LINE PRICING METHODOLOGY

FOR THE ELECTRICITY INVERCARGILL LIMITED (EIL) NETWORK AS AT 1 APRIL 2022

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GLOSSARY OF TERMS

After Diversity Maximum Demand (ADMD) is the customer's Maximum Demand after it has been adjusted by the Diversity Factor.

Anytime Maximum Demand (AMD) is the Maximum Demand of the customer measured at the customer's installation during any half hour period during the year.

Coincident Grid Maximum Demand is the average of the 100 demand measurements of the customer which are coincident with the 100 highest demands which occur on the Transpower grid in the lower South Island region during the assessment period 1 September to 31 August which the Transpower Interconnection charges are based.

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 Electricity Invercargill Limited'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 have been applied should equal the Maximum Demand measured at the GXP.

ENA is the Electricity Networks Association

Grid Exit Point (GXP) means the Grid Exit Point and is the connection point between the Transpower grid and the Electricity Invercargill Limited network

Residential and General Customers include most customers with a Contract Capacity up to and including 100 kVA.

Half Hour Metering (HHM) describes the metering equipment that is capable of measuring electricity consumption on a half hour basis and when the half hour readings are used for billing purposes.

Individual Customers are in most cases commercial or industrial customers that have a Contract Capacity equal to or in excess of 100kVA.

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

Maximum Demand (MD) of a customer is the maximum demand of the customer that occurs throughout the specified Peak Period Energy time periods for each GXP or if that measurement is not available it is based on the Contract Capacity.

Optimised Depreciated Replacement Cost (ODRC) relates to the network assets and is the current depreciated value of all the network assets based on an efficient network design using modern equivalent assets.

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

Time of Use (TOU) refers to meters that are capable of providing Anytime and Maximum Demand readings and Peak, Shoulder and Low 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).

1. INTRODUCTION

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 2019. 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 economically 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.

We first provide contextual information about the EIL's network (**section 2**), then present an overview of our prices and how they are set (**section 3**). We then assess our pricing against the Authority's Distribution Pricing Principles (**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 9**). Charges that would be applied for generators connected to EIL's network are described (**section 10**). In section 4, we discuss our forward pricing strategy.

2. BACKGROUND INFORMATION ABOUT EIL

2.1 The EIL 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. PowerNet Limited (PowerNet) has a responsibility for the management of the network assets owned by EIL.

A geographically compact network, EIL supplies more than 17,400 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.

Transpower's Invercargill Transmission Grid Exit Point (GXP) substation is the 33 kV supply point for both the Invercargill and Bluff network areas. In addition, a limited backup supply is available from

the North Makarewa GXP. Bluff is supplied at 11 kV via TPCL's overhead subtransmission lines, and the Bluff zone substation.

EIL's distribution network includes 23km of 11kV lines and 156km of 11kV underground cables. With more than 400 distribution substations, comprising 11 kV switchgear and distribution transformers, the distribution network supplies over 452 km of low voltage network operating at 400/230 V. EIL has 26.4 ICPs per KM of line, which is the 4th highest customer density ranking out of the 29 New Zealand Distributors.

2.2 Network Investment

As at end March 2021, the value of EIL's network assets in its Regulatory Asset Base was $91.1 million. Over the next three years, EIL intends to invest capital of $18.04 million in its network, of which the majority relates to asset replacements ($12.24 million).

EIL's network is generally unconstrained and with a maximum demand growth forecast of only 0.4%, EIL is not currently forecasting any system growth capital expenditure during the next three years.

2.3 Uptake of evolving technology

A number of technologies have the potential to change the way electricity is used and generated. Pricing has a role to play in providing efficient signals about the economic costs of using electricity networks. In that context, we provide a brief summary of existing and expected uptake of a number of these technologies: solar, electric vehicles and battery storage.

Solar (Photovoltaic) connections

As February 2022, EIL had 121 solar connections to its network, equivalent to 0.7% of all EIL ICPs. This rate is below the national average of 2.4%, and significantly below the rate of 5.7%, which is the average of the top 10 highest uptake EDB areas. There is slight deceleration in uptake on EIL's network: the average number of new solar connections per month over the 12 months to February 2022 was 0.6, as compared with 0.8 and 1.0 for the prior two preceding 12-month periods April – March.

The potential for growth in solar uptake and impact on the network is explored in the company's Asset Management Plan (AMP). Through our annual customer engagement survey, intentions to purchase and installing solar panels on rooftops in the next five years has increased to 33%; an increase of 16% from 2019. The main barriers to adoption was found to be relating to economic reasons where projected payback period has a large influence on the purchase intention. Other considerations that may limit solar uptake are (1) it appears that the majority of customers are unable to install solar as they do not own the property (e.g. rental), or prefer to dispose of their income elsewhere; and (2) energy cost reduction options such as home insulation and electric vehicles are now also receiving increased attention and generally offer a superior return.

Total energy consumption is likely to be reduced to some extent by solar installations 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.

Electric vehicles

There are approximately 92 electric vehicles registered in the EIL area – an uptake rate per connection of 0.5%. With the introduction of the Clean Car rebate where electric cars can get up to $8,625 rebate and with increase in cost of fuel, we expect electric vehicle adoption to grow year on year. As is explained in our AMP, EVs have the potential to have large impacts on network demand with sufficient adoption. Prices are an important means for signalling 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 exacerbate 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 EV's.

Having pricing structures in place before EV uptake reaches widespread levels will enable a degree of customer education before load shifting is required 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.

Energy storage

As is explained in our AMP, energy storage could have a large impact on network demand especially if used in combination with distributed generation installations. However, there is significant uncertainty in this area around the value streams of energy storage from the customers' point of view and also the timing of their introduction; the regulatory environment and the extent to which electricity distribution businesses will be able to promote/utilise/market storage services; and the level of responsiveness of the public to load-driven pricing signals.

Under the status quo energy storage technology is not economic except in exceptional circumstances, and it is not expected that there will be significant organic adoption unless electricity distribution businesses provide incentives for their adoption or it is coupled with significant solar PV installations on a customer premise. EIL has been engaged in pilot studies and will continue to explore how customers may use energy storage to respond to price signals that provides mutual benefits to customers and EIL.

2.4 Electricity Invercargill Ltd (EIL) and PowerNet Limited Structure

PowerNet is an incorporated joint venture owned by TPCL and EIL and 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.

3. EIL 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. As highlighted above, 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 variable consumption charges are based on electricity volumes injected into the network at the Transpower grid exit points, rather than based on the usage at individual customer connection points. Quantities are determined by the wholesale electricity market reconciliation process, which is itself governed by an Industry Participation Code. This method saves on administration costs, which are ultimately transferred back into the pricing.

3.1 Consumer load groups used for pricing

There are two defined types of consumers for the purposes of EIL's pricing: Residential and General consumers; and Individual Consumers (for which prices are connection-specific).

3.1.1 Individual Consumers

These consumers have half-hour or time-of-use meters, including kVA maximum demand registers.

In most cases these installations have contract capacities in excess of 100kVA. Due to their size, these consumers have a higher impact on the network design and operation and therefore this 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 considered 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 supplies, n-1.
- Higher importance on network maintenance

These consumers, through the half-hour or time-of-use metering, have individual profiles, which are used to calculate the line charges. Metering of these consumers includes kVA demand metering which provides the winter or seasonal peak demand and also the anytime peak demand. The latter

figures are used 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.

3.1.2 Residential and General Consumers

The Residential and General category includes all residential connections and general single and 3 phase connections up to 100kVA capacity. Prices for these customers include a daily charge and a kWh price applied to energy used during the Peak period, which is defined as 7am to 11am and 5pm to 9pm, the Shoulder period, which is defined as 11am to 5pm and 9pm to 11pm and energy usage during the Night period (11pm to 7am).

Prices for Residential and General Consumers vary according to:

- 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. 8kVA 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”.
- **Control:** Whether there is significant controllable load on the premises. If so, the connection qualifies for a “with off peak” line charge, which is lower than the “all peak” prices that apply 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.
- 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 able to transfer to the Residential Low User option tariffs. From 1 April 2022 the Low fixed Charge Tariff Option is being phased out over a 5-year period by the Government. 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 when it reaches 90 cents per day in 5-years' time it will be removed altogether. 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 principle 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.

The consumer specific pricing options available for Residential and General Consumers are as follows:

Contract Capacity Group	Code
Residential	
Residential (8kVA 1 Phase) - All Peak *	ND08P
Residential (8kVA 1 Phase) - With Off Peak *	ND08Q
Standard Residential (15kVA 1 Phase) - All Peak	ND20P
Standard Residential (15kVA 1 Phase) - With Off Peak	ND20Q
Residential Low User (15kVA 1 Phase) - All Peak	NDL20P
Residential Low User (15kVA 1 Phase) - With Off Peak	NDL20Q
Residential Low User (8kVA 1 Phase) - All Peak*	NDL08P
Residential Low User (8kVA 1 Phase) - With Off Peak*	NDL08Q
General Single Phase	
Street Lights (1 Phase) per street light	NS001L
1 kVA 1 Phase - All Peak	NS001P
8 kVA 1 Phase - All Peak	NS008P
8 kVA 1 Phase - With Off Peak	NS008Q
15 kVA 1 Phase - All Peak	NS020P
15 kVA 1 Phase - With Off Peak	NS020Q
General Three Phase	
15 kVA 3 Phase - All Peak	NT015P
15 kVA 3 Phase - With Off Peak	NT015Q
30 kVA 3 Phase - All Peak	NT030P
30 kVA 3 Phase - With Off Peak	NT030Q
50 kVA 3 Phase - All Peak	NT050P
50 kVA 3 Phase - With Off Peak	NT050Q
75 kVA 3 Phase - All Peak	NT075P
75 kVA 3 Phase - With Off Peak	NT075Q
100 kVA 3 Phase - All Peak	NT100P

100 kVA 3 Phase - With Off Peak	NT100Q

3.2 Summary of target revenue and pricing changes

EIL has made a significant change to its pricing structure as we move to more cost-reflective pricing for the 12 months from 1 April 2022. Changes made to EIL's pricing are:

- Time of Use (TOU) pricing for Residential and General Customers' is replacing the existing Day/Night variable (kWh) line charge price structure. TOU now consists of three time periods for variable line charge prices these being:

  Peak period, which is defined as 7am to 11am and 5pm to 9pm; and

  Shoulder period, which is defined as 11am to 5pm and 9pm to 11pm; and

  Night period (11pm to 7am).

- In line with the Government announced phase out of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 EIL has increased the daily fixed charge to the Residential Low Fixed Charge Option customers.

Target revenue for 2022/23 is calculated at $18.8 million, increasing from $17.9 million the previous year. Below is a summary revenue for both transmission costs and distribution price components broken down by the two customer group categories for the 2022-23 year. We also outline the change in revenue compared with the previous year:

Year 2022-23	**Residential & General**	**Individual**	**Total**
Distribution	$10,902,859	$1,847,141	$12,750,000
Pass-through costs	$195,886	$1,995	$197,881
Recoverable costs	$89,177	$18,077	$107,254
Transmission	$4,301,640	$1,460,094	$5,761,734
Total	$15,489,562	$ 3,327,037	$18,816,869
Revenue from previous year			
Distribution	$10,717,938	$1,779,062	$12,497,000
Pass-through costs	$275,609	$2,838	$278,447
Recoverable costs	($293,779)	($79,091)	($372,870)
Transmission	$4,166,467	$1,319,616	$5,486,083
Total	$14,866,235	$ 3,022,425	$17,888,660

Pass-through and recoverable costs have now been itemised, as this is a requirement of the Default Price-Quality Path. Transmission changes relate to a decrease in Transpower's interconnection charge rate but off-set by an increase in the interconnection peak demand.

On average lines charges will reduce by 5.2% from 1 April 2022. Residential customer pricing is as follows:

	Unit	2021/22	2022/23	2022/23	2022/23
Fixed Charges					
Residential – Off Peak	$/day	**0.7670**	**0.7670**		
Residential Low User	$/day	**0.1000**	**0.2000**		
Variable Charges		**Day**	**Peak**	**Shoulder**	**Night**
All except low user	c/kWh	**6.367**	**6.711**	**5.600**	**1.00**
Low User Off Peak	c/kWh	**9.827**	**10.358**	**8.437**	**1.00**

3.3 Customer consultation

Where significant changes in pricing structure are considered, EIL through PowerNet consults with customers and retailers.

Even in the absence of significant pricing change, EIL seeks the views of consumers as part of the Asset Management Process (AMP) and has reflected these views in the published AMP. This included

1. A face to face survey with key clients including expectations on price and current service
2. A bulk phone survey of current customers including expectations on price and quality
3. Consultation meetings at various locations throughout the network
4. 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 is able to 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.

4. PRICING STRATEGY

Given that EIL's pricing to Individual Customers is highly cost reflective and service based, the focus of the pricing strategy has been on the structure of pricing for residential and general customers.

4.1 Time of Use (TOU) Pricing

EIL's variable pricing previously consisted of a variable price for Day (7am to 11pm) energy and zero for Night (11pm to 7am) energy. This pricing sent a strong signal for customers to shift consumption into the night period, it did not however 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 electric vehicles (EV) charged their cars at 5pm, network peak time or at 2pm, 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 came out on top of all other options under the evaluation process. From 1 April 2022 this combination will be 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 price implementation.

PowerNet has 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 will be provided; and preparing TOU pricing models along with comprehensive customer impact analysis. We have introduced new loss codes to identify low user energy at a GXP level to aid the analysis.

As a result of all the previous work a combination of installed capacity and TOU pricing for residential and general consumers is being implemented from 1 April 2022.

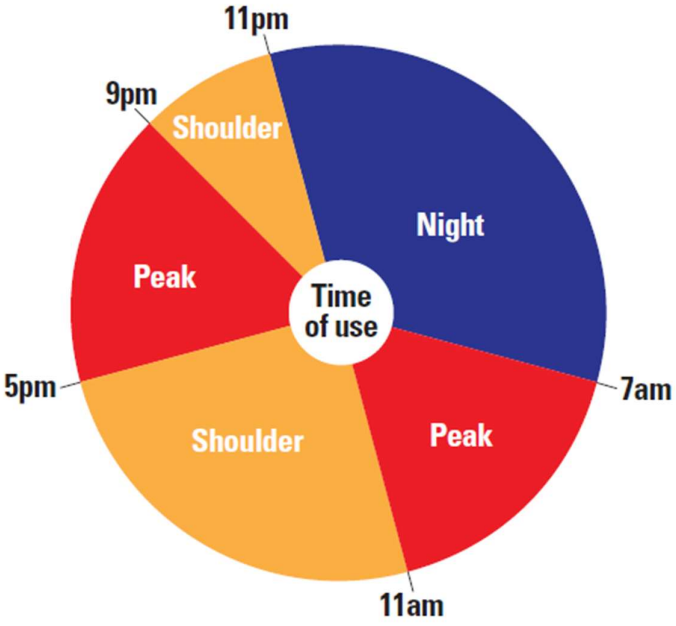
TOU pricing provides an incentive for consumers to shift energy usage out of peak periods, which can avoid or defer costly network upgrades. New uses of electricity such as solar generation, batteries, electrification and charging electric vehicles (EVs) are increasing the scope for network pricing to 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 time-bands shown in the graph below for peak, shoulder, and night were selected based upon the times that peaks occur on our network, and the times that the majority of Regional Control Period Demand (RCPD) peaks fall within (transmission charges being a significant variable cost).

While transmission charges will switch from a variable to a fixed cost once the new Transmission Pricing Methodology (TPM) is implemented, as our network peaks and the RCPD peaks generally align, we do not expect material changes to our time-bands, we will however continually review peak times at our individual GXP's and zone substations to ensure the time bands are appropriate and will make changes if required.

Graph: EIL TOU time periods



The price differential between the peak and shoulder price will initially be marginal but as network constraints become greater or we have EV clustering on the network, we will use the price differential as a tool to send stronger signals to customers to shift load out of the peak periods and therefore avoiding or deferring expensive network upgrades.

4.3 Installed Capacity (fixed Charges)

As 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.

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.

Currently 36% of EIL's total line charge revenue is from fixed charges, with the 5-year phase out of the LFC and the fact that the majority of costs are fixed, EIL will look to increase the share of total revenue from fixed charges over time.

4.4 Customer Impact analysis

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.

EIL has completed extensive impact analysis of a shift to installed capacity and TOU pricing. The analysis involved modelling over 53% 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. Summarized in the below table we examine the break-down of energy usage by customer category by deprivation level:

EIL: General Descriptive Statistics :Consumption

EIL ICP Spilt per Decile and Sample Data		Total	Depreviation Decile									
			Advantaged			Middle NZ				Most Deprived		
			1	2	3	4	5	6	7	8	9	10
Network ICP Count												
Residential		15,328	527	968	1,088	776	1,107	931	2,593	2,416	2,927	1,995
% of Total Network 17,411 ICPs		88%	3%	6%	6%	4%	6%	5%	15%	14%	17%	11%
% of Residential 15,238 ICPs		100%	3%	6%	7%	5%	7%	6%	17%	16%	19%	13%
Residential Standard		8,781	403	659	730	454	643	527	1,456	1,375	1,519	1,015
% of Total Network 17,411 ICPs		50%	2%	4%	4%	3%	4%	3%	8%	8%	9%	6%
% of Residential 15,238 ICPs		57%	3%	4%	5%	3%	4%	3%	9%	9%	10%	7%
% of Standard 8,781 ICPs		100%	5%	8%	8%	5%	7%	6%	17%	16%	17%	12%
Residential Low User		6,547	124	309	358	322	464	404	1,137	1,041	1,408	980
% of Total Network 17,411 ICPs		38%	1%	2%	2%	2%	3%	2%	7%	6%	8%	6%
% of Residential 15,238 ICPs		43%	1%	2%	2%	2%	3%	3%	7%	7%	9%	6%
% of Low User 6,547 ICPs		100%	2%	5%	5%	5%	7%	6%	17%	16%	22%	15%
Sample Average Consumption kWh			11,126 kWh, 12% of Residential			9,887 kWh, 20% of Residential				9,825kWh, 26% of Residential		
Residential Standard kWh		10,114	11,218	11,480	10,750	10,237	10,389	9,846	9,599	9,748	9,965	9,712
Residential Low User kWh		6,187	7,063	6,605	6,421	6,709	6,320	6,352	6,273	5,984	6,002	5,920
SAMPLE ICP COUNT 53% of In Scope ICPs			6,596kWh, 5% of Residential			6,354kWh, 15% of Residential				5,973kWh, 22% of Residential		
Residential Standard	52% of Group	4,598	213	348	381	239	329	271	827	747	782	461
Residential Low	56% of Group	3,658	70	188	196	176	242	229	668	589	770	530
Commercial ICP												
EIL 8kVA	31% of Group	57	0	0	1	1	2	1	12	7	22	11
EIL 15kVA	45% of Group	33	1	0	0	0	2	0	1	3	15	11
EIL 20kVA	39% of Group	142	0	3	4	2	1	5	29	18	58	22
EIL 30kVA	48% of Group	318	0	5	4	4	14	4	33	12	144	98
EIL 50kVA	46% of Group	176	1	3	6	1	5	3	11	18	99	29
EIL 75kVA	31% of Group	40	0	1	0	3	2	1	5	1	19	8
EIL 100kVA	27% of Group	20	0	0	0	2	0	2	2	1	8	5

* In Scope ICPs - All ICPS that do not have an Individual price calculated

- EIL 88% Residential with 42% of total ICPs, **7,338 ICPs in the Most Deprived Band**
- Sample Consumption indicates the Annual kWh for both Standard & Low User decreases as the decile becomes more deprived
- 26%, 3,429 Residential ICPs who are the most deprived, cannot take advantage of the Low User – as they are over the breakeven 9,000kWh.
- 5%, 791 Residential ICPs who are the Most Advantaged have benefited from the Low User regulations

In the table below we analyze the impact by customer group and decile level of the move to MOU variable pricing:

EIL Average Annual Bill Impact by Installed Capacity & TOU Pricing option with Deprivation Levels & Customer Groups					
EIL: Fixed + TOU: YEAR ONE Avg Annual Bill Impact by Price Category and Depreviation Band	ICP Sample No.	Avg Annual Energy Useage kWh	Avg Annual Line Charge	Avg Change to Annual Line Charge	
				%	$
Residential 88%					
Standard Residential 57%	**4,598**	**10,114**	**$858**	**0.27%**	**$2.33**
Standard Residential decile 10 - 8 (Most Deprived)	**1,990**	9,825	$844	0.18%	$1.51
Standard Residential decile 7- 4 (Middle NZ)	**1,666**	9,887	$845	0.30%	$2.56
Standard Residential decile 3-1 (Advantaged)	**942**	11,126	$910	0.40%	$3.67
Standard Domestic Decile 10	**461**	9,712	$834	0.19%	$1.55
Standard Domestic Decile 1	**213**	11,218	$922	0.34%	$3.12
Low User 43%	**3,658**	**6,187**	**$550**	**0.11%**	**$0.59**
Low User decile 10 - 8 (Most Deprived)	**1,889**	5,973	$531	0.08%	$0.43
Low User decile 7- 4 (Middle NZ)	**1,315**	6,354	$565	0.12%	$0.66
Low User decile 3-1 (Advantaged)	**454**	6,596	$586	0.18%	$1.05
Low User Decile 10	**530**	5,920	$523	0.10%	$0.53
Low User Decile 1	**70**	7,063	$630	0.13%	$0.83
Commercial 11%					
General 30kVA	**318**	15,026	$1,442	-1.24%	-$18.15
General 50kVA	**176**	33,688	$3,089	-1.17%	-$36.64
General 75kVA	**40**	59,785	$5,736	-0.44%	-$25.47
General 100kVA	**20**	58,173	$6,256	-0.52%	-$32.80

5. PRICING PRINCIPLES ASSESSMENT

The Authority has recently revised its distribution pricing principles and provided clarification of how the principles should be applied in practice.

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.

5.1 Prices are to signal the economic costs of service provision

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

The PowerNet cost of supply model allocates costs to individual customers based on their geographical location and taking into account the share of the actual assets employed to supply them. The remaining group customers 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 with regards to customers groups.

The methodology attempts to minimise cross subsidisation between the larger individual consumers and between consumer load groups. EIL applies the same pricing to residential and general customers in Invercargill and Bluff. While there may be some differences in the cost of supply, a single set of prices is considered to be the most pragmatic option given the small number of connections in Bluff - only 5% of the population in EIL's network area is in Bluff. The

pricing region of EIL's network in terms of both km^2 and the number of connections is relatively small as compared with price regions on a number of other networks.

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.

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 group customers. Load control can be utilised to keep charges down by: (1) minimising Transpower charges by controlling the network load during the LSI peaks; (2) managing GXP load when maximum demand reaches the capacity of that GXP; and (3) managing load on feeders during temporary arrangements to manage constraints.

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 will serve to refine and improve the signals of the previous day/night structure. Looking to the future, and the potential for developments such as electric vehicles, 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.

While EIL's network currently isn't facing capacity constraints, the potential for developments such as increased uptake of electric vehicles to bring network assets closer to capacity limits (especially on LV networks) means that a forward-looking approach to having pricing structures in place and understanding/developing the responsiveness of customers to price signals before they need to be relied upon has merit.

With regard to charges for individual customers, these 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 prices 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 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 and night periods through the use of night store heaters, heating the hot water or using their appliances such as clothes driers, washing machines etc. during this period. The customer is then financially rewarded, as the consumption does not attract any variable line charge. The "whole house TOU tariff" can reward consumers financially through prudent management of their power requirements.

EIL's peak demand component of the line charge provides a large reward to customers who invest in distribution alternatives.

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.

Encouraging efficient network alternatives

The locational 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. While geographic pricing isn't used by EIL for residential and general customers, the network is very compact such that there is unlikely to be significant impacts of this on decisions regarding network alternatives.

Signalling when the network is likely to be at its busiest or when capacity is available provides signals on when network alternatives can aid in meeting peak loads or in smoothing peaks through load shifting. TOU pricing will assist 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 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.

5.2 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). These types of charges would have less distortionary impacts in recovering sunk costs than kWh or demand charges would, but are 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 as a result of the Low Fixed Charge Regulations, as well as fairness considerations.

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 (as discussed in section 2.3) likely means that there will be limited adverse consequences from variable 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.

5.3 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 9, 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.

EIL's pricing model for large individual consumers ensures that the price is cost reflective and takes into consideration a distance factor from the customer's premises to the local zone substation, thus relating their line charges to the assets used for their supply. The closer to the zone substation the lower the distribution cost component. This component also allows for the shared use of those assets.

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

Each zone substation has individual costs allocated to it based on the substation assets and the share of the use of the subtransmission network as determined by load flow analysis. These individual zone substation costs are allocated to the individual consumers based on their respective load profiles and share of the use of the zone substation.

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 with 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.

Each year EIL conducts a customer survey of 400 residential and commercial customers. Customers are asked if they would pay an extra $10 per month in their line charge to reduce the number of outages they experienced each year, 82% stated no to this question.

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

EIL's current price structure has been in place since 1996 and has only seen changes to tariff options in response to customer demand or legislative requirements such as the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.

Through the disclosure of the line 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.

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 tariff for the majority of customers. EIL recognises that whilst the pricing structure is simple, there is a number of options with 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 location of the premises to be supplied (governs the assets used), 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 (eg, 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 does incorporate structural changes and as a result, consumer impacts of the change in price levels have been predicted with thorough analysis.

5.5 Revenue Requirement for the Year Ended 31 March 2022

The following table lists the revenue allowances as per the Commission's Electricity Distribution Services Default Price-Quality Path Determination 2021.

The Determination is based on a variety of Input Methodologies that determines the inputs into the calculation of the Weighted Average Cost of Capital (WACC) used in the Commissions price reset calculations.

The inputs have concernedly resulted in lower price reset outcomes. The inputs include out of date market risk premiums (2016) and narrow time bands for calculations of interest costs used in the WACC calculation and in the reset calculation non-independent use of inflation assumptions from parties with vested interests in a mid-range inflation outcome.

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.

The use of inputs that are more current and independent results in a higher Allowable Revenue outcome than that calculated by the Commission as outlined in the table below.

Forecast allowable revenue RY23 ($000)	
Forecast net allowable revenue	12,750
Forecast pass through costs	222
Forecast recoverable costs	5,869
Opening wash-up account balance	-
Wash-up Amount	($24)
Total	18,817

Pass-through costs are made up of:

Forecast Pass-through Costs RY23 ($000)	
Rates on system fixed assets	131
Commerce Act levies	27
Electricity Authority levies	53
Utilities Disputes levies	11
Total forecast pass-through costs	**222**

Recoverable costs are made up of:

Forecast Recoverable Costs RY22 ($000)	
IRIS incentive adjustment	214
Transpower transmission charges	5,425
New investment contract charges	337
Quality incentive adjustment	8
Capex wash-up adjustment	(134)

Fire and emergency NZ levies	19
Innovation project allowance	-
Total forecast recoverable costs	**5,869**

6. METHOD FOR COST ALLOCATION

6.1 Allocations

EIL uses a cost of supply model which uses a number of key inputs or cost drivers which can be determined and appropriately allocated between the relevant consumers and consumer groups.

The key cost drivers used within this model are:

- Transmission Grid Asset Management costs (Connection and Interconnection costs)
- Subtransmission network costs split into a "supply" component and a "maintenance" component – 66,000 and 33,000V line and cables and 4 zone substations.
- Distribution network costs split into a "supply" component and a "maintenance" component - 11,000, 400V networks and distribution Substations.
- Overhead non asset related direct costs.
- Ownership costs comprising depreciation return on investment and other costs of ownership.
- Pass Through Costs

Each consumer or consumer groups' share of the use of the above assets and costs are then calculated to reflect their respective use. The objective is to reflect the share of the costs in a robust and equitable manner and the line charges be structured so that the network investment and line charges are responsive to the consumer and consumer groups' behavior or pattern of usage.

6.2 Customer Profiles

The derivation of the line charges is based on seven consumer profile parameters. They are:

- The Contract Capacity kVA (kW) of the installation
- The Winter Peak demand kVA (kW) (0700-1100 hours and 1700-2100 hours, each weekday between May and September inclusive)
- The Winter Peak energy MWh (0700-1100 hours and 1700-2100 hours, each weekday between May and September inclusive)
- The Winter Day energy MWh (0700-2300 hours, May to September inclusive)
- The Summer Day energy MWh (0700-2300 hours, October to April inclusive)
- The Total energy for the 12 month period MWh.

- Coincident Peak demand with Transpower's 100 highest peaks for the lower South Island (kVA), half hour metered customers only

6.3 Transpower and Subtransmission costs

The basis of allocation of Transpower and subtransmission costs is on the after diversity maximum demand for each customer during the periods of network maximum demand. Similarly the allocation of the distribution costs is on an after diversity distribution capacity of the customer's installation.

The EIL methodology takes into account the duration that the customer impacts on the peak loading hours of the network. This is achieved by allocating some of the Transmission, subtransmission and distribution costs based on the Winter Peak energy and the Winter Day energy.

This in effect reduces the charges for a customer who incurs just one half hour peak for the whole winter or is only impacting on the peak hours for part of the winter and increases the charges for those customers who are impacting regularly on the peak periods during the whole winter.

It has the effect of integrating the peak demand over a longer period.

6.4 Winter Peak

The Winter Peak demands for the various customers and customer groups have a diversity factor applied to them, which reflects to some extent their impact on the total after diversity maximum demand on the network. These diversity factors, based on their peak demands, are as follows:

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%.

These diversity factors reflect the increased diversity of a large number of smaller customers compared to less diversity for the larger customers.

6.5 Contract Capacities

Similarly diversity factors are applied to the contract capacities of the various customers. These diversity factors are as follows:

- 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 the smaller customers than with the large customers with respect to the capital investment in the local distribution network.

6.6 Subtransmission and Distribution split

The costs of the subtransmission and distribution components of the line charges are split into two categories:

6.6.1 Supply

The "supply" part is based on the depreciation of the network assets, other ownership costs and required return on the assets, the latter using the companies weighted average cost of capital.

6.6.2 Maintenance

The "maintenance" part is based on the Maintenance Works Programme for the current year.

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

The profile parameters for determining the line charges for the individual customers, grouped by capacity are:

Contract Capacity kVA	Number of Connections	Coincident Peak Demand Reading kVA	Peak Demand Reading kVA	Total Energy Reading MWh	Peak Reading MWh	Winter Day Reading MWh	Summer Day Reading MWh
30	2	22	32	104	15	41	43
50	5	45	178	423	60	138	169
75	9	125	479	1,103	148	390	458
100	13	309	769	1,801	243	631	749
150	40	944	3,767	7,004	1,081	2,595	2,819
200	39	1,493	3,988	10,023	1,386	3,457	4,181
300	29	2,288	4,649	11,910	1,613	4,139	4,893
500	26	4,206	6,708	21,890	2,815	7,291	8,804
750	9	1,311	1,990	8,187	910	2,466	3,128
1000	3	687	1,132	4,286	524	1,255	1,570
1250	1	190	218	380	60	125	175
1750	1	1,040	1,827	7,349	767	2,071	2,856

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

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							
Residential (8kVA 1 Phase) - All Peak *	ND08P	35	37	56	226	42	93
Residential (8kVA 1 Phase) - With Off Peak *	ND08Q	88	91	113	539	75	200
Standard Residential (15kVA 1 Phase) - All Peak	ND20P	1,114	1,268	3,728	15,089	2,801	6,236
Standard Residential (15kVA 1 Phase) - With Off Peak	ND20Q	7,459	7,690	19,138	91,133	12,689	33,898
Residential Low User (15kVA 1 Phase) - All Peak	NDL20P	764	21	3,119	6,297	1,169	2,602
Residential Low User (15kVA 1 Phase) - With Off Peak	NDL20Q	5,382	100	12,508	29,605	4,122	11,012
Residential Low User (8kVA 1 Phase) - All Peak*	NDL08P	22	1,058	45	161	30	66
Residential Low User (8kVA 1 Phase) - With Off Peak*	NDL08Q	104	5,146	162	685	95	255
General Single Phase							
Street Lights (1 Phase) per street light	NS001L	5,604	719	2,281	423	943	849
1 kVA 1 Phase - All Peak	NS001P	44	46	433	80	179	161
8 kVA 1 Phase - All Peak	NS008P	183	268	1,083	201	448	403
8 kVA 1 Phase - With Off Peak	NS008Q	9	10	48	7	18	17

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 1 Phase - All Peak	NS020P	269	824	3,335	619	1,378	1,241
15 kVA 1 Phase - With Off Peak	NS020Q	82	196	931	130	346	340
General Three Phase							
15 kVA 3 Phase - All Peak	NT015P	66	183	741	137	306	276
15 kVA 3 Phase - With Off Peak	NT015Q	5	12	58	8	22	21
30 kVA 3 Phase - All Peak	NT030P	513	3,226	9,287	1,724	3,838	3,456
30 kVA 3 Phase - With Off Peak	NT030Q	114	603	2,042	284	759	745
50 kVA 3 Phase - All Peak	NT050P	308	3,946	14,198	2,636	5,868	5,284
50 kVA 3 Phase - With Off Peak	NT050Q	65	719	3,042	424	1,132	1,110
75 kVA 3 Phase - All Peak	NT075P	118	2,851	8,207	1,524	3,392	3,055
75 kVA 3 Phase - With Off Peak	NT075Q	14	281	952	133	354	347
100 kVA 3 Phase - All Peak	NT100P	70	2,615	7,526	1,397	3,110	2,801
100 kVA 3 Phase - With Off Peak	NT100Q	7	247	836	116	311	305

7. COST ALLOCATIONS TO CAPACITY GROUPS

This section describes the cost allocations to each capacity group and individual customers using the methodology described above.

7.1 Transmission Charges

Transmission charges reflect the Transpower grid asset management costs incurred by EIL based on the Invercargill point of supply.

Transpower transmission charges have two components:

(a) Connection charge

(b) Interconnection charge

7.1.1 Connection Charge

The Transpower connection charge is based on the Transpower local assets utilised to provide the supply.

In the case of the Invercargill point of supply the connection charge is split between TPCL and EIL, each network is connected to the transmission grid there.

The total connection charge for Invercargill is $1,021,670. EIL's share is of the connection charge is $590,783.

The connection charges which include the Transpower new investment charges are applied to customers on the basis of the following allocation:

Winter Peak Demand 70%

Winter Peak Energy 20%

Winter Day Energy 10%

For individual customers this equates to:

$6.53 per kVA Peak Demand.

$2.90 per Winter Peak MWh.

$0.96 per Winter Day MWh

After the revenue from the individual customers has been subtracted from the total the remaining residential and group customer charges are as follows:

- $6.27 per kVA Peak Demand
- $3.24 per Winter Peak MWh
- $1.09 per Winter Day MWh

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

7.1.2 Interconnection Charge

This charge is based on the average of the coincident 100 highest peak demands recorded for Transpower's lower South Island region during the assessment period 1 September to 31 August each year at the Invercargill grid exit point.

EIL's share of the Invercargill interconnection charge of $8,543,470 is $5,170,951

The interconnection charges are applied to customers on the basis of the following allocation:

Half Hour Metered:

Coincident peak with lower south island region 100%

Non Half Hour Metered:

Winter Peak Demand 60%

Winter Peak Energy 30%

Winter Day Energy 10%

For individual non half hour metered customers this equates to the following charges:

$48.98 per kVA Winter Peak Demand.

$39.23 per Winter Peak MWh.

$8.68 per Winter Day MWh.

For individual Half Hour Metered customers this equates to the following charges:

Point of Supply	Per kVA Coincident Peak Demand
Invercargill	$96.89

After the revenue from the individual customers has been subtracted from the total the remaining group customer charges are as follows:

	Per kVA Peak Demand	Per Winter Peak MWh	Per Winter Day MWh
Electricity Invercargill	$44.07	$39.82	$8.91

The differences in the above rates reflect the differences in losses and diversity factors between the large individual customers and the small customer groups.

7.1.3 Transpower Revenue for Individual Customers

The total Transpower revenue for individual customers grouped by capacity is shown in the following table:

Consumer Capacity kVA	Number of Connections	Transpower Revenue per Consumer Group	Average Line Charge
30	2	$2,211.03	$1,105.51
50	5	$7,339.67	$1,467.93
75	9	$18,657.57	$2,073.06
100	13	$37,470.80	$2,882.37
150	40	$158,565.95	$3,964.15
200	39	$198,314.23	$5,084.98
300	29	$257,265.16	$8,871.21
500	26	$439,525.07	$16,904.81
750	9	$136,802.06	$15,200.23
1000	3	$71,638.85	$23,879.62
1250	1	$19,229.63	$19,229.63
1750	1	$113,073.97	$113,073.97

7.1.4 Transpower Revenue for Residential and General Customers

The total Transpower revenue for residential and general customers is shown in the following table.

Consumer Capacity	Code	Number of Connections	Transpower Charge	Transpower Revenue per Consumer Group
Residential				
Residential (8kVA 1 Phase) - All Peak *	ND08P	37	$128.11	$4,740.21
Residential (8kVA 1 Phase) - With Off Peak *	ND08Q	90.5	$106.60	$9,647.23
Standard Residential (15kVA 1 Phase) - All Peak	ND20P	1268	$256.23	$324,896.51
Standard Residential (15kVA 1 Phase) - With Off Peak	ND20Q	7690	$213.20	$1,639,496.07
Residential Low User (15kVA 1 Phase) - All Peak	NDL20P	1057.5	$197.77	$209,664.60
Residential Low User (15kVA 1 Phase) - With Off Peak	NDL20Q	5145.5	$165.83	$854,090.97
Residential Low User (8kVA 1 Phase) - All Peak*	NDL08P	21	$121.68	$2,555.19
Residential Low User (8kVA 1 Phase) - With Off Peak*	NDL08Q	99.5	$101.38	$10,087.52
General Single Phase				
Street Lights (1 Phase) per street light	NS001L	5604	$9.95	$55,768.04
1 kVA 1 Phase - All Peak	NS001P	43.5	$148.12	$6,443.33

Consumer Capacity	Code	Number of Connections	Transpower Charge	Transpower Revenue per Consumer Group
8 kVA 1 Phase - All Peak	NS008P	183	$128.11	$23,444.82
8 kVA 1 Phase - With Off Peak	NS008Q	8.5	$106.60	$906.09
15 kVA 1 Phase - All Peak	NS020P	268.5	$256.23	$68,797.09
15 kVA 1 Phase - With Off Peak	NS020Q	81.5	$213.20	$17,375.67
General Three Phase				
15 kVA 3 Phase - All Peak	NT015P	66	$240.21	$15,854.08
15 kVA 3 Phase - With Off Peak	NT015Q	4.5	$199.87	$899.43
30 kVA 3 Phase - All Peak	NT030P	512.5	$474.24	$243,050.32
30 kVA 3 Phase - With Off Peak	NT030Q	113.5	$396.15	$44,963.15
50 kVA 3 Phase - All Peak	NT050P	308	$1,069.59	$329,433.11
50 kVA 3 Phase - With Off Peak	NT050Q	65	$891.20	$57,927.86
75 kVA 3 Phase - All Peak	NT075P	118	$1,822.24	$215,024.20
75 kVA 3 Phase - With Off Peak	NT075Q	13.5	$1,522.17	$20,549.33
100 kVA 3 Phase - All Peak	NT100P	70	$2,901.23	$203,085.97
100 kVA 3 Phase - With Off Peak	NT100Q	7	$2,423.49	$16,964.40

7.2 Subtransmission Charges

Subtransmission charges are based on the subtransmission costs (66kV and 33kV network) and the zone substation costs.

There are two components making up the subtransmission charges:

(a) Supply charge

(b) Maintenance charge

7.2.1 Supply Charge

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

All the costs of the subtransmission 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 $1,018,333 and for the 33kV line and cables is $509,167 giving a total supply charge for EIL City of $1,527,500

As EIL also supplies power to Bluff through TPCL 33kV line and Bluff zone substation there is a supply charge of $449,724 for this zone substation and subtransmission lines.

The supply charge totaling $1,527,500 for EIL City and $49,724 for EIL Bluff is allocated across all customers on the following basis:

Winter Peak Demand	70%
Winter Peak energy	20%
Winter Day energy	10%

7.2.2 Maintenance Charge

The maintenance charges for the EIL city zone substations and subtransmission system total $368,604 and for EIL Bluff total $77,464

The total subtransmission maintenance charges of $446,068 are allocated across the customers on the following basis:

Total Energy	50%
Winter Peak Demand	50%

7.2.3 Subtransmission Charges for Individual Customers above 100 kVA

EIL City

(a)	Subtransmission Supply charge	$18.05 per kVA Winter Peak Demand
(b)	Subtransmission Supply charge	$8.29 per Winter Peak MWh
(c)	Subtransmission Supply charge	$2.76 per Winter Day MWh
(e)	Subtransmission Maintenance charge	$0.75 per Commercial Total MWh
(f)	Subtransmission Maintenance charge	$3.11 per kVA Winter Peak Demand

EIL Bluff

(a)	Subtransmission Supply charge	$66.17 per kVA Winter Peak Demand
(b)	Subtransmission Supply charge	$36.74 per Winter Peak MWh
(c)	Subtransmission Supply charge	$9.18 per Winter Day MWh
(e)	Subtransmission Maintenance charge	$1.83 per Commercial Total MWh
(f)	Subtransmission Maintenance charge	$9.14 per kVA Winter Peak Demand

7.2.4 Subtransmission Charges for Residential and General Customers

After the revenue from the individual customers has been subtracted from the total the remaining Residential and General Customer charges are as follows:

EIL City

(a)	Subtransmission Supply charge	$17.41 per kVA Winter Peak Demand
(b)	Subtransmission Supply charge	$8.98 per Winter Peak MWh
(c)	Subtransmission Supply charge	$3.01 per Winter Day MWh
(d)	Subtransmission Maintenance charge	$0.78 per Residential Total MWh
(e)	Subtransmission Maintenance charge	$0.78 per Commercial Total MWh
(f)	Subtransmission Maintenance charge	$2.91 per kVA Winter Peak Demand

EIL Bluff

(a)	Subtransmission Supply charge	$83.40 per kVA Winter Peak Demand
(b)	Subtransmission Supply charge	$36.24 per Winter Peak MWh
(c)	Subtransmission Supply charge	$11.87 per Winter Day MWh
(d)	Subtransmission Maintenance charge	$1.89 per Residential Total MWh
(e)	Subtransmission Maintenance charge	$1.89 per Commercial Total MWh
(f)	Subtransmission Maintenance charge	$8.68 per kVA Winter Peak Demand

7.3 Distribution Charges

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.

7.3.1 Supply Charge

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

All the costs of the distribution network are averaged and the supply charge is allocated on the basis of the relative asset value compared to the total network asset value.

The supply charges are as follows:

(a) Overhead lines, Underground Cables and Distribution Substations

EIL City	$5,855,415
EIL Bluff	$254,583

(b) The supply charge is allocated across all customers on the following basis:

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

7.3.2 Maintenance Charge

The maintenance charges are as follows:

(a) Overhead lines, Underground Cables and Distribution Substations

EIL City	$1,105,812
EIL Bluff	$174,602

(b) The maintenance portion is allocated across all customers on the following basis:

Total Energy	50%
Contract Capacity	50%

7.3.3 Distribution Transformers

The transformer charges are as follows:

EIL Supply	$848,611
EIL Maintenance	$291,003

The transformer portion of the distribution charges is allocated across consumers on the following basis:

Number of transformers and transformer capacity 100%.

7.3.4 Distribution Charges for Individual Customers

EIL City

(a)	Distribution Supply charge	$31,77 per kVA Contract Capacity
(b)	Distribution Supply charge	$31.78 per Winter Peak MWh
(c)	Distribution Supply charge	$6.35 per Winter Day MWh
(d)	Distribution Maintenance charge	$2.26 per Commercial Total MWh
(e)	Distribution Maintenance charge	$4.29 per kVA Contract Capacity

EIL Bluff

(a)	Distribution Supply charge	$19.80 per kVA Contract Capacity
(b)	Distribution Supply charge	$18.94 per Winter Peak MWh
(c)	Distribution Supply charge	$3.66 per Winter Day MWh
(d)	Distribution Maintenance charge	$3.64 per Commercial Total MWh
(e)	Distribution Maintenance charge	$9.70 per kVA Contract Capacity

Transformer Charges

(a)	Distribution Transformer supply charge	$346.13 per Transformer
(b)	Distribution Transformer maintenance charge	$662.88 per Transformer

The Transformer charge of $346.13 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	1.00
30kVA Transformer	1.44
50kVA Transformer	1.88
75kVA Transformer	2.30
100kVA Transformer	3.00
150kVA Transformer	4.04
200kVA Transformer	4.60
300kVA Transformer	5.32
500kVA Transformer	7.40
750kVA Transformer	8.80
1,000kVA Transformer	9.96
1,250kVA Transformer	13.20
1,500kVA Transformer	15.60

7.3.5 Distribution Charges for Residential and General Customers

After the revenue from the individual customers has been subtracted from the total the remaining residential and general customer charges are as follows:

EIL City

(a)	Distribution Supply charge	$32.86 per kVA Contract Capacity
(b)	Distribution Supply charge	$37.47 per Winter Peak MWh
(c)	Distribution Supply charge	$12.58 per Winter Day MWh
(d)	Distribution Maintenance charge	$2.67 per Residential Total MWh
(e)	Distribution Maintenance charge	$2.67 per Commercial Total MWh
(f)	Distribution Maintenance charge	$4.32 per kVA Contract Capacity
(g)	Distribution Transformer charge	$6.28 per kVA Contract Capacity

EIL Bluff

(a)	Distribution Supply charge	$25.53 per kVA Contract Capacity
(b)	Distribution Supply charge	$27.24 per Winter Peak MWh
(c)	Distribution Supply charge	$9.26 per Winter Day MWh
(d)	Distribution Maintenance charge	$6.93 per Residential Total MWh
(e)	Distribution Maintenance charge	$6.93 per Commercial Total MWh
(f)	Distribution Maintenance charge	$11.82 per kVA Contract Capacity
(g)	Distribution Transformer charge	$6.28 per kVA Contract Capacity

The model applies a 2.5% discount for the residential and single phase general customers compared to three phase general customers of similar size. This is to reflect the reduced investment in network assets for single phase customers.

7.4 Non asset related Overheads

The overhead charges are based on those costs which cannot be allocated directly to either capital or maintenance.

These costs include the following:

(a) Executive Management

(b) Directors Fees

(c) System Control

(d) Miscellaneous overheads, e.g. buildings, etc.

These charges are split equally over the total customer base.

The total overhead costs are $1,892,092

The charge per customer is $108.39

7.5 EIL Charges

7.5.1 EIL Revenue for Individual Customers

The total EIL revenue for individual customers grouped by capacity is shown in the following table.

Consumer Capacity kVA	Subtransmission Charge	Distribution Charge	Overhead Charge	Total EIL Charge
15	$0.00	$0.00	$0.00	$0.00
30	$416.91	$2,133.81	$216.78	$2,767.50
50	$1,862.44	$8,626.43	$541.96	$11,030.83
75	$5,418.97	$23,583.97	$975.53	$29,978.47
100	$10,536.47	$32,328.33	$1,409.10	$44,273.90
150	$66,566.11	$148,187.03	$4,335.68	$219,088.82
200	$65,060.02	$198,119.96	$4,227.29	$267,407.26
300	$71,996.81	$209,530.02	$3,143.37	$284,670.20
500	$140,997.27	$324,383.95	$2,818.19	$468,199.42
750	$35,645.64	$145,499.80	$867.14	$182,012.58
1000	$18,621.76	$80,575.40	$325.18	$99,522.34
1250	$2,810.83	$25,907.83	$108.39	$28,827.05
1750	$153,171.80	$56,082.60	$108.39	$209,362.79

7.5.2 EIL Revenue for Residential and General Customers

The total EIL revenue for residential and general customers is shown in the following table.

Consumer Capacity	Code	Number of Connections	Subtransmission Charge	Distribution Charge	Overheads	Total EIL Revenue
Residential						
Residential (8kVA 1 Phase) - All Peak *	ND08P	37	$2,120	$7,867	$4,011	$13,998
Residential (8kVA 1 Phase) - With Off Peak *	ND08Q	91	$4,156	$16,457	$9,809	$30,422
Standard Residential (15kVA 1 Phase) - All Peak	ND20P	1,268	$135,536	$538,572	$137,441	$811,549
Standard Residential (15kVA 1 Phase) - With Off Peak	ND20Q	7,690	$696,395	$2,795,874	$833,535	$4,325,804
Residential Low User (15kVA 1 Phase) - All Peak	NDL20P	1,058	$93,002	$374,778	$114,625	$582,405
Residential Low User (15kVA 1 Phase) - With Off Peak	NDL20Q	5,146	$351,446	$1,553,564	$557,731	$2,462,741
Residential Low User (8kVA 1 Phase) - All Peak*	NDL08P	21	$2,453	$4,380	$2,276	$9,109
Residential Low User (8kVA 1 Phase) - With Off Peak*	NDL08Q	100	$8,119	$17,756	$10,785	$36,660
General Single Phase						
Street Lights (1 Phase) per street light	NS001L	5,604	$24,617	$99,014	$217	$123,848
1 kVA 1 Phase - All Peak	NS001P	44	$2,457	$7,028	$4,715	$14,200
8 kVA 1 Phase - All Peak	NS008P	183	$9,642	$38,855	$19,836	$68,332
8 kVA 1 Phase - With Off Peak	NS008Q	9	$332	$1,540	$921	$2,794

Consumer Capacity	Code	Number of Connections	Subtransmission Charge	Distribution Charge	Overheads	Total EIL Revenue
15 kVA 1 Phase - All Peak	NS020P	269	$32,288	$114,279	$29,103	$175,670
15 kVA 1 Phase - With Off Peak	NS020Q	82	$6,622	$29,557	$8,834	$45,013
General Three Phase						
15 kVA 3 Phase - All Peak	NT015P	66	$6,725	$26,288	$7,154	$40,167
15 kVA 3 Phase - With Off Peak	NT015Q	5	$561	$1,551	$488	$2,600
30 kVA 3 Phase - All Peak	NT030P	513	$105,766	$393,152	$55,551	$554,469
30 kVA 3 Phase - With Off Peak	NT030Q	114	$19,631	$74,440	$12,303	$106,373
50 kVA 3 Phase - All Peak	NT050P	308	$135,293	$475,285	$33,385	$643,963
50 kVA 3 Phase - With Off Peak	NT050Q	65	$25,557	$86,010	$7,045	$118,613
75 kVA 3 Phase - All Peak	NT075P	118	$93,274	$288,321	$12,790	$394,385
75 kVA 3 Phase - With Off Peak	NT075Q	14	$9,496	$28,277	$1,463	$39,236
100 kVA 3 Phase - All Peak	NT100P	70	$80,716	$198,667	$7,587	$286,971
100 kVA 3 Phase - With Off Peak	NT100Q	7	$9,243	$17,220	$759	$27,221

7.6 Pass-Through Costs

Pass-through costs are costs relating to rates on network fixed assets charged to EIL by local authorities and industry levies imposed by the Commerce Act, the Authority and the Utilities Disputes. These are deducted or added from the estimated pass-through costs is the pass-through balance, from the previous year.

The total estimated Pass-through costs for 2022-23 are $197,881

Pass-through costs are recovered by $11.34 per ICP

7.6.1 Recoverable costs

Recoverable costs (excluding transmission costs) recover 3 components

- Quality Incentive Scheme – an adjustment either positive or negative is allocated to EIL based on the previous years' performance against the networks target SAIDIs and SAIFIs, for the 2022 -23 year this adjustment is $7,957.

- IRIS incentive adjustment – an additional recoverable cost has been allocated to EIL due to the amount of opex and capex completed over the previous regulatory control period. For the 2022-23 year EIL will under recover $213,800.

- Capex wash-up – is a recoverable cost has been allocated to EIL due to the amount of capex completed, for the 2022-23 year this adjustment is -$134,472.

- Fire Emergency New Zealand is a new recoverable cost introduced by the Commission to allow future increases and decreases to be shared with customers. For the 2022 -23 year the allowance is $19,969.

The total recoverable costs amounts to $107,254, this is allocated to the customer groups on the same methodology basis as the supply costs of the subtransmission and distribution costs outlined in section 7.2.1 and 7.3.1 above

7.7 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.

7.7.1 Line Charge Revenue for Individual Customers

The line charge revenue for individual customers grouped by capacity is shown in the following table.

Consumer Capacity kVA	Number of Connections	Line Charge Revenue per Consumer Group	Average Line Charge
30	2	$5,026	$2,513
50	5	$18,531	$3,706
75	9	$49,025	$5,447
100	13	$82,316	$6,332
150	40	$380,232	$9,506
200	39	$468,766	$12,020
300	29	$545,048	$18,795
500	26	$912,621	$35,101
750	9	$320,697	$35,633
1000	3	$172,176	$57,392
1250	1	$48,352	$48,352
1750	1	$324,517.36	$324,517

7.7.2 Line Charge Revenue for Residential and General Customers

The line charge revenue for residential and general customers is shown in the following table.

Consumer Capacity	Code	Number of Connections	Line Charge Revenue per Consumer Group
Residential			
Residential (8kVA 1 Phase) - All Peak *	ND08P	37	$19,256
Residential (8kVA 1 Phase) - With Off Peak *	ND08Q	91	$41,299
Standard Residential (15kVA 1 Phase) - All Peak	ND20P	1,268	$1,157,486
Standard Residential (15kVA 1 Phase) - With Off Peak	ND20Q	7,690	$6,087,008
Residential Low User (15kVA 1 Phase) - All Peak	NDL20P	1,058	$808,584
Residential Low User (15kVA 1 Phase) - With Off Peak	NDL20Q	5,146	$3,393,917
Residential Low User (8kVA 1 Phase) - All Peak*	NDL08P	21	$11,970
Residential Low User (8kVA 1 Phase) - With Off Peak*	NDL08Q	100	$48,132
			Group
General Single Phase			

Consumer Capacity	Code	Number of Connections	Line Charge Revenue per Consumer
Street Lights (1 Phase) per street light	NS001L	5,604	$180,861
1 kVA 1 Phase - All Peak	NS001P	44	$21,470
8 kVA 1 Phase - All Peak	NS008P	183	$94,331
8 kVA 1 Phase - With Off Peak	NS008Q	9	$3,815
15 kVA 1 Phase - All Peak	NS020P	269	$248,961
15 kVA 1 Phase - With Off Peak	NS020Q	82	$63,670
General Three Phase			
15 kVA 3 Phase - All Peak	NT015P	66	$57,095
15 kVA 3 Phase - With Off Peak	NT015Q	5	$3,940
30 kVA 3 Phase - All Peak	NT030P	513	$809,033
30 kVA 3 Phase - With Off Peak	NT030Q	114	$154,216
50 kVA 3 Phase - All Peak	NT050P	308	$982,925
50 kVA 3 Phase - With Off Peak	NT050Q	65	$178,381
75 kVA 3 Phase - All Peak	NT075P	118	$614,520
75 kVA 3 Phase - With Off Peak	NT075Q	14	$62,472
100 kVA 3 Phase - All Peak	NT100P	70	$493,613
100 kVA 3 Phase - With Off Peak	NT100Q	7	$44,527

8. HOW FIXED AND VARIABLE PRICES ARE SET

Individual Customers

The total line charge is split into fixed charges and variable charges. The fixed/variable split is approximately 50:50.

For the individual line charge installations with half hour metering the total line charge is halved 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 $0.06711 per Peak kWh, $0.05600 per Shoulder kWh and $0.0100 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.

Residential and General Customers

This year we have introduced installed capacity and TOU variable pricing for the Residential and General customers.

The introduction of TOU variable pricing is a way to move to more cost reflective and service based pricing and is a way of encouraging efficient network use and investment, for the long term benefit of our customers. By efficient use of the network, we mean increasing the use of the network within its existing capacity, including by shifting load outside of peak periods, and incentivising new load to also go onto the network outside of peak periods. More energy delivered across the network without incurring costly upgrades means lower cost per unit of energy delivered for all of us.

TOU pricing periods are:

Peak period, which is defined as 7am to 11am and 5pm to 9pm.

Shoulder period, which is defined as 11am to 5pm and 9pm to 11pm.

Night period 11pm to 7am.

TOU enables us to increase prices at times when there is congestion on the network, and reduce them at times when there is plenty of capacity. This sends a price signal to transfer load outside of congestion periods, and incentivises growth in consumption at times when there is no incremental cost for us to deliver the additional energy.

The application of fixed and variable charges is an application of the line charge to the end-use consumer. The objectives behind the fixed and variable charges are as follows:

- Variable line charge is a compromise between a totally fixed charge that would benefit the large consumer within a load group, and a totally variable charge that would benefit the small consumer within a load group.
- As stated above, the fixed and variable charge allows the larger consumer in a load group to pay more which reflects to some extent their reduced diversity on the maximum demands seen at subtransmission and transmission level. Although the distribution network in the vicinity of the premises has to have enough capacity to supply the full capacity of the installation, the remainder of the network is designed to take into account the diversity between consumer demands. As a

general rule, the less energy a consumer uses, the greater the diversity, hence the less capital investment required to supply. A totally fixed line charge does not take this into account so there would need to be more load sub-groups such as very small, small, medium, large and very large domestic consumers besides the existing All Peak and With Off Peak categories.

- It is important to note that the variable charge is cheaper during, Shoulder and Night time periods, so residential consumers with large night loads, such as storage or water heating, do not pay extra as this consumption is utilising network assets, the capacity of which is designed on the basis of and costs recovered by the peak load in daytime hours. This encourages better utilisation of the network and less capital investment.

- It is a means whereby the line owner can share the risk of climatic variations and be responsive to changes in the local economy. It has been well received in the commercial market that when a consumer has a production downturn or invests in energy conservation measures, there is an immediate response through a reduction in the variable charges.

- Consumers also have the opportunity to shift load to night time to receive immediate benefits.

- If a consumer is expanding its business, the variable charges mean that the line owner can receive some immediate extra revenue and it can also cushion the increase in line charges for the following year.

- The practical application of a variable component of the line charge for the Residential and General resulted in a necessity for a uniform variable charge and individual fixed charges for each segment. EIL uses the 'GXP billing" approach for the Residential and General customers, where, variable charges are based on electricity volumes measured at the Transpower grid exit points. Quantities are determined by the wholesale electricity market reconciliation process with adjustments for embedded networks and individual customer quantities.

9. 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.

9.1 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.

10. 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. Currently there is no large scale Distributed Generation connected to the network.

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 electricity 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.

10.1 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 the electricity network are:

Transaction Types	Capacity
Normal off take Line Charge **(paid by the Distributed Generator to PowerNet)**	All capacities
Capital Contribution **(paid by the Distributed Generator to PowerNet)**	All capacities where incremental costs are incurred by the network
New Investment Agreement charge **(paid by the Distributed Generator to PowerNet)**	For capacities > 500kW
Recovery of High Voltage Direct Current (HVDC) Transmission Charges **(paid by the Distributed Generator to PowerNet)**	Where the Distributed Generation is injected into the Transmission Network
Avoided Transmission Charges **(paid by PowerNet to the Distributed Generator)**	Where the Distributed Generation reduces Interconnection Charges at peak times

10.2 Capital Contributions

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

10.3 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.

10.4 HVDC Transmission Charges

HVDC Transmission Charges are recovered from Distributed Generators based on their share of the injection demand into the Transmission Network at the grid exit point they inject into.

10.5 Avoided Transmission Charge revenue

Avoided Transmission Charge revenue is allocated to Distributed Generators based on their generation demand injected into the network coincident with Transpower's top 100 demand peaks for the lower South Island, under the TPM, for the period 1 September to 31 August.

The Transpower interconnection charge is then applied over the period 1 April to 31 March. This lag can result in a one year delay in the allocation of revenue to Distributed Generators.

The revenue paid to Distributed Generators is based on the annual interconnection rate set by Transpower under the TPM. The Avoided Transmission Charge revenue allocation to Distributed Generators is subject to change in the TPM. Currently there are no Distributed Generators receiving this payment.

Avoided Transmission Charge payments are only paid to Distributed Generators who the Authority determines are necessary to enable Transpower to meet the grid reliability standards under Schedule 6.4 of the Electricity Industry Participation Code (Code) or have a connection agreement with Electricity Invercargill Limited for such payments. Distributed Generators must also be submitting full half hour metered export consumption data to the network on a monthly basis to be eligible for payments.

10.6 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).

The introduction of a zero-price export price will ensure that retailers provide export kWh volumes for all small-scale DG connections (ie, solar).

APPENDIX 1: COMMERCE COMMISSION INFORMATION DISCLOSURE REQUIREMENTS

In the below table we describe the relevant sections of this methodology where we demonstrate compliance with the key sections of the Commission's Electricity Distribution Information Disclosure Determination 2012 requirements:

IDD Section	Key sections of methodology demonstrating compliance
2.4.1 (1)	Sections 3, 5-9
2.4.1 (2)	Section 3.2
2.4.1 (3)	Sections 9 & 10
2.4.1 (4)	Section 3.3
2.4.2	No changes to the methodology
2.4.3 (1)	Section 6
2.4.3 (2)	Section 4
2.4.3 (3)	Section 5
2.4.3 (4)	Section 5
2.4.3 (5) (a) , (b)	Section 3
2.4.3 (6)	Section 3.2
2.4.3 (7)	Sections 6 & 7
2.4.3 (8)	Appendix 2
2.4.4 (1-3)	Section 4
2.4.5 (1) (a) to (c)	Section 9
2.4.5 (2) (a) & (b)	Section 9
2.4.5 (3) (a) & (b)	Section 10

APPENDIX 2: LINE CHARGE TABLES

Line Charge Breakdown for Individual Customers

ICP Number	Contract Capacity kVA	Trans Power Charge	Subtransmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
880323NV-EBD	150	$9,599.46	$2,386.93	$5,418.61	$108.39	$88.52	$17,601.91	$8,800.95	$21.87
9003081NV-0FF	200	$2,326.03	$423.34	$4,407.79	$108.39	$59.11	$7,324.66	$3,662.33	$39.65
8803298NV-3CC	500	$18,779.45	$4,110.10	$11,508.33	$108.39	$165.78	$34,672.05	$17,336.03	$37.37
740649NV-C13	75	$1,754.73	$385.95	$2,439.63	$108.39	$39.28	$4,727.98	$2,363.99	$31.49
7446911NV-954	150	$10,138.64	$1,521.53	$3,585.30	$108.39	$61.84	$15,415.70	$7,707.85	$64.23
880327NV-FB7	300	$17,004.69	$4,185.48	$10,079.48	$108.39	$152.40	$31,530.44	$15,765.22	$20.47
836598NV-F14	150	$4,493.57	$1,457.13	$4,582.93	$108.39	$71.06	$10,713.09	($5,872.44)	$67.11
8102959NV-5D5	300	$12,246.59	$3,303.44	$7,879.74	$108.39	$121.92	$23,660.09	$11,830.04	$33.74
900350NV-C69	100	$3,565.20	$721.02	$2,439.43	$108.39	$42.59	$6,876.62	$3,438.31	$38.64
810201NV-DAD	150	$2,845.60	$590.08	$3,406.66	$108.39	$50.86	$7,001.59	$3,500.79	$42.23
734802NV-A50	150	$6,477.50	$1,317.99	$4,061.93	$108.39	$64.54	$12,030.35	$6,015.18	$36.31
734355NV-C9C	300	$1,938.55	$685.56	$5,442.76	$108.39	$71.94	$8,247.19	$5,445.47	$67.11
850948NV-9C2	30	$846.40	$189.25	$1,046.26	$108.39	$23.55	$2,213.85	$1,106.93	$26.35
900327NV-4FE	50	$2,172.28	$463.36	$2,163.98	$108.39	$37.32	$4,945.33	$2,472.67	$22.31
8803283NV-7B5	150	$8,590.95	$2,500.99	$5,034.84	$108.39	$85.86	$16,321.03	$8,160.52	$21.50
740385NV-DE7	200	$7,147.60	$1,734.62	$5,616.32	$108.39	$84.03	$14,690.96	$7,345.48	$21.99

ICP Number	Contract Capacity kVA	Trans Power Charge	Subtransmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
9003503NV-035	200	$5,445.65	$1,375.83	$5,130.29	$108.39	$75.67	$12,135.83	$6,067.92	$38.82
8509006NV-D55	150	$4,710.30	$1,164.54	$4,258.79	$108.39	$64.97	$10,306.99	$5,153.49	$19.99
880344NV-C87	300	$7,785.49	$2,608.92	$7,679.12	$108.39	$113.07	$18,294.99	($2,829.22)	$67.11
740896NV-23B	300	$10,396.96	$2,344.25	$6,806.56	$108.39	$101.83	$19,757.98	$9,878.99	$31.26
7559027NV-3C7	200	$8,329.33	$1,939.43	$5,714.80	$108.39	$87.03	$16,178.98	$8,089.49	$35.95
7433294NV-FC6	150	$3,713.37	$1,358.39	$3,102.17	$108.39	$55.45	$8,337.77	$5,618.59	$67.11
743331NV-CBF	150	$2,971.65	$945.12	$3,628.77	$108.39	$56.57	$7,710.50	$1,799.09	$67.11
900330NV-399	500	$32,965.03	$8,423.15	$17,811.74	$108.39	$270.77	$59,579.07	$29,789.54	$21.23
740373NV-C7F	200	$5,085.73	$1,038.14	$4,718.44	$108.39	$68.26	$11,018.97	$5,509.48	$42.28
721862NV-A61	30	$1,364.63	$227.66	$1,087.54	$108.39	$24.34	$2,812.56	$1,406.28	$33.60
8803601NV-E7B	150	$4,279.73	$1,523.68	$3,438.93	$108.39	$60.41	$9,411.14	$3,232.49	$67.11
734326NV-501	200	$3,166.12	$1,037.12	$4,695.67	$108.39	$68.03	$9,075.33	$3,144.09	$67.11
734325NV-9C1	150	$1,633.74	$584.63	$3,086.43	$108.39	$47.64	$5,460.83	$2,534.73	$67.11
7227954NV-421	100	$2,162.87	$764.57	$2,292.14	$108.39	$41.56	$5,369.53	$1,522.25	$67.11
734165NV-163	750	$14,681.20	$3,204.31	$16,016.71	$108.39	$201.41	$34,212.02	$17,106.01	$35.67
7344586NV-96L	500	$14,681.06	$3,204.03	$11,237.59	$108.39	$154.15	$29,385.22	$14,692.61	$30.67
8541431NV-DF3	150	$3,722.76	$1,368.01	$3,119.89	$108.39	$55.72	$8,374.77	$5,158.71	$67.11
722703NV-43B	200	$5,882.85	$1,414.41	$5,512.91	$108.39	$79.84	$12,998.39	$6,499.20	$24.14
90030815NV-060	500	$14,138.29	$3,372.40	$12,078.11	$108.39	$164.12	$29,861.31	$14,930.66	$29.39
734846NV-9FF	50	$544.04	$171.50	$1,245.12	$108.39	$25.34	$2,094.39	$1,581.98	$67.11

ICP Number	Contract Capacity kVA	Trans Power Charge	Subtransmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
900356NV-DE6	300	$3,289.85	$1,164.61	$5,816.47	$108.39	$80.37	$10,459.69	$2,644.21	$67.11
8665558NV-6AF	200	$3,847.22	$708.14	$4,533.24	$108.39	$63.17	$9,260.15	$4,630.08	$51.20
8803767NV-900	50	$1,014.76	$348.98	$1,677.80	$108.39	$31.38	$3,181.31	($918.51)	$67.11
740394NV-B0F	200	$5,743.08	$2,088.86	$4,679.19	$108.39	$78.26	$12,697.79	$3,271.30	$67.11
9003071NV-0E8	500	$23,557.88	$6,089.32	$13,496.50	$108.39	$205.02	$43,457.10	$21,728.55	$22.61
8509026NV-000	500	$8,126.84	$1,982.38	$10,477.73	$108.39	$134.55	$20,829.89	$10,414.94	$30.09
9003387NV-273	200	$4,416.09	$1,804.55	$5,282.32	$108.39	$81.42	$11,692.77	$5,846.38	$28.24
7551948NV-7E0	300	$9,588.84	$2,354.13	$7,317.19	$108.39	$106.97	$19,475.52	$9,737.76	$32.26
9003385NV-2F6	150	$4,367.85	$1,608.68	$4,179.60	$108.39	$68.57	$10,333.10	$5,166.55	$22.61
7302939NV-E0B	150	$3,100.11	$1,235.01	$4,516.49	$108.39	$68.21	$9,028.21	$4,514.10	$31.59
734424NV-A86	100	$1,920.63	$342.80	$2,242.57	$108.39	$36.90	$4,651.29	$2,325.64	$38.05
835871NV-C17	500	$8,892.88	$2,217.70	$10,402.71	$108.39	$136.14	$21,757.82	$10,878.91	$36.03
9003117NV-793	300	$22,103.82	$6,401.15	$9,581.24	$108.39	$169.38	$38,363.99	$19,182.00	$30.05
900399NV-693	1250	$19,229.63	$2,810.83	$25,907.83	$108.39	$295.33	$48,352.01	$24,176.00	$80.59
900305NV-92E	750	$9,412.54	$2,462.60	$16,041.55	$108.39	$194.32	$28,219.40	$14,109.70	$48.19
900306NV-5EE	750	$10,069.64	$3,050.97	$15,419.60	$108.39	$193.99	$28,842.59	$14,421.29	$51.53
744103NV-5A5	750	$15,002.59	$4,205.47	$17,998.63	$108.39	$230.91	$37,545.99	$18,773.00	$23.17
734318NV-162	300	$3,980.14	$1,907.25	$6,238.64	$108.39	$91.89	$12,326.31	$6,163.15	$37.86
754696NV-0EE	200	$10,016.42	$2,344.16	$6,380.49	$108.39	$97.61	$18,947.07	$9,473.54	$32.96
831121NV-B96	300	$3,148.46	$1,258.13	$5,867.01	$108.39	$81.79	$10,463.79	$5,231.89	$49.10

ICP Number	Contract Capacity kVA	Trans Power Charge	Subtransmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
755825NV-937	200	$3,481.37	$1,291.49	$3,993.45	$108.39	$63.60	$8,938.30	$7,306.71	$67.11
7433014NV-08B	500	$16,358.87	$3,744.36	$11,933.18	$108.39	$166.37	$32,311.17	$16,155.59	$29.41
9003083NV-07A	500	$12,358.99	$3,737.25	$12,166.54	$108.39	$168.60	$28,539.78	$14,269.89	$20.33
880363NV-C18	200	$2,707.76	$734.33	$4,686.20	$108.39	$64.94	$8,301.63	$4,150.81	$29.71
880302NV-FAD	150	$4,078.18	$1,184.74	$4,088.62	$108.39	$63.48	$9,523.42	$4,761.71	$20.96
8803047NV-B57	150	$2,763.16	$648.23	$3,451.57	$108.39	$51.88	$7,023.23	$3,511.61	$37.76
73015753NV-A0E	150	$3,429.87	$1,188.90	$4,012.71	$108.39	$62.77	$8,802.65	$4,401.33	$22.95
8803625NV-224	200	$6,742.63	$2,102.52	$6,033.63	$108.39	$91.79	$15,078.96	$7,539.48	$21.06
7301152NV-DC2	750	$19,946.63	$4,697.21	$16,493.11	$108.39	$220.88	$41,466.22	$20,733.11	$39.64
9003212NV-9DF	100	$2,323.74	$550.26	$2,517.08	$108.39	$41.67	$5,541.14	$2,770.57	$24.20
7301908NV-756	100	$2,770.87	$782.78	$2,732.14	$108.39	$46.09	$6,440.27	$3,220.14	$20.65
880308NV-D3C	75	$3,172.19	$1,027.82	$3,312.73	$108.39	$54.26	$7,675.40	$3,837.70	$22.74
7301973NV-CDF	75	$2,763.44	$861.20	$3,238.12	$108.39	$51.87	$7,023.03	$3,511.51	$20.48
8803164NV-3C6	75	$3,405.28	$749.08	$3,088.60	$108.39	$49.29	$7,400.64	$3,700.32	$27.69
8803165NV-F83	50	$2,419.23	$453.52	$1,923.12	$108.39	$34.84	$4,939.10	$2,469.55	$29.61
744611NV-08F	300	$9,232.45	$2,261.74	$7,268.55	$108.39	$105.58	$18,976.71	$9,488.35	$32.97
9003603NV-336	300	$21,669.05	$5,067.99	$12,702.79	$108.39	$187.07	$39,735.29	$19,867.65	$25.97
9003051NV-DBD	300	$12,039.93	$3,395.29	$7,860.87	$108.39	$122.65	$23,527.13	$11,763.56	$26.19
7757907NV-783	500	$13,597.64	$4,192.92	$11,238.49	$108.39	$163.93	$29,301.36	$14,650.68	$37.88
7757994NV-4A4	200	$6,137.44	$1,861.50	$5,032.91	$108.39	$79.51	$13,219.76	$6,609.88	$40.98

ICP Number	Contract Capacity kVA	Trans Power Charge	Subtransmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
880336NV-95F	500	$24,219.78	$6,250.86	$14,064.00	$108.39	$212.22	$44,855.25	$22,427.63	$28.08
8803031NV-F85	200	$6,382.70	$1,978.29	$5,844.77	$108.39	$88.70	$14,402.85	$7,201.42	$19.79
880321NV-E38	200	$5,663.46	$1,917.17	$5,697.96	$108.39	$86.64	$13,473.63	$6,736.81	$19.56
8665382NV-F7A	200	$7,411.82	$2,500.39	$5,578.51	$108.39	$91.23	$15,690.35	$411.90	$67.11
721876NV-1C6	200	$2,594.12	$461.01	$4,435.45	$108.39	$59.76	$7,658.73	$3,829.37	$44.43
750191NV-4A6	150	$3,259.62	$1,024.19	$3,814.43	$108.39	$59.18	$8,265.82	$624.31	$67.11
733395NV-F13	200	$1,630.20	$536.19	$4,508.37	$108.39	$61.22	$6,844.37	$638.51	$67.11
880317NV-84F	300	$1,394.65	$210.12	$5,381.99	$108.39	$66.63	$7,161.78	$3,580.89	$94.46
8365737NV-155	300	$16,657.10	$3,554.27	$7,602.56	$108.39	$121.66	$28,043.98	$14,021.99	$38.65
9003244NV-058	300	$9,908.21	$2,640.40	$8,159.20	$108.39	$118.13	$20,934.33	$10,467.17	$20.02
8509245NV-937	200	$7,869.49	$2,156.11	$6,226.06	$108.39	$94.23	$16,454.28	$8,227.14	$19.81
7447592NV-D72	150	$582.99	$192.52	$3,056.73	$108.39	$43.47	$3,984.10	$1,395.87	$67.11
9003243NV-D92	200	$6,846.10	$1,686.14	$6,006.60	$108.39	$87.41	$14,734.64	$7,367.32	$23.57
880361NV-C9D	500	$29,197.01	$7,049.08	$16,176.26	$108.39	$241.01	$52,771.74	$26,385.87	$21.29
744655NV-320	200	$4,560.77	$977.81	$5,098.03	$108.39	$71.42	$10,816.43	$5,408.21	$27.98
931741NV-60C	500	$12,590.49	$11,545.97	$10,928.50	$108.39	$233.58	$35,406.93	$17,703.46	$30.48
7341276NV-90B	200	$3,570.40	$717.20	$4,661.27	$108.39	$64.52	$9,121.78	$4,560.89	$29.23
7341272NV-801	150	$1,730.86	$315.05	$3,159.36	$108.39	$45.69	$5,359.36	$2,679.68	$46.94
733399NV-C0D	100	$2,868.98	$656.71	$2,556.68	$108.39	$43.11	$6,233.87	$3,116.94	$25.64
7447142NV-C31	200	$4,542.93	$1,006.68	$4,976.54	$108.39	$70.50	$10,705.06	$5,352.53	$28.73

ICP Number	Contract Capacity kVA	Trans Power Charge	Subtransmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
900392NV-B03	750	$23,956.01	$6,572.68	$20,375.34	$108.39	$277.82	$51,290.24	$25,645.12	$22.72
7344583NV-C71	150	$3,022.02	$965.05	$3,626.75	$108.39	$56.74	$7,778.95	$1,883.01	$67.11
900325NV-47B	500	$34,191.47	$9,980.28	$19,286.89	$108.39	$300.75	$63,867.78	$31,933.89	$18.80
8509962NV-AA6	75	$708.67	$219.87	$2,083.30	$108.39	$34.11	$3,154.35	$1,577.17	$31.38
7317032NV-617	200	$7,639.46	$1,665.90	$5,194.73	$108.39	$79.18	$14,687.66	$7,343.83	$37.34
9003573NV-568	200	$7,716.59	$2,655.39	$5,295.82	$108.39	$89.96	$15,866.15	$1,800.52	$67.11
880375NV-73A	300	$5,039.26	$1,864.95	$5,822.04	$108.39	$87.35	$12,921.99	$3,139.08	$67.11
880309NV-179	300	$7,411.38	$1,778.89	$7,134.43	$108.39	$99.48	$16,532.57	$8,266.28	$25.19
8144266NV-0A8	200	$6,643.25	$1,728.50	$5,977.30	$108.39	$87.54	$14,544.97	$7,272.49	$23.55
880329NV-C2C	1000	$48,013.42	$13,149.03	$35,535.83	$108.39	$492.77	$97,299.44	$48,649.72	$25.81
755884NV-D6D	200	$3,445.49	$613.01	$4,448.49	$108.39	$61.39	$8,676.77	$4,338.38	$53.89
7205085NV-6A2	100	$4,121.55	$1,215.12	$2,988.97	$108.39	$52.91	$8,486.95	$4,243.47	$22.13
8305967NV-D0E	500	$1,138.04	$678.18	$8,870.78	$108.39	$105.76	$10,901.16	$5,450.58	$106.29
7501996NV-A4D	150	$1,396.03	$442.41	$3,469.09	$108.39	$50.02	$5,465.93	($744.10)	$67.11
7341792NV-7BE	200	$5,752.78	$1,342.37	$5,103.26	$108.39	$75.08	$12,381.88	$6,190.94	$26.37
9003235NV-940	500	$25,877.04	$6,178.27	$15,063.53	$108.39	$221.39	$47,448.63	$23,724.32	$24.47
7229001NV-0AF	100	$3,491.89	$725.83	$2,546.16	$108.39	$43.69	$6,915.97	$3,457.98	$31.63
880397NV-D05	500	$13,509.09	$3,080.06	$14,630.06	$108.39	$186.47	$31,514.07	$15,757.03	$34.33
880395NV-D80	1000	$15,240.32	$4,078.59	$23,405.06	$108.39	$283.12	$43,115.48	$21,557.74	$32.64
724187NV-3BD	150	$5,386.97	$1,877.57	$4,106.81	$108.39	$70.51	$11,550.25	$5,775.13	$28.03

ICP Number	Contract Capacity kVA	Trans Power Charge	Subtransmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
760737NV-A1C	500	$13,336.61	$4,063.33	$11,022.77	$108.39	$160.52	$28,691.62	$14,345.81	$43.85
7227011NV-2C2	300	$2,679.92	$646.83	$5,567.83	$108.39	$72.79	$9,075.76	$4,537.88	$59.81
9003995NV-251	300	$7,090.40	$1,302.78	$6,629.99	$108.39	$89.78	$15,221.34	$7,610.67	$34.98
82029943NV-B5B	150	$2,162.73	$716.84	$3,140.87	$108.39	$49.48	$6,178.31	$4,571.56	$67.11
835083NV-C88	300	$1,696.38	$1,159.64	$5,569.68	$108.39	$77.88	$8,611.98	$4,305.99	$149.90
825292NV-886	500	$20,284.68	$5,214.63	$13,373.61	$108.39	$195.15	$39,176.46	$19,588.23	$26.33
740340NV-747	150	$3,709.63	$1,190.10	$4,146.93	$108.39	$64.11	$9,219.17	($2,248.53)	$67.11
7433753NV-0E6	150	$4,488.86	$1,455.44	$4,324.91	$108.39	$68.50	$10,446.11	($2,914.10)	$67.11
900384NV-021	500	$30,793.93	$7,404.21	$14,686.30	$108.39	$229.78	$53,222.61	$26,611.31	$29.81
7302313NV-BC5	75	$1,244.76	$164.12	$1,966.84	$108.39	$32.41	$3,516.52	$1,758.26	$60.13
7302304NV-CA2	150	$1,799.09	$561.56	$3,432.14	$108.39	$50.83	$5,952.02	$816.91	$67.11
900383NV-DEB	500	$6,031.36	$1,592.99	$9,614.76	$108.39	$122.17	$17,469.68	$8,734.84	$55.46
730262NV-92A	100	$3,385.87	$1,185.38	$2,683.71	$108.39	$49.60	$7,412.94	($316.78)	$67.11
900313NV-20C	300	$4,859.56	$1,368.10	$6,679.47	$108.39	$90.92	$13,106.44	$6,553.22	$33.49
7350005NV-3D0	75	$1,889.00	$665.64	$2,485.91	$108.39	$42.50	$5,191.45	$772.77	$67.11
7403555NV-A42	200	$5,715.36	$1,393.10	$5,256.96	$108.39	$77.10	$12,550.90	$6,275.45	$33.91
7447635NV-BA4	300	$15,504.78	$3,245.29	$7,405.01	$108.39	$116.65	$26,380.14	$13,190.07	$43.97
734360NV-62B	75	$2,012.69	$758.98	$2,670.48	$108.39	$45.25	$5,595.79	($2,079.28)	$67.11
735249NV-D8B	200	$3,614.05	$1,279.55	$4,490.60	$108.39	$68.40	$9,560.99	$3,350.96	$67.11
850908NV-B67	750	$28,913.55	$7,445.25	$21,859.16	$108.39	$301.12	$58,627.47	$29,313.73	$20.74

ICP Number	Contract Capacity kVA	Trans Power Charge	Subtransmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
734110NV-971	300	$5,435.37	$1,640.09	$6,364.78	$108.39	$90.49	$13,639.13	$6,819.57	$36.35
7501257NV-2E9	150	$1,581.01	$520.52	$3,184.67	$108.39	$47.98	$5,442.56	$2,485.52	$67.11
7350693NV-BBE	75	$1,706.82	$586.30	$2,298.35	$108.39	$39.86	$4,739.72	$1,421.25	$67.11
900358NV-E7D	500	$5,268.61	$1,300.72	$9,450.79	$108.39	$117.66	$16,246.18	$8,123.09	$52.34
734460NV-929	200	$2,000.17	$312.33	$4,184.17	$108.39	$55.80	$6,660.86	$3,330.43	$63.14
724179NV-031	100	$865.72	$194.32	$2,008.18	$108.39	$33.12	$3,209.73	$1,604.86	$53.43
8425758NV-FE5	150	$6,263.26	$1,675.00	$4,346.05	$108.39	$70.88	$12,463.59	$6,231.79	$31.60
7302953NV-36A	300	$3,820.17	$921.16	$6,180.51	$108.39	$81.56	$11,111.80	$5,555.90	$31.76
900351NV-02C	200	$9,322.97	$2,405.45	$6,999.88	$108.39	$104.34	$18,941.03	$9,470.52	$17.95
7341793NV-BFB	100	$4,774.94	$820.33	$2,675.20	$108.39	$45.90	$8,424.77	$4,212.39	$29.20
734188NV-482	300	$18,567.69	$4,545.91	$10,027.37	$108.39	$155.45	$33,404.81	$16,702.40	$19.90
724111NV-DD5	150	$2,904.23	$709.69	$3,210.37	$108.39	$50.10	$6,982.78	$3,491.39	$49.13
900308NV-675	750	$14,819.90	$4,007.15	$21,295.71	$108.39	$261.55	$40,492.70	$20,246.35	$30.37
8305981NV-63B	500	$19,561.10	$5,030.81	$12,456.36	$108.39	$184.26	$37,340.92	$18,670.46	$39.89
832431NV-6DE	1000	$8,385.10	$1,394.14	$21,634.51	$108.39	$239.06	$31,761.21	$15,880.61	$56.85
8305375NV-D2C	50	$1,189.36	$425.08	$1,616.42	$108.39	$31.52	$3,370.78	$230.45	$67.11
760735NV-A99	150	$4,288.92	$1,027.20	$3,592.80	$108.39	$57.02	$9,074.33	$4,537.17	$42.48
900319NV-09D	200	$3,041.43	$1,050.31	$4,515.61	$108.39	$66.38	$8,782.12	$2,477.67	$67.11
740630NV-71F	150	$6,782.38	$1,412.59	$3,989.13	$108.39	$64.75	$12,357.24	$6,178.62	$36.68
7433292NV-E49	500	$12,342.34	$3,553.59	$10,849.46	$108.39	$153.76	$27,007.54	$13,503.77	$39.94

ICP Number	Contract Capacity kVA	Trans Power Charge	Subtransmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
744592NV-A06	200	$825.76	$260.20	$4,116.77	$108.39	$54.62	$5,365.74	$2,722.84	$67.11
8509025NV-CC0	300	$11,569.37	$2,551.14	$7,780.09	$108.39	$113.50	$22,122.48	$11,061.24	$24.32
8803032NV-345	150	$4,714.39	$795.40	$3,855.28	$108.39	$57.33	$9,530.78	$4,765.39	$33.87
900342NV-641	100	$3,985.83	$745.83	$2,695.64	$108.39	$45.37	$7,581.06	$3,790.53	$27.64
744608NV-473	300	$7,398.83	$2,012.45	$6,897.31	$108.39	$99.44	$16,516.42	$8,258.21	$28.84
933534NV-759	200	$2,568.08	$4,022.23	$4,360.36	$108.39	$94.23	$11,153.30	$5,576.65	$24.68
931777NV-07B	750	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
931749NV-418	300	$3,807.27	$5,616.87	$5,787.33	$108.39	$124.11	$15,443.97	$7,721.98	$29.05
931775NV-0FE	150	$4,279.73	$5,428.87	$3,103.43	$108.39	$95.71	$13,016.13	$6,037.12	$67.11
930503NV-F8B	100	$1,232.69	$1,831.54	$1,950.43	$108.39	$48.74	$5,171.79	$2,585.90	$52.49
930505NV-E04	150	$2,844.89	$3,575.04	$3,189.50	$108.39	$78.23	$9,796.05	$2,487.02	$67.11
920755NV-4EA	150	$6,525.14	$7,520.30	$4,543.19	$108.39	$130.63	$18,827.65	$9,413.82	$29.02
931776NV-C3E	150	$3,651.46	$4,804.70	$2,848.97	$108.39	$87.02	$11,500.54	$8,451.93	$67.11
931326NV-837	150	$3,344.68	$4,357.57	$2,962.41	$108.39	$83.72	$10,856.77	$6,356.31	$67.11
9406013NV-102	500	$7,562.35	$8,831.85	$9,032.04	$108.39	$187.99	$25,722.62	$12,861.31	$49.11
9406011NV-187	500	$20,164.24	$18,168.83	$12,526.96	$108.39	$314.88	$51,283.29	$25,641.65	$30.10
931746NV-BC6	200	$5,920.20	$7,663.24	$4,446.09	$108.39	$131.08	$18,269.00	$6,652.41	$67.11
9408016NV-48D	1750	$113,073.97	$153,171.80	$56,082.60	$108.39	$2,080.60	$324,517.36	$162,258.68	$32.94
931760NV-71C	150	$1,205.24	$1,375.77	$3,020.54	$108.39	$54.81	$5,764.76	$1,916.59	$67.11
931704NV-9E6	200	$2,561.36	$2,832.99	$4,278.68	$108.39	$81.66	$9,863.09	$4,931.54	$34.42

ICP Number	Contract Capacity kVA	Trans Power Charge	Subtransmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
934525NV-5D1	150	$1,725.40	$2,038.13	$3,088.41	$108.39	$62.03	$7,022.36	$1,910.48	$67.11

Line Charge Breakdown for Residential and General Customers

	Code	Number of	Transpower	Sub transmission	Distribution	PowerNet	Pass through	Fixed
Capacity		**Connections**	**Charge**	**Charge**	**Charge**	**Overheads**	**Costs**	**Charge**
								per Day
Residential								
Residential (8kVA 1 Phase) - All Peak *	ND08P	37	$4,740	$2,120	$7,867	$4,011	$518	$0.6300
Residential (8kVA 1 Phase) - With Off Peak *	ND08Q	90	$9,647	$4,156	$16,457	$9,809	$1,230	$0.4383
Standard Residential (20kVA 1 Phase) - All Peak	ND20P	1268	$324,897	$135,536	$538,572	$137,441	$21,040	$1.1641
Standard Residential (20kVA 1 Phase) - With Off Peak	ND20Q	7690	$1,639,496	$696,395	$2,795,874	$833,535	$121,708	$0.8084
Residential Low User (20kVA 1 Phase) - All Peak	NDL20P	1057	$209,566	$93,002	$374,778	$114,625	$16,614	$0.3000
Residential Low User (20kVA 1 Phase) - With Off Peak	NDL20Q	5145	$854,008	$351,446	$1,553,564	$557,731	$77,168	$0.2000
Residential Low User (8kVA 1 Phase) - All Peak*	NDL08P	21	$2,555	$2,453	$4,380	$2,276	$306	$0.3000
Residential Low User (8kVA 1 Phase) - With Off Peak*	NDL08Q	99	$10,088	$8,119	$17,756	$10,785	$1,384	$0.2000
General Single Phase								

Street Lights (1 Phase) per street light	NS001L	5604	$55,768	$24,617	$99,014	$217	$1,245	$0.0966
1 kVA 1 Phase - All Peak	NS001P	43	$6,443	$2,457	$7,028	$4,715	$587	$0.4520
8 kVA 1 Phase - All Peak	NS008P	183	$23,445	$9,642	$38,855	$19,836	$2,554	$0.6300
8 kVA 1 Phase - With Off Peak	NS008Q	8	$906	$332	$1,540	$921	$115	$0.4383
20 kVA 1 Phase - All Peak	NS020P	268	$68,797	$32,288	$114,279	$29,103	$4,493	$1.1641
20 kVA 1 Phase - With Off Peak	NS020Q	81	$17,376	$6,622	$29,557	$8,834	$1,282	$0.8084
General Three Phase								
15 kVA 3 Phase - All Peak	NT015P	66	$15,854	$6,725	$26,288	$7,154	$1,075	$0.9733
15 kVA 3 Phase - With Off Peak	NT015Q	4.5	$899	$561	$1,551	$488	$72	$0.6300
30 kVA 3 Phase - All Peak	NT030P	512	$243,050	$105,766	$393,152	$55,551	$10,743	$1.6301
30 kVA 3 Phase - With Off Peak	NT030Q	113	$44,963	$19,631	$74,440	$12,303	$2,217	$1.1094
50 kVA 3 Phase - All Peak	NT050P	308	$329,433	$135,293	$475,285	$33,385	$9,529	$3.3284
50 kVA 3 Phase - With Off Peak	NT050Q	65	$57,928	$25,557	$86,010	$7,045	$1,840	$2.2601
75 kVA 3 Phase - All Peak	NT075P	118	$215,024	$93,274	$288,321	$12,790	$5,111	$6.8349
75 kVA 3 Phase - With Off Peak	NT075Q	13	$20,549	$9,496	$28,277	$1,463	$527	$4.9722
100 kVA 3 Phase - All Peak	NT100P	70	$203,086	$80,716	$198,667	$7,587	$3,556	$8.3141
100 kVA 3 Phase - With Off Peak	NT100Q	7	$16,964	$9,243	$17,220	$759	$341	$6.0269
Variable Line Charge Prices		**Peak**		**Shoulder**		**Night**		

	$/kWh	$/kWh	$/kWh
Residential Standard & General	$0.067110	$0.056000	$0.01000
Residential Low Fixed Charge Fixed Charge Option (8kVA	$0.084370	$0.062324	$0.01000
Residential Low Fixed Charge Fixed Charge Option 20kVA	$0.103580	$0.081148	$0.01000