Line Pricing Methodology

AS AT 1 APRIL 2026

Electricity Invercargill Ltd

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GLOSSARY

AMP is Asset Management Plan.

Contract Capacity is the capacity of a customer used for billing purposes. It is formalised by way of agreement and control can be by way of the ICP fusing or the Anytime Maximum Demand.

Customer refers to the person or body that is responsible for an electrical installation that is connected to EIL's electricity network.

Distributed Generation or embedded generation is electricity generation that is connected directly to a distribution network.

Diversity Factor is the factor applied to a load or customer demand to allow for the use of electricity at different times. In theory, the sum of the customer Maximum Demands after the Diversity Factors has been applied should equal the Maximum Demand measured at the GXP.

ENA is Electricity Networks Aotearoa.

Grid Exit Point (GXP) means the Grid Exit Point and is the connection point between the Transpower grid and EIL's network.

Group Customers include most customers with a Contract Capacity up to 100 kVA.

Individual Customers are in most cases commercial or industrial customers that have a Contract Capacity equal to or in excess of 150kVA.

Installation Control Point (ICP) is the point of connection between EIL's network and the Retailer's customer.

LRMC is Long-Run Marginal Cost.

Retailers are the companies that generate and/or buy electricity and then sell this service to end use customers utilising the local electricity network.

The Code is the Electricity Industry Participation Code 2010, which is the set of rules created and administered by the Electricity Authority.

Time of Use (TOU) refers to meters that are capable of providing Anytime and Maximum Demand readings and Peak, Shoulder and Night Period Energy readings for billing purposes.

Transpower is the State-Owned Enterprise that owns the transmission network and delivers electricity to Electricity Distribution Businesses (EDBs).

SUMMARY

Electricity Invercargill Limited (EIL) is the council-owned electricity distribution network that services Invercargill City and the Bluff township.

Our Pricing Methodology Disclosure describes how we determine the prices in a way that recovers costs across a diverse range of connection types, and the pricing structures we use to signal information about the cost of using the network during peak periods.

Our customers and pricing groups

Our network conveys electricity to the majority of Invercargill and Bluff, supplying approximately 17,780 customers.

We set our pricing using three main customer pricing groups: Residential, General, and Individual. Individual customers are typically commercial or industrial customers that have a contract capacity at or above 150 kVA and have connection-specific pricing.

For residential and general customers, our pricing differs according to the fusing and size of the connection (measured in capacity). Connections that choose to have their hot water heating controlled receive lower charges – this reflects that we can shift some hot water heating load away from congested periods and avoid or defer costly capital upgrades.

	Residential	General	Individual
Definition	Connection at a primary place of residence: 8kVA or 15 KVA. Single-phase only.	Any connection that is nor residential or Individual.	Generally 100kVA+
Number of connections	15,687	1,932	161
Price structure	Fixed daily charge plus peak, shoulder and off-peak usage charges.	Fixed daily charge plus peak, shoulder and off-peak usage charges.	Annual charge (billed monthly) and calculated using attributes of the connection.

Where we fit in the electricity industry

Generation

Electricity is generated using a variety of resources – water, geothermal, gas, wind, coal, and solar.

Transmission

Transpower owns and operates the high voltage transmission system that transports electricity from generators to local distribution networks.

Distribution

High voltage electricity is stepped down at substations, then the **EIL** network distributes it safely to local residential and business consumers using our network of poles, lines, and underground cables. **PowerNet** manages our network for us.

Retail

Your retailer measures how much power you use and sends you your power bill. Some of what you pay your retailer comes to us to cover the cost of investing in and maintaining a reliable network.

Customers

Our customers are the households and businesses in Invercargill City and Bluff, who use the electricity provided to power their home or business.

What our pricing covers

EIL's network prices are charged to retailers and include the costs of electricity distribution and transmission.

Our network is managed by PowerNet

EIL has a Network Management Agreement with PowerNet. Through this agreement, PowerNet manages our network and carries out many of the corporate functions of our business. PowerNet invoices retailers on EIL's behalf.

PowerNet is an electricity network management company. It was established in 1994 to achieve scale benefits through integrated network management across the Southern region's Electricity Distribution Businesses (EDBs).

PowerNet provides services to over 79,000 customers through more than 14,300 circuit kilometres and manages the fourth-largest suite of EDB assets in New Zealand. With its head office in Invercargill, the company has over 300 staff based at depots across Southland and Otago.

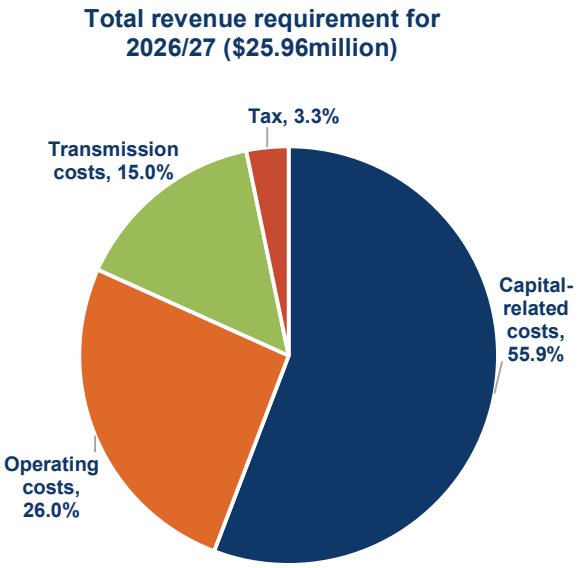
Our target revenue and pricing reflect costs of developing and maintain the EIL network

Our annual revenue is regulated by the Commerce Commission under the Default Price-Quality Path (DPP).

The methodology used by the Commission to set a cap on our annual revenue (allowable revenue) is based on our expected costs, which include:

- the costs of operating and maintaining the network (direct network costs),
- business support costs (indirect network costs),
- the costs of connecting to and using the national transmission network,
- tax, and
- capital-related costs (depreciation and the cost of capital) associated with assets.

Our allowable revenue also includes adjustments for incentives and penalties that relate to reliability targets and cost targets.



Our revenue requirement for the 12 months from 1 April 2026 is $25.96 million, which is an increase of 9.7% from the previous year. This includes a 17.3% increase in transmission charges and a 10% increase in distribution charges.

Before setting lines charges, we remove capital contribution revenue – that is, revenue from new or upgraded connections that provides a direct contribution to costs of required network augmentation.

Recovering costs across customers

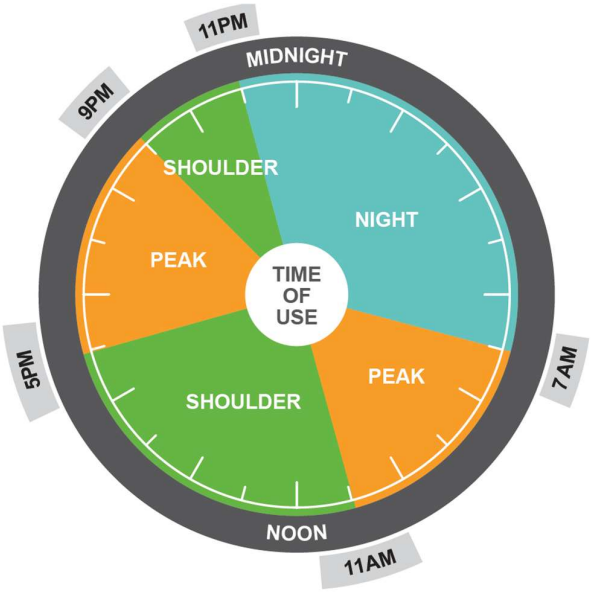
We allocate costs across the customer groups according to their network use characteristics, including capacity, demand during peak periods (kVA), electricity use during peak times (kWh), and total electricity use. The cost allocation process gives an annual cost for each of the individually priced connections, which is recovered through a monthly charge and a usage charge. For residential and general connections, we convert the allocated cost into daily fixed charges and usage charges per kWh that vary according to the time of day.

In line with requirements by the Electricity Authority, we carry out a check to ensure that our pricing doesn't result in a cross-subsidy. This analysis shows that the revenue from each customer group covers the costs directly associated with serving that group (avoidable costs) but that the revenue does not exceed the standalone costs.

Signalling the busy times on our network

We use a Time-of-Use (TOU) pricing structure, where the price of electricity usage is higher during times when there is most likely to be congestion on the network, and lower (or zero) at times when there is plenty of capacity. Pricing in this way sends a signal to transfer load outside of congestion periods and incentivises use of the network at times when there is little or no incremental cost for us to deliver the additional energy.

As a result, this type of pricing can defer or avoid the need to make costly investments in network capacity upgrade, benefiting all consumers in the longer term.



To date, few consumers have received these pricing signals because only some retailers have incorporated TOU into their retail pricing. As a broader range of retailers offer TOU retail prices, we will observe how consumers respond and what that means for network peaks and future investment.

Key changes made to the previous methodology

The changes made to the previous year's methodology are:

- Phase out of Low-User Fixed Charges (LFC) – In line with regulation changes, EIL has continued to phase out LFC charges to support the move towards more cost-reflective pricing. RY27 is the fifth and final year of a five-year phase out that will result in fixed charges for residential consumers increasing, from $0.75 per day to $0.90 per day from 1 April 2026.
- Implementation of a peak-period rebate for distributed generation exported to the network by residential and general customers (up to 45 kW connection capacity), aligned with the peak periods used for consumption charges.
- Time of Use price differentials between the peak and shoulder prices are strengthened to encourage the use of off-peak energy.
- Revision of our capital contributions policy, in line with regulatory requirements.

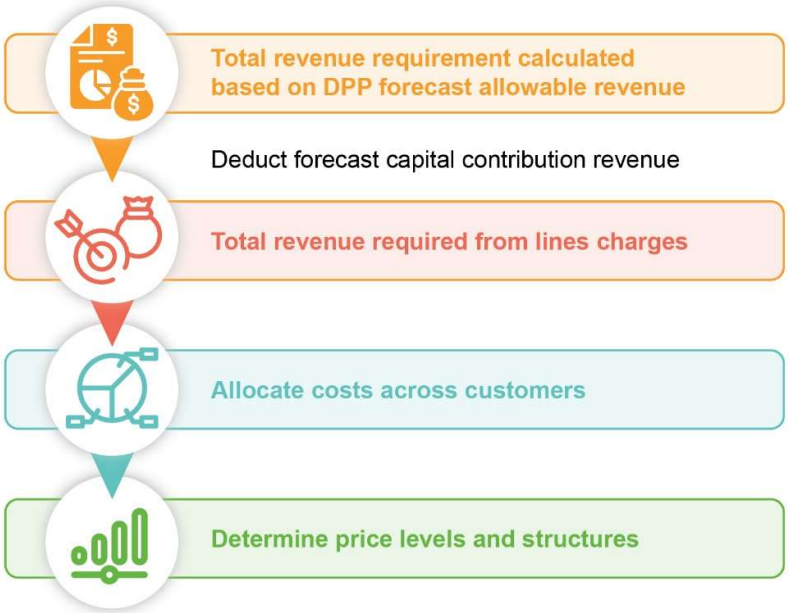
1. INTRODUCTION

Electricity Invercargill Limited is an electricity network asset company formed in 1991. The company is owned by the Invercargill City Council through its subsidiary company Invercargill City Holdings Ltd (ICHL). EIL owns the electricity network assets in Invercargill City and the Bluff township area.

EIL faces a number of regulatory requirements relevant to pricing that are administered by either the Commerce Commission (the Commission) or the Electricity Authority (the Authority). EIL's total revenue is regulated under the Commission's Default Price-Quality Path Determination 2025 (DPP Determination). In addition, the Commission's Information Disclosure Determination requires EIL to disclose a pricing methodology each year. The purpose of this document is to comply with the disclosure requirements by describing the methodology EIL uses to reflect the costs of providing delivery services to the different consumer groups supplied on the network. This document also assesses how our pricing compares with the Authority's Distribution Pricing Principles.

EIL sets its total revenue requirement to comply with the Commerce Commission's DPP Determination. We then deduct the capital contribution revenue that we expect to receive from new and upgraded connections to determine the total revenue required from lines charges. The next step is to allocate the revenue requirement across customers and customer groups, before determining the pricing structures and price levels that will apply to each customer group.

Figure 1 EIL's process for setting prices



The following sections explain how we implement this process. We first provide contextual information about EIL's network **(section 2)**, then present an overview of our prices and how they are set (**section 3).** We discuss our pricing strategy **(section 4).** This is followed by a more detailed discussion of how overall target revenue is determined, how that revenue is allocated to customer groups, and the methodology used to convert the revenue requirement into prices **(sections 5 to 7)**. We then assess our pricing against the Authority's Distribution Pricing Principles **(section 10) and discuss our pricing for non-standard contracts (section 8)**. Finally, we describe charges for generators connected to EIL's network **(section 9)**.

2. CONTEXTUAL INFORMATION ABOUT EIL

2.1 EIL's Network

Electricity Invercargill Limited is an electricity network asset company formed in 1991. The company is owned by the Invercargill City Council through its subsidiary company Invercargill City Holdings Ltd (ICHL). It is a wholly owned subsidiary of Invercargill City Holdings Limited (ICHL).

EIL owns the electricity network assets in Invercargill City and the Bluff township area.

A geographically compact network, EIL supplies more than 17,774 connections to residential, commercial and industrial customers.

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 Power Company Limited's surrounding network) and the township of Bluff. The Invercargill area network is almost entirely underground; 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.

The high proportion of underground cabling means that the EIL network consistently performs as one of the most reliable networks in New Zealand.

2.2 Network management arrangements

PowerNet Limited (PowerNet) manages the network assets owned by EIL. PowerNet is contracted to manage the network assets of EIL in accordance with a Management Agreement (Agreement). The Agreement includes provision for PowerNet to act as manager on behalf of EIL to collect revenue from line and metering charges to retailers or end consumers, pay transmission costs, incur maintenance expenditure and to pass the net amount through to EIL each month. PowerNet charges a management fee that covers its overheads for operating the line and metering businesses for EIL.

2.3 Upcoming investment in network capacity

As at end March 2025, the value of EIL's network assets in its Regulatory Asset Base was $119 million. Over the next three years, EIL intends to invest capital of $26.87 million in its network, of which the majority relates to asset replacements and renewal ($22.73 million).

2.4 Uptake of evolving technologies

Several technologies have the potential to change the way customers use and generate electricity. Pricing has a role to play in providing efficient signals about the economic costs of using electricity networks. In that context, we provide a summary of existing and expected uptake of a number of these technologies: solar (Photovoltaic; PV) with and without battery storage as well as electric vehicles.

2.4.1 The uptake of solar (Photovoltaic) is significantly below the national rate

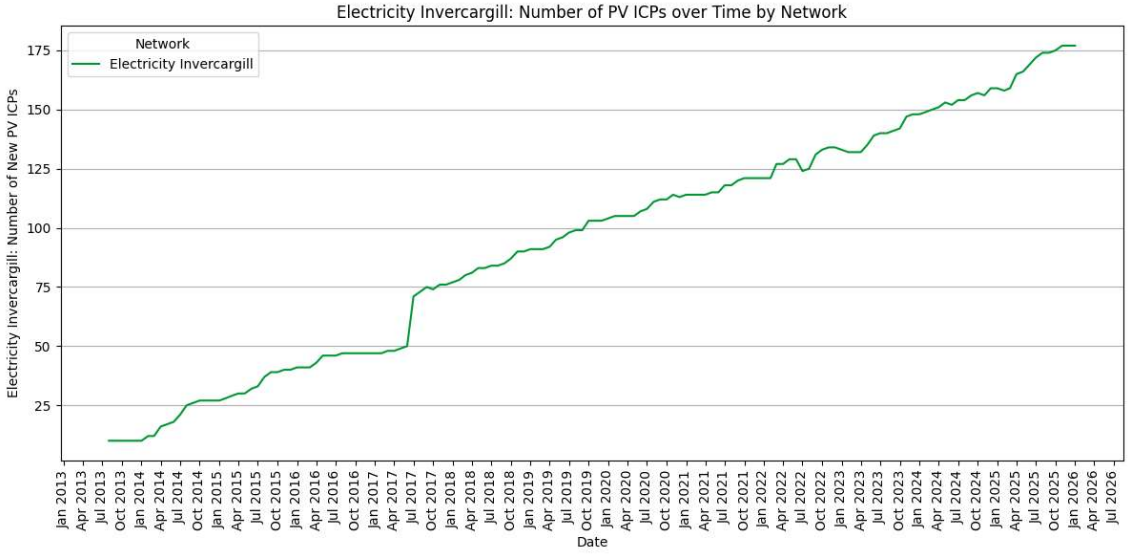
Over the past 12 years, there is a growing number of solar (Photovoltaic) connections without battery within the Electricity Invercargill (EIL) network (see Figure 1). This is also similarly reflected in the uptake rates over time (see Figure 2). As of January 2026, the uptake rate of solar in EIL at 1% was still below

the national rate of 2.80%. The national rate was still relatively lower than the 5.00% rate in the top ten highest uptake EDB areas[1] with the highest being Top Energy at 7.01%.

Another perspective of assessing an increasing interest in the technology is the average number of connections per month. Between February 2025 and January 2026, EIL had an insignificant increase in the average new connections compared to the preceding 12-month period (see Table 1).

Solar installations are likely to reduce total energy consumption within the AMP planning period. While energy consumption levels do not tend to affect network planning, which focuses on providing capacity for peak demand periods, it does affect price levels, to the extent that some component of price is set based on energy consumption (kWh). This is relevant to the development of our forward pricing strategy.

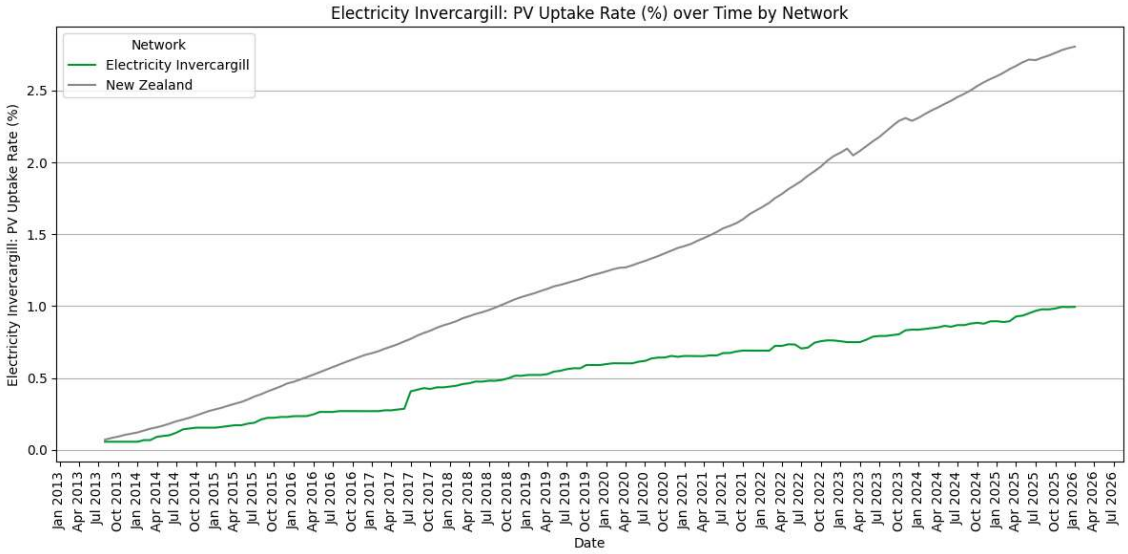
Figure 1 Monthly solar without battery connections (ICPs) over time



Source: Electricity Authority EMI Installed distributed generation trends

[1] Top ten EDB areas include Top Energy, MainPower NZ, Network Tasman, Marlborough Lines, Counties Power, Nelson Electricity, Waipa Networks, Lakeland Network, Northpower, and Electra.

Figure 2 Monthly solar without battery uptake rate (%) over time



Source: Electricity Authority EMI Installed distributed generation trends

Table 1 Relevant metrics on solar without battery across networks

	EIL
Solar connections (ICPs) as of January 2026	177
Solar uptake rate (%) as of January 2026	1.00%
Average new connections per month (Feb 2025–Jan 2026)	1.33
Average new connections per month (Feb 2024–Jan 2025)	1.25
Average new connections per month (Feb 2023–Jan 2024)	1.33

Source: Electricity Authority EMI Installed distributed generation trends

Solar Connections with Battery

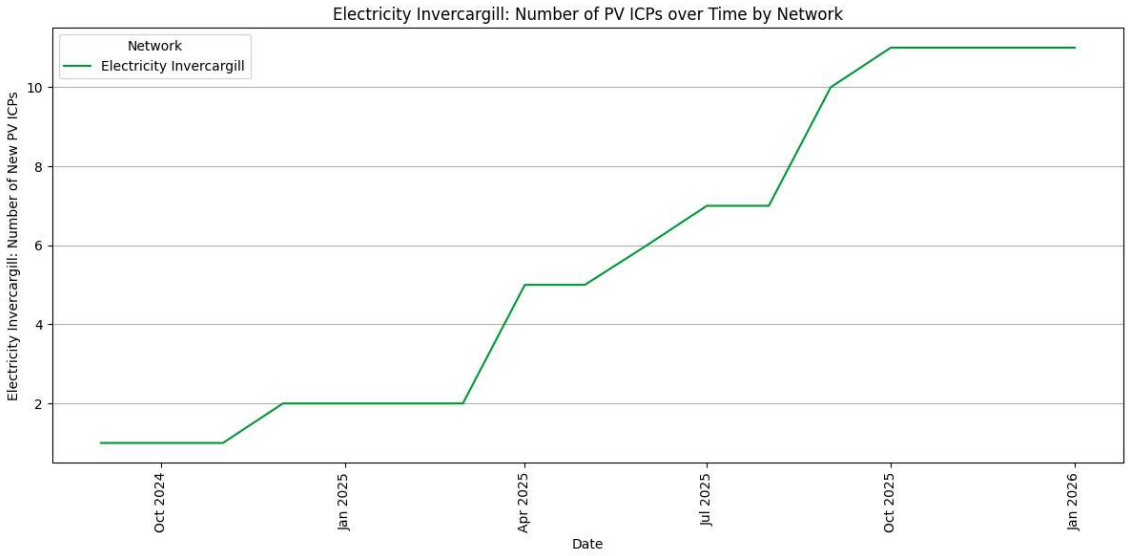
While the majority of new DGs is from solar connections, EIL networks' peak is historically on winter evenings, and coupling solar generation with battery energy storage could change this dynamic. In New Zealand this technology started to be adopted around late 2023. Within EIL the adoption began a year later around September 2024 and has gained a slow interest as reflected by the relatively flat uptake rates (see Figures 3 and 4). As of January 2025, EIL has 11 solar with battery connections, representing 0.19% of all its ICPs.

At present, the adoption of this technology in EIL is still at an early stage and the impact on the network is relatively insignificant. The major barrier for this slow adoption is likely the high upfront cost and long payback period, which is a concern given the rising cost of living. Many customers are also uncertain about the immediate benefits of batteries, despite the potential long-term savings. Any impact these devices have, nonetheless, is likely to be beneficial in terms of network constraints, as they act to reduce rather than increase the peak demand on network assets. To encourage adoption, future pricing should aim to reward customers where batteries benefit the network as well as to focus on educating customers about the long-term financial and environmental advantages.

Having a battery storage gives customers some control over their demand without impacting their consumption and could make it possible for customers to go "off grid" with a sufficiently sized generation source. However, there is an uncertainty in this area around the viability of alternative battery chemistries

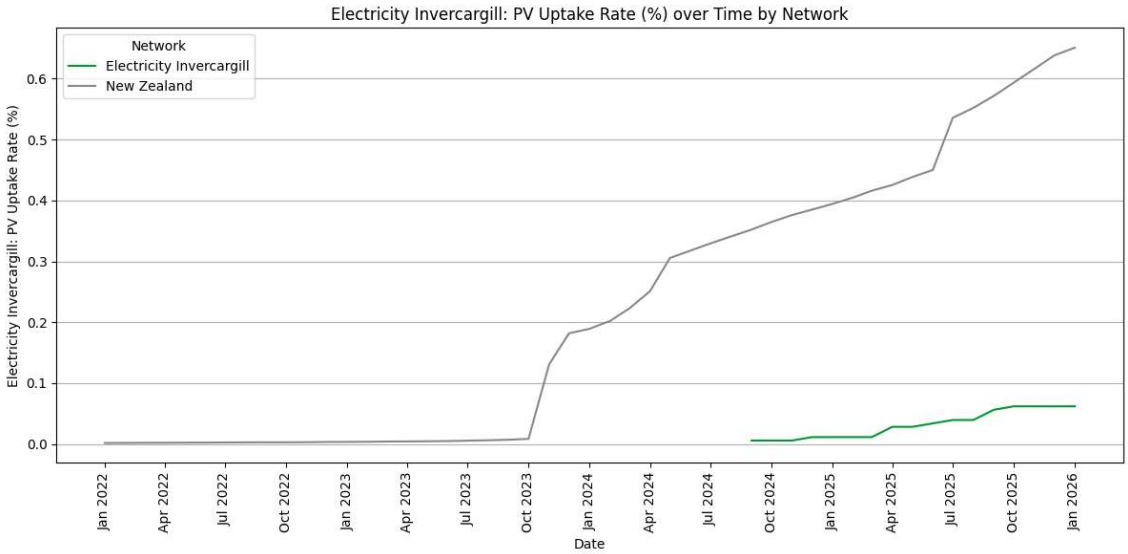
and the timing of their introduction; the regulatory environment and the extent to which electricity distribution businesses will be able to utilise storage services; and future pricing structures and the level of responsiveness of the public to load-driven pricing signals.

Figure 3 Monthly solar with battery connections (ICPs) over time



Source: Electricity Authority EMI Installed distributed generation trends

Figure 4 Monthly solar with battery uptake rate (%) over time



Source: Electricity Authority EMI Installed distributed generation trends

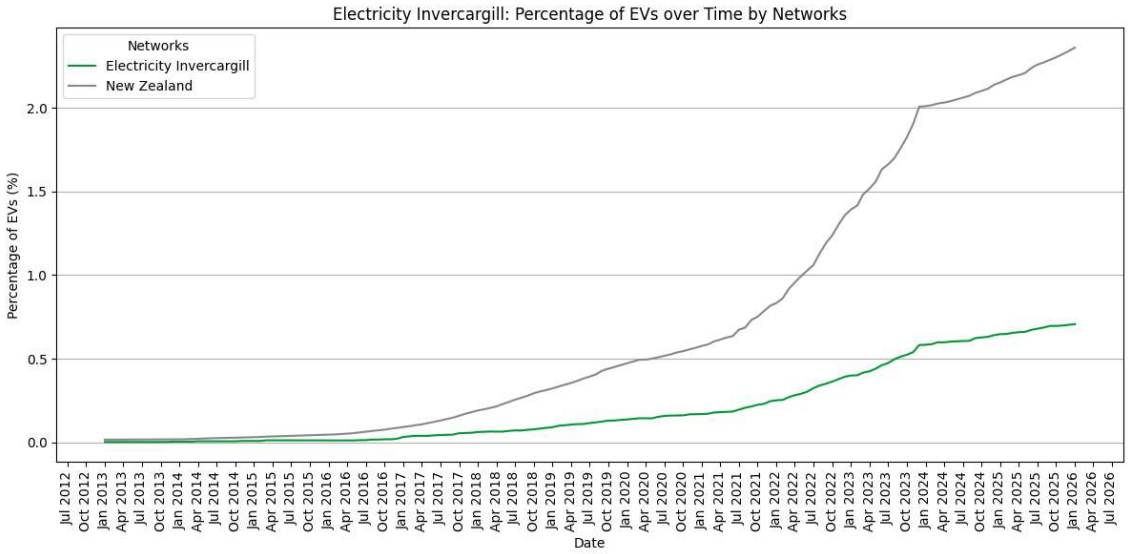
2.4.2 Electric vehicles

With rising fuel costs, increasing concerns about global warming, and the impact of carbon emissions, we expect electric vehicle adoption in New Zealand to continue growing each year, despite the end of

the Clean Car rebate. In fact, there have been a consistent growth in the number of electric vehicles[2] (EVs) across in the EIL network with approximately 0.71% of the fleet registered as EVs[3]. As of January 2026, the national rate is 2.36% so for EIL the percentage of EVs compared with the entire vehicle fleet at less than 1% is insignificant (see Figure 5).

EVs have the potential to have large impacts on network demand with sufficient adoption. Prices are an important means for signaling peak periods and enabling customers to choose whether to charge off-peak or pay a premium and charge during peak periods. If customers choose not to charge off-peak in response to price signals, EV charging may increase peak demand, triggering greater investment. This effect will be greatest on the suburban LV network in built-up urban and semi-urban areas as the upstream MV network generally has sufficient capacity to allow for the forecast increases in load from EVs.
Having pricing structures in place before EV uptake reaches widespread levels will enable a degree of customer education before load shifting is needed from a network capacity perspective. It will also allow networks to understand the effectiveness of price signals in managing EV loads before load capacity is reached. Reducing peak load would also reduce the average marginal carbon intensity (AMCI) in the grid.

Figure 5 Monthly percentage of registered EVs over time



Source: NZTA's Motor Vehicle Register open data as of January 2026

[2] The definition of EV vehicles follows that of NZTA which includes vehicles with BEV, PHEV, range extended motive powers. Here all vehicle types and classes are included.
[3] EV registrations in the Invercargill City Territorial Authority as a proxy.

3. EIL'S CONSUMER GROUPS AND PRICING OVERVIEW

EIL's prices are used to charge electricity retailers for the cost of its local electricity distribution network, pass-through costs (such as industry levies) and the costs associated with national grid transmission. Electricity retailers determine how to package these charges together with the energy, metering and other retail costs when setting the retail prices that appear in consumers' power accounts.

EIL uses "GXP billing" for its residential and general connections. This means that consumption charges are based on electricity volumes injected into EIL's network at the Transpower grid exit points, rather than being based on the usage at individual customer connection points. Quantities are determined by the wholesale electricity market reconciliation process, which is itself governed by the Electricity Industry Participation Code (the Code). This method saves on administration costs, which are ultimately transferred back into the prices.

3.1 Consumer load groups used for pricing

EIL defines two broad types of consumers for pricing purposes: Residential & General consumers; and Individual Consumers. The prices for Individual customers are connection specific.

3.1.1 Residential and General customers

The Residential and General category includes all residential connections and other single and 3 phase connections up to 100kVA capacity. Prices for these customers include a daily charge and a consumption price applied to energy used (kWh).

Prices for Residential and General consumers vary according to:

- Capacity
- Whether the connection has significant controllable load (typically controlled hot water heating)
- Residential Low User or Standard options

Consumption prices differ according to the time of use.

Capacity

General connections are split between single and three phase categories. They are then further disaggregated into load groups based on the size of the service fuse or size of transformer supplying them. The differentials between load groups reflect the use of the network assets for each group and the diversity each group has around peak load times.

Residential connections are either 8 kVA or 15 kVA. 8 kVA residential connections require a 32-amp circuit breaker to be installed on the main switchboard to control the complete installation. This capacity is only allowed for single-phase installations.

Different consumer groups are based on practical fuse sizes. For pricing purposes, all residential consumers are classed as single-phase irrespective of whether they are supplied two-phase or three-phase. This is due to the fact that for many of the consumers there was no choice in their method of supply and there are many older multi-phase residential installations. All old residential consumer installations are classed as "historic residential".

Controlled connections ("with off peak")

Controllable load can be used to smooth load outside of peak periods, deferring or avoiding network upgrades. If there is a significant controllable load on the premises, the connection qualifies for a "with off peak" line charge, which is lower than the "all peak" prices that apply to connections without significant controllable load. The eligibility for a "with off peak" line charge is determined on the basis that at least 25% of the total annual energy consumption is separately metered on a ripple-controlled tariff, such as a water heater or consumed between 23:00 and 07:00 hours.

Residential Low User or Standard

In line with the *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004,* residential customers consuming less than 9000 kWh per annum are eligible for the Residential Low User option.

To be eligible for the Low Fixed Charge Tariff Option the connection must meet the residential definition of "a residential consumer is where the consumer's metered point of connection to the network is for the purposes of supplying a home (the principal place of residence of the consumer), not normally used for any business activity and not used as a holiday home. The connection must meet the definition of "Domestic premises" under Section 5 of the Electricity Industry Act 2010".

These options attract a lower fixed daily charge and a higher variable consumption charge. Retailers with customers on these pricing plans must submit the monthly consumption amounts for these customers in a separate file to PowerNet.

From 1 April 2022, we commenced a phase-out of the Low Fixed Charge Tariff Option over a 5-year period in line with the Government phase out of this regulation. The phase out allows distributors to increase the daily fixed charge by an additional 15 cents per day for each of the 5 years, and after that the regulation will be removed altogether. The pricing year beginning 1 April 2026 is the final year of the 5-year phase-out.

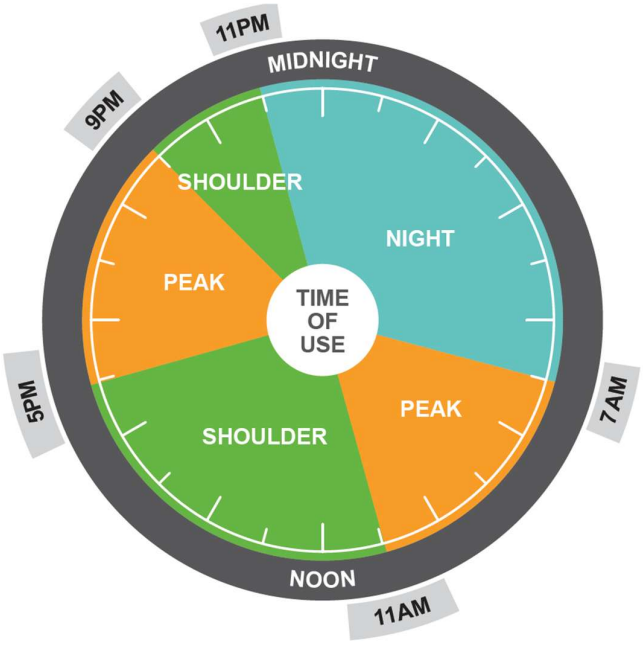
Time of use pricing

Time of Use (TOU) pricing for Residential and General Customers consists of three time periods, which are:

- **Peak** period: 7am to 11am and 5pm to 9pm,
- **Shoulder** period: 11am to 5pm and 9pm to 11pm, and
- **Night** period 11pm to 7am.

The time-bands shown for peak, shoulder, and night were selected based upon the times that peaks occur on our network. We will continue to review peak times at our individual GXPs and zone substations to ensure the time bands are appropriate and will make changes if required.

Figure 2: EIL TOU time periods



TOU pricing applies to all EIL's residential and general consumers and provides an incentive for consumers to shift energy usage out of peak periods, which can avoid or defer costly network upgrades. New uses of electricity such as solar generation, batteries, electrification and charging EVs are increasing the scope for network pricing to influence investment, and cost-shifting outcomes mean that it will be even more important to have meaningful peak pricing signals. Ensuring that the supporting price structures, such as TOU, are in place before EV uptake is widespread will mean that pricing will be up and running and effective when it is needed, allowing time for consumer education and for networks to understand consumer preferences and price responsiveness.

The price differential between the peak and shoulder price can be increased over time if network constraints become greater or we have EV clustering on the network.

3.1.2 Individual Consumers

There are 161 consumers for whom EIL calculates a connection-specific lines charge. These consumers are referred to as "Individual Consumers," and are required to have half-hour or time-of-use meters, including kVA maximum demand registers.

In most cases, these installations have contract capacities of 150 kVA and above. Due to their size, these consumers have a higher impact on the network design and operation which is taken into account when calculating their individual line charges. This also provides a signal for future investment and through the correct pricing discourages network by-pass.

Individual factors that we use in cost allocations to individual line charge customers include:

- Connections having dedicated transformers
- Low percentage use of the low voltage network
- Low diversity as capacity and demand increases
- Customer-owned transformers
- Additional security and back-up supplies, n-1

- Higher importance on network maintenance.

In the case of these consumers, there are also individually calculated or estimated loss factors.

These consumers, through half-hour metering, have individual energy and demand profiles, which are used to calculate the line charges. Metering of these consumers includes kVA demand metering which provides us with measures of peak demand and anytime peak demand. We use this demand data in the calculation of line charges and to determine the contract capacity. For these consumers, the contract capacity is based on the next highest standard transformer size above their anytime demand or, alternatively, as per the original contract if growth is predicted and the network has been designed and built to supply the increased level.

Although costs are allocated to Individual consumers based on a number of factors that proxy cost-drivers, once that annual allocation is determined for each consumer it is converted to fixed daily and consumption based variable prices.

4. PRICING STRATEGY

Given that EIL's pricing to Individual Customers is highly cost-reflective and service-based, the focus of our pricing strategy has primarily been on pricing for Residential and General customers.

The mandatory TOU pricing that applies to Residential and General consumers was introduced by EIL in 2022 as the first stage in moving to more cost-reflective network pricing. Over time as more consumers face TOU price signals through retailer pricing, we will observe how this impacts electricity use, which will help us to refine our pricing.

EIL's costs including Transpower charges are largely fixed. To reflect this cost structure, EIL's strategy has been to increase the proportion of overall revenue that is recovered through daily capacity charges, From 1 April 2025 we continue this strategy and pass through the majority of the price increases through an increase to the prices of the capacity charges. Half hour metered individually assessed line charge customers who previously had their annual line charge recovered 50% through the fixed charge and 50% through the variable charge have had this increased to 60% fixed charge and 40% through the variable line charge.

4.1 Time of Use (TOU) Pricing

EIL's consumption pricing previously consisted of a price for Day (7am to 11pm) energy use and zero for Night (11pm to 7am) energy use. This pricing sent a strong signal for customers to shift consumption into the night period, but it did not signal times during the day when the network is at peak loading or times when there is there is spare capacity in the network. It made no difference, if for example people with EVs charged their cars at 5pm, which is a network peak time, or at 2pm, which is a network off-peak time. This lack of signal could force the network to invest in expensive upgrades and pushing the price of line charges higher for everyone.

EIL has completed significant work on examining alternative cost reflective pricing options.

We evaluated five different cost reflective pricing options on the following criteria:

1. Economic Efficiency
2. Actionable and Simple
3. Supports retail Competition
4. Durable and Flexibility
5. Stable/Predictable

The combination of installed capacity and TOU was superior to all other options under the evaluation process. From 1 April 2022 this combination was the start of our cost reflective pricing journey as we look to provide customers with better pricing signals and a choice of when and how much they pay for their line charges, which is efficient and fair for the long-term benefit to all our customers.

4.2 TOU implementation

PowerNet engaged in work streams to enable TOU pricing including billing system changes, engagement with retailers seeking support and feedback on best practice to implementing a change to TOU and how the necessary data is provided and preparing TOU pricing models along with comprehensive customer impact analysis. We also introduced new loss codes to identify low user energy at a GXP level to aid the analysis.

4.3 Customer impact analysis

When selecting the combination of capacity and TOU as our preferred pricing option, we examined the impact on consumers in detail. The change in consumers' lines charges as a result of TOU will depend on usage profiles, but generally TOU implementation will have the least bill impact of available price reform options, while still providing valuable pricing signals.

EIL completed extensive impact analysis of a shift to installed capacity and TOU pricing. The analysis involved modelling over 50% of the residential and general customers who had more than 12 months' worth of half hourly smart meter data. Each ICP was overlaid with a NZ deprivation level index rating which was derived by the University of Otago using NZ census data to enable us to evaluate the impact at a socioeconomic level.

The analysis showed that the change to TOU pricing would have very little impact on total charges for residential consumers, regardless of whether the consumer is a standard or low user. The analysis also shows that consumers in the most deprived deciles would face less impact on their charges than customers in the least deprived deciles.

4.4 Refining TOU price signals by observing consumer responses

While EIL implemented TOU for network price charged to retailers, there was little use of TOU pricing by retailers in the prices that they charge customers. The Electricity Authority has issued a decision requiring all retailers to offer a TOU pricing option to their customers. Going forward, we will be observing and monitoring the impacts of TOU pricing and customer response as more consumers are exposed to TOU signals in retail prices, which will help us to refine our TOU pricing.

4.5 Understanding forward-looking costs of peak usage

The nature of electricity network costs is that they are largely fixed – consumer electricity usage does not change our existing costs. However, the timing of customer usage can affect future investments. In particular, increases in consumer use of electricity at the times when the network is most heavily congested (typically winter mornings and evenings) can trigger network upgrades to accommodate higher network demand. Conversely, electricity use at times when network load is at its lowest, such as overnight, does not drive additional future cost.

In an effort to better inform our TOU pricing, we have prepared a model of the forward-looking costs associated with electricity consumption at peak times – the Long-Run Marginal Cost (LRMC). We describe details of this modelling exercise in section 10.1.2. We expect to continue to refine this estimate and to draw on it when setting TOU prices as well as using it to set the peak injection rebate.

4.6 Installed Capacity pricing and the LFC phase-out

Given that a significant proportion of EIL's costs are essentially fixed, it would not be efficient for all costs to be recovered through charges that relate to energy usage. As a result, a portion of our costs are recovered from daily fixed charges. EIL's daily charges vary according to a connection's capacity (installed capacity) and availability of controlled load.

This year 50% of EIL's total line charge revenue is from fixed (capacity) charges. With the 5-year phase out of the Low Fixed Charges and the fact that the majority of costs are fixed, EIL will look to continue to increase the share of total revenue from fixed charges over time.

Customers with at least 25% of their total energy consumption on a controlled load or energy used during the night period qualify for the "off-peak" fixed charge price, which is up to 35% reduction on the "peak" price. This price incentive is fixed for customers and does not vary according to monthly

consumption; it provides a strong signal and a tool for EIL to control the load on the network during congestion periods therefore helping to avoid network upgrades and price increases.

5. REVENUE REQUIREMENT

EIL is subject to the Commerce Commission's Default Price-Quality Path regulation that sets an annual revenue cap (allowable revenue). Net Allowable Revenue is calculated based on various building block inputs including network operating expenditure (opex), non-network opex, a return of capital employed (depreciation), a return on capital employed (based on asset values and the WACC) and regulatory tax. Forecast pass-through costs and recoverable costs are added to the Net Allowable Revenue to determine the Total Allowable Revenue for the year. Table 1 below shows the calculation of Total Allowable Revenue. Table 2 and Table 3 provide the details of the forecast pass-through costs and recoverable costs.

Table 1 Allowable revenue

Forecast allowable revenue RY27 ($000)	
Forecast net allowable revenue	18,653
Forecast pass through costs	6,437
Forecast recoverable costs	870
Total allowable revenue	**25,960**

Table 2 Pass-through costs

Forecast Pass-through Costs RY27 ($000)	
Rates on system fixed assets	240
Commerce Act levies	70
Electricity Authority levies	80
Utilities Disputes levies	13
Transpower transmission charges	5,712
New investment contract charges	322
Total forecast pass-through costs	**6,437**

Table 3 Recoverable costs

Forecast Recoverable Costs RY27 ($000)	
IRIS incentive adjustment	-734
Quality incentive adjustment	-27
Wash-up draw down amount	1,607
Fire and emergency NZ levies	24
Innovation project allowance	-
Total forecast recoverable costs	**870**

In accordance with the DPP requirement that forecast revenue should not exceed allowable revenue, EIL's target revenue for 2026/27 is set at $25.938 million, increasing from $23.676 million the previous year. Below is a summary of target revenue for both transmission costs and distribution price components broken down by the two customer group categories for the 2026-27 year. We also outline the change in revenue compared with the previous year.

Table 4 Target revenue

	Residential & General	Individual	Total
Target revenue for 2026-27			
Distribution	$15,910,980	$2,719,785	$18,630,765
Pass-through costs	$399,692	$3,652	$403,344
Recoverable costs	$664,793	$205,465	$870,258
Transmission	$4,323,803	$1,709,830	$6,033,633
Total	$21,299,268	$4,638,732	$25,938,000
Revenue from previous year			
Distribution	$14,449,767	$2,500,233	$16,950,000
Pass-through costs	$329,484	$3,213	$332,697
Recoverable costs	$1,037,351	$210,731	$1,248,082
Transmission	$3,684,269	$1,460,911	$5,145,180
Total	$19,500,871	$4,175,088	$23,675,959

6. COST ALLOCATION

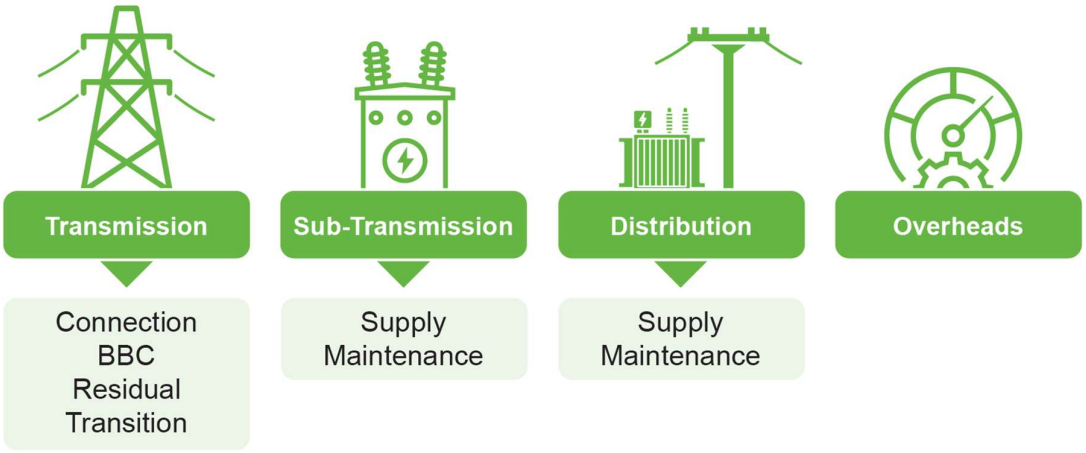
The costs used to calculate the revenue requirement are allocated between the relevant consumers and consumer groups. In carrying out this allocation, the objective is to reflect the share of the costs in a robust and equitable manner. Each consumer or consumer group's share of the use of the assets and costs is calculated to reflect their respective use.

6.1 Methodology and allocators

We allocate costs separately for categories and sub-categories of network asset groups and other costs:

- **Transmission charges** are what we pay to Transpower for access to and use of the national grid.
- **Sub-transmission costs** relate to the 33kV network and the zone substation costs.
- **Distribution costs** relate to 11kV and 400V line and cables as well as distribution substations and transformers.
- **Overhead costs** are other costs associated with operating our distribution network business that cannot be allocated directly to either capital or maintenance.

Figure 3 Cost categories and sub-categories



The costs of the sub-transmission and distribution components of the line charges are split into two categories:

- Supply, which is the depreciation of the network assets, other ownership costs and the cost of capital required to fund the assets.
- Maintenance, which is based on the Maintenance Works Program for the current year.

Management costs for capital and maintenance work are allocated to Supply and Maintenance respectively.

6.1.1 Our allocators are selected to reflect cost-drivers

The allocators we use are based on seven profile parameters relating to the customer group, or the Individual customer.

We use a measure of demand to allocate sub-transmission costs and Transpower's connection charges, as this is a key driver of costs. Similarly, for distribution costs we allocate using a measure of consumer's installed capacity. However, our methodology also considers the duration that the customer impacts on the peak loading hours of the network. We do this by allocating some of the transmission, sub-transmission and distribution costs based on the amount of electricity that consumers use during peak times and during winter days. In effect, this reduces the charges for a customer who incurs just one-half hour peak for the whole peak period or is only impacting on the peak hours for part of the peak period and increases the charges for those customers who are impacting regularly on the peak periods.

Measures of network use for cost allocation

Capacity

1. The Contract Capacity kVA (kW) of the installation

Peak Demand

2. The Peak demand kVA. (kW) (0700-1100 hours and 1700-2200 hours, each weekday during sub-transmission peak months of individual grid exit points)
3. For Individual customers only, Coincident Peak demand with Transpower's individual GXP residual charge peak times.

Amount of electricity used

4. The Peak energy MWh. (0700-1100 hours and 1700-2200 hours, each weekday during sub-transmission peak months)
5. The Winter Day energy MWh. (0700-2300 hours, May to September inclusive)
6. The Summer Day energy MWh. (0700-2300 hours, October to April inclusive)
7. The Total energy for the 12-month period MWh.

The following table provides a summary of the customer profile measures, with further details provided in Appendix B.

Table 5: Summary of customer profile measures

Capacity (kVA)	Number of Connections	After Diversity Demand Reading (kVA)	Total Energy (MWh)	Winter Peak (MWh)	Winter Day (MWh)	Summer Day (MWh)
Residential	15,687	37,595	150,840	22,369	58,367	53,023
General	6,966	17,420	52,853	9,569	22,010	18,843
Individual customers	161	9,609	77,701	10,146	25,887	30,648

6.1.2 We apply diversity factors to peak demands and contract capacities

For the purposes of cost allocations, we apply diversity factors to the peak demand and contract capacity measures.

For peak demand, we use the following diversity factors, which reflect the increased diversity of a large number of smaller customers compared to less diversity for the larger customer:

- Up to 21kVA = 17%
- Between 21kVA and 110kVA = ramp function from 17% - 37.5%
- Between 110kVA and 2,000kVA = ramp function from 37.5% - 75%
- Above 2000kVA = 75%.

Similarly, we also apply diversity factors to the contract capacities of the various customers. These diversity factors are:

- For connections up to 16kVA = 25%
- For connections between 16kVA and 100kVA = ramp function from 25% - 33%
- For connections between 101kVA and 2,000kVA = ramp function from 33% - 70%
- For connections above 2,000kVA = 70%.

These diversities reflect the differing impacts of the different sized customers on the local capacity of the reticulation system. There is an increased diversity between smaller customers than with the larger customers with respect to the capital investment in the local distribution network.

6.2 Transmission Charges

Transmission charges reflect the Transpower grid asset management charges faced by EIL at the Invercargill grid exit point.

Transpower's charges have four components: connection charges, Benefit Based Charges, Residual Charge and a Transitional Cap. The following discussion explains how we allocate each of these charges across consumers and consumer groups.

6.2.1 We allocate Transpower's connection charges using a mix of peak demand and energy usage

The Transpower connection cost allocation is based on the Transpower local assets utilised to provide the supply and includes Transpower new investment charges. At the Invercargill point of supply the connection charge is incurred and allocated by PowerNet between EIL and TPCL.

For Individual customers this equates to the allocation rates described in the following table.

Table 6 Connection charge allocation to Individual customers

Point of Supply	Per kVA Peak Demand	Per Winter Peak MWh	Per Winter Day MWh
Invercargill	$6.87	$3.02	$0.99

After the revenue from the Individual customers has been subtracted from the total Transpower connection charges, the remaining group allocations are as described in the following table.

Table 7 Connection charge allocation to Residential and General customers

Point of Supply	Per kVA Peak Demand	Per Winter Peak MWh	Per Winter Day MWh
Invercargill	$6.63	$3.28	$1.083

The difference between the rates in the two tables above reflects the difference in losses and diversity factors between the large individual customers and the smaller customer groups.

6.2.2 We allocate the Transpower Benefit Based Charge (BBC) using total energy consumption

The costs of new and some historic interconnection investments (the BBIs) are allocated by Transpower according to the beneficiaries of those investments through the BBC. BBIs include investments in new interconnection assets or interconnection transmission alternatives and the replacement or refurbishment of existing ones. The cost recovered through the BBCs is referred to as the BBI's "covered cost" and includes capital components (return of and on capital expenditure) and an allocation of Transpower's total operating costs (including overheads).

Transpower allocates each BBI's covered cost between transmission customers broadly in proportion to the positive net private benefit (NPB) each customer is expected to derive from the BBI. That is, the BBC paid to Transpower by a transmission customer must reflect the positive NPB that customer is expected to receive from the BBI (if any) relative to all other customers.

The NPB of each BBI is derived by historic load flow analysis (MWh). As a result, EIL allocates BBCs on an annual energy consumption basis.

To calculate the BBC allocation to Individual Customers, we divide the BBC for the GXP by the annual total energy consumption of the GXP, to provide a $/MWh rate. Each Individual consumer's total annual energy consumption (MWh) is then multiplied by the rate to calculate the annual BBC. The total benefit-based charge and the allocation rate for Individual customers are contained in the following table.

Table 8 BBC allocation rates for Individual Customers

Point of Supply	Total Benefit Based Charges	Allocation rate (MWh)
Invercargill	$655,166	$2.39

The remaining BBC charges (net of the amount allocated to the Individual customers) are allocated to Residential and General customers. After the revenue from the Individual customers has been subtracted from the total the remaining BBC to be allocated to Residential and General customers equates to $2.39 per MWh.

6.2.3 We allocate Residual Charges using measures of demand

Residual Charges recover Transpower's remaining revenue that is not recovered through other transmission charges. Residual Charges are paid by Transpower load customers only, in proportion to their historic (or, for new load customers, estimated) maximum gross demand. Gross load excludes contributions from batteries when charging or discharging other than their storage losses.

The initial (baseline) allocations of residual charges are in proportion to Transpower customers' maximum gross demand (kW) at the grid exit point averaged across the four financial years (FYs) from FY 2014/15 to FY 2017/18, i.e., the period 1 July 2014 to 30 June 2018. For a Transpower load customer that did not exist on 1 July 2014, including a new load customer, Transpower estimates maximum gross demand based on the customer's assets and the assets connected to them being fully operational.

Load customers' initial allocations are adjusted annually based on changes in their lagged average gross energy usage (kWh) over the period of four financial years commencing eight financial years ago, e.g., for PY 2026/27 the relevant period is from FY 2018/19 to FY 2021/22.

The annual Residual charge for EIL is described in the following table.

Table 9 Total Residual charges paid by EIL by GXP

GXP	Residual Charge
Invercargill	$4,757,194

For Individual customers the allocation of the Residual Charge is calculated using the same method that Transpower uses to allocate the residual charge to EIL (based on average gross demand and lagged average energy usage). For Individual customers that were not active during the baseline allocations or who are new customers, the initial average gross demand and lagged average energy will be estimated as if it was fully operational during the baseline period. The estimate is based on similar-sized businesses' average gross demand. The estimates may be adjusted following the recording of actual demand levels through half-hour metered data. EIL may alter an individual customers' average gross demand and lagged average energy should a major repurpose of the ICP occur.

For Residential and General groups, the total amount of residual charge allocated to the Individual customers is deducted from the total network residual charge, the result is the amount to be allocated to all the residential and general groups. This resultant amount is then divided by the total peak demand of the Residential and General customer groups to calculate a $/kW rate. Each Residential and General load group's average after-diversity maximum demand is then multiplied by the $/kW rate to calculate the annual allocation to each ICP in the load group. The annual allocation amount is then multiplied by the number of ICPs in the load group to calculate the residual amount allocated to the load group.

The allocation rates are in the following table.

Table 10 Residual charge allocation rates

	Per kVA Average Gross Demand
Individual customers, per kVA Average Gross Demand	$77.42
Residential and General Customers, per kVA After Diversity Maximum Demand	$62.72

8.1.4 Transitional Cap

The Transitional Cap applies to distributors and grid-connected consumers' BBCs for the seven historic (pre-July 2019) BBIs and residual charges, and caps those charges relative to the distributors or grid-connected consumer's interconnection and HVDC charges for PY 2019/20. This is not a cap on total transmission charges. The cap is funded by distributors.

The Transitional cap is allocated to customers based on their share of the overall Benefit Based and Residual Charges. The annual transitional cap for each GXP is shown in the following table.

Table 11 Annual Transitional Cap for EIL by GXP

GXP	Transition Cap charge
Invercargill	$2,940

For Individual customers the sum of the annual BBC and RC are divided by the sum of the total GXP's BBC and RC, this percentage is then multiplied by the annual Transitional Cap amount for the GXP to calculate the annual Transitional Cap charge.

For the Residential and General customers, once the total amount of Transitional Cap allocated to the individual customers is deducted from the total network Transitional Cap charge, the result is the

amount to be allocated to all the residential and general customers. The sum of the annual BBC and residual charge for each load group customer is divided by the sum of the total benefit-based charge and residual charge for the network. This percentage is then multiplied by the annual Transitional Cap amount for the network to calculate the annual Transitional Cap charge for each customer. The annual allocation amount is then multiplied by the number of ICPs in the load group to calculate the residual amount for the load group.

8.1.6 Summary of resulting transmission charge allocation

The resulting allocation of transmission charges across consumer groups and for Individual customers grouped by capacity is shown in the following table.

Table 12 Transmission charge allocations

Consumer Group	Number of connections	Transmission charges per consumer group	Average transmission charge per consumer
Residential		$2,996,448	$191.01
General		$1,320,840	$683.66
Individually Priced, by capacity of the connection (kVA):			
30	2	$1,251.04	$625.52
50	2	$4,620.76	$2,310.38
75	6	$16,166.81	$2,694.47
100	10	$29,043.82	$2,904.38
150	24	$129,057.30	$5,377.39
200	41	$269,707.73	$6,578.24
300	30	$314,139.10	$10,471.30
500	32	$540,837.04	$16,901.16
750	8	$142,980.20	$17,872.53
1000	4	$98,764.82	$24,691.20
1250	1	$56,046.84	$56,046.84
1750	1	$107,214.20	$107,214.20

8.2 Sub-transmission cost allocation

Sub-transmission charges are based on the Sub-transmission costs 33kV network and the zone substation costs.

There are two components making up the Sub-transmission charges:
(a) Supply charge
(b) Maintenance charge

6.2.4 Supply costs

The supply charge is based on the required return on the assets by the shareholder and depreciation

.

All the costs of the sub transmission network and zone substations are averaged and allocated on the basis of the relative asset value compared to the total network asset value.

The supply charge for the EIL city area zone substations is $1,725,365 and for the 33kV line and cables is $862,683 giving a total supply charge for EIL City of $2,588,048.

As EIL also supplies power to Bluff through TPCL 33kV line and Bluff zone substation there is a supply charge of $551,390 for this zone substation and the Sub-transmission lines.

The supply charges for EIL City and EIL Bluff are allocated across all customers on the following basis:

- Peak Demand 70%
- Peak Energy 20%
- Winter Day Energy 10%

6.2.5 Maintenance costs

The maintenance charges for the EIL city zone substations and sub transmission system total $504,974 and for EIL Bluff total $88,811.

. These maintenance costs are allocated across customers on the following basis:

- Total Energy 50%
- Peak Demand 50%

6.2.6 Sub-transmission Charges for Individual Customers 150 kVA and above

The sub-transmission cost allocation rates relating to each zone substation are shown in the following table, for Individual Customers 150 kVA and above.

Table 13 Sub-transmission cost allocation rate for Individual customers 150 kVA and above.

Zone Substations	Supply Charge per kVA Winter Peak Demand	Supply Charge per Winter Peak MWh	Supply Charge per Winter Day MWh	Maintenance Charge per Commercial Total MWh	Maintenance Charge per kVA Winter Peak Demand
Invercargill	$30.65	$13.51	$4.45	$1.00	$4.27
Bluff	$90.37	$42.79	$11.44	$2.19	$11.27

6.2.7 Sub-transmission cost allocation rates for Group customers

After the revenue from the Individual customers has been subtracted from the total sub-transmission costs, the remaining group customer cost allocation rates are calculated. These rates are displayed in the table below.

Table 14 Sub-transmission cost allocation rates for group customers

	Supply Charge per kVA Peak Demand	Supply Charge per Peak MWh	Supply Charge per Winter Day MWh	Maintenance Charge per Domestic Total MWh	Maintenance Charge per kVA Winter Peak Demand
Residential and General	$29.72	$14.63	$4.78	$1.03	$4.01

6.3 Distribution cost allocation

Distribution charges are based on the distribution costs which include 11,000 and 400V line and cables and distribution substations and transformers.
There are three components making up the distribution charges:

(a) Supply charge

(b) Maintenance charge

(c) Transformer charge

In calculating the distribution charges an allowance is made for the fact that customers above 150kVA have normally less use of the 400V network than smaller customers, i.e. they often have their own local transformer or exclusive supply cables from a transformer. The distribution charges are multiplied by a factor of 60% for both EIL City and EIL Bluff.

6.3.1 Supply cost

The supply cost includes the required return on the assets by the shareholder and depreciation, and totals $10,064,629.

The non-locational supply costs are allocated across customers on the following basis:

Contract Capacity	70%
Peak Energy	20%
Winter Day Energy	10%

6.3.2 Maintenance cost

The maintenance cost for EIL total $1,754,120.

The maintenance portion of the non-locational distribution cost is allocated across customers on the following basis:

Total Energy	50%
Contract Capacity	50%

6.3.3 Transformer costs

EIL's supply and maintenance transformer costs total $1,725,365.

The transformer portion of distribution costs is allocated across consumers on the basis according to the number of transformers and transformer capacity.

6.3.4 Distribution costs for Individual customers

	EIL City	Bluff
Distribution Supply Costs		
Allocation per kVA of Contract Capacity	$52.27	$33.55
Allocation per MWh of Winter Peak Energy Usage	$50.27	$32.85
Allocation per MWh of Winter Day Energy Usage	$9.99	$6.27
Distribution Maintenance Costs		
Allocation per MWh of Commercial Energy Usage	$3.00	$5.53
Allocation per kVA Contract Capacity	$5.87	$13.29
Distribution Transformer costs		
Distribution Transformer supply charge	$443.55	$443.55
Distribution Transformer maintenance charge	$883.95	$883.95

The Transformer charge of $443.55 per transformer is multiplied by a price ratio depending on the size of the transformer. The ratios for the different sized transformers are shown below.

Transformer Size	Ratio applied
15kVA Transformer	1
30kVA Transformer	1.44
50kVA Transformer	1.88
75kVA Transformer	2.30
100kVA Transformer	3.00
150kVA Transformer	5.00
200kVA Transformer	7.40
300kVA Transformer	8.16
500kVA Transformer	11.20
750kVA Transformer	14.00
1,000kVA Transformer	15.00
1,250kVA Transformer	20.20
1,500kVA Transformer	21.00

6.3.5 Distribution costs for Residential and General Customers

After the revenue from Individual customers has been subtracted from the total, the remaining residential and general customer cost allocations are set out in the following table.

Table 15 Distribution cost allocations for Residential and General Customers

	EIL City	Bluff
Distribution Supply Costs		
Allocation per kVA of Contract Capacity	$58.54	$45.75
Allocation per MWh of Winter Peak Energy Usage	$58.54	$47.70
Allocation per MWh of Winter Day Energy Usage	$19.27	$15.87
Distribution Maintenance Costs		
Allocation per MWh of Domestic Energy Usage	$3.52	$9.73
Allocation per kVA Contract Capacity	$5.89	$16.85
Distribution Transformer costs		
Allocation per AD of Transformer capacity	$11.88	$11.88

6.4 Overheads

Overhead cost allocation rates reflect those costs that cannot be allocated directly to either capital or maintenance. These costs can include Executive Management, Directors Fees, System Control, and Miscellaneous overheads such as buildings. These costs are split equally over the total customer base.

The total overhead costs are $1,767,615. The cost allocation rate per customer is $99.41.

6.5 Power Factor Charge

All cost allocations assume a power factor of not less than 0.95 lagging. Individual and general customers may have a data logger installed to assess their power factor. If a customer has a power factor of less than 0.95 lagging and after a period of notice has not been corrected, then an annual power factor cost of $80 per kVA will be applied.

The kVA is based on the total kVA less kVA at 0.95 power factor. The kVA will be assessed on the average of the 12 highest kWh half hour periods during the assessment period.

EIL works with customers to improve their power factor by facilitating education forums on how to manage power factor in conjunction with customers, electricians and power engineering consultants.

6.6 EIL cost allocations

Following the methodology set out in preceding sections, the total cost allocations for Individual customers grouped by capacity are shown in the following table. The cost allocation for group customers is set out in detail in Appendix D.

Table 16 Cost allocation for Individual customers (grouped by capacity)

Consumer Capacity	Sub-transmission Charge	Distribution Charge	Overhead Charge	Total EIL
30	$337.20	$2,767.33	$244.18	$3,348.71
50	$570.51	$4,563.43	$244.18	$5,378.12
75	$5,371.32	$27,214.06	$732.55	$33,317.93
100	$16,422.51	$42,282.79	$1,220.91	$59,926.21
150	$52,228.29	$154,529.35	$2,930.18	$209,687.83
200	$102,171.45	$356,519.84	$5,005.73	$463,697.01
300	$123,616.91	$363,754.51	$3,662.73	$491,034.15
500	$235,755.76	$639,907.12	$3,906.91	$879,569.78
750	$51,064.79	$239,415.53	$976.73	$291,457.05
1000	$30,816.38	$164,192.20	$488.36	$195,496.94
1250	$19,505.79	$58,673.05	$122.09	$78,300.94
1750	$135,405.75	$82,159.68	$122.09	$217,687.53

6.7 Loss Constraint Excess Payment

Loss Constraint Excess Payments are credits rebated by Transpower as a result of money received from the Clearing Manager for the Wholesale Electricity Market and are excluded from the Transmission Charges. The payments are allocated each month to the retailers on the basis of total energy consumption for the month in which the rebate applied.

6.8 Summary of target revenue and pricing changes

The total target revenue of $25.938 million for 2025/26 compares with $23.66 million the previous year. The following table provides a summary of revenue across both years for transmission distribution price components, broken down by the two customer group categories.

Table 17 Target revenue comparison with last year

	Residential & General customers	Individual customers	Total
2026-27 Revenue			
Distribution	$16,975,465	$2,928,902	$19,904,367
Transmission	$4,323,803	$1,709,830	$6,033,633
Total	$21,299,268	$4,638,732	$25,938,000
Previous year			
Distribution	$15,816,602	$2,714,177	$1,8530,779
Transmission	$3,684,269	$1,460,911	$5,145,180
Total	$19,500,871	$4,175,088	$23,675,959

Distribution revenue changes reflect changes in line with EIL's allowable revenue under the Commerce Commission default price-quality path.

The changes in revenues are based on changes to our costs and our allocation of these costs to the customer groups. Other factors that impact on the allocation of costs relate to changes in quantities and individual customers profile changes as well as contractual changes.

The changes in transmission charges relate to an increase in Transpower's charges in line with their allowable revenue under the Commerce Commission default price-quality path.

For the average residential consumer, the total EIL price (including distribution and transmission) will increase by approximately $7.29 (excluding GST) per month. Residential customer pricing is as described in the following table.

Table 18 Residential and General customer pricing

Daily prices	Units	2025/26	2026/27
Residential	$/day	$1.19	$1.37
Residential – Low Fixed Charge	$/day	$0.75	$0.90
All except low user			
Peak	c/kWh	$0.07636	$0.08140
Shoulder	c/kWh	$0.05565	$0.05650
Off-peak	c/kWh	$0.01000	$0.01000
Low User			
Peak	c/kWh	$0.10724	$0.10724
Shoulder	c/kWh	$0.08016	$0.08463
Off-peak	c/kWh	$0.01000	$0.01000

7. SETTING PRICES

After having set the target revenue and determining the revenue to be determined from each customer group, we then determine each price that appears in the EIL pricing schedule. The following discussion describes how we set pricing, having regard to economic principles, network cost drivers and consumer impacts.

7.1 Residential and General Customers

As was described in section 3, our pricing for Residential and General customers includes a daily capacity charge and TOU usage pricing, where the price per kWh varies across Peak, Shoulder and Night periods. To set prices for each group, we need to decide what the optimal prices are for network use during each of these periods and then set the prices for capacity charges to recover the remainder of the target revenue. As part of this calculation, we also need to forecast usage volumes for the coming year. The following sections discuss how we set prices and the resulting prices for Residential and General customers are presented in Appendix E.

7.1.1 The balance between fixed and variable charges

Strictly applying economic principles tells us that the off-peak price should be set at or close to zero, with peak price set at the forward-looking cost of upgrading the network to serve additional demand. As discussed in section 10.1.2, we estimate the Long Run Marginal Cost (LRMC) of use of the EIL network during our peak TOU times to be $0.01 per kWh. Our peak TOU price for 2026/27 is higher than this at $0.0814 per kWh. However, if we were to reduce this price to be closer to the LRMC-based price, then we would need to significantly increase the daily capacity charges.

While forward-looking LRMC estimates form an input into our decision-making, we also account for customer impacts in making pricing decisions. This year daily capacity charges increased to reflect an increase in transmission and distribution costs. As was discussed in section 4, our current strategy is to rebalance our fixed and variable charges over time so that fixed charges account for 60% of revenue.

7.1.2 Recovery of Transpower Charges

Transpower's charges, which follow the Transmission Pricing Methodology (TPM), are fixed in nature and not intended to influence customer network use decisions. As a result, EIL recovers Transpower charges through fixed (capacity) charges where possible.

For half-hour metered Individual customers, we recover the residual, benefit based and transitional cap charges through fixed daily charges and the connection charge through variable line charges.

Currently the recovery of total line charges is on a 60/40 split between fixed and variable charges, EIL's strategy is to recover more line charge revenue through the fixed daily charge. This will be achieved by increasing the fixed charge percentage each year to allow all the Transpower charges to be recovered through the fixed daily charge over time.

7.1.3 Forecasting usage and loss factors when setting prices

We forecast consumption for combined residential and general customers including the low user consumption based on the last three years consumption. The low user forecast quantity is then deducted from the combined averaged consumption to establish the forecast quantities for the remaining residential and general customer groups.

7.1.4 Loss Factors

The amount of energy delivered from the Transpower grid exit points through the distribution network to supply electricity to customers is greater than the amount of energy metered at the customers' premises. The difference between these volumes is called 'distribution losses'.

EIL charges electricity retailers based on the volumes of electricity metered at the grid exit point, this is called grid exit point (GXP) billing. To calculate the energy volumes at the GXP, the customer-metered volumes are multiplied by the loss factor. The electricity retailer therefore must multiply the GXP energy price that EIL charges them by the loss factor to arrive at the customer energy price for distribution charges.

The loss factors for 2026-27 for residential and general customers are:

- Winter Day 1.0519
- Winter Night 1.0401
- Summer Day 1.0354
- Summer Night 1.0311

The periods referred to above are defined as:

- Winter May – September
- Summer October – April
- Day 7am – 11pm
- Night 11pm – 7am

Loss factors for individual line charge customers are calculated on an individual basis.

7.2 Individual Customers

The total line charge allocation for Individual customers is converted into fixed charges and variable charges. The fixed/variable split is approximately 60:40. With more costs, particularly Transpower costs, being of a fixed nature EIL will be increasing the fixed charge percentage split of the total line charge.

For the Individual line charge installations with half hour metering the total line charge is multiplied by 0.6 to establish the fixed charge per annum. The variable charge is calculated as the remaining charge divided by the number of Day kWh in the customer energy profile to give a variable charge in cents per Day kWh.

In the case of all non-half hour metered individual line charge installations the variable charge is a standard charge GXP rate of $0.0814 per Peak kWh, $0.0565 per Shoulder kWh and $0.01 per Night kWh. The fixed charge is then calculated as the difference between the total charge and the total variable charge. This method of calculating the fixed charge accounts for the fact that some installations have negative fixed charges.

Individual line charge customers have their line charges reviewed each year in line with the line pricing methodology. Actual day energy volumes recorded from December 2024 to November 2025, are used as the forecast quantity for the 2026 - 2027 forecast period.

7.3 Customer Consultation

Where significant changes in pricing structure are considered, EIL consults with retailers and customer groups. The changes to pricing that took effect on 1 April 2022 involved significant changes, EIL consulted with retailers and the Southland Electric Power Supply Consumer Trust on the change to Time-of-Use pricing and the likely impact to customers.

Even in the absence of significant pricing change, EIL seeks the views of consumers as part of the asset management process and has reflected these views in the published AMP. This included a face-to-face survey with key clients including expectations on price and current service

1. A bulk phone survey of current customers including expectations on price and quality
2. Consultation meetings at various locations throughout the network
3. Individual consumers are consulted as they consider supply upgrades or new connections to the network.

The views are considered in preparation of the AMP.

Quality in the form of security of supply (n versus n-1), capacity (equipment loadings) both impact on the cost of supply and subsequently prices charged. Price can be varied through different payment options (such as capital contributions, line charges and new investment agreements) which are discussed with large individual consumers as they consider supply upgrades or new connections to the network.

8. NON-STANDARD CONTRACTS

EIL has a standard methodology for the determination of line charges for large customers; these line charges are charged to the customer via an interposed basis with the energy retailer.

In rare cases the standard methodology may not fully recover the return and operating costs of the large capital expenditure required in supplying these customers. These customers may also have enhanced security arrangements. In these situations where customers have significant capital contributions, robust commercial contracts incorporating prudential requirements are prudent to mitigate the risk of these assets being stranded. These contracts can also assist in avoiding uneconomic by-pass of the network when negotiating commercial arrangements and encourage growth within the network.

There are currently no ICPs on non-standard contracts.

8.1 Line Services Interruptions

Customers on non-standard contracts can contract to have an N-1 security arrangement, this is where the customer has an alternative supply to their site from the substation should their normal supply route be interrupted, this can be an automatic or manual change over process. Should customers choose to have the additional security of supply, their line charges will reflect the additional cost.

Customers on non-standard contracts who have standard security arrangements are subject to the same restoration arrangements as customers on standard contracts.

9. DISTRIBUTED GENERATION

EIL's line pricing methodology and Part 6 of the Electricity Industry Participation Code 2010 applies to Distributed Generation connected to the electricity network for varying capacities.

In certain situations, it will be possible to connect Distributed Generation to the network downstream of the meter at a low capacity without modifications to the electricity network, in which case a standard off- take Line Charge will be required to be paid to EIL.

In other situations, there may be incremental costs incurred by EIL due to investigation and network modifications required. As with all customers seeking connection to the EIL network where incremental costs are incurred an upfront capital contribution may be required to be paid.

For large capacity Distributed Generation options may exist to meet incremental costs either through payment of an upfront capital contribution and /or entering into a New Investment Agreement and / or Delivery Services Agreement with appropriate prudential security. A normal line charge will also apply according to the installation connection capacity of the Distributed Generators off take.

9.1 Financial Transactions with Distributed Generators

An application fee based on the capacity of connection is payable by the party making application to connect Distributed Generation to the network.

Financial transactions that can occur when Distributed Generation is connected to EIL's electricity network are:

Transaction Types	Capacity
Normal off take Line Charge (paid by the Distributed Generator to EIL)	All capacities
Capital Contribution (paid by the Distributed Generator to EIL)	All capacities where incremental costs are incurred by the network
New Investment Agreement charge (paid by the Distributed Generator to EIL)	For capacities > 500kW
Recovery of Benefit Based Transmission Charges (paid by the Distributed Generator to EIL)	Where the Distributed Generation is injected into the Transmission Network

9.2 Capital Contributions

Capital Contributions are calculated in accordance with the published Capital Contribution policy.

9.3 New Investment Agreement and / or Delivery Services Agreement Charges

New Investment Agreement and / or Delivery Services Agreement charges are negotiated with each customer and depend on factors including length of contract, asset lives, sunk costs, recoverable costs, maintenance costs, return on investment and prudential security provided.

9.4 Benefit Based Transmission Charges

Benefit Based Transmission Charges are recovered from Distributed Generators based on their share of the injected energy into the Transmission Network at the grid exit point they inject into.

9.5 Energy Reporting

Where distributed generation is connected to the distributor's network, kWh being exported onto the distributor's network must be submitted to the distributor.

The format the data is submitted must match the format of the ICPs other submitted data, e.g. either EIEP1 or EIEP3 format.

For clarity, export onto the distributor's network, and consumption off the distributor's network, are to be reported separately under the relevant price options (i.e. they should not be netted off).

9.6 Distributed Generation Injection Rebate

In accordance with new requirements in the Electricity Industry Participation Code, EIL has introduced a distributed generation injection negative variable price. The new negative injection price is only available to all residential and general connections with a connected load capacity of 45kVA and below with an export capacity of less than 45kW that inject energy into the network during the distributed generation peak times, with volumes submitted in the half hour format (HHR) with a network approved application.

As per the Authority's Negative Charge Guidance for Distributors (Guidance), we have taken a three-step approach to setting prices, using the long run marginal price (LRMC) to base the negative charge based on a similar LRMC methodology as in section 10 below. The final negative charge for peak injection for the pricing year beginning 1 April 2026 is -$0.0105 per kWh with a 50% adjustment factor applied.

Step 1: Determine the pricing window for the negative charge.

The peak time periods for the negative charge aligns with our top 100 peak times on the total network, being 7am to 11.00am and 5.00pm to 9pm during the winter months. EIL network is dominated by the winter domestic heating load, this results in the network peaking during the winter period. For the negative charge, the pricing window is the months of (May to September). This is because:

- For the negative charge for peak injection, as per the guidance, the goal is to determine the periods when demand on our network is at its greatest and when additional demand is likely to drive future network investment. Our network peaks occur during the winter months and times and our future network investment is driven by the growth in our peak demand, therefore we believe the pricing window for the negative charge to these months only is appropriate, which aligns with the Guidance's principles.

Step 2: Calculate the LRMC for Distributed Generation during Network Peak Times

For the pricing year beginning 1 April 2026, our peak LRMC for Distributed Generation Injection is -$0.021 before the adjustment factor is applied. We calculated this using the ENA LRMC template model with the best estimate we had of forecast capex at the time of setting prices*. The ENA model uses an Average Incremental Cost methodology.

*We note that as the AMP was in draft form at the time that we set the injection price, the forecast capex and demand that we used to calculate the LRMC may differ from what appears in the finalised version of the AMP

Step 3: Determine an appropriate adjustment factor.

As allowed under subclause (1)(c) in Part 12A.7 of the Code, we have adopted a 50% adjustment factor to negative charges. This scales the negative charge down to reflect the specific risks and characteristics of injection with regard to transaction costs, consumer impacts, uptake incentives, and network stability, which are outlined below. At the outset, as suggested by the Authority in the guidance, we have been prudent to begin with a relatively high adjustment factor (and therefore lower negative charge), and will fine-tune it over time as better data and consumer feedback become available. In the Guidance, the Authority mentioned that Australian distributors use a range of adjustment factors ranging from around 10% to over 70%. To align with the prudent approach, we therefore have adopted 50% - the higher end of the adjustment factor range as a starting point.

Transaction costs

This consideration has prompted us to adopt a simple and broad approach, rather than a granular locational pricing approach, because:

- ICPs with distributed generation on our network is a very small portion with only around 193 ICPs – less than 1.3% of the total ICPs.
- Our estimate of total negative charge is likely to be less than $1k per year for all eligible ICPs.
- With such low penetration of ICPs with DG and low negative charge amount, changes to systems and processes (such as billing system upgrade) to facilitate granular pricing would outweigh the benefit itself.

Consumer impacts

This consideration has prompted us to adopt a conservative approach initially at setting the negative charge, because:

- As suggested by the Authority in the guidance, to avoid price shock, this means setting a negative charge at a relatively conservative rate initially, which increases over time, rather than setting it too high and discovering it needs to be lowered. This allows distributors to test and learn while sufficient visibility into our LV network is not available.
- Starting conservatively will also minimise the risks where the benefits from peak injection do not eventuate and same network investments are still required, leading to existing load customer cross-subsidising the negative charges.

Uptake incentives

This consideration also relates to us adopting a simple and broad approach. By not having a granular and complex set up, it facilitates retailers to pass them through efficiently.

Network stability

Injection at the wrong time/place may not only provide no network benefits but may incur additional network costs by causing localised export congestion or voltage issues. This is also one of the reasons why we have adopted a conservative approach to avoid a sudden spike in generation leading to congestion. As we learn and gather more data throughout this journey, it will allow us finetune the negative charge amount to drive the best outcome for both the consumers and the network.
To further manage this risk:

- From a pricing perspective, additional costs caused by excess injection can be recovered under our export charge as incremental costs to distributed generation customers under Part 6 of the Code.
- From a technical perspective, setting appropriate export limit and smart meter data availability will also help us monitor and address potential congestion issues.

9.7 The form and the time periods in which it applies

As a result of the consultation with the retailers, new pricing component codes will be created for retailers to be able to submit injection volume for peak, shoulder and off-peak time band, and negative charges will apply accordingly.

10. PRICING PRINCIPLES ASSESSMENT

The Authority revised its distribution pricing principles in 2019 and provided clarification of how the principles should be applied in practice. The pricing principles are as follows:

The 2019 Distribution Pricing Principles

(a) Prices are to signal the economic costs of service provision, including by:

(i) being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs).

(ii) reflecting the impacts of network use on economic costs.

(iii) reflecting differences in network service provided to (or by) consumers; and

(iv) encouraging efficient network alternatives.

(b) Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.

(c) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:

(i) reflect the economic value of services; and

(ii) enable price/quality trade-offs.

(d) Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.

We have considered each of these principles in developing our line prices.

10.1 Prices are to signal the economic costs of service provision

10.1.1 By being subsidy-free (equal to or greater than avoidable costs, and less than or equal to standalone costs)

EIL's cost of supply model allocates costs to Individual customers based on their share of the actual assets employed to supply them. The remaining group customers (Residential and General) have the resulting costs allocated to them on an averaged basis once the Individual customers' costs have been deducted from the total costs. It is not easy to accurately establish the stand-alone costs for most customers supplied by a common service via a meshed network. However, we can conclude that stand alone costs would be higher than average costs for those customers given the scale efficiencies in supplying them from a meshed network. EIL believes that the cost allocators used in the model are a representation of the underlying cost drivers of the business and therefore is subsidy free.

As a further check on existence of subsidies between consumer groups, we provide a calculation of avoidable and standalone costs based on a methodology that uses the readily available and audited data published in our information disclosures, rather than a methodology that involves remodelling the network. The methodology is assumption-driven but nevertheless provides comfort for each of our three load groups (Residential, General, Individual), our target revenue lies between avoidable and standalone costs. The following tables and chart set out the results of this analysis.

Table 19 Avoidable costs by load group

	Residential	General	Individual
Avoidable opex ($000)	$1,728	$785	$221
Transmission ($000)	$3,004	$1,305	$1,725
Avoidable cost ($000)	$4,732	$2,090	$1,946
Revenue ($000)	$15,179	$6,120	$4,639
Revenue > Avoidable cost?	Yes	Yes	Yes

Table 20 Standalone costs by load group

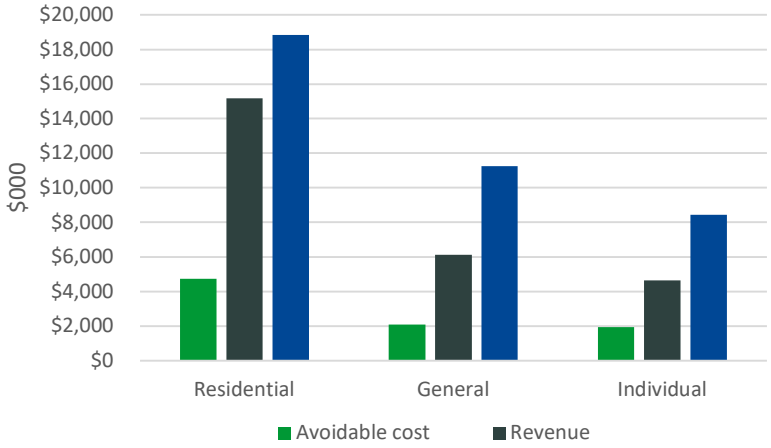
	Residential	General	Individual
Depreciation	$3,252	$2,256	$1,660
Return on capital (pre-tax)	$7,980	$5,474	$3,975
Opex	$4,612	$2,227	$1,087
Transmission	$3,004	$1,305	$1,725
Total standalone costs	$18,848	$11,262	$8,446
Revenue	$15,179	$6,120	$4,639
Revenue < Standalone costs	Yes	Yes	Yes

When carrying out this analysis, we estimated avoidable costs by first identifying which types of assets could be abandoned if each consumer groups was no longer be supplied. We then used data published in our regulatory Information Disclosures to estimate the avoidable costs associated with abandoning those assets.

To estimate the standalone asset costs for each customer load group, we:

- Identified which asset classes most resemble common assets, where the value of the assets needed to serve an individual customer load group are similar to value of assets needed to serve all customer load groups. Then we identified the RAB value of those assets, by asset class for each customer load group
- For asset classes that are more attributable to individual load groups (rather than being common to the supply of multiple customer groups), we allocated the RAB value to each customer load group
- We then calculated, for each customer load group, the depreciation and return on capital for common assets and for allocated attributable assets to estimate the standalone asset costs.

Figure 4 Subsidy-free test



New connections to the network pay a capital contribution if the expected revenue from the line charge does not cover the capital recovery cost required, this ensures that new connections are not subsidised and that total revenue from the new customer is not less than the expected incremental costs.

10.1.2 Reflecting the impacts of network use on economic costs

EIL's pricing structure uses capacity-based load groups to ensure prices have regard to the level of service capacity and encourages the use of controlled energy consumption by having a price differential in the fixed charge for Residential and General customers. Load control is utilised to keep charges down by managing GXP load when maximum demand reaches the capacity of that GXP, managing load on feeders during temporary arrangements to manage constraints, and contributing to lower regional peak load which can help to avoid or defer Transpower grid upgrades.

The introduction of Peak, Shoulder and Night energy component of line charges to residential and general customers also provides a strong signal to consumers to utilise spare network capacity at Shoulder or Night time's thus reducing capital investment in the network. A time-of-use pricing structure assists in deferring network upgrades. The move to TOU pricing has served to refine and improve the signals of the previous day/night structure. Looking to the future, and the potential for developments such as EV's, to bring network assets closer to capacity limits, a forward-looking approach to having structures in place and understanding/developing the responsiveness of customers to signals before they need to be relied upon has been implemented.

As we look to further develop our pricing, we need to have a greater understanding of our economic cost of supply. To do this, we have estimated our Long-Run Marginal Cost of supply (LRMC), and this will help with setting the time of use prices in the future. LRMC provides a measure of the forward-looking economic cost of network use and enables us to move towards price signals about the costs that will be incurred in future as a result of network use – that is, if peak usage increases, how much additional cost will be incurred by the network?

There are several methodologies that can be used to estimate the economic cost of incremental network use. We have used the Average Incremental Cost methodology (AIC) model developed by Link Economics on behalf of the ENA, which unitises forecast network costs that are demand-driven by incremental demand. We applied this methodology because it:

- uses information that is already prepared for network management and disclosure purposes, rather than requiring network models of hypothetical changes in demand.

- is the most widely adopted and well-established method used in Australia, where AIC has been used for a number of years to set price levels, and this provides precedent on calculation and application to pricing.

However, we note that this methodology can provide volatile results because network investment is typically lumpy.

To estimate the LRMC using the Average Incremental Cost (AIC) methodology, we divide the Present Value (PV) of annualised incremental capex and opex by the PV of incremental demand. To do this, we:

- Sourced capex from EIL's system growth capex forecasts. We then used a WACC estimate with a 40-year assumption on asset lives to calculate annualised incremental capex.
- Included incremental opex by applying an opex factor to system growth capex. The opex factor was calculated using 2024 opex as a % of RAB (adjusted for average asset life) to estimate incremental opex as a percentage of incremental capex.

For simplicity, we calculated an average LRMC across all customer load groups (i.e., rather than calculating disaggregated estimates). Our resulting estimate of LRMC per kW was $25.24. Given our TOU definitions, this translates to a LRMC of approximately $0.01.[4]

The LRMC-based kWh prices imply fixed charges that are substantially higher than EIL's existing fixed charges. These results support the continued rebalancing of prices to increase the proportion of revenue earned through fixed charges, as the networks have done for the FY2026 year.

In practice, daily fixed charges are constrained by affordability considerations, an EDB's need to maintain social license, and the Low Fixed Charge Regulations.

Daily fixed charges can be suppressed by increasing kWh charges above LRMC levels. Exactly how this is done is a judgement call. EIL has a low off-peak charge (1 c/kWh) which, in the context of growing EV uptake is likely a key focus. In other words, it is arguably more important to keep prices closer to the LRMC rate for off-peak periods than it is for peak and shoulder (as EIL has done).

We continue to refine our LRMC modelling and note that one issue for further consideration is the treatment of replacement capex. Our LRMC analysis has focussed on system growth capex, but this approach could potentially understate the true LRMC. Arguably some replacement capex could be included as replacement may include some degree of capacity increase to cater to future growth.

With regard to charges for individual customers, total allocations are determined annually through a method which incorporates allocation of a portion of charges through peak demand measures. This is because the most significant cost driver that influences investment requirements in the network is the combined peak demand of all consumers in an area. EIL designs and constructs its network to meet this peak load. This ensures that charges signal the impact of additional demand on future investment costs. The use of a more sophisticated charging arrangement for individual customers reflects that they typically have greater capacity to manage and respond to demand-driven charges than smaller customers.

EIL's peak times are outlined in the methodology and have encouraged individual customers to employ demand response actions such as turning on alternative generation or load shifting during these times to

[4] LRMC price per kWh = (Probability of system peak x LRMC/kW/year)/ (number of hours per year in peak TOU period)

reduce their peak demands. Residential customers have the option to put some of their appliances on controlled tariffs to qualify for the off-peak fixed charge.

Customers are encouraged to use energy at shoulder or night times through the use of night store heaters, heating the hot water or using their appliances such as clothes driers, washing machines etc. during these periods. The customer is then financially rewarded, as the consumption attracts lower variable line charge prices. The "whole house TOU tariff" can reward consumers financially through prudent management of their power requirements.

10.1.3 Reflecting differences in network service provided to (or by) consumers

Different levels of daily charges for residential and general consumers with controlled as compared with uncontrolled connections reflect that controlled load has different service availability than uncontrolled load.

For individual customers, pricing reflects that different assets are used by different customers, which could also be associated with different service levels.

10.1.4 Encouraging efficient network alternatives

The specific pricing that is incorporated into Individual Customer charges assists in providing signals on the cost of network provision in particular locations that can then be compared against network alternatives to encourage efficient decision-making by consumers.

Signalling when the network is likely to be at its busiest or when capacity is available also provides signals on when network alternatives can aid in meeting peak loads or in smoothing peaks through load shifting. TOU pricing assists with this – for example, by encouraging EV charging overnight. However, it is envisaged that TOU pricing will allow more accurate signalling of network busy times than the broad day/night periods that were previously in use. For individual customers, charges reflect demand during peak periods which would encourage efficient decision-making on customer investment in and use of network alternatives.

10.2 Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use

EIL uses capacity charges to recover costs that are not recovered through peak demand charges (Individual Customer) or TOU kWh charges (Residential and General) charges. These types of charges would have less distortionary impacts in recovering sunk costs than kWh or demand charges would, but arguably fairer than a single fixed charge for each and every ICP. However, there are limitations on the proportion of costs that can be recovered through capacity or daily charges because of the Low Fixed Charge Regulations, as well as fairness considerations. EIL is continuing to follow the transition path in the LFC Regulations for increasing fixed charges to low users.

EIL also notes that while the recovery of sunk or fixed costs from variable charges will distort usage to some extent, reasonably low uptake of evolving technologies (PV, EVs) on EIL's network area for the foreseeable future likely means that there will be limited adverse consequences from consumption charges.

Another interpretation of prices that least distort network use is Ramsey pricing, where those consumers with inelastic demand face higher charges as their consumption is least likely to be distorted as a result. However, this principle is difficult to apply as price elasticity information is difficult to obtain, and it is likely the price elasticities will be different within each load group.

10.3 Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to: (i) reflect the economic value of services; and (ii) enable price/quality trade-offs

As is discussed in section 10, in some cases non-standard prices and contracts are appropriate. This may be the case where, for example, a customer has enhanced security arrangements. In situations where customers have significant capital contributions or new investment agreements, robust commercial contracts incorporating prudential requirements are prudent to mitigate the risk of these assets being stranded. These contracts can also assist in avoiding uneconomic by-pass of the network when negotiating commercial arrangements and encourage growth within the network. EIL's individual pricing for large customers and individual account management to industrial and large commercial customers addresses the risk of bypass by negotiating arrangements that, as closely as is practical, reflect the network costs incurred by each individual consumer.

The pricing model allows customers to own their own distribution transformers passing on the savings made by ownership.

The use of individual capacity and demands also ensures that the price is cost reflective. By these processes, EIL discourages uneconomic bypass of its network and allows negotiation to tailor its services to the specific needs of the consumer.

During the consultation process with consumers, particularly the larger individual consumers, and often when they are extending or requiring a new supply, price/quality trade-offs are discussed and offered, these often in the form of offering the customer an (n-1) supply. Consumers who choose this level of supply will have the extra costs reflected in their individual line charge.

10.4 Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.

Through the disclosure of the pricing methodology, the costs allocated to each consumer group are transparent. This allows stakeholders to make informed decisions between capacity-based price categories.

EIL has maintained its fixed pricing structure and differentials between peak and off-peak fixed charges and has introduced Peak, Shoulder and Night consumption periods for variable charges to give stability and certainty to customers who have invested in controllable load due to the price differential and potential savings when the investment is made.

Price levels for individual consumers each year are based on the previous year's performance and projections for the current year following discussions with the consumer when required.

More efficient use of electricity by these consumers may be reflected at the time in the variable charges but will primarily be effective as the basis for calculating reduced line charges (in real terms) for the following year.

All retailers who use the network are subject to the same tariff schedules from EIL therefore, EIL considers that its prices are economically equivalent across all retailers.

Once the line charges have been established by the methodology, the pricing structure is straight forward, limited to a fixed daily charge and variable consumption period tariff for most customers. EIL recognises that whilst the pricing structure is simple, there are a large number of options due to the peak/off-peak options available within each capacity group. The Electricity (Low Fixed Charge Tariff

Option for Domestic Consumers) Regulations 2004 requiring a low fixed charge option for each residential tariff has also greatly increased the number of options.

The issue is a compromise between simplicity and equitability of pricing. Three parameters influence the cost, the load to be supplied (governs the size of assets used) and the time the load is supplied (governs the diversity and hence size and share of the assets used).

EIL's line charge methodology has endeavoured to incorporate these aspects and then apply in the most equitable but simple way practicable.

EIL uses "GXP billing" for its residential and general connections, which saves on administration costs, and ultimately should result in lower costs and prices.

With regard to uptake incentives, because pricing is at a GXP level for residential and general customers, EIL's pricing structure (e.g., TOU) is necessarily applied for all customers at a wholesale level. Whether EIL's pricing structure is passed on to end consumers or repackaged is a decision made by retailers.

EIL's pricing from 1 April 2022 did incorporate structural changes and as a result, consumer impacts of the change in price levels were predicted with thorough analysis.

APPENDIX A COMMERCE COMMISSION INFORMATION DISCLOSURE REQUIREMENTS

In the table below, we describe the relevant sections of this methodology where we demonstrate compliance with the key sections of the Commission's information disclosure requirements.

IDD Section	Requirement	Key sections of methodology demonstrating compliance
2.4.1	Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which:	
2.4.1 (1)	Describes the methodology, in accordance with clause 2.4.3, used to calculate the prices payable or to be payable;	Sections 3 to 7
2.4.1 (2)	Describes any changes in prices and target revenues;	Section 6.8
2.4.1 (3)	Explains, in accordance with clause 2.4.5, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any);	Sections 8 and 9
2.4.1 (4)	Explains whether, and if so how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.	Section 7.3
2.4.2	Any change in the pricing methodology or adoption of a different pricing methodology, must be publicly disclosed at least 20 working days before prices determined in accordance with the change or the different pricing methodology take effect.	Compliant
2.4.3	Every disclosure under clause 2.4.1 must-	
2.4.3 (1)	Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group;	Sections 6 and 7 Appendix B
2.4.3 (2)	Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;	Section 10
2.4.3 (3)	State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	Section 5
2.4.3 (4)	Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;	Section 5
2.4.3 (5) (a), (b)	State the consumer groups for whom prices have been set, and describe- (a) the rationale for grouping consumers in this way; (b) the method and the criteria used by the EDB to allocate consumers to each of the consumer groups;	Sections 3 and 6
2.4.3 (6)	If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons;	Section **Error! Reference source not found.**
2.4.3 (7)	Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way;	Section 6
2.4.3 (8)	State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	Appendix D
2.4.4	Every disclosure under clause 2.4.1 must, if the EDB has a pricing strategy-	

2.4.4 (1-3)	(1) Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set. (2) Explain how and why prices for each consumer group are expected to change because of the pricing strategy. (3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.	Section 4
2.4.5	Every disclosure under clause 2.4.1 must-	
2.4.5 (1)	Describe the approach to setting prices for non-standard contracts, including- (a) the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to nonstandard contracts. (b) how the EDB determines whether to use a non-standard contract, including any criteria used. (c) any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology is consistent with the pricing principles;	Section 8
2.4.5 (2)	Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain- (a) the extent of the differences in the relevant terms between standard contracts and non-standard contracts. (b) any implications of this approach for determining prices for consumers subject to non-standard contracts;	Section 8
2.4.5 (3)	Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the- (a) prices; and (b) value, structure and rationale for any payments to the owner of the distributed generation.	Section 9

APPENDIX B PROFILE PARAMETERS

The profile parameters for determining the line charges for the Residential and General customers are:

Table 21 Profile parameters for Residential and General customers

Consumer Capacity	Code	Number of Connections	After Diversity Peak Demand (kW)	Total Energy Group (MWh)	Winter Peak Group (MWh)	Winter Day Group (MWh)	Summer Day Group (MWh)
Residential Standard							
Small Residential (8kVA 1 Phase) - All Peak	ND08P	71	111	472	88	199	169
Small Residential (8kVA 1 Phase) - With Off Peak	ND08Q	99	118	592	83	225	207
Residential (15kVA 1 Phase) - All Peak	ND20P	1,403	4,037	17,135	3,214	7,236	6,126
Residential (15kVA 1 Phase) - With Off Peak	ND20Q	7,714	18,543	92,589	13,024	35,191	32,439
Residential Low Fixed Charge Option (15kVA 1 Phase) - All Peak	NDL20P	28	2,849	6,719	1,260	2,837	2,402
Residential Low Fixed Charge Option (15kVA 1 Phase) - With Off Peak	NDL20Q	89	11,781	32,679	4,597	12,421	11,449
Residential Low Fixed Charge Option (8kVA 1 Phase) - All Peak	NDL08P	1,064	53	198	37	84	71
Residential Low Fixed Charge Option (8kVA 1 Phase) - With Off Peak	NDL08Q	5,220	103	457	64	174	160
General Single Phase							
Streetlights (1 Phase)	NS001L	5,034	652	2,171	407	917	776
1 kVA 1 Phase - All Peak	NS001P	53	55	428	80	181	153
8 kVA 1 Phase - All Peak	NS008P	137	184	780	146	329	279
8 kVA 1 Phase - With Off Peak	NS008Q	10	11	54	8	21	19
15 kVA 1 Phase - All Peak	NS020P	263	708	3,006	564	1,270	1,075
15 kVA 1 Phase - With Off Peak	NS020Q	83	190	949	133	361	332
General Three Phase							

Consumer Capacity	Code	Number of Connections	After Diversity Peak Demand (kW)	Total Energy Group (MWh)	Winter Peak Group (MWh)	Winter Day Group (MWh)	Summer Day Group (MWh)
15 kVA 3 Phase - All Peak	NT015P	74	197	836	157	353	299
15 kVA 3 Phase - With Off Peak	NT015Q	7	17	86	12	33	30
30 kVA 3 Phase - All Peak	NT030P	552	3,343	10,089	1,892	4,261	3,607
30 kVA 3 Phase - With Off Peak	NT030Q	104	536	1,904	268	724	667
50 kVA 3 Phase - All Peak	NT050P	353	4,344	14,341	2,690	6,056	5,127
50 kVA 3 Phase - With Off Peak	NT050Q	65	694	2,696	379	1,025	945
75 kVA 3 Phase - All Peak	NT075P	125	2,908	8,229	1,543	3,475	2,942
75 kVA 3 Phase - With Off Peak	NT075Q	15	300	997	140	379	349
100 kVA 3 Phase - All Peak	NT100P	83	2,982	5,624	1,055	2,375	2,011
100 kVA 3 Phase - With Off Peak	NT100Q	9	298	662	93	251	232

The profile parameters for determining the line charges for the individual customers, grouped by capacity are in the following table.

Figure 5 Profile parameters for individual customers

Contract Capacity (kVA	Number of Connections	Coincident GXP Peak Demand (kVA)	Peak Demand (kVA)	Total Energy Reading (MWh)	Peak Reading (MWh)	Winter Day (MWh)	Summer Day (MWh)
30	2	14	23	37	7	18	14
50	2	57	43	51	12	19	13
75	6	170	242	818	101	287	355
100	10	304	566	1,385	184	497	561
150	24	1,412	2,124	4,565	634	1,602	1,799
200	41	2,935	4,057	10,301	1,512	3,689	4,309
300	30	3,371	4,598	13,154	1,699	4,344	5,314
500	32	5,746	7,891	23,234	3,204	8,059	9,216

750	8	1,487	1,738	7,541	867	2,286	2,902
1000	4	1,047	1,261	4,976	476	1,174	1,485
1250	1	600	590	2,421	313	921	1,170
1750	1	1,080	1,313	6,042	607	1,639	2,415
30	2	14	23	37	7	18	14
50	2	57	43	51	12	19	13
75	6	170	242	818	101	287	355
100	10	304	566	1,385	184	497	561
150	24	1,412	2,124	4,565	634	1,602	1,799
200	41	2,935	4,057	10,301	1,512	3,689	4,309
300	30	3,371	4,598	13,154	1,699	4,344	5,314
500	32	5,746	7,891	23,234	3,204	8,059	9,216
750	8	1,487	1,738	7,541	867	2,286	2,902
1000	4	1,047	1,261	4,976	476	1,174	1,485
1250	1	600	590	2,421	313	921	1,170
1750	1	1,080	1,313	6,042	607	1,639	2,415

APPENDIX C LINE CHARGE TABLES

Line Charge Breakdown for Individual Customers

Contract Capacity kVA	Number of connections	Line Charge Revenue per Capacity	Average Line Charge
30	2	$4,600	$2,300
50	2	$9,999	$4,999
75	6	$49,485	$8,247
100	10	$88,970	$8,897
150	24	$338,745	$14,114
200	41	$733,405	$17,888
300	30	$805,173	$26,839
500	32	$1,420,407	$44,388
750	8	$434,437	$54,305
1000	4	$294,262	$73,565
1250	1	$134,348	$134,348
1750	1	$324,901.73	$324,902

APPENDIX D EIL REVENUE FOR RESIDENTIAL AND GENERAL CUSTOMERS

Consumer Capacity	Code	Number of Connections	Sub-transmission Cost Recovery	Distribution Cost Recovery	Overhead Cost Recovery	Total Revenue
Residential Standard						
Small Residential (8kVA 1 Phase) - All Peak	ND08P	71	$6,607	$22,440	$7,008	$36,055
Small Residential (8kVA 1 Phase) - With Off Peak	ND08Q	99	$6,388	$26,512	$9,792	$42,691
Residential (15kVA 1 Phase) - All Peak	ND20P	1,403	$220,238	$885,505	$139,469	$1,245,211
Residential (15kVA 1 Phase) - With Off Peak	ND20Q	7,714	$999,073	$4,152,257	$766,830	$5,918,159
Residential Low Fixed Charge Option (15kVA 1 Phase) - All Peak	NDL20P	1,064	$135,926	$574,382	$105,770	$816,077
Residential Low Fixed Charge Option (15kVA 1 Phase) - With Off Peak	NDL20Q	5,220	$533,367	$2,396,760	$518,907	$3,449,034
Residential Low Fixed Charge Option (8kVA 1 Phase) - All Peak	NDL08P	28	$3,409	$8,743	$2,783	$14,936
Residential Low Fixed Charge Option (8kVA 1 Phase) - With Off Peak	NDL08Q	89	$5,097	$22,994	$8,847	$36,938
		71	$6,607	$22,440	$7,008	$36,055
General Single Phase						
Streetlights (1 Phase)	NS001L	5,050	$33,102	$137,186	$203	$170,491
1 kVA 1 Phase - All Peak	NS001P	53	$3,841	$10,877	$5,269	$19,987
8 kVA 1 Phase - All Peak	NS008P	137	$9,317	$42,826	$13,569	$65,711
8 kVA 1 Phase - With Off Peak	NS008Q	10	$555	$2,543	$944	$4,043
15 kVA 1 Phase - All Peak	NS020P	263	$35,902	$165,028	$26,144	$227,073
15 kVA 1 Phase - With Off Peak	NS020Q	83	$9,693	$44,443	$8,251	$62,388
General Three Phase						
15 kVA 3 Phase - All Peak	NT015P	74	$10,592	$43,733	$7,356	$61,681
15 kVA 3 Phase - With Off Peak	NT015Q	7	$1,005	$3,567	$696	$5,267
30 kVA 3 Phase - All Peak	NT030P	552	$160,424	$629,544	$54,873	$844,841

30 kVA 3 Phase - With Off Peak	NT030Q	104	$25,888	$101,258	$10,338	$137,484
50 kVA 3 Phase - All Peak	NT050P	353	$210,766	$772,028	$35,091	$1,017,885
50 kVA 3 Phase - With Off Peak	NT050Q	65	$34,618	$121,670	$6,461	$162,750
75 kVA 3 Phase - All Peak	NT075P	125	$136,900	$443,939	$12,426	$593,265
75 kVA 3 Phase - With Off Peak	NT075Q	15	$14,319	$45,552	$1,491	$61,362
100 kVA 3 Phase - All Peak	NT100P	83	$122,525	$291,558	$8,251	$422,334
100 kVA 3 Phase - With Off Peak	NT100Q	9	$13,402	$27,240	$895	$41,537

APPENDIX E LINE CHARGE FOR RESIDENTIAL AND GENERAL CUSTOMERS

Consumer Capacity	Code	Number of Connections	Daily Fixed Price
EIL			
Residential Standard			
Small Residential (8kVA 1 Phase) - All Peak	ND08P	71	$ 1.0700
	ND08Q	99	$ 0.7558
Residential (15kVA 1 Phase) - All Peak	ND20P	1,403	$ 1.9770
Residential (15kVA 1 Phase) - With Off Peak	ND20Q	7,714	$ 1.3729
Residential Low Fixed Charge Option (15kVA 1 Phase) - All Peak	NDL20P	1,064	$ 0.9000
Residential Low Fixed Charge Option (15kVA 1 Phase) - With Off Peak	NDL20Q	5,220	$ 0.8500
Residential Low Fixed Charge Option (8kVA 1 Phase) - All Peak	NDL08P	28	$ 0.9000
Residential Low Fixed Charge Option (8kVA 1 Phase) - With Off Peak	NDL08Q	89	$ 0.7558
General Single Phase			
Streetlights (1 Phase)	NS001L	5,050	$ 0.1643
1 kVA 1 Phase - All Peak	NS001P	53	$ 0.7677
8 kVA 1 Phase - All Peak	NS008P	137	$ 1.0700
8 kVA 1 Phase - With Off Peak	NS008Q	10	$ 0.7444
15 kVA 1 Phase - All Peak	NS020P	263	$ 1.9770
15 kVA 1 Phase - With Off Peak	NS020Q	83	$ 1.3729
General Three Phase			
15 kVA 3 Phase - All Peak	NT015P	74	$ 1.7969
15 kVA 3 Phase - With Off Peak	NT015Q	7	$ 1.1630
30 kVA 3 Phase - All Peak	NT030P	552	$ 2.7684
30 kVA 3 Phase - With Off Peak	NT030Q	104	$ 1.8842
50 kVA 3 Phase - All Peak	NT050P	353	$ 5.6527
50 kVA 3 Phase - With Off Peak	NT050Q	65	$ 3.8385
75 kVA 3 Phase - All Peak	NT075P	125	$ 11.6078
75 kVA 3 Phase - With Off Peak	NT075Q	15	$ 8.4443
100 kVA 3 Phase - All Peak	NT100P	83	$ 14.1199
100 kVA 3 Phase - With Off Peak	NT100Q	9	$ 10.2357

Variable Line Charge Prices	Peak c/kWh	Shoulder c/kWh	Night c/kWh
Residential Standard and General	$0.081400	$0.056500	$0.01000
Residential Low Fixed Charge Fixed Charge Option (8kVA 1 Phase)	$0.081380	$0.056520	$0.01000
Residential Low Fixed Charge Fixed Charge Option (20kVA 1 Phase)	$0.107240	$0.0846329	$0.01000