Electricity Invercargill Ltd

Invercargill CBD Development

Asset Management Plan 2020 - 2030

Publicly disclosed in March 2020

Contents

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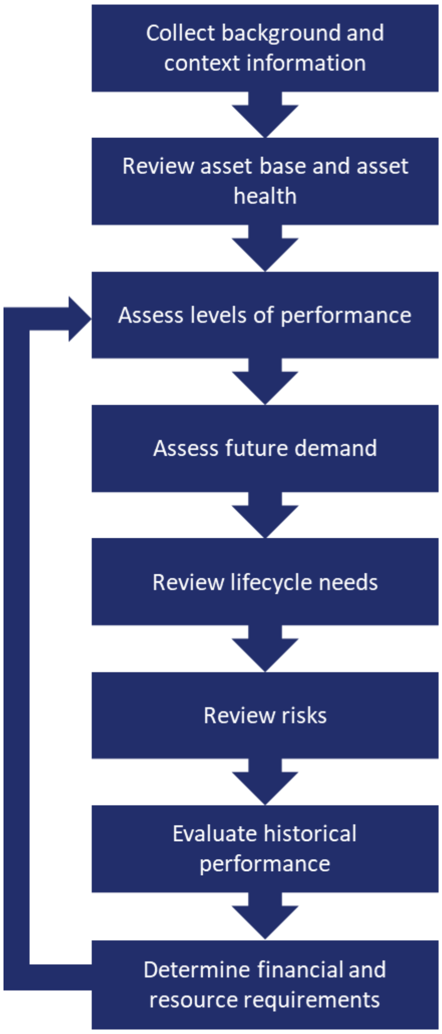
The world is currently experiencing a pandemic caused by a new strain of coronavirus. Covid-19 is spreading around the world. This is already affecting our supply chain and it may have an effect on the resources available to execute this plan. This AMP assumes that the pandemic will be controlled and that it will not have a significant effect on the availability of skills, equipment and material. Should this not be the case, the plan will be subject to change.

Type text

Preparation of the Asset Management Plan

EIL has a network management contract with PowerNet Limited which it jointly owns with The Power Company Limited (TPCL). The AMP is produced by PowerNet after extensive consultation throughout the business, with EIL's Board of Directors, and with EIL's customers. The AMP is approved by the EIL Board prior to the end of March of each year when it is publically disclosed.

The Asset Management Plan (AMP) development restarts in July every year in order to deliver a new or updated AMP by end March of the following year. The following diagram shows the process followed in the development of the AMP:



- Regulatory Environment
- Environmental Influences
- Purpose, critical success factors, strategic goals
- Financial and economic environment
- Technological developments
    - Service areas
    - Network configuration, resilience, redundancy
    - Assets and asset health details
- Regulatory criteria
- Customer requirements and expectations
- Internal efficiency and effectiveness
- Target levels and measurement
    - Known customer initiatives – supply and demand
    - Regional and local development plans
    - Population growth
    - Social and economic developments and changes
- Condition monitoring
- Asset lifecycle planning and information systems
- Operations and maintenance needs
- Asset replacement and renewal requirements
    - Risk strategy, policy, tolerance levels
    - Risk management methodologies
    - Specific asset related risk
    - Emergency response and contingency
- Historical performance against asset creation plans
- Historical performance against maintenance plans
- Historical performance against service level targets
- Performance against asset management best practice
- Gap analysis and corrective measures
    - Capital and operating expenditure requirements
    - Vehicle and equipment requirements
    - Human resource requirements

We use the finalised and audited information from the immediate past financial year as the base data for the development of the new plan. This is the most accurate data available at that stage of the process. Any forecast figures will still be highly inaccurate.

These figures are the figures used for the asset life cycle planning throughout the document. Where forecast figures are shown, they are indicative and for information only. They will change after the financial year end close and the annual audit.

Summary

Background and Objectives

Electricity Invercargill Limited (EIL) is the electricity lines business that conveys electricity to the majority of Invercargill and to Bluff for approximately 17,417 customers.

EIL's Asset Management Plan (AMP) provides an internal asset management framework for EIL's network. Disclosure in this format is also intended to meet the requirements of the Electricity Distribution Information Disclosure Determination 2012 as amended on 21 December 2017. It covers the ten year planning period from 1 April 2020 to 31 March 2030. Other key asset management documents for EIL are:

- The Annual Works Programme (AWP) detailing the capital and operational expenditure forecasts for the next ten years being produced as part of the development of the AMP.
- The Annual Business Plan (ABP) which consolidates the first three years of the AMP along with any recent strategic, commercial, asset, or operational issues from the wider business and defines the priorities and actions for the three years ahead.
- The Statement of Intent which is the principal accountability mechanism between EIL's Board and the shareholder: Invercargill City Holdings.

EIL's business goals are driven mainly by shareholder's and customers' expectations. Aligned corporate and asset management strategies have been developed to guide EIL's commercial operation, investment, risk management, business efficiency, and customer satisfaction objectives.

EIL's commercial goal is to deliver a sustainable earnings stream to their shareholders. This creates a primary driver for EIL, and formal accountabilities to the shareholder are in place for financial and network performance.

Customers provide EIL's revenue via the electricity retailers in return for the services provided by the EIL network assets. It is important for EIL to meet customers' expectations. Annual customer surveys are undertaken to monitor customer satisfaction with service levels. Targets are set aimed at ensuring standards are maintained or improved.

Stakeholders' interests are accommodated as far as possible. Conflicting interests are managed using a priority hierarchy considering safety, viability, pricing, supply quality, and compliance in that order.

Assets Covered

EIL's service area includes two fully urban, geographically separate areas comprising of the city of Invercargill (except for some of the outer regions supplied from the surrounding TPCL network) and the township of Bluff. The Invercargill area network is almost entirely underground after an extensive program converting overhead lines to underground cable; only a few streets remain as overhead construction. The Bluff network is predominantly overhead line due to the difficulty associated with laying cable in the rocky subsurface.

EIL supplies 17,417 residential, commercial and industrial customers across the two network areas. Transpower's Invercargill GXP substation is the 33 kV supply point for both network areas however a limited backup supply is available from the North Makarewa GXP. Bluff is supplied at 11 kV via TPCL's overhead subtransmission and Bluff zone substation. EIL's subtransmission has a total length of

27.6 km and comprises a mix of oil filled and Cross-Linked Polyethylene (XLPE) cables supplying the four Invercargill zone substations. The distribution network has a total length of over 182 km with all feeders operating at 11 kV. Via more than 400 distribution substations comprising 11 kV switchgear and distribution transformers the distribution network supplies over 450 km of low voltage network operating at 400/230 V.

The undergrounding program has caused much of the network to be replaced since the late 1950s, making the distribution network relatively young. However the oldest assets, particularly 11 kV switchgear, are at end of life and due for replacement.

Service Levels

EIL set and maintain a number of service levels on behalf of its stakeholders especially its customers. Two important metrics measuring network reliability are SAIFI and SAIDI:

- SAIFI is a measure around outage frequency which translates to the average number of faults an average customer would experience annually. EIL is forecasting a SAIFI of about 0.72.
- SAIDI is a measure around outage duration which translates to the average amount of time an average customer would be without power annually. EIL is forecasting SAIDI of about 35.
    - These forecasts are average values around which significant variation can be expected due to the low number of faults creating statistical volatility. Weather impacts also have a randomising influence on the overhead sections of the network. EIL's reliability has been extremely good due to the underground nature of the Invercargill network; however, these levels will be difficult to maintain towards the end of the DPP3 period due to the Revenue cap limiting additional investment into reliability improvement initiatives and equipment renewal.

Secondary service levels are also set for customer satisfaction for those customers who have experienced an outage (both planned and unplanned) regarding their satisfaction with the amount of time they were without supply, and with the information made available to them about their outages. Independent surveys are undertaken annually to determine how customers perceive the service levels they receive from EIL; generally responses are very positive.

Other service levels maintained are the compliance with safety legislation, amenity value legislation and regulations requiring certain performance standards for the business while avoiding interference with other parties.

In addition EIL are required to set financial efficiency and energy efficiency service levels. EIL sets targets for both network and non-network operational expenditure in terms of each of ICPs supplied, km of network length and total distribution transformer capacity. These ratios are disclosed directly by the other distribution businesses may therefore be used for benchmarking EIL's performance against its industry peers. Targets for next years' network operational expenditure ratios are set at: per ICP \$108, per km \$2,800, and per MVA \$12,200 while targets for non-network operational expenditure ratios are set at: per ICP \$221, per km \$6,000, and per MVA \$25,500.

For efficiency of energy delivery EIL is aiming to achieve an overall load factor of 50%, capacity utilisation of 40% and loss ratio of 5.5%. These are long term average targets as year-to-year variation can be significant and often largely out of EIL's control.

Benchmarking service levels against other electricity distribution businesses indicates EIL is performing well on behalf of its stakeholders.

Development

Network development may be driven by the need to create additional network capacity for supplying increasing demand, or by the need to maintain or improve service levels. These drivers are monitored and trigger points set to identify when development projects are needed. When a development trigger is reached, several options are considered with the most cost efficient option selected as a solution. Standardisation is a valuable strategy in providing cost efficiencies in the delivery of capital projects.

Forecasts of demand growth are required to help EIL predict when in future years the development triggers will be reached, thus enabling effective planning of future projects. Historical demand is trended and projected into future years while accounting for foreseeable future drivers that may influence the current trend. Projections and associated planning around future expected constraints are based on what is considered the most likely scenario, while EIL's strategy of deferring capital expenditure until necessary minimises the risk of overinvestment.

EIL's work program includes the following capital expenditure on network development:

- Consumer Connections – the provision of connection points and additional network capacity as needed for new customers is budgeted at $244k - $516k per annum on average. Additional budgets between $496k and $837k is allocated in 2020/21 – 2022/23 for known customer connection projects.
- System Growth – Future work to complete reconfiguration at Doon Street has been deferred until the 2024/25 year and is budgeted at $411k.
- Asset Relocations – a small budget of $6k is allowed for the relocation of poles or pillar boxes as may be needed from time to time. An additional $21k is allocated in 2021/22 for a known and customer-funded relocation project.
- Quality of Supply – network upgrades to ensure sufficient voltage is delivered at customer connection points and automation of network equipment to allow faster location, isolation and supply restoration following a fault. This is budgeted at $46k in the long term for proactive supply quality fixes anticipated through smart meter data. Additional budget of $144k for 2021/22 and 2022/23 has been allocated for automation projects aimed at early detection and reduction in severity of faults in the Bluff network.
- Reliability, Safety and Environmental – $103k to $443k p.a. for several initiatives aimed at improving safety to public and field operators..

Total capital expenditure (including Asset Replacement and Renewal described under Lifecycle below) is budgeted at $4.4M for 2020/21, with the following two years set at $4.4M and $4.0M respectively

Table 1: Material Development Projects

Project	Driver	Year	$,000
Customer Connection	Commercial developments	2020 – 2023	496 – 837 pa
Doon Street Reconfiguration	System growth	2024/25	411
LV Tie Disconnectors	Safety, Reliability	2022 onwards	243 pa

Lifecycle

Once an asset has been installed it must be managed throughout its lifecycle to continue to fulfil its purpose for as long as it is required, and to minimise any adverse effects the asset might create. Maintenance activities are generally undertaken throughout an assets operational life to support its continued reliable service. Eventually continued maintenance of the asset will become uneconomic, and the asset will be retired from service. At that point the asset will be replaced (assuming the need for the asset remains) while the retired asset is disposed of appropriately.

EIL's works program includes the following capital expenditure on asset lifecycle management:

- Asset Replacement and Renewal – replacement of assets that are at the end of their economic life or in some cases major refurbishment of assets to extend their expected life budgeted at $3.5M, $3.2M, and $3.0M for the years 2020/21, 2021/22 and 2022/23 respectively. This includes significant projects for RMU renewal, and completion of the major upgrade of the Southern zone substation

The remainder of EIL's works program is made up of the following operational expenditure on asset lifecycle management:

- Asset Replacement and Renewal – minor replacement and renewal work that doesn't impact on an asset's valuation is budgeted at $210k each year ongoing.
- Vegetation Management – a small budget of $2k is allowed yearly for the trimming of trees to prevent contact with overhead lines, and vegetation clearance around ground mounted equipment to prevent corrosion and ingress.
- Routine and Corrective Maintenance and Inspection – inspection, testing and investigation of network condition and resulting maintenance or repair as well as general routine asset maintenance and repairs budgeted at $1.1M each year ongoing.
- Service Interruptions and Emergencies – reactive work following network faults and customer outages to locate, isolate and repair faulty network assets budgeted at $485k each year 2020 - 2025. This is budgeted to increase in 2025/26 onwards for expected deterioration in EIL fleet.

Total network operational expenditure is budgeted at about $1.8M each year 2020 – 2025. This is expected to increase to $1.9M p.a. from 2025/26 onwards. Non-network operational expenditure adds $3.9M consisting of System Operations and Network Support ($1.4M) and Business Support ($2.5M)

Table 2 - Material Non-Routine Lifecycle Projects

Project	Driver	Year	$,000
RTU Replacement	Replacement	2020/21	87
Power Transformer Refurb	Renewal	2022/23	169 pa
Southern Substation Upgrades	Replacement, safety, reliability	2020 – 2022	1,405– 1,995 pa
Racecourse Road Switchboard Replacement	Renewal, safety, reliability	2022-2025	137 – 866 pa
RMU Replacement	Safety and reliability	2020 2030	735 – 1,862 pa

Risk Management

EIL is exposed to a wide range of risks and utilises risk management techniques to bring risk within acceptable levels. Firstly risks associated with EIL's network are actively identified through regular reviews. Identified risks are then quantified in terms of the probability that an adverse occurrence would eventuate and the consequences for EIL if it does. A risk matrix is then used to systematically combine the probability and consequence into a resulting level of risk. Risk management looks at the most appropriate options for reducing risk to acceptable levels using the following general methods:

- Terminate – not proceeding with risky activity or eliminating a risk by choosing an alternative approach.
- Treat – reduce probability and/or consequence of an adverse occurrence
- Transfer – engage a more suitable party to effectively manage a certain risk
- Tolerate – accept a low level risk as tolerable (including residual risk after treatment of higher level risks)

EIL's risk management framework recognises that resources for managing risk are finite. It may be appropriate to increase certain resources to manage risk appropriately, however ultimately risk treatment measures need to be prioritised using a philosophy of greatest risk reduction for the resources available. Many risks have been identified and are being managed under the following broad categories:

- Assets
- People
- Community/Stakeholders
- Ownership/Governance
- Legal & Regulatory
- Economic/Political

For potential serious business interruptions EIL has developed a Business Continuity Plan and has a Pandemic Action Plan for use in the outbreak of any highly infectious illness. EIL also holds critical network spares and has contingent operating plans to support efficient restoration of supply following unexpected equipment failure as well as holding a range of business insurances.

Performance

For the financial year ending 31st March 2019 EIL's finalised and audited performance is summarised as follows.

Capital expenditure was 7% below budget due to three main factors:

- Large consumer connections work was lower than forecast within the 2018/19 year due to customer side delays. This timing difference will show in the 2019/20 spend.
- Asset replacement and renewal, net 3% underspend due to field staff vacancies
- Asset Relocations, 246% overspend due to significant costs of managing archeological finds during excavations

Operational expenditure was 4% under target with reactive fault response work lower than anticipated, as well as lower maintenance activity due to field staff vacancies.

Reliability performance on the overall network in 2018/19 was in line with long term averages. with SAIFI of 0.31 under the target of 0.59 and SAIDI of 18.0 under the target of 24.1 minutes. These results were well within the Commerce Commission's supply quality limits.

EIL's financial efficiency results were good with the ratio OPEX/RC below target and Indirect Costs per Customer below target.

Network efficiency performance was fair with the Capacity Utilisation target achieved but the Loss Ratio and Load Factor falling fractionally outside the target. EIL recognises that these results are subject to some random variation from year to year, and that the long term average of its performance is consistent with the targets.

Capability to Deliver

PowerNet owns the many systems, processes, and tools used to effectively and efficiently manage EIL's network assets. PowerNet's information systems hold data about EIL's network assets including technical details, location, operational states, and condition. The data is collated and displayed in various ways to help support efficient decision making for EIL's asset management planning and activities. The maintenance of these systems and the information that they contain is a PowerNet function executed by staff dedicated to this function.

EIL's business is funded from the revenue received from customers via several electricity retailers and in return EIL maintains a network for the conveyance of electricity to these customers within certain service levels. Revenue is closely tied to the value of assets as set out in a "price path" determined by the regulating authority; the Commerce Commission. Significant expenditure is required each year to maintain network assets and to develop the network to meet increasing customer demand.

On 27 November 2019, the Commerce Commission, set the third default price-quality path (DPP) for electricity distributors subject to price-quality regulation. EIL is one of 17 electricity distributors subject to these regulations. These price-quality paths apply for the period 1 April 2020 to 31 March 2025.

The revised revenue allowances for EIL are lower than preceding periods. This imposes significant financial constraints on EIL, and its ability to meet the network's renewal needs. The constraints are mostly around cash flow management due to insufficient revenue.

In addition, the revised network reliability regime is much less favourable for the type of faults that EIL experiences due to the nature and density of the underground network.

Staffing and contracting resource is an ongoing issue that EIL is managing and EIL's Annual Works Program recognises existing constraints, and incorporates future management of resourcing levels. EIL mainly uses PowerNet's field services to carry out much of the operational, maintenance and development work on its network but also utilises local contractors where additional resources are required.

1. Background and Objectives

Infrastructure, in the form of public buildings, roads, water and sewerage systems, electricity and other services, supports quality of life and is the foundation of a healthy economy. Apart from its social benefits, electricity is also a driving factor in the economy. Its usage ranges from communication and transportation to production.

Electricity Invercargill Limited (EIL) is the electricity lines business that conveys electricity to the majority of Invercargill and to Bluff for approximately 17,417 customer connections on behalf of sixteen 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, Wanaka areas of Central Otago.
- 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 EIL, TPCL, and ESL.
- A 45.5% stake in PowerNet Central Limited, an electrical contracting company based in Frankton. (through EIL's 50% stake in PowerNet). PowerNet Central Limited, formerly Peak Power Services Limited, will amalgamate with PowerNet Limited on 31 March 2020.
- A 25% stake in Southern Generation Ltd, a generation company with wind and hydro assets in New Zealand jointly owned with TPCL and Pioneer Generation Ltd.

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

1.1. Purpose Statement

The purpose of EIL's Asset Management Plan (AMP) is to provide an internal governance and management framework for asset management practice on EIL's network. Disclosure in this format is also intended to 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 as amended.

The plan:

- documents the nature, extent, age, utilisation, condition, performance and value of the infrastructure;
- identifies existing and proposed levels of service to be achieved over a five year period, as well as any expected changes in demand;
- identifies the life-cycle management needs (development, renewal, operations and maintenance and any disposal) over the five year period;
- assesses capital and operational budget needs and funding implications; and
- assesses the prevailing infrastructure asset management practice and identifies further improvements.

1.2. Commerce Commission Determination – November 2019

Part 4 of the Commerce Act 1986 (the Act) requires the Commerce Commission to reset the current DPP for EDBs that are subject to price-quality regulation four months before the end of the current DPP period. From 1 April 2020, EDBs will be subject to new requirements set out in the DPP determination.

Changes in the way consumers and other industry participants make use of distribution networks, innovations in the way EDBs deliver services, electrification driven by decarbonisation, and the risk of increasingly severe weather events all have the potential to reshape investment needs and quality expectations in unpredictable ways. The stated intent of the Commerce Commission is to provide sufficient flexibility to accommodate increasing uncertainty and change across the electricity distribution sector.

Financial Impact

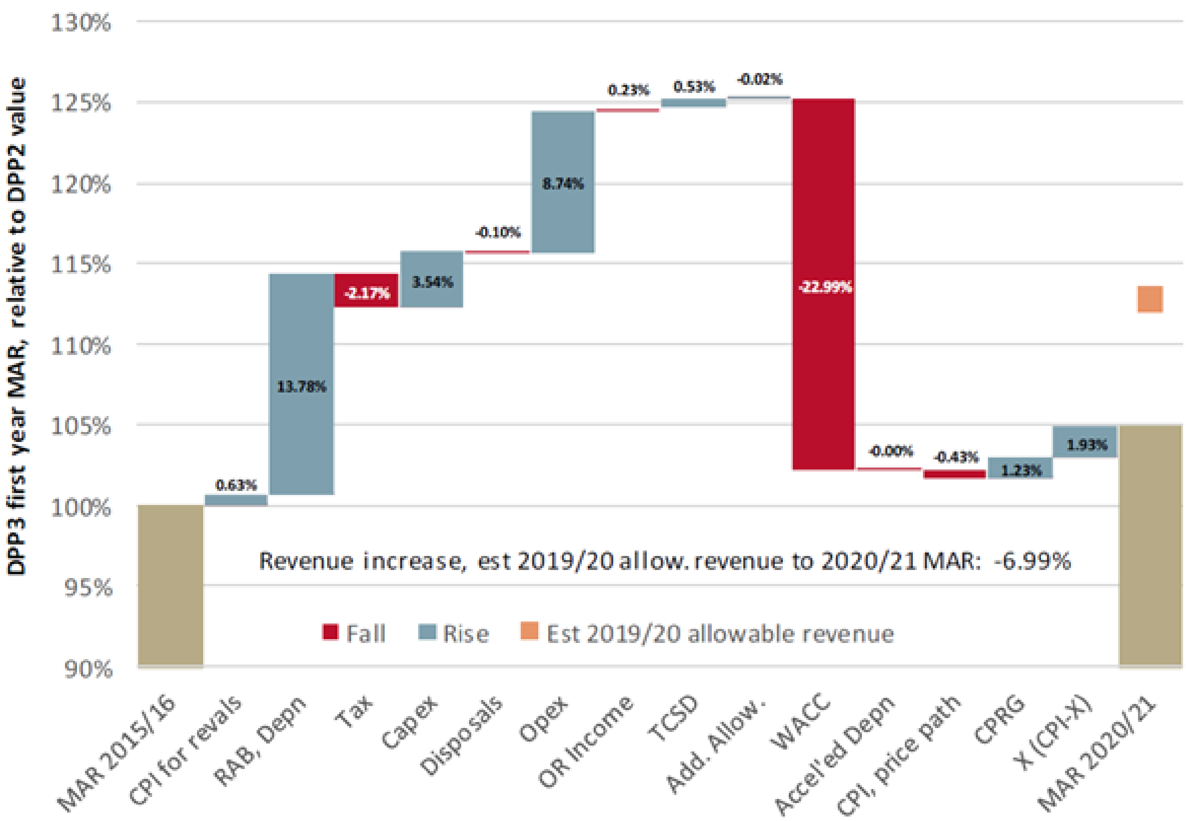
The new DPP3 introduces a revenue cap as opposed to the previous price cap. This is intended to give EDBs the flexibility to price in ways that offer more choice to consumers and that enhance incentives for energy efficiency and demand-side management as well as to give EDBs greater certainty about revenue recovery. Setting revenue limits means that profitability depends on the extent to which EDBs control costs.

DPP3 revenue caps are based on an assumption of a reduction in the weighted-average cost of capital, as reflected in the current state of the broader economy. Low global interest rates have led to lowered profitability expectations across many sectors.

The Commerce Commission has set a net revenue allowance of $1.01 billion in the first year of the DPP3 period across the 15 regulated EDBs. This is an overall decrease of 6.7% relative to allowances in the final year of DPP2.

The methodology followed was to add together forecasts of each EDB’s over the DPP3 period, then spreading this revenue out over the period such that they increase at a consistent rate of forecast CPI-X, resulting in the ‘maximum allowable revenue’ (MAR).

The overall result is shown in the following figure (copied from the Commerce Commission’s **Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision** document.



The result for Electricity Invercargill is allowable revenue in 2020/21 ($m) of $12.26 million

This is a reduction in revenue of 12% for Electricity Invercargill.

Directly related to the Revenue targets are the operating expenditure targets:

Electricity Invercargill: Allowable OPEX for 2020-2029 $27.24 million

These are distributed as follows:

	2020/21	2021/22	2022/23	2023/24	2024/25
Electricity Invercargill	5.18	5.31	5.45	5.59	5.72

The allowed capital expenditure is:

Electricity Invercargill: Allowable CAPEX for 2020-2029 $25.98 million

Distributed as follows:

	2020/21	2021/22	2022/23	2023/24	2024/25
Electricity Invercargill	4.66	5.05	5.57	5.58	5.13

Reopeners for significant unforeseen or uncertain capital expenditure projects that will allow EDBs to undertake investments in response to changing conditions without risking capital under-recovery are introduced.

The possibly unintended consequence of these financial determinations is that it places severe constraints on the cash flows of the PowerNet managed networks. Prudent management of the cash flows of the EDBs has the effect that the expenditure will be below the set allowances.

Quality of Service Impact

Quality of service incentives is a major focus of the determination. The approach followed is one of 'no material deterioration'. The stated intent is that aligning reliability incentives to the value consumers place on reliability frees EDBs (within certain bounds) to target the level of reliability and of price that best meets the expectations of their consumers. Additionally, a new approach to normalisation is intended to prevent the effects of severe storms being mistaken for signs of deterioration.

The changes in the quality standards are:

- Separating planned and unplanned reliability standards;
- Setting the unplanned reliability standards at 2 standard deviations above the normalised historical average, and defining contraventions on an annual basis, rather than a 'two-out-of-three' year basis;
- Setting the planned reliability standard at three times the historical average, and assessing it on a regulatory period basis;
- Capping the inter-period (DPP2 to DPP3) movement in unplanned standards at ±5%; and
- Implementing a new 'extreme event' SAIDI standard, set at either 120 SAIDI minutes or 6 million customer interruption minutes, and excluding specified events that we consider are predominantly caused by external factors.

The targets for Electricity Invercargill are presented in the following table:

EDB	Unplanned SAIDI (1 year)	Unplanned SAIFI (1 year)	Planned SAIDI (5 year)	Planned SAIFI (5 year)	Extreme event
Electricity Invercargill	25.86	0.6956	114.49	0.5183	120 SAIDI

Unplanned SAIDI and SAIFI are assessed annually while the planned SAIDI and SAIFI are assessed at the end of the 5 year period.

Of particular significance is the increase in the planned interruption allowance. This allows for more efficient work practices on condition that customers are notified well in advance of the planned interruptions.

Summary

It is concerning that the Commerce Commission through a mixture of low regulatory returns, investment disincentives and increased pressure on quality limits is making the sector less attractive to investors. It creates an inappropriate balance between quality expectations and allowed revenue, creating a risk of a reduction in investment in network capital and maintenance expenditure and a deterioration in reliability and asset health.

As noted in the section on the Financial Impact of the determination, expenditure is being curtailed to manage the cash flows in the EDBs. This will place pressure on maintaining service levels to within the set target and on maintaining asset health. We anticipate that unplanned SAIDI and SAIFI targets will be difficult to achieve in the later years of the reset period.

1.3. Asset Management Objectives

Asset Management refers to a formal approach through which an organisation manages its physical assets and their associated performance, risks and expenditures over their lifecycle for the purpose of achieving the company's vision and business objectives.

The objective of asset management for Electricity Invercargill is therefore to ensure that the utility's assets deliver the required function and level of performance, in a sustainable manner at an optimum whole-life cost without comprising health, safety, environmental performance or the organisation's reputation. It therefore contributes directly to the business capability and performance while enhancing customer satisfaction and improving health, safety and environmental performance.

We align our asset management activities with our corporate business plan and targets to ensure that the management of the physical assets enables the delivery of customer and stakeholder value.

We achieve this through the operation of a co-ordinated end-to-end asset management system that:

- Produces an asset management strategy, asset management objectives, and asset performance, asset health and asset condition targets that are consistent with our business priorities and strategic business plan
- Gives consideration to the complete lifecycle of our assets and develops asset management plans that are sustainable, efficient and based upon an optimised consideration of cost, risk and performance
- Promotes interaction with customers and stakeholders to determine their required levels of service
- Optimises and prioritises maintenance and investment activities
- Uses new technologies to appropriately improve efficiency, effectiveness and service levels
- Is supported by asset and financial information, and technical knowledge
- Ensures delivery of the objectives and targets required by our plans
- Ensures that all our activities meet with applicable legislation, statutory and regulatory requirements and integrate with and complements the risk, health & safety, environmental and quality management system requirements of PowerNet; and
- Incorporates regular formal reviews designed to seek and implement continual improvement
- Provides our staff and contractors with sufficient information, training and resources to ensure that we achieve our objectives.

At a more detailed level, this implies that EIL needs to:

- Set service levels for the electricity distribution services supplied by EIL, which will meet customer, community and regulatory requirements.
- Understand 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 an ever-increasing knowledge of EIL's asset locations, ages, conditions, and likely future behaviour as age increases and operational demands change.

- Have robust and transparent processes in place for managing all phases of the network life cycle from design, procurement, and installation to maintenance, operations and disposal.
- Have adequate provision for funding all phases of the network lifecycle.
- Have adequately considered the classes of risk EIL's network business faces and ensured that there are systematic processes in place to manage identified risks.
- Make business decisions within systematic and structured frameworks.

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.

1.4. AMP Planning Period and Director Approval

EIL's Asset Management Plan (AMP) is prepared annually by PowerNet however an "AMP update" is produced in place of a full AMP two years within each five year default price path period as allowed for by the Electricity Distribution Information Disclosure Determination 2012 (latest amendments incorporated). The AMP update which focusses on updates to the development and lifecycle works and expenditure is a cut down version of the full AMP represented by this document.

This latest edition was prepared during August 2019 to March 2020 and covers the ten year period from 1 April 2020 to 31 March 2030. It was approved by EIL's Board on 29 March 2020 (see Appendix Directors Approval) and publicly disclosed at the end of March 2020.

There is a degree of uncertainty in any predictions of the future, with the immediate future reasonably predictable and the longer term becoming more and more uncertain.

The first year of the AMP is considered reasonably certain. Planned capital works are generally well planned and only subject to minor variations. New customer connections are driven by turbulent commodity markets, public policy trends, and possible generation opportunities; so while long-term trends are reasonably predictable, year-to-year variation around those trends can still be significant, especially with larger capacity connections that tend to have lower and more sporadic connection rates but have a comparatively large impact on spend.

Planned maintenance works are relatively predictable as most tasks require a similar amount of effort year. Occasionally step changes are warranted due to age profiles or if new initiatives are introduced, but these changes are planned in advance. Reactive maintenance requirements are less predictable. Response to service interruptions is probabilistic by nature and due to the low number of faults on EIL's network can be very sporadic. Network faults on overhead parts of the network are also unpredictable, being heavily influenced by the weather.

The two to four year timeframe has lower certainty than the first year. However customer connection rates, maintenance and response to service interruptions are expected to largely correlate with the current trend. Major projects are typically identified and scheduled well in advance; however as detailed scope, design and costings are developed, the work necessary to implement the project may change, influencing expenditure and timing. External influences – particularly the changing perceptions around health and safety – can cause some smaller projects to be introduced within this timeframe.

The final five year period of the AMP's ten year planning horizon has little if any certainty. Projects for age-based replacements can be proposed and growth trends can be used to predict when capacity triggers will be reached. However standards may change, growth may not match forecast, and new maintenance philosophies may be developed as asset management practice is continually improved; each of these factors can have a large impact on scope and timeframes for these projects. Experience shows these changes and other external influences are likely to introduce and reshape major and minor projects within this time frame in a way that is very difficult to predict.

1.5. Drivers and Constraints

EIL's business goals are driven by its stakeholder's interests, of which the shareholder's expectations and the meeting of customer expectations have a primary influence. Also shaping business operation is the wider context in which the business operates, which includes a number of drivers ranging from governmental and regulatory strategies that may create incentives or impose constraints, to natural constraints such as the unpredictability of weather or the laws of physics.

This section describes the identification of EIL's stakeholders, their interests in EIL, how these interests are met and how conflicts between stakeholder's expectations are managed before identifying other influences that drive and shape EIL's business.

Stakeholder Interests

The stakeholders EIL has identified are listed in the following tables with the stakeholder's interests and how these interests are identified shown in Table 1 and Table 2 respectively. Table 3 shows how stakeholder's interests are accommodated in EIL's asset management practices. A stakeholder is identified as any person or organisation that does or may do any of the following:

- Have a financial interest in EIL (be it equity or debt).
- Pay money to EIL (either directly or through an intermediary) for delivering service levels.
- Is physically connected to EIL's network.
- Use EIL's network for conveying electricity.
- Supply EIL with goods or services (includes labour).
- Is affected by the existence, nature or condition of the network (especially if in 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).

Table 1: Key stakeholder interests

Interests:	Viability	Price	Quality	Safety	Compliance
Invercargill City Holdings (Shareholder)	✓	✓	✓	✓	✓
Connected Customers	✓	✓	✓	✓	
Contracted Manager (PowerNet)	✓	✓	✓	✓	✓
Ministry of Business, Innovation & Employment		✓	✓	✓	✓
Commerce Commission	✓	✓	✓		✓
Electricity Authority					✓
Electricity & Gas Complaints Commission			✓		✓
Councils (as regulators)				✓	✓
Transport Agency				✓	✓
Energy Safety				✓	✓
Industry Representative Groups	✓	✓	✓		
Public (as distinct from customers)				✓	✓
Mass-market Representative Groups	✓	✓	✓		
Staff and Contractors	✓			✓	✓
Energy Retailers	✓	✓	✓		
Transpower		✓	✓	✓	
Suppliers of Goods and Services	✓				
Land owners				✓	✓
Bankers	✓	✓		✓	✓

Table 2: Identifying stakeholder's interests

Stakeholder	How Interests are Identified
Invercargill City Holdings (Shareholder)	• By their approval or required amendment of the SOI • Regular meetings between the directors and executive
Connected Customers	• Regular discussions with large industrial customers as part of their on-going development needs • Customer consultation evenings (meetings open to public) • Annual customer surveys
Contracted Manager (PowerNet)	• Board Chairman weekly meeting with the Chief Executive • Board meets monthly with Chief Executive and PNL Staff
Ministry of Business, Innovation & Employment	• Release of legislation, regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Commerce Commission	• Regular bulletins on various matters • Release of regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Electricity Authority	• Weekly updates and briefing sessions • Release of regulations and discussion papers • 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
Councils (as regulators)	• Formally as necessary to discuss issues such as assets on Council land • Formally as District Plans are reviewed

Stakeholder	How Interests are Identified
Transport Agency	• Formally as required
Energy Safety	• Promulgated regulations and codes of practice • Audits of EIL's activities • Audit reports from other lines businesses
Industry Representative Groups	• Informal contact with group representatives
Public (as distinct from customers)	• Word of mouth around the city • Feedback from public meetings
Mass-market Representative Groups	• Informal contact with group representatives
Staff & Contractors	• Regular staff briefings • Regular contractor meetings
Energy Retailers	• Annual consultation with retailers
Transpower	• Deliver transmission grid energy into EIL network • Regular engagement on network performance and asset integration • Annual input on future demand forecasts • Planned and unplanned network outage co-ordination • Through costs are paid by EIL to Transpower
Suppliers of Goods & Services	• Regular supply meetings • Newsletters
Land Owners	• Individual discussions as required
Bankers	• Regular meetings between bankers, PowerNet's CEO & CFO • By adhering to EIL's treasury/borrowing policy • By adhering to banking covenants

Table 3: Accommodating Stakeholder's Interests

Interest	Description	How EIL Accommodates 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 that will deliver the returns and Service Level maximised within those constraints accordingly..
Price	Price is a key means of both gathering revenue and signalling underlying costs. Getting prices wrong could result in levels of supply reliability that are less than or greater than what EIL's customers want.	EIL's total revenue is constrained by the price path threshold regime. Prices will be restrained to within the limits prescribed by the price path threshold, unless doing so would comprise 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 intended to be cost-reflective, but issues such as the Low Fixed Charges requirements can distort this.

Interest	Description	How EIL Accommodates Interests
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 within touching distance of the ground is earthed. The safety of staff and contractors is ensured by providing all necessary equipment, improving safe work practices and ensuring that they are stood 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.

EIL's commercial goal is to deliver a sustainable earnings stream to their shareholder Invercargill City Holdings that is the best use of their funds. This creates a primary driver for EIL and formal accountabilities to the shareholder are in place for financial and network performance. See section Key Planning Docs (Statement of Intent).

Customers via the electricity retailers provide EIL's revenue in return for the services provided by the EIL network assets. Due to the importance EIL places on meeting customer's expectations annual customer surveys are undertaken to monitor customer satisfaction, with service level targets set to ensure standards are maintained or improved. See sections Service Levels and Performance for details of these surveys, customer feedback and performance targets EIL sets.

EIL is also subject to the requirement to compile and publically disclose performance and planning information (including the requirement to publish an AMP) and EIL is subject to price and quality regulations which guide prices and require no material decline in network reliability measures. These requirements are established under Part 4 of the Commerce Act 1986.

EIL is also subject to regulatory restrictions on generating and retailing energy established under the Electricity Industry Act 2010 and requirements for the connection of distributed generation established under the Electricity Industry Participation Code. Electricity lines businesses are being increasingly required to give effect to many aspects of government policy.

Managing Conflicting Stakeholder Interests

When a conflict of stakeholder interests has been identified EIL must arrive at an appropriate resolution. To achieve this outcome the following priority hierarchy is used to analyse the conflicting issues and options available:

1. **Safety**. Top priority is given to safety. The safety of staff, contractors and the public is of paramount importance and is given an exceptionally heavy weighting in asset management decisions.
2. **Viability**. Second priority is viability (as defined above), because without it EIL would cease to exist, making 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**. 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.

Once an appropriate resolution has been determined a recommendation will be presented to management. A decision may then be made by the management team or escalated to the EIL Board if appropriate.

Other Influences

There are several other issues that are not directly related to stakeholders but have a significant impact on EIL's asset management practice, and strategies may be developed to effectively manage these issues. These issues are as follows:

- Competitive pressures from other lines companies that might try to supply EIL customers.
- Pressure from substitute energy sources at end-user level (such as substituting electricity with coal or oil at a facility level) or by offsetting load with distributed generation.
- Advancing technologies such as solar generation coupled with battery storage, which could potentially strand conventional wire utilities.
- Local, national and global economic cycles which affect 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.
- Technical regulations including such matters as limiting harmonics to specified levels.
- Safety requirements such as earthing of exposed metal and line clearances.
- Asset configuration, condition and deterioration. These parameters will significantly limit the rate at which EIL can re-align their large and complex asset base to fit ever-changing strategic goals.
- Physical risk exposures: exposure to events such as flooding, wind, snow, earthquakes and vehicle impacts.
- Regulatory issues: for example if the transport agency required all poles to be moved back from the carriage way.

1.6. Strategy and Delivery

EIL's vision, corporate strategies and asset management strategies have been designed to accommodate the interests and expectations of the various stakeholders while recognising the need to work within constraints imposed by both stakeholders and the wider issues that affect asset management. Managing conflicts between stakeholders and managing numerous risks to the business are also recognised.

Vision Statement

To be one of the top performing New Zealand electricity distribution businesses, with an integrated investment portfolio.

Corporate Strategy

Key corporate drivers from EIL's Strategic Plan are:

- Manage operations in a progressive and commercial manner
- Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value
- Provide its customers with reliable and affordable service
- Understand and effectively manage appreciable business risk
- Strive to be an efficient but effective operation
- Pursue alternative technologies and energy forms within the current regulatory requirements

Asset Management Strategy

EIL's asset management strategy follows these guiding principles:

- 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

Interaction of Goals/Strategies

EIL's vision underpins both Corporate and Asset Management Strategies with linkage between these strategies shown in Table 4.

Table 4: Corporate and Asset Management Strategy Linkage

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		✓			✓
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		✓	✓		✓

1.7. Key Planning Documents

In addition to the AMP the following documents are produced annually by PowerNet on EIL's behalf and approved by EIL as part of the company's planning processes.

Annual Works Programme

The Annual Works Programme (AWP) is produced as part of the AMP development process and is included in the AMP's development and lifecycle planning sections. It covers the same ten year planning horizon and lists the works to be undertaken for each financial year.

The AWP details the scope for each activity or project identified, sets the associated budget for the first year and forecasts expenditure for future years. Critical activities are to firstly ensure that this annual works program accurately reflects the projects in the AMP and secondly to ensure that each project is implemented according to the scope prescribed in the works program. Ensuring the AWP is achievable requires careful consideration of the available workforce and management capabilities which is discussed further in Capability to Deliver.

Annual Business Plan

Each year, the first three years of the AMP is consolidated with any recent strategic, commercial, asset or operational issues into EIL's Annual Business Plan (ABP). The AWP for the three years ahead is an important component of the ABP.

The ABP defines the priorities and actions for the year ahead which will contribute to EIL's long-term alignment with their vision, objectives and strategies, while fully understanding that this alignment process must at times cater for "moving goal posts". The ABP contains the following:

- Core Business, Vision Statement and Critical Success Factors
- Commercial Objectives, The Nature and Scope of Commercial Activity and Company Policies
- Annual Works Programme (first three years)
- Business Plan Financials and Business Unit Reports

Progress updates are reported monthly to assist in monitoring of performance and delivery to plan.

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. EIL's corporate strategies gain shareholder approval via the SOI.

The SOI includes financial performance projections for:

- EBIT% (Percentage Group Earnings Before Tax and Interest on Assets Employed),
- NPAT% (Percentage Group Tax Paid Profit on Equity) and
- Percentage of Consolidated Equity to Total Assets

It also includes the quality performance projections for SAIFI and SAIDI which are set in the AMP Proposed Service Levels.

These projections are given over a three year period, 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 in the Line Owners area under Electricity Invercargill Limited, Company Information.

1.8. Interaction between Objectives, Drivers, Strategies and Key Documents

The interaction between EIL's corporate vision, asset management objectives, business drivers, strategies and key planning documents is shown in Figure 1 and is summarised as follows.

The vision leads to the objectives for EIL's asset management processes. These asset management processes are documented in the AMP which serves as a guidance and communication mechanism ensuring understanding and consistency within EIL's asset management company PowerNet and for the EIL board.

The asset management strategies are designed to provide guidance in achieving the asset management objectives while aligning with EIL's vision and corporate strategies. Stakeholder interests and expectations as well as other external influences create business drivers which shape the strategies developed. They also shape the asset management objectives and the corporate vision, however these tend to remain relatively consistent whereas strategies tend to be more flexible and evolve as the driving factors change with time.

The asset management strategies are applied to the existing network assets to meet the asset management objectives including realising development opportunities as they arise. This involves the setting of performance targets which leads the AWP development.

The AMP (and especially the AWP incorporated into the AMP) sets and drives asset management works and expenditure to reshape network assets, and is prepared in a format that assists communication of the key deliverables. Delivery of the AWP projects over time creates a network closely aligned with the asset management strategies, objectives and EIL's corporate vision whilst meeting stakeholder expectations, in particular those of the shareholder and network customers.

Capital expenditure budgets and performance targets from the AMP and the AWP are incorporated into the ABP; these together with any wider business issues provide the overall business planning summary used by the wider management team and EIL Board. The SOI incorporates performance targets (including key asset management targets) from the AWP, forming the accountability mechanism between the EIL Board and the shareholder.

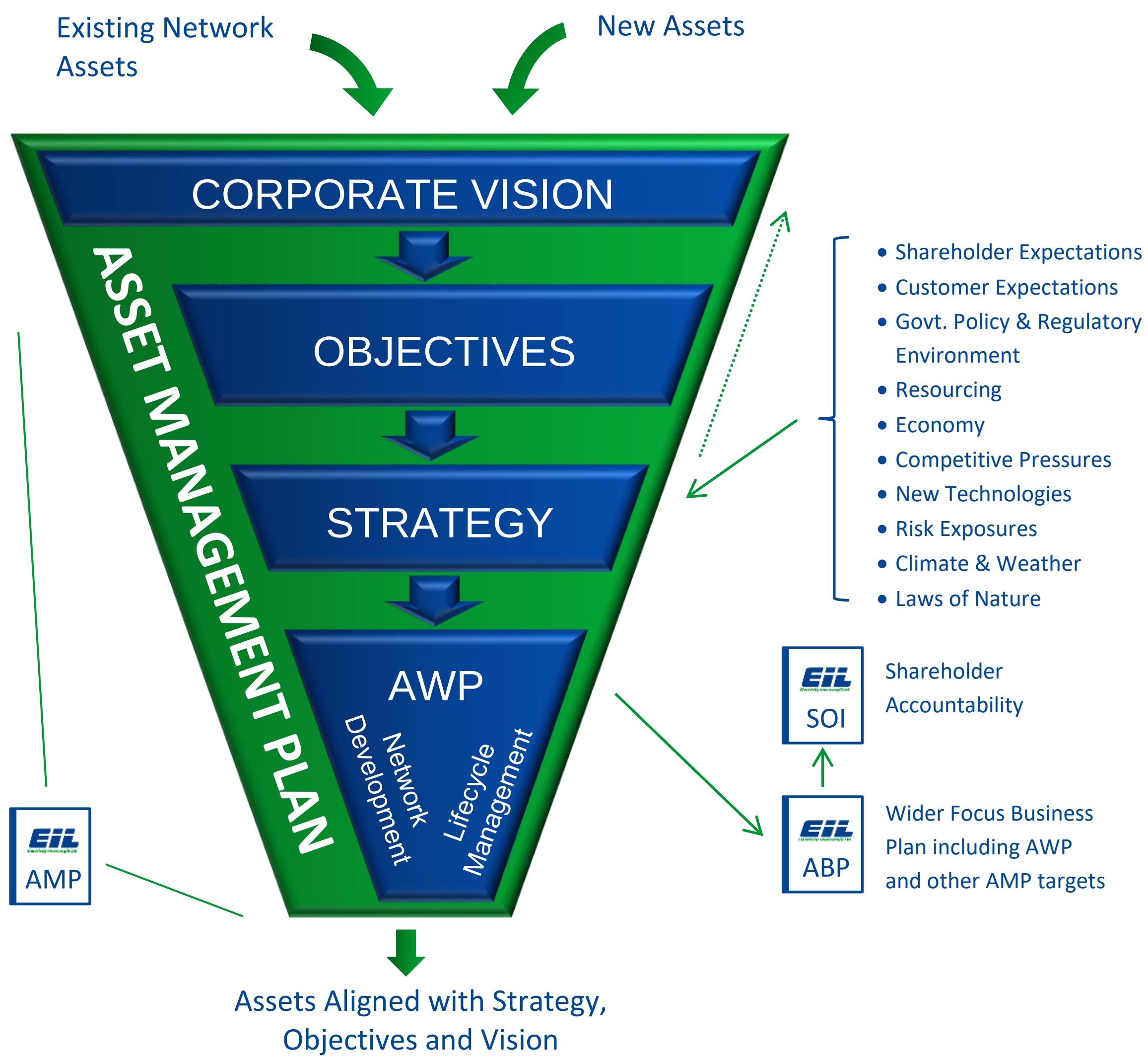


Figure 1: Interaction of Objective, Strategies and Key Plans

1.9. Systems and Information Management

EIL has a variety of information management tools which capture asset data and can be used to aggregate this data into summary information. A summary of the key data repositories is shown in Table 5.

Table 5: Key Data Repositories

Information System	Data Type	Data Source
Asset Management System (AMS – Maximo)	Description, Age, Condition	Network Equipment Movement (NEM)Forms, Field Survey, Supplier Data, Commissioning Records, Test Records,
Geographic Information System (GIS)	Location, Age, Connectivity	As-built information, Roading Authorities, Land Surveys
SCADA	Switch Status, Loading	Polled devices
PowerNet Connect	Customer Details	MARIA registry, GIS
PowerNet Connect	Customer calls regarding faults	Customer calls to System Control
Outage Reporting System	Regulatory recording of outages SAIDI & SAIFI	System Outage Logs
Defect Database	Equipment failures	System Control, Reports from field staff, Project Managers
Risk Manager	Risk management information	System Control and Staff

Data completeness is generally good with a summary of completeness and noted limitations provided in Table 6.

Table 6: Knowledge Completeness

System	Parameter	Completeness	Notes
GIS	Description	Good	Some delays between job completion and GIS update, some cable size/types unknown
GIS	Location	Excellent	Some delays between job completion and GIS update
GIS	Age	Reasonable	Equipment ages include some estimate by type (era of manufacture)
Condition Assessment Database	Condition	Okay	Regular inspections but some subjectivity and condition data not updated with repair
AMS	Description	Okay	Some delays between job completion and Maximo update
AMS	Details	Okay	Some delays between job completion and Maximo update
AMS	Age	Okay	Missing age on old components, mix of installation and manufacturing dates used as age estimate
AMS	Condition	Poor	Some condition monitoring data (DGA)
SCADA	Zone Substations	Excellent	All monitored
SCADA	Field Devices	Good	Monitoring and automation increasing

1.10. Accountabilities and Responsibilities

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 (as at 31 March 2020) has five directors:

- Brian Wood (Chair)
- Graham Lewis
- Tim Loan
- Darren Ludlow
- Lindsay Thomas

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

Accountability at Governance Level

EIL's use of PowerNet as their contracted asset management company effectively creates a two-tier governance structure. 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 (as at 31 March 2020) has four directors:

- Tom Campbell (Chair)
- Sarah Brown
- Joe O'Connell
- Paul Kiesanowski

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

Any new project over $100,000 added will need to gain approval from the EIL Board. Large projects with capital budgets exceeding $1,000,000 are required to be supported by a business case explaining the project scope and justification. The business case will generally include a detailed cost-benefit and risk analysis of the recommended scope over alternative options. The business case will form an integral part of the project Charter and staged gate approval process. Variations to projects already in the approved AWP (by more than +10% or -30%), are reported to the Board on a monthly basis.

Accountability at Executive Level

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.

Accountability at Management Level

There are seven 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 is the Chief Engineer, through his responsibility for preparation of the AMP which guides the nature and direction of the other managers' work.

Accountability at Operational Level

PowerNet's Network Assets and Major Projects Team (under the Chief Engineer), Operations (Technical) Team and Operations (Distribution) Team each manage their respective major projects, technical projects and distribution projects which make up the AWP. Their objectives are to deliver the AWP projects on time, to scope and to budget while also delivering to the AWP works category and overall CAPEX and OPEX budgets. Major projects typically utilise external consultants and contractors while technical and distribution projects utilise PowerNet's in-house field services.

Where 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 schedule.

Accountability at Work-face Level

PowerNet's internal field staff are managed within PowerNet's Operations Team to deliver work divided into technical and distribution projects. External contractors are used for vegetation management (Asplundh) and communications network maintenance and projects (Broadspectrum). Civil works including cable trenching and earthworks for zone substations are typically completed by external contractors. External contractors are typically used to deliver major projects and occasionally when necessary to supplement workforce capacity or skillsets and include:

- DECOM Limited
- Broadspectrum Limited
- Electrix Limited
- Peak Power Services Limited
- Local Electrical Inspectors (M Jarvis, I Sinclair, W Harper)
- Asplundh Tree Expert (NZ) Limited
- Corys Limited
- Consultants (Beca, Edison, Mitton Electronet, ProTechtion Consulting, Mitchell Daysh, Ergo Consulting)

The principal accountability mechanism when utilising these external contractors is through contracts that reflect the outcomes PowerNet must create for EIL.

Key Reporting Lines

EIL's ownership, governance and management structure is depicted in Figure 2:

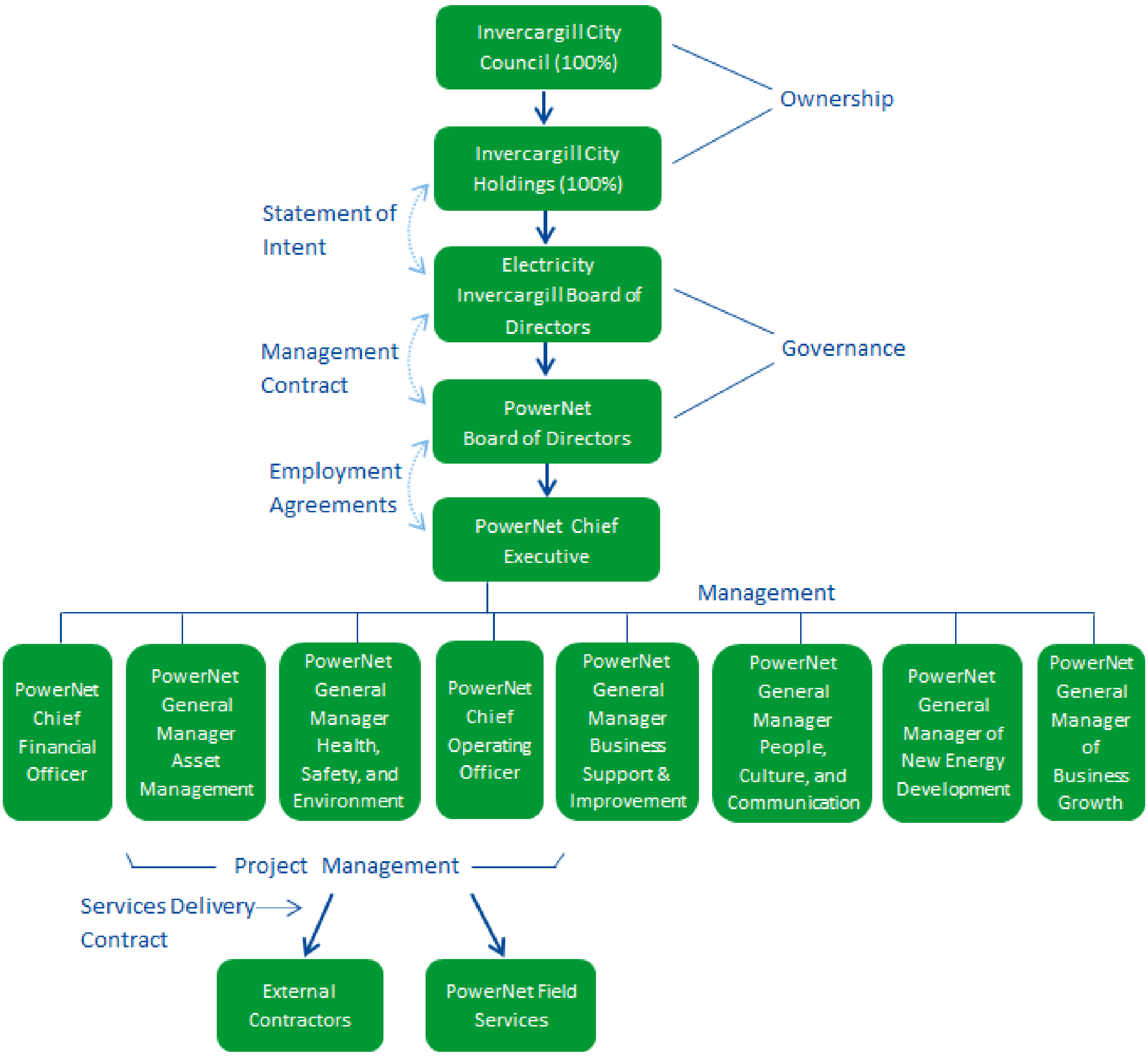


Figure 2: Governance and management accountabilities

The EIL Board receives monthly 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 supply quality 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 line charges received
- Retailer activity – detail on volumes and numbers per energy retailer operating on the network
- Works Programme – Summary expenditure actuals and forecasts by works programme category with notes on major variations

Each level of management has defined financial authority limits set out in the PowerNet Financial Authorities Policy. It includes general financial authority levels and increased levels specifically for project work previously approved in the AWP. Generally most projects in the AWP are approved by the EIL Board as part of ABP process in the previous year.

1.11. AMP Communication and Participation Processes

A first draft of the AMP is generally created by November each year and is circulated around management for review and comment. The AWP is developed concurrently as part of the AMP process and has generally been through several revisions by the time it is circulated with the first AMP draft.

Customer perceptions and expectations gauged from surveys and customer consultation evenings are compared with the performance targets set in the previous year's AMP. Any improvements or changes deemed appropriate from this process will be incorporated into the AMP and AWP as necessary.

Management and Operations Participation

The planning team is in regular contact throughout the year with those responsible for implementing the current AWP to monitor progress and any variations as they arise with large capital projects covered in a formal monthly review meeting. Any changes are consolidated into the initial AWP revision and further revisions are developed in consultation with the management, project managers and field staff who will be involved in its implementation.

Through this consultation the costs and resources for the desired work in the year ahead are estimated. The process tends to be iterative with a level of trade-off reached between what is considered an optimal level of works against realistic expectations of the work force available. "Smoothing" of the year to year works variations is utilised to keep a relatively constant and manageable work stream for both internal and external workforce resources; however longer term variations need to be met by adjusting the resources available. Additionally this process tends to be one of moving goal posts as variations generally need to be accounted for up until the information disclosure date.

Governance Participation

The initial consolidated AWP is submitted to the EIL Board supported by a presentation. Any business cases required for large capital projects or other papers covering any novel projects are submitted in advance and will be included in the AWP presentation. After their initial review the Board may request clarifications or changes which are then incorporated into the AWP. These changes tend to be more commercially motivated but will also recognise the need to address any identified health and safety related issues as a high priority. Any recommended changes to the wider AMP that the Board may need to consider, for example strategy updates, may be presented at this stage for review.

The AMP is then updated to reflect changes to the AWP (development planning and lifecycle management) incorporating any other changes required by management before being submitted in full to the EIL Board for review in February. The Board may request further changes to be completed before giving final approval for disclosure at the end of March.

Post Disclosure Communication

Once the AMP has been finalised and publically disclosed, project scopes are produced for non-routine projects that will be initiated in the next year. These scopes are passed to the relevant project managers to ensure that sufficient detail has been provided for each project in the AWP to proceed in line with the planner's expectation.

An initial communication meeting is held with internal field staff and key contractors invited to highlight the body of work for the year ahead, especially large or crucial projects. Future years as set out in the AMP are also presented to assist contractors in preparing their resources and their ability to compete for any tendered work in the short to medium term.

Planners are in contact with the project managers throughout the year to monitor progression of the AWP and ensure agreement on any significant variations as design and implementation progresses.

1.12. Assumptions

Planning is based on the assumption that the scenario considered most likely will eventuate, except for ongoing but sporadic (typically reactive) work, where budgets reflect a longer term average. This philosophy is used to minimise variation to performance targets (especially financial) including average performance over the short to medium term. Exceptions are made where the consequences of this assumption are asymmetric – for example building additional capacity early results in a slight overinvestment, whereas building additional capacity too late may have much greater consequences such as equipment damage or inability to supply customer load.

The standard life of assets is based on the Commerce Commission's Optimised Deprival Valuation (ODV) asset life, with actual replacement done based on condition, and economic life and work efficiency. Equipment housed indoors will often exceed ODV life, whereas in the harsh coastal environment assets tend to have a shorter life.

No significant change in present regulation other than the recent default price-quality path is anticipated. (This is briefly discussed section 1.2). Any changes are likely to add additional cost. For example, outages less than one minute are not recorded against reliability KPIs; this allows a lower cost network automation solution which would be less appropriate if the one minute allowance were removed.

Project costs and timeframes are estimated based on previous experience and anticipated resourcing. Other than the disclosure schedules included in Appendix 3, all figures are represented as constant 2020 dollars and assume no significant variation in exchange rates where applicable.

Assumption	Discussion & Implications
Demand growth tracks close to projected rates Demand growth rates (including effects of generation) are discussed in Forecasting Demand and Constraints. The drivers of future demand described are as per the most likely scenario and this section discusses how EIL manages the risk of different patterns of growth eventuating.	Actual future demands may depart significantly from forecasts. Prediction of demand growth based on "ground-up" analysis is uncertain, due to limited visibility of many variables. Declining growth rates mean that investments to accommodate previously projected growth are deferred. Higher growth rates require adjustment in EIL's resourcing and/or work scheduling to be able to respond to these opportunities. Visibility is often limited to the near term, particularly for large commercial developments.

Assumption	Discussion & Implications
	De-carbonation of large plants are treated on an individual basis and accommodated within contingency plans and projects.
Distributed generation is expected to have little coincidence with network peak demand, and therefore will have little impact on network configuration within the ten year planning horizon	Increased injection of generation, especially during periods of low demand, could create voltage issues. Increased connection requests for distributed generation will require increased resourcing to analyse potential issues arising from connection (particularly safety and voltage)
Electric vehicle adoption rate within forecast, and that consumers will respond well to price signals such that vehicle charging occurs off-peak	Potential to have large impact on network demand with sufficient adoption. If consumers do not respond well to price signals, electric vehicle charging may exacerbate peak demand, triggering greater investment. This effect will be greatest on the LV network where issues are more likely due to lower diversity, and are more difficult to predict.
Service life of assets, tend towards expected life for the asset type and operating environment	Long term projected service life of asset fleets is based on expected service life for the asset type, operating environment, expected duty, and maintenance practices. Actual replacement and maintenance works are programmed on a near term basis; and are driven by condition and safety for the specific asset. More benign operating environment may increase service life. Investment may be deferred if condition analysis provides reasonable certainty of extended asset life. Harsher environment and/or greater operating duty tends to shorten asset life, requiring consideration for earlier replacement.
No material deviation from historical failure rates	Deterioration of asset reliability compared to expected failure rates, would require accelerated asset replacement (to maintain service levels to customer expectations)
Resourcing is sufficient for projected works programme	Considerable effort has been made to ensure work volumes are deliverable by our key providers. However, unanticipated labour constraints may cause works to be delayed, and/or labour costs to rise.
Little change in safety & work practice regulations	Increases in health & safety requirements will have corresponding increases in cost of works
Inflation for electricity industry input costs track close to expected (CPI forecasts by Treasury, where specific forecasts unavailable)	Deviation from expected material, labour, overhead input costs, will result in increased costs to works programmes. The projected treatment of network constraints may change, depending on the specific changes to each input cost factor.
Future technologies that may impact work methodologies are not priced into cost estimates	Planning for the inclusion of, currently non-commercial or uneconomic technologies is considered to be imprudent, due to uncertainty of timing, costs, and impacts. Cost savings may occur if technologies develop to a stage where implementation is feasible and economic.

Assumption	Discussion & Implications
No significant changes in national energy policy	Changes to current national energy policy may affect consumer and/or industry behaviour in such a way that EIL investments decisions become un-economic.
No significant changes to the shift towards cost-reflective pricing	The Electricity Authority has, in recent publications, signalled an expectation for electricity distributors to progress towards more service-based and cost-reflective pricing. Challenges, from external parties, to pricing reform may cause currently proposed investments to be reconsidered. Changes in low usage fixed charge will not affect total revenue.
No significant changes to requirements regarding resource consenting, easements, land access (private, commercial, local and national authorities)	Increasing requirements are likely to result in increased costs.
No material change to customer expectations of service levels	Changes to customer expectations will require adjustment to service levels and subsequent investments.
No significant changes to local and/or national government development policies	Developmental policies have the potential to affect aggregate and local demand. Investment levels will be adjusted to suit.
Improving industry co-operation	Deterioration in industry co-operation may result in duplicated efforts, mis-coordination, and higher costs.
Cost impact of equipment size step changes are assumed to remain minor with labour cost being a large proportion of works.	Historic trend expected to continue.
No step changes in underlying growth are considered likely based on historical trending over a long period. Population growth for sizing of equipment is based on the high projection.	Lower population growth may result in some equipment being oversized. Likely impact on total project cost is minor. Higher population growth may initiate capacity improvement works earlier.
Abnormal price movements caused by major external events (war, terrorism, union action, natural disaster) affecting pricing of equipment or labour substantially are difficult to predict and not allowed for in estimates.	These major external events are unable to be predicted with any certainty and EIL must react accordingly to any changes.
The current line pricing methodology combines a fixed daily charge and a charge per kWh. The line pricing methodology is currently under review. Until the changes have been defined it is difficult to determine the effect any such changes in line pricing will have on consumer behaviour. Therefore, demand forecasts reflect the status quo	Actual future demands may depart significantly from forecasts. Prediction of demand growth is uncertain due to changing line pricing methodology. Declining growth rates mean that investments to accommodate previously projected growth are deferred. Higher growth rates require adjustment in EIL's resourcing and/or work scheduling to be able to respond to these

Assumption	Discussion & Implications
for line pricing, whilst acknowledging that the future line pricing methodology and subsequent consumer behaviour may impact on these forecasts.	opportunities. Visibility is often limited to the near term, particularly for large commercial developments.

1.13. Potential Variation Factors

The following factors have the potential to cause significant variation between the forecasts set out in this AMP and the actual information that will be disclosed in future disclosures:

Cause of variation	Implications
Cost and time estimate inaccuracies	Project cost increase. Timing may vary, resulting in lower work efficiencies. These may trigger review of project approval if variations are sufficiently large.
Variation in inflation rates and exchange rates	Higher input costs than forecast
Staffing resource losses or inability to recruit as required	Higher cost to be able to meet staffing level required to complete works. This may be coupled with deferment of investment programme, or outright cancellation of certain works if issues become ongoing.
Reactive work varying from that estimated	Deferment of capital or planned maintenance work, if those works are dependent on the asset being in-service. Deferment of capital or planned maintenance work may also arise from staff resourcing constraints.
Equipment failure (especially large capital plant) which may influence future economic options	Greater replacement costs for unplanned failure. Greater costs to maintain supply to customers, until replacement. Review of equipment selection and work methodologies.
New safety issues identified and initiatives created	Higher labour or material costs. Triggers reviews of work methodologies on existing scheduled works.
Reprioritisation of projects as new work activities are identified	Increased scope, scheduling, design, planning costs if not communicated sufficiently ahead of time. Also requires revision of longer term investment programme.
Detailed analysis of the available options for projects commencing in the short to medium term, which may indicate an alternative approach is preferable to that assumed for long-range forecasting	Similar implications compared to if new work activities are identified.
Greater demand growth than anticipated levels, especially new large industry or customers	May cause certain capital investments to be accelerated, or advanced. May constrain staffing resources.
Lower demand growth than anticipated levels, especially loss of existing industry or customers	May cause certain capital investments to be deferred, or cancelled.

2. Assets Covered

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

2.1. Service Areas

EIL's service area includes two geographically separate areas:

- 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, as shown in Figure 3.
- The borough of Bluff extending as far west as the former Ocean Beach freezing works, as shown in Figure 4.

Note for the purposes of information disclosure Bluff, having less than 25km of distribution lines and less than 2000 ICPs connected, is not considered a sub-network and therefore values presented in this AMP for EIL are inclusive of the Bluff area network except where stated otherwise.

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.

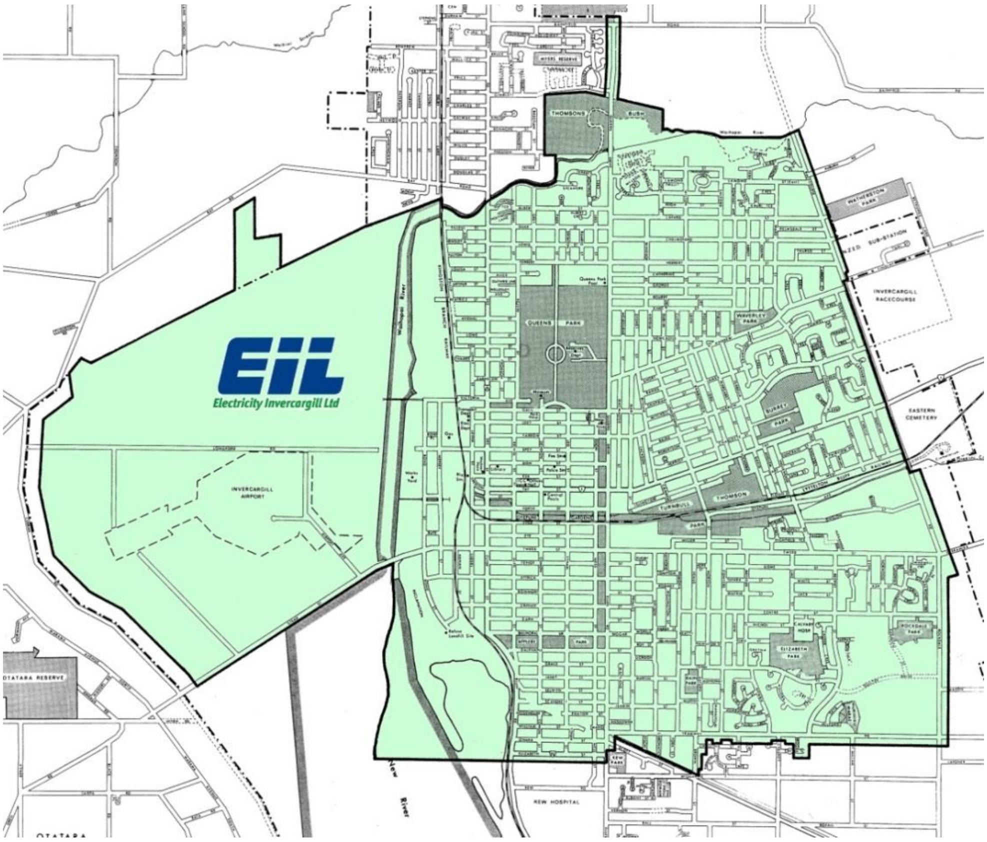


Figure 3: EIL Invercargill Distribution Area

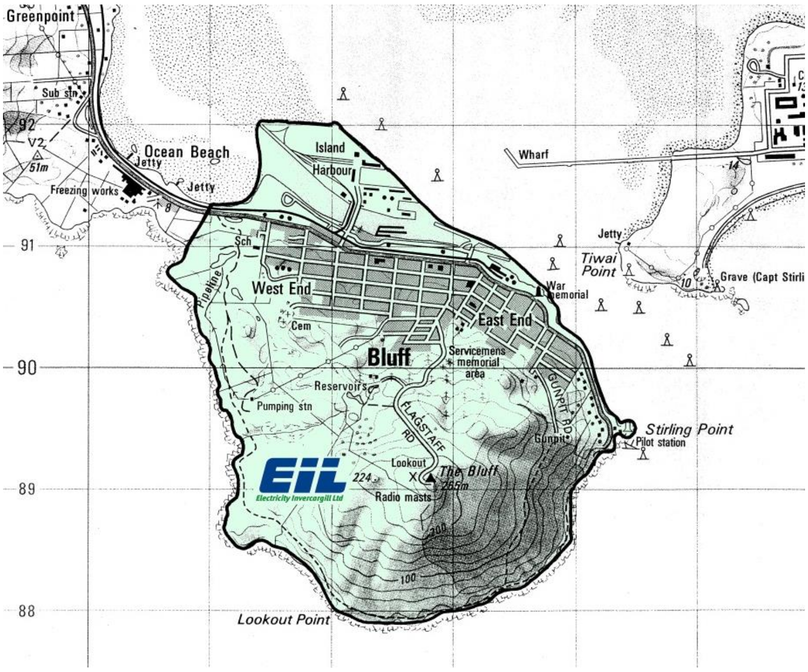


Figure 4: EIL Bluff Distribution Area

Key Industries

EIL's largest customer is a large port in the Bluff distribution area which regularly peaks at about 1.6 MW and consumes approximately 6.5 GWh 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.

Load Characteristics

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. A typical daily domestic load profile and a typical annual domestic load profile are shown in Figure 5 and Figure 6 respectively.

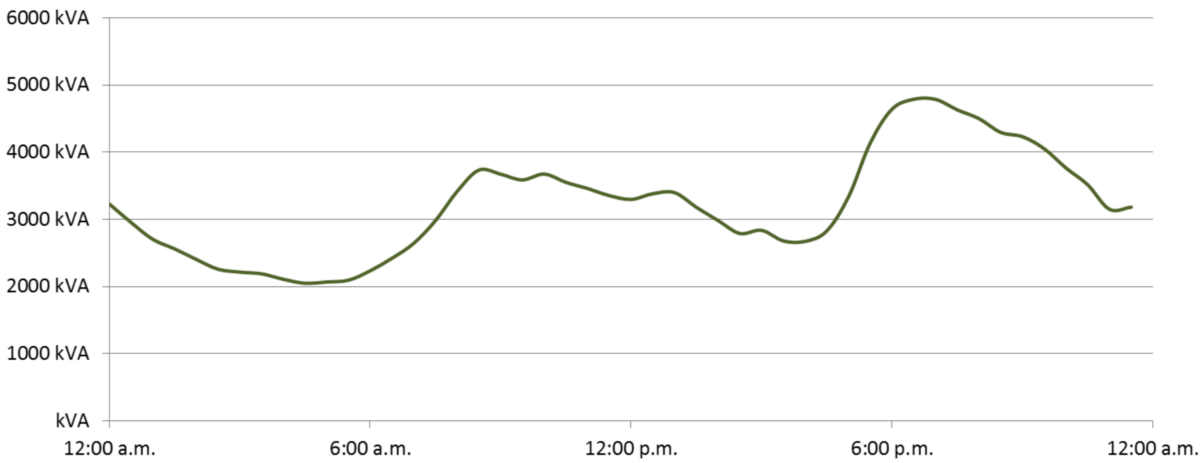


Figure 5: Typical Domestic Feeder Daily Load Profile (July, Racecourse Road CB8)

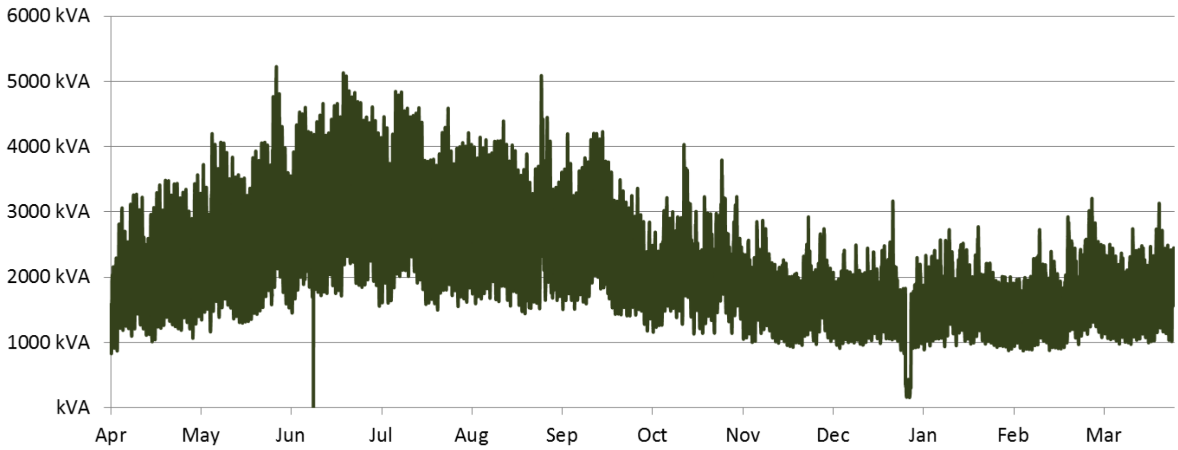


Figure 6: Typical Domestic Feeder Yearly Load Profile (Racecourse Road CB8)

CBD: Load peaks in the CBD later in the day (10am-12pm) 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 7 and Figure 8 include some industrial load which tends to follow similar consumption patterns.

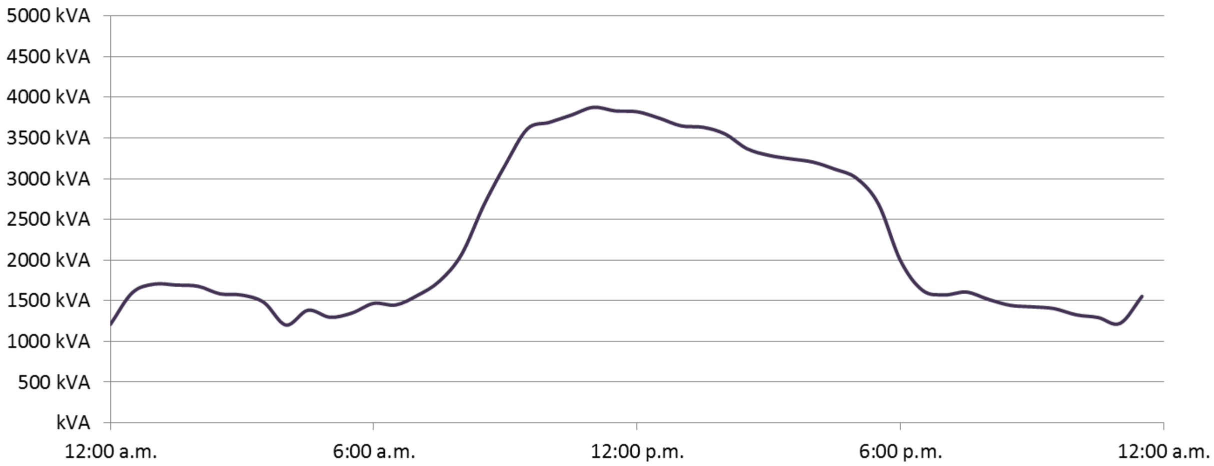


Figure 7: Typical CBD Feeder Daily Load Profile (July, Leven Street CB10)

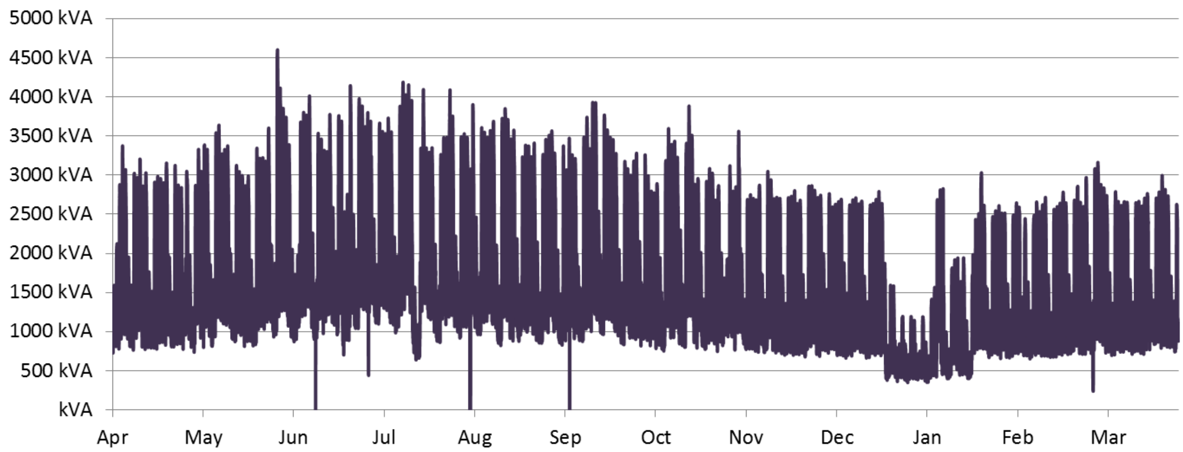


Figure 8: Typical CBD Feeder Yearly Load Profile (Leven Street CB10)

Energy and Demand Characteristics

Key energy and demand figures for the year ending 31 March 2019 are as shown in Table 5.

Table 5: Energy and Demand

Parameter	Value	Long-term trend
Energy Conveyed	267 GWh	Variation around minimal growth
Maximum Demand[1]	63 MW	Large variation around minimal growth
Load Factor	48%	Reasonably constant
Losses	4.9%	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.

[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.

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 give variable results due to the large influence of each particular calendar year, while longer time periods do not account for recent trends. Growth rates therefore tend to reflect an educated estimate on the part of the planning engineer, and accordingly certainty with the growth rates shown in Table 5 is low. Forecasting Demand and Constraints examines the analysis, trending, and forecast of growth for EIL.

2.2. Network Configuration

To supply EIL's 17,417 customers EIL owns and operates two electrically separate networks that are both supplied by the Grid Exit Point (GXP) at Invercargill. The Bluff network comprises two 11 kV feeders supplied by TPCL's zone substation situated just west of Bluff Township. EIL also owns interconnectors to TPCL's Otatara and Seaward Bush 33 kV lines that provide alternative supplies to the Leven Street and Southern zone substations respectively.

Bulk Supply Points and Embedded Generation

Invercargill GXP comprises a strong point in the 220 kV 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 Aluminium Smelter.

The 33 kV supply arrangement at Invercargill comprises an indoor switchboard that is energised by two three-phase 120MVA 220/33 kV transformers. There are eleven 33 kV 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 33 kV line (but not the circuit breakers or bus) that run within the GXP land area and also accommodates a backup control room for PowerNet's System Control. EIL also owns one of the two 33 kV 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.

Table 6: EIL Bulk Supply Characteristics

	Voltage	Rating	Firm Rating	Maximum Demand 2018/19	LSI* Coincident Demand 2018/19
Invercargill GXP	220/33 kV	210 MVA	141.8 MVA	96.49 MW (09:00 01/06/2018)	77.25 MW (07:30 06/08/2018)
EIL	*(GXP assets shared with TPCL)*			63.07 MW (09:00 01/06/2018)	48.39 MW (07:30 06/08/2018)

*LSI = Lower South Island

There is no significant generation embedded within EIL's network, but the wind farm at Flat Hill near Bluff (installed 6.8 MW capacity) is connected at TPCL's Bluff substation, from which the Bluff area network takes its supply. A small number of distributed generation connections exist but are only a few kW each in size. These generators are generally installations which due to their generation profiles (tied to sunlight conditions) have negligible effect on GXP loading.

Subtransmission

EIL's subtransmission network is a single electrically connected 33 kV network that takes supply from a single GXP at Invercargill and can take emergency supply from the North Makarewa GXP through TPCL's 33 kV network as depicted in Figure 9.

Note that EIL's two Bluff 11 kV feeders are supplied from TPCL's 33 kV subtransmission network. EIL's subtransmission network comprises 1.4 km of 33 kV line and 26.8 km of 33 kV cable and has the following characteristics:

- Two points of interconnection with TPCL's 33 kV 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 300 m long) and in the middle of the tie between Leven Street zone substation and TPCL's Otatara 33 kV feeder.
- It is predominately a ring topology except for Racecourse Road which is a spur.

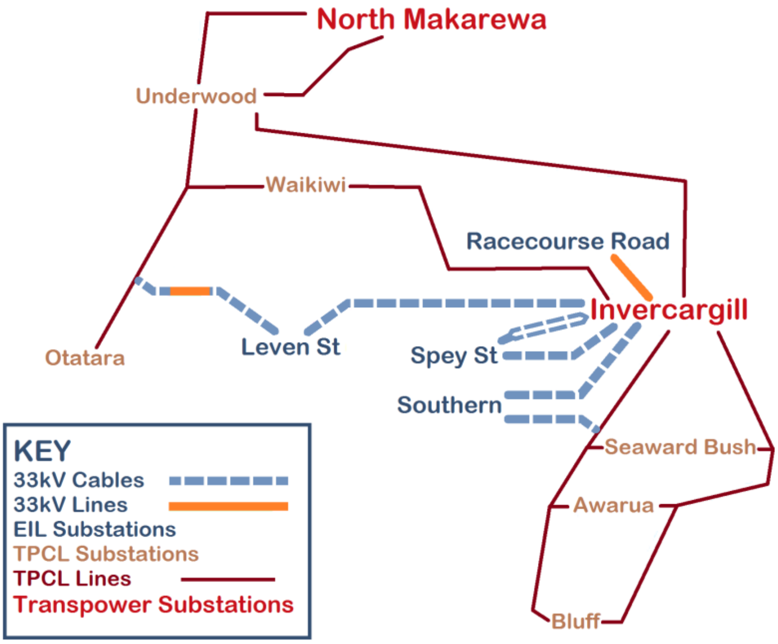


Figure 9: Subtransmission network

Zone Substations

EIL currently owns and operates four zone substations in Invercargill which have either AA or AAA security levels (see Development Criteria for security level definitions) however the Bluff network area also takes an 11 kV supply from a TPCL owned substation. Descriptions for EIL's zone substations are given in Table 7.

Table 7: EIL's Zone Substations

Substation	Nature of load	Description	Supply security
Spey Street	CBD, Urban Residential	Spey Street is a modern urban substation with dual transformers providing a capacity of 72 MVA and a firm rating of 36 MVA. This substation was constructed as a relocation and replacement for the Doon Street substation which had many assets at end of life and was at risk of third party damage from a potential earthquake. It is a fully indoor site built to blend inconspicuously into its semi-commercial environment. The substation is supplied via a new 33 kV XLPE cable and a second cable feeder consisting of the oil filled cables (that previously supplied Doon Street) paralleled and extended with a new 33 kV XLPE cable to Spey street. The 11 kV switchboard has 12 feeders and is split by two bus coupler circuit breakers, with each half located in separate fire rated rooms for added security.	AAA
Leven Street	CBD, Heavy Industrial, Urban Residential	Leven Street is an urban substation with dual transformers providing a capacity of 46MVA and a firm rating of 23MVA. It is supplied by a single 33 kV XLPE cable from Invercargill GXP but has an alternative 33 kV supply from TPCL's Otatara 33 kV feeder (which can be supplied from an alternative GXP). This alternative supply achieves the necessary AAA security for the substation however due to its supply being from another GXP the 33 kV back-feed cannot be 'normally in service' and therefore a short interruption (i.e. break before make) has to be accepted. The 11kV switchboard has 9 feeders and is split by a bus coupler circuit breaker.	AAA
Southern	Urban Residential, Light Industrial	Southern is an urban substation with a single transformer providing 23 MVA capacity. It is supplied by a single 33 kV oil filled cable from Invercargill GXP. An alternative 33 kV supply is available from TPCL's Seaward Bush 33 kV feeder as backup if required. The 11kV switchboard has 5 feeders, one of those feeders is split from the other by a bus coupler circuit breaker.	AA
Racecourse Road	Urban Residential, Rural Residential	Racecourse Road is an urban substation with a single transformer providing 23 MVA capacity. It is supplied by a short 33 kV 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. The 11kV switchboard has 9 feeders and is split by a bus coupler circuit breaker.	AA
Bluff	Port, Heavy Industrial, CBD, Urban Residential	EIL's Bluff area is supplied from two metered 11 kV feeders from TPCL's Bluff substation to the North West of the town. Two other feeders are used as a supply to rural customers North of Bluff and as a connection point for Southern Generation's Flat Hill Windfarm. The Bluff substation has two transformers providing a capacity of 26 MVA and a firm rating of 13 MVA. Bluff substation is supplied from two 33 kV overhead lines from Invercargill GXP via TPCL's Colyer Road substation. The size of the total load on the Bluff substation is technically only large enough to justify AA security, but due to the lack of 11 kV backup capacity, it is more economic to provide AAA security at the site.	AAA

Distribution Network

The 11 kV distribution network is heavily meshed throughout the entire Invercargill area, with almost all distribution transformers having two separate 11 kV supplies. In the CBD most supplies to each transformer are protected by 'Solkor' unit protection. Distribution in Bluff is largely meshed except at feeder extremities.

The 11 kV distribution network construction is as follows:

- All underground cable within the Invercargill CBD. Cable type (PILC – Paper Insulated Lead Covered, or XLPE – Cross-Linked Polyethylene) largely depends on date of installation.
- 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 less than 10 km of overhead construction that will remain overhead.
- Bluff is almost totally overhead construction due to the geological makeup of the area – shallow soil over rock substrata – which makes undergrounding difficult. The Bluff area was originally operated at 3.3 kV distribution, with conversion to 11 kV taking place after EIL took over the assets.

EIL's split of distribution network on a per substation basis is presented in Table 12. Safety and reliability are EIL's strongest drivers for allocation of resources, with customer density providing an indication of priority of other works.

Distribution Substations

Just as zone substation transformers form the interface between the subtransmission and the 11 kV distribution networks, distribution substations form the interface between the 11 kV distribution and 400 V distribution networks. The distribution substations range from a few remaining pole-mounted transformers to 3-phase 1,000 kVA ground-mounted transformers supplied via circuit breaker ring main units that may include 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 in vaults below pavements or road centre-plots, particularly in the CBD where land for ground mounted equipment was not available, although these are being replaced with above-ground sites. Table 13 shows distribution transformer quantities by rating.

Each distribution transformer has medium voltage (MV) protection, usually provided by fuses, although some larger units are protected by circuit breakers with basic overcurrent and earth fault relays. Generally individual protection is applied at each site, although 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 permitted.

Low voltage protection is by DIN[2] standard High Rupture Capacity (HRC) fuses sized to protect overload of the distribution transformer or outgoing LV cables.

[2] 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.

Low Voltage Network

The 230/400 V Low Voltage (LV) network almost totally overlays the 11 kV 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.

The LV 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.

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 LV reticulation on most 11 kV poles. Some undergrounding has occurred in a few locations.

Customer Connection Assets

EIL has 17,417 customer connections – for which revenue is earned for providing a connection to the network via the sixteen 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 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 8.

Table 8: Classes of Customer Connections

	Small (≤ 20 kVA)				Medium (21 – 99 kVA)				Large (≥100 kVA)			
	1 kVA 1ph	8 kVA 1ph	Low User	20 kVA 1ph	15 kVA 3ph	30 kVA 3ph	50 kVA 3ph	75 kVA 3ph	100kVA 3ph	Non ½hr Metered Individual	½hr Metered Individual	Total
Apr-18	50	334	5,706	9,816	73	674	390	133	75	52	127	**17,430**
May-18	50	331	5,807	9,699	73	674	389	133	75	52	127	**17,410**
Jun-18	50	331	5,827	6,693	74	675	391	133	75	52	127	**17,428**
Jul-18	50	330	5,831	9,685	74	675	391	132	73	51	128	**17,420**
Aug-18	50	327	5,849	9,682	74	674	392	131	71	51	128	**17,429**
Sep-18	50	327	5,852	9,676	72	673	392	132	71	51	128	**17,424**
Oct-18	50	326	5,849	9,671	72	672	393	133	72	51	127	**17,416**
Nov-18	50	323	5,858	9,655	74	671	390	133	71	51	128	**17,404**
Dec-18	50	326	5,851	9,685	75	670	391	132	71	51	128	**17,430**
Jan-19	50	325	5,870	9,658	76	668	389	132	71	50	128	**17,417**
Feb-19	50	330	5,903	9,631	75	666	387	132	71	50	126	**17,421**
Mar-19	50	322	6,245	9,295	75	668	384	132	70	50	126	**17,417**

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.

Other Assets

EIL has a range of other assets to provide control or other auxiliary functions as described in Table 9.

Table 9: EIL's Other Assets

Load Control Assets	
Ripple Injection Plant and Receivers	EIL currently owns and operates a 33 kV 216⅔Hz 125 kVA 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.
Protection and Control	
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	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 11 kV 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	Switches provide no protection function but allow simple manual operation to provide control or isolation. Some models of switch are 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, and so provide more economic but less convenient switch points.
Batteries and Chargers	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.
Voltage Regulating Relays	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.
Neutral Earthing Resistors (NERs)	Neutral Earthing Resistors (NERs) installed at zone substations limit earth fault currents on the 11kV network. These significantly reduce the earth potential rise which may appear on and around network equipment when an earth fault occurs.
SCADA and Communications	
SCADA Master Station	Supervisory Control and Data Acquisition (SCADA) is used for control and monitoring of zone substations and remote switching devices, and for activating load control plant EIL's SCADA is provided as a service by PowerNet Ltd, with the master station 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.
Communication Media	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. Fibre optics based communication is used to the newer Spey St zone substation.
Remote Terminal Units	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. Spey Street zone substation has a more modern SEL based RTU. There are eight GPT mini RTUs located in other distribution substations in the CBD communicating with HDLC protocol over 1200 baud modem.
Other Assets	
Generation	EIL do not own any mobile generation plant but may utilise three diesel generators owned by PowerNet. These are rated at 450 kW, 350 kW and at 220 kW. 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 3 MVA 11 kV regulator and circuit breaker with cable connections though it is unlikely to be required due to the excellent backup capability of the 11 kV network. EIL can utilise a TPCL owned trailer mounted 5 MVA 33/11 kV mobile substation with cable connections.
Metering	Most zone substations have time-of-use (TOU) meters on the incomers that provide details of energy flows and power factor.

2.3. Network Asset Details

The remainder of this section summarises key asset information that contributes to the long term lifecycle planning for EIL’s network.

Subtransmission Network

Basic details for EIL’s subtransmission circuits are shown in

Table 10. All circuits are 33 kV and operate within their respective ratings. Stated remaining lives are based on Optimised Deprival Valuation (ODV) standard lives; but in practice EIL subtransmission cables (being lightly loaded) are expected to last significantly longer than ODV standard life, and will be replaced on condition.

Table 10: Subtransmission Circuit Details

Location	Type	Length	Manufactured	Remaining Life	Condition
Invercargill GXP to Southern	Oil Cable	4.7 km	1968	18 yrs	Good, only lightly loaded.
Invercargill GXP to Doon Street ex T1	Oil Cable	3.5 km	1970	20 yrs	Good, moderately loaded.
Invercargill GXP to Doon Street ex T2	Oil Cable	3.5 km	1975	25 yrs	Good, moderately loaded.
Doon St to Spey St	XLPE Cable	0.6 km	2016	51 yrs	As new, lightly loaded.
Invercargill GXP to Spey Street	XLPE Cable	4.1 km	2015	50 yrs	As new, lightly loaded.
Invercargill GXP to Racecourse Road	O/H Line	0.3 km	1975	15 yrs	Good, short cross country, concrete poles.
Invercargill GXP to Leven Street	XLPE Cable	5.3 km	1983	8 yrs	Good, lightly loaded.
Seaward Bush Line to Southern	XLPE Cable	1.4 km	1999	34 yrs	Good, not normally loaded.
Otatara Line to Leven Street	XLPE Cable O/H Line	3.7 km 1.1 km	2000	35 yrs 25 yrs	Good, not normally loaded.

Subtransmission Cables

EIL has three oil filled cables taking supply from the Invercargill GXP substation, the oldest of which has approximately 18 years life remaining and is expected to be in sound condition. The oil cables supplying Southern substation operates up to half of its rating. The other two cables previously supplied Doon Street and operated up to half of their capacity. These cables have now been paralleled and extended with XLPE cable to supply Spey Street which has reduced typical loading to low levels.

There have been some concerns with the rating of the cables due to poor thermal resistivity backfill used. Temperature and thermal resistivity transducers were installed on the cables in 2015 to better understand their in-service capacity. The data to date indicates no concerns although the opportunity has not yet arisen to gather data during worst-case conditions, i.e. over an extended dry spell. Some minor maintenance work is required on the oil pressure and temperature monitors.

There is some concern over the integrity of the cable joints which have been found to be trending toward premature failure by other distribution companies. However, invasive exploration into the cables is likely to be uneconomic, and creates the risk of introducing defects. Supply risk has been mitigated through the installation of new XLPE cable in parallel to the oil-filled cables; all oil-filled cables on the network have an alternate supply option through an XLPE cable.

The other cables are XLPE cables, lightly loaded and in good condition. Some of these are unloaded cables used occasionally for backup. Earlier XLPE cables (pre-1985) have a shorter life expectancy, however for lightly loaded cables it is more appropriate to replace on condition than on age, particularly where a parallel supply option exists. Figure 10 shows the commissioning year and installed length for EIL's subtransmission cables (as of the end of March 2019).

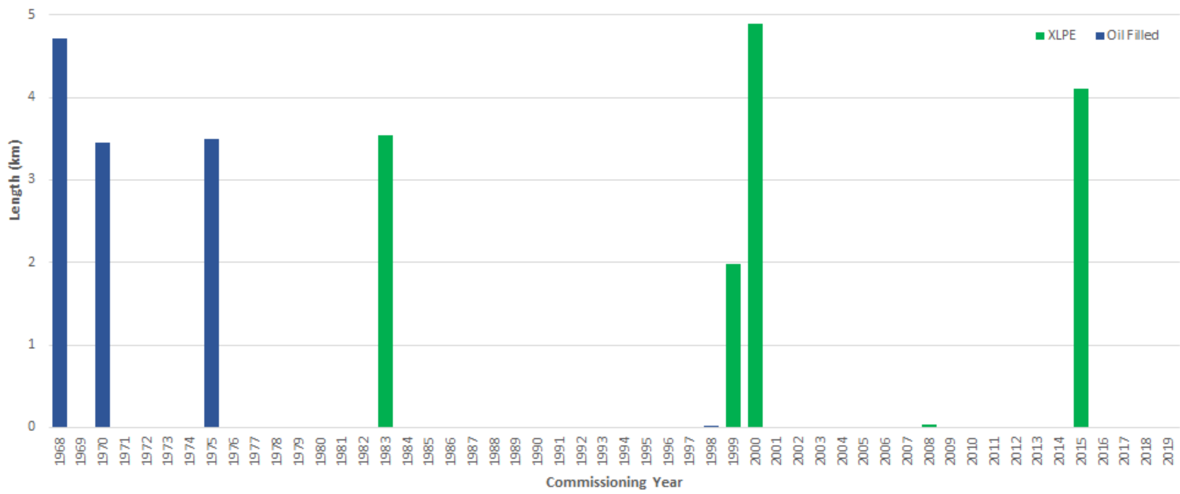


Figure 10: Subtransmission Cables

Zone Substations

Subtransmission Voltage Switchgear

The 33 kV switchboard at Leven Street Substation is indoor, relatively modern and in good condition. At Southern substation EIL's oldest subtransmission circuit breaker is an outdoor type and is at end of life while a second outdoor circuit breaker has had a service life of 35 years but has some rusting due to the harsh coastal environment in Bluff from where it was relocated. Two relatively young circuit breakers are located at Doon Street, but have now been removed from service, and options for their reuse are being considered.

Outdoor equipment at Southern Substation has been damaged by vandalism in the past. Protective barriers have been installed around critical equipment, but without fully enclosing equipment there remains a risk of insulators being damaged by thrown stones.

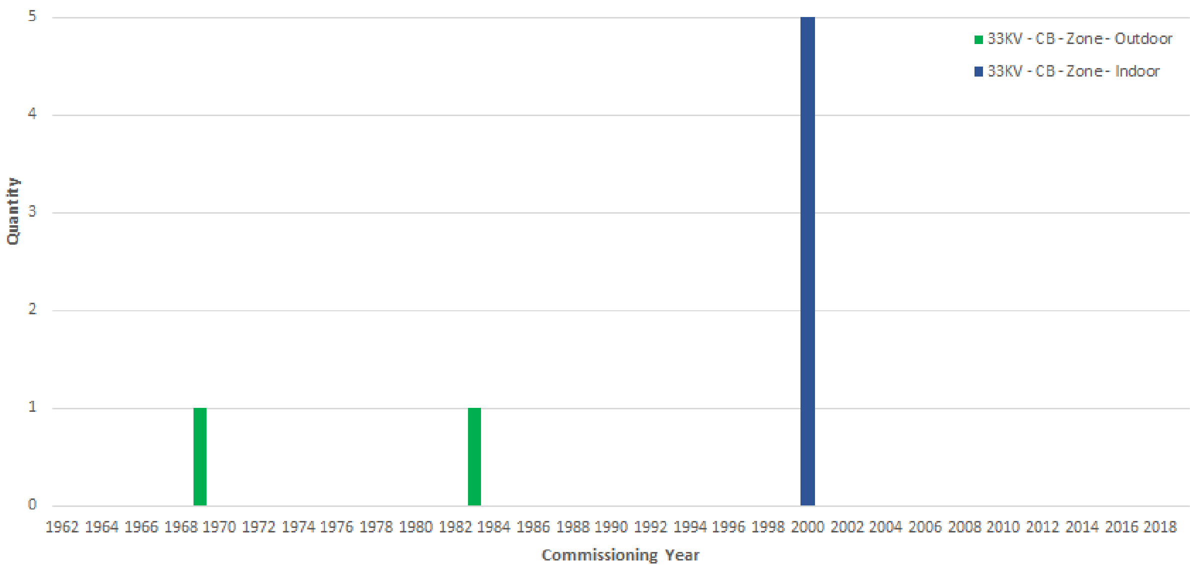


Figure 11: Subtransmission Voltage Circuit Breakers

Power Transformers

The power transformers at EIL's Leven St, Southern, and Racecourse Rd zone substations are all rated to supply load up to 23 MVA with forced cooling, based on an ambient temperature of 5°C (as peak load in EIL generally occurs at the coldest times when heating requirements are greatest).

The power transformers at EIL's remaining substation, Spey St, are relatively new and are rated up to 36 MVA with forced cooling. The Spey St substation replaces the Doon St substation where one 23 MVA transformer remains in a de-energised state. Furan analysis shows the remaining Doon Street unit's paper insulation to be advanced in age but not inconsistent with its service life to date.

It is intended to put the Doon St unit back into service to utilise remaining life as a second transformer at Southern substation in 2020/21. The existing Southern substation transformer has two years of a standard 55 year life (deemed appropriate under the ODV Handbook for lightly loaded, well maintained transformers) remaining; however Furan analysis suggests the insulation is in sufficiently good condition to provide an extended life.

The transformer at Racecourse Road was refurbished in 2017 (major rust), with condition assessment of the insulation showing that it too is able to provide an extended life. The other two transformers that are beyond half of their expected life are the Southern Substation unit and the Leven Street T1 unit; these will be refurbished in 2022/23 and 2023/24 respectively.

Due to the good condition of the older units, there are no power transformer replacements expected within the next 10 years.

Table 11: Power Transformers

Transformer Location	Rating	Installed	Remaining Life
Spey Street T1	18/36 MVA	2015	50
Spey Street T2	18/36 MVA	2012	47
Doon Street T1	11.5/23 MVA	1970	10*
Leven Street T1	11.5/23 MVA	1983	18
Leven Street T2	11.5/23 MVA	2002	37
Southern T1	11.5/23 MVA	1967	2
Racecourse Road T1	11.5/23 MVA	1975	25

* Removed from service 2015. To be installed at Southern Substation

Distribution Voltage Switchgear

The 11 kV circuit breakers installed at EIL's zone substations with their year of manufacture are shown in Figure 12 (as of the end of March 2019).

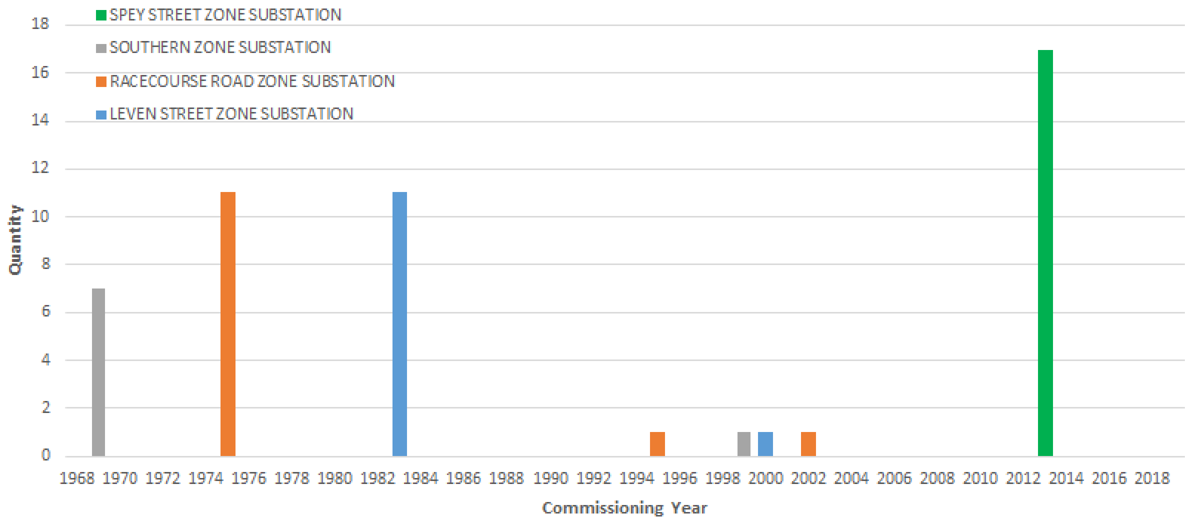


Figure 12: Circuit Breakers at Zone Substations

EIL's oldest switchgear was decommissioned at Doon Street in March 2016. The first seven circuit breakers were installed in 1964 and augmented with a further eight circuit breakers with the latest a second incomer added in 1984. The switchboard has been left in situ until the demolition of the building in 2020/21 and its circuit breakers or parts may be utilised as spares.

The Southern switchboard has reached end of standard life having been installed in 1969. It will be replaced in 2020/21 as part of the overall substation replacements and upgrades project. Condition monitoring is being used to manage risk associated with the continued operation of the aged switchgear. One of the circuit breakers was recently found to have elevated partial discharge levels indicating the beginning of insulation breakdown. This circuit breaker has now been removed from service and the load transferred onto another circuit breaker which was previously supplying only the local service transformer (substation supply). A new incomer circuit breaker was installed in 1999 as a contingency plan, to enable a spare transformer to be put into service relatively quickly should it be required.

The Racecourse Road switchboard was installed in 1975 and is due for its fixed time replacement in 2020/21. Again a new incomer circuit breaker was installed in 2003 as a contingency plan. There are no issues noted with any of the switchboards' circuit breakers. Partial discharge has recently been detected in some sections of the rear of the switchboard, indicating the beginning of insulation breakdown.

The 11 kV switchboard at Leven Street was installed in 1983 with an additional incomer installed in 2000 when the second transformer was installed. There are no issues noted with any of the switchboards' circuit breakers.

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 of ten years.

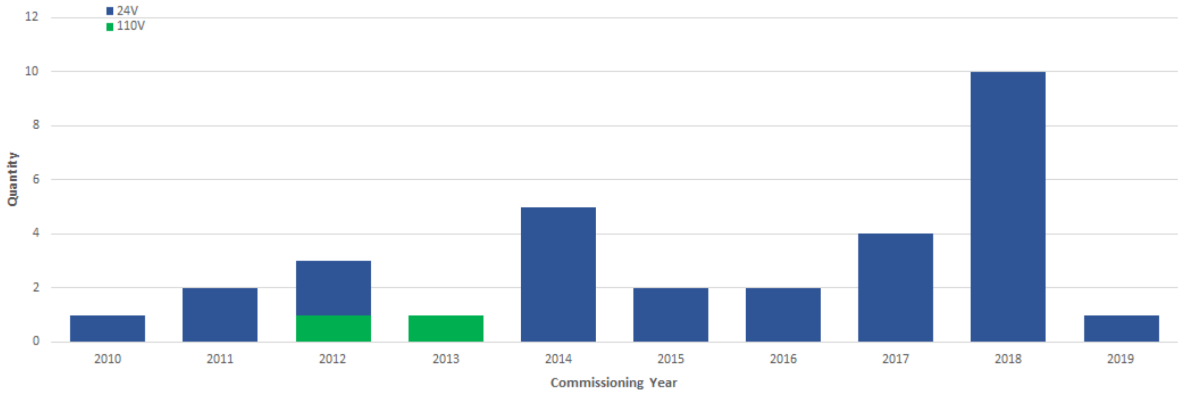


Figure 13: DC Batteries

Tap Changer Controls

Six voltage regulating relays are in operation having been installed with their associated transformers and are in good condition. Replacements will also coincide with transformer replacements when due, or in line with projects such as the upgrades planned at Southern substation in 2020/21. Unexpected failures may require replacement with the modern voltage regulating relay standardised solution based on an SEL controller; this solution has been installed for both new Spey Street transformers.

Distribution Network

EIL's Distribution network has a total length of 183 km to supply its 17,417 customers giving an overall customer density of 95.3 customers per kilometre. The proportions that are overhead or underground and the customer count and density is shown in Table 12 on a per substation basis. The table incorporates recent MV tie point shifts to allow major work to be completed. Once completed, normal tie points will be restored, improve zone substation transformer capacity utilisation and reliability.

Table 12: Distribution network per substation

Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Spey Street	-	61	7,423	122/km
Leven Street	4.8	31	1,959	54/km
Racecourse Road	3.1	21	2,432	102/km
Southern	1.6	37	4,546	117/km
Bluff – EIL feeders	13.2	5	1,009	56/km
Total/average	22.7	155	17,417	98/km

Overhead

EIL's overhead distribution network uses a mix of concrete and wood poles as shown in Figure 14 which displays estimated commissioning year. Most of the Invercargill network has been undergrounded as part of an extensive undergrounding programme with only a few overhead circuits remaining in industrial areas. The Bluff area remains overhead network, as Bluff's rocky sub-surface makes undergrounding difficult and expensive.

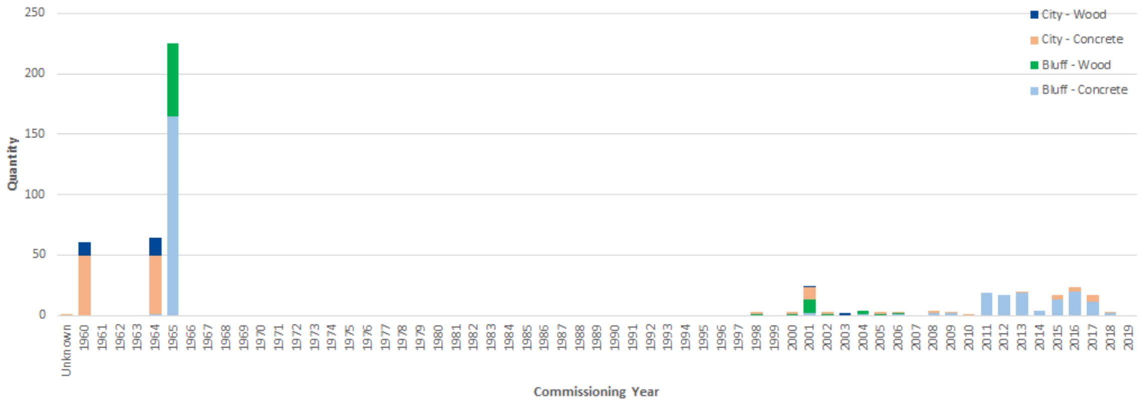


Figure 14: Distribution Poles

The nominal life of poles varies with pole type: 45 years for wood poles and 60 years for concrete. Industry experience has shown however that poles can last substantially longer than nominal life, therefore condition-based replacement is more appropriate than age-based replacement. The replacement and renewal programme is therefore driven from a five-yearly condition assessment carried out on all distribution lines.

Maintenance of 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 City renewal costs have been higher than usual in recent years as EIL catches up on this deferred maintenance.

The commissioning year for the distribution line conductors is displayed in Figure 15. Conductor is generally replaced based on condition as identified through routine inspection.

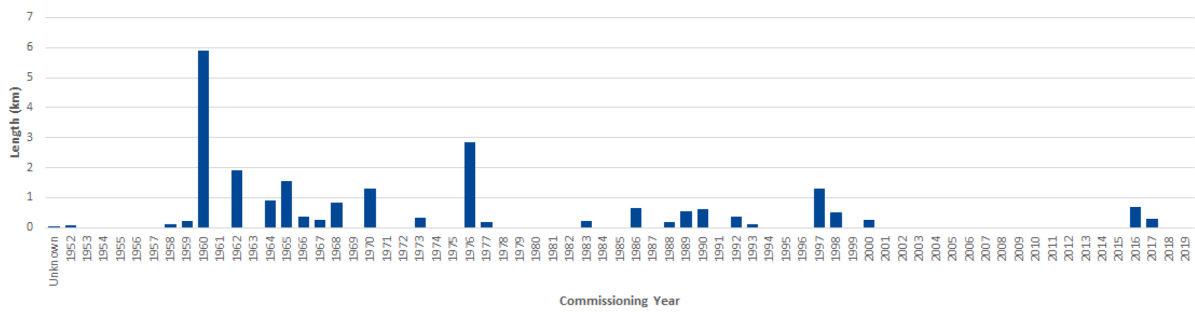


Figure 15: MV Line Conductors

EIL has two 11 kV pole mount field circuit breakers and an enclosed load break switch in service on the Bluff area network, located respectively at Gore, Bann and Palmer Streets. This switchgear was installed as part of network automation and reliability enhancements and is detailed as follows:

- The Gore Street circuit breaker is a Nulec N24 reclosing circuit breaker manufactured in 1997. It was relocated in 2015 to a more optimal location. It has minor signs of aging but is in satisfactory condition.

- The Bann Street circuit breaker is a Nova 15 reclosing circuit breaker manufactured in 2006 and kept in spares before being installed in 2015. It is in as new condition.
- The Palmer Street load break switch is an Entec solid insulation vacuum breaking switch and was installed new in 2015.

Figure 16 shows numbers of 11kV air break switches by commissioning year. Only twelve ABSs remain on the Invercargill network, with most having been removed as part of the undergrounding programme, while seventeen are in service in Bluff.

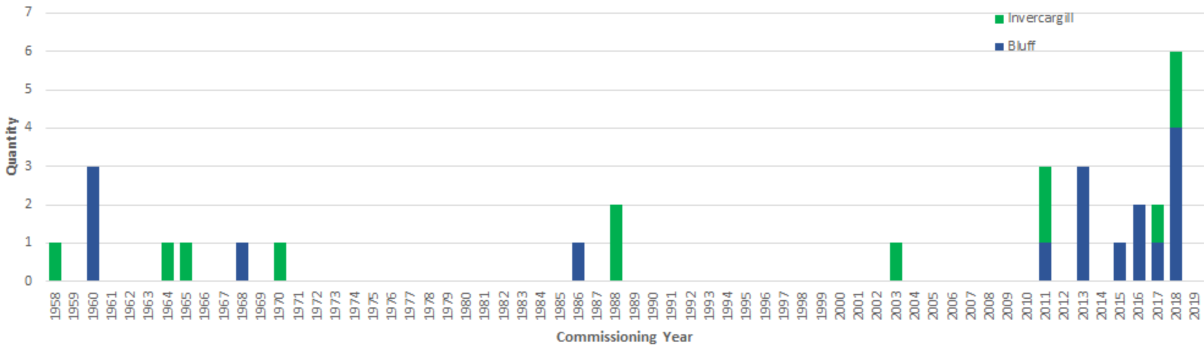


Figure 16: Air Break Switches

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.

Underground

Distribution cables were installed gradually as replacement for overhead lines on the Invercargill network as part of an ongoing undergrounding programme. Some cables have been installed in Bluff, but the Bluff network area remains mostly overhead because the rocky subsurface makes undergrounding service difficult. Figure 17 show the lengths of cables on EIL's distribution network by commissioning year.

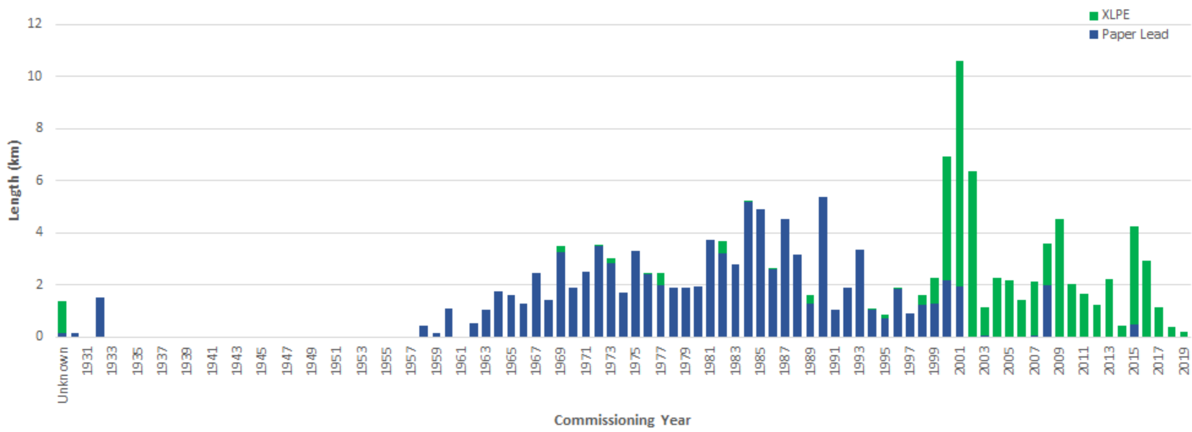


Figure 17: MV Cables

Paper lead cables were predominantly used up to about 2000 after which XLPE became the preferred cable type, due to the ease of installation and subsequent works. Actual practical life for any cable is likely to be greater than the standard life, and a programme of assessing and monitoring of condition will be developed and used in planning as the oldest cables begin to reach end of life. Most cables are lightly loaded and in sound condition however there have been termination and joint failures.

Distribution Substations

Transformers

Table 13 shows the numbers of distribution transformers by size on EIL's network, and their age profile is displayed in Figure 18. Transformers larger than 100 kVA are now installed at ground level, and after the extensive undergrounding programme only a few pole mounted transformers remain. Transformers found to be in poor condition after five-yearly inspections will be replaced, sometimes with units removed from service and refurbished for reuse. Many ground mounted units are enclosed, and the reduced exposure has kept these transformers in above average condition for their age.

Table 13: Number of distribution substations

Phases	Rating	Pole Mount	Ground Mount
1 phase:	up to 15 kVA	2	1
	30 kVA	1	-
3 phase:	up to 15 kVA	-	1
	30 kVA	-	3
	50kVA	1	2
	75 kVA	-	1
	100 kVA	2	17
	200 kVA	4	64
	300 kVA	1	248
	500 kVA	-	57
	750 kVA	-	18
	1,000 kVA	-	16
	Total	**11**	**428**

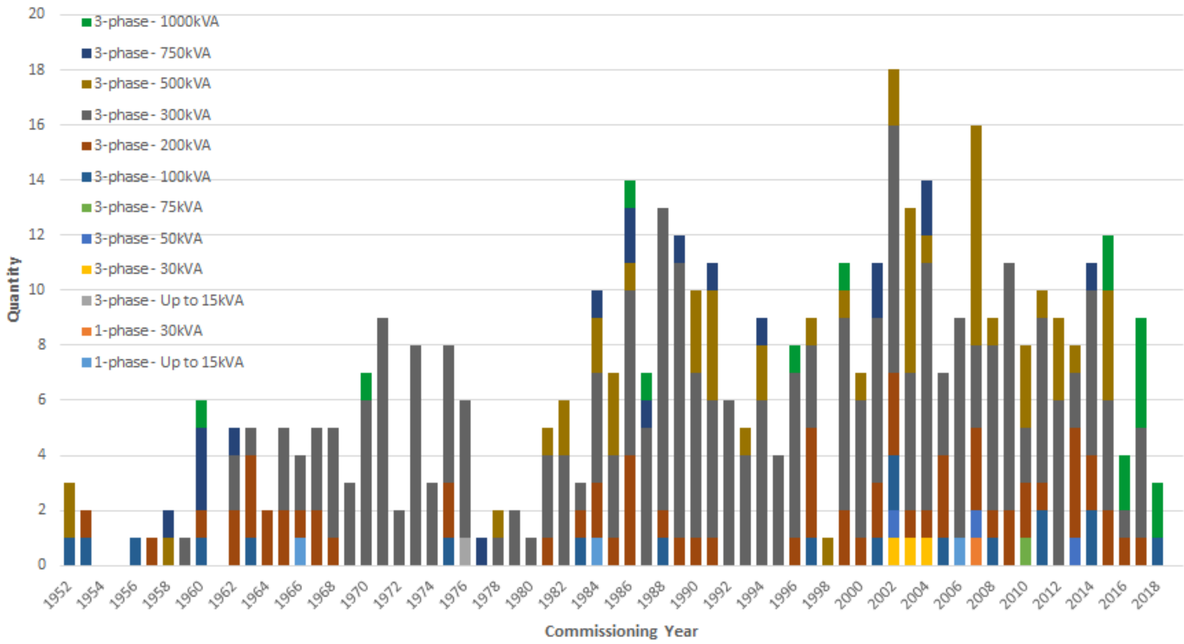


Figure 18: Distribution Transformers

Switchgear

Figure 19 shows the circuit breakers installed at EIL's distribution substations which are located within the Invercargill CBD. Several of EIL's older breakers have been replaced in recent years as part of the programme to remove the underground substations where those circuit breakers were located. The remaining older circuit breakers will be replaced in the coming years.

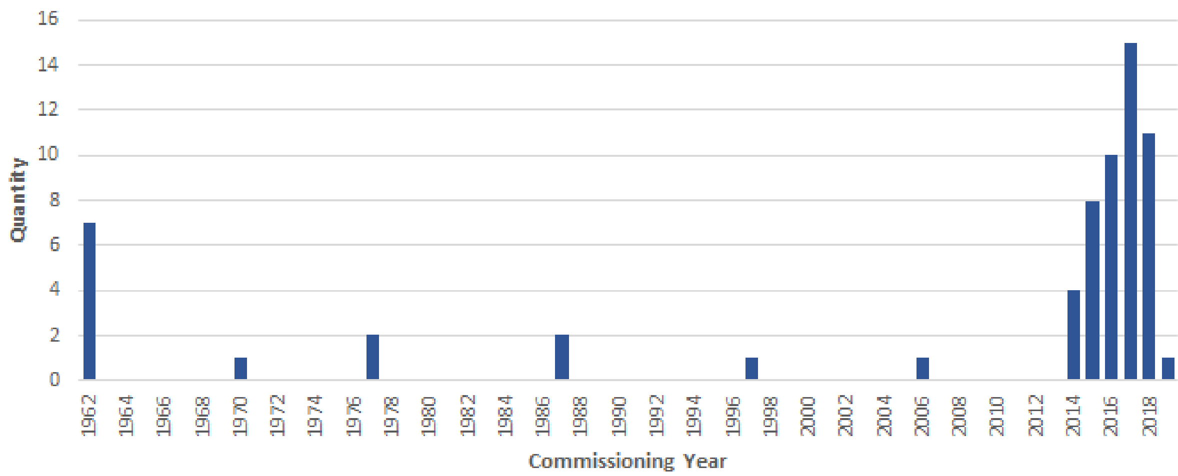


Figure 19: Field Circuit Breakers at Distribution Voltage

The age profile of ring main units (RMUs) is displayed in Figure 20 which shows a number of the older (generally indoor) units have reached their standard life of 45 years (although some ages have been estimated). It should be noted that the quantities in this graph are expressed in terms of RMU modules – modern RMUs are individual modules sharing a common bus, while some older models of RMU integrate all connections into a single housing.

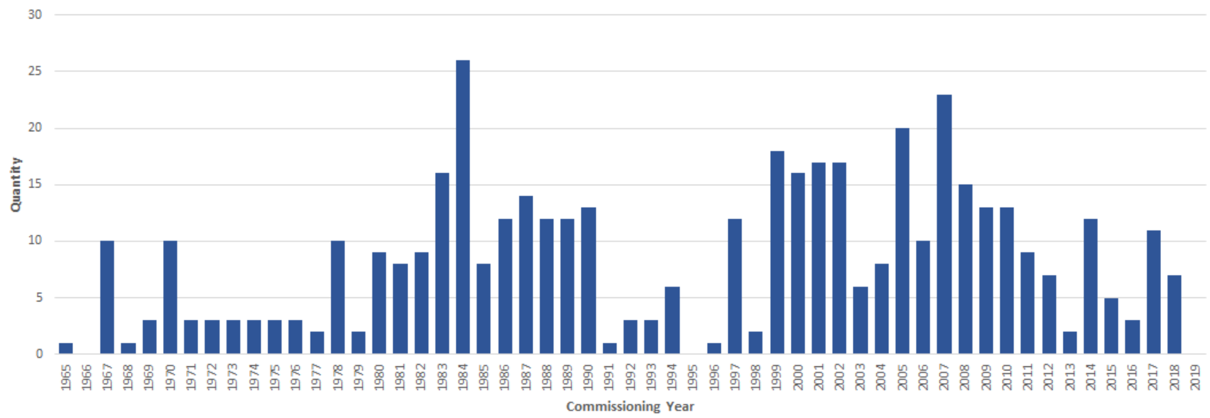


Figure 20: Ring Main Units

Some RMUs equipment have operating restrictions placed on it to manage hazards associated with oil filled switchgear as identified by incidents occurring in the wider industry. A solution has been developed that allows safe operation of suitable models of equipment without compromising arc-flash boundaries. Some outdoor units have also developed rusting issues that may lead to early replacement of affected switchgear. The oldest switchgear is being replaced as part of the programme to remove the underground substations where these RMUs are located; and other units are replaced as required based on an evaluation of age and condition.

Remote Terminal Units

The early GPT mini RTU's were installed in 1995-98 to automate circuit breakers at distribution substations in the CBD. These units are at end of life, and have proven unreliable. Replacements are done in tandem with switchgear replacements where most of these RTUs are located.

Three Kingfisher CP-11 RTUs were installed in 2004 at Doon Street, Southern and Racecourse Road zone substations and their replacements are scheduled for 2020/21. The Doon Street RTU has been retained to provide indications for the oil filled cables after the decommissioning of the power transformers, 11 kV switchboard and associated auxiliary equipment. Another smaller Kingfisher PC-1 RTU was installed in 2004 at a distribution substation in the CBD and will be replaced at end of life.

Two modern SEL RTUs were installed at the Spey St zone substation in 2013 for secure remote indications and control for each half of the AAA security substation. A third SEL unit was installed at Leven St substation in 2016 to replace an end-of-life Harris RTU.

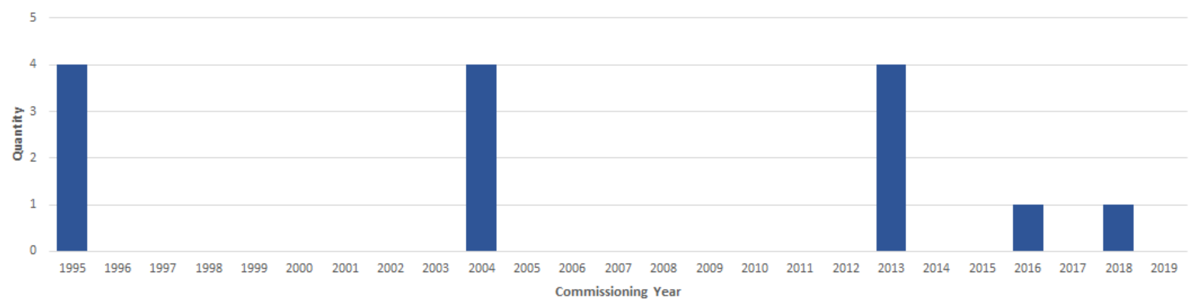


Figure 21: Remote Terminal Unit Assets

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 22.

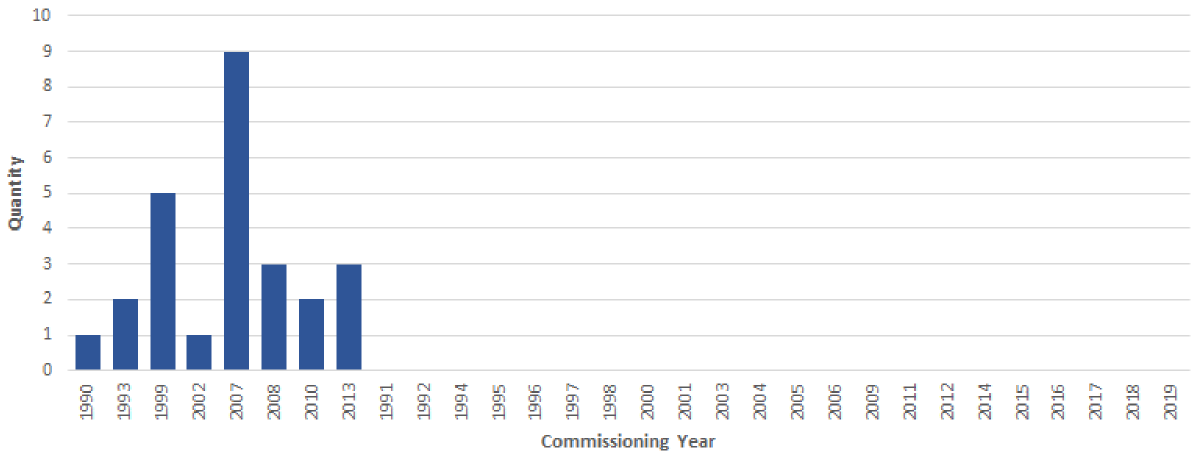


Figure 22: Metering Assets

LV Network

EIL's LV (400/230 V) network has a total length of 453km to supply its 17,417 customers giving an overall customer density of 38.4 customers per kilometre. The proportions of overhead and underground network and the customer count and density is shown on a per substation basis in Table 14.

Table 14: LV network per substation

Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Spey Street	0.2	184.7	7,423	40/km
Leven Street	3.3	53.7	1,959	34/km
Racecourse Road	0.8	63.6	2,432	38/km
Southern	1.2	116.2	4,546	39/km
Bluff – EIL feeders	24.1	3.4	1,009	37/km
Total/average	29.8	422.6	17,417	38/km

Overhead

The EIL's age profiles for overhead LV conductors and for poles are shown respectively in Figure 23 and Figure 24. Almost all LV lines in the city have gradually disappeared from the Invercargill network as the services have been undergrounded with less than 6 km line length remaining. Most of the LV line length is on the Bluff area network where undergrounding is difficult due to the rocky subsurface.

Poles are renewed as required based on condition as identified during the regular inspections of the network. Overhead LV conductor is also replaced on condition. New overhead line is installed as ABC

(Aerial Bundled Conductor) which does not require cross arms and insulators and has PVC insulation improving line safety.

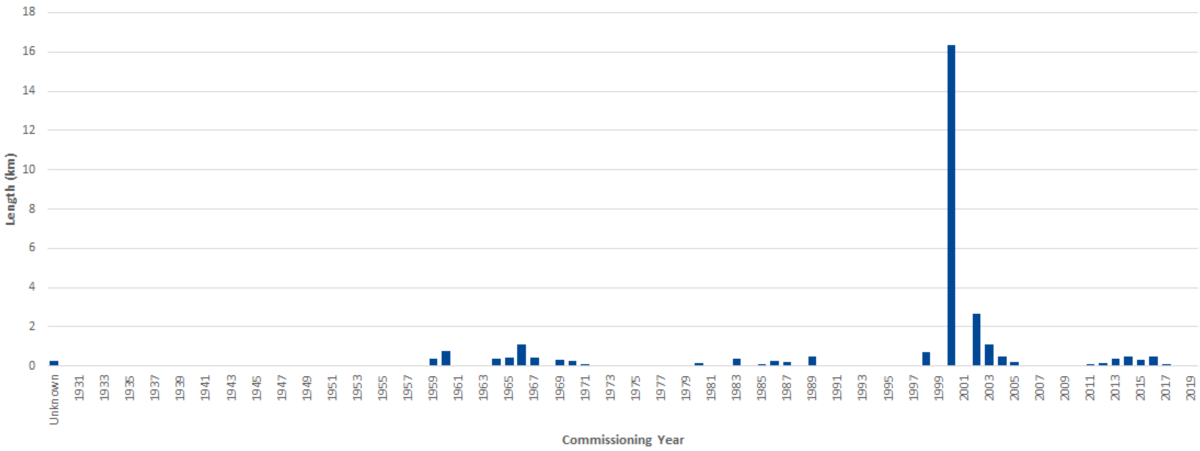


Figure 23: LV Lines

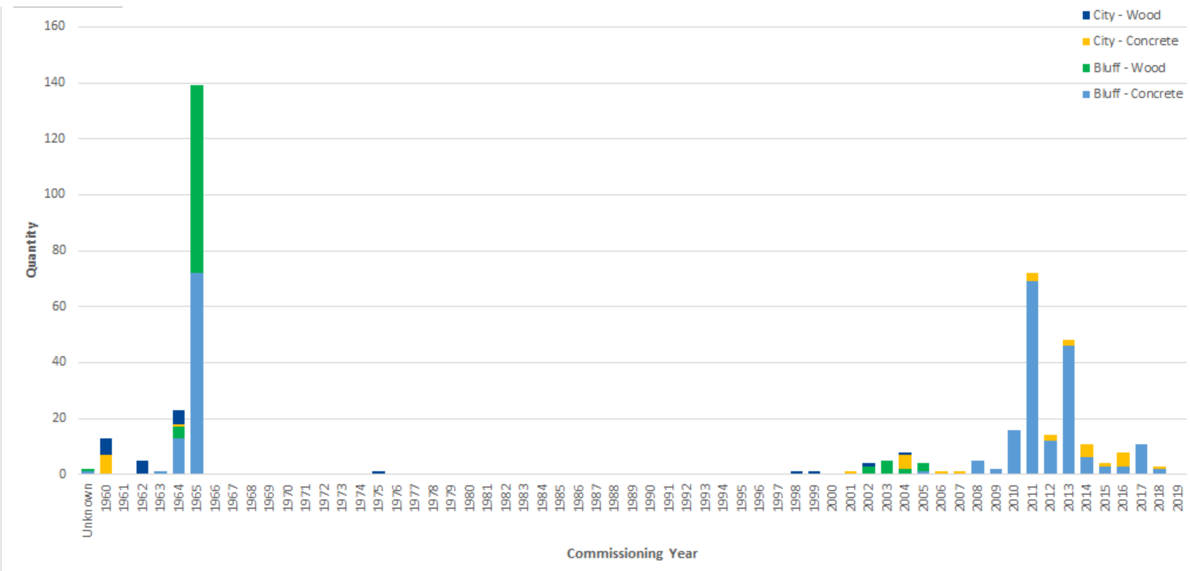


Figure 24: LV Poles

Underground

The LV cable commissioning year profile is shown in Figure 25 and shows a number of assets beyond nominal life. In practice cables are left in service until performance deteriorates and impacts on service levels.

Several 400 V 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. Smart meters being installed at customer's premises will much improve the network's ability to monitor voltage quality and proactively address issues before they are noticed by customers.

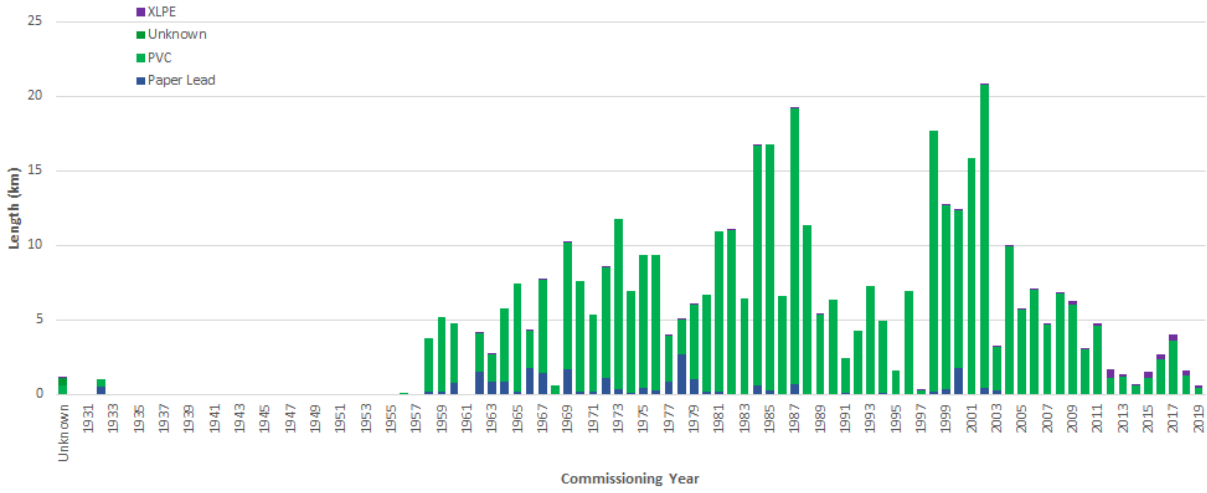


Figure 25: LV Cables

Other Assets

SCADA and Communications

The PowerNet SCADA master station was commissioned in 1999 with a further upgrade of the Server PC's and software in 2017. The communications links to Spey St Substation are fibre optic media, and the equipment is still in as-new condition. Links to the remaining zone substations and CBD distribution substations will need to be upgraded from the existing copper multicore approaches end-of-life; these upgrades are generally timed to coincide with other significant works on each substation.

Bulk Supply Assets

The company owns an injection plant at Invercargill GXP which was commissioned in 1989, with all plant enclosed within the building. This provides protection from the elements and therefore an extended life is expected 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 2005 upgrade and the general condition indicate that the plant will last until the completion of smart meter rollout makes it redundant.

Mobile Plant/ Load Correction/ Generation

EIL does not own any mobile substations, power factor correction plant, mobile generation or standby generation plant; however PowerNet own three mobile diesel generators rated at 500 kW, 350 kW and 275 kW which EIL utilise to maintain supply to customers when assets are removed from service for maintenance.

3. Service Levels

This section describes how EIL sets its various service levels according to the safety, viability, quality, compliance and price objectives that are most important to stakeholders (see Drivers and Constraints). It details how well EIL is meeting these objectives and what trade-offs 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.

A broad range of service levels are created for EIL's 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 electrical interference, compliance with the District Plan and submitting regulatory disclosures. This section describes those service levels in detail and how EIL justifies the service levels delivered to its stakeholders.

Safety is a top priority for EIL and is a primary consideration in the AMP, but it should be noted that safety has always been a prime consideration in network design, which means that the residual risk able to be addressed through asset management planning is extremely low. Operational factors tend to dominate the year-to-year variation in safety incidents and near hits. Therefore safety KPIs are not presented in the Asset Management Plan, but are available to interested parties upon request.

3.1. Customer Oriented Service Levels

Customer engagement surveys are completed annually to measure customer perceptions around a range of service levels. This involves contacting a large sample of customers by phone and asking a predetermined set of questions; the survey is carried out independently by Research First who collate the results into a customer satisfaction report for presentation. Face to face interviews are conducted by Gary Nicol Associates directly with major customers to help understand individual service level requirements and satisfaction with current service levels.

Statistics around voltage complaints are kept to measure how often voltage quality issues are experienced by customers. Issues are dealt with at the time of complaint, but these statistics give an indication of how voltage quality and the response services are trending over time. Following the completion of customer connection work a survey form is sent to the customer to measure satisfaction with the connections service. The results of these surveys are monitored, and any comments received are reviewed and responded to as appropriate.

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. Customer engagement telephone surveys indicate 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 also appears 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 causes genuine inconvenience.

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 raises the following 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 (or chain of assets) 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. For example Invercargill and North Makarewa GXP's are more secure than their size would normally deserve, due to the reliability required by the New Zealand Aluminium Smelter at Tiwai point.

Primary Customer Service Levels

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 EIL has adopted two internationally accepted indices:

- **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.

This aligns with the Commerce Commission's use of SAIFI and SAIDI (and determines their calculation methodology) in their regulation of local EDBs including EIL. EIL's projections for these measures over the next ten year period ending 31 March 2030 are shown Table 15 and utilise the calculation methodology of the 2020 Default Price-Quality Path Determination.

These forecasts are average values around which significant variation can be expected due to the random occurrence of a low number of faults and weather impacts. While planned work has less year-to-year random variation, the forecast can differ from previous years due to the influence of new initiatives that improve safety but have the side effect of increasing the reliability impact of network maintenance/renewal.

Historically, EIL's network reliability has been extremely good due to the underground nature of the Invercargill network. Forecasts allow for the fact that parts of the underground network are starting to reach end of life.. Distribution automation can counter some of the effect on SAIDI. However, distribution automation becomes less cost efficient with higher saturation on the network, and is less effective at countering the SAIFI impact of deteriorated equipment. Reliability is expected to be difficult to maintain in the medium to long term, until regulated revenue allowances permit renewal at rates that align with equipment deterioration.

Table 15: EIL Reliability Projections

Measure	Class	2020/21	2021/22	2022/23	2023/24	2024/25	...	2029/30
SAIDI	B (Planned)	12.40	11.50	11.50	11.50	11.50	...	11.50
	C (Unplanned)	21.55	21.50	22.50	23.50	23.50	...	23.50
	Total	**32.95**	**32.90**	**34.00**	**35.00**	**35.00**	**...**	**35.00**
SAIFI	B (Planned)	0.10	0.10	0.10	0.10	0.10	...	0.10
	C (Unplanned)	0.60	0.57	0.57	0.62	0.62	...	0.62
	Total	**0.70**	**0.67**	**0.67**	**0.72**	**0.72**	**...**	**0.72**

Historic network SAIDI and SAIFI are presented below, to enable comparison with projections:

Table 16: EIL Reliability History

Measure		2014/15	2015/16	2016/17	2017/18	2018/19
	B (Planned)	0.50	8.27	4.42	4.50	1.69
SAIDI	C (Unplanned)	25.02	17.47	9.05	22.98	16.29
	Total	**25.52**	**25.75**	**13.47**	**27.49**	**17.98**
SAIFI	B (Planned)	0.00	0.05	0.03	0.02	0.01
	C (Unplanned)	0.71	0.56	0.26	0.45	0.30
	Total	**0.71**	**0.61**	**0.29**	**0.47**	**0.31**

The underlying reliability for significant network areas and voltage levels can be broadly summarised as shown in Table 17:

Table 17: Expected fault frequency and restoration time

General location	Expected reliability	
Invercargill CBD	Frequency of faults	Estimated restoration[3]:
33 kV Fault	One every 15 years	1 min
11 kV Fault	2 every year	30 min
Invercargill other than CBD	Frequency of faults	Estimated restoration[3]:
33 kV Fault	One every 7 years	15 min
11 kV Fault	5 every year	45 min
Bluff	Frequency of faults	Estimated restoration[3]:
33 kV Fault	3 every year	1 min
11 kV Fault	6 every year	75 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.

Table 18 show the thresholds which the Commerce Commission applies to EIL's reliability performance starting from 1 April 2020. The boundary values represent the threshold for normalising major events, where if the sum of SAIDI or SAIFI for unplanned interruptions in any 24 hour rolling period, commencing in any half-hour period, exceeds the respective boundary, the contribution to the overall

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

annual SAIDI or SAIFI is capped at 1/48th of that boundary value for each half hour of the event. The limit represents the upper limits of acceptable reliability for network performance, after normalising out storm and extreme events, and must not be breached each year.

Table 18: EIL Reliability Thresholds – DPP3 Unplanned Outages – Per Year

	Class	Target	Collar	Cap	Limit	Boundary	Extreme Event	Incentive Rate
SAIDI	C (Unplanned)	15.39	0	25.86	25.86	4.13	120	$ 2,544 per SAIDI
SAIDI	B (Planned)	7.63	0	22.9	114.49 (5-year)	-	-	$ 1,272 per SAIDI
SAIFI	C (Unplanned)	-	-	-	0.6956	0.0804	-	-
SAIFI	B (Planned)	-	-	-	0.5183 (5-year)	-	-	-

Because of EIL's historically good reliability and low annual fault number, averaging effects on a random fault pattern are not strong in any particular year. The new limits that apply from 1 April 2020, which are assessed on an annual basis, may prove to be easier to breach due to the high variance in performance from year-to-year.

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 $94,916 (equivalent to 0.75% of the starting price maximum allowable revenue for the regulatory period) is the "revenue at risk" for SAIDI. For performance at the Target level, which is calculated as EIL's average historical reliability levels, there is no adjustment to EILs revenue. For performance worse than the target, EIL incurs a pro rata revenue loss up to the Cap where the maximum penalty of is imposed. Conversely for performance better than the reliability target EIL earns a pro rata revenue gain down to the Collar where the maximum bonus is achieved. Performance beyond either cap or collar attracts no further losses or gains however the cap is also the limit of acceptable reliability.

Table 19: EIL Reliability Thresholds – DPP2 for comparison

	Class	Target	Collar	Cap	Limit	Boundary
SAIDI	B + C	24.08	17.03	31.13	31.13	3.24
SAIFI	B + C	0.594	0.415	0.772	0.772	0.080

Under the DPP2 regime, the limits must not be breached once in any three year period.

Secondary Customer Service Levels

Secondary service levels are the attributes of service that EIL customers have ranked below the primary attributes of supply continuity and restoration. It is important to note 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.
- 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 20 sets out these service level targets.

Table 20: Secondary Service Level Projections

Attribute	Measure	2020/21	2021/22	…	2029/30
Planned Outages	Provide sufficient information. {CES}	>80%	>80%	…	>80%
	Satisfaction regarding amount of notice. {CES}	>80%	>80%	…	>80%
	Acceptance of one planned outage every two years lasting four hours on average. {CES} ***	>80%	>80%	…	>80%
Unplanned Outages (Faults)					
	No impact or minor impact of last unplanned outage. {CES} ***	>50%	>50%		>50%
	Information supplied was satisfactory. {CES}	>80%	>80%	…	>80%
	PowerNet first choice to contact for faults. {CES}	>35%	>35%	…	>50%
Supply Quality	Number of customers who have made supply quality complaints {IK}	<5	<5	…	<5
	Number of customers having justified supply quality complaints {IK}	<2	<2	…	<2

{ } indicates information source; CES = Customer Engagement Survey using independent consultant to undertake phone survey, IK = Internal KPIs.

***Survey questions were changed from the 2016/17 survey and the surveys 2017/18 onwards. The modified questions provided a wider range of options compared to previous surveys, which has influenced the response

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. Many 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.

Table 21: Other Service Levels

Service Level	Description
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 at Work Act 2015. • Electricity (Safety) Regulations 2010 • Electricity (Hazards from Trees) Regulations 2003. • Maintaining safe clearances from live conductors (NZECP34 or AS2067). • EEA Guide to Power System Earthing Practice 2009 as a means of compliance with the Electricity (Safety) Regulations.
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. • Land Transfer Act 1952 (easements)
Industry Performance	The Commerce Act 1986 empowers the Commerce Commission to require EIL to compile and disclose prescribed information to specified standards.
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 publications are used to prevent issues from interference: • Harmonic levels (NZECP 36:1993). • NZCCPTS: coordination of power and telecommunications (several guides).

3.2. Regulatory Service Levels

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

- Ensure 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 also available at http://www.comcom.govt.nz/regulated-industries/electricity/performance-analysis-and-data-for-distributors/

Financial Efficiency Measures

EIL financial efficiency measures fall into two groups:

- Network OPEX metrics
- Non-Network OPEX metrics

However for effective benchmarking this OPEX must be measured against the relative size of the EDBs in question. As there is no single fair measure of the "size" of an EDB, EIL has adopted the most consistent (and therefore predictable) measures from Information Disclosure Schedule 1:

- Interconnection Points (ICPs) as at year end
- Total km network length
- Total MVA of EDB-owned distribution transformer capacity.

EIL therefore has six financial efficiency targets as shown in Table 22:

Table 22: Financial Efficiency Targets

Measure		Network			Non-Network	
	OPEX/ICP	OPEX/km	OPEX/MVA	OPEX/ICP	OPEX/km	OPEX/MVA
2020/21	$108	$2,800	$12,200	$221	$6,000	$25,500
2021/22	$108	$2,800	$12,200	$221	$6,000	$25,500
2022/23	$108	$2,800	$12,200	$221	$6,000	$25,500
2023/24	$108	$2,800	$12,200	$221	$6,000	$25,500
2024/25	$108	$2,800	$12,200	$221	$6,000	$25,500
2025/26	$118	$3,000	$13,100	$221	$6,000	$25,500
2026/27	$118	$3,000	$13,100	$221	$6,000	$25,500
2027/28	$118	$3,000	$13,100	$221	$6,000	$25,500
2028/29	$118	$3,000	$13,100	$221	$6,000	$25,500
2029/30	$118	$3,000	$13,100	$221	$6,000	$25,500

Dollar values as constant 2020 dollars.

Energy Delivery Efficiency Measures

Projected energy efficiency forecasts and targets are shown in Table 23. 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 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 31 December, some estimation methodology is required.

Table 23: Energy Efficiency Targets

Measure	2019/20	2020/21	…	2029/30
Load Factor	50%	50%	…	50%
Loss Ratio	5.5%	5.5%	…	5.5%
Capacity Utilisation	40%	40%	…	45%

3.3. Service Level Justification

EIL's service levels are justified when:

- Customers have indicated preference for paying the same line charges for the same service levels.
- Improvements provide positive cost benefit within revenue capability.
- Customers make specific requests to receive a different mix of reliability and pricing from what would otherwise be available. E.g. 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, or cost recovery allowances do not permit renewal rates.
- Customer expectations of service levels set by historic investment decisions and resultant network performance

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-quality path methodology requires no material decline in network reliability and now includes a revenue incentive for improving reliability.
- The service level called "Safety" is expected to continually improve as public perceptions and regulations are updated to decrease industry related risk.
- EIL's cold storage customers require higher levels of continuity and restoration with interruptions to cooling and chilling being less acceptable as food and drink processing, storage and handling are subject to increasing scrutiny by overseas markets.
- Economic downturn may increase the incidence of theft of materials and energy.

3.4. Basis for Service Level Targets

Historical Trends

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 are typically difficult to influence and slow to change. Historical results are trended and projected to forecast future service levels and then adjusted to account for any particular initiatives or other issues that are anticipated to affect service levels.

Targets for network reliability and for financial and energy efficiency targets are generally set based on forecast levels to help drive the completion of performance enhancement initiatives. Targets for customer satisfaction are set based on the desired outcome of achieving positive customer experiences while accepting that targeting 100% satisfaction would be unrealistic.

Results over the last five years for the targeted reliability and energy efficiency service levels are listed in Table 24 and customer satisfaction as indicated from past surveys are shown in Table 25.

Table 24: Reliability and Energy Efficiency History

Measure	2014/15	2015/16	2016/17	2017/18	2018/19
SAIDI	25.5	25.7	13.5	31.1	21.6
SAIFI	0.71	0.61	0.29	0.77	0.33
Load Factor	51%	48%	49%	48%	48%
Loss Ratio	5.6%	5.3%	5.6%	5.2%	4.9%
Capacity Utilisation	39.7%	43.1%	41.8%	41.7%	42.0%
Network OPEX / ICP	$73	$72	$87	$76	$92
Network OPEX / km	$1,913	$1,860	$2,286	$2,005	$2,443
Network OPEX / MVA	$8,364	$8,237	$10,181	$8,834	$10,818
Non-Network OPEX / ICP	$167	$175	$190	$188	$191
Non-Network OPEX / km	$4,378	$4,549	$4,971	$$4,986	$5,061
Non-Network OPEX / MVA	$19,147	$20,140	$22,140	$21,969	$22,411

SAIDI and SAIFI disclosures for the years ending 2015 were calculated according to the methodology applicable to the 2010-15 Regulatory Control Period (RCP). Disclosures for the years ending 2016 and onward were calculated according to the revised methodology applicable to the 2015-20 RCP, as laid out in the 2015 Default Price-Quality Path Determination. Table 24 utilises the 2015 methodology for all of the years 2014 to 2019, as those are the figures relevant to EIL's trending and forecasting.

Table 25: Customer Satisfaction History

Attribute	Measure	2014/15	2015/16	2016/17	2017/18	2018/19
Planned Outages	Provided sufficient information. {CES}	100%	91%	90%	97%	98%
	Satisfaction regarding amount of notice. {CES}	81%	100%	95%	97%	89%
	Acceptance of one planned outage every two years. {CES}	98%	95%	95%	-	-
	Acceptance of planned outages lasting two hours on average. {CES }	95%	91%	89%	-	-
	Acceptance of one planned outage every two years lasting four hours on average. {CES} ***	-	-	-	86%	85%
Unplanned Outages (Faults)	Power restored in a reasonable amount of time. {CES}*	80%	67%	61%	-	-
	No impact or minor impact of last unplanned outage. {CES} ***	-	-	-	49%	64%
	Information supplied was satisfactory. {CES}*	100%	100%	75%	78%	86%
	PowerNet first choice to contact for faults. {CES}**	34%	19%	15%	25%	6%
Voltage Complaints	Number of customers who have made supply quality complaints {IK}	0	1	1	4	7
	Number of customers having justified supply quality complaints {IK}	0	0	0	2	3

{ } indicates information source: CES = Customer engagement survey using independent consultant to undertake phone survey, IK = Internal KPIs

* As these questions are limited to customers experiencing an unplanned outage in the last six months, the sample size is very small for a network as reliable as EIL. This can lead to substantial year-to-year fluctuations.

**Noting that each year a substantial proportion of responses (72% in 2017/18) simply state that the customer would not call anyone.

***Survey questions were changed from the 2017/18 surveys and onwards. The modified questions provided a wider range of options compared to previous surveys, which has influenced the response

Benchmarking

In addition to trending of these results, benchmarking against other local distribution networks, as shown in Figure 26 to Figure 36, helps identify where EIL might look to improve from current service levels. Comparisons with Nelson Electricity, and to a lesser extent Orion and Wellington Electricity, are useful as these networks are considered to be similar to EIL in terms of density and asset base.

SAIFI - available EDB reliability results since 2013 show EIL is a leading network in minimising the number of supply interruptions that customers experience. EIL's position relative to other local EDBs suggests no specific action to improve SAIFI is warranted.

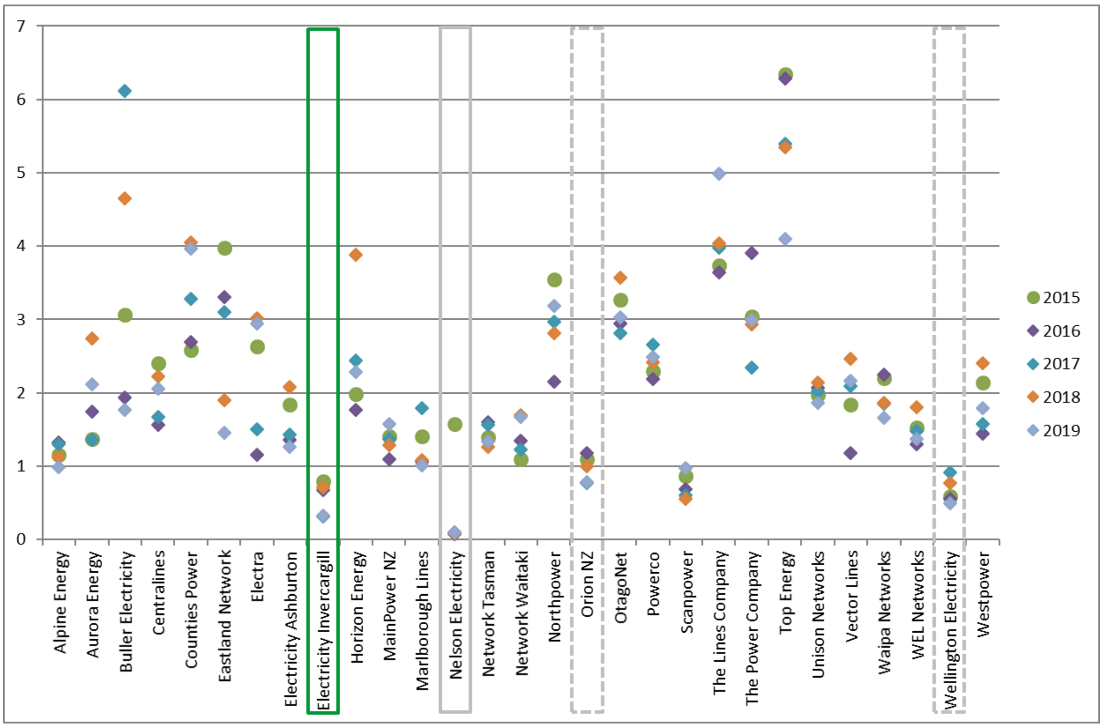


Figure 26: EIL SAIFI Comparison with Local EDBs

SAIDI – available EDB reliability results since 2013 show EIL is a leading network in minimising the amount of time that customers have no supply. EIL's position relative to other local EDBs suggests no specific action to improve SAIDI is warranted.

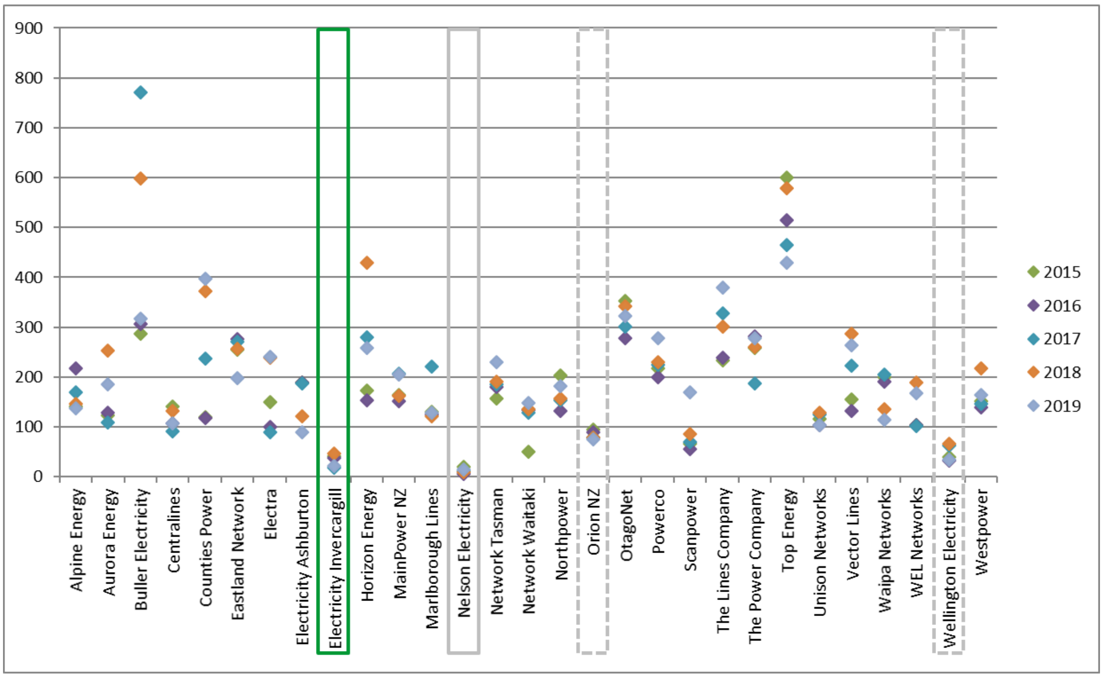


Figure 27: EIL SAIDI Comparison with Local EDBs

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 is also less diversity in customer consumption across the network than is usual, because the area supplied is completely urban.

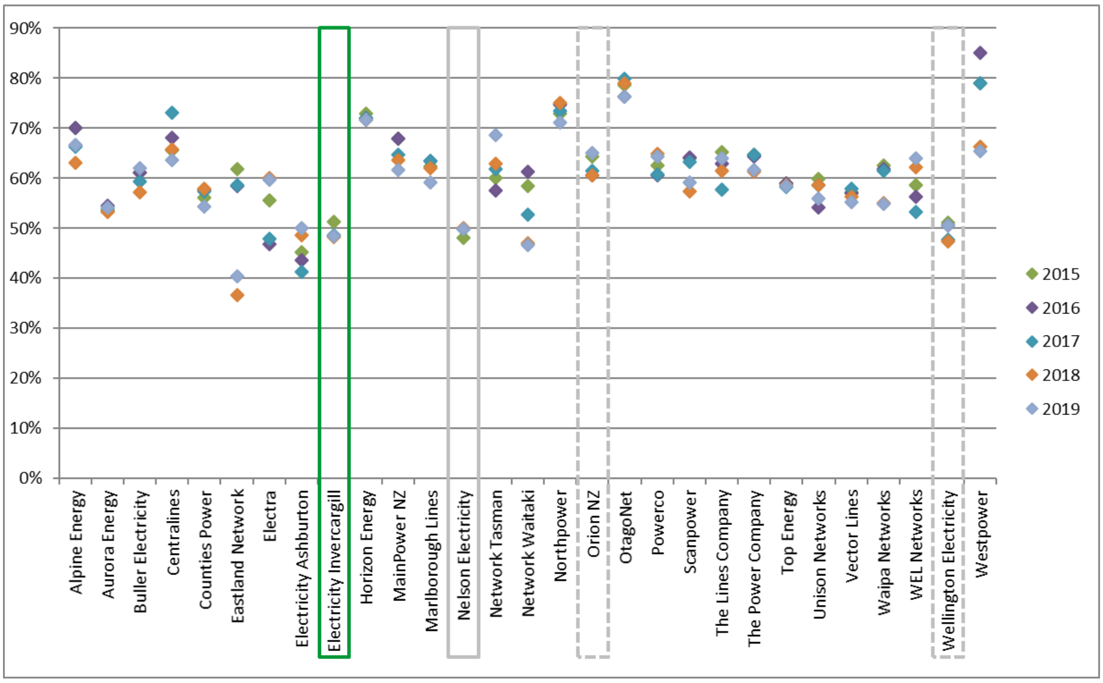


Figure 28: EIL Load Factor Comparison with Local EDBs

Comparison with other networks shows that EIL's load factor, although low, is comparable with similar networks. Improving load factor would require influencing customer's consumption patterns, which is difficult to achieve because any line charge incentives offered are repackaged by retailers billing methodologies. Load factor is expected to remain at current levels in the short term.

Loss Ratio - Despite increasing focus on energy efficiency, it is generally uneconomic to improve the efficiency of primary assets to improve losses. As losses are paid for by retailers, there is no financial incentive for the network company to reduce them, except when losses reach such an extent that other technical issues arise such as poor voltage or an exceedance of equipment ratings. Upgrading network equipment as growth occurs is expected to maintain losses at approximately present levels.

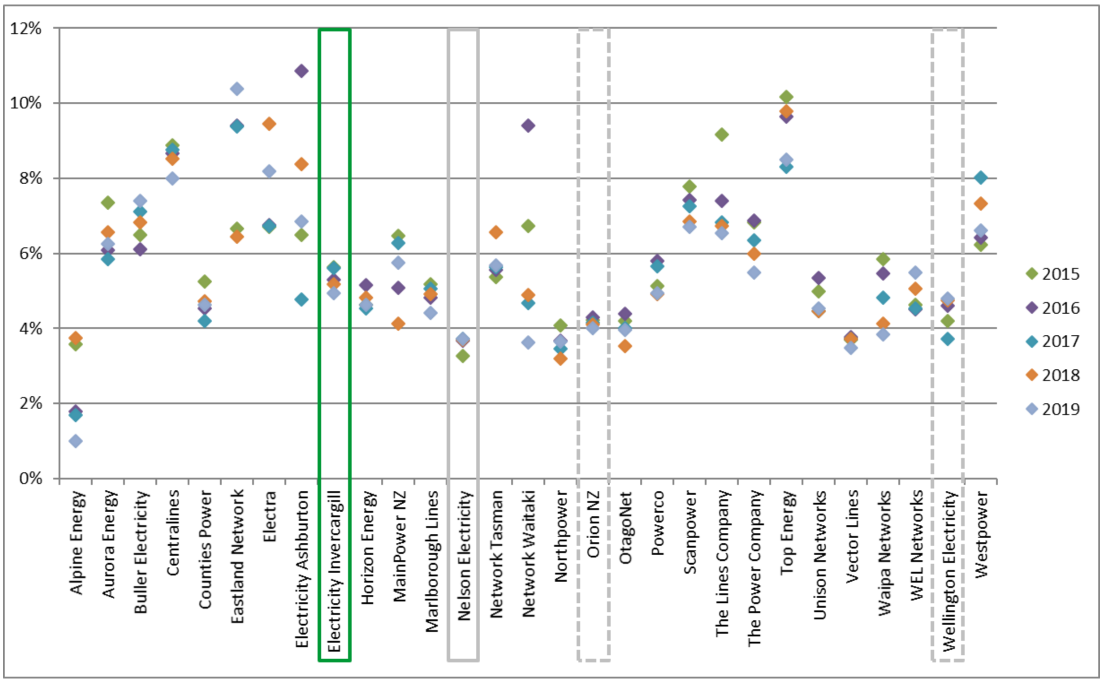


Figure 29: EIL Loss Ratio Comparison with Local EDBs

Comparison with other network companies shows EIL's network is moderately efficient. Trending over a five year period shows losses to be relatively stable between 5.3% and 5.6%. EIL can expect a long term average of about 5.5% to be maintained however year-to-year results can vary considerably due to retailer estimations. Smart meters will enable improved data and loss identification.

Capacity Utilisation - optimisation of transformer size and numbers 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 improvement is warranted. Smart meters will provide better equipment loading data, and allow better equipment utilisation.

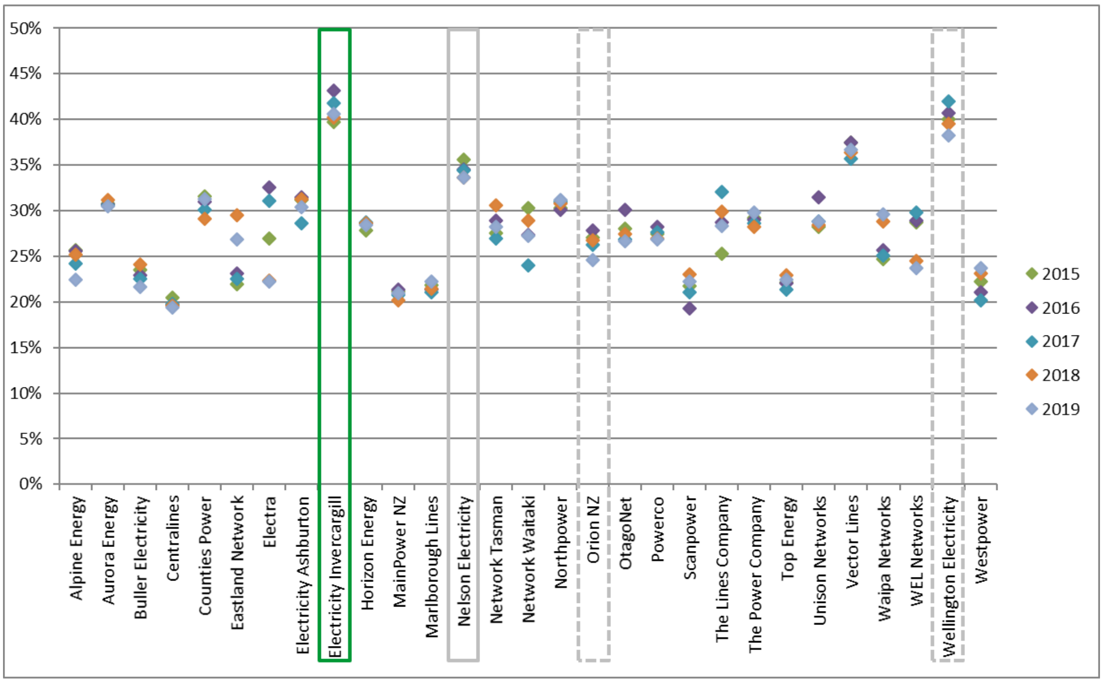


Figure 30: EIL Capacity Utilisation Comparison with Local EDBs

Financial efficiency – The six ratios that EIL has adopted as financial efficiency measures do not highlight any areas of concern as benchmarked against industry peers. Per ICP operational expenditure is average to good. Per km of network length operational expenditure is relatively high in comparison to industry peers however this is to be expected due to the high customer density and similar results can be seen from similar high density distribution networks. Per MVA of distribution transformer capacity operational expenditure is also moderate to good.

Recent expansions in the complexity of the business and its agency agreements have required an increase in the non-network targets to cover the associated increased consultancy costs. Reclassification of shared facility costs have also put upward pressure on this target. However initiatives to improve scheduling and efficiency of PowerNet's workforce are being progressed and are anticipated to have a positive impact on future results.

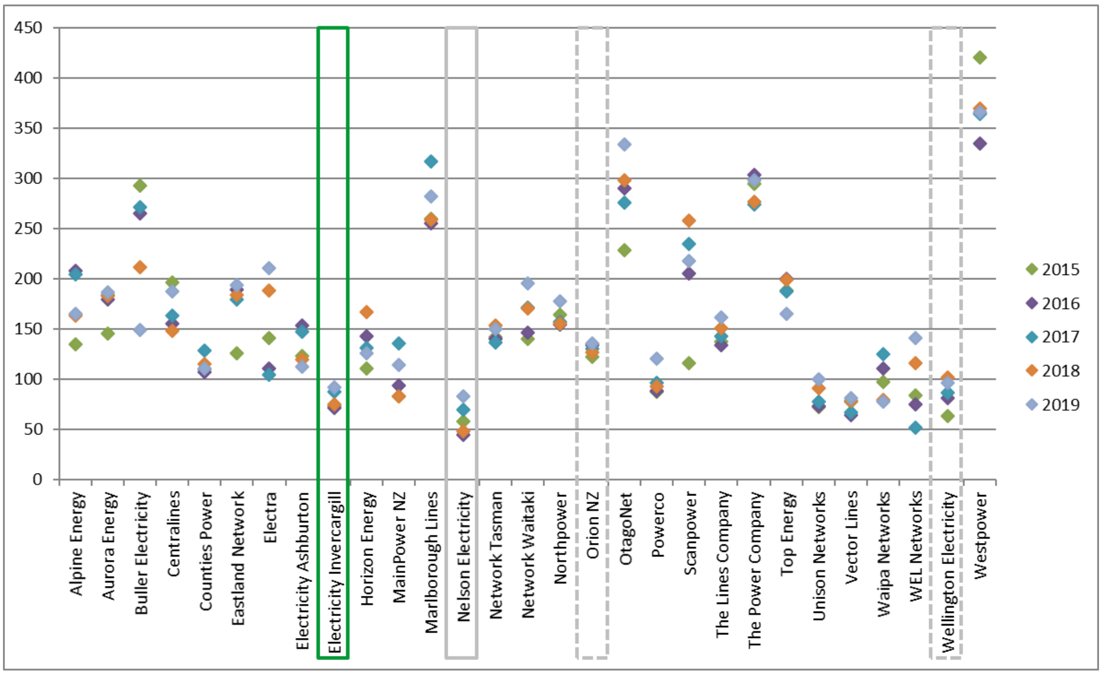


Figure 31: EIL Network $OPEX/ICP Comparison with Local EDBs

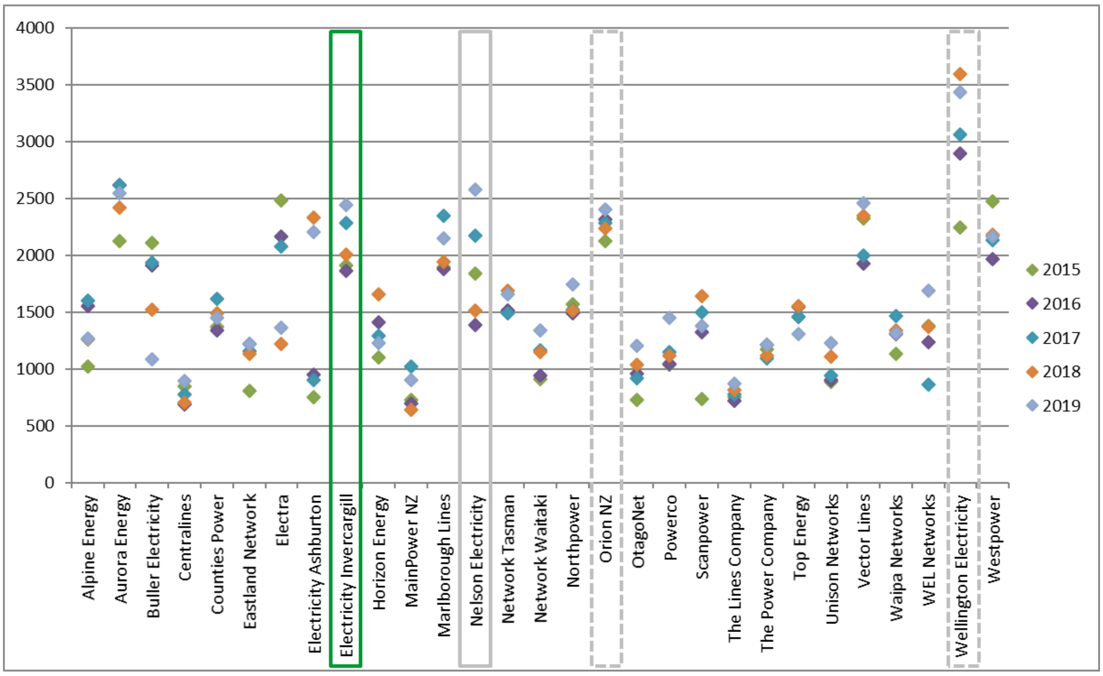


Figure 32: EIL Network $OPEX/km Comparison with Local EDBs

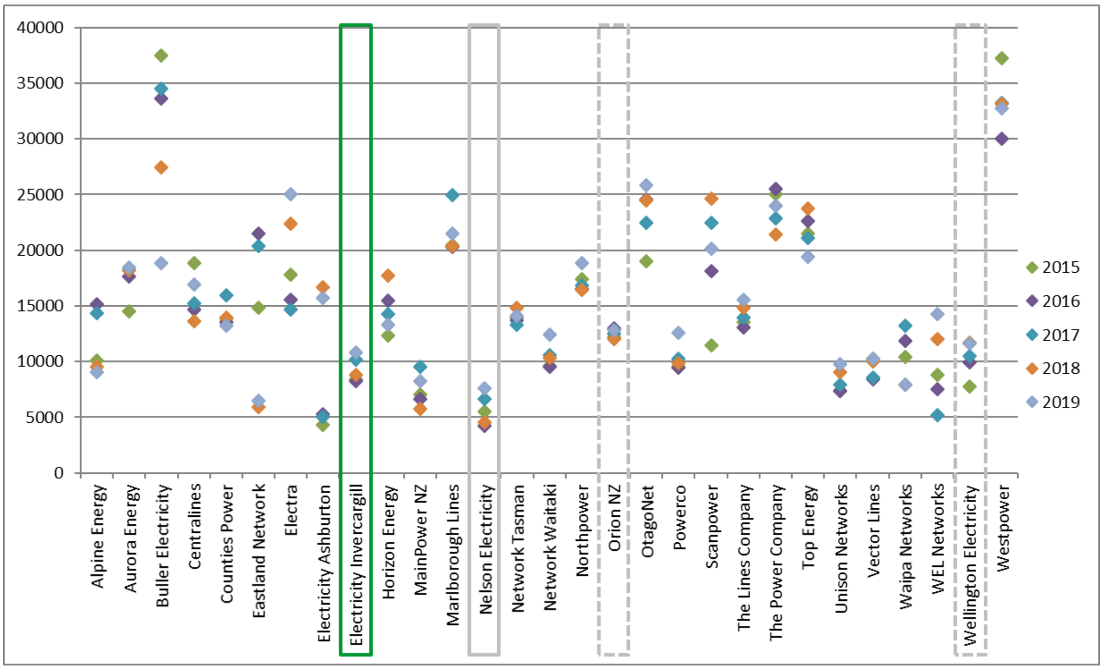


Figure 33: EIL Network $OPEX/MVA Comparison with Local EDBs

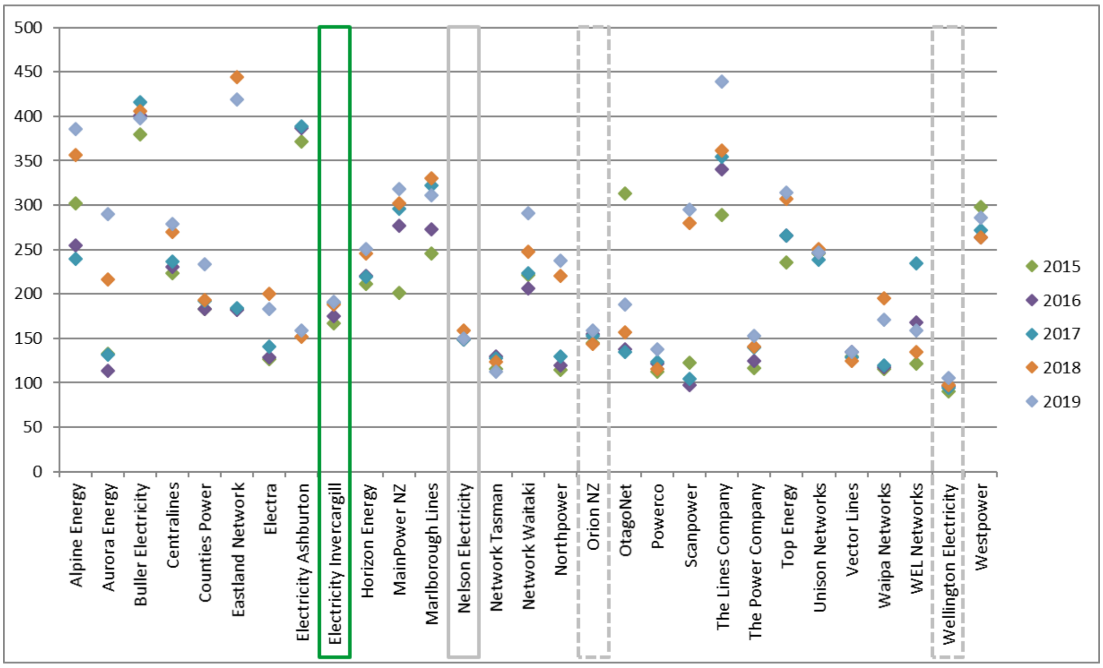


Figure 34: EIL Non-Network $OPEX/ICP Comparison with Local EDBs

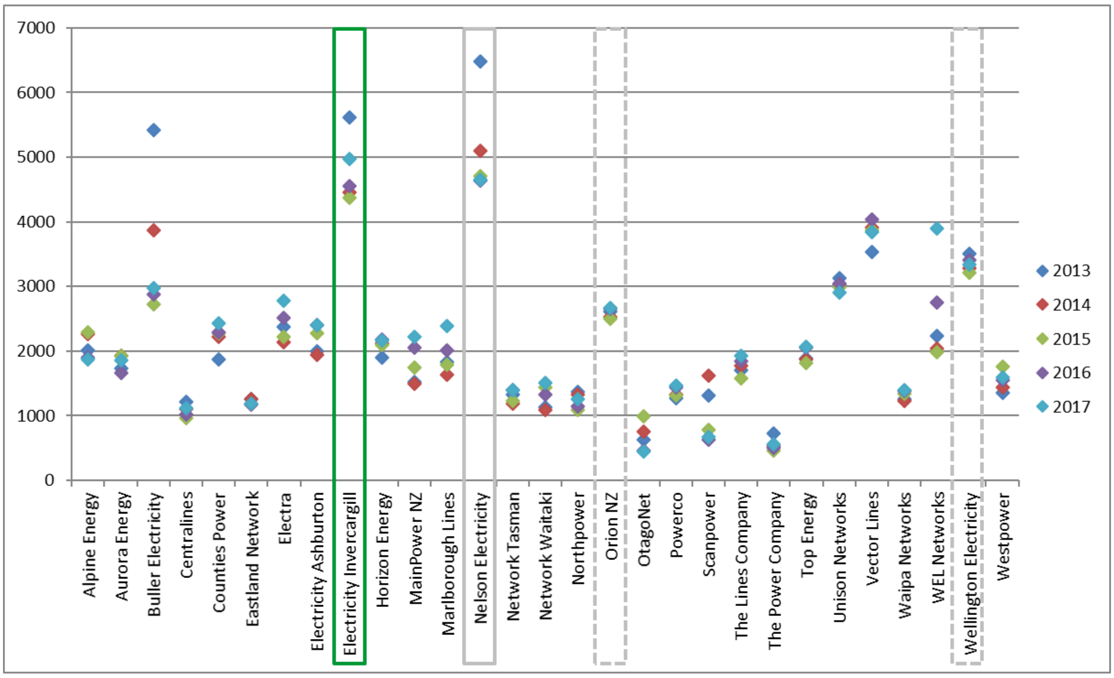


Figure 35: EIL Non-Network $OPEX/km Comparison with Local EDBs

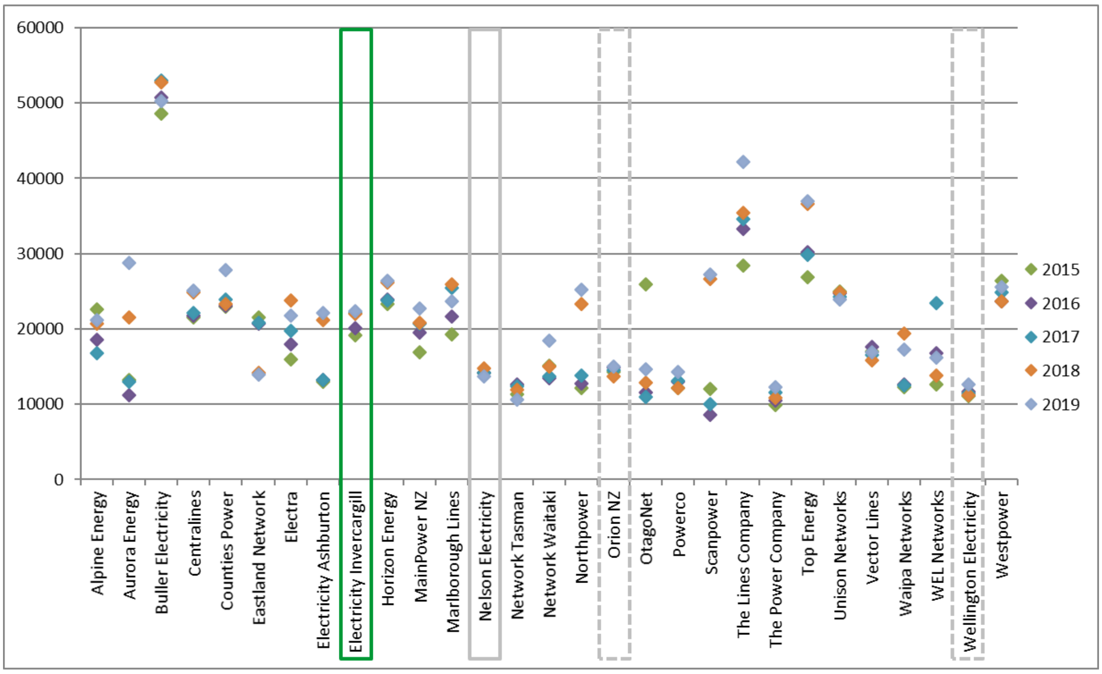


Figure 36: EIL Non-Network $OPEX/MVA Comparison with Local EDBs

4. Development Planning

EIL monitors the existing network assets and ensures their operation within limits imposed by capacity constraints and service level requirements. Regular updating of demand forecasts enables predictions for future network operation and in line with EIL's development criteria helps identify the need for network development.

4.1. Development Criteria

Network development is primarily associated with creating additional network capacity for supplying increasing demand (customer load). Large generation or an aggregation of many small generators may also become the dominant driver for increased capacity on some areas of the network. Requirements for maintaining or improving service levels, whether driven by statute, customer and other stakeholders' desire or internal strategic initiatives, also create development drivers. While asset renewal is generally a lifecycle management requirement, it may present an opportunity as the most economic time for development initiatives such as additional capacity, the introduction of new technology, or more efficient alternative solutions.

Network developments are triggered by events that necessitate changes to network capacity or service levels. These trigger events may directly dictate a development requirement for example a connection request from an intending customer requires an increase in network capacity to match their additional load requirements. They may also be less direct such as when load growth exceeds a threshold for increased security; the security trigger threshold being predetermined based on a strategic "line in the sand" designed to provide particular service levels when applied consistently across the network. Identified development triggers and the thresholds at which they are set form the key criteria for EIL's network development planning.

Growth Based Development Triggers

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. As the load aggregates up the network, load diversity tends to favour better load factor and capacity utilisation.

Demand growth creates the predominant driver for network development and therefore growth triggers have been identified and where appropriate corresponding thresholds have been set to achieve desired service levels. These development triggers provide simple scenario based indicators for development requirements although reliability incorporates probabilistic considerations. In meeting future demand while maintaining service levels, the first step 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 26.

If a trigger point is exceeded, EIL will 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 later in this section (see Cost Efficiency) which also embodies an overall preference for avoiding new capital expenditure. As new capacity has balance sheet, depreciation, and ROI implications for EIL, endeavours will be made to meet demand by other, less investment-intensive means. This point links strongly to EIL's discussion of asset life cycle in Lifecycle Planning.

Table 26: Development Triggers and Typical Network Solutions

Development	Trigger Point	Typical Network Solution
Extension	New customer requests a connection outside of the existing network footprint; often within network area but not immediately adjacent to existing infrastructure.	New assets are required to extend the network to the new customer. Additional capacity may also have to be built into the nearest existing network and upstream assets depending on customer size.
Capacity	Load exceeds capacity rating of network assets (or encroaches on spare capacity required to be maintained) or voltage drops below acceptable levels; i.e. below 0.94pu at customer's premises. Proactively identified through network modelling and monitoring load data from meters or MDIs* but may occasionally manifest as overload protection operation, temperature alarms or voltage complaints. The current roll out of smart meters will vastly improve ability to estimate loading and utilisation of asset capacity.	Replace assets with greater capacity assets. May utilise greater current ratings or increase voltage level (extension of higher voltage network, use of voltage regulators to correct sagging voltage or introduction of new voltage levels). Alternative options are considered prior to these capital intensive solutions but generally provide a means to delay investment; may be network based such as adding cooling fans to a zone substation transformer or non-network e.g. controlling peak demand with ripple control.
Security and Reliability	Load reaches the threshold for increased security as defined in EIL's security standard set out later in this section (see Security Standards). Customers especially large businesses may request (and be willing to provide a capital contribution for) increased security.	Duplicating assets to provide redundancy and continued supply after asset failures. Increase meshing/interconnection to provide alternative supply paths (backups). Additional switching points to increase sectionalising i.e. limit amount of load which cannot have supply reinstated by switching alone after fault occurrence. Automation of switching points for automatic or remote sectionalising or restoration.

*MDI = Maximum Demand Indicator – device that monitors the highest demand on the equipment

Service Level Changes

The general approach of monitoring network demand, and initiating projects when standardised development triggers are reached, serves to maintain existing service levels. Where a change in service level is desirable, this may be undertaken either directly (e.g. targeted seismic remediation program to improve safety and resilience under earthquake conditions), or indirectly through the adjustment of the thresholds used for the triggers (e.g. lowering the minimum number of downstream customers required to justify a dual transformer substation). These decisions tend to be strategic in nature and go beyond the general approach of monitoring network demand and initiating projects when standardised development triggers are reached.

These projects may be triggered by a complex interaction of many factors or driven (or required) by external influences. Justification for these projects will be discussed later in this section (see Development Programme). Examples are the shifting perceptions around staff/personnel safety or acceptable levels of risk, and these will create drivers for network development projects which are not a requirement arising from demand growth.

Relationship with Lifecycle Maintenance

It is important to understand the relationship between network development, lifecycle management practices and the network service levels discussed in section Service Levels. Demand growth on fixed network assets erodes supply reliability over time as a greater number of customers or level of demand is affected when a supply interruption occurs. Using increased network maintenance to preserve network reliability against demand growth requires a shift away from the most economic asset age profiles (generally about 50% average life) which then must be sustained so this approach is uneconomic as well as inherently limited. Essentially in the long term view, lifecycle maintenance counteracts declining reliability in the face of network aging and deterioration, while network development counteracts declining reliability in the face of demand growth.

Cost Efficiency

In the interests of cost efficiency, EIL aims to minimise capital expenditure when determining the most appropriate development option for the network. Being cost efficient with network development requires a “just enough, just in time” approach for the determination of appropriate new capacity, and an appropriate level of standardisation. Other works within the locale may be brought forward and combined to achieve economies of scale for design, safety, and traffic management costs.

Before capital intensive upgrades are required, the following options, in a broadly descending order of preference, are considered when development triggers have been reached:

- 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 drops below the network standard minimum level for a short period at the height of the holiday season – the benefits of correcting such a constraint are simply too low to justify the expense.
- 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.
- Demand management using load control or using other methods to influence customers’ consumption patterns so that assets operate at levels below 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 diminished by the retailer's practice of repackaging fixed and variable charges.

- Install generation or energy storage units so that an adjacent asset's performance is restored to a level below its trigger points. These options 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. Installation of voltage regulating transformers may be economic where voltage drops below acceptable levels but current capacity is not fully utilised.
- 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.

Installing new or greater capacity assets is generally the next step which increases asset capacity to a level at which the relevant trigger point is not exceeded. An example would be to replace a 200 kVA distribution transformer with a 300 kVA unit so that the capacity criterion is not exceeded.

For meeting future demands for capacity, reliability, security and supply quality there may be several options within the above range of categories and identifying potential solutions is dependent on the experience and ingenuity of the Engineers undertaking the planning.

Standardisation

Standardisation is an important strategy used by EIL to achieve cost efficiencies. It may not always be obvious that standardisation achieves this outcome; standardised equipment sizes will often mean larger equipment is used than would otherwise be strictly necessary. However, standardising assets allows efficient management of stock and spares, operator familiarisation, standardisation of operation procedures, and simplified selection of equipment and materials. Standardised designs or design criteria also avoid "reinventing the wheel", simplifies the design process, and can incorporate more learnings than could otherwise be practically managed. The benefits of standardisation easily outweigh the oversizing of assets where significant repetition of a particular network solution occurs.

PowerNet's Quality Systems (policies, standards and procedures) provide for the documentation and communication of the standards that are applied to EIL's network. EIL benefits from their close working relationship with the other line owners whose networks are managed by PowerNet, with the standardisation able to be maintained across networks for increased efficiencies. Examples include the keeping of critical spares, which can be more efficiently achieved when shared across the combined network's asset base; or lessons learnt on one network that can be incorporated into standards which then benefit the other networks. Standardised design is used for line construction with a Construction Manual and standard drawings in use by planners, designers, construction staff.

Standardised designs for projects may be used from time to time where projects with similarities occur within a short enough period of time. Though these opportunities do not arise often on EIL's network, similar projects are often managed by PowerNet on other networks and where project scopes overlap design "building blocks" may be utilised in several designs. Through this approach a degree of standardisation is achieved, with each consecutive design utilising these building blocks from the latest previous design. Continuous improvement is realised with lessons learnt able to be incorporated at each iteration.

Virtually all of the EIL network assets are standardised to some degree either by being an approved network material or asset type or by selection and installation in line with network standards. Examples of standardisation are listed in Table 27:

Table 27: Equipment Standardisation

Component	Standard	Justification
Underground Cable	Distribution and low voltage network: 35, 95, 185 & 300 mm^2 Al 11 kV Cable Cross-linked Polyethylene (XLPE)	Stocking of common sizes, lower cost Rating, ease of use.
Overhead Conductor	Subtransmission and distribution: All aluminium alloy conductor (AAAC) - Chlorine, Helium, Iodine, Neon or Aluminium conductor steel reinforced (ACSR) – Flounder, Wolf Low Voltage Aerial Bundled Cable (ABC): 35, 50 & 95 mm^2 Al (four core).	Low corrosion, low resistance, cost, stocking of common sizes Higher strength (longer spans, snow load) Safety, lower cost.
Structures	Poles: Busck pre-stressed concrete Cross-arms: Solid hardwood	Consistent performance, long life, strength Long life, strength.
Line equipment	Standard ratings (e.g. ABS 400 A, field circuit breaker 400 A), manufacturer/type	Cover-all specification, minimise spares, familiarity, environmental (non SF_6)
Power Transformers	Discrete ratings, tap steps, vector group, impedance, terminal arrangements etc.	Ratings match available switchgear ratings, interchangeability, network requirements.
33 kV & 11 kV Switchboards	Common manufacturers, common specification.	Interchangeability spares management.
Protection and Controls	Common manufacturer, communications interface, supply voltage etc.	Minimise spares, familiarity, proven history
Substation equipment	Standard ratings, equipment type, manufacturer etc.	Minimise spares, familiarity, proven history
Distribution Transformers	Standard ratings (residential areas - size based on domestic customer numbers), equipment type, manufacturer etc.	Minimise spares, familiarity, proven history, cover-all specification.
Ring Main Units	Standard ratings, equipment type, manufacturer etc.	Minimise spares, familiarity, proven history, cover-all specification.

Security Standard

Security is the level of redundancy that is built into the network to provide improved continuity of supply when faults occur. It enables supply to be either maintained or restored independently of repairing or replacing a faulty component. EIL's security standard is therefore crucial for the maintenance of network reliability levels. Security involves a level of investment beyond what is strictly required to meet demand, but maintenance of the desired security level must account for demand growth eroding surplus capacity. Typical approaches to providing security include:

Provision of alternative supplies: achieved by providing one or more inter-feeder tie switches (interconnection points). Urban areas can naturally achieve a high level of meshing with many tie points between feeders whereas rural area feeders may need significant line extension to meet adjacent feeders. The number of switches effectively dividing up a feeder also contributes to security, with the greater the number, the smaller the section which must be isolated after a fault for the duration of the repair. This requires those adjacent feeders to maintain spare capacity.

Duplication of assets: In normal service both sets of assets share the load. When a duplicated asset malfunctions it can be isolated, and all load can be transferred to the remaining asset. This approach generally provides the greatest security as it can completely prevent interruption to supply; but duplication of assets tends to be more expensive than merely allowing greater capacity in existing adjacent assets.

Use of generation: may be used to either provide an alternate supply, or to partially supplement supply and reduce capacity requirements for backup assets. From a security perspective, generation needs to have close to 100% availability to be of benefit. Diesel generation has good availability and is used occasionally to manage network constraints, although it is too expensive to run for extended periods. Other forms of generation such as run-of-the-river hydro, wind or solar, do not provide the needed availability due to lack of energy storage and so cannot be relied on to respond to varying load or provide sufficient generation during peak demand periods.

Use of demand management: (interruptible load) can be used to avoid security triggers based on load level or avoid capacity of backup assets being exceeded.

The preferred means of providing security to urban zone substations will be by secondary subtransmission assets with any available back-feed on the 11 kV providing an extra level of security. Table 28 summarises the security standards adopted by EIL. An exception to these standards occurs when a substation is for the predominant benefit of a single customer; in this case the customer's preference for security will be documented in their individual line services agreement and will set the minimum security level.

Table 28: Target security levels

Description	Load type	Security level
AAA	Greater than 12 MW or 6,000 customers.	No loss of supply after the first contingent event.
AA	Between 5 and 12 MW or 2,000 to 6,000 customers.	All load restored within 25 minutes of the first contingent event.
A(i)	Between 1 and 5 MW	All load restored by isolation and back-feeding. Isolated section restored after time to repair.
A(ii)	Less than 1 MW	All load restored after time to repair.

Table 29: EIL Zone Substation Security

Substation	Current Security Level	Required Security Level	Remarks
Spey Street	AAA	AAA	Dual 33kV transformer feeders from Invercargill GXP.
Leven Street	AAA	AAA	Short interruption required to switch to alternative supply from another GXP
Southern	AA	AAA	Relocation of transformer planned to address security of supply. Short interruption required to switch to alternative supply
Racecourse Road	AA	AA	Single transformer feeder from Invercargill GXP. Short 33kV cable. Alternative supply from 11kV backfeed.
Bluff	AAA	AA	More economic to provide AAA security at the site, due to the lack of 11 kV backup capacity.

Determining Capacity

When new or increased capacity has been determined as necessary the amount of new capacity must be quantified. Appropriate asset sizing is balanced to fit within EIL's guiding principle, which is to minimise the long term cost to provide service of sufficient quality under foreseeable demand.

Sizing network equipment carries an investment risk for assets being underutilised if not done correctly. While sizing a particular asset for the present time is relatively straight forward, load growth makes appropriately sizing an asset more difficult, especially for asset lifetimes over periods of high growth and growth unpredictability. Installing assets with too much spare capacity means an over investment however if assets are undersized the asset will need to be replaced early before their natural end of life. In many cases standardisation will limit the options available to assist in the selection of capacity. In general, this will mean the balancing of over-investment and under-investment will result in a small amount of over-investment (i.e. increased capacity). However, this is considered to be optimal, due to the often marginal cost of increased capacity versus significant cost of re-work should the investment prove to be under-sized.

Stranding of assets is a risk where new assets are required to supply one (or few) new customers representing the worst case in overinvestment if the expected growth does not eventuate. This stranding risk is particularly significant when network extension outside of the existing network footprint is required as the assets are less likely to be reutilised if the expected load disappears. Stranding risk is generally managed through capacity guarantee contracts with customers to recover expected line charges if necessary.

Relocation of assets provides a way to manage costs efficiently while limiting exposure to the above risks in areas of growth. However this strategy is only of benefit where the material cost dominates the installation cost of establishing an asset; the installation cost cannot be recovered. For example once load grows to a power transformers capacity the transformer can be relocated and used elsewhere so that a larger unit may be installed in its place. In comparison a cable (where trenching and reinstatement dominates installation costs) would typically be abandoned and replaced.

Examples of criteria to determine capacity of equipment in line with the above considerations are as shown in Table 30. Clearly understanding load growth into the future is crucial to making sound investment decisions. The method and considerations for forecasting network demand is discussed later in this section.

Table 30: Capacity Selection Criteria

Network Asset	Capacity Criteria Selection
Subtransmission network	Allow expected demand growth over life time of assets
Power transformers	Allow expected demand growth over 20 years then relocate
Switchgear	Allow expected demand growth over life time of assets
Distribution and LV cables	Allow growth over expected life when known or otherwise 100% growth over existing load
Overhead distribution and LV lines	Build to standard volt drop from nominal: Urban — 11 kV: -3%, LV: -5% Rural — 11 kV: -4%, LV: -4%
Distribution transformers	Size based on diversity and anticipated medium term load: Domestic Customers — Transformer Size 2 — 15 kVA 6 — 30 kVA 10 — 50 kVA 20 — 100 kVA 50 — 200 kVA 80 — 300 kVA 150 — 500 kVA Individual customers — Size to customer requirements

Energy Efficiency

EIL strives to make decisions based on the best outcome for its customers; customers pay for losses on the network in their energy bills, so it is in the customer's interest to deliver energy as efficiently as possible. However from a customer's benefit-cost point of view, the extra expense of a more efficient asset will generally outweigh the benefit of that asset. In the few cases where there is an economic justification to reduce losses in this way EIL will use these solutions, e.g. specifying low loss cores used in the magnetic circuits of transformers.

Power consumed by EIL and its organisational partners is used responsibly, with substation buildings and PowerNet's office buildings heated using efficient heat pump technology, insulation and draft control etc. where appropriate. EIL formed the Southland Warm Homes Trust (SWHT) in 2008 with the Southland Power Trust (TPCL's shareholder). The SWHT works in partnership with government, the Energy Efficiency and Conservation Authority (EECA) and local funders to provide subsidies for insulation and heating assessments and retrofits for warmer, healthier homes across the Deep South region. PowerNet provides administration and financial reporting services on behalf of the (SWHT).

The SWHT contracts Awarua Synergy to carry out assessments and the installation of insulation and heating products on behalf of the Trust. Under EECA's Warm Up NZ Healthy Homes program which came into effect on 1 July 2013, insulation is free for eligible homeowners. Landlords with eligible tenants are also included but will be required to make a contribution. The Healthy Homes scheme targets those who stand to benefit most from having their homes insulated, those being low income households with high health needs, including families with children and the elderly. EECA provides 50% of the funding conditional upon the remaining 50% funding coming from third party funders.

Identifying the Best Option

Development options to meet demand and service levels are identified. The option which best meets EIL's investment criteria is determined using a range of analytical approaches. Each of the possible approaches to meeting demand will contribute to strategic objectives in different ways. Increasingly detailed and comprehensive analytical methods are used for evaluating more expensive options. Table 31 summarises the decision tools used to evaluate options depending on their cost.

Table 31: Decision Tools Used Based on Cost

Cost and Nature of Option	Decision Tools	Approval Level
Up to $75,000: commonly recurring, individual projects not tactically significant but collectively add up.	EIL standards. Industry rules of thumb. Manufacturer's tables and recommendations. Simple spreadsheet model based on a few parameters.	Project Manager
$75,000 to $250,000: individual projects of tactical significance. Timing may be altered to allow resource focus on higher priority projects.	Spreadsheet model to calculate NPV that might consider one or two variation scenarios. Basic risk analysis including environmental and safety considerations. Consultation with stakeholders if necessary.	Chief Engineer
$250,000 to $1,000,000: individual projects or programmes of tactical or strategic significance. Timing may be flexible depending on priority.	Extensive spreadsheet model to calculate NPV that may consider several scenarios. Risk analysis including environmental and safety considerations with consideration to management cost. Consultation with stakeholders if necessary.	Chief Executive
Over $1,000,000: occurs maybe once every few years, likely to be strategically significant. May divert resources from routine lower cost projects in the short term.	Extensive spreadsheet model to calculate NPV, payback that will probably consider several variation scenarios. Detailed risk analysis including environmental and safety considerations - represented as cost estimates within NPV and Payback calculations. Resources (financial, workforce, materials, legal) across AWP need to be balanced across many projects and several years managed through analysis and planning meetings. Ongoing stakeholder consultation may be required especially large customers. Business case presented to the Board, highlighting options considered and justification of recommended option.	Board Approval

Prioritising Development Projects

Development projects are prioritised in line with the principles set out in Drivers and Constraints – Managing Conflicting Stakeholder Interests when competition for resources exists. Safety, viability, pricing, supply quality and compliance is the order of priority for managing these conflicts. These factors cannot be applied absolutely as each project will have its own combination of these factors presenting in various degrees. Instead a weighting approach is used recognising the relative severity of these factors between projects and their importance relative to each other. Each factor also implicitly recognises risk however this may need to be rationalised as it affects the AWP as a whole. The resulting prioritised AWP is presented to the EIL Board for approval with supporting justification in the updated AMP.

4.2. Forecasting Demand and Constraints

As development projects can take many months or even years to complete, understanding when trigger points may be exceeded in the future is necessary to ensure capacity can be made available by the time it is needed. This involves demand forecasting based on trends taken from historical data as well factoring in the many demand drivers which may cause future deviation from status quo trends.

EIL's Current Demand

EIL's maximum demand (MD) of 63.07 MW did not occur at the same time as the Lower South Island (LSI) peak which occurred at 09:30 on the 1stof June 2018. The EIL Bluff MD of 4.28 MW occurred at 18:30 on the 24th of May 2018, 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 48.39 MW with 2.98 MW of that load contributed by Bluff EIL. The individual maximum demands are shown in Figure 37

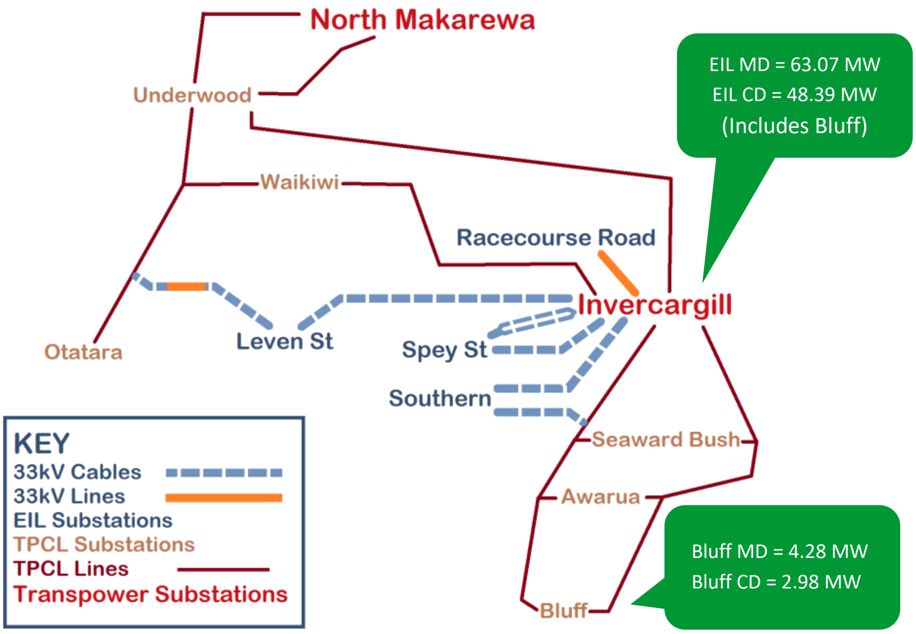


Figure 37: GXP and Generation Demands

Demand History and Trend

Growth trends are difficult to establish as there is somewhat random variation on top of underlying growth. Generally a ten year rolling average will vary substantially between successive years. Trending over a longer term tends to average out the random variations but also obscures recent changes to underlying growth. Some causes may be identified with hindsight but are typically difficult to predict, for example 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 38: Maximum Demand and Energy Transmitted shows the overall EIL data since 1950 and highlights the flattening out since the late ‘80s. The data presented is for supply to customers’ connection points and excludes transfers between networks. Recent increases in maximum demand have been affected by changes in Transpower’s transmission pricing methodology (TPM); these changes are not apparent in energy growth.

Analysis of historic demand and energy usage indicates maximum demand growth has been stabilising in recent years after an increasing trend at the start of the decade; while energy consumption is showing a clear and consistent downward trend. The following sections examine in detail the most significant drivers of the network demand over the next 10 to 15 years.

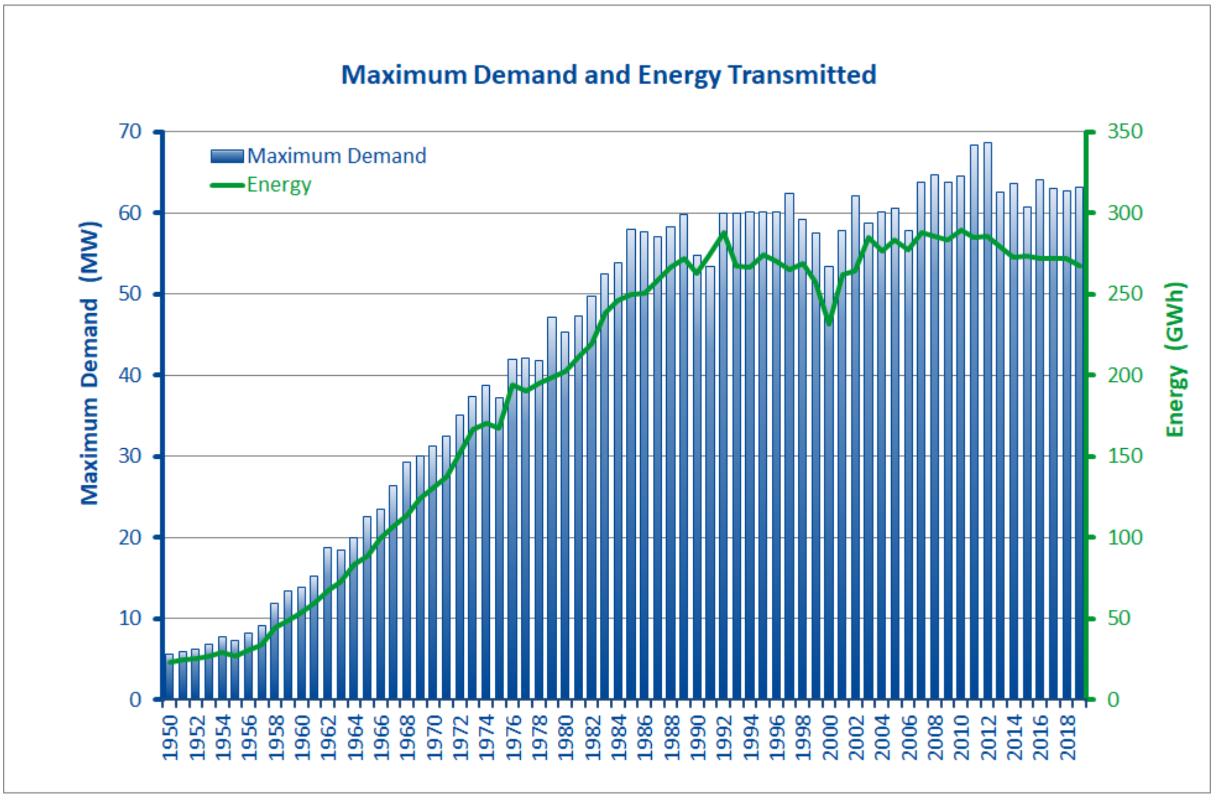


Figure 38: Maximum Demand and Energy Transmitted

Each zone substation recorded the maximum demands as listed in Table 32. The 99.9th percentile demand is given to remove any short term load transfers and produce a figure more indicative of actual area maximum demand. In recent years, extended or permanent load transfers between the zone substations have distorted these numbers, and allowance must be made for these transfers when analysing at the substation level. The overall EIL maximum demand gives a better representation of growth, although allowance must still be made for extended load transfers outside the network (e.g. from TPC's Seaward Bush substation to Southern substation in 2018/19).

Table 32: Substation Demand

Zone Substation	99.9% Percentile Demand (MVA)							
	2018/19	2017/18	2016/17	2015/16	2014/15	2013/14	2012/13	2011/12
Spey St*	25.5	24.8	21.0	19.0	17.0	17.2	14.5	13.6
Leven St	14.2	11.7	16.1	15.3	15.2	15.2	17.9	18.3
Racecourse Rd	10.2	10.1	10.6	9.7	9.2	9.4	12.7	12.7
Southern	12.9	14.2	14.8	14.5	14.7	13.5	14.3	14.2
Bluff (TPCL)	5.4	4.7	4.4	4.7	4.7	4.7	4.7	4.8

*Load was transferred to the new Spey Street substation from Doon St sub over 2015/16.

It has been noted in the past that growth rates tend to be slightly higher in the commercial and industrial areas of the network. Trends for these areas have become difficult to extract due to the shifting of load between substation feeders in recent years to manage substation loads and security risks around staging of previous development projects. However, regardless of the variation of growth affecting the distribution network areas, the loading on each zone substation can be monitored with respect to development triggers and managed by shifting load as required.

Drivers of Future Demand

Future demand is forecasted by understanding historical trends, projecting these trends into the future and altering these projections by factors which are likely to cause deviation of demand away from the current trends.

Table 33: Demographics and Lifestyle Drivers of Future Demand

Demographics and Lifestyle	
Population Growth and Decline	**Effect:** Population increasing in future years to ~5% by 2030. This corresponds to a similar increase in demand of 5% assuming similar housing and living arrangements, and assuming that employment is available under a similar business profile.
Description: The population of EIL's distribution area is approximately 35,000 of which the Bluff area accounts for approximately 5%. 2013 Census population projections for EIL's distribution area are shown in Figure 39. (Statistics NZ have not yet updated their population projections with 2018 Census data) Statistics NZ estimates that the Invercargill City population grew approximately 1% per annum between 2013-2018, and 0.7% between 2018-2019. This rate is in-line with previous population growth estimates. Long term growth is expected to be relatively flat in the medium term. Upper bound projection of population growth of ~5% by 2030. It is expected that the vast majority of growth would occur in urban areas of which Invercargill is Southland's largest metropolitan area. The Southland Regional Development Strategy has as its main target an increase in population to 105,000 by 2025 for the Southland region. Population growth over 2013-2019 is on target so far, and is poised to meet the 2025 target barring factors discussed below.	

Demographics and Lifestyle

Invercargill would attract the majority of potential migrants however the Invercargill area supplied by EIL is surrounded by TPCL which supplies the outer regions of the city. Expansion of Invercargill for additional housing would therefore often be outside of EIL's network boundary although this expansion requires new housing and individuals or families in a sufficient financial position. EIL does have some undeveloped land suitable for housing and there is further potential for in-build with subdivided sections which if increased demand eventuates would be utilised to some extent.

Business expansion is also a target for the Southland Regional Development Plan and again Invercargill would expect to be a key location for this to occur. A commercial subdivision to support any potential new commercial building is available within EIL's Invercargill network area.

Concerns about the closure of the Tiwai smelter and its effects on the local economy have resurfaced. The national government initiative to centralise certain functions of NZ Polytechnics may diminish the attractiveness of Southland Institute of Technology as a tertiary education provider to potential migrants.

Housing Density and Utilisation — **Effect:** Overall support of domestic power demand growth from increasing population as described above. Effects of increased housing density is somewhat offset by increasing housing utilisation as more people share heating and other power requirements.

Description: Housing density and utilisation can be expected to increase to some degree as the population increases. The trend for low care properties especially with an aging population is expected to continue while at the same time in-build is expected to continue as property owners subdivide in line with this demand. An increase in the student population may increase demand for higher density student accommodation facilities near central Invercargill.

Rural Migration to Urban Areas — **Effect:** Population growth especially from retirees (baby boomers) is expected to have a limited driver for increased demand. Effect is captured in population growth effect above discussed above.

Description: Urbanisation is a trend seen worldwide with rural people migrating into metropolitan areas and this trend has been seen in Southland also. Farming has been shedding jobs for some time as improved technology means fewer people are required per unit of production. This supports the above assumption that Southland's urban areas, particularly Invercargill is likely to see the vast majority of population growth if the population growth strategy is successful.

Figure 39 shows the number of people 65 years and older is projected to increase from about 15% to between 20% and 25% in 2026. The impact of farmers retiring to urban areas increases demand for townhouses in desirable locations. Building in new areas on the outskirts of Invercargill, outside of EIL's network area or demolishing older houses to replace with more efficiently heated homes may be common for these retirees. Some additional support for retail business in Invercargill may result but overall this would have a minor impact on power demand and as this is not a new effect it is largely included in previous years trending.

Increasing Energy use per Customer — **Effect:** Growth minimal and included in existing demand trends.

Description: The use of heat pumps as air conditioners is becoming more common especially in commercial buildings. However this effect would improve load factor rather than increase peak demand as it occurs in summer while peak demand is driven by heating which occurs over the winter months.

Consumer goods including appliances and electronic technology are generally becoming more affordable however while the numbers of these goods per household may be increasing they are often not used at the same time. Energy efficiency is also improving for many of these items offsetting any increases in household demand.

Demographics and Lifestyle	
Convenience of Electrical Heating	**Effect:** The effect of heat pump conversion is expected to be small, estimated to be about 0.5% growth in demand for EIL over the next ten years. Incorporates growth anticipated from Table 34; council fuel burner constraints.
Description: Electrical heating is generally the most convenient form of heating being available at the flick of a switch. Around 8% of energy consumption comes from gas and solid fuel based space heating and has the potential to be replaced by electrical heating. There is a trend of conversion to and greater reliance on electrical heating due to convenience and low running costs of electrical heating when using heat pumps. For EIL's customers, concerns with loss of heating during outages are close to negated by the high supply reliability these customers receive. However heat pump installation cost is a barrier for many people and some prefer the ambience of other heat sources. Therefore complete conversion to electrical heating cannot be expected and further conversions will occur over an extended period of time. The additional demand that arises will be partly offset by increased use of heat pumps over other traditional electric heaters which can use three to four times the power to run. Conversion will be both driven and constrained by the Breathe Easy clean air initiative discussed in Table 34.	
Electricity Affordability	**Effect:** Minimal change in demand for power supply is expected due to changes in electricity prices. Future change is likely to be a continuation of current demand trends.
Description: Consumption and demand are relatively inelastic to changes in power price as it is seen as an essential service for most people. Improving energy efficiency for heating and appliances and future technology such as smart meters and appliances are expected to counteract effects of increasing electricity prices continuing current trends.	

Figure 39 shows the current population projections for EIL's network area as estimated by Statistics New Zealand from 2013 Census base data updated with preliminary 2018 Census projections. Also the projections for the 65+ demographic are shown, highlighting the predicted significant aging of the population.

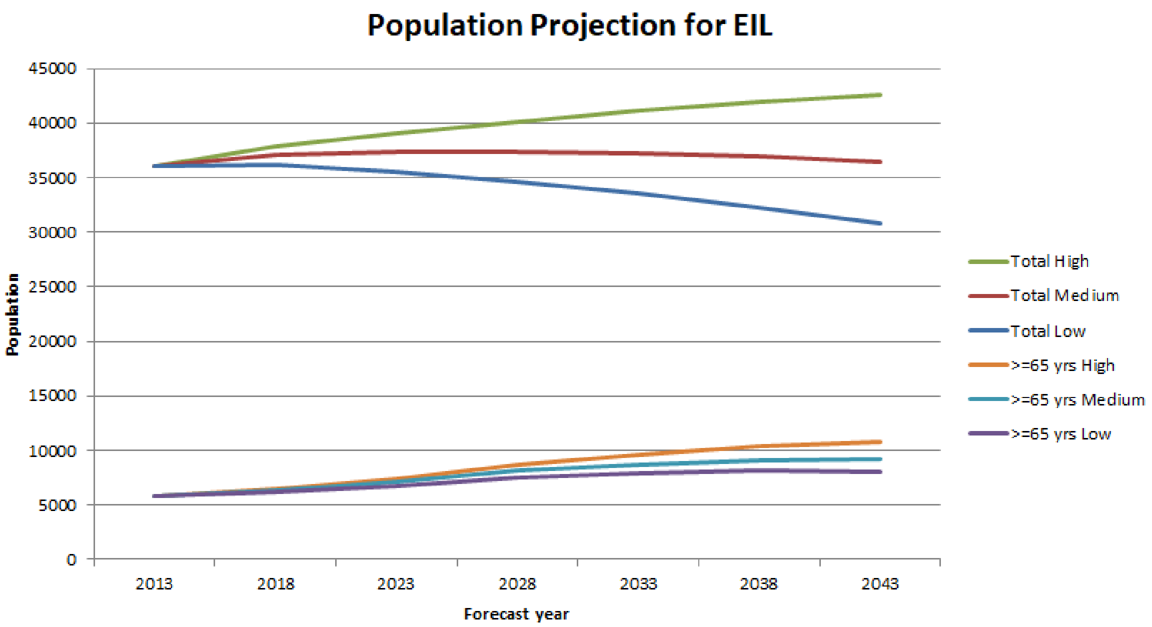


Figure 39: EIL Population Projections

Table 34: Environment and Climate Drivers of Future Demand

Environment and Climate

Council Fuel Burner Constraints — **Effect:** Continuation of existing trends towards electrical space heating

Description: Proposed updates to the Regional Air Quality Plan have been advised and include prohibition of open fires from 1 January 2017 in the Invercargill airshed area. Further prohibition of non-approved burner/boilers in the Invercargill airshed area occurs from the following dates:

Burner installation date	Prohibition date
Before 1 January 1997	1 January 2019 (wood), 1 January 2017 (other fuels)
1 January 1997 – 1 January 2001	1 January 2022
1 January 2001 – 1 September 2005	1 January 2025
1 September 2005 – 1 January 2010	1 January 2030
1 January 2010 – 6 September 2014	1 January 2034

Approved boilers and burners are those which meet the national environmental Standards for emissions and thermal efficiency. Any burners installed after September 2005 may be on the Ministry of the Environment's list of approved burners and not require replacement. This phase-out of inefficient heating will require replacement and some degree of conversion to electrical heating with heat pumps is to be expected.

Energy Conservation Initiatives — **Effect:** Customers are responding to marketing, strategies and the availability of energy efficient products to reduce their consumption. Considered a significant driver of demand contraction however is mostly recognised within existing trends. Energy savings are likely to increase to some degree estimated at 0.5% (demand contraction) over the next ten years.

Description: Energy efficiency in consumer appliances is increasingly popular due the combination of government or local council drivers, marketing and consumer demand. Replacement of appliances with improved energy efficiency provides customers with the same benefits or standard of living while requiring less power consumed and so reduces power bills. Similar drivers are contributing to further installations of insulation which also assists in reduced power requirements for heating (see above section Energy Efficiency).

Increasing Average Ambient Temperature — **Effect:** No impact on maximum demand but potentially some improvement in load factor.

Description: Increasing average ambient temperature predicted by climate scientists may create increased demand for cooling systems. This increased consumption would occur in the warmer months and therefore not coincide with the current peak demand occurring in the winter months being dominated by heating requirements. It would take a very large change in ambient temperature for peak consumption to be dominated by cooling in summer months and is expected to simply improve load factor by a small degree.

Wider Range in Weather Variations — **Effect:** Potential impact on maximum demand, and worsening load factor. Some impact on network reliability.

Description: Climate scientists forecast a potential for increasing frequency and/or intensity of storms, along with wider variations in seasonal weather. Colder periods may increase heating load, adding to current peak demand.

Government Decarbonisation Initiative — **Effect:** Potential large impact on maximum demand, load factor towards the end of the planning period.

Description: The government has set decarbonisation targets with a 100 percent renewable grid set as an "aspirational goal" by 2035 and a zero emissions economy targeted by 2050. A renewable grid supports a

Environment and Climate
zero emissions economy with electrification a key part of the decarbonisation strategy. Alongside electrification of transport, process heat electrification has been identified as critical to achieving decarbonisation targets and is anticipated as a significant driver of growth on distribution networks. While yet to be confirmed the government intends to set carbon budgets which are expected to be seen as intermediate targets that give some certainty around the trajectory of decarbonisation over the next 30 years. The emissions trading scheme (ETS) is the key tool identified to drive the transition with carbon prices effectively rising as necessary to curtail emissions. Secondary strategies such as education, emission standards and incentive schemes have also been proposed. EIL has approx 33MW of boiler capacity with 26MW fossil fuelled, generally coal or diesel. Many of these boilers are used for space heating and therefore heat pumps would be appropriate for conversion. Heat pump efficiency gain means that input electrified capacity (additional electrical demand) would likely be up to 14MW. Note some process heat requires temperatures beyond what current heat pump technology can deliver so heat pump conversion efficiency has not been considered for these plants. Additional electrical demand would likely be lower than 14 MW with some proportion opting for biomass conversion. Processes requiring high temperatures that heat pump technology cannot deliver may use a staged heating process using heat pumps to heat with 100 deg C and then using electrode boilers to increase temperature further. So full electrification of boiler capacity may not be realised.

Table 35: Economic Drivers of Future Demand

Economy	
Major Industry Continuance or Growth	**Effect:** The most likely scenario is considered that in which existing industries will continue or reduce, and no major new industries will eventuate therefore no change from existing trends forecasted.
Description: Dairy Industry, Tiwai, Major Petrochemical Extraction or Processing etc. The Tiwai aluminium smelter takes supply directly from the transmission grid; but it helps support many businesses and individuals in the EIL area, both directly and indirectly. Approximately 1000 full time equivalent employees and contractors work at the smelter. Concerns of the smelter closure have resurfaced, and likely outcome yet to be publicised as of time of writing. Loss of this business would have a major impact on the local economy and therefore growth on EIL's network in Invercargill and Bluff. The Great Southern Basin is a potentially viable location for deep water oil drilling. Possible flow on effects if a deposit is developed could create infrastructure and demand at the Bluff port however Dunedin port could be favoured over Bluff. The recent report of OMV's unsuccessful exploration of the Tawhaki 1 well, lowers confidence of the Great Southern Basin potential. Any subsequent exploration efforts are unlikely to occur before 2022. The likelihood of growth effect on the network is substantially reduced, and has therefore been excluded from forecasted growth within the planning horizon.	
$NZD Variation & Commodity Cycles	**Effect:** The improving economy will support the growth initiatives discussed in population growth and lifestyle.
Description: Economic downturn and recovery affects investment by customers and therefore the rate of growth. The global financial crisis affected the rate of growth causing a temporary stalling of new connections. A gradual recovery with growth increasing slowly has been evident. The recent coronavirus may result in an economic downturn, and stall recovery. Recent foreign exchange developments have not been favourable to the NZD, resulting in higher import prices for equipment.	

Table 36: Drivers of Future Demand

Technology	
Electric Vehicles	**Effect:** Some demand growth toward the end of the ten year planning horizon.

Description: Electric vehicles have the potential to have a large impact on network demand if there is sufficient penetration into the transport sector. While it is not considered likely that electric vehicles will be widely used in the next five years, it is forecast that by 2030 10% or more of the light passenger fleet could be electric. EIL intends to use strategies such as cost-reflective pricing to encourage electric vehicle owners to charge their vehicles during off-peak hours, thus reducing the impact on peak demand and increasing load factor.

However EIL must allow for the possibility that consumers may not respond well to price signals, causing vehicle charging to occur on-peak. In this scenario modelling shows that the EIL medium voltage network will be able to cope with the increased demand, with minor adjustments to normal configuration. However the lower diversity on the LV network makes it both more likely that voltage issues will occur, and more difficult to predict in advance where those issues will occur.

EIL, through PowerNet, has planned an upgrade of data analysis of ICP smart meters to provide increased visibility of power flow on the network. This data when analysed together with supplementary Maximum Demand Indicators at distribution substations, will better enable EIL to identify vulnerable points on the LV network and proactively upgrade to remove the weakness.

Autonomous Vehicles	**Effect:** Potential for residential customer density to spread. Potential clustering of electric vehicle charging during business hours, and greater loading on lines further from zone substations. Some impact expected toward the end of the ten year planning period.

Description: Autonomous vehicles have the potential to have a large impact on the spread of network demand if there is regulatory acceptance and sufficient penetration into the passenger transport sector.

Autonomous vehicles lowers the costs of commuting, and may make living further from centres of business more viable for consumers. The economic case for uptake is further weighted by higher housing costs in target destinations.

Adoption and network impact is highly correlated to uptake of electric vehicles, as the technology is often packaged into newer electric vehicles. Housing cost drivers are viewed as less urgent in Southland, compared to other areas of New Zealand. So the impact of this technology on network demand is expected to be less rapid.

Progress will be monitored through the same smart meter data programme described in the Electric Vehicles section above.

Distributed Generation	**Effect:** Generation tends not to coincide with network peak demand therefore the effect on network peak demand is expected to be negligible. However injection of generation during the midday trough could potentially create voltage issues toward the end of the ten year planning period.

Description: The vast majority of the distributed generation seen so far has been solar installations and this trend is expected to continue for the foreseeable future. Relatively low numbers of new solar connections have been seen on EIL's network to date. Although reducing costs are increasing the number of households for which a solar installation is cost-neutral, the majority of such customers either cannot afford a solar installation, are unable to install solar (e.g. rental), or prefer to utilise their income elsewhere.

Public awareness of the environmental disadvantages of solar power is gradually increasing. Recent customer surveys indicate that more customers are considering purchasing solar in the medium term than any of the other disruptive technologies, most likely due to the influence of solar marketing efforts in recent years; but with energy cost reduction options such as home insulation and electric vehicles now also receiving increased marketing and generally offering a superior return, solar penetration is not expected to be widespread by the end of the planning period.

The LV network can however be vulnerable to solar installations; solar tends to depress the midday trough in demand (or even reverse power flow) whilst leaving the evening peak unaffected. This increases the range of load currents (and therefore voltage drops) under which the LV network must operate. A network tuned to deliver the minimum acceptable voltage in the evening may still exceed the maximum acceptable voltage at midday, if sufficient solar generation is connected. In weaker areas of the network a relatively small cluster of solar may be sufficient to cause issues.

The impact of solar installations on the network can be significantly reduced when the solar inverters employ volt-var compensation. EIL requires the use of volt-var inverters on new solar installations.

Similarly to electric vehicles, the concentration of effects on the LV network makes the location of future issues difficult to predict. The programmed Maximum Demand Indicator upgrade together with individual ICP smart meter data will better enable EIL to identify and address vulnerable points on the network.

Total energy consumption is likely to be reduced to some extent by distributed generation within the planning period. However, planning focuses on providing capacity for peak demand periods.

Energy Storage **Effect:** Not expected to have a significant presence within the ten year planning horizon and therefore negligible effect on network demand.

Description: Energy storage is one technology that could have a large impact on network demand especially if used in combination with distributed generation installations. Storage gives customers some control over their demand without impacting on their consumption, and could make it feasible for customers to go “off-grid” with a sufficiently sized solar system or other generation source. However there is significant uncertainty in this area around the viability of alternative battery chemistries and the timing of their introduction; the regulatory environment and the extent to which electricity distribution businesses will be able to promote/utilise/market storage services; and future pricing structures and the level of responsiveness of the public to load-driven pricing signals.

Under the status quo this technology is not economic except in exceptional circumstances, and it is not expected that there will be major developments in this area for the next five years. If any such developments occur in the second half of the planning period, it is expected that they will take several years to have an impact at the network level, during which time EIL can respond in a focused manner. Any impact these devices have is likely to be beneficial in terms of network constraints, as they act to reduce rather than increase the peak demand on network assets.

Energy Efficiency **Effect:** Negative growth driver accounted a part of the above discussed driver Energy conservation initiatives.

Description: Improving energy efficiency has been a government strategy for several years as discussed in Table 34; Energy Conservation Initiatives. It is also desired by customers as a means of keeping their power bills down. More efficient appliances, lighting and heating are being developed to meet this demand. Other initiatives such as subsidies for home insulation are also helping customers to use energy more efficiently.

On-line shopping **Effect:** Likely to negatively affect the business sector in EIL’s network area however the overall effect on demand is expected to be relatively insignificant.

Description: Shopping online continues to become more and more popular, with these online shops tending to be based out of the larger centres. This in turn means less demand for retail businesses within EIL’s network area. However there is also some opportunity for local businesses to connect with customers outside of Invercargill or even worldwide and this will somewhat offset the potential loss of business. It is expected the overall effect will be a loss for the business sector in EIL’s area.

Internet of Things **Effect:** It is not considered likely that this technology will be extensively used in the near future and has therefore not affected demand forecasts. In the case that it does eventuate in the next ten years the uptake of this technology is likely to be gradual and so network plans would be able to react sufficiently quickly.

Description: The internet of things refers to the interconnection of the internet and many electronic enabled devices. In particular smart appliances may enable centrally controlled management of a dwelling’s or business’s consumption so that maximum demand may be minimised by staggering load to make the most of potential load diversity. This could enable customers to reduce line charges in line with a reduced network capacity requirement for their supply.

Demand Forecasts

The overall impact of the drivers explained above is a growth rate for maximum demand on EIL's network of 0.4% per annum. Table 37 shows this growth on a per substation basis as the most appropriate network level for identifying constraints on the network.

Table 37: Existing Substations Growth Projection

Substation	2020/ 21	2021/ 22	2022/ 23	2023/ 24	2024/ 25	2025/ 26	2026/ 27	2027/ 28	2028/ 29	2029/ 30
Spey Street	24.7	24.8	24.9	25.0	25.1	25.3	25.6	25.9	26.3	26.7
Leven Street	15.0	15.0	15.1	15.1	15.1	15.1	15.3	15.4	15.6	15.8
Racecourse Road	10.0	10.1	10.1	10.2	10.2	10.3	10.4	10.5	10.7	10.8
Southern	14.6	14.7	14.7	14.8	14.8	14.9	15.1	15.2	15.4	15.7
Bluff	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7

These projected substation demands are the "expected" growth forecast – the outlook considered most likely – and are the basis for EIL's network development planning. EIL also carries out an internal prudent growth forecast with appropriate contingency planning. It is accepted that there is significant uncertainty in these forecasts and actual future demands may depart significantly from these levels. Forecasts are updated annually to ensure plans are able to react quickly to any changes from previous assumptions.

If growth rates decline, schedules for projects to address capacity constraints are correspondingly delayed so as to minimise the risk of over investing. Ultimately EIL seeks to realise growth opportunities as they arise which means developing the network to alleviate constraints as required accepting, as with any investment that some risk is involved. Risk of stranding of new assets is managed where appropriate through capacity guarantee contracts with new customers. Otherwise risk is minimised by avoiding investment by utilising whatever options are available to defer investment until absolutely necessary while maintaining desired service levels.

Higher growth rates are also possible and present a risk of missed opportunity for growth for both EIL and EIL's customers. Growth affecting the entire network is most likely to come with sufficient warning to allow resources to be adjusted as required. Any large scale developments are likely to be largely funded by external investors through capital contributions and EIL generally has the ability to respond quickly to unforeseen large scale one off developments. Naturally there are limits to this capability and negotiation may be required around timing of project delivery. Unfortunately experience shows that while endeavours are made to warn customers of potential lead times around providing additional network capacity requests for supply tend to come relatively late in their planning processes due to commercial sensitivities.

Future demand for specific year may not hit projections due to a confluence of factors. Lower peak demand due to changing consumer habits, and increasing efficiency of homes is likely to be balanced by increased demand from the conversion of some end-of-life burners to electrical heating. Environment Southland have aligned their Regional Air Plan (released Sep 2014) to the National Environmental Standards.

Constraints Arising from Estimated Demand

The Invercargill GXP has a firm capacity of 143 MVA and therefore with the GXP demand at 96.5 MW has room for growth well beyond the ten year planning horizon at the forecast growth rates and with the potential for load control which could be utilised if necessary. There are no constraints on the subtransmission network that prevent the zone substation capacities being utilised therefore it is sufficient to consider the zone substations capacity and security.

Table 38 identifies the projected maximum demands at zone substation level at the end of the ten year planning 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.

Projected annual maximum demands incorporating the growth provisions identified is shown in Table 39 and 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 38: Substation Demand Growth Rates

Substation	MD 2019/20	MD 2029/30	Provision for Growth
Spey Street	23.9	27.1	Spey Street was recently commissioned as a new substation replacing the old Doon Street substation as part of a major development project for EIL. Spey Street has a capacity of 72MVA and a firm rating of 36MVA and is adequate for the anticipated load over the ten year planning horizon.
Leven Street	14.3	18.7	Leven Street has a capacity of 46MVA and a firm rating of 23MVA. The firm rating is unlikely to be exceeded by the end of the ten year planning period; if a capacity constraint did arise, it could be managed through load transfer to Spey St substation. The upcoming Invercargill CBD redevelopment is expected to have slightly net positive increase on long term electricity demand, as older buildings are replaced with newer buildings (more energy efficient but larger floor area).
Southern	10.0	16.9	Southern substation has a capacity of 23MVA available from its single transformer. Supply security is being addressed with the Southern Substation project, which will bring security to the required AAA level. Load transfer to neighbouring zone substations has been utilised to reduce loading to manage risk in the interim. On completion of the Southern Substation project, the optimal network configuration and normal loading will be restored.
Racecourse Road	12.1	11.1	Racecourse Road substation has a capacity of 23MVA available from its single transformer. Maximum demand has exceeded the 12MVA security trigger in recent years, due to load transfers from other substations. On completion of the Southern Substation project, the load will be re-balanced between the Invercargill substations. This will avoid triggering development of the Racecourse Road substation till after the planning period.

Substation	MD 2019/20	MD 2029/30	Provision for Growth
Bluff (TPCL)	5.1	4.7	Demand in Bluff is historically flat. Recent increases in demand are attributed to activity at SouthPort, which may reduce back to historic levels if an economic downturn were to occur. The introduction of Flat Hill wind farm produced a downward trend in the annual demand totals. The influence of the wind farm must be removed for forecasting purposes, due to the intermittent nature of wind generation. The economics of electric vehicles will be particularly attractive to Bluff residents who regularly commute to Invercargill. On-peak charging of these vehicles would lead to growth beyond the expected level, however Bluff substation has a firm capacity rating of 13 MVA, which is sufficient for a prudent growth forecast beyond the planning horizon.

Table 39: Substation Demands with Proposed Developments

Substation	2019/20 after transfers	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Spey Street	23.9	24.4	24.5	24.6	24.8	25.0	25.3	25.7	26.1	26.6	27.1
Leven Street	14.3	15.3	16.4	16.6	16.8	17.0	17.2	17.6	17.9	18.3	18.7
Racecourse Rd	10.0	10.1	10.2	10.3	10.3	10.4	10.6	10.7	10.9	11.1	11.4
Southern	14.6	14.6	14.6	14.7	14.9	15.2	15.5	15.8	16.1	16.5	16.9
Bluff	5.1	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7

EIL also manages other general constraints on its network as described in Table 40.

Table 40: EIL Network Constraints and Intended Remedy

Constraint	Description	Management Approach
MV Cables	Some MV cables operate near full capacity and would be unable to supply load in backup scenarios.	Several feeder cables emanating from the new Spey Street substation have been replaced with higher capacity to provide greater capacity for contingency scenarios. Operational measures ensure cables are not overloaded and smaller MV cables are 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. MDIs will be upgraded in the medium term to provide improved data for transformer loading and LV network analysis. Underutilised transformers may be relocated before purchasing new.
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.
Overhead Lines	The District Plan prohibits new overhead lines.	Underground cables have been utilised throughout Invercargill.

Distributed Generation and Demand Management

The Distributed Generation (DG) influence on Maximum Demand is considered negligible due to the estimated low connection density of DG, and the probability that only a small percentage of the capacity will be available during winter peaks.

Load Management is used when substation equipment is nearing overload, and during load transfers for maintenance. The projected demands above assume minimal influence from load management, although it should be noted that the older historical demand records will include these effects.

Response to Technology Impacts

The confluence of the various drivers, outlined above, is expected to change markets, regulations, and consumer behaviour. These changes create opportunities, as well as complexities and risks for EIL.

EIL is currently responding to these potential impacts by:

- Implementing more detailed demand data monitoring and analysis
- Increasing cross-industry collaboration
- Trialling new technology to better understand potential adoption and impact
- Continue improving dialogue with customers

EIL is considering the following potential responses:

- Pricing reform (target April 2020)
- Demand side management
- Partnerships for non-traditional solutions

However, if the extent of changes are sufficiently material, there is potential for assets to become underutilised such that EIL may be unable to fully recover regulated investments.

The Commerce Commission has endorsed an asset stranding risk mitigation option for those EDBs subject to price control. This allows EIL to apply for accelerated depreciation recovery (up to 15% reduction in asset lives), subject to the Commerce Commission's approval prior to the next regulatory period.

The risk of asset stranding is viewed as having lower likelihood of occurring for EIL, due to the uneconomic nature of deployment on dense urban networks. This assumes that markets, regulations, and consumer behaviour are supportive of peak shifting efforts.

4.3. Development Programme

EIL's development programme is shown in Table 44 at the end of this section and is described in the remainder of this section, except for replacement and renewal capital expenditure programmes which are described in Lifecycle Planning.

Table 41: Non-routine Development Projects – Underway or Planned for next 12 months

Project and Description	Cost and Timing
Customer 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. Connections activity is increased in years 2020-2023 due to the imminent Invercargill CBD redevelopment and other known customer initiated works. Capital expenditure has been increased for EIL to provide the required supporting electrical infrastructure. Scope and timing of works are adjusted to customers' works plans as communicated to EIL. Expenditure and timing may differ from that published as customer developments progress.	CAPEX – Consumer Connections $0.5M - $1.0M 2020/21 – 2022/23 Under $0.5M p.a. thereafter
Asset Relocation Projects: This budget captures costs for general minor 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 and typically above or below budget in any year.	CAPEX – Asset Relocations Under $0.5M p.a. ongoing
Supply Quality Upgrades: On the LV network, operation beyond capacity typically manifests as low voltage experienced by customers during periods of peak loading. This may occasionally require a new transformer site with associated 11 kV 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 standard 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 11 kV feeders have high load density supplied over a relatively short distance, low voltage is not seen as an issue on these feeders. Costs budgeted represent a long term average with actual spend varying around this average from year to year. Once smart meter low voltage information is more readily available, EIL anticipates an increase in supply quality related work, in advance of customer complaints. The allowance for this work will be adjusted with more accurate projections of work volume.	CAPEX – Quality of Supply Under $0.5M p.a. ongoing
Network Automation Projects: This budget is to allow implementation of network automation initiatives on the Invercargill and Bluff networks to add additional remote controllable switching points and automation technologies. The resulting improvements in reliability are intended to offset the reduction in reliability that is to be expected as the cable network is allowed to age back to the optimal average asset life remaining of 50%; the extensive underground programme and other recent or near future capital intensive projects have made EIL into an unusually young network.	CAPEX – Quality of Supply Under $0.5M p.a. ongoing

Project and Description	Cost and Timing
Earlier automation efforts in Bluff township have shown considerable reliability benefits. Two additional remote controllable switching points are planned for in 2021/22. The additional depth to the Bluff network automation scheme is expected to improve reliability to EIL's least reliable feeders.	
Pillar Box Lid Upgrade: EIL has traditionally used concrete pillar boxes with aluminium lids on the front to enclose the fusing for individual customers' supplies. However in very rare cases the internal cables can come into physical contact with the lid, and the cable insulation can be gradually abraded, e.g. as a result of minute vibrations caused by nearby traffic. If the insulation were to abrade sufficiently between pillar box inspections, this situation could result in livening of the aluminium lid. A supplier has been sourced for plastic lids that offer similar mechanical protection to the aluminium lids whilst being electrically nonconductive. These plastic lids are being installed as a part of the current inspection round, at a rate of 5% of the pillar box fleet per year.	CAPEX – Other Reliability, Safety and Environment. Under $0.5M p.a. ongoing;

Table 42: Non-routine Development Projects – Planned for following four years

Project and Description	Cost and Timing
Customer 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. Connections activity is increased in years 2020-2023 due to the imminent Invercargill CBD redevelopment and other known customer initiated works. Capital expenditure has been increased for EIL to provide the required supporting electrical infrastructure. Scope and timing of works are adjusted to customers' works plans as communicated to EIL. Expenditure and timing may differ from that published as customer developments progress. 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 at the customer's 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 energy storage which could make an installation uneconomic. Some schemes may be becoming cost competitive with supply from the network however the	CAPEX – Consumer Connections $0.5M - $1.0M 2020/21 – 2022/23 Under $0.5M p.a. thereafter

Project and Description	Cost and Timing
upfront cost is generally not attractive to most 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. Budgets for subdivisions and distributed generation are separated from other connections to support trending analysis; however these budgets are set low as it is expected that spend will occur against them only once every few years.	
Doon Street Reconfiguration: The planned demolition and reinstatement works for the remaining Doon Street site have been deferred until the 2024/25 year. Furan analysis of oil and DP testing of a paper sample from the 23MVA Doon Street T1 transformer indicate that the winding insulation is significantly aged. The unit was planned to be removed from site refurbished and stored until completion of upgrades at Southern substation where the unit would then be put back into service to complete the upgrade to AAA security. However given the age indicators it is considered an unacceptable risk to spend the additional costs for the refurbishment, storage and transformer movements when the unit may still fail soon after installation. However the un-refurbished unit should still provide several years of life, allowing deferment of capital expenditure on a new 23MVA transformer. Deferring the demolition works at Doon Street allows the unit to remain in situ until Southern substation is upgraded, thus allowing the Doon T1 transformer to be relocated to Southern substation at reduced cost. The remaining Doon St Substation works have been deferred to 2024/25 due to the delay of the Southern Substation project and to better manage other network safety risks.	CAPEX – System Growth Under $0.5M 2024/25
Stead St Stopbank: This project was previously managed and disclosed under the title "Undergrounding Programme". While the great majority of the City network has been converted to underground cable, the westernmost conductor toward the airport and Otatara is currently overhead line which runs along a stopbank. The stopbank is scheduled for a major upgrade as a key part of Invercargill city flood protection. Preliminary engineering studies commissioned by the local authorities indicate that the most likely stopbank options will involve relocation of the overhead line rather than the simple de-energisation and stopbank reinforcement previously budgeted for. The budget is relatively small, as relocation costs are anticipated to be allocated to the stopbank upgrade project with no expense to EIL. This budget may be adjusted as engineering concepts and funding models are developed by the local authorities. The line feeds critical drainage pumps and the Invercargill airport. Whilst the airport has an alternative 11kV supply, it is in the long term interests of the public that the dual supply to the airport is retained, as befits key infrastructure. The drainage pumps are essential to the local flood protection scheme, and therefore cannot be de-energised for significant periods. The most economic option for providing an alternative supply to the pumps involves replacing a section of the overhead line with cable. Timing of the work is contingent on the stopbank upgrade project, but current indications are that the work will be carried out in the 2021/22 year.	CAPEX – Asset Relocations Under $0.5M 2021/22
Earth Upgrades: Ineffective earthing may create, or fail to control, hazardous voltage that may occur on and around network equipment affecting safety for the public and for staff.	CAPEX – Other Reliability,

Project and Description	Cost and Timing
Ineffective earthing may prevent 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. 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. Routine testing is completed five yearly with the entire network tested in one year. This project has been increased to cover remediation of non-compliant / un-maintainable sites discovered in the most recent earth inspection / testing round.	Safety and Environmental Under $0.5M 2020/21 – 2022/23, 5-yearly thereafter
Spey St Fibre Chamber/Cable: The fibre run outside Spey St substation follows a sufficiently tortuous path that two individual fibres were damaged when the fibre cable was installed. While there are sufficient surplus fibres in the cable to meet the current requirement, there remains the possibility that other fibres were pressed during installation and may fail prematurely in the future. This budget provides for replacement of the damaged section of cable together with a new fibre chamber that will allow installation to occur over a less tortuous path.	CAPEX – Other Reliability, Safety and Environment Under $0.5M 2021/22
LV Tie Point Disconnectors: Distribution substations are routinely de-energised to carry out necessary maintenance on the ring main units. In order to prevent disruption of supply to customers, the substation's load is transferred to neighbouring substations prior to de-energisation. This load transfer is currently carried out by manually connecting live conductors together at tie points using cable taps. While the risks of this procedure are largely mitigated by the use of administrative controls, insulating mats, and personal protective equipment (PPE), the residual safety risk may be deemed inappropriate for a modern electricity distribution business working under current health and safety legislation. This project provides for the installation of disconnector switches at all LV tie points on the network. In addition to the safety benefit, this project is expected to reduce the switching time associated with a de-energisation by over 75%, and reduce wear / tear from manual handling of cables. The project will focus on two-way and three-way pillars, where a method has been devised to retrofit disconnectors into the existing pillar boxes. Retrofit installations will be aligned with the distribution substation maintenance servicing cycle and transformer replacements. Upon completion of the pillar retrofits, the focus will shift to switches that require pillar replacement. This will most likely involve replacing existing pillars with a larger injection moulded pillar box. Overall nearly 1000 pillars will be upgraded in a project that extends beyond the end of the planning period.	CAPEX – Other Reliability, Safety and Environment. Under $0.5M per annum 2022/23 onward

Table 43: Non-routine Development Projects – Considered for remainder of the planning period

Project and Description	Cost and Timing
Unspecified Projects: This budget is an estimate of costs for projects that are as yet unknown, but are considered likely to arise in the longer term. Certainty for these estimates is obviously low. The most likely source of material impact, in the first half of the planning period, is anticipated to be from energy and environmental policies driven by local and national government. The staggered prohibitions on coal burners are expected to drive the conversion of small-scale process heating, residential and commercial space heating, to electrical heating in a phased manner. In the second half of the planning period, electric vehicle uptake is expected to show material impact on LV and MV network capacity. Other likely drivers include: increased regulatory requirements, subsequent growth flow on from current city developments	CAPEX Under $0.5M p.a. 2025/26 onwards

4.4. Distributed Generation Policy

The value of distributed generation can be 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.
- Raising voltage above regulated levels.
- Can cause safety issues when the network de-energises a line to carry out work

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/your-power-supply/distributed-generation/ .

Despite the benefits noted above there are no distributed generators within EIL's network that have an appreciable effect on development planning.

Connection Terms and Conditions (Commercial)

- Connection of up to 10 kW of distributed generation to an existing connection to the network will not incur any additional line charges. Connection of distributed generation greater than 10 kW 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 application 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 (greater than 10 kW) 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.

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.

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 10 kW 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-Network Solutions

As discussed in section Cost Efficiency 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 in ways that sometimes remove the desired incentive. 'Use of System' agreements include lower tariffs for controlled, night-rate and other special channels.

Load control is utilised to control:

- Transpower charges by controlling the network load during the LSI peaks
- GXP load when maximum demand reaches the capacity of that GXP
- Load on feeders during temporary arrangements to manage constraints

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

Generators (owned by PowerNet) are used where appropriate for planned work on distribution transformers or LV network, to reduce the reliability impact of the work.

Other low investment options typically considered include:

- Conductor upgrades
- Voltage regulators
- Pumps and fans on power transformers
- Tie point shifts

It is however noted that there are limits to the capabilities of low investment options to meet growth when the capacity headroom is used up or when demand growth is significant or occurring in large lumps.

4.6. Non-network Development

EIL receives IT and management services support through its management services contract with PowerNet. Whilst it does not directly develop the GIS (Intergraph) or AMS (Maximo) systems, it does in conjunction with PowerNet develop interfaces and processes around these systems.

4.7. EIL's Forecast Capital Expenditure

These figures are also provided in the information disclosure schedule 11a included in Appendix 3.

Table 44: EIL's Forecast Capital Expenditure ($,000 - constant 2020/21 terms)

CAPEX: Consumer Connection	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Customer Connections (≤ 20 kVA)	61	61	61	61	61	61	61	61	61	61
Customer Connections (21 to 99 kVA)	54	54	54	54	54	54	54	54	54	54
Customer Connections (≥ 100 kVA)	496	609	375	123	123	123	123	123	123	123
Distributed Generation Connection	3	3	3	3	3	3	3	3	3	3
New Subdivisions	222	3	3	3	3	3	3	3	3	3
Unspecified Development Projects	0	0	0	0	0	272	272	272	272	272
	837	**731**	**496**	**244**	**244**	**516**	**516**	**516**	**516**	**516**

CAPEX: System Growth	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Doon Street Reconfiguration							411			
							411			

CAPEX: Asset Replacement and Renewal	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Link Box Replacement	82	82	82	82	82	82	82	82	82	82
RTU Replacement	87									
Southern Substation Upgrades	1,995	1,405								
Power Transformer Refurbishment			169			169				
Racecourse Road Switchboard Replacement			137	866	480					
Seismic Remedial Distribution		71	71	71	71					
Maximum Demand Indicator Upgrade		13	13	13	13					
Zone Substation Minor Replacement	4	4	4	4	4	4	4	4	4	4
Transformer Replacement - City	115	347	411	312	312	689	619	689	550	550
Transformer Replacement - Bluff			50	50	50	200	200	200	200	200
RMU Replacements	735	756	1,529	1,418	1,418	1,862	1,862	1,862	1,862	1,862
Reactive 11 kV Cable Replacement	21	21	21	21	21	21	21	21	21	21
Planned 11 kV Cable Replacement	185	197	197	197	197	727	727	727	989	727
General Technical Replacement	57	57	57	57	57	57	57	57	57	57
General Dist Replacement - City	21	21	21	21	21	21	21	21	21	21
General Dist Replacement - Bluff	105	105	105	105	105	209	209	209	209	209
LV Board Replacement	30	30	30	30	30	30	30	30	30	30
Pillar Box Replacement	71	71	71	71	71	71	71	71	71	71
LV Cable Replacement	69	69	69	69	69	69	69	69	69	69
Unspecified Asset Replacement & Renewal Projects						281	430	430	430	430
Bluff Conductor Replacement	59	59	59	59	59	59	59	59	117	59
Leven St Substation Roof Replacement						159				
Leven St 11kV Switchboard Replacement										1,003
	3,636	**3,309**	**3,097**	**3,445**	**3,059**	**4,711**	**4,464**	**4,533**	**4,715**	**5,398**

CAPEX: Asset Relocations	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Asset Relocation Projects	6	6	6	6	6	6	6	6	6	6
Stead St Stopbank		21								
	6	**27**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**

CAPEX: Quality of Supply	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Supply Quality Upgrades - City	13	13	13	13	13	13	13	13	13	13
Supply Quality Upgrades - Bluff	1	1	1	1	1	1	1	1	1	1
Network Automation Projects	46	144	144	31	31	31	31	31	31	31
	60	**158**	**158**	**46**	**46**	**46**	**46**	**46**	**46**	**46**

CAPEX: Other Reliability, Safety and Environment	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Earth Upgrades - City	55	55	55	55	55	55	55	55	14	
Earth Upgrades - Bluff	9	9	9	9	9	9	9	9	9	
Pillar Box Lid Upgrade		50	50	50	50	50	50	50	50	50
Spey St Fibre Chamber/Cable		22								
LV Tie Point Disconnectors			243	243	243	243	243	243	243	243
Fibre Installation	34	185	34	34	34	34	34	34	34	34
Locks and Security	5	5	53	53	53	53	53			
	103	**326**	**443**	**443**	**443**	**443**	**443**	**390**	**349**	**326**

Total Network CAPEX	**4,642**	**4,551**	**4,201**	**4,185**	**4,209**	**5,722**	**5,475**	**5,491**	**5,632**	**6,292**

5. Lifecycle Planning

Development criteria, the subject of the previous section, determine the need to introduce assets. Once this need has been established each asset must be managed throughout its lifecycle to create and maintain the fulfilment of the assets purpose as long as it is required and to minimise any adverse effects the asset might create.

5.1. Lifecycle Asset Management Processes

Following procurement of equipment and materials, assets are constructed or installed as per a design or network standard and commissioned through a process to ensure the asset is capable of operating as intended. The asset then enters its useful service life where it will often be operated over a considerable time period. Maintenance activities are generally undertaken throughout an assets operational life to support its continued reliable service for as long as it is economic to do so.

Lifecycle asset maintenance drivers:

- Support continued reliable service to customers
- Economic viability when compared to replacement
- Continued safety
- Operational efficiency
- Rate and extent of deterioration
- Criticality
- Probability of failure

At some point the asset will reach its end of life and is retired from service. Assuming the need remains the asset will be replaced while the retired asset must be disposed of appropriately. This process is outlined in Figure 40 below.

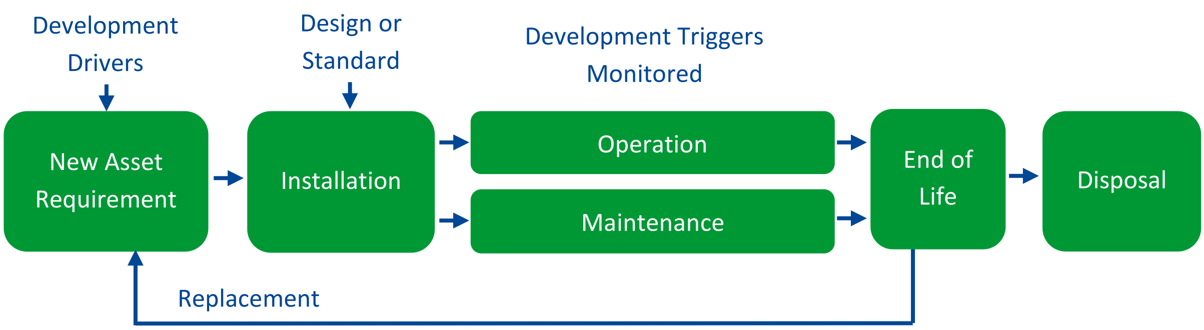


Figure 40: Asset Lifecycle

EIL follows several asset management procedures to manage network assets throughout these lifecycle stages as referenced in Appendix 1.

Installing Assets

The drivers for installation of new assets are as explained in the development section. Similarly the drivers requiring an asset on the network may change during the asset's operational life, and so may change the viability of maintaining or at end of life replacing an asset. Therefore these drivers need to be monitored beyond the installation to ensure the overall objective of providing an efficient cost effective service is achieved.

More complex assets such as a zone substation will require substantial design work to be completed whereas standards are used to guide the construction and installation of more regular tasks such as the installation of a distribution transformer. Equipment and materials are procured as per the design or standard to be implemented and in line with EIL's standardisation requirements (which are incorporated into designs and standards) as far as possible.

Assets are then installed to the design or standard, followed by a commissioning process to ensure the asset has been installed and will function as intended prior to putting into service. This process is either specified in the design or (for standardised installations) in a commissioning checklist.

Operating EIL's Assets

Operation of EIL's assets predominantly involves 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. Altering the operating parameters of an asset such as closing a switch or altering a voltage setting involves no physical modification to the asset, but merely a change to the asset's state or configuration.

Operation of the network is effectively the service that EIL's customers pay for so it is the customer desire which forms the driver for the continuous operation of assets the optimal balance between reliability and cost.

Maintaining EIL's Assets

Maintenance is primarily about replacing consumable components. Many of these components will be designed to "wear out" during an asset's design life and achieving the expected service life depends on such replacements. Examples of the way in which consumable components "wear out" include the oxidation or acidification of insulating oil, pitting or erosion of electrical contacts, or loss or contamination of lubricants.

Continued operation of such components will eventually lead to failure as indicated in Figure 41. 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 41 is not simply labelled "time".

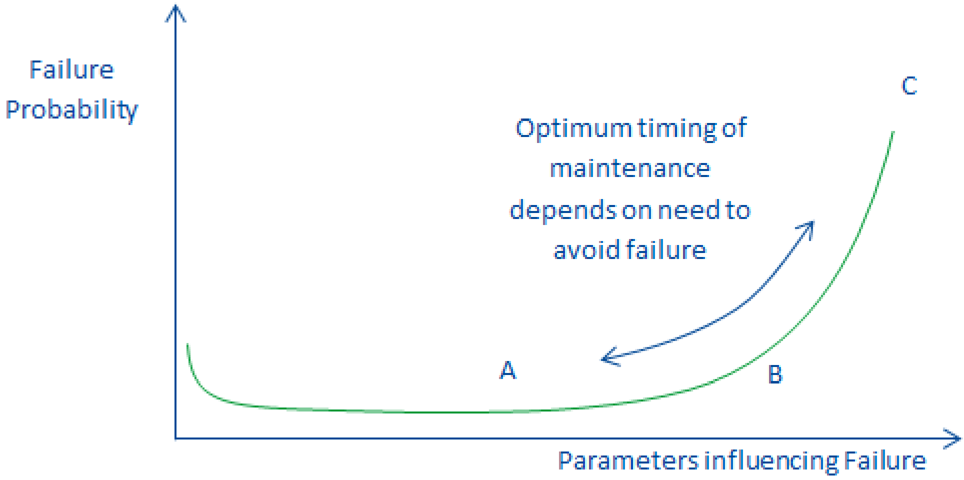


Figure 41: Component Failure

This probability of failure curve can also be viewed as applicable to the overall asset life in which case neglecting maintenance could result in a considerable contraction along the "parameters influencing failure" axis. Conversely appropriate maintenance activities would stretch out the curve toward the expected design life; effectively resetting or pushing out the increasing probability of failure. There is often significant asymmetry associated with consumables e.g. replacing lubricant may not significantly extend the life of an asset but not replacing a lubricant could significantly shorten the asset's life.

Like all EIL's other business decisions, maintenance decisions are made on cost-benefit criteria with the principal benefit being avoidance of supply interruption. Increasing maintenance costs (labour and consumables) over the asset's lifecycle, taken together with the cost of discarding unused component life, must be traded off against the desire to avoid failure. The optimal time for maintenance depends on an asset's criticality (impact of failure on customers) and ultimately on how much EIL's customers are willing to pay to reduce probability of failure.

The practical effect of this is that assets such as a 33/11 kV substation transformer, supplying large customers or large quantities of customers, may only be operated to point B in Figure 41; condition will be extensively monitored to minimise the likelihood of supply interruption. Meanwhile assets supplying merely a small customers, such as a 10 kVA transformer, will most often be run to failure represented as point C. In the extreme case of turbine blades in an aircraft engine for example, it would be desirable to avoid even the slightest probability of failure; in such a critical situation the assets may only be operated to point A.

Condition assessment is an important part of determining maintenance requirements, because many components do not deteriorate at a predictable age. Condition assessment allows deferral of maintenance cost for assets that are in good condition, and permits maintenance to be focused on the more deteriorated assets. Condition assessment involves inspections and testing to gather information about the condition of assets and their components, and can incorporate follow-up analysis (condition monitoring) to infer the condition of the asset through establishing trends in observable criteria.

By contrast some components are maintained at fixed intervals or operation counts. An example is replacing contacts in a circuit breaker which are pitted or eroded with each operation but are unable to be inspected without dismantling the circuit breaker (by which time the contacts can be replaced with a relatively small incremental cost).

As the value and/or criticality of an asset 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 comprehensive analysis of component condition (through such means as dissolved gas analysis (DGA) of transformer oil).

Replacement and Renewal of EIL's Assets

Renewals or refurbishments are more significant maintenance activities that generally focus on the non-consumable components of assets to achieve an extension to the originally expected life. This is typically less routine work and often represents a significant milestone in the life of an asset. Renewal may ultimately be part of a full asset replacement programme where the component replacements are "staggered" over time. A typical example is an overhead line, where the components (poles, cross-arms, and conductors) wear out and are replaced at different rates, but the result is complete replacement of the original line – perhaps several times over as long as the line asset required.

Ultimately an asset will reach end of life when it either fails or deteriorates to the point it becomes uneconomic to repair or maintain. This occurs when failure causes significant damage to the overall asset (highly likely at distribution or subtransmission voltages) or when a part of the asset that cannot be economically replaced has significantly aged or deteriorated, for example paper insulation in a transformer.

Retiring and Disposing of EIL's assets

Retiring assets generally involves de-energising the asset and disconnecting it from the network before removal from site or abandoning in-situ (typical for underground cables). Removed assets must be disposed of in an acceptable manner particularly if it contains SF_6, oil, lead or asbestos. The asset will be removed from the regulatory asset base.

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.
- There are no suitable opportunities for re-deployment after an asset has been replaced to increase capacity or where more economic options exist to create similar outcomes e.g. new technology offers a low cost maintenance free replacement.
- It becomes uneconomic to continue to maintain the asset as it is more cost effective to replace with a new asset.

5.2. Routine Corrective Maintenance & Inspection

Network assets are inspected routinely with the frequency dependent on the criticality of the assets and the outcome focussing on failure avoidance. Recognising that some deterioration is acceptable, inspections are intended to identify components which could lead to failure or deteriorate beyond economic repair within the period until the next inspection.

Deterioration noted may trigger corrective maintenance if economic, especially where significant further deterioration can be avoided, for example touching up paint defects before rust can take hold. Other forms of deterioration are unable to be corrected (or improved), for example pole rotting, and noting these issues may become a trigger for replacement or renewal depending on the extent of deterioration i.e. loss of structural integrity.

Inspections are not practical for all assets, for example cables buried underground, and may be limited by the availability of outages or the added effort (labour cost) required to remove covers. Therefore for the most part routine inspections are limited to what can be viewed from a walkover of the assets.

Testing supplements network inspections, and although it typically requires additional time and skilled staff, testing has strong advantages over visual inspection if cost effective. It is generally possible to gain greater detail around asset condition and often allows collection of condition data without the need to remove covers for inspection. Data gathered can be qualitative rather than quantitative, allowing more precise trending of an asset's condition over time. Testing may be destructive or non-destructive; for example insulation resistance (IR) testing simply gives an ohmic value for insulation under test, while very low frequency (VLF) testing causes damage if the cable is not in sufficiently good condition to pass the test.

EIL's Maintenance Approach

Most technical equipment such as transformers, switchgear and secondary assets are maintained in line with manufacturer's recommendations as set out in their equipment manuals. Experience with the same types of equipment may provide reason to add additional activities to this routine maintenance. Visual inspections and testing also determine reactive maintenance requirements to maintain the serviceable life of equipment which are not routine, but across a large asset base provide an ongoing need for additional maintenance resource.

Overhead line inspections are an economic means to prevent a large proportion of potential faults so the basic approach is to inspect these assets and perform preventative maintenance over the most cost effective period that achieves the desired service levels. A certain frequency of failure is accepted on overhead lines where this remaining proportion of failures becomes uneconomic to avoid. This recognises customers' acceptance of a low number of outages and the increasing cost for diminishing returns in attempting to reduce fault frequency.

As cables are underground they are unable to be visually inspected, and testing is generally not cost effective; it is difficult to obtain accurate results and to use them to predict time to failure. Cables are therefore often run to failure. However as the relatively young cable network ages and fault frequency begins to increase a more preventive strategy will be employed based on testing to determine condition for critical cables.

In terms of cost efficiency, failures are more acceptable for lines and cables than for ring main units and zone substation assets. Significant service life can be restored to lines and cables by simply repairing the fault. Asset criticality is a consideration in determining an acceptable level of outages, however increased security (redundancy) is often a more effective strategy than attempting to determine time to failure and performing preventative maintenance.

Table 45 sets out the maintenance approaches applicable to each network asset category and the frequency with which these maintenance activities are undertaken.

Table 45: Maintenance Approach by Asset Category

Asset Category	Sub Category	Maintenance Approach	Frequency
Subtransmission	O/H	Condition assessment through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	3-5 yearly
	U/G	Generally run to failure and repair. Inspection of visible terminations as part of zone substation checks, opportunistic inspection if covers removed for other work, sheath insulation IR test. Testing generally in conjunction with fault repair but may be initiated if anything untoward is noted during other inspections or work; may use IR, PI, TR, PD, VLF.	Annual
	Distributed Subtransmission Voltage Switchgear (ABSs)	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components. Lubrication of moving parts.	5 yearly
Zone Substations	Subtransmission Voltage Switchgear	Condition assessment through periodic visual inspection checking for: operation count, gas pressure, abnormal or failed indications and general condition. Testing: Contact Resistance, Partial Discharge, Insulation Resistance, CB operation time, cleaning of contacts, Thermal Resistivity viewed soon after unloading, VT/CT IR and characteristics. Corrective maintenance as required after any concerning inspection or test results.	Monthly 5 Yearly
	Power Transformers	Condition monitoring through periodic inspections. Winding & insulation resistances, Function checks on auxiliaries (Buchholz, pressure relief, thermometers). Predictive maintenance - oil analysis (dissolved gases, furan) to estimate age and identify internal issues arising or trends; frequency increased if issues and trends warrant. Oil processed as necessary. Tap changer servicing: mechanism and contacts inspected – replacements as necessary, DC resistance across winding each tap, diverter resistors resistances. Clean up and repair of corrosion, leaks etc. and replacement of deteriorated or damaged components. Replacement of breathers when saturated. Paper sample may be taken to estimate age for aged transformers in critical locations at Engineers instruction or otherwise during major refurbishment at half-life.	Monthly Annual Operation count Non-periodic

Asset Category	Sub Category	Maintenance Approach	Frequency
		Swept frequency test at start of life and after significant events such as relocation, repaired fault, refurbishment done to check for internal movement of components.	
	Distribution Voltage Switchgear	Condition assessment through periodic visual inspection checking for: operation count, gas pressure, abnormal or failed indications and general condition. Testing: Contact Resistance, Partial Discharge, Insulation Resistance, CB operation time, cleaning of contacts, Thermal Resistivity viewed soon after unloading, VT/CT IR and characteristics. Corrective maintenance as required after any concerning inspection or test results.	Monthly 5 Yearly Non-Periodic
	Other (Buildings, RTU, Relays, Batteries, Meters)	Monthly sub checks include inspection of auxiliary and other general assets for anything untoward; structures, buildings, grounds and fences for structural integrity and safety and general upkeep; rusting, cracked bricks, masonry or poles and weeds etc. Maintenance repairs and general tidying as necessary. Protection relays are tested typically with current injection to verify operation as per settings. Any alarms or indications from electronic equipment or relays reset and control centre notified for remediation. Relays recertified by external technicians as regulations require. Otherwise any other equipment visually inspected for anything untoward.	Monthly 5 yearly Non-Periodic
Distribution Network	O/H	Condition assessment through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	3-5 yearly
	U/G	Generally run to failure and repair. Inspection of visible terminations as part of zone substation checks and otherwise opportunistic inspection if covers removed for other work. Testing generally in conjunction with fault repair but may be initiated if anything untoward is noted during other inspections or work; may use IR, PI, TR, PD, VLF.	Reactive or opportunistic 5 yearly if visible
	Distributed Distribution Voltage Switchgear	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components. Function tests to verify operation as per settings; for any switchgear controlled by relays.	5 yearly
Distribution Substations	Distribution Transformers	Condition monitoring through periodic inspections. Infrared thermal camera inspection units 500 kVA and larger. Clean up and repair of corrosion, leaks etc. Some units have breathers; replaced when saturated. Winding resistances, Insulation resistance for older units if shut down allows. DGA for critical end of life units.	6 monthly (or 5-yearly if <150 kVA) Opportunistic Non-Periodic

Asset Category	Sub Category	Maintenance Approach	Frequency
	Distribution Voltage Switchgear (RMUs)	Condition monitoring visual inspection to assess deterioration or corrosion. Some minor repairs may be made but generally inspection determines when replacement will be required. Threshold PD tests to identify significant partial discharge.	6 monthly
		Periodic servicing undertaken including wipe down of epoxy insulation and oil replacement in critical switchgear. Some removed oil tested for dielectric breakdown as occasional spot check of general condition.	5-10 yearly
	Other	Inspection of enclosures for structural integrity and safety compromised by rusting or cracked brick or masonry. Overhead structures included in distribution network inspections.	6 monthly
LV Network	O/H	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	5 yearly
	U/G	Run to failure and repair.	Reactive
	Link and Pillar Boxes	External inspection for damage, tilting sinking etc. Internal components run to failure and repair. Some opportunistic inspections when opened for other work.	5 yearly
Other	SCADA & Communications	Generally self-monitored with alarms raised for failures or downtime. 24/7 control room initiate response.	Reactive
	Earths	Five yearly inspections to check locational risk, check for standard installation and any corrosion, deterioration or loosening of components. Testing is done to confirm connection resistances and electrode to ground resistance is sufficiently low.	5 yearly
	Ripple Plant	Inspection along with other assets at GXP for signs of deterioration or damage of components; oil leaks, corrosion etc. Reactive remedial actions will follow for any issues found.	Monthly

Maintenance and Inspection Programmes

Budget descriptions for routine corrective maintenance and inspection activities are set out in Table 46 and forecasts are provided in Table 52 at the end of this section. These budgets tend to be ongoing at similar levels year after year but may be adjusted from time to time to allow for improvements in maintenance practice. Increased maintenance activity is projected years 2025/26 onwards following the period of constrained renewal in 2020 – 2025.

Table 46: Routine and Corrective Maintenance and Inspection Budget Descriptions

Budget	Description	Expenditure Range/Type
Distribution Routine Inspections	All work where the primary driver is the five yearly network inspections (20% inspected annually), or other routine tests on distribution assets. Includes any minor maintenance works carried out during these inspections.	Under $0.5M p.a. OPEX
Technical Routine Inspections	All work where the primary driver is routine inspection and testing of Technical assets, for example oil DGA, earth mat testing, and protection testing. Includes any minor maintenance carried out during these inspections.	Under $0.5M p.a. OPEX
Distribution Routine Maintenance	All work where the driver is reactive work undertaken to correct issues found during the routine inspection. Also a general budget for all minor distribution work.	Under $0.5M p.a. OPEX
Technical Routine Maintenance	All work where the primary driver is inspection and testing of Technical assets of sufficient depth to require de-energisation of the asset. Includes any servicing activities (such as oil processing, CB oil replacement, or recalibration of relays) carried out while the equipment is de-energised for these inspections.	Under $0.5M p.a. OPEX
Distribution Corrective Maintenance	Permanent repairs carried out on faulted Distribution assets that had been temporarily been made safe/functional during the initial incident response.	Under $0.5M p.a. OPEX
Technical Corrective Maintenance	Permanent repairs carried out on faulted Technical assets that had been temporarily been made safe/functional during the initial incident response.	Under $0.5M p.a. OPEX
Zone Substation Routine Maintenance	All work where the primary driver is routine scheduled maintenance (other than preventative maintenance) on zone substations. For example SEPA unit cleaning, mowing, and minor weed control.	Under $0.5M p.a. OPEX
Distribution Substation Routine Maintenance	All work where the primary driver is routine scheduled maintenance (other than preventative maintenance) on distribution substations. For example cleaning, minor weed control, enclosure repainting.	Under $0.5M p.a. OPEX
Earth Testing	Routine testing of earthing assets and connections to ensure safety and functional requirements are met completed five yearly, next due 2022/23.	Under $0.5M 2022/23 and five yearly thereafter; OPEX
Partial Discharge Survey	Partial discharge condition monitoring of equipment to identify abnormal discharge levels before failure occurs.	Under $0.5M p.a. OPEX

Infra-Red & Corona Survey	Infra-Red and Corona Discharge condition monitoring survey of bus-work, connections, contacts etc. An Infra-Red survey checks for abnormal heating as an indication of poor electrical contact between current carrying components, which may lead to voltage quality issues and/or failure of equipment; while Corona Discharge testing looks for ionisation of air around insulators, as evidence of insulation defects or contamination.	Under $0.5M p.a. OPEX
Supply Quality Checks	Investigations into supply quality which are generally customer initiated.	Under $0.5M p.a. OPEX
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.	Under $0.5M p.a. OPEX
Customer Connections	Operational portion of expenditure for the customer connections process is captured in this budget.	Under $0.5M p.a. OPEX
Distribution Substation Seismic Survey	A budget to assess the seismic risk associated with EIL's distribution substations. Budget is allocated in 2020/21 to gather measurements and carry out seismic analysis. Remedial works to correct any deficiencies found will commence as a capital project in 2021/22.	Under $0.5M p.a. 2020/21 OPEX

Systemic Issues

EIL has been made aware of a potential systemic weakness in the 33 kV oil filled cables which supply Spey St 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. The reliability risk associated with this weakness has been mitigated through ensuring that all oil-filled cables on the network have an alternate supply option through an XLPE cable. Mitigation of environmental and repair risk are under development

EIL's underground substations have been identified as confined spaces and therefore require special operational procedures to manage the associated risks making these sites burdensome to access and maintain. Despite these controls, a significant level of residual risk remains. A further concern is the approaching end of life of these substations; their underground nature and their location in the CBD mean that renewal of these sites in situ would cause significant disruption for the public. The costs and risks associated with these substations make it appropriate to replace them with above ground sites. This replacement programme is complete with the exception of one site, which will be removed when the CBD works are complete. See Asset Replacement and Renewal.

EIL has many oil filled RMUs with operating restrictions in place to mitigate arc flash safety risk. Short term solutions have been able to be developed for some models of RMU, which allow safe operation without the inconvenience and reliability impact of operating restrictions. Where these solutions are not available or are not practical, operation of these RMUs has been suspended. This mitigates the risk to field staff operators, however, in-situ risk to public remains and the network has reduced capacity to segment resulting in wider outage areas. Longer term management of these issues is likely to require early replacement of many RMUs.

Some models of RMU have exhibited faster than usual corrosion which is likely to adversely affect the service life of the assets. Repairs will be carried out where economic and practical to do so, but it is expected that many of these assets will need to be replaced ahead of their nominal life, causing their replacement to overlap with the older but sturdier models that preceded them. It is expected that the majority of the "Unspecified Projects" budget in years 6 to 10 of forecast CAPEX will be devoted to RMU and cable replacements.

EIL has experienced water ingress issues with early ABB SD type RMUs that utilise high voltage busbar insulation tape (HVBT) in the bus couplings. All such RMUs are having their bus coupling boxes converted to the Guroflex insulating filling compound that succeeded the original HVBT bus coupling kit.

There are no other systemic issues presently being investigated. 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. Asset Replacement and Renewal

The overall objective for replacement and renewal programmes is to get the most out of the network assets by replacing assets as close as possible to their economic end of life. This is balanced by the need to manage workforce resources in the short term and delivery of desired service levels over the long term.

Inspection and testing programmes identify assets that are reaching the end of their economic life while critical assets may be replaced on a fixed time basis. For example, 11 kV switchboards at zone substations are generally replaced at the end of their nominal year life. Less critical assets or assets provided with redundancy as part of security arrangements may be run to failure and replaced reactively. Assets such as cables may be run to failure several times and repaired before the fault frequency increases to a point that complete replacement is more economic. This approach requires monitoring of failure rates.

Apart from whole of lifecycle cost analysis, there are several other drivers for replacement (though they can often be reduced to a cost analysis) including operational/public safety, risk management, declining service levels, accessibility for maintenance, obsolescence and new technology providing options for additional features or alternative solutions. Replacement of assets may also be heavily influenced by the development drivers discussed in the Development Criteria section.

Innovations That Defer Asset Replacement

There are a number of innovations that EIL uses to defer asset replacement. These include;

- Thermal (Infrared) and Partial Discharge (Corona) camera inspections of Zone Substation equipment
- Mid-life refurbishment of power transformers
- Dissolved Gas Analysis (DGA) of large distribution transformers
- Thor hammer analysis of poles
- Automation of switchgear to enable faster restoration in the event of faults

Table 47 sets out the approach to making decisions around when to undertake replacements or renewals applicable to each network asset category.

Table 47: Replacement and Renewal Decisions by Asset Category

Asset Category	Sub Category	Replacement and Renewal Decision Approach
Subtransmission	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally poles, cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	XLPE cables replaced when reliability declines to an unacceptable level or repairs become uneconomic. Oil cables may be damaged beyond economic repair depending on nature of failure.
	Distributed Subtransmission Voltage (ABSs)	Replacement if inspection/operation indicates deterioration sufficient to lose confidence in continued reliable operation and maintenance is considered uneconomic.
Zone Substations	Subtransmission Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Power Transformers	Major refurbishment for transformers is undertaken when units reach half of their expected life. Replaced after failure causing significant damage that is not economic to repair; most units will be allowed to run to failure to utilise entire lifespan unless failure risk is unacceptable. May be replaced if tank and fittings are deteriorating, spare parts are unavailable and not economic to maintain for aged units.

Asset Category	Sub Category	Replacement and Renewal Decision Approach
		May be scrapped if not economic to relocate (transport and installation costs) after aged transformers displaced e.g. for a larger unit. Paper, Furan and/or DGA analysis used to indicate insulation remaining life.
	Distribution Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Other (Buildings, RTU, Relays, Batteries, Meters)	Instrumentation/Protection at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic e.g. protection replaced with switchboard or transformer. Batteries replaced prior to the manufacturers stated life expectancy (typically 10 years) or on failure of testing. Buildings and fences when not economic to maintain after significant accumulating deterioration or seismic resilience concerns. Bus work and conductors not economical to maintain.
Distribution Network	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally poles cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	XLPE or paper lead cables replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	Distributed Distribution Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
Distribution Substations	Distribution Transformers	Replaced if rusting is advanced or other deterioration/damage is significant and maintenance becomes uneconomic. Otherwise units generally run to failure but transformers supplying critical loads may be replaced early based on age or as part of other replacements at site. Units removed from service <100 kVA and older than 20 yrs are scrapped; otherwise units testing satisfactory recycled as stock.
	Distribution Voltage Switchgear (RMUs)	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives.

Asset Category	Sub Category	Replacement and Renewal Decision Approach
		Significant damage from premature failure could require replacement.
	Other	Instrumentation/Protection at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic e.g. protection replaced with switchboard or transformer. Batteries replaced prior to the manufacturers stated life expectancy (typically 10 years) or on failure of testing. Enclosures not economic to maintain after significant accumulating deterioration or seismic resilience concerns.
LV Network	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally poles cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	Generally run to failure. Replaced when condition declines to an unreliable level e.g. embrittlement of insulation.
	Link and Pillar Boxes	Replaced if damaged or deterioration is advanced and could lead to failure before next inspection (or if public safety concerns exist).
Other	SCADA & Communications	RTUs or radios at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic.
	Earths	Replaced when inspections find non-standard arrangements, deteriorated components or test results are not acceptable.
	Ripple Plant	Becoming obsolete as smart meters are installed across the network. Run to failure but security provided by backup plant.

Non-Routine Replacement and Renewal Projects

Replacement and renewal projects that are not recurring are described in Table 48 and often represent one-off replacement or renewal of significant assets that have reached end of life or a significant miles stone in its life. Other projects may target a number of assets of similar age that will be replaced or renewed as part of short or medium term programme.

Table 48: Non-routine Replacement and Renewal Projects – Underway or Planned for next 12 months

Project and Description	Cost and Timing
RTU Replacements: RTUs provide the SCADA interface between PowerNet's System Control room and the devices located at remote substations. They allow remote indication and control for connected devices; for example the ability to open and close circuit breakers, view their status and receive alarms (such as a circuit breaker trip). RTUs are a critical part of maintaining service levels on the network, because the remote indication and the ability to remotely operate the network greatly reduce the time to respond to faults on the network. The RTUs at Leven Street zone substation and five of the eight mini GPT RTUs at automated distribution substations in the Invercargill CBD have been replaced. The remaining three mini GPT RTUs are expected to be replaced by the end of the 2019/20 year. The replacement of the Kingfisher RTU at Racecourse Road has been brought forward to 2020/21 (in advance of the switchboard replacement) as it has shown signs of failing. Design will be coordinated to ensure that the RTU replacement will align with the later switchboard replacement.	CAPEX Under $0.5M 2020/21
Southern Substation Upgrades: A major renewal and upgrade project is underway for Southern zone substation site as a combined solution for several development drivers. Several assets replacements are required at the substation as follows. • The 11kV switchboard has been in service for longer than industry standard life (was due for replacement in 2014). Its condition is currently serviceable, but has had repairs for defects of type indicating end of life. • The outdoor structures are showing signs of cracking and reinforcement rust, and have been assessed as below seismic standards • Air break switches and earth switches have reached Maximum Practical Life and show signs of significant deterioration • One of the two 33 kV circuit breakers is in poor condition with cracked insulators • The other 33kV circuit breaker has had significant rusting (ex-Bluff), and corona discharge at the bushing tank interfaces • The existing in-service transformer T1 is due for replacement or refurbishment in 2023 • There is no alternate supply to a large number of customers normally supplied from the substation during the winter period • The current substation equipment and configuration does not meet network security standards for current demand levels Seismic reinforcement work on the existing substation building was completed in 2017/18. This brought the seismic strength from 17% of new building standard to 85%.	CAPEX $0.5M – $2.5M 2020/21 and 2021/22

Project and Description	Cost and Timing
After the renewal and upgrade project, Southern Substation will have a new 11 kV switchboard, auxiliary services and a new 33 kV switchboard to replace the outdoor circuit breakers, CTs, air break switches, earth switches, VTs and associated structures. Both substation transformers in the AAA configuration will remain outdoor units. After the relocated ex-Doon St transformer has been in service long enough for any potential defects arising from extended de-energisation/transport/reinstallation to manifest, Southern T1 will be temporarily removed for refurbishment; After reinstallation of Southern T1 the substation will operate as a dual transformer site, with the ex-Doon St transformer expected to be replaced on condition beyond the end of the planning period. The oil cable termination and associated pressure tanks will remain outdoor but shielded from stone throwers (an ongoing issue at the site) until ultimately due for replacement beyond the planning horizon.	
Locks and Security: Renewal of locks and security of zone substation and distribution sites Maintain prevention of public access to equipment.	CAPEX Under $0.5M 2020/21 – 2026/27

Table 49: Non-routine Replacement and Renewal Projects – Planned for following four years

Project and Description	Cost and Timing
Power Transformer Refurbishment: Refurbishment is aimed at ensuring the expected life of transformers and potentially extending life; the resulting deferral of replacements will achieve cost efficiencies in maintaining service for EIL's customers. Three of EIL's 23MVA zone substation transformers are beyond their midlife and un-refurbished. However, the ex-Doon Street transformer which is to be relocated to Southern substation will not be refurbished. Furan and paper sample analysis show that this unit's insulation is consistent with its age and therefore the cost of refurbishment is considered uneconomic given the likely level of remaining life that can be achieved. Refurbishment of the other two transformers has been deferred until after April 2020 to best manage capital investment in respect of the regulator imposed revenue limits. The older of the Leven Street units is scheduled for refurbishment in 2025/26and the Southern substation transformer in 2022/23.	CAPEX Under $0.5M p.a. 2022/23
Racecourse Road Switchboard Replacement: The 11 kV switchboard at Racecourse Road substation consisting of 12 circuit breaker cubicles will reach the end of its nominal life in 2020/21. Its replacement is scheduled for 2023 - 2025 with design costs allowed for in 2022/23. This is a deferment from 2020/21 to allow for replacement of RMUs at higher risk of failure. There is a consistent level of partial discharge suspected to be from a few cable boxes and CTs. Repair will be attempted in the intervening years till replacement. Risks associated with continued operation of the 11 kV switchboard near end of expected life are being mitigated by regular condition monitoring of the switchgear.	CAPEX Under $0.5M 2022/23, 2024/25 and $0.5-2.5M 2023/24
Seismic Remedial Distribution: This project will implement seismic remedial solutions at EIL's distribution substations following seismic assessments. Various options are available depending on the site characteristics and include strengthening of buildings, enclosures or structures or replacement with self-contained freestanding equipment if more economic. Many sites are unique however there are several common "themes" to	CAPEX Under $0.5M p.a. 2021/22 – 2024/25

Project and Description	Cost and Timing
enclosures used for ground mounted distribution substations and therefore common solutions can be applied to groups of sites. This programme was deferred until the 2020 price path period to best manage capital investment in respect of the regulator imposed revenue limits as well as available resource being utilised on higher risk management programmes. The probability of an earth quake in the interim remains low, and as the damage from a credible earthquake in this period is not expected to be catastrophic across the network, the risk is considered acceptable. Remedial work will be spread across four years to manage workload; beginning in 2021/22 and being completed in the 2024/25 year.	
Maximum Demand Indicator Upgrade: EIL system planning relies on monitoring of distribution transformer loads. Currently, this is done through the use of maximum demand indicators (MDIs), which are read manually. Defective MDIs form a portion of the MDI population. Many MDIs are also at or approaching end of life. The increasing gaps in network load monitoring is beginning to encroach on EIL's ability to optimally manage equipment life and operational planning. This need becomes increasingly stark with substantial changes in power consumption. The effects on the network are expected to be most pronounced on the LV network, where the lesser diversity and lower power capacity increases the probability of overloaded cables due to unpredictable clusters of increased load. PowerNet as agents for EIL, is exploring the use of data aggregation from customer smart meters as a substitute measure to MDIs. This has advantages over traditional MDIs, which are unable to distinguish between load transfers and genuine load increase, and are incapable of recording the time series data necessary for a comparison with load end data. However, EIL has encountered issues with accessing data from the meter data provider. EIL has therefore considered a plan to replace the MDIs with smart MDIs. Where possible existing MDI CTs will be reused and the smart MDI will be mounted in the space vacated by the MDI. Replacements will be targeted where smart meter rollout is anticipated to be difficult, and where existing MDIs are defective. Where an LV board is being replaced in the next few years, a smart MDI will be installed (costs for smart meter MDIs are comparable to traditional MDIs). It is expected that load end smart meters will be operational in time. This project is to retrofit smart MDIs to the remaining substations where smart meter installation may be at risk, or uneconomic. The MDI upgrade will commence in 2021/22 and take place over the four years to 2024/25. This timeframe should allow for at least two years' data collection before EV clusters start to significantly affect voltage on the network, an issue which is not expected to occur before 2026. EIL will continue to evaluate alternatives to MDI installation as opportunities arise. If an alternative solution is found to be superior on a benefit/cost basis, then the Maximum Demand Indicator Upgrade project may be altered or cancelled in future AMPs. Alternatively, if the smart meter installation programme is not expected to complete on time, the Maximum Demand Indicator Upgrade project may expand to acquire the necessary data.	CAPEX Under $0.5M p.a. 2021/22 - 2024/25
RMU Replacements: EIL's Ring Main Unit (RMU) replacement programme had been curtailed in recent years, as limited resources have been directed at the higher priority underground substations and link box replacement programmes. Over 15% of EIL's fleet of RMUs is aged beyond industry good practice, and an operational risk analysis shows mid-level risk factors that are beyond EIL's normal tolerance for risk.	CAPEX $0.5-$2.5M p.a. 2020/21 on

Project and Description	Cost and Timing
While many years of investment will be required to fully restore the RMU fleet to acceptable levels, some individual units present a disproportionate level of risk. The riskiest RMU sites will be targeted initially. Beyond 2021, the budget is increased so as to aggressively replace sites at heightened risk, and to bring the condition of the RMU fleet back to acceptable levels. This programme has been reduced to manage capital investment in respect of the regulator imposed revenue limits of the 2020 price path period.	
Fibre Installation: Control and monitoring of Leven St zone substation is currently via a single communications circuit tee-d off from the Invercargill GXP - Spey St zone substation communication circuits. The single communications circuit to Leven St zone substation crosses areas that are prone to being damaged by incidental civil works. This project is to install new optical fibre between the communications network gap. This will complete the second communications circuit between the GXP and Leven St zone substation. This reduces the risk of communications and protection failure of the subtransmission supply to the CBD, and will allow faster protection, greater visibility, and enable future automation within the CBD distribution grid. External parties have projects involving trenching along part of the proposed route in 2020-2022. PowerNet and those parties have been in discussion over opportunities to share the trench, reducing trenching and reinstatement costs for both parties. EIL budget has been advanced two years from 2023 to 2021, in order to take advantage of this opportunity. Cost may decrease from budgeted depending on civil contractor tenders and cost allocation.	CAPEX Under $0.5M 2021/22

Table 50: Non-routine Replacement and Renewal Projects - Considered for remainder of the planning period

Project and Description	Cost and Timing
Unspecified Projects: This 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 (six to ten year time frame). Certainty for these estimates is quite low. However with EIL's current demand growth and asset age profile, the bulk of this expense is considered most likely to occur in the Asset Replacement & Renewal category. Other drivers include: premature failures, or greater than expected deterioration of asset condition.	CAPEX Under $0.5M p.a. 2025/26 on

Ongoing Replacement and Renewal Programmes

The remaining replacement and renewal budgets are for ongoing work that tends to recur year after year. These budgets are listed and described in Table 51 and expenditure forecasts are provided in Table 44 (CAPEX) and Table 52 (OPEX). A redefinition of work programmes to more closely align to Information Disclosure Determination definitions has resulted in a transfer of some distribution work from Routine Maintenance to Replacement & Renewal. A one-off adjustment in 2018/19 adapts the OPEX budgets below for a change in the financial treatment of these costs under a revised network management agreement

Table 51: Replacement and Renewal Programmes

Budget	Description	Expenditure
Link Box Replacement	On-going replacement of above ground link boxes, beyond the priority replacement of the underground link-boxes described above, which have deteriorated with age or have been damaged and are unfit for service/unsafe.	CAPEX Under $0.5M
Zone Substation Minor Replacement	On-going replacement of minor components at zone substations such as LTAC panels and battery banks.	CAPEX Under $0.5M p.a.
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 for use as spares.	CAPEX Under $0.5M p.a. 2020-2024 $0.5M-$2.5M p.a. 2024 on
RMU Replacements	On-going replacement of Ring Main Units as they reach end of life and risk of failure increases. Planned replacement of above-ground RMU have been reduced to align with regulator-imposed revenue limitations.	CAPEX $0.5M-$2.5M p.a.
Reactive 11 kV Cable Replacement	On-going reactive replacement of 11 kV cables as identified by condition after fault occurrence.	CAPEX Under $0.5M p.a.
Planned 11 kV Cable Replacement	An ongoing programme to proactively identify and replace 11 kV cables as they reach their economic end of life rather than continue to patch repair old cables beyond this point.	CAPEX Under $0.5M p.a. 2020-2024 $0.5M-$2.5M p.a. 2024 on onward
Fibre Installation	The copper communications network used for protection and SCADA in the Invercargill CBD is approaching end-of-life. Much of the existing network is not ducted; therefore excavation would be required for replacement, which is expensive and disruptive in the CBD environment. Solutions involving radio communications or lease of existing fibre have been investigated and found not to be practical. However several utilities maintain underground services in the CBD that need to be excavated on occasion for maintenance or renewal. Where such excavations coincide with a communications path needing replacement, there is an opportunity for EIL to co-operate and lay fibre/duct at reduced cost. $30k p.a. has been set aside to allow EIL to take advantage of such opportunities as they arise, effectively taking a piecewise approach to replacing the copper network while it is still within its operating life. This figure may be revised in future AMPs as the level of incidence of such opportunities becomes clearer. On completion of the GXP to Leven St fibre loop and the CBD mall, SCADA and protection capability within the Invercargill CBD will be restored.	CAPEX Under $0.5M p.a.
General Technical Replacement	On-going replacement of assets other than transformers, RMUs an LV boards as they reach end of life and risk of failure	CAPEX Under $0.5M p.a.

Budget	Description	Expenditure
	increases at distribution substations to maintain reliability of supply and safety in the vicinity of the substation.	
General Distribution Replacement	On-going replacements of distribution assets other than cables. These are identified through routine inspection.	CAPEX Under $0.5M p.a.
LV Board Replacement	Replacement of hazardous old LV distribution boards with modern touch safe boards – on-going for 10 years.	CAPEX Under $0.5M p.a.
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.	CAPEX Under $0.5M p.a.
LV Cable Replacement	On-going replacement of LV cables as by age with coincident works on underlying 11 kV cable, or as they reach their economic end of life rather than continue to patch repair old cables beyond this point.	CAPEX Under $0.5M p.a.
Bluff Conductor Replacement	On-going small scale replacement of conductors in Bluff due to high wind loading and marine corrosion.	CAPEX Under $0.5M p.a.
Distribution Replacement & Renewal	All OPEX work where the primary driver is the repair of distribution assets that have been found during inspection to fall short of the required standard; also includes scheduled replacements of parts/fluids under a preventative maintenance programme, and expenses incurred due obsolescence. Excludes CAPEX (work that will have a material effect on the functionality or the life of capital assets). Covers items like crossarms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.	OPEX Under $0.5M p.a.
Zone Substation Replacement & Renewal	All OPEX work where the primary driver is the repair of zone substation assets that have been found during inspection to fall short of the required standard; also includes scheduled replacements of parts/fluids under a preventative maintenance programme, and expenses incurred due obsolescence. Excludes CAPEX (work that will have a material effect on the functionality or the life of capital assets). Covers items like earth sticks, safety equipment, buildings, battery systems etc.	OPEX Under $0.5M p.a.
Distribution Substation Replacement & Renewal	All OPEX work where the primary driver is the repair of distribution substation assets that have been found during inspection to fall short of the required standard; also includes scheduled replacements of parts/fluids under a preventative maintenance programme, and expenses incurred due obsolescence. Excludes work that will have a material effect on the functionality or the life of capital assets, i.e. CAPEX. Covers items like enclosure repairs, paint touch-ups, spouting & roof repairs, etc.	OPEX Under $0.5M p.a.

5.4. EIL's Forecast Operational Expenditure

The forecast operational expenditure for EIL is shown in Table 52. These figures are also provided in the information disclosure schedule 11b included in Appendix 3. Two further categories not described earlier complete EIL's forecasted operational expenditure budget as follows.

Vegetation Management

Annual tree trimming in the vicinity of overhead network is required to prevent contact with lines maintaining network reliability. The first trim of trees has to be undertaken at EIL's expense as required under the Electricity (Hazards from Trees) Regulations 2003. 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. This OPEX cost is budgeted at $1,400 per annum.

Service Interruptions and Emergencies

This budget provides for the provision of staff, plant and resources to be ready for faults and emergencies. Fault staff respond to make the area safe, isolate the faulty equipment or network section and undertake repairs to restore supply to all customers. Any follow-up actions necessary to make further repairs are charged to the appropriate Corrective Maintenance budget. The Service Interruptions & Emergencies budget is set at $0.50 million per annum.

Table 52: EIL's Forecast Operational Expenditure ($,000 - constant 2020/21 terms)

OPEX: Asset Replacement and Renewal	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Distribution Replacement & Renewal - City	71	71	71	71	71	71	71	71	71	71
Distribution Replacement & Renewal - Bluff	33	33	33	33	33	33	33	33	33	33
Zone Substation Replacement & Renewal	17	17	17	17	17	17	17	17	17	17
Distribution Substation Replacement & Renewal	68	68	68	68	68	68	68	68	68	68
	189	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**

OPEX: Vegetation Management	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Vegetation Management - City	1	1	1	1	1	1	1	1	1	1
Vegetation Management - Bluff	1	1	1	1	1	1	1	1	1	1
	2	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**

OPEX: Routine and Corrective Maintenance & Inspection	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Distribution Routine Inspections - City	79	79	79	79	79	79	79	79	79	79
Distribution Routine Inspections - Bluff	39	39	39	39	39	39	39	39	39	39
Technical Routine Inspections - City	98	98	98	98	98	98	98	98	98	98
Technical Routine Inspections - Bluff	1	1	1	1	1	1	1	1	1	1
Distribution Routine Maintenance - City	3	3	3	3	3	3	3	3	3	3
Distribution Routine Maintenance - Bluff	26	26	26	26	26	32	32	32	32	32
Technical Routine Maintenance - City	366	366	366	366	366	403	403	403	403	403
Technical Routine Maintenance - Bluff	13	13	13	13	13	14	14	14	14	14
Distribution Corrective Maintenance - City	29	29	29	29	29	29	29	29	29	29
Distribution Corrective Maintenance - Bluff	22	22	22	22	22	24	24	24	24	24
Technical Corrective Maintenance - City	121	121	121	121	121	133	133	133	133	133
Technical Corrective Maintenance - Bluff	10	10	10	10	10	10	10	10	10	10
Zone Substation Routine Maintenance	34	34	34	34	34	34	34	34	34	34
Distribution Substation Routine Maintenance	37	37	37	37	37	41	41	41	41	41
Earth Testing - City			16					16		
Earth Testing - Bluff			13					13		
Partial Discharge Survey	32	32	32	32	32	32	32	32	32	32
Infra-red & Corona Surveys	10	10	10	10	10	10	10	10	10	10
Supply Quality Checks - City	2	2	2	2	2	2	2	2	2	2
Supply Quality Checks - Bluff	1	1	1	1	1	1	1	1	1	1
Spares Checks and Minor Maintenance	1	1	1	1	1	1	1	1	1	1
Customer Connections	25	25	25	25	25	25	25	25	25	25
Distribution Substation Seismic Survey	30									
	978	**949**	**978**	**949**	**949**	**1,010**	**1,010**	**1,039**	**1,010**	**1,010**

OPEX: Service Interruptions and Emergencies	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Incident Response - Distribution - Unplanned - City	258	258	258	258	258	310	310	310	310	310
Incident Response - Distribution - Unplanned - Bluff	86	86	86	86	86	103	103	103	103	103
Incident Response - Technical - Unplanned - City	81	81	81	81	81	97	97	97	97	97
Incident Response - Technical - Unplanned - Bluff	10	10	10	10	10	10	10	10	10	10
Incident Response - Technical - Fixed Fee - City	30	30	30	30	30	30	30	30	30	30
Incident Response - Technical - Fixed Fee - Bluff	8	8	8	8	8	8	8	8	8	8
	473	**473**	**473**	**473**	**473**	**558**	**558**	**558**	**558**	**558**

OPEX: Business, Systems Operations, and Network Support	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
System Operations and Network Support	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067
Business Support	2,226	2,207	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234
	3,293	**3,274**	**3,301**	**3,301**	**3,301**	**3,301**	**3,301**	**3,301**	**3,301**	**3,301**

Operational Expenditure Total	**4,935**	**4,886**	**4,943**	**4,913**	**4,913**	**5,060**	**5,060**	**5,089**	**5,060**	**5,060**

6. Risk Management

For the purposes of this document risk is defined as any potential but uncertain occurrence that may impact on EIL's ability to achieve its objectives, and ultimately the value of its business. EIL is exposed to a wide range of risks and utilises risk management techniques to bring risk within acceptable levels. This section examines EIL's risk exposures, describes what it has done and will do about these exposures and what it will do to reinstate service levels should disaster strike.

6.1. Risk Strategy and Policy

EIL embraces risk management as a critical business task with a key corporate strategy being to "Understand and Effectively Manage Appreciable Business Risk" while each of EIL's asset management strategies also, directly or indirectly, incorporate risk management (see Strategy and Delivery).

PowerNet has developed a risk management framework which is required by PowerNet's risk management policy and requires the framework to be consistent with the ISO 31000:2009 Standard: Risk Management - Principles and Guidelines. The framework aims to formalise the practices that are and have been used to effectively manage the risks that EIL's business faces. This will ensure greater consistency in the quantification of various risks and correct prioritisation of their mitigation as well as ensuring the regularity of review.

6.2. Risk Management Methods

PowerNet's risk management methods are used to manage EIL's risk to acceptable levels with decision making around EIL's asset management related risks 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

Risk Identification

To mitigate risks they must first be identified. While many risks may be obvious, identifying others requires experience and insight into the many factors that could have an appreciable impact on business objectives. The following risk categories have been created as a prompt for ensuring the various risk types are considered and responsibility for review allocated to the applicable manager:

- Procurement
- Health & Safety
- Network, Management, Field Operations and Environment
- Stakeholders, Community and Customers
- Strategic Commercial and Other
- Human Resources
- Finance
- Business Systems, Business Integrity and Technology
- Compliance
- Infrastructure, Plant and Vehicles
- Business Continuity

This top down approach is supplemented by a less formal bottom up approach where staff are encouraged to consider and report any risks as they become apparent. Health and Safety is the exception where formal policy is in place to ensure as many incidents as possible are proactively reported (including near hits) to help identify hazards and control measures as a priority.

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

Risk Quantification

Once a risk has been identified it must be quantified. This is done by determining the following two factors:

- Consequence severity associated with the risk that may eventuate
- Probability the consequences will be encountered

These factors are categorised using relative terms as set out in Table 53 and Table 54 to allow an intuitive assessment of consequence and probability. At the same time this categorisation allows for the use of more robust calculations for these factors where this is practical (especially regarding probability).

Table 53: Event Consequence Categorisation

Consequence:	Very Low	Low	Moderate	High
Safety	Any injury	Any Lost Time Injury (LTI)	Serious harm and/or multiple serious injuries for any reason	Any fatality(ies) &/or multiple serious injuries for any reason.
Performance	Insignificant budget or time over run(s) on work activity.	Budget and time over runs on a significant work activity.	Inability to achieve agreed works within budget and time over 12 month period.	Consistent inability to achieve agreed works within budget and time over several years.
Network Reliability	Marginal breach(es) of a reliability KPIs due to matters under PowerNet's control.	Significant breaches of an important reliability KPIs due to matters under PowerNet's control.	Repeat breaches of reliability KPIs due to matters under PowerNet's control (or perceived by stakeholders to be under PowerNet's control).	Repeat long term breaches of reliability KPIs due to matters under PowerNet's control (or perceived by stakeholders to be under PowerNet's control).
Network Disruption	Network disruption up to 6 hours.	Disruptions - up to 2 days - of a major network.	Repeat disruptions - up to 2 days per event of a major network.	Extended (10 days +) disruption of a major network.
Reputation	Local press attention - short-term impact on public memory.	Local press attention (not front page) and/or regulator inquiry.	Local TV news and/or regulator investigation - medium-term impact on public memory.	International TV news headlines and/or government investigation - long-term impact on public memory.
Financial	Loss of assets/revenue or unbudgeted costs less than: < 1% p.a.	Loss of assets/revenue or unbudgeted costs less than: 1-5% p.a.	Loss of assets/revenue or unbudgeted costs less than: 5-10% p.a.	Loss of assets/revenue or unbudgeted costs less than: >10% p.a.

Consequence:	Very Low	Low	Moderate	High
Governance	Shareholder awareness.	Perception of systemic underperformance, shareholder concern.	Shareholder dissatisfaction.	Dysfunctional governance - major conflicting interests or fundamental change in governing Board direction.
Compliance	Prosecution / improvement notice.	Prosecution of business / prohibition notice.	Prosecution of Director or other employees.	Breach resulting in Imprisonment of Directors or other employees, or appointment of statutory Board to a network due to matters under PowerNet control.
Environmental	Transient environmental harm.	Significant release of pollutants with mid-term recovery.	Significant long term environmental harm.	Catastrophic, long term environmental harm.

Table 54: Event Probability Categorisation

Probability Ranking	Descriptor	Expected Occurrence Interval
4	Highly Likely	Greater than once per year
3	Possible	Once every 1-10 years
2	Unlikely	Once every 10-100 years
1	Very Unlikely	Less than 100 years

Risk Ranking

Together consequence and probability give an overall measure of a risk. Table 55, commonly known as a risk matrix, shows how these factors are combined to give a relative risk level so that risks can be ranked. The risk matrix inherently recognises HILP (high impact low probability) events and gives them a high risk level ranking so that they receive appropriate attention.

Table 55: Risk Ranking Matrix

Consequence:	Very Low	Low	Moderate	High
Highly Likely	Level 3	Level 5	Level 6	Level 7
Possible	Level 3	Level 4	Level 5	Level 6
Unlikely	Level 2	Level 3	Level 4	Level 6
Very Unlikely	Level 1	Level 2	Level 3	Level 5

Asset Criticality

In practice, consequences of failure are influenced by a range of contextual factors that vary by situation, for example:

- Proportion of time that persons are in proximity to the asset
- Network configuration and loading conditions
- Potential for secondary consequential damage, e.g. proximity to other sensitive equipment
- Presence of substances harmful to the environment
- Asset characteristics that increase potential for harm, for example oil circuit breakers may fail more violently than vacuum types
- The presence (or absence) of engineering controls to limit harm, for example oil containment, fast acting protection systems or arc fault containment features

Intervention decisions consider both likelihood of failure, which is broadly related to asset health; and operating context, which defines how asset failure would affect the organisation's asset management objectives. While many assets may be physically similar or even identical, differences in operating context can lead to very different consequences of failure and therefore priority for intervention.

Risk Treatment and Mitigation Prioritisation

With finite resources, risk can never be completely eliminated and therefore an acceptable level of residual risk needs to be determined along with appropriate timeframes for the implementation of risk treatment. Often a number of options are available for the treatment of any risk, with each treatment option likely to come at various levels of cost, effort and time to implement. Each treatment option may be more or less effective than another option. Treatment options are not necessarily mutually exclusive and may be used in combination where appropriate. Table 56 summarises the types of treatment options that are considered, ordered by effectiveness for the control of risk.

Table 56: Options for Treatment of Risk

Treatment Options	
Terminate	Deciding not to proceed with the activity that introduced the unacceptable risk, choosing an alternative more acceptable activity that meets business objectives, or choosing an alternative less risky approach or process.
Treat	Implementing a strategy that is designed to reduce the likelihood or consequence of the risk to an acceptable level, where elimination is considered to be excessive in terms of time or expense.
Transfer	Implementing a strategy that shares or transfers the risk to another party or parties, such as outsourcing the management of physical assets, developing contracts with service providers or insuring against the risk. The third-party accepting the risk should be aware of and agree to accept this obligation.
Tolerate	Making an informed decision that the risk rating is at an acceptable level or that the cost of the treatment outweighs the benefit. This option may also be relevant in situations where a residual risk remains after other treatment options have been put in place. No further action is taken to treat the risk, however, ongoing monitoring is recommended.

Deciding on the most appropriate treatment option may be obvious, for example a low cost option providing very effective mitigation compared with a higher cost option providing less effective mitigation, however deciding between high cost effective treatments and low cost but less effective treatments may be difficult. Choosing the least “cost” option or combination of options that reaches an acceptable residual risk level within an appropriate timeframe is the desired outcome and requires careful judgement of all the factors involved.

Good risk management recognises that limited resources are available meaning that risks cannot be effectively mitigated immediately. Therefore effective risk management also requires prioritisation of the many risk reduction actions identified and to do this the “greatest risk reduction for the resource available” is used as a guiding principle. Appropriate resourcing also needs to be considered as adjusting available resources may be necessary to control risk appropriately. This is explicitly recognised as part of the new Health and Safety at Work Act where sufficient resource to reduce hazards “as far as reasonably practicable” must be provided. This represents an example where adjustment of the cost/staffing balance may be required.

Depending on the magnitude of risk identified a large scale programme may be initiated to quickly reduce risk. Often asset management related risks will have mitigating solutions that become a part of design standards used on the network. Again the level of risk will determine if standards are retrospective i.e. applied to shape existing network rather than only applying to new assets installed.

6.3. EIL's Asset Management Risk

Asset management related risks that have been identified for EIL have been classified under the categories; physical, safety and environmental, human, external, weather, and corporate; with a summary of the risk assessment under each of these categories is as follows.

Physical

The following physical risks have been identified with Table 58 and Table 57 summarising their quantification and treatment responses:

- Asset Failures – equipment failures can interrupt supply or negate systems from operating correctly, e.g. failure of a padlock could allow public access to restricted areas.
- 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 – may be 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.

Table 57: Risk Associated with Equipment Failures and Responses

Event	Likelihood	Consequence	Responses
33 kV & 66 kV Lines and Cables	Possible	Low	• Regular inspections and maintain contacts with experienced faults contractors. • Provide alternative supply by ringed subtransmission or through the distribution network. • All new lines designed to AS/NZS 7000:2010
Power Transformer	Unlikely	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.
11 kV Switchboard	Unlikely	Medium	• Annual testing including PD[4] and IR[5]. • Replacement at end of life and continue to provide sectionalised boards. • Able to reconfigure network to bypass each switchboard with use of mobile regulators.

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

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

Event	Likelihood	Consequence	Responses
11 kV & 400 V Lines and Cables	Possible	Low	• Regular inspections and maintain contacts with experienced faults contractors. • Provide alternative supply by meshed distribution network.
Batteries	Unlikely	Medium	• Continue monthly check and six monthly testing. Dual battery banks at critical sites.
Circuit breaker Protection	Unlikely	Medium	• Continue regular operational checks. • Engineer redundancy/backup into protection schemes. • Regular protection reviews. • Mal-operations investigated.
Circuit Breakers	Unlikely	Low	• Backup provided by upstream circuit breaker. • Continue regular maintenance and testing.
SCADA RTU	Unlikely	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 Unlikely	Low	• Continue to operate as a Dual Redundant configuration, with four 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.
Load Control	Unlikely	Medium	• Provide backup between EIL and TPCL ripple injection plants at Invercargill. • Manually operate plant with test set if SCADA controller fails.

As the impact of equipment failure 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 58: Risk Associated with Physical Events and Responses

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

Safety & Environmental

The following safety and environmental risks have been identified withTable 59 summarising their quantification and treatment responses:

- 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 confined 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.

Table 59: Risk Associated with Safety and Environmental Events and Responses

Event	Likelihood	Consequence	Responses
Public Accidental Contact	Possible	High	• Public awareness program – social media, radio, 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	Unlikely	High	• Adopt & follow EEA Guide to Power System Earthing Practice in compliance with Electricity (Safety) Regulations 2010
Arc Flash	Very Unlikely	High	• Install arc flash protection on new installations • Mandate adequate PPE for switching operations • De-energise installation before switching where PPE inadequate
Underground	Unlikely	High	• De-energise substation before manual switching within substation
Oil spill (zone sub)	Unlikely	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.

Event	Likelihood	Consequence	Responses
			• Bunding is installed in the remaining substations as the opportunity arises. • Regular checks of tank condition
Oil spill (distribution transformer)	Possible	Low	• Distribution transformers located away from waterways, etc. • Installations designed to protect against ground water accumulation
SF_6 release	Unlikely	Low	• SF6 storage and use recording and reporting • Procedures for correct handling.
Noise	Unlikely	Medium	• Designs incorporate noise mitigation • Acoustic testing at sub boundaries to verify designs • Adhere to RMA and district plans requirements
Electromagnetic fields	Unlikely	Medium	• Adhere to RMA and district plans requirements • Electromagnetic test at sub boundaries to demonstrate requirements met
Staff Error	Possible	High	• Standardised procedures • Training • Worksite audits • Certification required for sub entry, live-line work, etc. • Monitor incidents and investigate root causes
Historical Assets	Possible	Medium to High	• Replace old components with new components meeting current standards: scheduled replacement or replacement on failure, check specifications and replace if risk significant
Site Security	Very Unlikely	High	• Monthly checks of restricted sites • Alarms on underground sub hatches • Standardised exit procedures in 3rd party building • Above ground sub clearances to AS2067 s5 • Design to avoid climbing aids etc.

Human

The following human related risks have been identified with Table 60 summarising their quantification and treatment responses:

- 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"

Table 60: Human Event Risks and Responses

Event	Likelihood	Consequence	Responses
Pandemic	Current	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	Possible	Low to High	• Six monthly checks of all ground-mounted equipment. • Faults contractor to report all vandalism and repair depending on safety then economics. For example tagging/graffiti removal would depend upon the location and the content. • Any safety problems will be made safe as soon as they are discovered.
Terrorism	Very Unlikely	High	• Ensure security of restricted sites. • Use alternative routes and equipment to restore supply, similar to equipment failures below.
Cyber Attack	Very Unlikely	High	• Secure communications links • Analyse and remove vulnerabilities • Review and apply industry best practice

External Factors

The following external factor risks have been identified with Table 61 summarising their quantification and treatment responses:

- 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.

Table 61: External Factor Event Risks and Responses

Event	Likelihood	Consequence	Responses
Animal	Highly Likely	Low	• Possum guards all poles • Cattle guards, bird spikes as required
Third party accidental	Possible	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 available to bypass and repair.

Weather

The following weather related risks have been identified with Table 62 summarising their quantification and treatment responses:

- 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.

Table 62: Risk Associated with Weather Events and Responses

Event	Likelihood	Consequence	Responses
Wind	Possible	Low	• Impact is reduced by undergrounding of lines. • Design standard specifies wind loading resilience levels. • If damage occurs on lines this is remedied by repairing the failed equipment. • Inspections recognise asset criticality and resilience requirements.
Snow	Unlikely	Low	• Impact is reduced by undergrounding of lines. • Design standard specifies snow loading resilience levels. • If damage occurs on lines this is remedied by repairing the failed equipment. • Inspections recognise asset criticality and resilience requirements. • If access is limited then external plant is hired to clear access or substitute.
Flood	Unlikely	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.

Corporate

The following corporate risks have been identified with Table 63 summarising their quantification and treatment responses:

- 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.

Table 63: Corporate Risks and Responses

Event	Likelihood	Consequence	Responses
Investment	Unlikely	Low	• New larger contracts require Shareholder Guarantee before supply is provided.
Loss of Revenue	Very Unlikely	High	• Continue to have Use of System Agreements with retailers. • New large investments for individual customers to have a guarantee.
Management Contract	Very Unlikely	High	• Continue management contract with PowerNet noting that it operates a Business Continuity Plan
Regulatory	Very Unlikely	High	• Continue to contract PowerNet to meet regulatory requirements. • Ensure PowerNet has and operates to a Business Continuity Plan.
Resource	Unlikely	High	• PowerNet utilises internal staff allowing effective planning and management of recruitment training and retention of skilled staff. • Endeavour to provide a reasonably constant stream of work for key external contractors to assist in their continued viability.

6.4. Emergency Response and Contingency

The following tactics have been or are being implemented to manage risk for EIL (especially for HILP events):

- Align asset design with current best practice
- Regular inspections to detect vulnerabilities and potential failures
- Remove assets from risk zone
- Build appropriate resilience into network assets
- Provide redundancy of supply to large customer groups
- Involvement with the local Civil Defence
- Prepare practical response plans
- Operate a 24hr control centre

Additionally EIL has the following specific contingencies in place through its management company PowerNet.

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. PowerNet has developed a Business Continuity Plan which has the following principal objectives:

- 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.

In developing the business continuity plan each business unit identified their key business functions and prioritised them according to their criticality and the timeframes before their absence would begin to have a major impact on business functions. Where practicable continuity plans have been developed in line with each critical business function and preparation undertaken where appropriate to allow continuity plans to be implemented should they be required.

PowerNet Pandemic Action Plan

PowerNet must be able to continue in the event of a breakout of any highly infectious illness which could cause significant numbers of staff to be unable to function in their job. The plan aims to manage the impact of an influenza type pandemic on PowerNet's staff, business and services through two main strategies:

- Containment of the disease by reducing spread within PowerNet achieved by 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.
- Maintenance of essential services if containment is not possible 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.

Critical Network Spares

Critical network equipment has been identified and spares kept ensuring reinstatement of supply or supply security is achievable in an appropriate timeframe following unexpected equipment failure. Efficiencies have been achieved due to close relationship between the networks which PowerNet manage, for example a transformer was borrowed from TPCL to reinstate a firm supply following failure of a transformer at a critical Invercargill CBD zone substation.

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 a schematic based switching plan and accompanying operating order detailing steps required to restore supply after loss of a zone substation.

Insurance

EIL holds the following insurances:

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

Contractors working on the network hold their own liability insurance.

EIL has begun to develop an insurance captive through PowerNet to provide insurance for major events affecting network equipment, which are not covered under the insurances above. Assets insured are poles, wires, and cables which are currently unable to be insured under our existing policies.

7. Evaluation of Performance

7.1. Progress against Plan

Capital Expenditure

Table 64: Variance between Capital Expenditure Forecast and Actual Expenditure

Capital Expenditure	Forecast 2018/19 ($k)	Actual 2018/19 ($k)	Variance
Consumer Connection	525	297	-43%
System Growth	-	-	-
Asset Replacement and Renewal	4,447	4,330	-3%
Asset Relocations	26	90	250%
Quality of Supply	68	2	-98%
Legislative and Regulatory	-	-	-
Other Reliability, Safety and Environment	103	107	4%
Capital Expenditure on Network Assets	**5,168**	**4,825**	**-7%**

Capital works was under budget due to:

- Customer Connections – 43% underspent due largely to customer driven construction delays. These will show in the 2019/20 year.
- Asset Replacement and Renewal – 3% under budget due to several factors, including:
  - Underground substation replacements over budget due to higher than expected reinstatement and easement costs.
  - RMU replacements over budget as resource constraints caused delay in completion of one site, falling from 2017/18 into the 2018/19 year.
  - Under budget for other works due to resource constraints resulting in construction delays.
- Asset Relocations – small reactive budget, over spent due to: significant costs due to archeological finds during excavations; budget line error showing net of customer contributions; and customer driven construction delays driving spend from 2017/18 into the 2018/19 year.
- Quality of Supply – 97% underspent due to less customer initiated investigations within the year compared to long term averages.
- Reliability, Safety and Environment – within 5% of budget due to neutral earth resistor protection communications costs over budget, offset by lower pillar box lid upgrade works due to supply chain difficulties.

Operational Expenditure

Table 65: Variance between Operational Expenditure Forecast and Actual Expenditure

Operational Expenditure	Forecast 2018/19 ($k)	Actual 2018/19 ($k)	Variance
Asset Replacement and Renewal	211	129	-39%
Vegetation Management	2	2	4%
Routine and Corrective Maintenance and Inspection	1,051	1,071	2%
Service Interruptions and Emergencies	492	472	-4%
Operational Expenditure on Network Assets	**1,756**	**1,519**	**-5%**

Maintenance was slightly under budget due to:

- Asset Replacement and Renewal – 39% under spent due largely to lack of resource availability.
- Vegetation Management – small reactive budget, spend within $3k of budget.
- Routine and Corrective Maintenance and Inspection – within 5% of budget.
- Service Interruptions and Emergencies – 4% underspent with less reactive work than expected.

7.2. Service Level Performance

Customer Consultation

A face to face survey using a survey company was undertaken with eight key clients. Interviewees generally felt PowerNet had a very positive image in the community however there was a perception with some that PowerNet has quite a low profile. It was generally perceived that PowerNet has its customer's best interests at heart however some felt they were unable to comment on this due to lack of visibility.

Customers consistently ranked continuity of supply as the most important aspect of their provided network service, and indicated that PowerNet performed very well in this regard; five of the eight clients rated PowerNet at 9/10 or 10/10, two more stated that PowerNet did very well at providing a secure/reliable supply, and the last customer was unsure whether their company had experienced any recent outages. Other priorities for customers included prompt restoration of supply, sufficient notice of planned interruptions, cost of supply, and supply quality. Again customers indicated that they were generally satisfied with these aspects and the overall service from PowerNet. Some businesses expressed a desire for more proactive and regularly initiated contact from PowerNet staff to make them more aware of quality, efficiency or pricing options, but the majority saw no specific need for such contact.

Reliability

Table 66 displays the target versus actual reliability performance on the network. For the 2018/19 year the overall network performance was good, with SAIFI 47% under the Default Price-Quality Path (DPP) target and SAIDI 25% under DPP2 target.

Table 66: Performance against Primary Service Targets

	2018/19 DPP2 Target	2018/19 Actual
SAIFI	0.59	0.33
SAIDI	24.1	21.6

Targets are based on average performance since 1 April 2004, and due to the reliability of the network, have been set very low. This does however mean that single events have the potential to impact significantly on reliability performance, as was the case for several faults in the 2018/19 year. For example, a third party digger struck a cable resulting in a substation trip, incurring 2 SAIDI-minutes despite supply being restored within 30 minutes.

New reliability targets set out in the new Default Price-Quality Path comes into effect on 1 April 2020, and applies till 31 March 2025

Customer Satisfaction

The customer engagement survey conducted by phone provides feedback to understand customer satisfaction regarding a range of aspects around their supply services. Statistics are also recorded for any customer complaints received. Table 67 shows the 2018/19 results for the service levels that EIL have set targets for.

Table 67: Performance against Secondary Service Targets

Attribute	Measure	Target 2018/19	Actual 2018/19
Customer Satisfaction on Faults	No impact or minor impact of last unplanned outage {CES}	>50%	64%
	Information supplied was satisfactory {CES}	>80%	86%
	PowerNet first choice to contact for faults {CES}	>35%	6%
Voltage Complaints	Number of customers who have made supply quality complaints {IK}	<10	7
	Number of customers having justified supply quality complaints {IK}	<4	3
Planned Outages	Provide sufficient information {CES}	>80%	98%
	Satisfaction regarding amount of notice {CES}	>80%	89%
	Acceptance of one planned outage every two years lasting four hours on average {CES}	>80%	85%

{ } indicates information source; CES = Customer engagement survey using independent consultant to undertake phone survey, IK = Internal KPIs.

The percentage of customers who felt no impact or minor impact in their last unplanned outage was above target. However 31% indicated that they were unable to recall, which may indicate that the response time was not unsatisfactory enough to stick in their memory; only 8% indicated that they felt restoration time was unacceptable.

The number of customers who were satisfied with the information supplied to them when enquiring about an outage was above target. This result is very susceptible to random variation due to the small number of outage related enquiries. This volatility is evident in a comparison with the previous year's survey.

44% of customers surveyed indicated that PowerNet would be their first choice to contact if wanting to report or enquire about a fault. This is above target and has been increasing in recent years. 35% of customers surveyed indicated that they would first call their Retailer/Power Company. 8% of respondents said they would not call anyone while a further 12% would take other approaches such a contacting a friend or neighbour.

Performance against the remaining secondary service levels regarding customer satisfaction was better than the targets set for 2018/19.

Network Efficiency

Table 68: Performance against Efficiency Targets

Measure	2018/19 Target	2018/19 Actual
Load factor	> 50%	48%
Loss ratio	< 5.5%	4.9%
Capacity utilisation	> 40%	42%

Capacity utilisation and loss ratio were slightly better than the target while load factor did not quite achieve the targets.

Load factor reflects the ratio of EIL's average demand to peak demand and averages around 50%. Transpower's introduction of the Transmission Pricing Methodology has lowered commercial drivers for controlling peak demand having a negative impact on load factor.

Reported losses tend to vary from year to year more than can be explained by 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 and the longer term average is slightly over 5%. New smart meters will allow better analysis and monitoring.

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.

Financial Efficiency

Table 69: Performance against Financial Targets

Measure	2018/19 Target	2018/19 Actual
Network OPEX/ICP	$92	$92
Network OPEX/km	$2,398	$2,443
Network OPEX/MVA	$10,504	$10,818
Non-Network OPEX/ICP	$179	$191
Non-Network OPEX/km	$4,646	$5,061
Non-Network OPEX/MVA	$20,347	$22,411

EIL's financial efficiency results relating to network OPEX were satisfactory for 2018/19. The non-network OPEX results were over the 5 year period target

7.3. AMMAT Performance

EIL understands the foundations of good asset management practice and generally looks to implement each aspect, however implementation has not always been systematic and therefore may not always be consistent or applied to all potential areas of benefit. An independent external consultant was engaged in 2017 to rate EIL’s asset management practices using the Asset Management Maturity Assessment Tool (AMMAT).

The AMMAT is based on a selection of the questions asked in PAS-55 intended to prompt consideration of performance against a number of facets of asset management practice. Each question can be scored from ‘0’ to ‘4’ and each question has a series of answers to describe what is required to achieve each scoring level. Appendix 3 Schedule 13 shows the full AMMAT questions, the scores determined and the maturity description for each question.

In scoring EIL’s asset management practice against the Asset Management Maturity Assessment Tool (AMMAT) this results scores from ‘0.5’ to ‘3’ but with a typical score of ‘2’ as shown in Figure 42.

All the areas covered in the questionnaire are not of equal importance to an EDB, so target scores were set for each area. These scores are indicated by the red curve.

EIL through PowerNet undertook an AMMAT self-assessment for this AMP. The focus was on the changes that had occurred since the 2017 assessment. The green curve shows the result of this assessment. It shows that in most areas we have improved, with the exception of Questions 82 and 88.

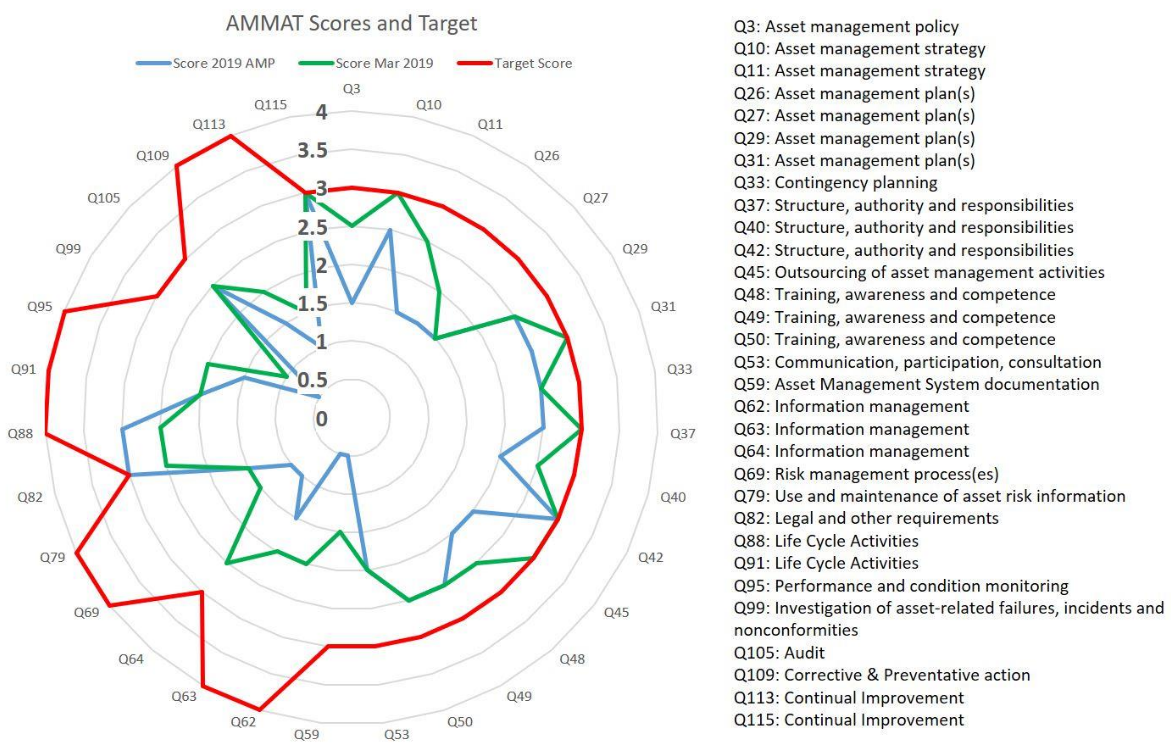


Figure 42: EIL's Asset Management Maturity Assessment Tool Scores

7.4. Gap Analysis and Planned Improvements

AMMAT

For a distribution company of EIL's size a score of '2' for many of the asset management functions is considered appropriate. However as PowerNet provides EIL's asset management services as well as providing this service across other networks, EIL believes that some improvements are realisable and appropriate. EIL therefore believes a score of '3' is desirable as a long term goal for each of the AMMAT functions and that improvements made over time would be generally in line with EIL's asset management and corporate strategies, ultimately supporting the achievement of EIL's asset management objectives.

Of the 30 questions posed in the AMMAT, seven scores of '2.5' have been determined across the areas of Asset Management Policy, Asset Management Plans, Contingency Planning, Structure Authority and Responsibilities, and Communication, Participation and Consultation. For the remaining questions there is room for improvement, especially with two questions assessed as '1' in the areas of Continual Improvement and Information Management.

Some changes in score have resulted since the previous AMP, following an external review by Utility Consultants in late 2017. Whilst noting that some scores have changed, the following improvements to asset management practice have been made or are ongoing:

- An Asset Management Policy and an Asset Management Strategy were developed and approved.
- Asset Fleet Plans are being developed that will allow improved management of assets over their full life cycle.
- A stage gate process for managing projects has been developed and introduced to improve project implementation.
- The PowerNet organisational structure has been refined to enhance the ability to deliver the EIL asset management objectives.
- Feedback from the Asset Management Strategy and asset management execution has been incorporated into the EIL and PowerNet business plans.
- The overhead lines inspection process has been an area of continued focus for PowerNet. The criteria previously set out in an inspection standard (Q95), for inspectors to use when determining how quickly a defect must be rectified have been refined and a process to ensure consistency in the inspection results has been implemented.
- EIL has initiated a Safety by Design system and has approved the policy, standard and procedure to ensure a systematic process for identifying and effectively managing risks (Q69) associated with each lifecycle stage of any new assets designed. This systematic risk management approach has been embedded into EIL's major projects, and is being extended to incorporate minor works. EIL is continuing to extend this to more classes of assets in ensuring regular comprehensive reviews are undertaken.

- A Data Strategy and an Information System Strategy are under development. Key to these strategies is recognising and agreeing that the computerised asset management information system (MAXIMO) will be the single source of truth around assets. Further improvements to the system are being implemented including:
    - Including a Risk Management module into the system.
    - Expanding work scheduling to more systematically and efficiently schedule and track asset maintenance activities to additional asset types.
    - Developing more compatible units to allow standardisation common asset types including cost by materials and labour to enable efficient costing and scheduling of future work.
    - Integration of EIL's financial management system to efficiently track costs supporting compatible units and understanding whole of lifecycle costs for these assets.
    - Rolling out field devices to operational staff that will allow the direct capturing of data from the field.

The two specific areas where we felt that we may have been overrated previously are captured by Questions 82 and 88.

Question 82 centres around procedures to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how these requirements are incorporated into the asset management system. The feedback received was that access to these documents are difficult. This is being addressed by the implementation of a new document management system.

Question 88 is about how the organisation establishes, implements and maintains 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. To address this we have implemented a stage gate approach to the acquisition of all new assets that will address any issues we have in these areas.

Capital and Maintenance Works

The initiatives above will improve efficiency for capital and maintenance project delivery and support consistent performance against delivery EIL's AWP.

In addition, EIL's amalgamation of EIL's network management company PowerNet and its previous field service contracting companies has improved relationships and communication between planning and field staff. More efficient work practices are being realised; and are expected to 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.

Reliability

On the whole reliability of the EIL network is good and the SAIDI and SAIFI results for 2018/19 were within targets set. 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. The exposed overhead network in Bluff has been targeted for improvements.

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 is being 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. Again the initiatives noted as improvements under the AMMAT will assist with the improvement of reliability by enhancing EIL's maintenance practices.

In the long term, network reliability will be difficult to maintain due to the lack of incentive to invest in network reliability initiatives caused by revenue constraints. Network renewal has been lowered for continued viability of EIL, with corresponding adjustment in long term service levels.

Efficiency

Load factor is low compared to other distribution businesses, 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 is expected to allow some additional leverage to influence customer's consumption behaviour. Longer term emerging technologies such as electric vehicles and battery storage are also expected to have a positive effect on load factor.

Losses and capacity utilisation are not specifically being targeted for improvement except for selecting efficient and optimally sized assets when required for network development or replacements.

8. Capability to Deliver

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. To achieve successful delivery EIL must have sufficient staffing (planning, management, field services) and financial resources available along with having appropriate systems and processes in place.

8.1. Systems and Processes

The core of EIL's asset management activities lies 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 43 describes the typical sorts of information residing within EIL's business (including PowerNet employee knowledge).

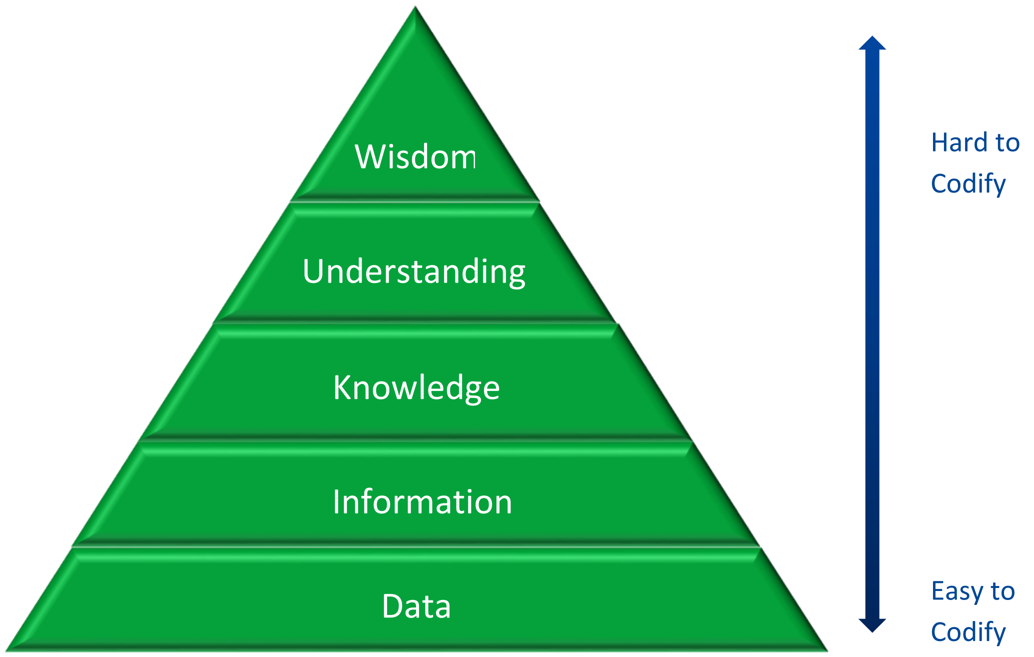


Figure 43: Hierarchy of Data

- The bottom two layers 'Data' and 'Information' of the hierarchy tend to relate strongly to EIL's asset and operational data and the summaries of this data that form one part of EIL's decision making.
- The middle 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 'Understanding' and 'Wisdom' 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 43 it is generally hard to codify these things, hence correct application is heavily dependent on skilled and experienced people.

Asset Management Systems

EIL has access to a variety of PowerNet owned information management tools which capture asset data and can be used to aggregate this data into summary information. From this information EIL has a great deal of knowledge about almost all of the assets; their location, what they are made of, generally how old they are and how well they can perform. This knowledge will be used for either making decisions within EIL's own business or assisting external entities to make decisions.

The decision making process 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 roles and interaction of each component of the hierarchy are incorporated in Figure 44 which provides a high level summary of EIL's asset management processes and systems.

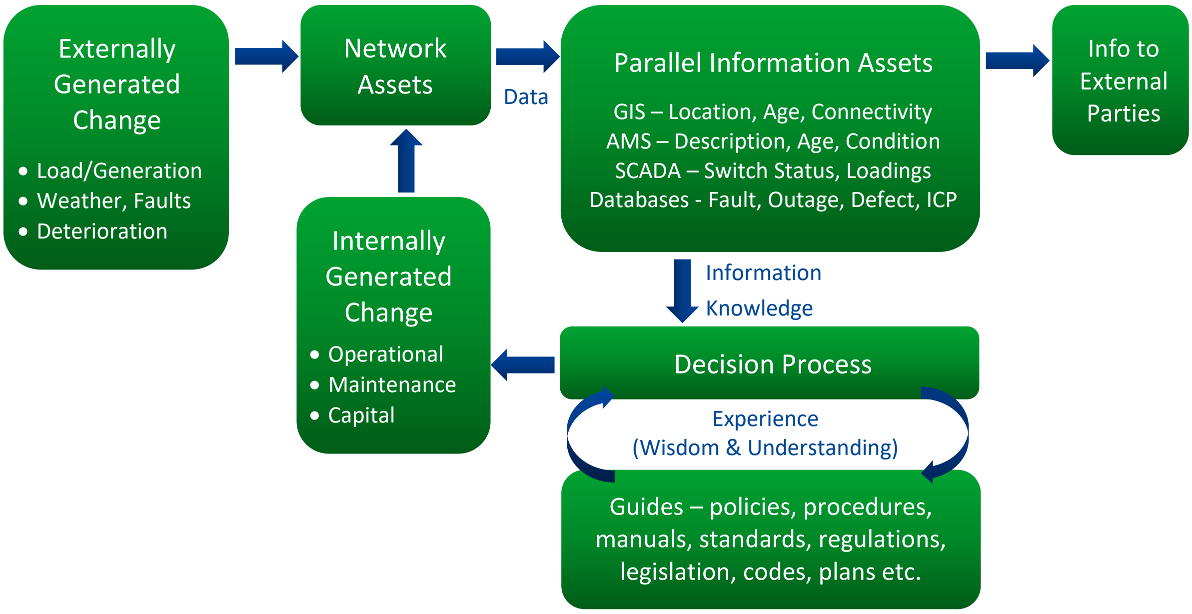


Figure 44: Key information systems and processes

Processes and Documentation

EIL's key processes and systems are based around the lifecycle activities defined in Figure 44, which are based around the AS/NZS9001 Quality Management System. The 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.

The asset management processes are documented and grouped in the following categories with a complete list provided in Appendix 1:

- Operating Processes and Systems
- Maintenance Processes and Systems
- Renewal Processes and Systems
- Up-sizing or Extension Processes and Systems
- Retirement Processes and Systems
- Performance Measuring Processes
- Other Business Processes

Some processes are prescribed in external documents (such as the information disclosure determination which this AMP is required to comply with) and as such they are not copied onto internal documentation. Processes are often embedded within asset management tools including external requirements such as the need to produce network reliability statistics for disclosure being embedded within the outage management database.

Documents and Control Reviews

Each document is controlled by an owner at management level who is given responsibility for the documents review and update. The documents are reviewed periodically (which includes review of the underlying processes that have been documented) to ensure they are kept up to date and incorporate any changes that have been identified as necessary. Lean Management practices have recently been introduced to refine business and asset management processes with the changes identified ultimately reflected in documented procedures.

Once updates have been finalised they are approved by the controlling manager and all staff are notified by email and where necessary by placement on notice board and direct training and communication to individuals affected.

External audits of specific systems and processes are also conducted. Current external audits include;

- Public Safety Management System (PSMS) (AS/NZS 7901 compliance)
- Occupational Health and Safety Management (AS/NZS 4801 compliance)
- Worksite safety audits (completed by Network Compliance Ltd)
- AMMAT review
- AMP format and compliance review
- Spend forecast assessment
- Spend approval process review

Asset Management Tools

PowerNet maintain and utilise a number of software based tools to efficiently and effectively manage data and knowledge for EIL's network assets.

The computerised **Asset Management System (AMS), Maximo,** stores EIL's assets descriptions, details, ages and condition information for serial numbered components. It also provides work scheduling and asset management tools with most day to day operations being managed through the AMS. Maintenance regimes, field inspections and customers produce tasks and/or estimates, that are sometimes grouped and a 'work order' issued from the AMS which is intricately linked to the financial management system. This package tracks major assets and is the focus for work packaging and scheduling. The individual assets that make up large composite items such as substations are managed through the AMS in conjunction with other more traditional techniques such as drawings and individual test reports. EIL utilises the Maximo software package for its AMS.

An Intergraph based **Geographic Information System (GIS)** is utilised to store and map data on individual components of distributed networks. The GIS focuses primarily on geographically distributed assets such as cables, conductors, poles, transformers, switches, fuses and similar items and provides asset description, location and age information for each asset. Locational data is used to provide mapping type displays of existing equipment for planning network upgrades, extensions and maintenance scheduling. It allows these plans to account for distance and travel time and any other factors influenced by the geographic distribution of the assets. Electrical connectivity, capacity and ratings also form a crucial data set stored in the GIS which assists the analysis of the networks ability to supply increasing customer load or determine contingency plans.

Export of data from the GIS into **Load Flow and Fault Analysis Software** allows modelling of the network. This helps predict network capability in the existing arrangement and in future "what if" scenarios considered as planning options as well as determining fault levels to assess safety and effectiveness of protection and earthing systems. Two software packages PSS Adept and Cyme are used to perform this analysis for EIL.

The **Supervisory Control and Data Acquisition (SCADA)** system provides real time operational data such as loadings, voltages, temperatures and switch positions. It also provides the interface through which PowerNet's System Control staff can view the data through a variety of display formats and remotely operate SCADA connected switchgear and other assets. Historical data is stored and provides a reference for planning. For example network loading can be downloaded over several years allowing growth trends to be determined and extended to forecast future loading levels.

Monthly reports out of the **Finance One (F1)** financial system provide recording 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 the AMS track estimates and costs against assets.

Outage, Fault and Defect Databases are populated by the System Control staff as information is reported by field staff or via the faults call centre to ensure efficient tracking of operational issues affecting network service levels.

- The faults database logs all customer initiated calls reporting power cuts or part power to store reported information and contact details. Calls are therefore able to be tracked to ensure effective response and restoration.
- The outage database logs outage data used to provide regulatory information and statistics on network performance. As such data capture is in line with regulatory focuses, it excludes LV network outages. Reports from this system are used to highlight poorly performing feeders which can then be analysed to determine maintenance requirements or if reliability may be enhanced by other methods. Monthly reports are provided to the EIL Board for monitoring, together with details of planned outages.
- Asset defects are captured in another database for technical asset issues which don't have an immediate impact on service levels but potentially could, if not responded to. Defects are tracked in this database and scheduled for remediation.

The **Condition Assessment Database** tracks the results of routine overhead line inspection rounds and is used as a basis for assigning line repair/renewal work. Severely deteriorated structures are marked as red-tagged and are prioritised for repair, and low conductor spans are also marked for a heightened priority. The Condition Assessment Database is being replaced as part of an overhaul of line inspections on all PowerNet-managed networks; the replacement database will permit the recording of repairs and will allow more precision in reliability analysis.

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

Data Control, Improvement and Limitations

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 ascertain asset age, but certain asset classes such as cables, had limited supporting information. As old cables do not have a manufacture date affixed, it is very difficult to update GIS. Options have been considered to get ages measured for the un-dated cables but no economic methodology has been found. Where economic, condition data is collected, as it is considered to be more useful in determining replacement timeframes.

Almost all GIS data entered for assets is standardised and selected from lists to ensure quality of data entry; and for all other data (for example electrical connectivity), thorough processes, peer reviews, and well trained staff are used to ensure data entry quality is very good. Key process improvements will include more timely as-builts with PowerNet staff taking GPS[6] coordinates for poles and use of scan-able forms for data input (Teleform system).

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

Improvements to the AMS are continually being undertaken to allow additional asset details to be captured which were historically captured in spreadsheets; especially the addition of condition based indicators to assist in making better asset management decisions. Data validation and completeness controls are also being added over time to prevent new assets being created without all required data being captured.

Assets are assigned a unique reference common to both the GIS and AMS. Where asset data is common to both systems it will be input into one system (deemed the master for that data) and automatically copied to the other to ensure consistency. Other systems also have some degree of interface for copying across common data such as customer data residing in both the ICP database and in GIS and referenced by the common ICP number. However for the most part, these tools do not interact directly, with staff pulling together information from the necessary tools for their use as part of their asset management activities.

The SCADA system and monitoring completeness and accuracy is excellent at zone substations as it is critical for both safety and reliability of the network as it is used for the day to day operation of the network. More field devices are be being added to SCADA for remote monitoring and operation.

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

Other data repositories have very good data quality with these database systems controlling data entry through drop down lists and validation controls. Modifications may be made from time to time to better align with maintenance processes as they evolve.

Table 70 provides a summary for the completeness of EIL's data.

Table 70: Knowledge Completeness

System	Parameter	Completeness	Notes
GIS	Description	Good	Some delays between job completion & GIS update, some cable size/types unknown
GIS	Location	Excellent	Some delays between job completion & GIS update
GIS	Age	Okay	Some estimates required
Condition Assessment Database	Condition	Okay	Regular inspections but some subjectivity and condition data not updated with repair
AMS	Description	Okay	Some delays between job completion & Maximo Update
AMS	Details	Okay	Some delays between job completion & Maximo Update
AMS	Age	Okay	Missing age on old components, mix of installation and manufacturing dates used as age estimate
AMS	Condition	Poor	Some condition monitoring data (e.g.DGA and earthing data) in the AMS. Other data not consolidated in a single system.
SCADA	Zone Substations	Excellent	All monitored
SCADA	Field Devices	Good	Monitoring and automation increasing

8.2. Funding the Business

EIL's business is funded from the revenue received from their customers. And through a wide range of internal processes, policies and plans, the company converts that funding into fixed assets. These fixed assets in turn create the service levels such as capacity, reliability, security and supply quality that customers want. This business model is shown in Figure 45.

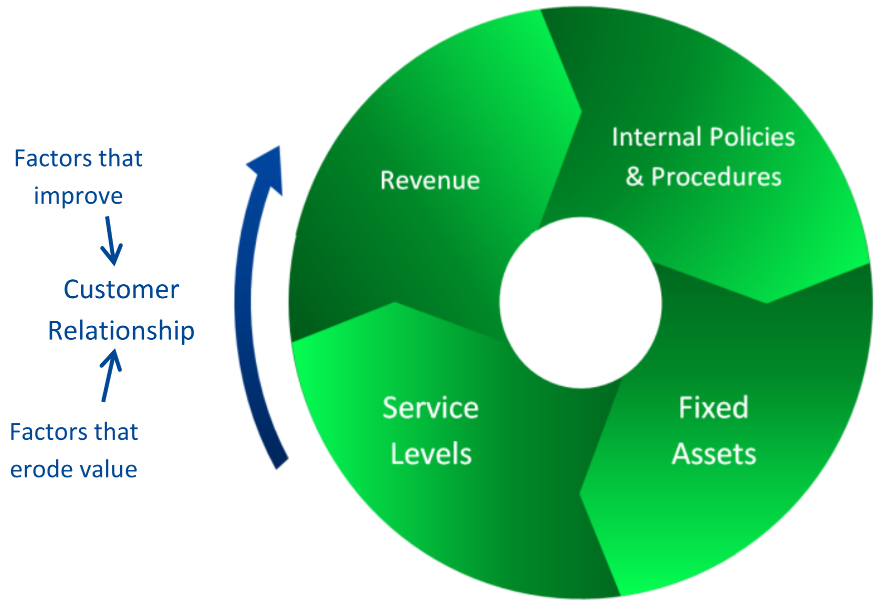


Figure 45: Customer Interface Model

Revenue

EIL's money comes primarily from the retailers who pay for the conveyance of energy over EIL's network but also from customers providing contributions for the uneconomic part of works. Revenue is set out in a "price path", aligned to determinations by the Commerce Commission .

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 balance sheet, but perhaps more importantly also allows EIL to treat any increased Transpower charges as a pass-through cost

Expenditure

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

Influences the Value of Assets

An annual independent telephone survey is undertaken in September each year and consistently indicates EIL's customer's price-quality trade-off preferences are as follows:

- A large majority are not willing to pay $10 per month more in order to reduce interruptions
- A small minority are willing to pay $10 per month more in order to reduce interruptions
- A small minority feel they 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 71 below:

Table 71: 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	Removal of assets from the network
Renewal of existing assets	On-going depreciation of assets
Increase of standard component values implicit in valuation methodology	Reduction of standard component values implicit in valuation 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.

Depreciating the Assets

The accounting treatment of using straight-line depreciation doesn't strictly model the decline in service potential of an asset. It may well 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.

8.3. Staff and Contracting Resources

Each item or project making up the AWP is carefully considered as to the man hours required using the experience gained over many years of network management. The Works Programme 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. It is important that the AWP "smooths" the year-to-year work volumes required (to the extent possible acknowledging appropriate risk controls) in order to provide a relatively constant work stream.

The internalising of PowerNet's field services has great benefit in ensuring a longer term approach may be taken to resourcing. Staff numbers can be increased with added confidence that they will be fully utilised in future years given the long term plans developed. Working closely with EIL's contractors is also an important part of the AWP development process, carefully communicating the detailed works plan and getting commitment that sufficient resources will be available for the year ahead. The future Works Programme is also communicated so that contractors can confidently commit to hiring extra staff where appropriate, recognising EIL's on-going development and maintenance requirements.

Appendix 1 – Policies, Standards and Procedures

Operating Processes and Systems

Commissioning Network Equipment	NMPR-100
Network Equipment Movements	PNM-063
Planned Outages	NMPR-115
Network Faults, Defects and Supply Complaints	NMPR-125
Major Network Disruptions	PNM-069
Use of Operating Orders (O/O)	NMPR-140
Control of Tags	PNM-073
Access to substations and Switchyards	NMPR-010
Entry to EIL Underground Substations	FOPR-275
Operating Authorisations	NMPR-040
Radio Telephone Communications	NMPR-020
Operational Requirements for Live Line Work	PNM-081
Control of SCADA Computers	PNM-083
Operating Near Electrical Works	PNM-085
Customer Fault Calls/Retail Matters	PNM-087
Site Audits	QYPR-010
Meter/Ripple Receiver Control	NMPR-005

Maintenance Processes and Systems

Transformer Maintenance	NMPR-030
Defect Submission & Retrieval from the NEDeRS Database	PNM-066
Control of Network Spares	PNM-097
Maintenance Planning	PNM-105
Network Overhead Lines Equipment Replacement	PNM-106
Earth Tests	PNM-133

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

Renewal Processes and Systems

Network Development	PNM-113
Design and Development	PNM-114

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

Retirement Processes and Systems

Disconnected and/or Discontinued Supplies	NMPR-240

Performance Measuring Processes

These processes are embedded within, and controlled by, the outage, faults and defects databases.

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 Project	PNM-010
Tendering	NMPR-045
Progressing the Project	PNM-020
Construction Approval	PNM-025
Materials Management	PNM-030
Project Control	PNM-035
Project Close Out	PNM-040
Customer Satisfaction	PNM-050
Internal Audits	QYPR-085
Drawing Control	PNM-089
Network Operational Diagram/GIS Control	PNM-091
Control of Operating and Maintenance Manuals	PNM-093
Control of External Standards	QYPR-005
Control of Power Quality Recorders	NMPR-195
Quality Plans	PNM-107
Health and Safety Requirements for Contractors	HSST-010
Accidents and Incidents	HSPR-015
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

Appendix 2 – Customer Engagement Questionnaire

PowerNet Customer Engagement

Residential: Can I speak to " insert name " or the person mainly or jointly responsible for paying the electricity account?

Business: Can I speak to the person mainly or jointly responsible for paying the power bill or making decisions about power supply for "insert company name"

My name is ….Calling from Research First on behalf of PowerNet. We are conducting a survey to help PowerNet deliver the right levels of service to its customers and plan effectively for your future needs.

The survey will take about 15 minutes and you will be entered in a draw to win <one of 5 $50 grocery vouchers>

Great, I just have to check if you are eligible:

S1. Are you a PowerNet staff member, or are any of your immediate family a PowerNet staff member?

If yes - I am sorry but you are unable to complete the survey but thank you for time.

If no – Great. We will be linking your responses to your customer number (ICP) this is just to help with analysis. I will start with some general questions about PowerNet...

<INTERVIEWER NOTES: PHONE NUMBERS HAVE BEEN SUPPLIED BY POWERNET FROM THE CUSTOMER DATABASE. WE WILL NOT USE NUMBERS FOR ANY OTHER PURPOSE. RESPONDENTS CAN CALL POWERNET ON +64 3 211 1899 WITH ANY QUERIES)

A	Do you live in a rural area or in a town?	
	O	Rural (country)
	O	Town (urban)

SECTION 1: Awareness and Perceptions of Performance

1.	Have you heard of PowerNet?	
	O	Yes – Q2
	O	No – Q3

2.	Where have you most recently seen or heard about PowerNet? <do not prompt> <route to 3 except if Facebook mentioned>	
	○	Billboard
	○	Sponsorship – St John
	○	Sponsorship – Tour of Southland
	○	Sponsorship – other
	○	Website
	○	Facebook page – Go to Q4
	○	Logos on vehicles
	○	Radio ads
	○	Newspaper ads
	○	Other specify

3.	Were you aware that PowerNet has a Facebook page?	
	○	Yes
	○	No

	PowerNet is your local electricity network management company. It maintains the local electricity lines and substations that supply power to your premises for <insert retailer from sample frame: EIL Electricity Invercargill Limited, ONJV OtagoNet Joint Venture, TPCL The Power Company Limited>.

4. On a scale of 1 to 5 where 1 = 'very poor', 2 = 'poor', 3 = 'neutral', 4 = 'good', and 5 = 'very good', how would you rate PowerNet's performance on the following aspects over the last 12 months? <allow don't know>

	Very poor	Poor	Neutral	Good	Very good	Don't know
Caring for customers	1	2	3	4	5	6
Supporting the community	1	2	3	4	5	6
Being safety conscious	1	2	3	4	5	6
Efficiency in service response	1	2	3	4	5	6

5.	On the same scale of 1 to 5, how would you rate the reliability of your power supply?							
			Very poor	Poor	Neutral	Good	Very good	Don't know
		Reliability of power supply	1	2	3	4	5	6

6.	And how satisfied are you with that reliability? Again, use a 1 to 5 scale where 1= very dissatisfied, 2= dissatisfied, 3= neutral, 4= satisfied, 5 = very satisfied.							
			Very dissatisfied	Dissatisfied	Neutral	Satisfied	Very satisfied	Don't know
		Satisfaction with reliability	1	2	3	4	5	6

7.	<If coded 1 or 2 at Q5> What is the main reason for your dissatisfaction	
		Open comment

SECTION 2: Planned Interruptions to Service

	To allow time for essential maintenance and upgrades all network companies have to plan interruptions to services. Currently, PowerNet plans one interruption to your power supply every two years. The average length of time for an interruption is 4 hours.

8	Given the length of time for a planned interruption would be around 4 hours, what length of time between interruptions do you think is reasonable? <read out single code>	
	O	More than 1 per year
	O	1 per year
	O	1 every 2 years
	O	1 every 3 years
	O	1 every 4 years
	O	1 every 5 years
	O	No interruptions
	O	Don't know
	O	Don't care

9	Which of the following options would you prefer?	
	O	Retain the current plan: 1 interruption of 4 hours every 2 years
	O	Have more frequent interruptions but of shorter duration
	O	Have less frequent interruptions but of a longer duration
	O	Don't know <do not prompt>

10	Would you prefer planned interruptions to take place at a certain time of day?	
	O	Yes - mornings
	O	Yes - afternoons
	O	Yes – evenings
	O	Yes – overnight
	O	No – it does not matter

11	Would you prefer planned interruptions to take place on a weekday or over the weekend?	
	O	Weekdays
	O	Weekends
	O	It does not matter

12	Would you prefer planned interruptions to take place at a certain time of year? <multicode>	
	O	Autumn
	O	Winter
	O	Spring
	O	Summer
	O	It does not matter
	O	Other specify

SECTION 3: Communications – Planned Interruptions

13	Have you received advice of a planned electricity interruption during the last 6 months?	
	O	Yes – Q14
	O	No – Q19
	O	Don't know – Q19

14	Can you remember how much notice you were given?	
	O	1-2 day -Q15
	O	3-4 days -Q15

14	Can you remember how much notice you were given?	
	○	5-6 days -Q15
	○	1 week -Q15
	○	2 weeks -Q15
	○	More than 2 weeks -Q15
	○	Don't know – Q16

15	Do you feel that you were given enough notice of this planned interruption?	
	○	Yes - Q17
	○	No - Q16
	○	Don't know - Q17

16	How much notice would you like to be given?	
	○	1-2 day
	○	3-4 days
	○	5-6 days
	○	1 week
	○	2 weeks
	○	More than 2 weeks

17	Were you satisfied with the amount of information given to you about this planned interruption?	
	○	Yes – Q19
	○	No - Q18
	○	Don't know – Q19

18	What additional information was needed	
		Open comment

19	How would you prefer to be notified about planned interruptions? <do not prompt, single code 1st mention>	
	○	Post
	○	Email
	○	Facebook
	○	Phone call
	○	Text
	○	App

19	How would you prefer to be notified about planned interruptions? <do not prompt, single code 1st mention>	
	○	Other specify

SECTION 4: Unplanned Interruptions

	Unplanned power outages and faults can be caused by any number of events, from a vehicle hitting a pole, to lightning strikes, trees falling over the power lines, or even vandalism.

20	Who would you telephone in the event of the power supply to your home being unexpectedly interrupted? <do not prompt>	
	○	PowerNet
	○	Retailer/Power company
	○	Local government
	○	Other
	○	No-one

21	Were you aware that PowerNet has a call free 0800 faults number?	
	○	Yes
	○	No
	○	Don't know

22	Can you recall when the last unexpected interruption to your power supply was?	
	○	Yes – In the last week – Q23
	○	In the last month – Q23
	○	2<3 months ago – Q23
	○	3<6 months ago – Q23
	○	More than 6 months ago – Q28
	○	Never had an unexpected interruption to power at this address – Q28
	○	Don't know – Q28
		Don't care – Q28

23	Do you recall how long your most recent power cut lasted?	
	○	Under a minute/it just flicked off and back on
	○	1<30 minutes
	○	30min < 1 hour

23	Do you recall how long your most recent power cut lasted?	
	○	1<2 hours
	○	2<3 hours
	○	3<4 hours
	○	More than 4 hours
	○	Don't know

24	On a scale of 1 to 5 where 1 is no impact at all, 2 is minor impact, 3 is neutral, 4 is moderate impact and 5 is major impact, how much impact did your last power cut have on you?	
	○	No impact
	○	Minor impact
	○	Neutral
	○	Moderate impact
	○	Major impact
	○	Don't know

25	Did you call your power company or network provider when the supply was interrupted?	
	○	PowerNet – Q26
	○	Retailer/Power company – Q28
	○	Local government – Q28
	○	No-one – Q28
	○	Other – Q28
	○	Don't know/can't remember – Q28

26	On a scale of 1 to 5 where 1 = 'very dissatsfied', 2 = 'dissatisfied', 3 = 'neutral', 4 = 'satisfied', and 5 = 'very satisfied', how satisfied were you with...?						
			Very dissatisfied	Dissatisfied	Neutral	Satisfied	Very satisfied
		The system you had to use to get information	1	2	3	4	5
		The information that was provided	1	2	3	4	5

If coded 1 or 2 at Q26 – go to Q27

If coded 3,4,5 at Q26 – go to Q28

27	<If coded 1 or 2 at Q26> What could be done to improve this process	
	○	Open comment
	○	Don't know

28	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?	
	○	Under 30 minutes
	○	30min < 1 hour
	○	1<2 hours
	○	2<3 hours
	○	3<4 hours
	○	More than 4 hours
	○	Don't know

29	In the event of an unexpected interruption to your electricity supply, what is the most important information that you wish to receive? <do not prompt, multicode>	
	○	Accurate time power will be restored
	○	Reason for fault
	○	That they know the problem and that it is being fixed
	○	Other specify
	○	No information required

<NEED TO TEST WHICH OF THE FOLLOWING 2 QUESTIONS WORKS BEST>

30 b	PILOT: Currently there is an average of one interruption to power supply due to faults every 2 years IF different options were available. Which of these scenarios would you prefer?	
	○	Reduce the number of interruptions but pay a bit more per month
	○	Increase the number of interruptions and pay a bit less each month
	○	Keep the numbers of interruptions and prices the same
	○	Don't know

Section 5: Evolving Technology

	PowerNet needs to plan for future energy use, so they are interested in understanding what people know about new technologies.

31	Which of the following technologies are you aware of?	
	O	Solar/photovoltaic panels
	O	Battery storage
	O	Electric vehicles
	O	Home energy management systems
	O	None of these

32	<remove codes not marked at Q31> Do you have any of these now, or are you considering purchasing them in the next year, 5 years or 10 years?						
			Already have	Considering in next year	Considering in next 5 years	Considering in next 10 years	No plans to purchase
		Solar/photovoltaic panels	1	2	3	4	6
		Battery storage	1	2	3	4	6
		Electric vehicles	1	2	3	4	6
		Home energy management systems	1	2	3	4	6

33	<if coded 1 at electric vehicles Q32> When do you **normally** charge your Electric vehicle	
	O	Overnight
	O	During the day
	O	Other specify

34	<if coded 1 at electric vehicles Q32> If it was cheaper to charge overnight would you change the time you charge?	
	O	Yes
	O	No
	O	Don't know

35	<from Q33 – all codes 2,3,4> What would prompt you to purchase each of the following...? <do not prompt>						
			Drop in purchase price	Heightened environmental	Reasonable pay back period	Other specify	

35	<from Q33 – all codes 2,3,4> What would prompt you to purchase each of the following...? <do not prompt>						
		Solar/photovoltaic panels	1	2	3	4	6
		Battery storage	1	2	3	4	6
		Electric vehicles	1	2	3	4	6
		Home energy management systems	1	2	3	4	6

Section 6: Final comments

36	Finally, are there any other comments you would like to make about PowerNet services?	
	○	No comment
	○	Happy with service
	○	Other specify

That concludes this survey.
Just to remind you my name is from Research First. Thank you very much for your time and the information you have provided.

Appendix 3 – Disclosure Schedules

Schedule 11a. – Capital Expenditure Forecast

Company Name	**Electricity Invercargill Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**

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 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10	Consumer connection		503	837	746	517	259	266	574	585	597	609	621
11	System growth		-	-	-	-	-	448	-	-	-	-	-
12	Asset replacement and renewal		3,866	3,636	3,377	3,224	3,657	3,332	5,234	5,059	5,240	5,559	6,491
13	Asset relocations		-	6	27	6	6	6	6	6	7	7	7
14	Reliability, safety and environment:												
15	Quality of supply		68	60	162	165	48	50	51	52	53	54	55
16	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment		185	103	333	462	471	483	493	503	451	412	392
18	**Total reliability, safety and environment**		253	163	494	627	519	533	543	554	504	466	447
19	**Expenditure on network assets**		4,622	4,642	4,645	4,373	4,441	4,585	6,358	6,205	6,347	6,640	7,567
20	Expenditure on non-network assets		-	-	-	-	-	-	-	-	-	-	-
21	**Expenditure on assets**		4,622	4,642	4,645	4,373	4,441	4,585	6,358	6,205	6,347	6,640	7,567
22													
23	*plus* Cost of financing												
24	*less* Value of capital contributions		61	247	285	192	204	222	172	195	226	266	320
25	*plus* Value of vested assets												
26													
27	**Capital expenditure forecast**		4,561	4,395	4,360	4,181	4,237	4,362	6,185	6,010	6,122	6,374	7,247
28													
29	Assets commissioned		3,346	4,021	6,480	4,181	4,237	4,362	6,185	6,010	6,122	6,374	7,247
30			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31		for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30
32			**$000 (in constant prices)**										
33	Consumer connection		503	837	731	496	244	244	516	516	516	516	516
34	System growth		-	-	-	-	-	411	-	-	-	-	-
35	Asset replacement and renewal		3,866	3,636	3,309	3,097	3,445	3,059	4,711	4,464	4,533	4,715	5,398
36	Asset relocations		-	6	27	6	6	6	6	6	6	6	6
37	Reliability, safety and environment:												
38	Quality of supply		68	60	158	158	46	46	46	46	46	46	46
39	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment		185	103	326	443	443	443	443	443	390	349	326
41	**Total reliability, safety and environment**		253	163	484	602	489	489	489	489	436	395	372
42	**Expenditure on network assets**		4,622	4,642	4,551	4,201	4,185	4,209	5,722	5,475	5,491	5,632	6,292
43	Expenditure on non-network assets		-	-	-	-	-	-	-	-	-	-	-
44	**Expenditure on assets**		4,622	4,642	4,551	4,201	4,185	4,209	5,722	5,475	5,491	5,632	6,292
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		-	-	21	-	-	-	-	-	-	-	-
49	Research and development		-	-	-	-	-	-	-	-	-	-	-
50													

Schedule 11a. – Capital Expenditure Forecast (continued)

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30
Difference between nominal and constant price forecasts	$000										
Consumer connection	-	-	15	20	15	22	57	69	81	92	105
System growth	-	-	-	-	-	37	-	-	-	-	-
Asset replacement and renewal	-	-	69	127	211	273	523	595	707	844	1,094
Asset relocations	-	-	1	0	0	1	1	1	1	1	1
Reliability, safety and environment:											
Quality of supply	-	-	3	6	3	4	5	6	7	8	9
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	-	7	18	27	40	49	59	61	63	66
Total reliability, safety and environment	-	-	10	25	30	44	54	65	68	71	75
Expenditure on network assets	-	-	94	172	257	376	636	730	856	1,009	1,275
Expenditure on non-network assets	-	-	-	-	-	-	-	-	-	-	-
Expenditure on assets	-	-	94	172	257	376	636	730	856	1,009	1,275

11a(ii): Consumer Connection

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
*Consumer types defined by EDB**	$000 (in constant prices)					
Customer Connections (≤ 20 kVA)	82	61	61	61	61	61
Customer Connections (21 to 99 kVA)	34	54	54	54	54	54
Customer Connections (≥ 100 kVA)	382	496	609	375	123	123
Distributed Generation Connection	-	3	3	3	3	3
New Subdivisions	6	222	3	3	3	3
**include additional rows if needed*						
Consumer connection expenditure	503	837	731	496	244	244
less Capital contributions funding consumer connection						
Consumer connection less capital contributions	503	837	731	496	244	244

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	-	-	-	-	-	-
Zone substations	-	-	-	-	-	411
Distribution and LV lines	-	-	-	-	-	-
Distribution and LV cables	-	-	-	-	-	-
Distribution substations and transformers	-	-	-	-	-	-
Distribution switchgear	-	-	-	-	-	-
Other network assets	-	-	-	-	-	-
System growth expenditure	-	-	-	-	-	411
less Capital contributions funding system growth	-	-	-	-	-	-
System growth less capital contributions	-	-	-	-	-	411

11a(iv): Asset Replacement and Renewal

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
	$000 (in constant prices)					
Subtransmission	-	-	-	-	-	-
Zone substations	2,214	1,999	1,409	310	870	484
Distribution and LV lines	42	184	184	184	184	184
Distribution and LV cables	233	275	288	288	288	288
Distribution substations and transformers	792	290	518	632	532	532
Distribution switchgear	301	735	756	1,529	1,418	1,418
Other network assets	285	153	153	153	153	153
Asset replacement and renewal expenditure	3,866	3,636	3,309	3,097	3,445	3,059
less Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
Asset replacement and renewal less capital contributions	3,866	3,636	3,309	3,097	3,445	3,059

Schedule 11a. – Capital Expenditure Forecast (continued)

11a(v): Asset Relocations

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
*Project or programme**		$000 (in constant prices)					
Asset Relocation Projects		-	6	27	6	6	6
Stead St StopBank		-	-	-	-	-	-
**include additional rows if needed*							
All other project or programmes - asset relocations		-	-	-	-	-	-
Asset relocations expenditure		-	6	27	6	6	6
less Capital contributions funding asset relocations		-	-	-	-	-	-
Asset relocations less capital contributions		-	6	27	6	6	6

11a(vi): Quality of Supply

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
*Project or programme**		$000 (in constant prices)					
Supply Quality Upgrades - City		-	13	13	13	13	13
Supply Quality Upgrades - Bluff		-	1	1	1	1	1
Network Automation Projects		68	46	144	144	31	31
**include additional rows if needed*							
All other projects or programmes - quality of supply		-	-	-	-	-	-
Quality of supply expenditure		68	60	158	158	46	46
less Capital contributions funding quality of supply		-	-	-	-	-	-
Quality of supply less capital contributions		68	60	158	158	46	46

11a(vii): Legislative and Regulatory

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
*Project or programme**		$000 (in constant prices)					
**include additional rows if needed*							
All other projects or programmes - legislative and regulatory							
Legislative and regulatory expenditure		-	-	-	-	-	-
less Capital contributions funding legislative and regulatory							
Legislative and regulatory less capital contributions		-	-	-	-	-	-

Schedule 11a. – Capital Expenditure Forecast (continued)

150		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme**	**$000 (in constant prices)**					
153	Earth Upgrades - City	2	55	55	55	55	55
154	Earth Upgrades - Bluff	-	9	9	9	9	9
155	Pillar Box Lid Upgrade	183	-	50	50	50	50
156	Spey St Fibre Chamber/Cable	-	-	22	-	-	-
157	LV Tie Point Disconnectors	-	-	-	243	243	243
	Fibre Installation	-	34	185	34	34	34
	Locks and Security	-	5	5	53	53	53
158	**include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment	-	-	-	-	-	-
160	**Other reliability, safety and environment expenditure**	185	103	326	443	443	443
161	*less* Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
162	**Other reliability, safety and environment less capital contributions**	185	103	326	443	443	443
163							
164		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
165	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme**	**$000 (in constant prices)**					
169							
170							
171							
172							
173							
174	**include additional rows if needed*						
175	All other projects or programmes - routine expenditure						
176	**Routine expenditure**	-	-	-	-	-	-
177	**Atypical expenditure**						
178	*Project or programme**						
179							
180							
181							
182							
183							
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure						
186	**Atypical expenditure**	-	-	-	-	-	-
187							
188	**Expenditure on non-network assets**	-	-	-	-	-	-

Schedule 11b. – Operational Expenditure Forecast

Company Name	Electricity Invercargill Limited
AMP Planning Period	1 April 2020 – 31 March 2030

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 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	628	473	482	492	502	515	619	632	644	657	671
11	Vegetation management	2	2	2	2	2	2	2	2	2	2	2
12	Routine and corrective maintenance and inspection	1,354	978	968	1,018	1,007	1,033	1,122	1,144	1,201	1,191	1,214
13	Asset replacement and renewal	620	189	193	197	201	206	210	214	218	223	227
14	**Network Opex**	2,604	1,641	1,645	1,708	1,711	1,756	1,953	1,992	2,066	2,073	2,114
15	System operations and network support	1,025	1,067	1,089	1,111	1,133	1,163	1,186	1,210	1,234	1,258	1,284
16	Business support	2,048	2,226	2,252	2,326	2,372	2,434	2,483	2,532	2,583	2,635	2,687
17	**Non-network opex**	3,072	3,294	3,342	3,437	3,504	3,597	3,668	3,742	3,817	3,893	3,971
18	**Operational expenditure**	5,676	4,935	4,987	5,145	5,215	5,352	5,621	5,734	5,882	5,966	6,085

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 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	628	473	473	473	473	473	558	558	558	558	558
23	Vegetation management	2	2	2	2	2	2	2	2	2	2	2
24	Routine and corrective maintenance and inspection	1,354	978	949	978	949	949	1,010	1,010	1,039	1,010	1,010
25	Asset replacement and renewal	620	189	189	189	189	189	189	189	189	189	189
26	**Network Opex**	2,604	1,641	1,612	1,641	1,612	1,612	1,758	1,758	1,787	1,758	1,758
27	System operations and network support	1,025	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067
28	Business support	2,048	2,226	2,207	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234
29	**Non-network opex**	3,072	3,294	3,274	3,302	3,302	3,302	3,302	3,302	3,302	3,302	3,302
30	**Operational expenditure**	5,676	4,935	4,886	4,943	4,913	4,913	5,060	5,060	5,089	5,060	5,060
31	**Subcomponents of operational expenditure (where known)**											
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	136	141	141	141	141	141	141	141	141	141	141

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 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	10	19	29	42	62	74	87	100	113
43	Vegetation management	-	-	0	0	0	0	0	0	0	0	0
44	Routine and corrective maintenance and inspection	-	-	20	40	58	85	112	135	162	181	205
45	Asset replacement and renewal	-	-	4	8	12	17	21	25	29	34	38
46	**Network Opex**	-	-	33	67	99	144	195	234	279	315	356
47	System operations and network support	-	-	22	44	65	95	119	142	166	191	216
48	Business support	-	-	46	92	137	200	248	298	348	400	453
49	**Non-network opex**	-	-	68	135	203	295	367	440	515	591	669
50	**Operational expenditure**	-	-	101	203	301	439	562	674	794	906	1,025

Schedule 12a. – Asset Condition

Company Name: **Electricity Invercargill Limited**
AMP Planning Period: **1 April 2020 – 31 March 2030**

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	H1	H2	H3	H4	H5	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.	-	1.00%	21.00%	58.00%	20.00%	-	3	1.00%
11	All	Overhead Line	Wood poles	No.	0.10%	7.00%	54.00%	38.00%	0.90%	-	2	9.00%
12	All	Overhead Line	Other pole types	No.	-	-	-	100.00%	-	-	3	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	-	100.00%	-	-	3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	N/A	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	-	-	70.00%	-	30.00%	-	2	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	100.00%	-	-	-	2	-
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	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	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	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	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	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	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	N/A	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%	10.00%	15.00%	15.00%	35.00%	-	4	15.00%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	N/A	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%	-	-	-	3	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	100.00%	-	-	-	-	-	3	100.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	45.00%	9.00%	18.00%	28.00%	-	-	3	45.00%
30	HV	Zone substation switchgear	33kV RMU	No.	N/A	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	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	N/A
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	13.00%	14.00%	42.00%	-	31.00%	-	3	27.00%
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	N/A
35												

Schedule 12a. – Asset Condition (Continued)

Row	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
36					Asset condition at start of planning period (percentage of units by grade)							
37												
38	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	17.00%	33.00%	17.00%	33.00%	-	4	-
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	23.00%	29.00%	41.00%	3.00%	4.00%	-	2	19.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
42	HV	Distribution Line	SWER conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	3.00%	2.00%	12.00%	73.00%	10.00%	-	3	0.50%
44	HV	Distribution Cable	Distribution UG PILC	km	2.00%	6.00%	69.00%	20.00%	3.00%		3	1.50%
45	HV	Distribution Cable	Distribution Submarine Cable	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	50.00%	50.00%	-	-	3	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	33.00%	67.00%	-	-	-	-	3	33.00%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	39.00%	2.00%	16.00%	14.00%	29.00%	-	2	39.00%
49	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	N/A
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	16.00%	31.00%	13.00%	31.00%	9.00%	-	3	12.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	19.00%	13.00%	24.00%	28.00%	16.00%		2	15.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	6.00%	15.00%	41.00%	29.00%	9.00%	-	3	5.00%
53	HV	Distribution Transformer	Voltage regulators	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	11.00%	49.00%	40.00%	-	-	-	2	6.00%
55	LV	LV Line	LV OH Conductor	km	8.00%	11.00%	59.00%	19.00%	3.00%	-	2	10.00%
56	LV	LV Cable	LV UG Cable	km	1.00%	15.00%	60.00%	22.00%	2.00%	-	2	0.50%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	7.00%	6.00%	79.00%	7.00%	1.00%	-	1	2.00%
58	LV	Connections	OH/UG consumer service connections	No.	6.00%	4.00%	85.00%	2.00%	3.00%	-	2	0.50%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	40.00%	-	-	60.00%	-	-	3	40.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	20.00%	-	-	80.00%	-	-	3	20.00%
61	All	Capacitor Banks	Capacitors including controls	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
62	All	Load Control	Centralised plant	Lot	N/A	100.00%	N/A	N/A	N/A	N/A	3	-
63	All	Load Control	Relays	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
64	All	Civils	Cable Tunnels	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Schedule 12b. – Capacity Forecast

Company Name **Electricity Invercargill Limited**
AMP Planning Period **1 April 2020 – 31 March 2030**

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**									
8	*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	28	36	N-1	40	79%	36	70%	No constraint within +5 years	
10	Leven Street	13	23	N-1	25	55%	21	72%	No constraint within +5 years	Short interruption for changeover (Normally Open supply from alternate GXP, via TPCL owned subtransmission circuits). Growth in surrounding areas will erode subtransmission backfeed capability.
11	Racecourse Road	12	-	N	12	-	-	-	No constraint within +5 years	No firm capacity
12	Southern	15	-	N	9	-	23	65%	No constraint within +5 years	Upgrade to N-1 security by 2022; limited transfer capacity for extended periods. Further transfer of load will result in poorer network reliability. Utilisation projected to increase with planned feeder tie-point shifts from Racecourse Rd to Southern substation in post substation upgrade
13						-				
14						-				
15						-				
16						-				
17						-				
18						-				
19						-				
20						-				
21						-				
22						-				
23						-				
24						-				
25						-				
26						-				
27						-				
28						-				
29	[1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*									

Schedule 12c. – Demand Forecast

		Company Name	Electricity Invercargill Limited
		AMP Planning Period	1 April 2020 – 31 March 2030

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 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
11	*Consumer types defined by EDB**							
12	Customer Connections < 20 kVA		44	50	40	40	40	40
13	Customer Connections 21-99 kVA		9	5	5	5	5	5
14	Customer Connections > 100 kVA		2	3	2	2	2	2
15								
16								
17	**Connections total**		55	58	47	47	47	47
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		14	10	15	15	20	20
21	Capacity of distributed generation installed in year (MVA)		0.1	0.1	0.2	0.2	0.2	0.2
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 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
25	GXP demand		62	62	62	62	62	63
26	*plus* Distributed generation output at HV and above		-	-	-	-	-	-
27	**Maximum coincident system demand**		62	62	62	62	62	63
28	*less* Net transfers to (from) other EDBs at HV and above		1	1	1	1	1	1
29	**Demand on system for supply to consumers' connection points**		60	60	61	61	61	61
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		251	252	252	253	254	254
32	*less* Electricity exports to GXPs		-	-	-	-	-	-
33	*plus* Electricity supplied from distributed generation		0	-	-	-	-	-
34	*less* Net electricity supplied to (from) other EDBs		(13)	(13)	(13)	(13)	(13)	(13)
35	**Electricity entering system for supply to ICPs**		264	265	265	266	267	268
36	*less* Total energy delivered to ICPs		251	250	251	251	252	253
37	**Losses**		13	15	15	15	15	15
38								
39	**Load factor**		50%	50%	50%	50%	50%	50%
40	**Loss ratio**		5.0%	5.5%	5.5%	5.5%	5.5%	5.5%

Schedule 12d. – Reliability Forecast

Note: These forecasts are presented using the SAIDI/SAIFI calculation method detailed in the Electricity Distribution Services Default Price-Quality Path Determination 2020 As such they correlate with the Compliance Statement and the majority of publications in the public domain, but do not correlate with Schedule 10 of year-end disclosures. A rough correlation with Schedule 10 may be obtained through multiplying the Class B figures in rows 11 and 14 by a factor of 2.

Company Name	**Electricity Invercargill Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**
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		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	6.5	12.4	11.5	11.5	11.5	11.5
12	Class C (unplanned interruptions on the network)	48.0	21.6	21.5	22.5	23.5	23.5
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.03	0.10	0.10	0.10	0.10	0.10
15	Class C (unplanned interruptions on the network)	1.04	0.60	0.57	0.57	0.62	0.62

Schedule 13. – Asset Management Maturity Assessment Tool

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 .

Q No.	Function	Question	Score Mar 2019	Maturity Level Description
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2.5	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?	3	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.
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?	2.5	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?	1.5	Communicated to those responsible for delivery is either irregular or ad-hoc.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	2.5	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.

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)	3	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.
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?	2.5	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.
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?	2.5	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?	3	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system
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)?	2.5	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?	2.5	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?	2.5	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, 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?	2	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.
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?	1.5	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?	2	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.
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?	2.5	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?	1.5	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?	1.5	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	2.5	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.

		requirements incorporated into the asset management system?		
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?	2.5	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 activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.
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?	1	The organisation understands the requirements and is in the process of determining how to define them.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2.5	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?	1.5	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.

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.

Appendix 4 - Directors Approval

We, Thomas Campbell and Sarah Jane Brown, being directors of Electricity Invercargill Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) The attached information of Electricity Invercargill Limited prepared for the purposes of clauses 2.6.1 and 2.6.6 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, 12c and 12d are based on objective and reasonable assumptions which both align with Electricity Invercargill Limited corporate vision and strategy and are documented in retained records.

T Campbell

S J Brown

Date: 26 March 2020