present levels.	Transpower have recently upgraded the two 220/33kV banks to 120MVA. This will allow over 20MVA of additional load.

4.6.6 Issues Arising from Estimated Demand

The significant issues arising from the estimated demand in section 4.6.4 are the capacity short fall and the requirement for the replacement and upgrade of transformers at Doon Street (relocated to Spey Street) and a second transformer at Southern substation within the next two years. Also the 33kV oil cables supplying Doon Street will require supplementation with an additional higher rated 33kV cable to allow the additional installed transformer capacity to be utilised. This is discussed in full in section 4.8.1.

4.7 EIL Network Constraints[A11.8.3]

EIL's network includes the constraints as shown in Table 32:

Table 32: EIL Network Constraints and Intended Remedy

Constraint	Description	Intended remedy
Capacity at Zone Substations	Demand is exceeding the 12MVA security trigger at Southern and Racecourse Road. Load has been transferred to these substations from Doon Street to manage the firm supply capacity of the 33kV oil cables (temporarily de-rated).	A replacement substation for Doon Street at Spey Street will have additional supply capacity. Once complete a spare transformer will be relocated from Doon Street to Southern to provide a firm supply and further additional capacity on the Invercargill network. Load can then be balanced appropriately between the four Invercargill zone substations to avoid security and firm supply triggers being exceeded.
Doon St 33kV Oil-filled Cables	Capacity of these cables will not allow utilisation of the added capacity of the new Spey Street transformers. These have also been temporarily de-rated so capacity has been reduced below existing Doon Street capacity.	The cables will be supplemented with an additional 33kV XLPE cable to allow full utilisation of transformer capacity at Spey Street. The Oil-filled cables will then be paralleled and extended with XLPE cable to Spey Street as a second feeder. Additional work will be carried out to determine the correct rating for the oil cables which is expected to restore ratings sufficiently to fully utilise additional capacity at Spey Street.
MV Cables	Some MV cables operate near full capacity and would be unable to supply load in backup scenarios.	Several cables around the new Spey Street substation will be replaced and upsized to provide greater capacity out of Spey Street feeders. Operational measures ensure cables are not overloaded and smaller MV cables may be protected with fuses.
MV Transformers	Some transformers are near full capacity.	Maximum Demand Indicators (MDIs) are monitored and transformers will be upsized or supplemented with additional units as appropriate. Underutilised transformers may be relocated before purchasing new.

Constraint	Description	Intended remedy
LV Switching in CBD	Limited locations are available for above ground equipment.	Communication with the Council to determine appropriate locations for above ground link boxes has worked well. Underground equipment may be utilised where a suitable above ground location cannot be found.
Overhead Lines	The District plan prohibits new overhead lines.	Underground cables have been utilised throughout Invercargill.

4.8 Development Programme[A11.9, 11.10]

4.8.1 Current Projects[A11.10.1]

Projects scheduled for the 2015/16 year are as follows. These projects have a high certainty. Timing of projects in the 2015/16 year and beyond has been estimated based on currently available resources but may be brought forward depending how quickly contractors are able to respond to the increasing demands of EIL's works programme.

4.8.1.1 New Connections

This budget provides allowance for new connections to the network including subdivisions where a large number of customers may require connection. Each specific solution will depend on location and customer requirements.

Planning for new connections uses averages based on historical trending, modified by any local knowledge if appropriate however customer requirements are generally unpredictable and quite variable. Larger customers especially, which have the greatest effect on the network, tend not to disclose their intentions until connection is required (perhaps trying to avoid alerting competitors to commercial opportunities), so cannot be easily planned for in advance.

Various options are considered generally to determine the least cost option for providing the new connection. Work required depends on the customer's location relative to existing network and the capacity of that network to supply the additional load. This can range from a simple LV connection at a fuse in a distribution pillar box on the customers property boundary, to upgrade of LV cables or replacement of overhead lines with cables of greater rating, up to requirement for a new transformer site with associated 11kV extension if required. Even small customers can require a large investment to increase network capacity where existing capacity is already fully utilised.

The district plan requires all new network to be underground in Invercargill however Bluff may utilise overhead construction which tends to be a lower cost option.

Distributed generation as a network alternative tends to be intermittent so cannot be relied on without storage which would make an installation uneconomic. Some schemes may be becoming cost competitive with supply from the network however the upfront cost is generally not attractive to customers and generally a connection to the network is still desired as backup, supplementation and sometimes the ability to sell surplus energy. Customers may be encouraged to better manage diversity of load within their facilities where details are known and there is perceived benefit to the customer or network.

Under $0.5M per annum on-going; CAPEX - Consumer Connections.

4.8.1.2 New Spey Street Substation

The existing Doon Street substation is located in very close proximity to the old Invercargill water tower which is a large tall brick structure. A large concrete walled water storage reservoir is also located next to the substation. As highlighted by the recent Christchurch earthquakes, structures of these types may not survive in a large earthquake with brickwork or other parts of the structure falling from the tower or flooding from the water reservoir which could cause significant damage to the substation. The substation fence itself and part of the substation building is of an old brick construction and would also be likely to be damaged in a large earthquake. Also access to the Doon Street substation may not be allowed for some time if the surrounding structures are damaged or even suspected of being damaged until they are confirmed safe by inspection, support, strengthening or possibly demolition.

A decision was made to replace both 11.5/23MVA Doon Street transformers after one unit failed in service and it was determined that given the age of the unit, the extent of repair required and risk that further undetected damage may cause another failure, it was uneconomic to repair. The new transformers will be upsized to 18/36MVA units to provide capacity for growth in Invercargill which is timely as the substation load has now reached 23MVA meaning firm supply of the full substation load would not be achieved at peak times with 23MVA units. This is presently being managed by transferring load onto other zone substations. A second new unit is necessary as running different sized transformers in parallel (if replacing only the failed transformer) is generally not practical (it is possible if designed to match but this would not provide ideal operational characteristics for the present and future network) and would not achieve the required security of supply as loss of the larger new unit would leave only the smaller unit's capacity. The dual transformer replacement option works well as, due to load growth, EIL's Southern substation has reached the 12MVA security trigger requiring a firm supply and a second transformer. The replacement and upsizing of both the Doon Street units means the remaining transformer will become spare and available for use at Southern substation. 11kV load transfers are being utilised short term to manage load below the security trigger until this spare unit is available.

An overall increase in capacity of 49MVA will be achieved between the scrapping of the failed transformer and installation of the two new larger units. Demand side control may be viewed as an alternative to capacity upsizing, however at present it is very difficult to provide customers with incentive to manage their consumption patterns due to repackaging of lines company charges by retailer billing methodologies. This may be more practical with the introduction of smart meters over the next few years. EIL has contributed to the improvement of consumption efficiency through the "Warm Homes" scheme which provides subsidy initiatives to help insulate customer's homes and install more energy efficient space heating alternatives. These initiatives are now being extended to market solar power installations to customers as a means of reducing power bills or even selling power back to the grid. It is hard to gauge how much load growth has been offset by these initiatives and how the status quo forecasts might be affected; however overall growth seen at the zone substation level is still positive and increased capacity is now necessary on the EIL network. This increased capacity is expected to provide for growth beyond the 10 year planning period.

The 11kV switchboard at Doon Street was installed in stages, with the first seven circuit breakers installed in 1964 and the remaining circuit breakers installed over the next few years. Therefore these circuit breakers have reached their standard ODV life of 45 years. Due to the impact failure of switchgear would have on service levels (which are regulated such that the very high reliability of EIL's network must be maintained) and EIL's strategy to "Replace critical assets near to their technical end-of-life" these units are programmed for replacement. EIL conducts regular tendering processes to ensure that the most economic replacement equipment which meets network design requirements is installed as replacements.

An alternative option to replacing switchgear is to retrofit existing circuit breaker trucks with modern units. However this would not renew all components and those remaining would continue to age leaving an increased risk of failure following a significant proportion of the replacement cost. Switchboards may fail explosively and damage may be extensive requiring lengthy repairs which may not even be possible depending on damage sustained. Extensive reconfiguration of the 11kV network would be required to restore supply which would take time and if the entire switchboard was affected complete restoration may not be possible with some customers left without supply for a prolonged period. The switchboard continuous capacity rating would also remain the same with a retrofit option while growth on the network requires greater capacity in the near future. Given that Doon Street substation provides a critical supply to a large part of Invercargill city including parts of the CBD and the considerations already mentioned, retrofitting is not considered an appropriate option. The "do nothing" option is to allow the switchboard to operate to failure which means the risks mentioned above would actually occur at some point as well as greatly increase the risk of injury to field staff and is therefore not appropriate. Other cost saving options such as simplification of the switchboard (reducing number of replaced circuit breakers) would result in decreased service levels with faults affecting a greater number of customers which would not be acceptable. The replacement switchboard however had two spare circuit breakers which will not be replaced and instead room for expansion will be allowed for with the new switchboard.

Protection is provided by old electromechanical type relays which are mounted in the switchgear panels and are of generally the same vintage as the switchgear. These relays are therefore at the end of their intended life and their accuracy and functionality is not up to the modern standard. Modern digital relays are generally far superior in terms of accuracy and flexibility and also provide a lot of additional functionality including safety features such as arc flash. EIL has standardised on manufacturer to realise the benefits of staff familiarisation and training and in retaining spares for equipment across the network, otherwise the most economic option within the manufacturers range is chosen that provides the necessary features.

The substation building which houses the switchgear, protection and other minor auxiliary equipment also requires a major renovation or replacement due to seismic requirements and issues with asbestos.

Given that most of the major substation components are due for immediate renewal and considering the risk of damage posed by the neighbouring structures as well as potential site access issues resulting from a large earthquake, it has been decided that a new substation is to be built in the area but located safely away from large earthquake prone structures as replacement for the existing substation.

The Queens Park site proposed in earlier AMPs was abandoned when it appeared the consenting process would cause excessive delays and that proximity to large park trees risked issues around installation and maintenance. 217 Spey Street was selected as a development site after shortlisting from several potential sites in the area and then eliminating remaining alternatives based on difficulties likely to be encountered. The Spey Street site is the most appropriate location in terms of access, timely progression of the project and proximity to the load centre. The new substation will be entirely indoor with an exterior design to minimise visual impact and fit with the surrounding area buildings.

The 11kV feeder cables out of the substation will be replaced in the immediate area surrounding the new Spey Street substation as rerouting these feeder cables requires a significant rearrangement. Some of these cables also need to be upgraded as their capacity is not sufficient to allow simple backup in contingency events with increasingly complex outage plans needing to be developed. Without upgrade these constraints will begin to have an unacceptable impact on restoration time and could cause further outages if cables are overloaded and fail. Cable will be replaced with a standard size allowing a supply capacity up to about 8MVA over which load should be transferred to other more lightly loaded feeders to manage impact on reliability. Replacements will also eliminate several cable joints which tend to be weak points in cables and should help maintain EIL's reliability as the network cable population ages.

Full replacement of existing equipment as opposed to refurbishment type renewals is further justified as relocation of equipment to a new site would be impractical without unacceptable outage periods or reduction in security. The only equipment retained will be an NER which was installed at Doon Street temporarily and will be relocated when required at Spey Street (see section 4.8.1.9).

Construction is underway with the Spey Street substation planned to be energised and supplying load transferred from Doon Street by the end of the 2014/15 year. The second 18/36MVA transformer will be relocated from Doon Street to Spey Street, the incoming 33kV cable (extension from the oil cables at Doon Street, see section 4.8.1.3) will be terminated into the relocated transformer to achieve the AAA security rating and reconfiguration of 11kV feeder cables will be completed before all remaining Doon Street load can be transferred onto the new Spey Street substation in the 2015/16 year.

Cost \$0.5M - \$2.5M 2015/16; CAPEX – System Growth.

4.8.1.3 Extend Oil Filled 33kV Cable

A new XLPE cable was installed from Transpower's Invercargill GXP directly to the new Spey Street substation last year. The 33kV oil cables currently supplying Doon Street substation are planned to be paralleled and extended to create a second feeder to the new Spey Street substation.

At the supply end the oil cables previously each supplied by separate Invercargill GXP 33kV circuit breakers have been paralleled onto one of the circuit breakers. This has been completed so as to free up the other circuit breaker for the new 33kV XLPE cable now supplying the new Spey Street substation.

With the 11kV cable reconfiguration completed (see section 4.8.1.2), all substation load will have been transferred to the new Spey Street substation and the Doon Street substation will be decommissioned. The oil filled cables which currently terminate at Doon Street will then be paralleled at the Doon Street end and a new section of 33kV XLPE cable, of the same specification as the new cable between Invercargill GXP and Spey Street, will be installed to extend this supply to Spey Street to achieve the required AAA security.

Options for the paralleling of the oil cables and connection to the new XPLE extension cables are being considered and include;

- Retaining the overhead oil cable terminations and constructing a bus or cable connection arrangement to parallel the oil cable terminations and provide a connection point for the XLPE extension cable. This is a lower cost option which avoids interfering with the oil cables so as to avoid associated risk and expensive oil cable joint work.
- Cutting back each oil cable and installing transition joints to XLPE cables which can then be joined to the new XLPE extension cable within pits below ground level. This option would minimise visual impact of assets remaining at the Doon Street site however costing of this option shows the oil cable transition joints are very expensive.
- Retain overhead terminations but relocate from the overhead structures to ground level or below, parallel and connect to new XLPE extension cable. This option avoids expensive oil cable joint work and will result in a more compact, low profile and fully enclosed site remaining at Doon Street. This option carries some risk that moving the aged oil cables could cause damage reducing the life of the cables.

Risks associated with the reliability of the oil cables were discussed in the 2013 AMP and formed part of the justification for the new XLPE cable installed between the Invercargill GXP substation and the new Spey Street substation last year. The new XLPE cable provides a level of redundancy which is satisfactory to allow continued operation of the oil filled cables and make use of their remaining life however costs for the above options need to be weighed against abandoning the aged oil cables and installing a new larger capacity XLPE cable in its place.

Use of the XLPE extension, as opposed to new oil cable, is a deliberate move away from oil cable technology which while providing great life expectancy is more complex, requiring additional maintenance and oil processing equipment, pressure vessels and skilled staff to be available for repairs in the event of any faults resulting in an overall greater expense over the assets life.

The cable extension work detailed above is planned to be completed in 2015/16. The budget has been based around costs estimated for the transition joint option however this is being reviewed in light of the excessive cost.

Cost $0.5M - $2.5M 2015/16; CAPEX – System Growth.

4.8.1.4 Southern Substation Upgrades

The 11kV switchboard replacement and relocation of the 23MVA Doon Street transformer as part of security upgrades were planned for southern substation in 2014/15. However seismic assessments have brought in additional resilience concerns for Southern Substation and therefore a major renewal and upgrade project has been planned for the site in line with three key drivers;

- Seismic strengthening requirements following control building assessment at 17% of new building standard and under strength outdoor structures.
- Assets at end of life; the 11kV switchboard is due for replacement in 2014, outdoor structures show signs of cracking and reinforcement rust, air break switches and earth switches have reached ODV life and show signs of deterioration, one 33kV circuit breaker at end of ODV life, the second 33kV circuit breaker has significant rusting (ex-Bluff) and the control building is in need of significant maintenance.
- The substation load has reached the threshold in EIL's security standard where upgrade to AAA security is required (no interruption for any single failure event). This has been deferred as long as possible by utilising load transfers to the other Invercargill zone substations.

Planned upgrades

A staged approach toward a fully indoor substation is planned combining the prior planned work with the new seismic requirements and incorporates opportunities to create a more secure, reliable and resilient supply point for the existing substation load equal to about a third of EIL's customer count.

Initially a new 100% "new building standard" strength building is to be constructed on the existing site with an increased area to house both the previously planned new 11kV switchboard, auxiliary services and a new 33kV switchboard to replace the outdoor circuit breakers, CTs, air break switches, earth switches, VTs and associated structures. The backup 33kV supply available from the cable that tee's off TPCL's overhead subtransmission line on Rockdale Road becomes a normally in service supply to realise AAA security and will be metered to reconcile consumption between networks.

The two 23MVA transformers (one to be refurbished and relocated from Doon Street) are open bushing units not suitable for locating indoors and as they have expected remaining lives of nine and eleven years the enclosure of these units are delayed for approximately ten years until they are replaced with new cable entry transformers. The initial building design takes into account future extension requirements. The oil cable termination and associated pressure tanks would most likely remain outdoor but shielded from stone throwers (an ongoing issue at the site).

Options Considered
Several options were identified and considered as alternative options;

"Do nothing" was ruled out as inappropriate due to safety, security and reliability concerns with an earthquake prone building and primary assets beyond end of life at site.

A new building would be similar cost to the strengthening and maintenance requirements for retaining the existing building and brings additional benefits associated with a new modern building and was therefore considered the better option.

Renewal and upgrade of the existing outdoor concept was compared with the preferred indoor option described above including several variations around these themes. While there would be a small immediate cost benefit in retaining the outdoor concept the benefits of the indoor substation were considered to outweigh the difference in cost which amounts to about 5% of replacement cost for the overall replacement cost of the substation ($3.5 - 4 million). The additional benefits are extended life of indoor 33kV switchgear and reduced maintenance costs, a more comprehensive protection scheme and importantly a more reliable substation with protection from environmental impacts. The indoor solution protects from weather impacts, windblown rubbish and birds or other animal-life which reduce reliability for outdoor structure mounted equipment.

For EIL network reliability is very good, however this means that single events have the potential to significantly affect SAIDI and SAIFI reliability measures. Therefore it is particularly important for EIL to look for any opportunities to design out failure modes which have the potential to affect a large proportion of customers. A complete outage at Southern substation (supplying about a third or EIL's customers) could quickly cause regulatory limits to be exceeded, as happened recently at Doon Street substation where a transformer failure significantly contributed to both SAIDI and SAIFI limits being exceeded in 2010 and ultimately to a breach of Commerce Commission regulatory requirements with a subsequent event the following year. Future breaches could incur costs if significant investigation is required. There may also be significant benefit for customers in terms of the "Value of Lost Load" which quickly adds up for an outage at a critical supply point such as a zone substation. Other benefits of the indoor option are improvements in public safety and visual perception.

Locating 33kV switchgear offsite was considered however the resulting configuration would require additional communications assisted protection eroding cost benefits and the overall relative reliability of the concept was not considered sufficient for EIL's network.

Building a fully indoor substation at another site was considered as an option to allow construction and an easy switchover before decommissioning of the existing site however the additional cost to reroute 33kV supply and 11kV feeder cables could not be justified while it is considered feasible to redevelop the existing site and utilising 11kV backup to load if necessary for brief periods. Another option was decommissioning the substation and extending feeders from a nearby substation were considered however again the impacts on reliability of grouping feeders is not considered appropriate for EIL and significant associated upgrade costs would mean little if any cost could be saved.

Implementation
Design will be completed in 2015/16 however construction has been delayed from the timeframe set out in the previous AMP to manage resourcing constraints. Asset procurement and construction will be spread over two years beginning in 2017/18 with completion planned for 2018/19.

Cost under $0.5M 2015/16, $0.5M – 2.5M 2017/18 and 2018/19; CAPEX – System Growth.

4.8.1.5 Asset Relocation Projects

This budget captures costs for smaller general relocation works required such as shifting a pole or pillar box to a more convenient location. Costs budgeted represent a long term average with actual spend being reactive typically being above or below in any year.

Under $0.5M per annum on-going; CAPEX – Asset Relocations

4.8.1.6 Supply Quality Upgrades

On the LV network operation beyond capacity manifests as low voltage experienced by customers during periods of peak loading. This may occasionally require a new transformer site with associated 11kV extension if required. However in most cases replacing LV cables with larger cables will be a more economic option to maintain acceptable voltage for all customers. The minimum cable size which provides the existing and spare capacity for expected growth will be used.

An alternative to network upgrade is demand side management however cost incentives to reduce demand are proving ineffective due to the retailers repackaging of line charges into their billing. As EIL's 11kV feeders have high load capacity supplied over a relatively short distance, low voltage is not seen as an issue on these feeders. Harmonics have not caused any known issues to date.

Costs budgeted represent a long term average with actual spend being reactive typically being above or below in any year. The years 2016/17 to 2018/19 have increased budget to manage an increase in upgrades foreseen as the rollout of smart meters on the EIL network progresses and identifies voltage constraints.

Under $0.5M per annum on-going; CAPEX – Quality of Supply.

4.8.1.7 Network Automation Projects

This budget is to allow implementation of further network automation initiatives on the underground Invercargill network to add additional remote controllable switching points and automation technologies. This will contribute to improvements in reliability and aim to offset the reduction in reliability expected as the cable network is allowed to age back to the optimal average asset life remaining of 50% following the extensive underground programme and other recent or near future capital intensive projects.

This project was initiated last year targeting the overhead Bluff network which sees a relatively high number of faults. Automation technology application will target Invercargill starting 2015/16 and continue over the ten year planning horizon.

Under $0.5M per annum on-going; CAPEX – Quality of Supply.

4.8.1.8 Substation Safety

Arc flash hazards have been identified around MV switchgear at zone substations, presenting a risk of harm to personnel inside substation buildings, especially during operation of the switchgear.

Solutions may include additional PPE requirements, operational controls and protection improvements including retrofit of arc flash detection. A retrofit arc-flash installation was completed on the Leven Street 11kV switchboard last year and will be completed for the Racecourse Road substation 11kV switchboard in the 2015/16 year.

Cost under $0.5M 2015/16; CAPEX – Other Reliability, Safety and Environmental.

4.8.1.9 Oil Cable Temperature Monitoring

Temperature and soil resistivity probes were installed on each of the oil cables last year to provide useful data for accurately estimating the ratings of these cables. Presently these cables have been temporarily de-rated as the cable trench backfill has been identified as having poor thermal characteristics affecting design ratings. Understanding the temperature variation as these cables are loaded and soil moisture varies will help understand the practical rating of these cables so that overload can be avoided while making the most of their capacity.

A budget for interpreting the data collected from the temperature and soil resistivity probes by modelling of the cable thermal performance is allowed for in the 2015/16 year.

Cost under $0.5M 2015/16; CAPEX – Other Reliability, Safety and Environmental.

4.8.1.10 NER Installation at Substations

As part of compliance with the new EEA Guide to Power System Earthing Practice 2009, Neutral Earthing Resistors (NERs) are being installed at each zone substation to limit earth fault currents on the 11kV network. While NERs alone will not ensure network safety they will generally significantly reduce the earth potential rise which may appear on and around network equipment when an earth fault occurs. EIL considers NERs to be effectively a requirement of the EEA guide as when cost is considered to be distributed over all affected earth sites downstream of the zone substation this per site cost is quite low. The extent of work required at these individual sites (section 0) to improve earth effectiveness is therefore reduced making the NER an overall more cost effective solution.

Most of the EIL network in Invercargill is now underground which makes other impedance earthing options, installation of a ground fault neutraliser or Peterson coil, uneconomic as the cable network has very high capacitance which these inductive coil devices have to oppose. This means a very large coil would be required and would be many times more expensive than an NER installation. The large cable network does however mean that the entire Invercargill network, which includes the neighbouring TPCL Invercargill areas, creates a very large MEN (multiple earthed neutral) system which essentially interconnects all earths in Invercargill and provides another means to assist in controlling dangerous earth potential rise on the network.

The Bluff network is mostly overhead however Peterson Coils are still many times more expensive than an NER installation. The per earth site cost of the NER is again more cost effective than the additional per site upgrades that would be required without the NER. Some benefit is gained by the Bluff MEN, however this is much smaller and may include smaller "islands" without the MV cables tying LV MEN systems together as happens in Invercargill. The NER affecting EIL's Bluff network will be installed at TPCL's Bluff substation which supplies this network area.

The more resistance the NER has the greater the safety benefit and the smaller and therefore the lower the cost will be. However at a certain point the discrimination between network fuses and upstream feeder circuit breakers will be lost. Lost discrimination will have a large negative impact on network reliability with some outages being much more widespread so this effectively dictates the minimum NER size that can be installed. Two sizes have been standardised on with the Spey Street and Leven Street substations requiring larger NERs since they supply larger transformers in the CBD which require higher rated fuses for protection.

The NERs will also provide an additional benefit in limiting damage to faulted equipment and in some situations allow lower rated equipment to be installed, for example light duty cable screens. An NER was installed at Doon Street temporarily to limit earth fault current below the old switchboard fault rating with the new lower impedance 18/36MVA transformer in service. A second NER was installed last year at Spey Street as part of the new substation and the Doon Street NER will be relocated to Spey Street as a necessary spare in 2015/16 with costs being associated with the Spey Street substation project.

While the significant procurement costs were met last year this budget is for the remaining NER installations at Leven Street, Southern and Racecourse Road to be completed in 2015/16.

Under $0.5M 2013/14; CAPEX – Other Reliability, Safety and Environment.

4.8.2 Planned Projects[A11.10.2]

Expected projects for years two to five (1 April 2016 to 31 March 2020) have moderate certainty. Note some projects described above are on-going, these are not repeated in this section or the following Considered Projects sections.

4.8.2.1 Earth Upgrades

Ineffective earthing may create, or fail to control, hazardous voltage which may occur on and around network equipment affecting safety for the public and for staff. Also other functional requirements may not be met preventing protection systems from operating correctly which may affect safety and reliability of the network. Routine earth site inspection and testing identifies any sites that require upgrades.

Compliance with the new EEA Guide to Power System Earthing Practice 2009 has been required since the end of March 2012 when the Safety Management System (SMS) came into force. This requires an assessment of the risk of exposure to any hazards that may be created at earth sites and hazard mitigation measures appropriate to the risk to be carried out.

The analysis to determine what upgrade options are appropriate can be quite complex but essentially it looks to find the best trade-off between cost and risk reduction. Generally in EIL the earthing upgrades required will be minimal with safety being achieved by simple connection to the large urban MEN (multiple earthed neutral) system. However for sites where risk of potential exposure to EPR is high additional measures for example insulating barriers will be required to ensure public safety.

This testing is completed 5 yearly with the entire network tested in one year. Testing is next due in 2017/18.

Cost under $0.5M 2017/18, 2022/23 and five yearly thereafter; CAPEX – Other Reliability, Safety and Environmental.

4.8.3 Considered Projects[A11.10.3]

Projects expected for years six to ten (1 April 2020 to 31 March 2025) apart from those on-going described in previous sections.

4.8.3.1 Unspecified Projects

The unspecified projects budget is an estimate of costs for projects that are as yet unknown but from experience are considered likely to arise in the longer term. Certainty for these estimates is obviously quite low.

$0.5M - $2.5M 2018 per annum onwards; System Growth.

4.8.4 Contingent Projects

The following projects are contingent on uncertain events. These have been excluded from EIL's spend plans until they become certain.

4.8.4.1 Coal, Silicon or Oil Extraction and Refineries

Possible major new industry that may require a new substation and subtransmission lines, most likely would be connected onto the Transpower 220kV network.

4.8.5 Proposed Network Configuration

The planned network configuration in 2025 is shown in Figure 45.

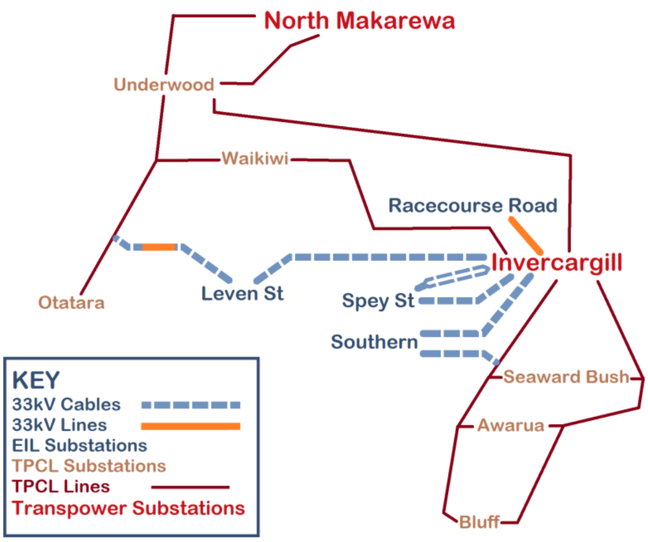


Figure 45: Proposed Network Configuration 2025

4.9 Non-network assets

Non-network capital projects for EIL are as detailed below.

4.9.1 Oil Processing Plant Refurbishment

EIL owns an oil processor for degassing insulating oil before use in the three oil filled cables on EIL's network following a cable fault or leak. It is currently housed in an old caravan with the setup needing significant maintenance to ensure it is adequate for use should it be required.

The caravan will be sold or scrapped and the oil processing plant refurbished and stored so that it may be efficiently transported to location if required.

Cost under $0.5M 2015/16; Non-network Assets.

4.9.2 Non-asset description and treatment [A13.1, A13.2]

EIL owns none of the following assets that are non-network, as these are owned by PowerNet:

- Information and technology systems.
- Asset management systems.
- Office buildings.
- Office furniture and equipment.
- Motor vehicles.
- Tools, plant and machinery.

Future upgrades include:

- System Control upgrades including new Outage Management System

The PowerNet costs of providing and servicing for the above are incorporated into charges to EIL and reflected in the System Operations and Network Support and the Business Support costs in EIL's maintenance budget (see section 5.10).

4.9.3 Capital Budget

The estimated capital budget for EIL is shown below in Table 33.

CAPEX: Consumer Connection	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Customer Connections (≤ 20kVA)	59,577	59,577	59,577	59,577	59,577	59,577	59,577	59,577	59,577	59,577
Customer Connections (21 to 99kVA)	47,662	47,662	47,662	47,662	47,662	47,662	47,662	47,662	47,662	47,662
Customer Connections (≥ 100kVA)	95,324	95,324	95,324	95,324	95,324	95,324	95,324	95,324	95,324	95,324
Distributed Generation Connection	2,383	2,383	2,383	2,383	2,383	2,383	2,383	2,383	2,383	2,383
New Subdivisions	14,299	14,299	14,299	14,299	14,299	14,299	14,299	14,299	14,299	14,299
	219,244	**219,244**	**219,244**	**219,244**	**219,244**	**219,244**	**219,244**	**219,244**	**219,244**	**219,244**

CAPEX: System Growth	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
New Spey Street Substation	1,551,393	-	-	-	-	-	-	-	-	-
New Spey Street 33kV Cable	-	-	-	-	-	-	-	-	-	-
Extend Oil Filled 33kV Cable	861,885	-	-	-	-	-	-	-	-	-
Southern Substation Upgrades	104,004	-	841,942	2,113,603	-	-	-	-	-	-
Unspecified Projects	-	-	-	-	-	858,675	858,675	858,675	858,675	858,675
	2,517,282	**-**	**841,942**	**2,113,603**	**-**	**858,675**	**858,675**	**858,675**	**858,675**	**858,675**

CAPEX: Asset Replacement and Renewal	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
RTU Replacement	85,771	148,088	42,886	42,886	64,328	74,472	-	-	-	-
Racecourse Road Switchboard Replacement	-	-	-	-	115,560	1,363,608	-	-	-	-
UG Substation Replacement	646,280	387,768	387,768	387,768	387,768	387,768	387,768	387,768	387,768	387,768
Siesmic Remedial Zone Substations	94,374	-	-	-	-	-	-	-	-	-
Siesmic Remedial Distribution	-	-	-	-	-	248,240	303,752	303,752	-	-
Power Transformer Refurbishment	-	161,570	-	-	-	161,570	161,570	161,570	-	-
Zone Substation Minor Replacement	3,635	3,635	3,635	3,635	3,635	3,635	3,635	3,635	3,635	3,635
Transformer Replacement - City	357,464	357,464	357,464	357,464	357,464	357,464	357,464	357,464	357,464	357,464
Transformer Replacement - Bluff	84,826	84,826	84,826	84,826	84,826	84,826	84,826	84,826	84,826	84,826
RMU Replacements	193,888	193,888	193,888	193,888	193,888	193,888	193,888	193,888	193,888	193,888
Reactive 11 kV Cable Replacement	18,177	18,177	18,177	18,177	18,177	18,177	18,177	18,177	18,177	18,177
Planned 11kV Cable Replacement	-	-	-	-	-	25,851	45,240	58,165	77,554	77,554
General Technical Replacement	48,472	48,472	48,472	48,472	48,472	48,472	48,472	48,472	48,472	48,472
General Dist Replacement - City	18,177	18,177	18,177	18,177	18,177	18,177	18,177	18,177	18,177	18,177
General Dist Replacement - Bluff	171,519	171,519	171,519	171,519	171,519	171,519	171,519	171,519	171,519	171,519
LV Board Replacement	31,507	31,507	31,507	31,507	31,507	31,507	31,507	31,507	31,507	31,507
Link Box Replacement	530,720	1,061,440	796,080	53,072	53,072	53,072	53,072	53,072	53,072	53,072
Pillar Box Replacement	14,894	14,894	14,894	14,894	14,894	14,894	14,894	14,894	14,894	14,894
Reactive LV Cable Replacement	96,944	96,944	96,944	96,944	96,944	96,944	96,944	96,944	96,944	96,944
	2,396,650	**2,798,371**	**2,266,238**	**1,523,230**	**1,660,233**	**3,354,086**	**1,990,906**	**2,003,831**	**1,557,898**	**1,557,898**

CAPEX: Asset Relocations	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Asset Relocation Projects	5,416	5,416	5,416	5,416	5,416	5,416	5,416	5,416	5,416	5,416
	5,416	**5,416**	**5,416**	**5,416**	**5,416**	**5,416**	**5,416**	**5,416**	**5,416**	**5,416**

CAPEX: Quality of Supply	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Supply Quality Upgrades - City	11,915	59,577	59,577	59,577	11,915	11,915	11,915	11,915	11,915	11,915
Supply Quality Upgrades - Bluff	1,192	5,958	5,958	5,958	1,192	1,192	1,192	1,192	1,192	1,192
Network Automation Projects	59,577	59,577	59,577	59,577	59,577	59,577	59,577	59,577	59,577	59,577
	72,684	**125,112**	**125,112**	**125,112**	**72,684**	**72,684**	**72,684**	**72,684**	**72,684**	**72,684**

CAPEX: Legislative and Regulatory	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
	-	-	-	-	-	-	-	-	-	-
	-	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

CAPEX: Other Reliability, Safety and Environment	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Earth Upgrades - City	-	-	11,915	-	-	-	-	11,915	-	-
Earth Upgrades - Bluff	-	-	1,192	-	-	-	-	1,192	-	-
Substation Safety	59,577	-	-	-	-	-	-	-	-	-
Oil Cable Temperature Monitoring	11,556	-	-	-	-	-	-	-	-	-
NER Installations	182,756	-	-	-	-	-	-	-	-	-
	253,889	**-**	**13,107**	**-**	**-**	**-**	**-**	**13,107**	**-**	**-**

Network Capital Expenditure Total	**5,465,166**	**3,148,144**	**3,471,060**	**3,986,606**	**1,957,578**	**4,510,106**	**3,146,926**	**3,172,958**	**2,713,918**	**2,713,918**
Oil Processing Plant Refurbishment	53,072	-	-	-	-	-	-	-	-	-
Non-Network Capital Expenditure Total	**53,072**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total Capital Expenditure	**5,518,238**	**3,148,144**	**3,471,060**	**3,986,606**	**1,957,578**	**4,510,106**	**3,146,926**	**3,172,958**	**2,713,918**	**2,713,918**

Table 33: Capital Budget

5. Managing the Assets' Lifecycle

All physical assets have a lifecycle. This section describes how EIL manages assets over their entire lifecycle from "commissioning" to "retirement".

5.1 Lifecycle of the Assets

The lifecycle of EIL's existing assets is outlined in Figure 46 below:

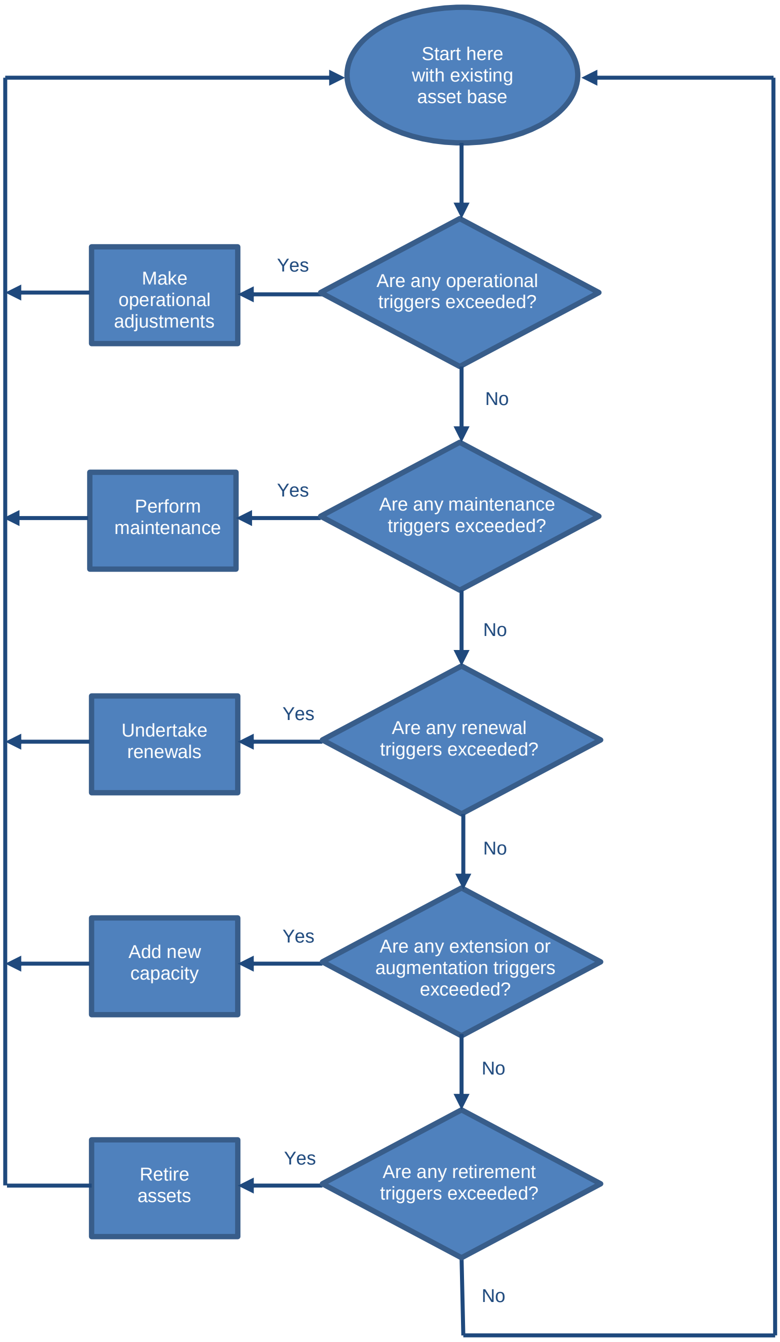


Figure 46: Asset Lifecycle

Table 34 provides some definitions for key lifecycle activities.

Table 34: Definition of key lifecycle activities

Activity	Detailed definition
Operations	Involves altering the operating parameters of an asset such as closing a switch or altering a voltage setting. Doesn't involve any physical change to the asset, simply a change to the asset's configuration that it was designed for. In the case of electrical assets it will often involve doing nothing and just letting the electricity flow.
Maintenance	Involves replacing consumable components like the seals in a pump, the oil in a transformer or the contacts in a circuit breaker. Generally these components will be designed to wear out many times over the asset's design lifecycle and continued operation of the asset will require such replacement. There may be a significant asymmetry associated with consumables such as lubricants in that replacing a lubricant may not significantly extend the life of an asset but not replacing a lubricant could significantly shorten the asset's life.
Renewal	Generally involves replacing a non-consumable item like the housing of a pump with a replacement item of identical functionality (usually capacity). Such replacement is generally regarded as a significant mile-stone in the life of the asset and may significantly extend the life of the asset (a bit like "Grandpa's axe"). Renewal tends to dominate the Capital expenditure in low growth areas (Quadrant 1 of Figure 40) because assets will generally wear out before they become too small. The most typical criteria for renewal will be when the capitalised costs of operations and maintenance exceed the cost of renewal. A key issue with renewal is technological advances that generally make it impossible to replace assets such as SCADA with equivalent functionality.
Up-sizing	Generally involves replacing a non-consumable item like a conductor, busbar or transformer with a similar item of greater capacity but which does not increase the network footprint i.e. restricted to Quadrants 1 and 2 in Figure 40.
Extensions	Involves building a new asset where none previously existed because a location trigger in Table 24 has been exceeded e.g. building several spans of line to connect a new factory to an existing line. This activity falls within Quadrants 3 and 4 of Figure 40. Notwithstanding any surplus capacity in upstream assets, extensions will ultimately require Up-sizing of upstream assets.
Retirement	Generally involves removing an asset from service and disposing of it. Typical guidelines for retirement will be when an asset is no longer required, creates an unacceptable risk exposure or when its costs exceed its revenue.

5.2 Operating EIL's Assets

As outlined in Table 34 operations predominantly involves doing nothing and simply letting the electricity flow from the GXPs to customer's premises year after year with occasional intervention when a trigger point is exceeded (however the workload arising from tens of thousands of trigger points is substantial enough to merit a dedicated control room). As outlined in Figure 46 the first efforts to relieve excursions beyond trigger points are operational activities with typical activities listed in Table 35.

Table 35: Typical responses to operational triggers

Asset class	Trigger event	Response to event	Approach
GXP	Voltage is too high or low on 33kV or 11kV.	Automatic operation of tap changer.	Reactive
	Demand exceeds allocated Transpower limit.	Activate ripple injection plant to switch off load control relays.	Reactive
		Move zone substations between GXPs to relieve load from highly loaded GXP.	Reactive
	Transition from day to night.	Activate ripple injection plant to switch street lights on or off.	Proactive
	On-set of off-peak tariff periods.	Activate ripple injection plant to switch controlled loads on or off.	Proactive
Zone substation transformers	Voltage is too high or low on 11kV.	Automatic operation of tap changer.	Reactive
	Demand exceeds rating.	Move tie points to relieve load from zone sub.	Reactive
Distribution reclosers	Fault current exceeds threshold.	Automatic operation of recloser.	Reactive
Distribution ABSs	Component current rating exceeded.	Open & close ABSs to shift load.	Proactive or reactive
	Fault has occurred.	Open & close ABSs to restore supply.	Reactive
Distribution transformers	Voltage is too high or low on LV.	Manually raise or lower tap where fitted.	Reactive
	Fuses keep blowing.	Shift load to other transformers by cutting and reconnecting LV jumpers.	Reactive
LV distribution	Voltage is too low at customer's board.	Supply from closer transformer if possible by cutting and reconnecting LV jumpers.	Reactive

Table 36 outlines the key operational triggers for each class of EIL's assets. Note that whilst temperature triggers will usually follow demand triggers they may not always. For example an overhead conductor joint might get hot because it is loose or rusty rather than overloaded.

Table 36: Operational triggers

Asset category	Voltage trigger	Demand trigger	Temperature trigger
LV lines and cables	Voltage routinely drops too low to maintain at least 0.94pu at customers' switchboards. Voltage routinely rises too high to maintain no more than 1.06pu at customers' switchboards.	Customer's pole or pillar fuse blows repeatedly.	Infra-red survey reveals hot joint.

Asset category	Voltage trigger	Demand trigger	Temperature trigger
Distribution substations	Voltage routinely drops too low to maintain at least 0.94pu at customers' switchboards. Voltage routinely rises too high to maintain no more than 1.06pu at customers' switchboards.	Load routinely exceeds rating where MDIs are fitted. LV fuses blow repeatedly. Short term loading exceeds guidelines in IEC 354.	Infra-red survey reveals hot connections.
Distribution lines and cables		Alarm from SCADA that current has exceeded a set-point.	Infra-red survey reveals hot joint.
Zone substations	Voltage drops below level at which OLTC can automatically raise or lower taps.	Load exceeds guidelines in IEC 354.	Top oil temperature exceeds manufacturer's recommendations. Core hot-spot temperature exceeds manufacturer's recommendations.
Subtransmission lines and cables	Alarm from SCADA that voltage is outside of allowable set-points.	Alarm from SCADA that current is over allowable set-point.	Infra-red survey reveals hot joint.
EIL equipment within GXP	Alarm from SCADA that voltage is outside of allowable set-points.	Alarm from SCADA that current is over allowable set-point.	Infra-red survey reveals hot joint.

5.3 Maintaining EIL's Assets [A12.1, 12.2 (with AMP section 5.10)]

As described in Table 34 maintenance is primarily about replacing consumable components. Examples of the way in which consumable components "wear out" include the oxidation or acidification of insulating oil, pitting or erosion of electrical contacts and wearing of pump seals. Continued operation of such components will eventually lead to failure as indicated in Figure 47 following. Failure of such components is usually based on physical characteristics and exactly what leads to failure may be a complex interaction of parameters such as quality of manufacture, quality of installation, age, operating hours, number of operations, loading cycle, ambient temperature, previous maintenance history and presence of contaminants – note that the horizontal axis in Figure 47 is not simply labelled "time".

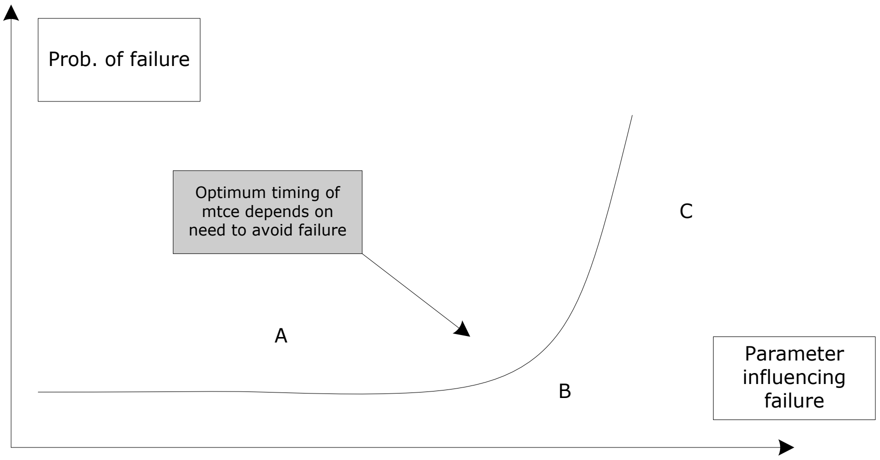


Figure 47: Component Failure

Exactly when maintenance is performed will be determined by the need to avoid failure. For instance the need to avoid failure of a 10kVA transformer supplying a single customer is low; hence it might be operated out to point C in Figure 47 whilst a 66/11kV substation transformer may only be operated to point B due to a higher need to avoid failure. In the extreme case of, say, turbine blades in an aircraft engine it would be desirable to avoid even the slightest probability of failure hence the blades may only be operated to point A. The obvious trade-off with avoiding failure is the increased cost of labour and consumables over the asset's lifecycle along with the cost of discarding unused component life.

Like all EIL's other business decisions, maintenance decisions are made on cost-benefit criteria with the principal benefit being avoiding supply interruption. The practical effect of this is that assets supplying large customers or numbers of customers will be extensively condition monitored to avoid supply interruption whilst assets supplying only a few customers such as a 10kVA transformer will more than likely be run to failure. The maintenance strategy map in Figure 48 broadly identifies the maintenance strategy adopted for various ratios of costs and benefits.

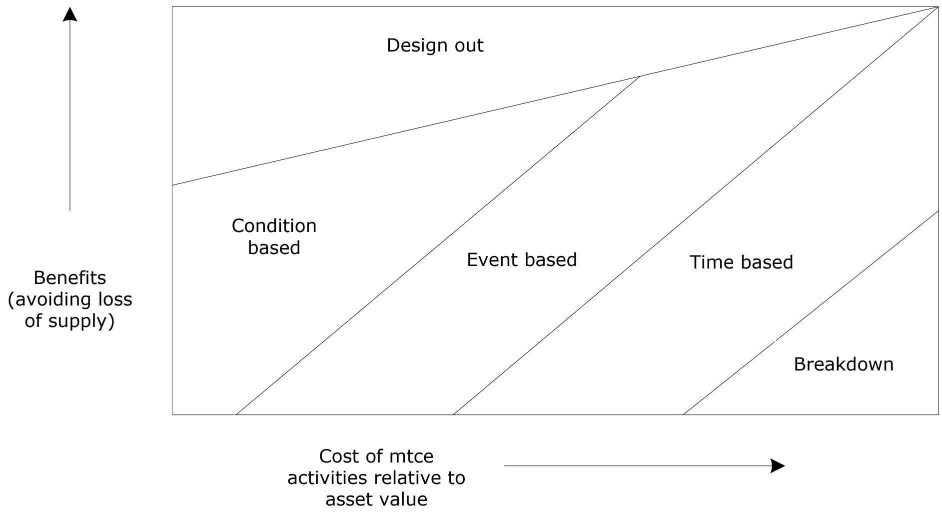


Figure 48: Maintenance Strategy Map

This map indicates that where the benefits are low (principally there is little need to avoid loss of supply) and the costs of maintenance are relatively high, an asset should be run to failure. As the value of an asset and the need to avoid loss of supply both increase, the company relies less and less on easily observable proxies for actual condition (such as calendar age, running hours or number of trips) and more and more on actual component condition (through such means as dissolved gas analysis (DGA) of transformer oil).

Component condition is the key trigger for maintenance; however the precise conditions that trigger maintenance are very broad, ranging from oil acidity to dry rot. Table 37 describes the maintenance triggers adopted:

Table 37: Maintenance Triggers

Asset category	Components	Maintenance trigger
LV lines and cables Five yearly inspection	Poles, arms, stays and bolts	Evidence of dry-rot. Loose bolts, moving stays. Displaced arms.
	Pins, insulators and binders	Obviously loose pins. Visibly chipped or broken insulators. Visibly loose binder.
	Conductor	Visibly splaying or broken conductor.
Distribution substations Five yearly inspection Six monthly for sites >150kVA	Poles, arms and bolts	Evidence of dry-rot. Loose bolts, moving stays. Displaced arms.
	Enclosures	Visible rust. Cracked or broken masonry.
	Transformer	Excessive oil acidity (500kVA or greater). Visible signs of oil leaks. Excessive moisture in breather. Visibly chipped or broken bushings.
	Switches and fuses	Visible rust. Oil colour. Visible signs of oil leak.
Distribution lines and cables Five yearly inspection	Poles, arms, stays and bolts	Evidence of dry-rot. Loose bolts, moving stays. Displaced arms.
	Pins, insulators and binders	Loose tie wire. Chipped or cracked insulator.
	Conductor	Loose or pitted strands. Visible rust.
	Ground-mounted switches	Visible rust. Oil colour. Visible signs of oil leak.
	Regulators	Visible rust. Oil colour. Visible signs of oil leak. Excessive moisture in breather. High Dissolved Gas Analysis results.
Zone substations Monthly checks	Fences and enclosures	Weeds. Visible rust. Gaps in fence.
	Buildings	Flaking paint. Timber rot. Cracked or broken masonry.
	Bus work and conductors	Hot spot detected by Infrared detector. Corrosion of metal or fittings.

Asset category	Components	Maintenance trigger
	33kV switchgear	Visible rust. Operational count exceeded. Low oil breakdown.
	Transformer	Visible rust. High Dissolved Gas Analysis results (Annual test). Low oil breakdown. High oil acidity.
	11kV switchgear	Visible rust. Operational count exceeded. Low oil breakdown.
	Instrumentation/protection Electromechanical three yearly Electronic five yearly	Maintenance period exceeded. Possible mal-operation of device.
	Batteries Six monthly test	Discharge test or Impedance test.
Substation-transmission lines and cables Five yearly inspection	Poles, arms, stays and bolts	Evidence of dry-rot. Loose bolts, moving stays. Displaced arms.
	Pins, insulators and binders	Loose tie wire. Chipped or cracked insulator.
	Conductor	Loose or pitted strands. Visible rust.
	Cable Annual check	High Partial discharge detected. Sheath insulation short. Oil pressure declining.
Our equipment within GXP Monthly check	Injection plant	Alarm from failure ripple generation. Period exceed for checks.

Typical maintenance policy responses to these trigger points are described in Table 38.

Table 38: Typical responses to maintenance triggers

Asset class	Trigger point	Response to trigger	Approach
Subtransmission lines	Loose or displaced components	Tighten or replace	Condition as revealed by annual inspection
	Rotten or spalled poles	Brace or bandage pole unless renewal is required	Condition as revealed by annual inspection
	Cracked or broken insulator	Replace as required	Breakdown
	Splaying or broken conductor	Repair conductor unless renewal is required	Condition as revealed by annual inspection
GXP and zone substation transformers	Oil acidity	Filter oil	Condition as revealed by annual test
	Excessive moisture in breather	Filter oil	Condition as revealed by monthly inspection
	Weighted number of through faults	Filter oil, possibly de-tank and refurbish	Event driven
	General condition of external components	Repair or replace as required	Condition as revealed by monthly inspection

Asset class	Trigger point	Response to trigger	Approach
Distribution lines	Loose or displaced components	Tighten or replace	Condition as revealed by three yearly inspection
	Rotten or spalled poles	Brace or bandage pole unless renewal is required	Condition as revealed by three yearly inspection
	Cracked or broken insulator	Replace as required	Breakdown
	Splaying or broken conductor	Repair conductor unless renewal is required	Condition as revealed by three yearly inspection
Distribution reclosers	Weighted number of light and heavy faults	Repair or replace contacts, filter oil if applicable	Event driven
Distribution ABS's	Loose or displaced supporting components	Tighten or replace unless renewal is required	Condition as revealed by three yearly inspection
	Seized or tight	Lubricate or replace components as required	Breakdown
Distribution transformers	Loose or displaced supporting components	Tighten or replace unless renewal is required	Condition as revealed by three yearly inspection
	Rusty, broken or cracked enclosure where fitted	Make minor repairs unless renewal is required	Condition as revealed by three yearly inspection
	Oil acidity	Filter oil	Remove from service for full overhaul every 15 years
	Excessive moisture in breather where fitted	Filter oil	Condition as revealed by three yearly inspection
	Visible oil leaks	Remove to workshop for repair or renewal if serious	Condition as revealed by three yearly inspection
	Chipped or broken bushings	Replace	Breakdown or condition as revealed by three yearly inspection
LV lines	Loose or displaced components	Tighten or replace	Breakdown unless revealed by five yearly inspection
	Rotten or spalled poles	Brace or bandage pole unless renewal is required	Five yearly inspection
	Cracked or broken insulator	Replace as required	Breakdown unless revealed by five yearly inspection
	Splaying or broken conductor	Repair conductor unless renewal is required	Breakdown unless revealed by five yearly inspection

The frequency and nature of the response to each of the above triggers are embodied in EIL's policies and work plans.

5.3.1.1 Systemic Faults[A12.2.2]

EIL has been made aware of a potential systemic weakness in the 33kV oil filled cables which supply Doon and Southern substations. Similar cables on other distribution company's networks have been found showing signs of insulation damage due to weakness in the cable joints allowing movement of the cores with thermodynamic expansion and contraction.

Development projects will help mitigate some of the reliability concerns and are detailed in section 4.8.

There are no other projects presently investigating systemic failures.

Examples of past investigations and outcomes are shown below. Some of these examples represent learnings from issues found on other networks managed by PowerNet but which are common to the EIL network.

- Kidney strain insulators: Replaced with new polymer strains.
- DIN LV fuses: Sourced units that can be used outdoor.
- Parallel-groove clamps: Replaced with compression joints.
- Non-UV stabilised insulation: Exposed LV now has sleeve cover, with new cables UV stabilised.
- Opossum faults: Extended opossum guard length.

5.3.2 Routine and Corrective Maintenance and Inspection

Each maintenance trigger has a related inspection period listed in Table 37, e.g. zone substations are checked each month.

Monitoring of assets includes the following areas:

- Statistic data collection of loading data on substations and large transformers.
- Protection relay testing / checks.
- Earthing checks.
- DGA of transformer oil.
- Partial discharge and infrared survey of substations and major distribution equipment.
- Injection plant tuning checks.
- Supply quality checks.
- Line surveys and testing.

The on-going maintenance of assets is also covered by this budget. Items covered include:

- Lubrication of ABS's.
- Cleaning of air insulated switchgear.
- Battery replacements.
- Rust repairs and painting.
- TCOL and CB service.
- Minor customer connections.

Additionally seismic checks are planned for next year to determine how the distribution network might be affected by a large earthquake.

OPEX on this is budgeted at $0.75 - $0.80 million per annum.

5.3.3 Service Interruptions and Emergencies

Service interruption and emergency maintenance provides for the provision of staff, plant and resources to be ready for faults and/or emergencies. This resource attends and makes the area safe, then may isolate the faulty section so other customers are restored or undertake quick repairs to restore supply to all customers.

OPEX on this is budgeted at $0.69 million per annum.

5.3.4 Vegetation Management

Electricity (Hazards from Trees) Regulations 2003, put the requirement on EIL to undertake the first trim of trees free, and this budget is the on-going actioning of this. While some customers have received their first free trim, some are disputing the process and additional costs are occurring to resolve the situation. As EIL's network is mostly underground tree issues are minimal and therefore costs are relatively low.

OPEX on this is budgeted at $1,400 per annum.

5.4 EIL's Maintenance Policies[A12.3 (with AMP section 5.5)]

EIL's maintenance policies are embodied in the PowerNet standards PNM-97, PNM-99 and PNM-105 which broadly follow manufacturer's recommendations but tend to be modified by industry experience.

5.5 Renewing EIL's Assets[A12.3 (with AMP section 5.4)]

Work is classified as renewal if there is no change (and such change would usually be an increase) in functionality i.e. the output of any asset doesn't change. EIL's key criterion for renewing an asset is when the capitalised operations and maintenance costs exceed the renewal cost and this can occur in a number of ways:

- Operating costs become excessive e.g. addition of inputs to a SCADA system requires an increasing level of manning.
- Maintenance costs begin to accelerate away e.g. a transformer needs more frequent oil changes as the seals and gaskets perish.
- Supply interruptions due to component failure become excessive; what constitutes "excessive" will be a matter of judgment which will include the number and nature of customers affected.
- Renewal costs decline, particularly where costs of new technologies for assets like SCADA decrease by several fold.

Table 39 below lists EIL's renewal triggers for key asset classes.

Table 39: Renewal Triggers

Asset category	Components	Renewal trigger
LV lines and cables	Poles	• Fails pole test. • Failure due to external force.
	Pins, insulators and binders	• Done with pole renewal.
	Conductor	• Excessive failures. • Multiple joints in a segment
Distribution substations	Poles	• Failure due to pole test. • Failure due to external force.
	Enclosures	• Uneconomic to maintain.
	Transformer	• Excessive rust. • Old technology, pre-1970 core. • Not economical to maintain.
	Switches and fuses	• Not economical to maintain.
Distribution lines and cables	Poles	• Fails pole test. • Failure due to external force.
	Pins, insulators and binders	• Done with pole renewal.

Asset category	Components	Renewal trigger
	Conductor	• Excessive failures. • Multiple joints in a segment.
	Ground-mounted switches	• Not economical to maintain. • No source of spare parts. • If not able to be remote controlled.
	Regulators	• Not economical to maintain. • No spare parts. • Greater than Standard Life and maintenance required.
Zone substations	Fences and enclosures	• Not economical to maintain.
	Buildings	• Not economical to maintain.
	Bus work and conductors	• Not economical to maintain.
	33kV switchgear	• Not economical to maintain. • No spare parts. • Greater than Standard Life and maintenance required.
	Transformer	• Not economical to maintain. • No spare parts. • Greater than 1.2 Standard Life and maintenance required.
	11kV switchgear	• Not economical to maintain. • No spare parts. • Greater than Standard Life and maintenance required.
	Bus work and conductors	• Not economical to maintain.
	Instrumentation/Protection	• Not economical to maintain. • No spare parts. • Greater than Standard Life and maintenance required.
	Batteries	• Prior to manufacturers' stated life. • On failure of testing.
Subtransmission lines and cables	Poles,	• Not economical to maintain. • Fails pole test. • Failure due to external force.
	Pins, insulators and binders	• Not economical to maintain.
	Conductor	• Not economical to maintain. • Excessive joints in a segment
	Cables	• Not economical to maintain.
Our equipment within GXP		• Not economical to maintain.

Broad polices for renewing all classes of assets are:

- When an asset is likely to create an operational or public safety hazard.
- When the capitalised operations and maintenance costs exceed the likely renewal costs.
- When continued maintenance is unlikely to result in the required service levels.

5.5.1 Current Renewal Projects[A12.3.3]

Renewal projects planned for the 2015/16 year.

5.5.1.1 SCADA RTU Replacement

Present GPT mini RTU units are beyond expected end of life and are becoming less reliable. Quality of operational data capture would suffer and loss of control of network equipment would affect EIL's service levels so full remote control needs to be maintained. Replacement of RTU's at the eight automated distribution substations with modern units would also provide greater reliability and added functionality.

Communications between the RTUs and the SCADA system has used multicore copper cables installed around the Invercargill CBD. An audit of cable integrity and spare cores available will be undertaken to verify that these can be used with the replacement RTUs. The RTUs are mostly located in underground substations deemed "confined spaces", therefore work at these sites incurs additional cost in managing the hazards presented.

This replacement programme will be undertaken over the 2015/16 year. A few of these RTU replacements may be incorporated into other replacement projects such as the underground sub replacement programme or seismic remediation replacements.

Under $0.5M 2015/16; CAPEX – Asset Replacement and Renewal.

5.5.1.2 Underground Substation Replacements

EIL owns several underground distribution substations in and around the Invercargill CBD. These substations contain 11kV switchgear, distribution transformers, LV distribution boards and several other minor components. Equipment has now reached end of life at some sites and requires replacement as risk of failure increases to ensure acceptable service levels are maintained. Each underground substation is a fully enclosed space with limited access. They have been deemed "confined spaces" due to the risk of toxic or oxygen deficient atmosphere and the difficulties of rescuing a person unconscious due to an accident or health condition. Extensive measures have been put in place to manage these risks however some residual risk remains and accessing these sites has become rather cumbersome and ultimately expensive.

EIL sees that the best option is to relocate these sites above ground and while finding suitable locations within the Invercargill CBD will be difficult it is the only way to eliminate the additional confined space risks. Negotiating sites within carparks is desirable as this will also help avoid future traffic management in the busy CBD, pavement disruption and pavement reinstatement works (often stylized with paving stones) when working around these sites in future.

This programme was initiated last year with the replacement of the Kelvin Hotel substation with an above ground substation in the Southland Times building carpark. A smaller substation was already located at this new site and the replacement substation has a larger capacity to replace, and supply the load of, both sites.

The replacement programme will continue with two underground sites relocated and renewed per year until the remaining eleven distribution substations are complete.

Cost Under $0.5M 2015/16 to 2020/21; CAPEX – Asset Replacement and Renewal.

5.5.1.3 Seismic Remedial - Zone Substations

Leven Street substation was strengthened last year after seismic assessments found a number of structural weaknesses. With Spey Street substation under construction as replacement for Doon Street substation and the Southern substation upgrade works being undertaken over the next two years, Racecourse Road is the only EIL zone substation remaining with seismic weaknesses to be addressed.

Strengthening design for the Racecourse Road building and outdoor structures was completed last year with strengthening work scheduled for the 2015/16 year.

Under $0.5M 2015/16; CAPEX – Asset Replacement and Renewal.

5.5.1.4 Seismic Remedial Distribution

This project will implement seismic remedial solutions at EIL's distribution substations following seismic assessments. Various options will be available depending on the site characteristics and include strengthening of buildings, enclosures or structures or replacement with self-contained freestanding equipment. Many sites are unique however there are several common "themes" to enclosures used for ground mounted distribution substations and therefore common solutions can be applied to groups of sites.

Remedial work will be spread across three years to manage workload; beginning in 2015/16 and being completed in the 2017/18 year.

Cost Under $0.5M 2015/16 to 2017/18; CAPEX – Asset Replacement and Renewal.

5.5.1.5 Power Transformer Refurbishment

EIL's new strategy to refurbish power transformers at midlife will commence in 2015/16 with the Racecourse Road transformer and the ex-Doon Street transformer to be relocated to Southern. The existing Southern Substation transformer will be refurbished in 2016/17 and the older Leven Street unit in 2017/18. These refurbishments will catch up EIL's zone substation transformer fleet with this new strategy aimed at preventing premature failures through identification of design weaknesses or developing faults and undertaking repairs or modifications necessary to achieve expected (or extend) life of these units.

Cost Under $0.5M 2015/16 to 2017/18; CAPEX – Asset Replacement and Renewal.

5.5.1.6 Zone Substation Minor Replacement

On-going replacement of minor components at zone substations such as LTAC panels and battery banks.

Cost Under $0.5M on-going; CAPEX – Asset Replacement and Renewal.

5.5.1.7 Transformer Replacement

On-going replacements of distribution transformers which are generally identified during distribution inspections and targeted inspections based on age. Some removed units are refurbished.

Cost Under $0.5M on-going; CAPEX – Asset Replacement and Renewal.

5.5.1.8 RMU Replacements

On-going replacement of Ring Main Units as they reach end of life and risk of failure increases at distribution substations outside of the CBD area to maintain reliability of supply and safety in the vicinity of the substation.

Cost Under $0.5M on-going; CAPEX – Asset Replacement and Renewal.

5.5.1.9 Reactive 11kV Cable Replacement

On-going reactive replacement of 11kV cables as identified by condition after fault occurrence.

Cost Under $0.5M on-going; CAPEX – Asset Replacement and Renewal.

5.5.1.10 General Technical Replacement

On-going replacement of switchgear other than RMUs as they reach end of life and risk of failure increases at distribution substations outside of the CBD area to maintain reliability of supply and safety in the vicinity of the substation.

Cost Under $0.5M on-going; CAPEX – Asset Replacement and Renewal.

5.5.1.11 General Distribution Replacement

On-going replacements of distribution assets other than cables. These are identified through routine inspection.

Cost Under $0.5M on-going; CAPEX – Asset Replacement and Renewal.

5.5.1.12 LV Board Replacement

Replacement of hazardous old LV distribution boards with modern touch safe boards – on-going for 10 years.

Cost Under $0.5M on-going; CAPEX – Asset Replacement and Renewal.

5.5.1.13 Link Box Replacement

On-going replacement of link boxes which have deteriorated with age or have been damaged and are unfit for service or unsafe.

Cost Under $0.5M on-going; CAPEX – Asset Replacement and Renewal.

5.5.1.14 Pillar Box Replacement

On-going replacement of pillar boxes which have deteriorated with age or have been damaged and are unfit for service or unsafe.

Cost Under $0.5M on-going; CAPEX – Asset Replacement and Renewal.

5.5.1.15 Reactive LV Cable Replacement

On-going replacement of LV cables as identified by condition after fault occurrence.

Cost Under $0.5M on-going; CAPEX – Asset Replacement and Renewal.

5.5.1.16 Routine Distribution Inspections, Checks & Maintenance

Five yearly network inspections (20% inspected annually), other routine tests and minor maintenance works on distribution assets.

Cost Under $0.5M on-going; OPEX – Routine and Corrective Maintenance and Inspection.

5.5.1.17 Minor Work Distribution Inspections, Checks & Maintenance

Generally reactive work undertaken to correct issues found during the routine distribution inspection. Also a general budget for all minor distribution work.

Cost Under $0.5M on-going; OPEX – Routine and Corrective Maintenance and Inspection.

5.5.1.18 Routine Technical Inspections, Checks & Maintenance

Routine inspection and testing of assets at zone substations. Includes such things as oil DGA, breakdown, moisture and acidity, operation counts, protection testing etc. Also covers responses to maintenance triggers, such as oil processing or recalibration of relays.

Cost Under $0.5M on-going; OPEX – Routine and Corrective Maintenance and Inspection.

5.5.1.19 Minor Work Technical Inspections, Checks & Maintenance

Generally reactive work undertaken to correct issues found during the routine technical inspection. Also a general budget for all minor technical work.

Cost Under $0.5M on-going; OPEX – Routine and Corrective Maintenance and Inspection.

5.5.1.20 Partial Discharge Survey

Routine partial discharge condition monitoring surveying of subtransmission cables, terminations and equipment to identify abnormal discharge levels before failure occurs.

Cost Under $0.5M on-going; OPEX – Routine and Corrective Maintenance and Inspection.

5.5.1.21 Infra-Red Survey

Routine Infra-Red condition monitoring survey of bus-work, connections, contacts etc for abnormal heating as indication of poor electrical contact between current carrying components which may lead to voltage quality issues and/or failure of equipment.

Cost Under $0.5M on-going; OPEX – Routine and Corrective Maintenance and Inspection.

5.5.1.22 General Substation Maintenance

Routine maintenance at distribution substation assets such as cleaning, paint touch-ups and enclosure repairs.

Cost Under $0.5M on-going; OPEX – Routine and Corrective Maintenance and Inspection.

5.5.1.23 General RMU Maintenance

Routine maintenance for Ring Main Units such as cleaning, paint touch-ups and enclosure repairs.

Cost Under $0.5M on-going; OPEX – Routine and Corrective Maintenance and Inspection.

5.5.1.24 General Zone Substation Maintenance

Routine maintenance at zone substations such as grounds, fence and building maintenance, rust repair and paint touch-ups.

Cost Under $0.5M on-going; OPEX – Routine and Corrective Maintenance and Inspection.

5.5.1.25 Supply Quality Checks

Investigations into supply quality which are generally customer initiated.

Cost Under $0.5M on-going; OPEX – Routine and Corrective Maintenance and Inspection.

5.5.1.26 Spare Checks and Minor Maintenance

A budget for checks to confirm what equipment is kept in spares and perform minor maintenance required to ensure spares are ready for service.

Cost Under $0.5M on-going; OPEX – Routine and Corrective Maintenance and Inspection.

5.5.1.27 Seismic Checks

A one off budget to complete checks to determine what remedial strengthening work is required to ensure seismic resilience for network equipment generally at distribution substations.

Cost Under $0.5M 2015/16; OPEX – Routine and Corrective Maintenance and Inspection.

5.5.1.28 Customer Connections

Operational portion of expenditure for the customer connections process is captured in this budget.

Cost Under $0.5M on-going; OPEX – Routine and Corrective Maintenance and Inspection.

5.5.1.29 Vegetation Control

On-going tree trimming in the vicinity of overhead network to prevent contact with lines maintaining network reliability, mainly in the Bluff area.

Cost Under $0.5M on-going; OPEX – Vegetation Management

5.5.1.30 General Distribution Refurbishment

Refurbishment works for plant other than that located at distribution substations which won't impact on the valuation of the distribution asset. Covers items like crossarms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.

Cost Under $0.5M on-going; OPEX – Asset Replacement and Renewal

5.5.1.31 Transformer Refurbishment

Refurbishment of distribution transformers such as rust repairs, paint touch-up, oil renewal, replacement of minor parts such as bushings, seals etc.

Cost Under $0.5M on-going; OPEX – Asset Replacement and Renewal

5.5.1.32 Zone Substation Refurbishment

A budget to allow refurbishment works that won't impact on the valuation of the substation assets. Covers items like earth sticks, safety equipment, buildings, battery systems etc.

Cost Under $0.5M on-going; OPEX – Asset Replacement and Renewal

5.5.1.33 General Technical Refurbishment

Refurbishment works at distribution substations that won't impact on the valuation of the asset. Identified through routine inspection.

Cost Under $0.5M on-going; OPEX – Asset Replacement and Renewal

5.5.1.34 Incident Response

Initial response budget up to three hours for safety, isolation and onsite repairs after fault occurrence and additional time budget thereafter.

Cost Under $0.5M – $2.5M on-going; OPEX – Service Interruptions and Emergencies

5.5.2 Planned Projects[A12.3.4]

The following projects have been planned for the next two to five year period (2014/15 - 2017/18).

5.5.2.1 Earth Testing

Routine testing of earthing assets and connections to ensure safety and functional requirements are met completed five yearly, next due 2017/18.

Cost Under $0.5M 2017/18 and five yearly thereafter; OPEX – Routine and Corrective Maintenance and Inspection.

5.5.3 Future Projects[A12.3.5]

No future projects are expected in the six to ten year planning horizon additional to those ongoing as detailed above in sections 5.5.1 and 5.5.2.

5.5.4 Renewal Budget

CAPEX renewals are budgeted in the capital budget, see section 4.9.3.

5.6 Up-sizing or Extending EIL's Assets

If any of the capacity triggers in Table 24 are exceeded consideration is given to either Up-sizing or extending EIL's network. These two modes of investment are however, quite different as described in Table 40 below.

Table 40: Distinguishing Between Up-sizing and Extension

Characteristic	Up-sizing	Extension
Location	Within or close to existing network footprint (within a span or so).	Outside of existing network footprint (more than a couple of spans).
Load	Can involve supply to a new connection within the network footprint or increasing the capacity to an existing connection.	Almost always involves supply to a new connection.
Upstream reinforcement	Generally forms the focus of Up-sizing.	May not be required unless upstream capacity is constrained.
Visible presence	Generally invisible.	Obviously visible.
Quadrant in Error! Reference source not found.	Either 1 or 2 depending on rate of growth.	Either 3 or 4 depending on rate of growth.
Necessity	Possible to avoid if sufficient surplus capacity exists. Possible to avoid or defer using tactical approaches described in section 4.2.1.	Generally can't be avoided – a physical connection is required.
Impact on revenue	Difficult to attribute revenue from increased connection number or capacity to augmented components.	Generally results in direct contribution to revenue from the new connection at the end of the extension.
Impact on costs	Cost and timing can vary and be staged.	Likely to be significant and over a short time.
Impact on ODV	Could be anywhere from minimal to high.	Could be significant depending on length of extension and any consequent Up-sizing required.
Impact on profit	Could be anywhere from minimal to high.	Could be minimal depending on level of customer contribution.

Characteristic	Up-sizing	Extension
Means of cost recovery	Most likely to be spread across all customers as part of on-going line charges.	Could be recovered from customers connected to that extension by way of capital contribution.
Nature of work carried out	Replacement of components with greater capacity items.	Construction of new assets.

Despite the different nature of Up-sizing and extension work, similar design and build principles are used as described in sections 5.6.1 and 5.6.2.

5.6.1 Designing New Assets

EIL uses a range of technical and engineering standards to achieve an optimal mix of the following outcomes:

- Meet likely demand growth for a reasonable time horizon including such issues as modularity and scalability.
- Minimise over-investment.
- Minimise risk of long-term stranding.
- Minimise corporate risk exposure commensurate with other goals.
- Maximise operational flexibility.
- Maximise the fit with soft organisational capabilities such as engineering and operational expertise and vendor support.
- Comply with sensible environmental and public safety requirements.

Given the fairly simple nature of EIL's network standardised designs are adopted for all asset classes with minor site-specific alterations. These designs, however, will embody the wisdom and experience of current standards, industry guidelines and manufacturer's recommendations.

5.6.2 Building New Assets

EIL uses external contractors to augment or extend assets. As part of the building and commissioning process EIL's information records will be "as-built" and all testing documented.

5.7 Enhancing Reliability

Although enhancing reliability does not neatly fit into the life-cycle model, EIL believes that enhancing reliability is strategically significant enough in reshaping the business platform to merit inclusion in the AMP. As described in Section 3.2.1 customers prefer to receive about the same reliability in return for paying about the same line charges, so it is acknowledged that there is no mandate to go improving reliability just because it can be improved, even if EIL doesn't need to increase line charges to do it. However there are many factors that will lead to a decline in reliability over time:

- Tree re-growth.
- Declining asset condition (especially in coastal marine areas).
- Extensions to the network that increase its exposure to trees and weather.
- Increased customer numbers that increase the lost customer-minutes for a given fault.
- Installation of customer requested asset alterations that can reduce reliability (e.g. needing to lock out reclosers on feeders that have embedded generation).

EIL believes it is necessary to offset these impacts in order to maintain reliability; hence a reliability enhancement program using an approach that embodies the following steps has been developed:

- Identifying the customer-minutes lost for each asset by cause.
- Identifying the scope and likely cost of reducing those lost customer-minutes.
- Estimating the likely reduction in lost customer-minutes if the work scope was to be implemented.
- Calculating the cost per customer-minute of each enhancement opportunity.
- Prioritising the enhancement opportunities from lowest cost to highest. EIL expects the incremental cost of regaining lost customer-minutes will accelerate away at some point which will set an obvious limit to implementing opportunities.

5.8 Converting Overhead to Underground

Conversion of overhead lines to underground cable is also an activity that doesn't fit neatly within the asset life-cycle because it tends to be driven more by the need to beautify areas rather than for asset-related reasons (which doesn't really fit the renewal or up-sizing triggers). As such, conversion tends to rely on other utilities cost sharing or local communities funding the work.

5.9 Retiring of EIL's assets

Retiring assets generally involves doing most or all of the following activities:

- De-energising the asset.
- Physically disconnecting it from other live assets.
- Curtailing the asset's revenue stream.
- Removing it from the ODV.
- Either physical removal of the asset from location or abandoning in-situ (typically for underground cables).
- Disposal of the asset in an acceptable manner particularly if it contains SF6, oil, lead or asbestos.

Key criteria for retiring an asset include:

- Its physical presence is no longer required (usually because a customer has reduced or ceased demand).
- It creates an unacceptable risk exposure, either because its inherent risks have increased over time or because emerging trends of safe exposure levels are declining. Assets retired for safety reasons will not be re-deployed or sold for re-use.
- Where better options exist to create similar outcomes (e.g. replacing lubricated bearings with high-impact nylon bushes) and there are no suitable opportunities for re-deployment.
- Where an asset has been augmented and no suitable opportunities exist for re-deployment.

5.10 EIL's Maintenance Budget[A12.2.3]

Estimated expenditure on maintaining the assets are given in Table 41. EIL aims to maintain the ratio of maintenance to total network replacement cost at about 4.0% or less as detailed in section 3.3.1. This budget covers both Operation and Maintenance areas.

OPEX: Asset Replacement and Renewal	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
General Dist Refurbishment - City	13,320	13,320	13,320	13,320	13,320	13,320	13,320	13,320	13,320	13,320
General Dist Refurbishment - Bluff	9,168	9,168	9,168	9,168	9,168	9,168	9,168	9,168	9,168	9,168
Transformer Refurbishment	9,723	9,723	9,723	9,723	9,723	9,723	9,723	9,723	9,723	9,723
Zone Substation Refurbishment	16,179	16,179	16,179	16,179	16,179	16,179	16,179	16,179	16,179	16,179
General Technical Refurbishment - City	43,144	43,144	43,144	43,144	43,144	43,144	43,144	43,144	43,144	43,144
General Technical Refurbishment - Bluff	10,786	10,786	10,786	10,786	10,786	10,786	10,786	10,786	10,786	10,786
	102,320	**102,320**	**102,320**	**102,320**	**102,320**	**102,320**	**102,320**	**102,320**	**102,320**	**102,320**
OPEX: Vegetation Management	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
Vegetation Management - City	863	863	863	863	863	863	863	863	863	863
Vegetation Management - Bluff	539	539	539	539	539	539	539	539	539	539
	1,402	**1,402**	**1,402**	**1,402**	**1,402**	**1,402**	**1,402**	**1,402**	**1,402**	**1,402**
OPEX: Routine and Corrective Maintenance and Ins	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
Routine Dist Insp Check & Mtce - City	42,416	42,416	42,416	42,416	42,416	42,416	42,416	42,416	42,416	42,416
Minor Work Dist Insp Check & Mtce - City	53,930	53,930	53,930	53,930	53,930	53,930	53,930	53,930	53,930	53,930
Routine Dist Insp Check & Mtce - Bluff	7,119	7,119	7,119	7,119	7,119	7,119	7,119	7,119	7,119	7,119
Minor Work Dist Insp Check & Mtce - Bluff	21,572	21,572	21,572	21,572	21,572	21,572	21,572	21,572	21,572	21,572
Earth Testing - City	-	-	15,908	-	-	-	-	15,908	-	-
Earth Testing - Bluff	-	-	12,727	-	-	-	-	12,727	-	-
Routine Tech Insp Check & Mtce - City	145,828	145,828	145,828	145,828	145,828	145,828	145,828	145,828	145,828	145,828
Minor Work Tech Insp Check & Mtce - City	164,547	164,547	164,547	164,547	164,547	164,547	164,547	164,547	164,547	164,547
Routine Tech Insp Check & Mtce - Bluff	1,219	1,219	1,219	1,219	1,219	1,219	1,219	1,219	1,219	1,219
Minor Work Tech Insp Check & Mtce - Bluff	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222
Partial Discharge Survey	48,537	48,537	48,537	48,537	48,537	48,537	48,537	48,537	48,537	48,537
Infra Red Surveys	5,303	5,303	5,303	5,303	5,303	5,303	5,303	5,303	5,303	5,303
General Substation Maintenance	34,515	34,515	34,515	34,515	34,515	34,515	34,515	34,515	34,515	34,515
General RMU Maintenance	162,329	162,329	162,329	162,329	162,329	162,329	162,329	162,329	162,329	162,329
General Zone Substation Maintenance	32,358	32,358	32,358	32,358	32,358	32,358	32,358	32,358	32,358	32,358
Supply Quality Checks - City	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222
Supply Quality Checks - Bluff	1,111	1,111	1,111	1,111	1,111	1,111	1,111	1,111	1,111	1,111
Spares Checks and Minor Maintenance	1,079	1,079	1,079	1,079	1,079	1,079	1,079	1,079	1,079	1,079
Seismic Checks	48,208	-	-	-	-	-	-	-	-	-
Customer Connections	23,190	23,190	23,190	23,190	23,190	23,190	23,190	23,190	23,190	23,190
	797,702	**749,494**	**778,129**	**749,494**	**749,494**	**749,494**	**749,494**	**778,129**	**749,494**	**749,494**
OPEX: Service Interruptions and Emergencies	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
Incident Response Dist - City	257,208	257,208	257,208	257,208	257,208	257,208	257,208	257,208	257,208	257,208
Incident Additional Time Dist - City	80,895	80,895	80,895	80,895	80,895	80,895	80,895	80,895	80,895	80,895
Incident Response Dist - Bluff	126,447	126,447	126,447	126,447	126,447	126,447	126,447	126,447	126,447	126,447
Incident Additional Time Dist - Bluff	3,236	3,236	3,236	3,236	3,236	3,236	3,236	3,236	3,236	3,236
Incident Response Tech - City	43,262	43,262	43,262	43,262	43,262	43,262	43,262	43,262	43,262	43,262
Incident Additional Time Tech - City	164,421	164,421	164,421	164,421	164,421	164,421	164,421	164,421	164,421	164,421
Incident Response Tech - Bluff	12,188	12,188	12,188	12,188	12,188	12,188	12,188	12,188	12,188	12,188
Incident Additional Time Tech - Bluff	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222
	689,879	**689,879**	**689,879**	**689,879**	**689,879**	**689,879**	**689,879**	**689,879**	**689,879**	**689,879**
Network Operational Expenditure Total	**1,591,303**	**1,543,095**	**1,571,731**	**1,543,095**	**1,543,095**	**1,543,095**	**1,543,095**	**1,571,731**	**1,543,095**	**1,543,095**
System Operations and Network Support	1,080,451	1,148,220	1,223,395	1,275,318	1,275,318	1,275,318	1,275,318	1,275,318	1,275,318	1,275,318
Business Support	3,019,289	3,260,095	3,278,173	3,278,173	3,278,173	3,278,173	3,278,173	3,278,173	3,278,173	3,278,173
Non-Network Operational Expenditure	**4,099,740**	**4,408,315**	**4,501,568**	**4,553,491**	**4,553,491**	**4,553,491**	**4,553,491**	**4,553,491**	**4,553,491**	**4,553,491**
Operational Expediture Total	**5,691,043**	**5,951,410**	**6,073,299**	**6,096,586**	**6,096,586**	**6,096,586**	**6,096,586**	**6,125,222**	**6,096,586**	**6,096,586**

Table 41: EIL Maintenance Budget

6. Capability to Deliver[A16.1, 16.2]

EIL succeeds in delivering when the network development and maintenance plans are achieved on time and to budget while achieving service level targets from the present time to the long term.

Processes and Systems

To do this EIL has a number of processes and systems, as set out in section 9, which help to ensure the efficient delivery of the objectives of the AMP.

Funding the Business

Section 8 describes how EIL's business is funded so that the network development and maintenance plans can be paid for.

Staff and Contracting Resources

The greatest issue presently facing EIL is staff and contracting resources. Each item or project making up the works plan is carefully considered as to the man hours required using the experience gained over many years of network management. The works plan as a whole is then considered to ensure that it is realistic with the resources expected to be available and any adjustments can be made. Low priority work may be delayed short term where a commitment to increase staff or contractor numbers has been made such that the necessary works plan will not fall behind.

An important part of this process involves working closely with EIL's contractors, carefully communicating the detailed works plan and getting commitment that sufficient resources will be available for the year ahead. The future works plan is also communicated so that contractors can confidently commit to hiring extra staff where appropriate, recognising that EIL's development and maintenance requirements are on-going over the long term.

7. Risk Management[A14.1]

The business is exposed to a wide range of risks. This section examines EIL's risk exposures, describes what it has done and will do about these exposures and what it will do when disaster strikes.

Risk management is used to bring risk within acceptable levels.

7.1 Risk Methods[A14.2 (with AMP section 7.3)]

The risk management process as it applies to the electricity network business is intended to assess exposure and prioritise mitigating actions. The risk on the network is analysed at a high level, reviewing major work components and systems to see if possible events could lead to undesirable situations.

Risk is reviewed when there is a change in perception of the risks that EIL faces especially following events which may affect local networks or other catastrophic events which might have global impact or otherwise when there is a change in regulations which may require risk to be considered in greater detail.

Depending on the magnitude of risk identified a large scale programme may be initiated to quickly reduce risk. Generally identified risks will have mitigating solutions which become a part of design standards used on the network.

Each risk identified is graded in terms of its likelihood and potential consequences, and responses are developed to minimise the risk as low as reasonably possible. The criteria used to grade the risks are shown below.

LIKELIHOOD	Probability of Occurrence
High	Greater than once per year
Medium	Once every 1-10 years
Low	Once every 10-100 years
Very Low	Less than once per 100 years

CONSEQUENCE	Very Low	Low	Medium	High
CAPEX ($M)	< 0.5	0.5 to 5	5 to 20	> 20
Reliability	KPI Breach	Marginal repeat breaches	Repeat breaches	Repeat breaches over long term
Workplace H&S	Less than minor injury	Minor injury (med treatment reqd.)	Serious injury (LTI)	Fatality / multiple serious injury
Public Safety	Reversible health effects	Reversible health effects of concern	Irreversible health effects of concern	Life threatening or disabling event
Environmental	Single on-site event, negligible harm	Immediately recoverable on-site harm	Recoverable localised off-site harm	Severe localised or widespread off-site harm
Community	Negligible impact on social benefits or developments	Minor impact on social benefits or developments	Moderate impact on social benefits or developments	Extensive impact on social benefits or developments

7.1.1 Guiding Principles

EIL's behaviour and decision making is guided by the following principles:

- Safety of the public and staff is paramount.
- Essential services are the second priority.
- Large impact work takes priority over smaller impact work.
- Switching to restore supplies prior to repair work.
- Plans will generally only handle one major event at a time.
- Risks will be removed, mitigated, or otherwise lessened as appropriate to reduce risk as low as reasonably possible.

7.1.2 Risk Categories

Risks are classified against the following categories:

Safety & Environmental

- Accidental public contact with live equipment – whether through using tall equipment near overhead lines or through excavating near cables
- Step & touch – faults/lightning strikes causing a voltage gradient, across surfaces accessible to the public, that is capable of causing electric shock
- Arc flash – potential for significant injury to staff from a fault on or near equipment they are using/working on
- Underground – safety risks amplified by the close proximities and contained space around underground assets
- Oil spills from transformers or oil circuit breakers
- Staff error causing worksite safety risk
- Historical assets not meeting modern safety requirements
- Site security – unauthorised persons approaching live components through unlocked gate etc.

Weather

- Wind – strong winds that either cause pole failures or blow debris into lines.
- Snow – impact can be by causing failure of lines or limiting access around the network.
- Flood – experience of 1984 floods has caused Environment Southland to install flood protection works, but still need to consider if similar water levels do occur again.

Physical

- Earthquake – no recent history of major damage. The November 2004 7.2 Richter scale quake 240 km south-west of Te Anau caused no damage to the network. Although recent earthquakes in Christchurch have proven that large and unexpected events may occur and have significant impact on the network.
- Tsunami – maybe triggered by large off shore earthquake.
- Liquefaction – post Christchurch's 22 February 2011 6.3 magnitude earthquake, the hazard of liquefaction has become a risk to be considered.
- Fire – transformers are insulated with mineral oil that is flammable and buildings have flammable materials so fire will affect the supply of electricity. Source of fire could be internal or from external sources.
- Asset Failures – equipment failures can interrupt supply or negate systems from operating correctly. i.e. failure of a padlock could allow public access to restricted areas.

External

- Animals either physically bridging overhead conductors – e.g. birds, possums – or causing conductor clashing – e.g. cattle against stays.
- Third party accidental damage to network – e.g. car versus pole, over-height loads breaking conductors. The presence of a pole may also increase the damage done to a car and its occupants if the driver veers off the road.

Human

- Pandemic – impact depends on the virility of the disease. Could impact on staff work as they try to avoid infection or become unable to work.
- Terrorism/Vandalism – range varies from malicious damage to copper theft to 'tagging' of buildings or equipment. Cyber-attack could also occur; considered low risk at present but vulnerability increases as the network becomes "smarter"

Corporate

- Investment – providing business processes that ensure appropriate contracts and guarantees are agreed prior to undertaking large investments.
- Loss of revenue – loss of customers through by-pass or economic downturn could reduce revenue.
- Management contract – failure of PowerNet as EIL's asset manager.
- Regulatory – failure to meet regulatory requirements.
- Resource – field staff to undertake operation, maintenance, renewal, Up-sizing, expansion and retirement of network assets.

7.2 Risk Tactics[A14.4]

The following tactics are used to manage risk under the following broad categories:

- Operate a 24hr control centre.
- Provide redundancy of supply to large customer groups.
- Remove assets from risk zone.
- Involvement with the local Civil Defence.
- Regular inspections to detect vulnerabilities and potential failures.
- Align asset design with current best practice.

7.3 Risk Details[A14.2 (with AMP section 7.1)]

7.3.1 Safety & Environmental

Table 42: Risk Associated with Safety and Environmental Events and Responses

Event	Likelihood	Consequence	Responses
Public Accidental Contact	Medium	High	Public awareness program – TV, print, signage at high-risk areas Offer cable location service Emergency services training Relocate/underground near high-risk areas e.g. waterways where feasible Include building proximity to lines in local body consent process Audit new installations for correct mitigation, e.g. marker tape/installation depth/Magslab for cable Regular inspections of equipment to detect degraded protection of live parts
Step & Touch	Low	High	Adopt & follow EEA Guide to Power System Earthing Practice in compliance with Electricity (Safety) Regulations 2010
Arc Flash	Very Low	High	Install arc flash protection on new installations Mandate adequate PPE for switching operations De-energise installation before switching where PPE inadequate
Underground	Very Low	High	De-energise substation before manual switching within substation
Oil spill (zone sub)	Low	Medium	Oil spill kits located at some substations for the faults contractor to use in event of oil leak or spill. Most zone substations have oil bunding and regular checks that the separator system is functioning correctly. Bunding is installed in the remaining substations as the opportunity arises. Regular checks of tank condition
Oil spill (dist. transformer)	Medium	Low	Distribution transformers located away from waterways, etc. Installations designed to protect against ground water accumulation
Staff Error	Medium	High	Standardised procedures Training Worksite audits Certification reqd for sub entry, live-line work, etc. Monitor incidents and investigate root causes
Historical Assets	Medium	Medium to High	Replace old components with new components meeting current standards: scheduled replacement or replacement on failure, depending on risk
Site Security	Very Low	High	Monthly checks of restricted sites Alarms on underground sub hatches Standardised exit procedures in 3rd party bldg Above ground sub clearances to AS2067 s5 Design to avoid climbing aids etc.

7.3.2 Weather

Table 43: Risk Associated with Weather Events and Responses

Event	Likelihood	Consequence	Responses
Wind	Medium	Low	Impact is reduced by undergrounding of lines. Network design standard specifies level for design. If damage occurs on lines this is remedied by repairing the failed equipment.
Snow	Low	Low	Impact is reduced by undergrounding of lines. If damage occurs on lines this is remedied by repairing the failed equipment. If access is limited then external plant is hired to clear access or substitute.
Flood	Low	Low	Impact is reduced by undergrounding of lines. Transformers and switchgear in high risk areas to be mounted above the flood level. Zone substations to be sited in areas of very low flood risk.

7.3.3 Physical[A14.2]

Table 44: Risk Associated with Physical Events and Responses

Event	Likelihood	Consequence	Responses
Earthquake (>8)	Extremely Low	Major	Disaster recovery event. Projects underway to investigate and improve survivability through large seismic events.
Earthquake (6 to 7)	Very Low	Low to High	Specify so buildings and equipment will survive. Review existing buildings and equipment and reinforce if necessary.
Tsunami	Very Low	Low to Medium	Review equipment in coastal areas and protect or reinforce as necessary.
Liquefaction	Very Low	Low to Medium	Specify buildings and equipment foundations to minimise impact.
Fire	Very Low	High	Supply customers from neighbouring substations. Maintain fire alarms in buildings.

A seismic remedial work project is progressing with zone substation strengthening almost complete and distribution substation remediation work continuing over the next three years.

7.3.4 Equipment Failures

As the impact of this is variable, a central control room is provided, which is manned 24 hours a day by PowerNet staff. Engineering staff are on standby at any time to provide backup assistance for network issues. Faults contractors provide onsite action and minor failure repairs with contractors 'on-call' for medium to large failures or storms.

Table 45: Risk Associated with Equipment Failures and Responses

Event	Likelihood	Consequence	Responses
33kV & 66kV Lines and Cables	Medium	Low	Regular inspections and maintain contacts with experienced faults contractors. Provide alternative supply by ringed subtransmission or through the distribution network. All new works to Southern Power Contractors Line Design Standard.
Power Transformer	Low	Low to medium	At dual power transformer sites, one unit can be removed from service due to fault or maintenance without interrupting supply. Continue to undertake annual DGA to allow early detection of failures. Relocate spare power transformer to site while damaged unit is repaired or replaced.
11kV Switchboard	Low	Medium	Annual testing including PD[12] and IR[13]. Replacement at end of life and continue to provide sectionalised boards. Able to reconfigure network to bypass each switchboard with use of mobile regulators.
11kV & 400V Lines and Cables	Medium	Low	Regular inspections and maintain contacts with experienced faults contractors. Provide alternative supply by meshed distribution network.
Batteries	Low	Medium	Continue monthly check and six monthly testing. Dual battery banks at critical sites.
Circuit breaker Protection	Low	Medium	Continue regular operational checks. Engineer redundancy/backup into protection schemes. Regular protection reviews. Mal-operations investigated.
Circuit Breakers	Low	Low	Backup provided by upstream circuit breaker. Continue regular maintenance and testing.
SCADA RTU	Low	Low	Monitor response of each RTU at the master station and alarm if no response after five minutes. If failure then send faults contractor to restore, if critical events then roster a contractor onsite.
SCADA Master-station	Very low	Low	Continue to operate as a Dual Redundant configuration, with two operator stations. This requires both Servers to fail before service is lost. Continue to have a support agreement with the software supplier and technical faults contractor to maintain the equipment.

[12] PD = Partial Discharge, indication of discharges occurring within insulation.

[13] IR = Infrared, detection of heat of equipment that highlights hot spots.

Event	Likelihood	Consequence	Responses
Load Control	Low	Medium	Provide backup to and from EIL Invercargill 2 Ripple Injection Plant for Invercargill, Winton backs up North Makarewa and Gore and Edendale backup each other. Manually operate plant with test set if SCADA controller fails.

7.3.5 External

Table 46: Human Event Risks and Responses

Event	Likelihood	Consequence	Responses
Animal	High	Low	Possum guards all poles Cattle guards, bird spikes as required
Third party accidental	Medium	High (Safety) Low (Network)	Design (assets, protection settings) to minimise electrical safety consequences of failure Underground particularly vulnerable areas Approval process for railway crossings, etc. Regular inspections for sag etc. Resource to bypass and repair.

7.3.6 Human

Table 47: Human Event Risks and Responses

Event	Likelihood	Consequence	Responses
Pandemic	Low	Low to High	Work to the PowerNet pandemic plan. Includes details such as working from home, only critical faults work and provide emergency kits for offices etc.
Vandalism	Medium	Low to High	Six monthly checks of all ground-mounted equipment. Faults contractor to report all vandalism and repair depending on safety then economics. i.e. Tagging/graffiti would depend on the location and content. Any safety problems will be made safe as soon as they are discovered.
Terrorism	Very Low	High	Ensure security of restricted sites. Use alternative routes and equipment to restore supply, similar to equipment failures below.
Cyber Attack	Very Low	High	Secure communications links Analyse and remove vulnerabilities Review and apply industry best practice

7.3.7 Corporate

Table 48: Corporate Risks and Responses

Event	Likelihood	Consequence	Responses
Investment	Low	Low	New larger contracts require Shareholder Guarantee before supply is provided.
Loss of Revenue	Very Low	High	Continue to have Use of System Agreements with retailers. New large investments for individual customers to have a guarantee.
Regulatory	Extremely low	High	Continue to contract PowerNet to meet regulatory requirements. Ensure PowerNet has and operates to a Business Continuity Plan.
Resource	Low	High	Continue to enhance Alliance contractor relationship with present contractors. Provide a long term commitment and support, for the contractor to be sufficiently resourced to achieve the contract service levels on the network.

7.4 Contingency Plans

EIL has the following contingency plans through its management company PowerNet:

7.4.1 PowerNet Business Continuity Plan

PowerNet must be able to continue in the event of any serious business interruption. Events causing interruption can range from malicious acts through damaging events, to a major natural disaster such as an earthquake.

The principal objectives of the Business Continuity Plan are to:

- Eliminate or reduce damage to facilities, and loss of assets and records.
- Planning alternate facilities.
- Minimise financial loss.
- Provide for a timely resumption of operations in the event of a disaster.
- Reduce or limit exposure to potential liability claims filed against the Company, its Directors and Staff.

7.4.2 PowerNet Pandemic Action Plan

PowerNet must be able to continue in the event of a breakout of any highly infectious illness which could cause staff to be unable to function in their job.

The plan aims to manage the impact of an influenza pandemic on PowerNet's staff, the business and services through two main strategies:

1. Containment of the disease by reducing spread within PowerNet. This is achieved by such measures as; reducing risk of infected persons entering PowerNet's premises, social distancing, cleaning of the work environment, managing fear, management of cases at work and travel advice.
2. Maintenance of essential services if containment is not possible. This is achieved through identification of the essential activities and functions of the business, the staff required to carry out these tasks and special measures required to continue these tasks under a pandemic scenario.

7.4.3 Network Operating Plans

As contingency for major outages on the EIL network PowerNet holds network operating plans for safe and efficient restoration of services where possible. For example, an operating order detailing operational steps required to restore supply after loss of a zone substation.

7.5 Insurance

EIL holds the following insurances:

- Material damage and business interruption over Substations and Buildings.
- Contracts works
- Directors and officers liability
- Utilities Industry Liability Programme (UILP) that covers Public, Forest & Rural Fires and Products liability.
- Statutory liability
- Marine Cargo.

Contractors working on the network hold their own Liability Insurance.

8. Funding the Business

Everything discussed in EIL's AMP so far has been (indirectly) about costs. This section discusses how EIL's business is funded.

8.1 Business Model

EIL's business model is based around the right-hand side of Figure 49.

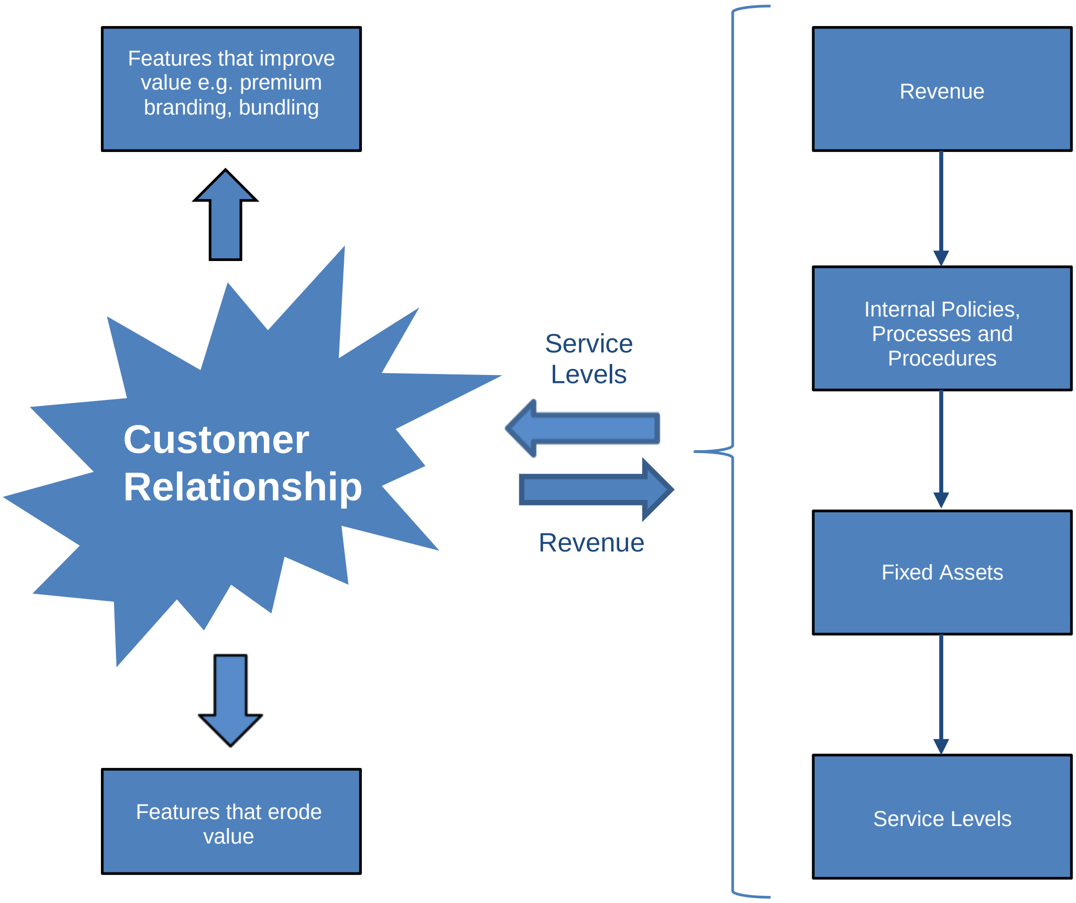


Figure 49: Customer Interface Model

This model clearly shows that the company receives cash from EIL's customers (via the retailers who operate on EIL's network) and then, through a wide range of internal processes, policies and plans, the company converts that cash into fixed assets. These fixed assets in turn create the service levels such as capacity, reliability, security and supply quality that customers want.

8.2 Revenue

EIL's money comes primarily from the retailers who pay EIL for conveying energy over EIL's network or by customer contributions for the uneconomic part of works. In regard to funding new assets (i.e. beyond the immediate financial year) EIL has considered the following approaches:

- Funding from revenue within the year concerned.
- Funding from after-tax earnings retained from previous years.
- Raising new equity (very unlikely given the current shareholding arrangement).
- Raising debt (which has a cost, and is also subject to interest cover ratios).

- Allowing Transpower to build and own assets which allows EIL to avoid new capital on its ODV and its balance sheet, but perhaps more importantly also allows EIL to treat any increased Transpower charges as a pass-through cost.

8.3 Expenditure

Work is done to maintain the asset value of the network and to expand or augment to meet customer demands.

8.4 Changes in the Value of Assets

Given the preferences expressed by EIL's customers for the following price-quality trade-offs in the telephone 'Customer Engagement Survey' undertaken by Gary Nicol Associates September 2014:

- 80% are not willing to pay $10 per month more in order to reduce interruptions.
- 12% are willing to pay $10 per month more in order to reduce interruptions
- 8% don't know or are unsure of price-quality trade-offs.

In response, EIL's asset value should either remain about the same or be allowed to decline in a controlled manner (and knowing how to do this is obviously a complex issue). However this presents EIL with the dilemma of responding to customers wishes for lower cost supply in the face of a "no material decline in SAIDI" requirement and in fact revenue incentives to improve reliability. Factors that will influence EIL's asset value are shown in Table 49 below:

Table 49: Factors influencing EIL's asset value

Factors that increase EIL's asset value	Factors that decrease EIL's asset value
Addition of new assets to the network. Need to confirm exactly when asset value can be added to valuation base under ODV rules.	Removal of assets from the network. Need to confirm when asset value can be removed from valuation base under ODV rules.
Renewal of existing assets. Note definition of renewal as being restoration of original functionality – no increase in service potential beyond original functionality.	On-going depreciation of assets.
Increase of standard component values implicit in the ODV methodology.	Reduction of standard component values implicit in the ODV methodology.

At a practical level EIL's asset valuation will vary even in the absence of component revaluations. This is principally because the accounting treatment of depreciation models the decline in service potential as a straight line (when in most cases it is more closely reflected by an inverted bath-tub curve) whilst the restoration of service potential is very "lumpy". However the aggregation of many depreciating assets and many restoration projects tends to smooth short-term variations in asset value.

8.5 Depreciating the Assets

As outlined in section 8.4 above, the accounting treatment of depreciation doesn't strictly model the decline in service potential of an asset - sure it probably does quite accurately model the underlying physical processes of rust, rot, acidification, erosion etc. – but an asset often tends to remain serviceable until it has rusted, rotted, acidified, or eroded substantially and then fails quickly. Straight-line depreciation does, however, provide a smooth and reasonably painless means of gathering funds to renew worn out assets. This will be particularly important as the "bow wave" of asset renewals approaches.

9. Processes and Systems

The core of EIL's asset management activities lie with the detailed processes and systems that reflect EIL's thinking, manifest in EIL's policies, strategies and processes and ultimately shape the nature and configuration of EIL's fixed assets. The hierarchy of data model shown in Figure 50 describes the typical sorts of information residing within EIL's business (including in PowerNet employees brains).

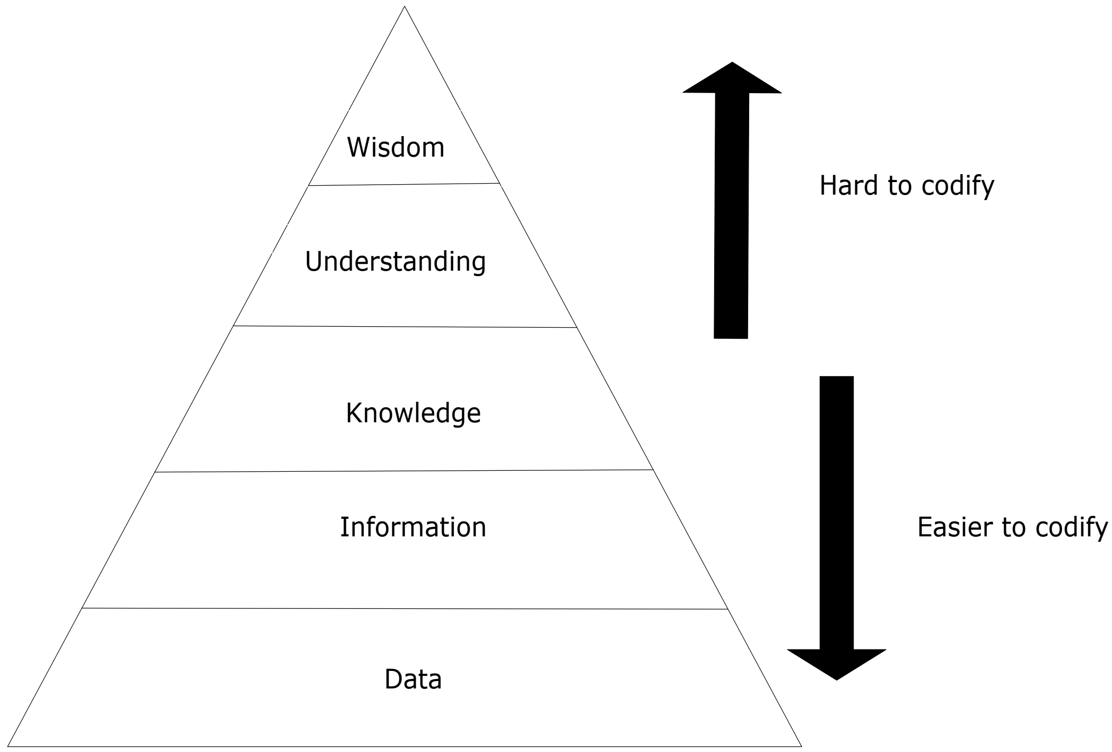


Figure 50: Hierarchy of Data

The bottom two layers of the hierarchy tend to relate strongly to EIL's asset and operational data which reside in the GIS and SCADA respectively and the summaries of this data that form one part of EIL's decision making.

The third layer – knowledge – tends to be more broad and general in nature and may include such things as technical standards that codify accumulated knowledge into a single useful document.

The top two layers tend to be very broad and often quite fuzzy. It is at this level that key organisational strategies and processes reside. As indicated in Figure 50 it is generally hard to codify these things, hence correct application is heavily dependent on skilled people.

9.1 Asset Knowledge

EIL knows a great deal about almost all of the assets; their location, what they are made of, generally how old they are and how well they can perform.

EIL's asset data resides in two key locations:

- Asset description, location, age and condition information of line, cables and field devices resides in the Geographical Information System (GIS).

- Asset descriptions, details, age and condition information of serial numbered components resides in the Asset Management System (AMS).
- Asset operational data such as loadings, voltages, temperatures and switch positions reside in the Supervisory Control and Data Acquisition (SCADA) system.

An additional class of data (essentially commercial in nature) includes such data as customer details, consumption and billing history.

Table 50: Knowledge Accuracy

System	Parameter	Completeness	Notes
GIS	Description	Excellent	Some delays between job completion and updating into the GIS
GIS	Location	Excellent	
GIS	Age	Poor	Pole ages not available for 63%
GIS	Condition	Poor	No recent information
AMS	Description	Okay	Some delays between job completion and updating into WASP
AMS	Details	Okay	
AMS	Age	Okay	Missing age on old components
AMS	Condition	Poor	Some condition monitoring data (DGA)
SCADA	Zone Substations	Excellent	All monitored
SCADA	Field Devices	Okay	A few sites monitored

9.2 Improving the Quality of the Data

9.2.1 GIS Data Improvement

EIL's original data capture emphasised asset location and configuration and was used to populate the GIS, but didn't include a high level of asset condition. As part of this original data capture the company developed a field manual of drawings and photos to minimise subjectivity. Records and drawings have been used to apply an age but 63% of poles had no supporting information. Due to old poles not having a manufacture date affixed, it is very difficult to obtain the actual age to update GIS. Options have been considered to get ages measured, for the un-dated poles, but no economic methodology has been found.

About 20% of the network (by length) each year is condition assessed to update asset condition data (noting that asset condition is continually varying), and any discovered details are updated.

Key process improvements will include more timely as-builts with PowerNet staff GPS-ing[14] poles and use of scan-able forms for data input (Teleform system).

9.2.2 AMS Data Improvement

Data for the AMS is collected by the Network Equipment Movement (NEM) form that records every movement of serial numbered assets. Some updating of data is obtained when sites are checked with a barcode label put on equipment to confirm data capture, and highlight missed assets.

[14] GPS = Global Positioning System, a device that uses satellites and accurate clocks, to measure the location of a point.

The AMS system has recently been replaced as highlighted in section 9.6.2 and as part of this process data was reviewed for completeness and accuracy so data improvements can be achieved. Future improvements are planned to allow additional assets details to be captured and enable better decision making around asset management.

9.3 Use of the Data

All data will be used for either making decisions within EIL's own business or assisting external entities to make decisions. This data is almost always aggregated into information (the second level of the pyramid) in order to make decisions e.g. a decision to replace a zone substation transformer may be based on an aggregation of loading data.

9.4 Decision Making

The decision making process also involves the top two levels of the hierarchy, understanding and wisdom, which tend to be broad and enduring in nature. Although true understanding and wisdom are difficult to codify, it is possible to capture discrete pieces of understanding and wisdom and then codify them into such documents as technical standards, policies, processes, operating instructions, spreadsheet models etc. This is called knowledge and probably represents the upper limit of what can be reasonably codified.

Accurate decision making therefore requires the convergence of both information and (a lot of) knowledge to yield a correct answer. Deficiencies in either area (incorrect data, or a failure to correctly understand issues) will lead to wrong outcomes. The source, roles and interaction of each component of the hierarchy are shown in Figure 51.

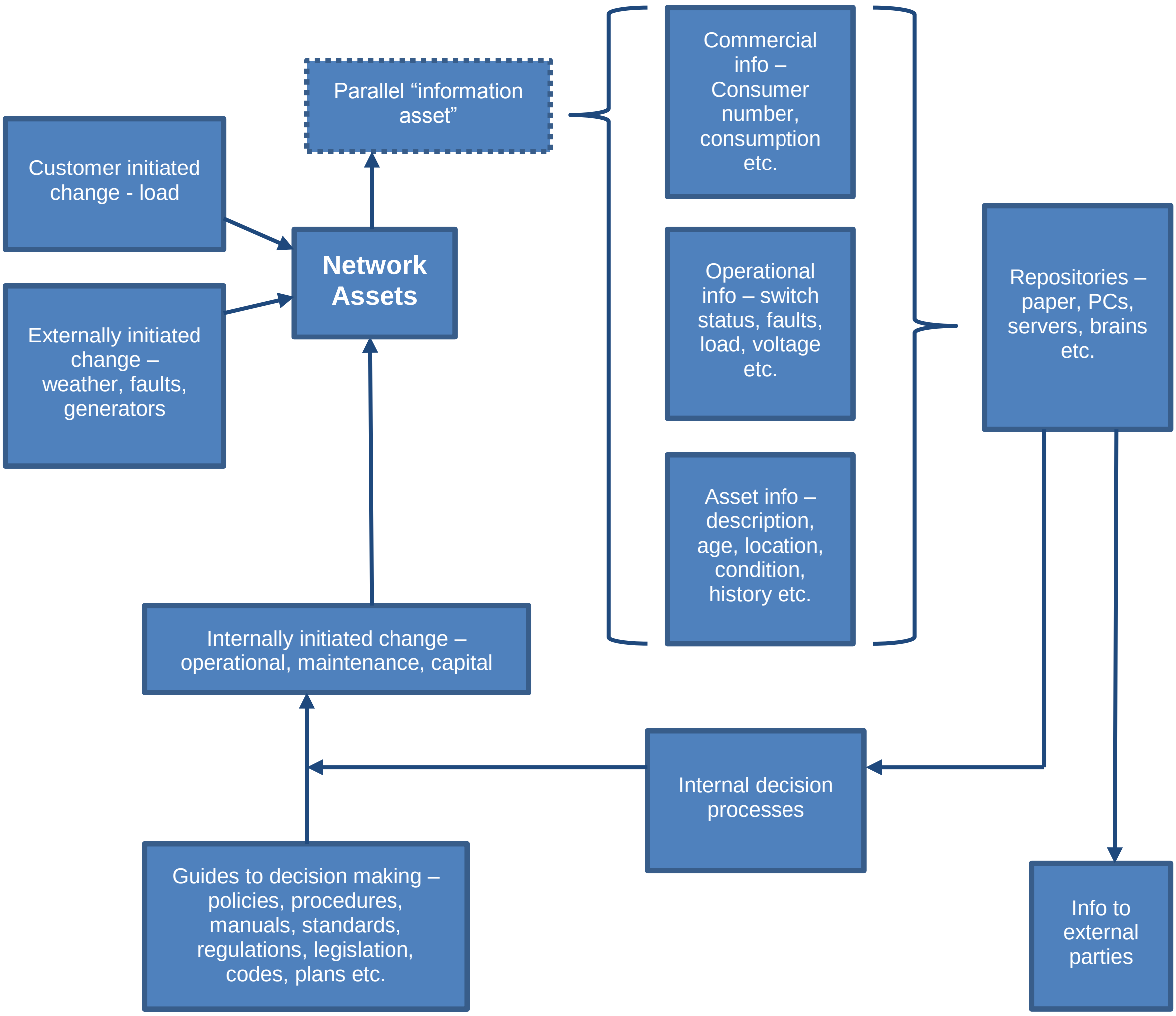


Figure 51: Key information systems and processes

9.5 Key Processes and Systems

EIL's key processes and systems are based around the key lifecycle activities defined in Figure 51, which are based around the AS/NZS9001 Quality Management System and are described in the following sections. These processes are not intended to be bureaucratic or burdensome, but are rather intended to guide EIL's decisions toward ways that have proved successful in the past (apart from safety related procedures which do contain mandatory instructions). Accordingly these processes are open to modification or amendment if a better way becomes obvious.

9.5.1 Operating Processes and Systems

Commissioning Network Equipment	PNM-61
Network Equipment Movements	PNM-63
Planned Outages	PNM-65
Network Faults, Defects and Supply Complaints	PNM-67
Major Network Disruptions	PNM-69
Use of Operating Orders (O/O)	PNM-71
Control of Tags	PNM-73
Access to substations and Switchyards	PNM-75
Operational Requirements for Confined Space Entry	PNM-76
Operating Authorisations	PNM-77

Radio Telephone Communications	PNM-79
Operational Requirements for Live Line Work	PNM-81
Control of SCADA Computers	PNM-83
Machinery Near Electrical Works	PNM-85
Customer Fault Calls/Retail Matters	PNM-87
Site Safety Management Audits	PNM-88
Meter/Ripple Receiver Control	PNM-121

9.5.2 Maintenance Processes and Systems

Transformer Maintenance	PNM-99
Maintenance Planning	PNM-105
Control of Network Spares	PNM-97

Other maintenance is to manufacturers' recommendations or updated industry practise.

9.5.3 Renewal Processes and Systems

Network Development	PNM-113
Design and Development	PNM-114

9.5.4 Up-sizing or Extension Processes and Systems

Processing Installation Connection Applications	PNM-123
Network Development	PNM-113
Design and Development	PNM-114
Easements	PNM-131

9.5.5 Retirement Processes and Systems

Disconnected And/Or Discontinued Supplies	PNM-125

9.5.6 Performance Measuring Processes and Systems

9.5.6.1 Faults

All faults are entered into the 'Faults' database and reported monthly to the board, together with details of all the planned outages.

9.5.6.2 Financial

Monthly reports out of the Finance One (F1) financial system provide measurement of revenues and expenses for the EIL line business unit. Project costs are managed in PowerNet with project managers managing costs through the AMS system. Interfaces between F1 and AMS track estimates and costs against assets.

9.5.6.3 Customer

Customer statistics are monitored by a Customer Database system developed by ACE computers. This interfaces with the National Registry to provide and obtain updates on customer connections and movements. Customer consumption is monitored by another ACE Computers system 'BILL'. BILL receives monthly details from retailers and links this to the customer database.

9.5.6.4 Service Levels

Customers that have had work done are sent a survey form at the end of the job. Results are monitored and any comments given are reviewed and responded to.

9.5.7 Other Business Processes

In addition to the above processes that are specific to life cycle activities, EIL has a range of general business processes that guide activities such as evaluating tenders and closing out contracts:

Setting Up the Contract	PNM-10
Tender Evaluation	PNM-15
Contract Formation	PNM-20
Construction Approval	PNM-25
Materials Management	PNM-30
Contract Control	PNM-35
Contract Close Out	PNM-40
Customer Satisfaction	PNM-50
Internal Quality Audits	PNM-55
External Contracting	PNM-60
Drawing Control	PNM-89
Network Operational Diagram/GIS Control	PNM-91
Control of Operating and Maintenance Manuals	PNM-93
Control of External Standards	PNM-95
Control of Power Quality Recorders	PNM-103
Quality Plans	PNM-107
Health and Safety	PNM-109
Accidents and Incidents	PNM-111
Design and Development	PNM-114
Network Purchasing	PNM-115
Network Pricing	PNM-117
Customer Service Performance	PNM-119
Incoming and Outgoing Mail Correspondence	PNM-129

9.6 Asset Management Tools

A variety of tools and procedures are utilised by PowerNet to best manage the assets of the various networks. GIS and MAXIMO software packages are used to store and evaluate assets data. Quality system procedures are in place to highlight and focus on various management techniques. The outputs of these systems produce 1 year and 10 year AMP's, together with data for on-going day to day planning and control.

9.6.1 GIS

An Intergraph based Geographic Information System is utilised to store and map data on individual components of distributed networks. This focuses primarily on cables, conductors, poles, transformers, switches, fuses and similar items. Large composite items such as substations are managed by more traditional techniques such as drawings and individual test reports.

Equipment capacity, age and condition are listed by segment. The data is used to provide base maps of existing equipment, for extensions to the network, for maintenance scheduling and similar functions.

9.6.2 AMS

EIL's Asset Management System MAXIMO provides work scheduling and asset management tools. It is intricately linked to the financial management system. This package tracks major assets and is the focus for work packaging and scheduling.

Most day to day operations are managed using MAXIMO. Maintenance regimes, field inspections and customers produce tasks and/or estimates that are sometimes grouped and a 'work pack' issued from MAXIMO.

The MAXIMO software package is a replacement for the predecessor AMS system WASP and is more up to date and better suited to EIL's needs. It provides greater functionality and helps streamline administration of EIL's maintenance practices. As part of the transfer of data to the new system data was checked for accuracy and completeness and updated where possible to provide better information about EIL's assets to facilitate better maintenance management decisions.

9.6.3 Faults Database

All outages are logged into a database which is used to provide regulatory information and statistics on networks performance. Reports from this system are used to highlight poorly performing feeders, these are then analysed to determine if it is a maintenance issue or if reliability may be enhanced by other methods. A typical display of annual faults is shown in Figure 52, and indicates no areas of concern.

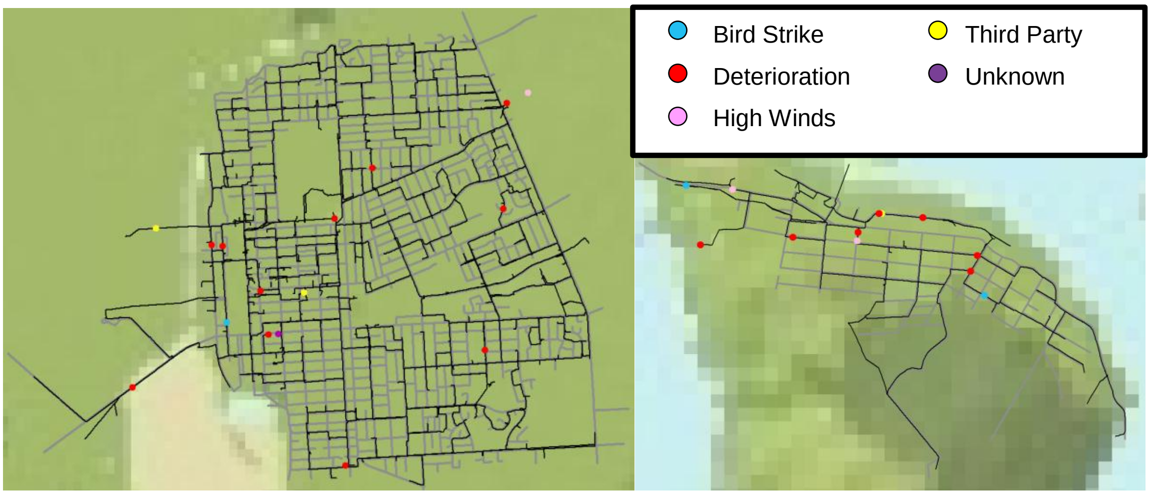


Figure 52: EIL Faults April 2010 to March 2011

9.6.4 PNM-105 Maintenance Planning

The quality system procedure PNM-105 drives maintenance planning. It is the procedure used to drive this document to completion. The flowchart from this quality system document is shown in Figure 53.

Relevant inputs into the plan include:

- MAXIMO Records
- Surveys (field, CDM)
- Analysis of faults database
- GIS database
- System network loading data
- Major customers
- Growth (domestic, commercial, industrial) in geographic areas

- Legislation
- Cyclic maintenance on major plant items
- Current AMP.

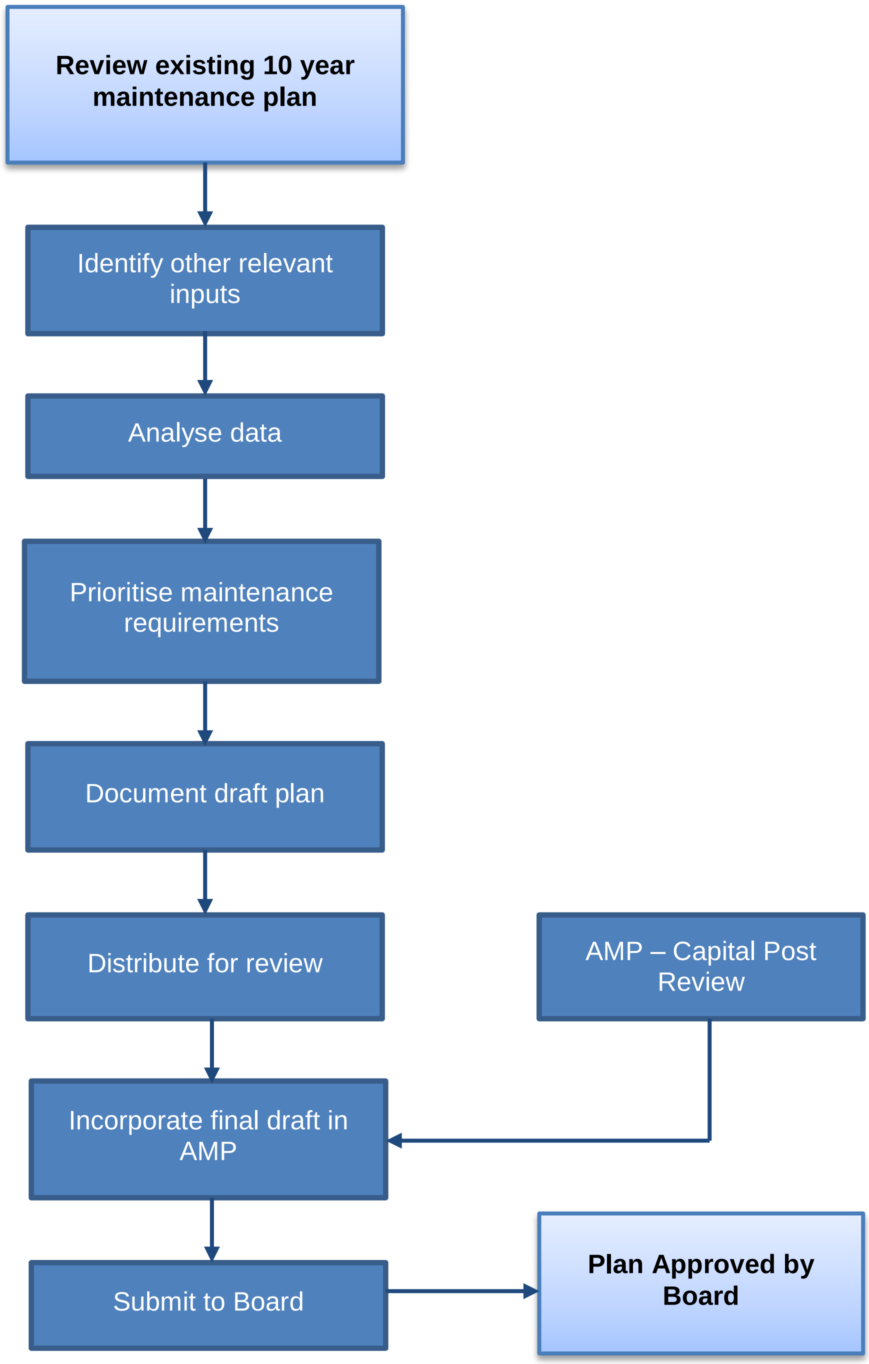


Figure 53: PNM-105 Maintenance Planning Flowchart

10. Performance and Improvement

10.1 Outcomes Against Plans[A15.1]

10.1.1 Maintenance

Table 51: Variance between Operational Expenditure Forecast and Actual Expenditure

Operational Expenditure	Forecast 2013/14 ($k)	Actual 2013/14 ($k)	% Variance
Asset Replacement and Renewal	158	73	-53.8%
Vegetation Management	1	-	-100.0%
Routine and Corrective Maintenance and Inspection	856	1,121	31.0%
Service Interruptions and Emergencies	578	689	19.2%
Operational Expenditure on Network Assets	**1,592**	**1,883**	**18.3%**

Maintenance was over budget due to;

- Asset Replacement and Renewal – 54% below budget. Work here has been delayed due to overspending in other areas.
- Vegetation Management – Overall OPEX managed in line with budget.
- Routine and Corrective Maintenance and Inspection – 31% above budget die to additional inspections on the network, increased safety awareness and extra seismic analysis undertaken.
- Service Interruptions and Emergencies – 19% above budget due to contractor charging error found.

10.1.2 Capital

Table 52: Variance between Capital Expenditure Forecast and Actual Expenditure

Capital Expenditure	Forecast 2013/14 ($k)	Actual 2013/14 ($k)	Variance
Consumer Connection	190	232	22.1%
System Growth	4,452	2,713	-39.1%
Asset Replacement and Renewal	1,608	1,411	-12.3%
Asset Relocations	157	36	-77.1%
Quality of Supply	13	-	-100%
Legislative and Regulatory	-	-	-
Other Reliability, Safety and Environment	265	122	-54.0%
Capital Expenditure on Network Assets	**6,684**	**4,514**	**-32.5%**

Capital works was under budget due to;

- Customer Connections – 22% more customer connections than was forecast. Actuals depend on regional growth and development.

- System Growth – 39% under spent due to a substation and 33kV cable installation delayed due to building consent delays.
- Asset Replacement and Renewal – 12% underspent to manage overall CAPEX in line with budget.
- Asset Relocations – 77% underspent due to territorial local authority driven charges on a realignment project leading to fewer costs than forecast.
- Reliability, Safety and Environment – Project delayed due to late delivery of major components.

10.2 Performance Against Targets[A15.2]

10.2.1 Primary Service Levels

Table 53 displays the target versus actual reliability performance on the network. For the 2013/14 year the overall network performance was very good, with SAIFI 48% under target and SAIDI 37% under target.

Table 53: Performance against Primary Service Targets

	2013/14 AMP Target	2013/14 Actual
SAIFI	1.00	0.52
SAIDI	40.0	25.1

Targets are based on averages over the previous few years and due to the reliability of the network have been set very low. This, however, means single events have the potential to have a significant impact on reliability performance as was the case in the 2011/12 year when a human error incident resulted in a single fault affecting multiple feeders and being difficult to locate.

10.2.2 Secondary Service Levels

Results for 2013/14 are shown in Table 54:

Table 54: Performance against Secondary Service Targets

Attribute	Measure	Target 2013/14	Actual 2013/14
Customer Satisfaction: New Connections	Phone: Friendliness and courtesy. {CSS: Q3(c)}[15]	>3.5[16]	5*
	Phone: Time taken to answer call. {CSS: Q3(a)}	>3.5	5*
	Overall level of service. {CSS: Q5}	>3.5	5*
	Work done to a standard which met your expectations. {CSS: Q4(b)}	>3.5	5*

15 CSS = Customer Satisfaction Survey undertaken by sending questionnaire to customers with invoices.

16 Where 1 = poor and 5 = excellent

Attribute	Measure	Target 2013/14	Actual 2013/14
Customer Satisfaction: Faults	Power restored in a reasonable amount of time. {CES: Q4(b)}	>90%	80%
	Information supplied was satisfactory. {CES: Q8(b)}	>80%	100%
	PowerNet first choice to contact for faults. {CES: Q6}	>20%	34%
Voltage Complaints	Number of customers who have made voltage complaints	<10	1
	Number of customers who have justified voltage complaints regarding power quality	<4	1
	Average days to complete investigation	<30	4
	Period taken to remedy justified complaints	<60	4
Planned Outages	Provide sufficient information {CES: Q3(a)}	>75%	100%
	Satisfaction regarding amount of notice {CES: Q3(c)}	>75%	81%
	Acceptance of maximum of one planned outages every two years. {CES: Q1}	>50%	98%
	Acceptance of planned outages lasing two hours on average {CES: Q2}	>50%	95%

**only two customer satisfaction survey responses were received (from several forms sent out) within the 2013/14 period. Improvements to this process will be looked at to prompt a response when few are received.*

The percentage of customers who were satisfied that their supply was restored within a reasonable amount of time following an unexpected outage was 80% which was below the target of 90%. However 10% indicated that they didn't know or were unsure which may indicate that they were reasonably satisfied as most people might recall a negative experience. Only 10% indicated that the restoration time was unacceptable.

It was interesting to note that 25% of customers recalled time taken to restore their supply exceeded three hours while fault data indicated that only one fault affecting a relatively small number of customers exceeded three hours over the time period. It is possible customers were recalling the duration of a planned interruption.

Performance against all other secondary service levels matched or performed better than the targets set for 2013/14.

10.2.3 Other Service Levels

10.2.3.1 Efficiency

Table 55: Performance against Efficiency Targets

Measure	2013/14 Target	2013/14 Actual	Comment
Load factor	> 50%	48.9%	No load control required
Loss ratio	< 5.0%	5.3%	Variable - dependant on Retailer accruals
Capacity utilisation	> 45%	42.1%	Influenced by load factor

The growth seen at the GXP level has been distorted with Transpower's introduction of the TPM[17] where individual EDB peaks have been replaced by a regional grouping. This has allowed EIL to relax load control during the year but has had a negative impact on load factor.

Losses tend to vary from year to year more than would be expected due to changes in operation and network assets. This variation can mostly be attributed to the retailer accrual process. Therefore a longer term average is more likely to be indicative of actual loss ratio.

While it is desirable to have a capacity utilisation factor as high as possible, standardisation of transformer sizing, allowance for growth and the unpredictable consumption patterns of some customers means there is a practical and economic limit to how much this factor can be improved. EIL's capacity utilisation compares very well with other distribution businesses.

10.2.3.2 Financial

Table 56: Performance against Financial Targets

Measure	2013/14 Target	2013/14 Actual
OPEX/RC	3.81%	3.76%
Indirect Cost per Customer	$119.33	$99.76

OPEX to RC ratio and Indirect Costs per Customer were both below targets.

10.3 Improvement Areas and Strategies[A15.4]

10.3.1 Maintenance and Capital Works

Improvement of short and long term project and maintenance planning processes should lead to better scheduling of resources and improved budget estimations.

Amalgamation of EIL's network management company PowerNet and contracting company Power Services has improved relationships and communication between planning and field staff. More efficient work practices are being realised and expected to

[17] Transmission Pricing Methodology: Allocation of Transpower costs are based on the share of the average of the top 100 peaks for all loads in the Lower South Island (LSI) region. See http://www.electricitycommission.govt.nz/rulesandregs/rules Part F, Section IV for more details.

continue. The amalgamated company PowerNet has also employed additional technical field staff to extend the in-house field services concept to further realise efficiencies. This should help increase productivity and with some additional resource EIL should be better placed to deliver the planned projects.

Long term relationships with external contractors are being maintained so they can more confidently build their resources and personnel. This will allow more work to be completed and ensure a resource for future years.

10.3.2 Reliability

On the whole reliability of the EIL network is very good and the SAIDI and SAIFI results for 2013/14 were well within targets set.

The quality limits that have applied to EIL's network have been problematic in that the exception reliability of the network means single events can have a very large impact on SADI and SAIFI reliability measures in any year. From April 2015 the new normalisation boundaries calculated under the default price-quality path look to more fairly account for EIL's situation and better enable EIL to avoid breach of the regulatory reliability limits.

Nevertheless EIL will look to control the impact of events that might incur large customer-minute totals primarily by increasing the number of remotely controlled devices on the network to speed isolation of faulty sections and restoration of supply to healthy sections.

EIL's network management company PowerNet will work to retain experienced field services staff and maintain long term relationships with external contractors so quality personnel with sufficient network familiarity are available for efficient restoration of supply.

Regular network inspections will be continued and critical items will be acted on as they are identified. Also data capture and condition assessment will be increased above reactive maintenance practices to increase knowledge of the assets and their condition to enable better planning based on more accurate and comprehensive asset data.

10.3.3 Efficiency

Load factor is low compared to other distribution businesses and could be better however load factor has always been difficult to improve on the network and Transpower's current pricing methodology has caused a decrease in this measure. The introduction of smart meters in future years may provide some leverage to influence customer's consumption behaviour.

10.3.4 Data

EIL holds some good data about assets but could be better and an effort to continually improve data is being made as records are updated when assets are renewed or upgraded. Field survey projects have been undertaken from on occasion where gap analysis reveals insufficiencies in data.

The updated Asset Management System software has assisted with better capture and use of asset data.

A. Appendix – PowerNet Customer Survey

PowerNet Customer Engagement Telephone Survey: EIL

Phone	Date	Interviewer

Good afternoon/evening my name is _____. I am conducting a brief customer survey on behalf of PowerNet.

May I please speak to a person in your home who is responsible for paying the electricity account?

(Reintroduce if necessary) May I trouble you for a few minutes of your time?

A1: Do you know who PowerNet is?	Yes	**1**	*Go to A2*
	No	**2**	*Go to A3*

A2: Where did you most recently hear about PowerNet?	Billboard	**1**
	Other	**2**
	Don't know/Unsure	**3**

A3: Using a 1 to 5 rating scale where 1 is Poor and 5 is Excellent can you rate the performance of PowerNet over the last 12 months for:	Caring for customers	**1**	**2**	**3**	**4**	**5**	**X**
	Sensitive to the environment	**1**	**2**	**3**	**4**	**5**	**X**
	Supporting the community	**1**	**2**	**3**	**4**	**5**	**X**
	Safety conscious	**1**	**2**	**3**	**4**	**5**	**X**
Go to D1	Efficient	**1**	**2**	**3**	**4**	**5**	**X**

A4: PowerNet maintains the local electricity lines and substations that supply power to your premises.

D1: Are you a commercial or residential customer?	Commercial	**1**
	Residential	**2**

Question 1: PowerNet is proposing a maximum of one planned interruption to your power supply, on average, every two years in order to carry out maintenance or upgrade work on its electricity network. Do you consider this number of planned interruptions to be reasonable?	Yes	**1**	*Go to Q 2*
	No	**2**	*Go to Q 1(a)*
	Don't know/unsure	**3**	*Go to Q 2*

Question 1(a): How many years between planned interruptions do you consider to be more reasonable?	3 years	**1**
	4 years	**2**
	5 years	**3**

Question 2: PowerNet expects such planned interruptions will on average last up to two hours each. Do you consider this amount of time to be reasonable?	Yes	**1**	*Go to Q 3*
	No	**2**	*Go to Q 2(a)*
	Don't know/unsure	**3**	*Go to Q 3*

Question 2(a): What length of time would you consider to be more reasonable? *(Specify hours)*	30 min	**1**
	1 hours	**2**
	$1^1/_2$ hours	**3**

Question 3: Have you received advice of a planned electricity interruption during the last 6 months?	Yes	**1**	*Go to Q 3(a)*
	No	**2**	*Go to Q 3(e)*
	Don't know/unsure	**3**	*Go to Q 3(e)*

Question 3(a): Were you satisfied with the amount of information given to you about this planned interruption?	Yes	**1**	*Go to Q 3(c)*
	No	**2**	*Go to Q 3(b)*
	Unable to recall	**3**	*Go to Q 3(c)*
Question 3 (b): What additional information would you have liked?			

Question 3(c): Do you feel that you were given enough notice of this planned interruption?	Yes	**1**	*Go to Q 3(e)*
	No	**2**	*Go to Q 3(d)*
	Don't know/unsure	**3**	*Go to Q 3(e)*

Question 3(d): How much notice of planned interruptions would you prefer to be given? *(Specify days/weeks)* *(Do not prompt)*	1 day	**1**	1 week	**4**
	3 days	**2**	2 weeks	**5**
	5 days	**3**	Other	**6**

Question 3(e): Do you have a preferred day and time(s) for a planned interruptions?	Yes	**1**	*Go to Q 3(f)*
	No	**2**	*Go to Q 4*

Question 3 (f): What is your preferred day and time(s)?

Question 4: Have you had an unexpected interruption to your power supply during	Yes	**1**	*Go to Q 4(a)*
	No	**2**	*Go to Q 5*

the last 6 months?	Unable to recall **3** *Go to Q 5*

Question 4(a): Thinking about the most recent unexpected interruption to your electricity supply, how long did it take for your supply to be restored? *(Specify hours/days)* *(Do not prompt)*	Within 45 min	**1**	3 hours	**5**
	1 hour	**2**	4 hours	**6**
	$1^{1}/_{2}$ hours	**3**	12 hours	**7**
	2 hours	**4**	Don't know	**8**
			Other	**9**

Question 4(b): Do you consider your electricity supply was restored within a reasonable amount of time?	Yes	**1**	*Go to Q 5*
	No	**2**	*Go to Q 4(c)*
	Unable to recall	**3**	*Go to Q 5*

Question 4(c): What do you consider would have been a more reasonable amount of time? *(Specify hours/days)* *(Do not prompt)* ***Go to Q5(a)***	30 minutes	**1**	$1^{1}/_{2}$ hours	**4**
	45 minutes	**2**	2 hours	**5**
	1 hour	**3**	Other	**6**

Question 5: In the event of an unexpected interruption to your electricity supply, what do you consider would be a reasonable amount of time before electricity supply is restored to your home? *(Specify hours/days)* *(Do not prompt)*	5 minutes	**1**	2 hours	**10**
	10 minutes	**2**	3 hours	**11**
	15 minutes	**3**	4 hours	**12**
	20 minutes	**4**	5 hours	**13**
	30 minutes	**5**	6 hours	**14**
	40 minutes	**6**	12 hours	**15**
	45 minutes	**7**	1 day	**16**
	1 hour	**8**	Unsure	**17**
	$1^{1}/_{2}$ hours	**9**	Other	**18**

Question 5(a): PowerNet is reviewing the level of service provided to its customers and options include increasing spending. Presently there is an average of one interruptions every two years. If this was reduced to one interruption every three years would you be happy to pay an additional $10 per month on your electricity bill?	Yes	**1**
	No	**2**
	Don't know/unsure	**3**

Question 5(b): If PowerNet was to reduce your power bill by $10 per month, would you be happy that the number of interruptions increased to one every year?	Yes	**1**
	No	**2**
	Don't know/unsure	**3**

Question 6: Who would you contact in the event of the power supply to your home	Meridian Energy	**1**
	Contact Energy	**2**

being unexpectedly interrupted? *(Do not prompt)*	Mighty River Power	**3**	
	TrustPower	**4**	
	PowerNet	**5**	
	Genesis Energy	**6**	
	Other	**7**	

Question 7: Have you made such a call within the last 6 months?	Yes	**1**	*Go to Q 8*
	No	**2**	*Go to Q 8(d)*
	Unable to recall	**3**	*Go to Q 8(d)*

Question 8: Were you satisfied that the system worked in getting you enough information about the supply interruption?	Yes	**1**	*Go to Q 8(b)*
	No	**2**	*Go to Q 8(a)*
	Don't know/unsure	**3**	*Go to Q 8(b)*

Question 8 (a): What, if anything, do you feel could be done to improve this system?			
Question 8 (b): Were you satisfied with the information that you received?	Yes	**1**	*Go to Q 8(d)*
	No	**2**	*Go to Q 8(c)*
	Don't know/unsure	**3**	*Go to Q 8(d)*
Question 8 (c): What, if anything, do you feel could be done to improve this information or the way in which it is delivered?			

Question 8 (d): What is the most important information you wish to receive when you experience an unplanned supply interruption? *(Do not prompt)*	Accurate time when power will be restored	**1**
	Reason for fault	**2**
	Other	**3**

Question 8(e): Are you aware of PowerNet's 0800 faults number?	Yes **1**	No **2**

Question 9: Finally, do you have any comments or suggestions about anything to do with PowerNet which we haven't already covered in our interview today?	
Happy with things as they are/no comments/nothing to add, etc.	**1**
Comment(s):	

This concludes our survey - Thank you for your time

B. Appendix – Expanded Data Tables

Table 57: Existing Substations Growth Projection

Substation	2014/ 15	2015/ 16	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	2024/ 25
Doon Street	22.3	22.7	23.2	23.7	24.1	24.6	25.1	25.6	26.1	26.6	27.2
Leven Street	22.0	22.4	22.9	23.3	23.8	24.3	24.8	25.3	25.8	26.3	26.8
Racecourse Road	14.4	14.6	14.7	14.9	15.0	15.2	15.3	15.5	15.6	15.8	15.9
Southern	16.7	16.9	17.0	17.2	17.4	17.5	17.7	17.9	18.1	18.3	18.4
Bluff	5.1	5.1	5.2	5.2	5.3	5.3	5.4	5.4	5.5	5.5	5.6

Table 58: Substation Demands with Proposed Developments 2020 - 2025

Zone Substation	Δ '20/21	MD 2020/21	Δ '21/22	MD 2021/22	Δ '22/23	MD 2022/23	Δ '23/24	MD 2023/24	Δ '24/25	MD 2024/25
Doon Street										
Spey Street		32.9		33.6		34.2		34.9		35.6
Leven Street		20.4		20.8		21.2		21.7		22.1
Racecourse Road		11.0		11.1		11.2		11.3		11.4
Southern		-		-		-		-		-
Southern (Dual Tx)		17.5		17.7		17.9		18.1		18.3
Bluff		5.3		5.4		5.4		5.5		5.5

Table 59: Substation Demands with Proposed Developments 2015 - 2020

Zone Substation	Δ '14/15	MD 2014/15	Δ '15/16	MD 2015/16	Δ '16/17	MD 2016/17	Δ '17/18	MD 2017/18	Δ '18/19	MD 2018/19	Δ '19/20	MD 2019/20
Doon Street	-3.5	18.4	-18.7	-		-		-		-		-
Spey Street	+3.5	3.5	26.2	29.8		30.4		31.0		31.6		32.3
Leven Street		21.6	-3.5	18.5		18.9		19.2		19.6		20.0
Racecourse Road		14.3	-4.0	10.4		10.5		10.6		10.7		10.9
Southern		16.5		16.7	-16.9	-		-		-		-
Southern (Dual Tx)		-		-	+16.9	16.9		17.0		17.2		17.4
Bluff		5.0		5.1		5.1		5.2		5.2		5.3

C. Appendix – Assumptions[A3.8]

The asset management plan is developed under a number of assumptions as follows;

Growth rates will be similar to historic trends. Developers rarely let EIL know of their plans keeping large projects confidential until the last minute. Any major development could require significant new network to be built however planning for possibilities would inevitably lead to overinvestment.

- No major developments in coal, gas, oil, mineral etc extraction or processing either in the region or off shore which may utilise ports and industry in Bluff and/or staff and accommodation in Invercargill.
- No step changes in underlying growth are considered likely which is supported by historical trending over a long period.

Population growth for sizing of equipment is based on the high projection.

- Sizing of equipment step changes are minor with labour cost being a large proportion of works.

Distributed generation will develop slowly with little impact over the ten year planning horizon.

- The current rate of connection is quite manageable with the first adopters typically reducing load on network assets. A large increase in connections could lead to upgrade requirements to maintain supply quality which could come about through government incentives or unexpected technology breakthroughs.

No change in present regulation. Any changes are likely to add additional cost.

- For example outages less than one minute aren't recorded against reliability KPIs; this allows a lower cost network automation solution which would be less appropriate if the one minute allowance were removed.

The standard life of assets is based on the ODV asset life, with actual replacement done on a condition basis.

- Equipment housed indoor will often exceed ODV life whereas the harsh coastal Bluff environment tends to shorten life.

Abnormal price movements are difficult to predict and not allowed for in estimates.

- Industry specific inflationary rates where available are used to account for increasing costs and otherwise by CPI.

D. Appendix – Schedule 11a

Company Name: Electricity Invercargill Limited
AMP Planning Period: 1 April 2015 – 31 March 2025

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	49	219	224	229	235	239	242	246	250	254	258
11	System growth	7,505	2,517	-	881	2,265	-	949	963	978	993	1,009
12	Asset replacement and renewal	1,843	2,397	2,860	2,372	1,633	1,807	3,706	2,234	2,283	1,802	1,830
13	Asset relocations	6	5	6	6	6	6	6	6	6	6	6
14	Reliability, safety and environment:											
15	Quality of supply	73	73	128	131	134	79	80	82	83	84	85
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	80	254	-	14	-	-	-	-	15	-	-
18	**Total reliability, safety and environment**	153	327	128	145	134	79	80	82	98	84	85
19	**Expenditure on network assets**	9,556	5,465	3,217	3,633	4,273	2,130	4,984	3,531	3,615	3,140	3,188
20	Non-network assets	-	53	-	-	-	-	-	-	-	-	-
21	**Expenditure on assets**	9,556	5,518	3,217	3,633	4,273	2,130	4,984	3,531	3,615	3,140	3,188
22												
23	*plus* Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less* Value of capital contributions	31	33	34	34	35	36	36	37	38	39	39
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27	**Capital expenditure forecast**	9,525	5,485	3,184	3,599	4,238	2,095	4,947	3,494	3,577	3,101	3,149
28												
29	Value of commissioned assets	12,309	5,464	3,217	2,752	5,459	2,130	4,984	3,531	3,615	3,140	3,188

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
30	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
32		**$000 (in constant prices)**										
33	Consumer connection	49	219	219	219	219	219	219	219	219	219	219
34	System growth	7,505	2,517	2,162	-	-	-	859	859	859	859	859
35	Asset replacement and renewal	1,843	2,397	1,964	1,964	2,370	2,484	3,354	1,991	2,004	1,558	1,558
36	Asset relocations	6	5	5	5	5	5	5	5	5	5	5
37	Reliability, safety and environment:											
38	Quality of supply	73	73	125	125	125	73	73	73	73	73	73
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	80	254	-	13	-	-	254	-	13	-	-
41	**Total reliability, safety and environment**	153	327	125	138	125	73	327	73	86	73	73
42	**Expenditure on network assets**	9,556	5,465	4,476	2,327	2,719	2,782	4,764	3,147	3,173	2,714	2,714
43	Non-network assets	-	53	-	-	-	-	-	-	-	-	-
44	**Expenditure on assets**	9,556	5,518	4,476	2,327	2,719	2,782	4,764	3,147	3,173	2,714	2,714
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses		-	-	-	-	-	-	-	-	-	-
48	Overhead to underground conversion	-	-	-	-	-	-	-	-	-	-	-
49	Research and development	-	-	-	-	-	-	-	-	-	-	-

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
58		for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
59	**Difference between nominal and constant price forecasts**		$000										
60	Consumer connection		-	-	5	10	16	19	23	27	31	34	38
61	System growth		-	-	(2,162)	881	2,265	-	90	105	120	135	150
62	Asset replacement and renewal		-	-	896	408	(737)	(677)	352	243	279	244	272
63	Asset relocations		-	-	0	0	0	0	1	1	1	1	1
64	Reliability, safety and environment:												
65	Quality of supply		-	-	3	6	9	6	8	9	10	11	13
66	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
67	Other reliability, safety and environment		-	-	-	1	-	-	(254)	-	2	-	-
68	**Total reliability, safety and environment**		-	-	3	6	9	6	(246)	9	12	11	13
69	**Expenditure on network assets**		-	-	(1,259)	1,306	1,553	(651)	220	384	442	426	474
70	Non-network assets		-	-	-	-	-	-	-	-	-	-	-
71	**Expenditure on assets**		-	-	(1,259)	1,306	1,553	(651)	220	384	442	426	474
72													

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
73		for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
74	**11a(ii): Consumer Connection**							
75	*Consumer types defined by EDB**		$000 (in constant prices)					
76	Customer Connections (≤ 20kVA)		27	60	60	60	60	60
77	Customer Connections (21 to 99kVA)		5	48	48	48	48	48
78	Customer Connections (≥ 100kVA)		5	95	95	95	95	95
79	Distributed Generation Connection		-	2	2	2	2	2
80	New Subdivisions		12	14	14	14	14	14
81	**include additional rows if needed*							
82	**Consumer connection expenditure**		49	219	219	219	219	219
83	*less* Capital contributions funding consumer connection		31	33	34	34	35	36
84	**Consumer connection less capital contributions**		18	186	186	185	184	184
85	**11a(iii): System Growth**							
86	Subtransmission		2,741	862	-	-	-	-
87	Zone substations		4,582	750	2,162	-	-	-
88	Distribution and LV lines		-	-	-	-	-	-
89	Distribution and LV cables		183	905	-	-	-	-
90	Distribution substations and transformers		-	-	-	-	-	-
91	Distribution switchgear		-	-	-	-	-	-
92	Other network assets		-	-	-	-	-	-
93	**System growth expenditure**		7,505	2,517	2,162	-	-	-
94	*less* Capital contributions funding system growth							
95	**System growth less capital contributions**		7,505	2,517	2,162	-	-	-

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
104		for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
105		**11a(iv): Asset Replacement and Renewal**	$000 (in constant prices)					
106		Subtransmission	-	-	-	-	-	-
107		Zone substations	157	98	164	164	4	118
108		Distribution and LV lines	96	95	94	94	94	94
109		Distribution and LV cables	284	210	208	208	208	208
110		Distribution substations and transformers	681	797	935	935	646	646
111		Distribution switchgear	406	566	417	417	417	417
112		Other network assets	218	631	147	147	1,001	1,001
113		**Asset replacement and renewal expenditure**	1,843	2,397	1,964	1,964	2,370	2,484
114	*less*	Capital contributions funding asset replacement and renewal						
115		**Asset replacement and renewal less capital contributions**	1,843	2,397	1,964	1,964	2,370	2,484
116		**11a(v):Asset Relocations**						
117		*Project or programme**						
118		Asset Relocation Projects	6	5	5	5	5	5
119		[Description of material project or programme]						
120		[Description of material project or programme]						
121		[Description of material project or programme]						
122		[Description of material project or programme]						
123		**include additional rows if needed*						
124		All other asset relocations projects or programmes						
125		**Asset relocations expenditure**	6	5	5	5	5	5
126	*less*	Capital contributions funding asset relocations						
127		**Asset relocations less capital contributions**	6	5	5	5	5	5
128								
129		**11a(vi):Quality of Supply**						
130		*Project or programme**						
131		Supply Quality Upgrades - City	19	12	60	60	60	12
132		Supply Quality Upgrades - Bluff	1	1	6	6	6	1
133		Network Automation Projects	53	60	60	60	60	60
134		[Description of material project or programme]						
135		[Description of material project or programme]						
136		**include additional rows if needed*						
137		All other quality of supply projects or programmes						
138		**Quality of supply expenditure**	73	73	125	125	125	73
139	*less*	Capital contributions funding quality of supply						
140		**Quality of supply less capital contributions**	73	73	125	125	125	73
141								
142		**11a(vii): Legislative and Regulatory**						
143		*Project or programme**						
144		[Description of material project or programme]						
145		[Description of material project or programme]						
146		[Description of material project or programme]						
147		[Description of material project or programme]						
148		[Description of material project or programme]						
149		**include additional rows if needed*						
150		All other legislative and regulatory projects or programmes						
151		**Legislative and regulatory expenditure**	-	-	-	-	-	-
152	*less*	Capital contributions funding legislative and regulatory						
153		**Legislative and regulatory less capital contributions**	-	-	-	-	-	-

Row			for year ended	Current Year CY 31 Mar 15	CY+1 31 Mar 16	CY+2 31 Mar 17	CY+3 31 Mar 18	CY+4 31 Mar 19	CY+5 31 Mar 20
161									
162									
163	**11a(viii): Other Reliability, Safety and Environment**								
164		*Project or programme**		**$000 (in constant prices)**					
165		Earth Upgrades - City		-	-	-	12	-	-
166		Earth Upgrades - Bluff		-	-	-	1	-	-
167		Substation Safety		58	60	-	-	-	-
168		Oil Cable Temperature Monitoring		-	12	-	-	-	-
169		NER Installations		21	183	-	-	-	-
170		**include additional rows if needed*							
171		All other reliability, safety and environment projects or programmes							
172		**Other reliability, safety and environment expenditure**		80	254	-	13	-	-
173	*less*	Capital contributions funding other reliability, safety and environment							
174		**Other reliability, safety and environment less capital contributions**		80	254	-	13	-	-
175									
176									
177									
178	**11a(ix): Non-Network Assets**								
179	**Routine expenditure**								
180		*Project or programme**							
181		[Description of material project or programme]							
182		[Description of material project or programme]							
183		[Description of material project or programme]							
184		[Description of material project or programme]							
185		[Description of material project or programme]							
186		**include additional rows if needed*							
187		All other routine expenditure projects or programmes							
188		**Routine expenditure**		-	-	-	-	-	-
189	**Atypical expenditure**								
190		*Project or programme**							
191		Oil Processing Plant Refurbishment		-	53	-	-	-	-
192		[Description of material project or programme]							
193		[Description of material project or programme]							
194		[Description of material project or programme]							
195		[Description of material project or programme]							
196		**include additional rows if needed*							
197		All other atypical projects or programmes							
198		**Atypical expenditure**		-	53	-	-	-	-
199									
200		**Non-network assets expenditure**		-	53	-	-	-	-

E. Appendix – Schedule 11b

Company Name	Electricity Invercargill Limited
AMP Planning Period	1 April 2015 – 31 March 2025

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	450	690	708	725	741	755	770	784	799	814	830
11	Vegetation management	4	1	1	1	2	2	2	2	2	2	2
12	Routine and corrective maintenance and inspection	659	798	770	817	805	821	836	852	901	885	902
13	Asset replacement and renewal	88	102	105	107	110	112	114	116	119	121	123
14	**Network Opex**	1,201	1,591	1,584	1,651	1,658	1,690	1,722	1,754	1,821	1,822	1,856
15	System operations and network support	1,327	1,080	1,179	1,285	1,370	1,396	1,423	1,450	1,477	1,505	1,534
16	Business support	2,912	3,019	3,348	3,444	3,522	3,589	3,657	3,727	3,798	3,870	3,943
17	**Non-network opex**	4,239	4,100	4,527	4,729	4,893	4,986	5,080	5,177	5,275	5,375	5,477
18	**Operational expenditure**	5,440	5,691	6,111	6,380	6,551	6,675	6,802	6,931	7,096	7,197	7,333

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
20	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	450	690	690	690	690	690	690	690	690	690	690
23	Vegetation management	4	1	1	1	1	1	1	1	1	1	1
24	Routine and corrective maintenance and inspection	659	798	749	778	749	749	749	749	778	749	749
25	Asset replacement and renewal	88	102	102	102	102	102	102	102	102	102	102
26	**Network Opex**	1,201	1,591	1,543	1,572	1,543	1,543	1,543	1,543	1,572	1,543	1,543
27	System operations and network support	1,327	1,080	1,148	1,223	1,275	1,275	1,275	1,275	1,275	1,275	1,275
28	Business support	2,912	3,019	3,260	3,278	3,278	3,278	3,278	3,278	3,278	3,278	3,278
29	**Non-network opex**	4,239	4,100	4,408	4,502	4,553	4,553	4,553	4,553	4,553	4,553	4,553
30	**Operational expenditure**	5,440	5,691	5,951	6,073	6,097	6,097	6,097	6,097	6,125	6,097	6,097
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses	125	125	125	125	125	125	125	125	125	125	125
34	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
35	Research and Development	-	-	-	-	-	-	-	-	-	-	-
36	Insurance	91	88	90	92	94	96	98	100	102	104	106
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
40	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	19	35	51	65	80	94	109	124	140
43	Vegetation management	-	-	0	0	0	0	0	0	0	0	0
44	Routine and corrective maintenance and inspection	-	-	20	39	56	71	87	103	123	135	152
45	Asset replacement and renewal	-	-	3	5	8	10	12	14	16	18	21
46	**Network Opex**	-	-	41	79	115	146	179	211	249	278	313
47	System operations and network support	-	-	31	62	95	121	148	175	202	230	259
48	Business support	-	-	87	165	244	311	379	449	519	591	665
49	**Non-network opex**	-	-	118	227	339	432	527	623	721	822	924
50	**Operational expenditure**	-	-	160	306	454	579	705	834	970	1,100	1,237

F. Appendix – Schedule 12a

Company Name	Electricity Invercargill Limited
AMP Planning Period	1 April 2015 – 31 March 2025

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
7					Asset condition at start of planning period (percentage of units by grade)						
8											
9											
10	All	Overhead Line	Concrete poles / steel structure	No.	-	5.00%	75.00%	20.00%	-	1	5.00%
11	All	Overhead Line	Wood poles	No.	10.00%	70.00%	20.00%	-	-	1	10.00%
12	All	Overhead Line	Other pole types	No.	-	-	100.00%	-	-	1	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	100.00%	-	-	1	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	100.00%	-	-	1	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	100.00%	-	-	1	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	25.00%	75.00%	-	-	1	25.00%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	100.00%	-	-	1	50.00%
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	25.00%	75.00%	-	-	1	25.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	20.00%	80.00%	-	-	1	20.00%
30	HV	Zone substation switchgear	33kV RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	50.00%	50.00%	-	-	1	50.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A

sch ref	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
42					Asset condition at start of planning period (percentage of units by grade)						
43											
44											
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	83.00%	17.00%	-	1	-
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2.00%	23.00%	70.00%	5.00%	-	1	5.00%
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	HV	Distribution Line	SWER conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	2.00%	90.00%	8.00%	-	1	10.00%
50	HV	Distribution Cable	Distribution UG PILC	km	2.00%	5.00%	93.00%	-	-	1	15.00%
51	HV	Distribution Cable	Distribution Submarine Cable	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	100.00%	-	-	1	-
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	5.00%	25.00%	70.00%	-	-	1	25.00%
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	5.00%	15.00%	70.00%	10.00%	-	1	10.00%
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	4.00%	6.00%	80.00%	10.00%	-	1	10.00%
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	3.00%	7.00%	75.00%	15.00%	-	1	10.00%
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.00%	9.00%	75.00%	15.00%	-	1	5.00%
59	HV	Distribution Transformer	Voltage regulators	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	10.00%	90.00%	-	-	1	20.00%
61	LV	LV Line	LV OH Conductor	km	5.00%	10.00%	80.00%	5.00%	-	1	5.00%
62	LV	LV Cable	LV UG Cable	km	2.00%	3.00%	90.00%	5.00%	-	1	5.00%
63	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	1.00%	4.00%	85.00%	10.00%	-	1	5.00%
64	LV	Connections	OH/UG consumer service connections	No.	1.00%	4.00%	85.00%	10.00%	-	1	5.00%
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	50.00%	50.00%	-	-	1	50.00%
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	20.00%	80.00%	-	-	1	20.00%
67	All	Capacitor Banks	Capacitors including controls	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A
68	All	Load Control	Centralised plant	Lot	-	100.00%	-	-	-	1	100.00%
69	All	Load Control	Relays	No.	-	5.00%	10.00%	5.00%	80.00%	1	100.00%
70	All	Civils	Cable Tunnels	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A

G. Appendix – Schedule 12b

Company Name: **Electricity Invercargill Limited**

AMP Planning Period: **1 April 2015 – 31 March 2025**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	Existing Zone Substations	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Spey Street	-	-	n-1	-	-	36	65%	No constraint within +5 years	New sub as relocation replacement for Doon St, under construction
10	Doon Street	21	23	n-1	12	91%	N/A	N/A	No constraint within +5 years	Decommissioned in 2015/16 when load transferred to Spey Street
11	Leven Street	21	23	n-1	12	90%	23	87%	No constraint within +5 years	n-1 but momentary interruption, 2nd subtrans cct from other GXP
12	Southern	16	-	n	23	-	23	76%	No constraint within +5 years	Upgrades including 2nd transformer planned 2018/19
13	Racecourse Road	14	-	n	23	-	-	N/A	No constraint within +5 years	
14	[Zone Substation_06]					-			[Select one]	
15	[Zone Substation_07]					-			[Select one]	
16	[Zone Substation_08]					-			[Select one]	
17	[Zone Substation_09]					-			[Select one]	
18	[Zone Substation_10]					-			[Select one]	
19	[Zone Substation_11]					-			[Select one]	
20	[Zone Substation_12]					-			[Select one]	
21	[Zone Substation_13]					-			[Select one]	
22	[Zone Substation_14]					-			[Select one]	
23	[Zone Substation_15]					-			[Select one]	
24	[Zone Substation_16]					-			[Select one]	
25	[Zone Substation_17]					-			[Select one]	
26	[Zone Substation_18]					-			[Select one]	
27	[Zone Substation_19]					-			[Select one]	
28	[Zone Substation_20]					-			[Select one]	

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

30 **12b(ii): Transformer Capacity**

sch ref		(MVA)
32	Distribution transformer capacity (EDB owned)	
33	Distribution transformer capacity (Non-EDB owned)	
34	**Total distribution transformer capacity**	-
35		
36	**Zone substation transformer capacity**	

H. Appendix – Schedule 12c

Company Name: **Electricity Invercargill Limited**
AMP Planning Period: **1 April 2015 – 31 March 2025**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref								
7	**12c(i): Consumer Connections**							
8	*Number of ICPs connected in year by consumer type*				**Number of connections**			
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
11	*Consumer types defined by EDB**							
12	Customer Connections (≤ 20kVA)		22	22	22	22	22	22
13	Customer Connections (21 to 99kVA)		-	1	-	1	-	1
14	Customer Connections (≥ 100kVA)		1	1	1	1	1	1
15								
16								
17	**Connections total**		23	24	23	24	23	24
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		20	25	30	35	42	50
21	Installed connection capacity of distributed generation (MVA)		0	0	0	0	0	0
22	**12c(ii) System Demand**							
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)**	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
25	GXP demand		58	59	60	60	61	61
26	*plus* Distributed generation output at HV and above		-	-	-	-	-	-
27	**Maximum coincident system demand**		58	59	60	60	61	61
28	*less* Net transfers to (from) other EDBs at HV and above		2	2	2	2	2	3
29	**Demand on system for supply to consumers' connection points**		56	57	57	58	58	59
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		255	257	258	259	260	262
32	*less* Electricity exports to GXPs		-	-	-	-	-	-
33	*plus* Electricity supplied from distributed generation		-	-	-	-	-	-
34	*less* Net electricity supplied to (from) other EDBs		(19)	(19)	(19)	(19)	(19)	(20)
35	**Electricity entering system for supply to ICPs**		274	276	277	279	280	281
36	*less* Total energy delivered to ICPs		259	261	262	263	265	266
37	**Losses**		15	15	15	15	15	15
38								
39	**Load factor**		56%	56%	55%	55%	55%	55%
40	**Loss ratio**		5.5%	5.5%	5.5%	5.5%	5.5%	5.5%

I. Appendix – Schedule 12d

		Company Name	Electricity Invercargill Limited	
		AMP Planning Period	1 April 2015 – 31 March 2025	
		Network / Sub-network Name		

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref								
8			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
10	**SAIDI**							
11	Class B (planned interruptions on the network)		1.0	2.0	2.0	2.0	2.0	2.0
12	Class C (unplanned interruptions on the network)		37.7	22.2	19.1	18.7	18.4	18.0
13	**SAIFI**							
14	Class B (planned interruptions on the network)		0.00	0.01	0.01	0.01	0.01	0.01
15	Class C (unplanned interruptions on the network)		0.73	0.59	0.58	0.58	0.57	0.57

J. Appendix – Schedule 13

Summary of Asset Management Maturity Assessment Tool;

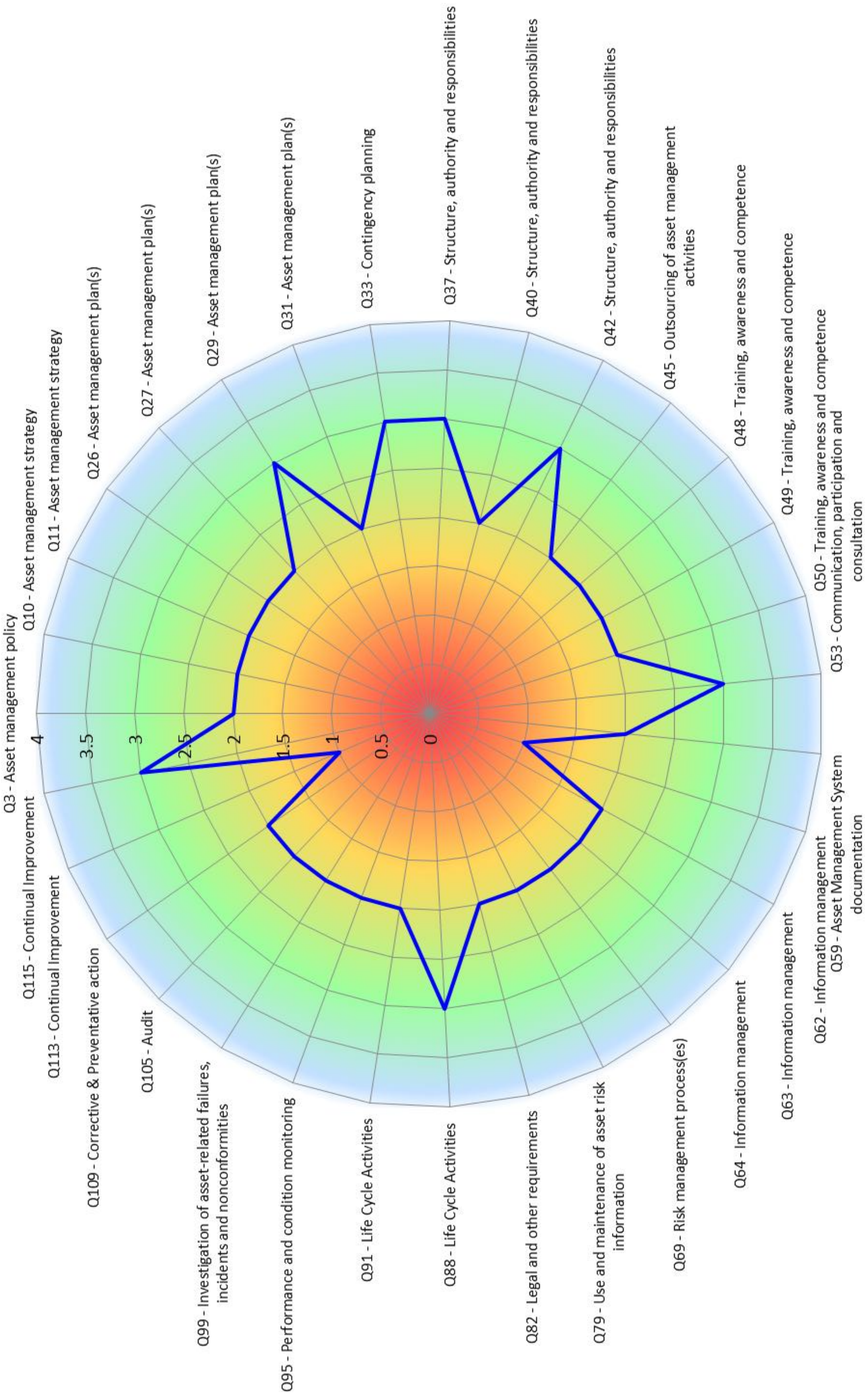
Company Name	Electricity Invercargill Limited
AMP Planning Period	1 April 2015 – 31 March 2025
Asset Management Standard Applied	Pass 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Question
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	1	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	2	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	2	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	2	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	1	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.

AMMAT Radar Plot;



11. Approval by Board of Directors

Certification for Year-beginning Disclosures

We, Neil Douglas Boniface and, Thomas Campbell being Directors of Electricity Invercargill Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) The following attached information of Electricity Invercargill Limited prepared for the purposes of clause 2.6.1 and subclauses 2.6.3(4) and 2.6.5(3) of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b and 12c are based on objective and reasonable assumptions which both align with Electricity Invercargill Limited's corporate vision and strategy and are documented in retained records.

N D Boniface

T Campbell

Date: 26 March 2015