Electricity Pricing Methodology

1 April 2025 - 31 March 2026

Pursuant to the requirements of clause 2.4 of the Electricity Information Disclosure (Targeted Review 2024) Amendment Determination 2024

Alpine ENERGY

Contents

Section 1: About Alpine Energy & our pricing methodology

Introduction

We are an electricity distribution business (EDB) that owns, maintains, and operates the electricity distribution network that delivers electricity to over 33,500 homes and businesses in South Canterbury. We deliver an essential lifeline service that is critical to support our region's economic growth. We also have an important role to play in New Zealand's transition to a low-carbon economy.

Our network stretches from the Rangitata River to the north and the Waitaki River to the south and extends west to the Southern Alps as far as Aoraki Mt Cook Village, while the coast is the natural eastern boundary, as shown in Figure 1.

We have seven grid exit points (GXP) on our network as shown in Figure 1 below.

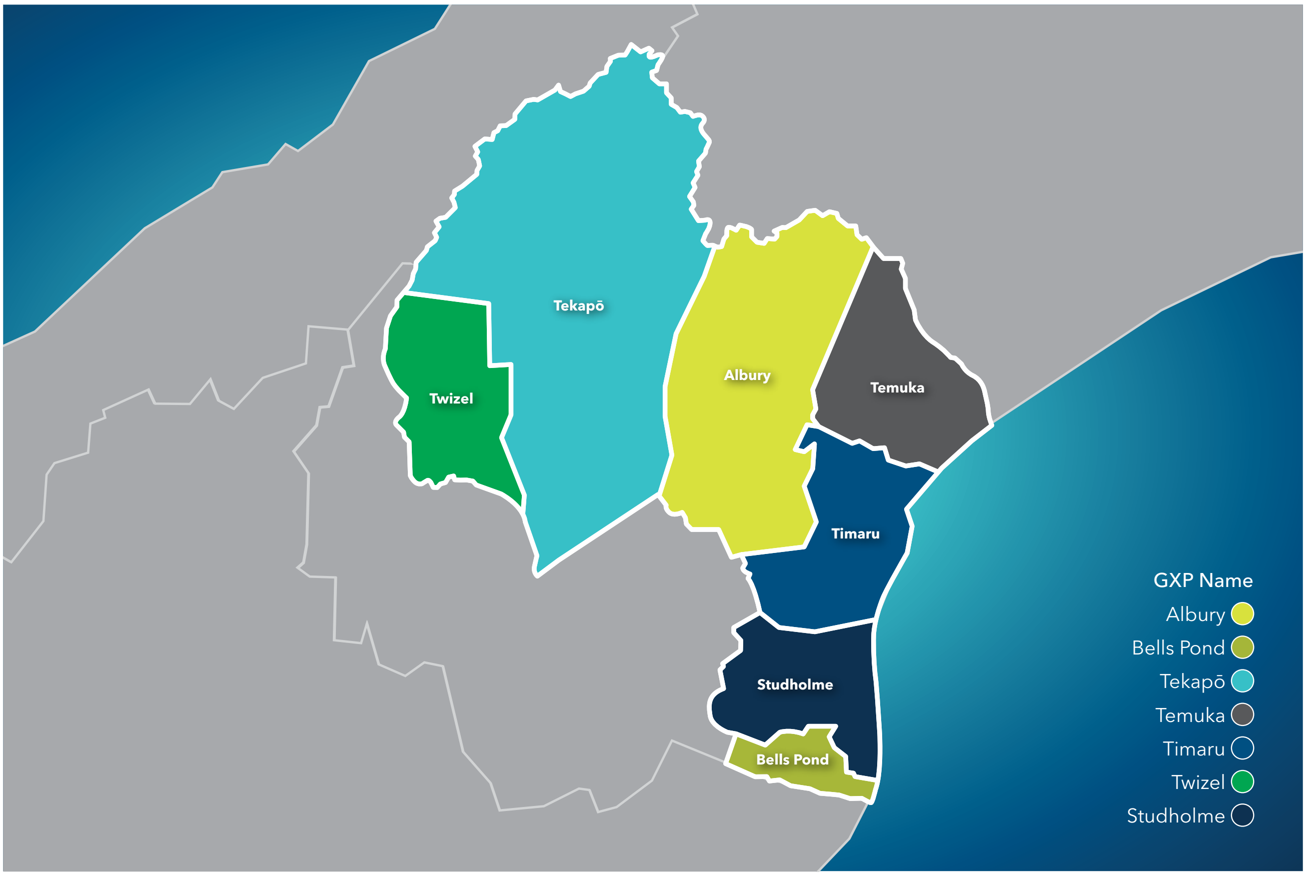

Figure 1: Our network

We are owned 47.5% by Timaru District Holdings Limited (TDHL) (a subsidiary of Timaru District Council), 40% by LineTrust South Canterbury, 7.54% by Waimate District Council, and 4.96% by Mackenzie District Council. This ownership model ensures that we deliver long-term benefits and cost-effective services to the South Canterbury community.

We want to help you understand how we set prices

This Pricing Methodology outlines our approach to setting electricity distribution delivery prices to apply from 1 April 2025.

Delivery prices describe the total prices we charge to provide electricity from the national grid to consumers' homes and businesses.

Delivery prices include:

- Alpine Energy distribution prices
- Pass-through charges and recoverable costs such as transmission charges, rates and industry levies.

Definitions of these charges are provided in the Glossary.

The purpose of this document is to show how our electricity Pricing Methodology (or approach) sets delivery prices to recover the costs of supplying electricity distribution services from consumers.

Consumer characteristics

Our network covers an area of 10,000 km², supplying the Timaru, Waimate, and Mackenzie districts, with 19 electricity retailers currently supplying consumers on our network. Approximately a third of connections are served by the biggest retailer. Our delivery prices are passed to consumers along with transmission prices and energy supply charges by the electricity retailers, except for six large consumers, who we directly bill for electricity distribution.

The Timaru supply area constitutes almost half of our network connection points and consumption and primarily comprises residential, commercial, and small industrial consumers. The rest of our region is comprised mainly of residential and agricultural consumers.

Table 1 below shows the number of consumers (ICPs) in each supply area.

Supply area	ICP Count	%
Timaru	16,284	47.91%
Waimate	3,748	11.03%
Temuka	3,497	10.29%
Geraldine	3,133	9.22%
Twizel	1,800	5.30%
Pleasant Point	1,262	3.71%
Fairlie	1,212	3.57%
Lake Tekapo	908	2.67%
Pareora	482	1.42%
Orari	314	0.92%
Glenavy	274	0.81%
St Andrews	234	0.69%
Winchester	225	0.66%
Cave	205	0.60%
Albury	183	0.54%
Makikihi	118	0.35%
Mount Cook	108	0.32%
Total	**33,987**	**100%**

Table 1: Total ICP count and percentage of total by region on 31 December 2024

Regulatory frameworks

Our pricing approach is influenced by a range of regulatory requirements, including obligations set by the Commerce Commission and Electricity Authority.

The main implications are:

- We are required to set prices to recover no more than the revenue allowed by the Commerce Commission's *Electricity Distribution Services Default Price-Quality Determination 2025* (DPP Determination/DPP4).
- We are required to disclose information about our pricing approach and prices by the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 (ID Determination).
- We are expected to set efficient and cost-reflective prices consistent with the Electricity Authority's Distribution Pricing Principles.
- We are required to set prices for distributed generators connecting to and using our network according to Part 6 of the Electricity Industry Participation Code 2010 (the Code).
- We are required to offer primary residence consumers a low fixed charge tariff option (of 75 cents/day) by the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (the Low Fixed Charge Regulations (LFC)). The Electricity Authority monitors and enforces the regulations.

Section 2:
Current pricing and future pricing plans

Introduction

We determine delivery prices using a retail delivery approach, also known as the Installation Control Point (ICP) pricing methodology. This method prices network services at the consumer's metering point based on their electricity consumption at that location.

Our pricing reflects the network, consumer, and regulatory factors relevant to our operations, with the goal of aligning the cost of delivering services to each consumer group with the price charged.

To encourage efficient network use, we prioritise signalling the cost of network congestion to consumers. This strategy promotes informed energy consumption decisions during peak congestion periods, helping to defer or avoid costly network upgrades. By shifting or reducing usage at these times, consumers can also reduce their electricity costs. Additional information on network characteristics and constraints is available in our Pricing Strategy.

Current pricing

Our network service prices for most connections have a three-part structure, with a fixed daily price component, and two variable components: a volume-based price for daytime usage (7 am to 11 pm) and a volume-based price for night-time usage (11 pm to 7 am). Our fixed prices have remained at 80% (on average), making the variable price 20% (on average), which aligns with our cost structure. This balance reflects the influence of the Low Fixed Charge Regulations, which necessitate variable prices for low-usage residential consumers. Once these regulations are phased out on 1 April 2027, we will review the impact and reassess our pricing approach.

Network service prices for connections with time-of-use (TOU) metering, and capacity greater than 15kVA have a four-part structure, with an additional kW/day capacity price component. The daily capacity price component is fixed for the year, meaning the amount paid by the consumer does not vary with day-to-day consumption but may differ from year to year if the consumer chooses to vary their connection capacity.

Table 2 provides an overview of the price structure and components for each consumer group for the period from 1 April 2025 to 31 March 2026, excluding the directly billed consumers, who are charged only a daily rate. Additional details for each consumer group can be found in Section 6.

Consumer group (Load group)	Forecast # ICPs	Description	Fixed daily component	Capacity component	Variable day volume component	Variable night volume component
			$/day	$/kW/day	$/kWh	$/kWh
LOWHCA	2,301	Households using <9000kWh/ year, controlled, high-cost area	$0.7500	$0.0000	$0.1265	$0.1243
LOWLCA	10,830	Households using <9000kWh/ year, controlled, low-cost area	$0.7500	$0.0000	$0.1153	$0.1131
LOWUHCA	30	Households using <9000kWh/ year, uncontrolled, high-cost area	$0.7500	$0.0000	$0.1296	$0.1274
LOWULCA	68	Households using <9000kWh/ year, uncontrolled, low-cost area	$0.7500	$0.0000	$0.1184	$0.1162
015HCA	5,959	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, controlled, high-cost area	$3.5132	$0.0000	$0.0150	$0.0128
015LCA	11,563	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, controlled, low-cost area	$3.2319	$0.0000	$0.0150	$0.0128
015UHCA	43	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, uncontrolled, high-cost area	$3.5870	$0.0000	$0.0150	$0.0128
015ULCA	57	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, uncontrolled, low-cost area	$3.3107	$0.0000	$0.0150	$0.0128
030HCA	10	Commercial, 16 to 30 kW connection, no TOU metering, controlled, high-cost area	$7.8200	$0.0000	$0.0150	$0.0128
030LCA	15	Commercial, 16 to 30 kW connection, no TOU metering, controlled, low-cost area	$7.0787	$0.0000	$0.0150	$0.0128
030UHCA	N/A	Commercial, 16 to 30 kW connection, no TOU metering, uncontrolled, high-cost area	$7.9706	$0.0000	$0.0150	$0.0128
030ULCA	N/A	Commercial, 16 to 30 kW connection, no TOU metering, uncontrolled, low-cost area	$7.2418	$0.0000	$0.0150	$0.0128
045HCA	520	Commercial, 3-phase, 60-amp connection, no TOU metering, controlled, high-cost area	$12.1266	$0.0000	$0.0150	$0.0128
045LCA	725	Commercial, 3-phase, 60-amp connection, no TOU metering, controlled, low-cost area	$10.9254	$0.0000	$0.0150	$0.0128
045UHCA	13	Commercial, 3-phase, 60-amp connection, no TOU metering, uncontrolled, high-cost area	$12.3540	$0.0000	$0.0150	$0.0128
045ULCA	18	Commercial, 3-phase, 60-amp connection, no TOU metering, uncontrolled, low-cost area	$11.1728	$0.0000	$0.0150	$0.0128
ASSHCA	1,327	Commercial, capacity > 15kVA, no TOU metering, high-cost area	$6.1764	$0.2824	$0.0150	$0.0128
ASSLCA	416	Commercial, capacity > 15kVA, no TOU metering, low-cost area	$5.6805	$0.2513	$0.0150	$0.0128
TOU400HCA	38	Households and small commercials connected to LV network, TOU metering, high-cost area	$5.7612	$0.6191	$0.0130	$0.0108
TOU400LCA	98	Households and small commercial connected to LV network, TOU metering, low-cost area	$5.3274	$0.5535	$0.0130	$0.0108
TOU11HCA	5	Commercial, connected to 11kV network, TOU metering, high-cost area	$4.6823	$0.5685	$0.0130	$0.0108
TOU11LCA	5	Commercial, connected to 11kV network, TOU metering, low-cost area	$4.2701	$0.5026	$0.0130	$0.0108

Table 2: Overview of price structure and price components for each load group for 1 April 2025 – 31 March 2026

Economic signals delivered by current pricing

We recover the costs of delivering electricity to consumers through pricing. Our prices reflect the value of the network services provided at a specific location and time.

There is a relationship between the prices, cost, and value of the network service and consumer behaviour in using the network. As an example, a fixed price pricing signal would encourage network use at any time and level for many consumers but would discourage connection for some consumers, particularly with low levels of consumption. It might encourage each connection to be optimised to be as small as possible, especially if choice is possible with a larger variety of connection sizes on offer. It may also encourage low load factor (peaky type) consumers to select more appropriate sources of energy.

There are a range of long-term impacts of economic signalling in pricing:

- 'Unlimited Supply' fixed pricing on an unconstrained network may cause increased consumer consumption resulting in congestion which may require higher levels of network investment. However, specifying capacity limits during higher consumption periods could encourage more efficient network usage (TOU capacity pricing).
- If consumers opt for alternative energy supplies, it could lead to consumers disconnecting or not connecting to the network. This could lead to a reduction in connections and revenue base over time. However, if consumers with high-cost supplies opt for other energy sources more suitable for peaky loads, the average cost of electricity supply could be reduced.
- Variable volume-based prices can discourage the use of the network. They also create uncertainty in revenue and cost recovery as consumers can reduce electricity consumption.
- There could be adverse equity impacts where costs were increasingly borne by consumers with limited ability to reduce electricity consumption.

Pricing structures that reflect fixed or avoidable (variable) costs should signal the cost of the service appropriately.

The fixed daily and capacity prices (for connections with the metering capability to identify their contribution to loading) are recovered from the relevant time-of-use consumer groups.

Our pricing is designed to recover the following costs through fixed and variable prices:

- Operating expenditure relating to reliability, safety, and environment, routine and corrective maintenance and inspection, and system operations and network support;
- Depreciation, revaluations, and regulatory tax; and
- Pass-through and recoverable costs, including transmission prices.

Prices are set to reflect the economic signals for investment as follows:

- Directly billed customers' prices are based on the investment that we have made in these large connections and the contribution of transmission assets in use to provide these customers with electricity.
- Medium-sized connections with time-of-use metering are based on their share of assets and consumption within the low and high-cost areas of the network, signalling the cost to serve.
- Low user consumers' prices are based on the Low Fixed Charge Regulations.
- Mass market consumers are based on a shared residual cost of network assets within the low and high-cost areas of network density, signalling the cost to serve.

Table 3 below lists the average proportion of revenue recovered from each consumer group by fixed (daily) and capacity prices and by variable (volume) prices.

Most of our operational costs are fixed with a portion being avoidable depending on extreme events. Costs recovered through variable prices intend to manage consumer behaviour or future network investment.

Consumer group (Load group)	Revenue recovered by fixed & capacity prices %	Revenue recovered by variable prices %
LOWHCA	26%	74%
LOWLCA	30%	70%
015HCA	90%	10%
015LCA	90%	10%
030HCA	90%	10%
030LCA	89%	11%
045HCA	93%	7%
045LCA	91%	9%
ASSHCA	89%	11%
ASSLCA	88%	12%
TOU400HCA	86%	14%
TOU400LCA	79%	21%
TOU11HCA	78%	22%
TOU11LCA	83%	17%
IND (Directly billed customers)	100%	0%

Table 3: Average proportion of revenue recovered from each consumer group by fixed & capacity prices and variable prices

Evolving our pricing and prices

Our current delivery prices are set to reflect our circumstances and the cost of delivering a safe, reliable electricity supply. We recognise the importance of evolving our pricing and prices as circumstances change.

The energy sector is evolving in response to new consumer demands, new technologies and decarbonisation. 2025/26 is the first year of the new price-quality regulatory period, DPP4, and as we have signalled in our latest Asset Management Plan, we are forecasting significant increases in network investment over the DPP4 period. This has led to an increase in prices for the energy sector, which includes our delivery prices for this period. A key consideration for us as we continue to improve on our pricing roadmap and price model is affordability and equity for all our consumers. We see this new environment as an opportunity to design our pricing in response to an evolving market and consumer needs and demands.

Aligned with the Electricity Authority's distribution connection pricing reform and network connections project, we will initiate a comprehensive review of our connection prices and processes starting 1 April 2025.

We have developed a Pricing Strategy and Roadmap to support the delivery of our long-term pricing objectives and to align with Alpine Energy's purpose, to empower our vibrant and thriving communities now and for the future. Our Pricing Strategy and Roadmap are available on our website at www.alpineenergy.co.nz.

Our Pricing Strategy and Roadmap for 2025-2030 outlines our approach to transitioning towards more transparent and equitable pricing structures that better reflect network usage and costs.

The Low Fixed Charge is being phased out, with fixed prices increasing by 15c per year until reaching 90c on 1 April 2026. The phase-out of the LFC will be completed by 1 April 2027, marking a significant shift toward pricing structures that align more closely with actual network costs.

This year we are introducing a 030 pricing category, which is designed to better accommodate consumers whose requirements exceed the 015 category but do not justify the 045 category. This category aims to bridge the gap for consumers, offering a tailored option that supports both residential and small commercial users with specific connection needs.

Our Pricing Strategy also focuses on researching dynamic time-of-use (TOU) pricing to encourage more efficient electricity usage by providing price signals tied to demand. This initiative is currently in the research phase. Our roadmap highlights our ongoing commitment to consumer and retailer engagement to ensure that these changes are communicated and inclusive of stakeholder feedback.

We believe that our long-term strategic direction will promote efficient network usage, align prices more closely with the cost of service, and reduce cross-subsidisation for consumers. Further details on these initiatives can be found in the Pricing Strategy and Roadmap document.

Strategy implementation and review

We are committed to ensuring that changes to our pricing approach are implemented effectively and transparently, minimising any negative impact on consumers and retailers. These changes will be introduced over the next five years after thorough consultation with retailers, relevant consumer groups and other stakeholders. Additionally, we will conduct regular reviews of the outcomes and provide annual progress reports within this document to ensure transparency and continuous improvement.

Section 3: Pricing changes for 2025/26

Introduction

We are changing delivery prices in 2025/26 as follows:

- The overall revenue we recover through prices will increase by 18% compared to prices set in April 2024.
- We made a one-off reduction in prices in June 2024 to reflect the estimated impact of a historical pricing error. The estimated impact of the 2025/26 prices is a 25% increase when compared to these lower prices.
- We have introduced a new pricing category to address the gap between the 015 and 045 pricing categories. This category is designed to provide a more suitable option for large residential and small commercial consumers, helping to manage capacity increases and support scalable growth.

The reasons for changes and the average impact on consumer prices are described below.

Changes to price levels

We set prices to recover the allowable distribution revenue, transmission costs, and pass-through and recoverable costs.

Electricity distribution and transmission costs are increasing due to high inflation, rising interest rates since the last regulatory period and the need for greater investment to replace aging assets, improve resilience against extreme weather, and enable growth. The Commerce Commission reviews spending forecasts of EDBs to ensure that revenue increases are justified. It also limits revenue growth where uncertainties exist and adopts a gradual approach to price increases, aiming to balance affordability with the delivery of a safe, reliable, and resilient electricity network.

Forecast revenue from distribution prices for the 2025/26 pricing year is $81.625 million for 2025/26. This represents an overall increase of 18% from our FY25 forecast revenue from prices included in our April 2024 pricing disclosures. We lowered our prices in June 2024 to reflect the estimated impact of a historical pricing error. Relative to these prices the impact is approximately 25%.

Significant mid-year price changes are unusual and make price comparisons complicated depending on the circumstances that drove the price change, which consumer groups were affected, and when these changes were reflected in retail prices, depending on a consumer's contractual terms with their retailer. While the June 2024 price reduction did not change our forecast regulatory revenue for the year, it did impact how relative price impacts are communicated to consumers and stakeholders. We have included multiple comparison points in the document to reflect this atypical event.

The prices for the six directly billed customers are set based on the methodologies in their individual conveyance agreements. Delivery prices are mainly adjusted for inflation based on the change in the PPI or CPI (depending on the terms of the conveyance agreement) over a 12-month period. With significant changes to the Transmission Pricing Methodology (TPM) in April 2023, an interim arrangement has been established to adjust the transmission prices going forward. These adjustments are based on the percentage change in total Transpower charges to Alpine Energy and are aligned with the averaged demand approach introduced under the new TPM. The original contractual methodologies are no longer applicable, as Transpower no longer publishes Regional Coincidental Peak Demand (RCPD) data, making such calculations infeasible.

Transpower's transmission charges to Alpine Energy increased by 18.1% from 2024/25 to 2025/26, and this increase will be passed through to all customers in alignment with the Transmission Pricing Methodology.

Table 4 details the estimated change in average cost per customer for each consumer group and the impact of changes to pricing.

Consumer group	Avg. Annual delivery prices for FY24/25	Avg. Annual delivery prices for FY25/26	Annual Avg. increase / (decrease) in whole dollars	Avg. increase / (decrease) as a percentage from last year
LOWHCA	834	993	159	19.0%
LOWLCA	778	929	151	19.4%
015HCA	1,191	1,416	225	18.9%
015LCA	1,106	1,314	208	18.8%
030HCA[1]		3,157		
030LCA		2,904		
045HCA	4,035	4,793	758	18.8%
045LCA	3,672	4,355	683	18.6%
ASSHCA	10,806	12,855	2,049	19.0%
ASSLCA	9,819	11,666	1,847	18.8%
TOU400HCA	53,612	63,659	10,046	18.7%
TOU400LCA	49,057	58,179	9,122	18.6%
TOU11HCA	337,450	399,815	62,365	18.5%
TOU11LCA	305,994	362,985	56,991	18.6%

Table 4: Change in forecast revenue and average delivery prices between 2024/25 and 2025/26. All figures are rounded.

We considered the consumer impact of the delivery price changes. Our approach to assessing and managing the consumer impact of price changes is described in Section 7.

Changes to the price structure

For 2025/26, we have introduced minor adjustments to our pricing structures, including a new 030 (30kW) pricing category. This category bridges the cost gap between the 015 and 045 categories, offering a more suitable option for consumers whose requirements exceed the 015 category but fall well below the 045 category. The new category is designed to meet the needs of approximately 160 small and medium-sized commercial consumers who may not be best served with existing pricing options. It is also aimed at consumers with single-phase 80A connections, two-phase 60A connections, and three-phase 32A connections. This category will be made available to residential consumers once the Low Fixed Charge Regulation concludes on 31 March 2026.

By providing an intermediary option between the 015 and 045 categories, the 030 category is expected to reduce the financial impact of capacity increases for these consumers. This approach supports scalability for small commercial businesses and accommodates the growing energy needs of large residential consumers without imposing significant cost barriers.

[1] New load group with no consumers currently allocated, forecast for small number of consumers shift to this load group throughout the year

Scenario analysis indicates that the introduction of the 30kW pricing category will maintain overall revenue neutrality, with network costs recovered proportionally across pricing categories. This ensures that the new category does not create significant financial imbalances or unreasonable cost shifts among consumers. Consumers in the 015 category could experience slight cost increases if adjustments are needed to recover network costs proportionally. Conversely, consumers in the 045 category may see reduced cross-subsidisation, as those with lower demand levels are now allocated to the new 030 category.

Section 4:
How prices are set

Introduction

Prices for consumers using our networks to consume electricity are set in two ways.

1. Standard pricing for residential and most commercial consumers is supplied according to the price categories in the standard price schedule (standard consumers).
2. Non-standard for directly billed customers.

Defining our consumer groups

We assign our standard consumers to one of 14 consumer groups for pricing. We supply our standard consumers under the Default Distribution Agreements we have with electricity retailers. The majority of the consumers on our network are standard consumers. We have six directly billed customers connected to our network (IND load group).

Table 5 below lists the 15 consumer (load) groups and their defining characteristics. Consumers are assigned to a load group based on location, the capacity of the connection, maximum business day peak demand, and meter configuration. For the smaller consumers up to and including the 45kW group, there is a choice to allow a controllable load for a lower price.

Load group	Description
LOWHCA	Primary residence that consumes less than 9,000 kWh per annum – high-cost area
LOWLCA	Primary residence that consumes less than 9,000 kWh per annum – low-cost area
015HCA	0-15kVA and up to 60 Amp fuse – high-cost area
015LCA	0-15kVA and up to 60 Amp fuse – low-cost area
030HCA (new)	16 – 30 kW; 1 x 80 Amp fuse, 2 x 60 Amp fuses; or 3 x 32 Amp fuses – high-cost area
030LCA (new)	16 – 30 kW; 1 x 80 Amp fuse, 2 x 60 Amp fuses; or 3 x 32 Amp fuses – low-cost area
045HCA	31 – 45 kW; 3 x 60 Amp fuses – high-cost area
045LCA	31 – 45 kW; 3 x 60 Amp fuses – low-cost area
ASSHCA	Assessed capacity over 15kVA – high-cost area
ASSLCA	Assessed capacity over 15kVA – low-cost area
TOU400HCA	Time of use 400-volt supply – high-cost area
TOU400LCA	Time of use 400-volt supply – low-cost area
TOU11HCA	Time of use 11kV supply – high-cost area
TOU11LCA	Time of use 11kV supply – low-cost area
IND	Individually assessed sites – Directly billed customers

Table 5: Load groups

Location – high cost and low-cost area allocation

For standard consumers, the revenue requirement is allocated to high-cost areas and low-cost areas, using our geographic information system (GIS). The cost areas represent the load density of consumers, established using:

- Number of ICPs on each transformer
- Number of ICPs per kilometre of distribution line length.

On average, the load density is 2.5 times higher in the low-cost areas compared to the high-cost areas. Load density is a primary cost factor for an EDB – capital expenditure costs and operating expenditure costs to service connections in rural areas (high-cost areas with lower load density) are higher than servicing clustered connections (low-cost areas with higher load density) in the urban areas.

Allocation of consumers to load groups within cost areas

Consumers in the high-cost area and the low-cost area are split into the following load groups:

- Low fixed charge group
- Mass market installed capacity groups:
- 015 – (015 kVA – single-phase 60 A connection)
- 030 – (16 – 30 kVA – single-phase 80 A/two phase 60 A/three-phase 32 A connection) (new)
- 045 – (31 – 45 kVA – three-phase 60 A connection)
- Assessed (ASS) capacity groups based on fuse size, above 45 kVA up to 500 kVA
- TOU groups for LV and 11kV connections with half-hour metering, generally above 500 kVA.

Low fixed charge load group

We must comply with the LFC Regulations, which state that we must offer a fixed tariff for "domestic consumers" of no more than $0.75 per day. A domestic consumer is defined by the regulations as a person who purchases electricity for their 'principal place of residence' (clause 4(1)).[2] We meet the obligations by offering low user load groups who will pay a daily fixed price of $0.75 (from 1 April 2025).

We also ensure that an 'average' consumer (a consumer who uses less than 9000 kWh per annum) in the low load groups pays no more than an 'average' consumer in an alternate 015 load group, by adjusting the costs allocated to the low user load groups. This means the low user group pays less than the costs of supply, with these costs met by other consumers.

The low fixed charge obligations are currently being phased out with a $0.15 increase in fixed prices over a five-year period effective 1 April 2022. This is the fourth year of five and accordingly, the $0.75 per day fixed price for low users is in place.

015, 030, 045 and assessed capacity load groups

ICPs not in the low fixed charge load groups and without time of use (TOU) meters installed, fall into one of four other load groups:

1. 15 kVA (015 load group)
2. 30 kVA (030 load group) (new)
3. 3 x 60 A (045 load group)
4. Assessed capacity (ASS load groups).

ICPs in the 015 load group are single-phase and have a maximum capacity of 15 kVA (60 A). ICPs in the 030 load group have either a single-phase 80 A connection, a two-phase 60 A connection, or a three-phase 32 A connection. ICPs in the 045 load group have three-phase 60 A connections.

[2] Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 https://www.legislation.govt.nz/regulation/public/2004/0272/latest/dlm283614.html

ASS load group have a three-phase connection with a maximum capacity greater than 60 A per phase. Capacity prices for consumers in the ASS load group are calculated on the fuse size (installed capacity) of the connection.

The mass market and assessed capacity groups are grouped by installed capacity and fuse size. The resulting capacity bands broadly reflect the cost of supplying the distribution network by providing a proxy for relative use of the network, including during peak demand periods.

Time of use load groups

ICPs in the TOU load groups have TOU meters installed, which record kWh consumption every half an hour. From TOU meters we can calculate the after diversity maximum demand (ADMD), and coincident (network) peak demand (CPD), which are used to allocate costs to load groups and calculate capacity prices.

IND load group

The decision to place consumers onto a directly billed contract is made on a case-by-case basis. When making this decision, we consider the specific needs of a customer, and the:

- Cost of the build
- Number of new assets required
- The extent of the existing network that will be used by the new connection
- Capital contribution paid
- Ongoing costs that will be recovered through delivery prices
- Required security of supply.

We enter into long-term contracts with directly billed customers. This gives us the ability to negotiate outcomes that are consistent with market-like arrangements.

The methodology applied to determine the delivery prices for directly billed customers is specific to each customer. Section 5 provides more details on how the prices are determined for INDs and distributed generators.

Methodology applied in setting our prices for 2025/26

In setting the prices we have followed the steps below:

Step 1: Determine the allowable revenue under DPP4

This year, we are moving into the first year of the DPP4 period (2025/26 - 2030/31) and our allowed revenue is prescribed in the DPP4 Determination. Our calculations are published in a separate document (Annual Price-Setting Compliance Statement), and a summary is included here. Our FY26 forecast allowable revenue is $81.662 million (Table 6).

Component	Value ($000)
Distribution revenue	73,360
Transpower charges	17,020
Other pass-through and recoverable costs	(8,718)
Opening wash-up balance account	-
Forecast allowable revenue	81,662

Table 6: Forecast allowable revenue calculations

Following the determination of our forecast allowable revenue, we then calculate our target revenue by multiplying the forecast prices that apply from 1 April 2025 to 31 March 2026 by the forecast quantities for the period ending 31 March 2026, which results in a target revenue from distribution prices of $81.625 million. For compliance with our price-path, set by the Commerce Commission, this target revenue must be less than our forecast allowable revenue.

Step 2: Determine the forecast revenue for the six directly billed customers and deduct from target revenue

The prices for the six directly billed customers are set based on the methodologies in their conveyance agreements. Distribution prices are mainly adjusted for inflation based on the change in the PPI or CPI (depending on the terms of the conveyance agreement) over a 12-month period.

The delivery prices for directly billed customers are set out in Table 7 below, showing a comparison with the prior year's prices.

Component	2025/26 ($'000)	2024/25 ($'000)
Forecast distribution prices	3,475	3,316
Transmission prices	2,174	2,110
Total	5,649	5,426

Table 7: Total revenue allocated to directly billed customers in the IND load group

With these customers having forecast delivery costs set at $5.649 million, the remaining revenue to be allocated between all other load groups is $75.976 million.

Step 3: Forecast quantities

The forecast quantities consist of two parts – ICP counts and kilowatt-hours (kWh). The ICP counts are applied to the fixed portion of the prices while kWh/kW volumes are applied to the relevant variable portion of the prices. Our FY26 price-setting compliance statement outlines our forecasting approach, and the values assumed for setting FY26 prices. This is available on our website, www.alpineenergy.co.nz.

Forecasts of connections (ICPs) are based on an analysis of historical connections at a price category level and cross-checked against trends at a macro customer-group level. Long-term trends are used where the series is stable. Adjustments are made by exception where recent data suggests a deviation from these trends. We estimated the average number of active ICPs on the network to be 34,051 (when setting the fixed prices for 2025/26). Our forecasts for some categories show a low or no growth compared to recent historical levels.

Irrigation load can vary from year to year, largely driven by the climate conditions over the summer period. This is not known at the time of forecasting quantities. The monthly profile of forecast irrigation load is based on the historical average. A warmer winter or wetter summer resulted in lower volumes than forecast, and vice versa. For other customer groups, average kWh/ICP and kW/ICP are used for projecting the impacts of changes to values from increases or decreases in connections (ICPs).

In addition to forecasting energy use, we have also made assumptions on day versus night consumption. We used the actual day/night volumes from the prior year (which we get each month from the retailers as part of our billing process) to determine and estimate day/night consumption. In line with the prior year, the split is on average 70:30 day/night.

The forecast kWh and number of ICPs for FY26 are shown in Table 8 below:

Load group	Forecast Quantities - 31 March 2026			
	Day kWh	Night kWh	Capacity kW	Avg Number of ICPs
LOWHCA	9,943,457	4,261,482		2,301
LOWLCA	42,666,797	18,285,770		10,830
LOWUHCA	102,105	43,759		30
LOWULCA	232,201	99,515		68
015HCA	42,345,430	18,148,041		5,959
015LCA	72,105,482	30,902,349		11,562
015UHCA	420,892	180,382		43
015ULCA	332,333	142,428		57
030HCA[3]	153,517	65,793		10
030LCA	244,396	104,741		15
030UHCA	-	-		-
030ULCA	-	-		-
045HCA	7,879,633	3,376,986		520
045LCA	14,281,247	6,120,534		725
045UHCA	303,872	130,231		13
045ULCA	370,643	158,847		18
ASSHCA	93,755,134	40,180,772	115,457	1,327
ASSLCA	29,831,873	12,785,088	39,161	416
TOU400HCA	17,232,490	7,376,066	8,170	38
TOU400LCA	69,047,640	31,272,817	22,055	98
TOU11HCA	38,280,056	14,704,988	11,087	5
TOU11LCA	9,216,048	3,994,382	4,162	5
IND				12
Total	448,745,245	192,334,972	200,091	34,051

Table 8: Forecast quantities

Step 4: Determine the delivery prices for each load group

Other factors influence our approach to pricing including ensuring consumers do not experience price shocks, ensuring revenue adequacy, maintaining logical relationships between price categories, ensuring compliance with Low Fixed Charge Regulations, and pragmatically transitioning to greater cost reflectivity. Balancing these considerations requires an assessment of the impact of the split between fixed and variable prices for each load group.

Taking all these variables into account, we run multiple scenarios to determine what we believe is an equitable outcome for consumers in line with the application of our pricing principles.

The analysis resulted in the following pricing outcomes:

- We have maintained the fixed prices for all load groups except LOW load groups at 80% (on average) and variable at 20% (on average).

[3] New load group with no consumers currently allocated, forecast for small number of consumers shift to this load group throughout the year.

- We have passed through all transmission prices as a fixed price, i.e. the variable prices for the transmission prices component of the delivery prices have become $0 for all load groups except LOW (see bullet point below). This is in keeping with the new Transmission Pricing Methodology and the guidance provided by the Electricity Authority.
- To comply with the Low Fixed Charge Regulations, for LOW load groups, the fixed transmission price component is $0 for 2025/26. The fixed distribution price is $0.75 as stipulated in the Low Fixed Charge Regulations.

Refinement of prices

Ongoing refinements to network prices are focused on aligning them with the cost of supply, as a clear indicator of the relative cost across each pricing category. These adjustments ensure prices remain within the subsidy-free range, balancing the avoidable cost and stand-alone cost for each category. Sensitivity to consumer needs is also a key consideration, driving initiatives to introduce new pricing categories and modify existing ones. The gradual phase-out of Low Fixed Cost Regulations signals a shift towards accommodating smaller residential consumers within a dedicated pricing category.

Review of long-run marginal cost (LRMC)

In determining the LRMC, we evaluated three methodologies:

- the perturbation approach,
- the average incremental cost approach (applied here), and
- the stand-alone cost approach.

The perturbation approach evaluates how changes in costs arise from a fixed, permanent increase in forecast demand growth. It evaluates the incremental costs associated with accommodating additional demand on the network. This typically involves capacity upgrades or expansions, such as constructing new infrastructure or enhancing existing assets, to ensure the network can reliably manage the increased load. Implementing this method requires detailed data, including forecasts of annual operating and capital expenditure, load growth projections for the relevant network asset, and assumptions about the cost and size (in megawatts) of potential capacity upgrades over the specified time horizon.

The average incremental cost approach calculates LRMC by estimating the average change in projected operating and capital expenditure resulting from future demand increases. This involves projecting future costs associated with demand growth, forecasting load growth for relevant network assets, and dividing the present value of these projected costs by the present value of expected demand increases. Essentially, this approach spreads the total cost of meeting new demand across the forecasted growth in demand.

The stand-alone cost approach estimates LRMC based on the hypothetical cost of building an entirely new network to meet current demand, assuming no pre-existing infrastructure. It does not account for existing capacity and focuses solely on the cost of constructing new infrastructure. While simple, this approach is more suited to markets with rising demand and where supply can be expanded incrementally.

We opted for the average incremental cost approach for two reasons. Firstly, it provides a more realistic estimate of future network costs as it incorporates actual demand projections and planned investments. Second, it balances precision with practicality, avoiding the extreme assumptions of the stand-alone method while requiring less granular data than the perturbation approach.

LRMC values were calculated using our 2024 Asset Management Plan data to determine capital expenditure over a five-year period for increased maximum demand on our network. Both capital costs and capacity increases were adjusted for the time value of money using a present value calculation, applying the average weighted cost of capital (WACC). This calculation resulted in a cost per kilowatt ($/kW) for increasing total capacity, expressed in today's monetary terms. Finally, this cost was converted into a variable price per kilowatt hour ($/kWh) using the network's average load factor, ensuring the LRMC reflects current costs and network utilisation.

Developing variable capacity options for consumers, where reduced capacity during periods of network constraint results in discounted fixed or capacity prices, is a key focus area for future LRMC signalling and will be explored as part of our Pricing Strategy implementation in coming years.

Calculating the subsidy-free range

Our approach to calculating the subsidy-free range ensures that distribution prices are both equitable and cost-reflective while complying with regulatory pricing principles and guidelines. These specify that prices for each consumer group or pricing category should lie within a range defined by the avoidable cost and the stand-alone cost of serving that group. This range, known as the subsidy-free range, ensures that no consumer group subsidises or is subsidised by others.

The subsidy-free range represents the revenue levels where a consumer group pays an economically acceptable share of costs. At its lower bound, prices must exceed the avoidable cost, which reflects the costs that would no longer be incurred if the group were no longer connected to the network. At its upper bound, prices must remain below the stand-alone cost, which captures the cost of serving the group as if it were the sole user of the network. By setting prices within this range, we ensure that the revenue collected from each group neither imposes additional costs on others (by falling below avoidable costs) nor exploits the benefits of shared network use (by exceeding stand-alone costs).

To calculate the stand-alone cost, we rely on asset-sharing factors derived from our cost of supply study. These factors indicate the proportion of the network's assets used by each consumer group. For instance, if a consumer group or pricing category utilises 33% of the asset base, its stand-alone cost would be three times the standard cost, as it would bear the full cost of the network without support from other groups. This calculation neutralises the effect of shared costs and provides an independent measure of servicing that group.

Calculating the avoidable cost also uses data from our cost of supply modelling. For example, if a customer group accounts for 33% of the asset base, its avoidable cost equates to one-third of the standard cost as this portion of the network's costs would no longer need to be recovered through pricing. The avoidable cost establishes the minimum revenue required to ensure that the presence of a group does not impose additional costs on others.

By using these benchmarks, we define the subsidy-free range as the interval between the avoidable and stand-alone costs for each pricing category. To be subsidy-free, prices must at least cover the avoidable cost (ensuring no subsidies are required from others) but remain below the stand-alone cost (preventing over-reliance on shared network benefits). This method enables us to achieve equitable and cost-reflective pricing that aligns with pricing principles and encourages the efficient and sustainable use of the network. The following table and graph illustrate the subsidy-free range for network prices across various pricing categories, comparing the cost of supply, avoidable cost, and price to the average ICP.

	LOW	015	030	045	ASS	TOU4	TOU11	IND
Stand-alone cost ($)	766.35	376.52	1,136.67	1,372.39	612.70	7,653.67	2,371.23	960.80
$/kW cost of supply	196.66	134.91	121.52	91.96	83.07	67.59	64.80	64.15
Avoidable cost ($)	38.95	31.52	8.02	4.32	8.97	1.11	1.73	4.91
Average cost ($/ICP)	62.76	93.05	101.89	147.98	285.13	317.84	336.87	197.49

Table 9: Subsidy-free range for network prices

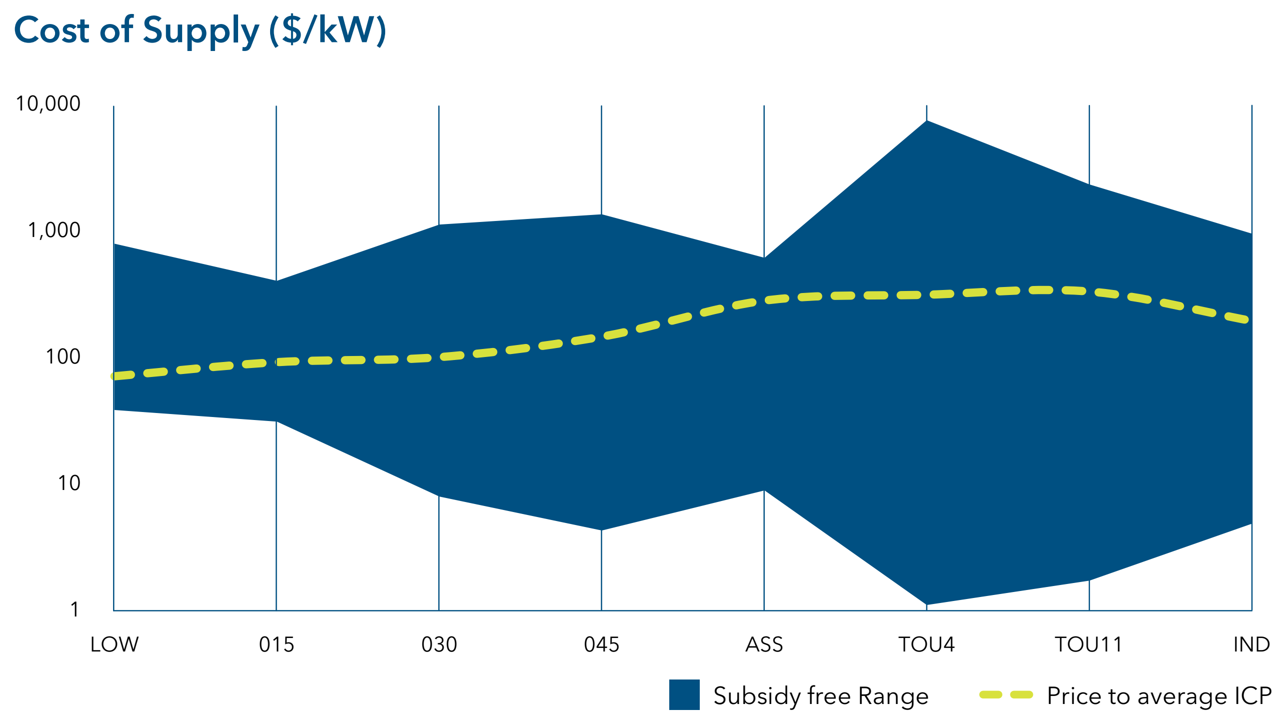

Figure 2: Illustration of the subsidy-free range for each pricing category. Note Y-axis is a log scale.

Transmission Pricing Methodology

The Transmission Pricing Methodology provides a stable framework for managing transmission costs. It sets fixed annual prices, which are paid in 12 equal monthly instalments each pricing year, ensuring prices are not influenced by short-term demand fluctuations from electricity users.

Transmission prices are treated as pass-through costs and are recovered through our pricing structure. Fixed daily prices and daily capacity prices are applied, while for LFC consumers, where regulations cap fixed daily prices, variable prices are used to recover costs. This approach ensures accurate cost recovery aligned with the fixed target amount.

The resulting delivery prices, by load group for distribution and recoverable and pass-through cost (including transmission prices), for 2025/26 are shown in Table 10 below.

Load group	Distribution				Recoverable and pass-through costs (incl. transmission prices)			
	Fixed per day	Variable Day per kWh	Variable Night per kWh	Capacity per kW/day	Fixed per day	Variable Day per kWh	Variable Night per kWh	Capacity per kW/day
LOWHCA	0.7500	0.1059	0.1037	-	-	0.0206	0.0206	-
LOWLCA	0.7500	0.0947	0.0925	-	-	0.0206	0.0206	-
LOWUHCA	0.7500	0.1068	0.1046	-	-	0.0228	0.0228	-
LOWULCA	0.7500	0.0956	0.0934	-	-	0.0228	0.0228	-
015HCA	3.1178	0.0150	0.0128	-	0.3954	-	-	-
015LCA	2.8365	0.0150	0.0128	-	0.3954	-	-	-
015UHCA	3.1278	0.0150	0.0128	-	0.4592	-	-	-
015ULCA	2.8515	0.0150	0.0128	-	0.4592	-	-	-
030HCA	7.1812	0.0150	0.0128	-	0.6388	-	-	-
030LCA	6.4399	0.0150	0.0128	-	0.6388	-	-	-
030UHCA	7.2012	0.0150	0.0128	-	0.7694	-	-	-
030ULCA	6.4724	0.0150	0.0128	-	0.7694	-	-	-
045HCA	11.2445	0.0150	0.0128	-	0.8821	-	-	-
045LCA	10.0433	0.0150	0.0128	-	0.8821	-	-	-
045UHCA	11.2745	0.0150	0.0128	-	1.0795	-	-	-
045ULCA	10.0933	0.0150	0.0128	-	1.0795	-	-	-
ASSHCA	5.1038	0.0150	0.0128	0.2725	1.0726	-	-	0.0099
ASSLCA	4.6079	0.0150	0.0128	0.2414	1.0726	-	-	0.0099
TOU400HCA	4.4515	0.0130	0.0108	0.6013	1.3097	-	-	0.0178
TOU400LCA	4.0177	0.0130	0.0108	0.5357	1.3097	-	-	0.0178
TOU11HCA	4.2155	0.0130	0.0108	0.5507	0.4668	-	-	0.0178
TOU11LCA	3.8033	0.0130	0.0108	0.4848	0.4668	-	-	0.0178

Table 11: 2025/26 delivery prices for all standard load groups

Section 5: Non-standard Contracts

Introduction

We enter into non-standard agreements with large or unique electricity users and distributed generators. These contracts are negotiated on a case-by-case basis. The general principles we apply in these negotiations are outlined in this section.

Over the next 12 months, we will review our customer connections policies and our large user contracts, consulting with our current customers in the IND load group. We will also be developing a framework and contract for connecting large-scale distributed generation to our network.

Calculation and recovery of the cost of new assets

The capital contribution paid for new assets can reduce the ongoing delivery prices that a customer will pay.

If a capital contribution equals the total value of the new assets allocated to the customer, the customer may not pay the cost of capital or depreciation charges for these new assets. They will, however, pay for ongoing maintenance charges for these assets through their delivery prices.

If the capital contribution does not cover the full cost of the value of new assets used by the customer, then the remaining value of the asset (after capital contributions) will be used to calculate the cost of capital and depreciation charges. Depreciation charges are calculated on a total asset life basis.

When calculating the return on capital charges we apply the Commerce Commission's weighted average cost of capital (WACC) for the industry, and the closing regulatory value of the new asset (adjusted for inflation) from the previous year, using a midyear cash flow.

Maintenance charges payable

Maintenance charges are the cost of maintaining assets. While new assets will have little maintenance after the first year of service, the maintenance charge will effectively also cover future replacement costs. However, the maintenance charge will not cover any future costs to upgrade capacity.

Recovering the cost of existing network assets

If a customer also requires the use of existing network assets, then the cost of capital charges, depreciation, and maintenance charges apply to these assets.

Allocators for recovering costs

The portion that a customer will pay for the use of existing network assets will depend on the most relevant cost driver for that asset. For lines and cables, costs are apportioned to the customer based on the customer's line/cable length to the total line/cable lengths in our network.

For substations, transformers, protection, and switchgear, costs are apportioned to the asset using the total demand or capacity of all users of the asset, including the directly billed customer, and the total demand or capacity of the asset type across the network. Costs are then apportioned according to the customer's demand or capacity to the total demand/capacity relevant to the asset.

Our costs are fixed in the short term so a drop in consumption will have little or no impact on our short-term (annual) costs. However, a decrease in consumption over the long term can delay or prevent upgrades in network capacity due to the under-recovery of our required revenue.

Recovery of transmission costs

Transmission costs are passed through to customers according to their demand compared to the total demand of all users of the GXP to which the consumer is connected. With the revised Transmission Pricing Methodology (which was introduced on 1 April 2023), this allocation is done based on a five-year average of previous prices (considering longer term variations in demand of the consumer) to ensure it is aligned with the methodology employed in the Transmission Pricing Methodology.

Capital contributions

In addition to the delivery price revenue that we receive from our consumers, we also charge capital contributions to consumers connecting to our network or needing upgrades to existing connections. Costs of upgrades to an existing connection can be shared with Alpine Energy where there are network benefits to the upgrade.

Where the upgrade is for the sole benefit of the consumer, they will pay in entirety for that upgrade.

Capital contributions cover the cost of the work carried out. If 100% of capital costs are paid by capital contributions, there should be no remaining connection costs to be recovered through delivery prices except ongoing operational costs (i.e. maintenance).

Distributed generation on our network

Our network provides the means for distributed generators of all types and sizes to convey electricity to end-users.

Fees payable by distributed generators to us are set by the Electricity Authority under the Electricity Industry Participation Code (the Code). Under the Code, we are allowed to charge certain fees upfront and can charge ongoing prices on an incremental cost basis.

We neither 'pay', nor 'charge', distributed generators for the electricity that they convey down our lines.

We encourage distributed generators to connect and distribute through our network.

Information about the connection to our network and our application process for connection and operation of distributed generation by both small and large distributed generators is available on our website at www.alpineenergy.co.nz/customers/generating-electricity

Section 6: Target Revenue

Introduction

We set prices by calculating and allocating costs across each specific consumer group. The process involves:

- Confirming the total forecast revenue allowed by the Commerce Commission for the pricing year.
- Identifying our major cost components, and whether the costs are fixed or avoidable.
- Allocating costs to specific consumer groups (as described in Section 4).
- Checking alignment between cost types and price components.

Total target revenue

Table 11 summarises the key components of target revenue required to cover the costs and return on investment associated with Alpine Energy's supply of electricity lines services.

Cost component	$ '000
Operating expenditure	38,051
Depreciation	13,122
Return on investment	16,615
Regulatory tax	5,535
Transpower charges	17,020
Other pass-through costs and recoverable costs	(8,718)[4]
Target revenue	81,625

Table 11: Summary of cost components of target revenue

Operating expenditure

Includes forecast costs related to the day-to-day operations, network maintenance, and the overall management of business functions, along with an adjustment for the time value of money on revenue. These are sourced from the Commerce Commission's DPP4 financial modelling.

Depreciation

Reflects the gradual decline in the value of Alpine Energy's asset base, primarily due to normal usage and aging of equipment. Depreciation values are provided by the Commerce Commission's DPP4 financial modelling.

Return on investment

A pre-tax return based on Alpine Energy's regulated asset base. Return on investment is provided by the Commerce Commission's DPP4 financial modelling.

[4] The driver for negative pass-through and recoverable costs is a $9.158M IRIS penalty resulting from Alpine Energy exceeding DPP3 opex allowances.

Regulatory tax

Regulatory taxes applied to Alpine Energy, as provided by the Commerce Commission's DPP4 financial modelling DPP4 modelling.

Transpower charges

Charges payable to the national electricity grid operator for transporting energy from generators to Alpine Energy's network. This includes connection charges, benefit-based charges, residual charges and other transmission provisions. These charges are passed onto our consumers at cost. These charges include Transpower Investment Contract Charges as notified by Transpower annually.

Other pass-through and recoverable costs

Includes local council rates, Commerce Commission levies, Electricity Authority levies and Utilities Disputes Limited levies. These costs are passed on to our customers at cost.

Recoverable costs

Include the recovery of adjustments related to capital expenditure, as well as quality and financial incentive payments and pass-through balances permitted under DPP4.

Allocating costs to specific consumer groups

The target revenue allocated to each consumer group for 2025/26 is shown in Table 12 below. For a prior-period comparison, we have used a forecast revenue based on the June 2024 price reduction instead of the values published in our 2024 Pricing Methodology. The allocation is based on the methodology described in Section 4 and has not changed materially this year compared to last year.

Consumer group	Year ending 31 March 2025 ($'000)	Year ending 31 March 2026 ($'000)	Change ($'000)	Change (%)
LOWHCA	$2,149	$2,417	$268	12.5%
LOWLCA	$8,635	$9,952	$1,317	15.3%
LOWUHCA	$20	$27	$7	35.1%
LOWULCA	$43	$58	$15	34.1%
015HCA	$7,074	$8,509	$1,435	20.3%
015LCA	$12,460	$15,117	$2,657	21.3%
015UHCA	$48	$65	$17	35.3%
015ULCA	$62	$76	$14	22.1%
030HCA	-	$33	$33	
030LCA	-	$44	$44	
030UHCA	-	$0	$0	
030ULCA	-	$0	$0	
045HCA	$2,153	$2,462	$309	14.4%
045LCA	$2,819	$3,182	$363	12.9%
045UHCA	$61	$65	$4	6.3%
045ULCA	$64	$81	$17	26.6%
ASSHCA	$13,993	$16,812	$2,819	20.1%
ASSLCA	$4,237	$5,065	$828	19.5%
TOU400HCA	$1,703	$2,230	$527	30.9%
TOU400LCA	$5,023	$5,882	$859	17.1%
TOU11HCA	$2,800	$2,966	$166	5.9%
TOU11LCA	$716	$934	$218	30.5%
IND	$5,423	$5,649	$226	4.2%
Total	$69,463	$81,625	$12,162	17.5%

Table 12: Target revenue by consumer group

Alignment between costs and prices

In this section, we discuss how we calculate prices for distribution, transmission, and pass-through components of our pricing. We use a combination of fixed, capacity, and variable pricing to recover distribution costs.

Allocating distribution costs

Our pricing model allocates distribution costs to load groups in a way that reduces cross-subsidisation between users of the network so that each load group pays for the assets that the load group uses.

Allocating Transmission prices

Due to the short lead times from receiving the final transmission prices and implementation, the allocation of costs to the load groups for 2025/26 is based on the historical allocations, adjusted to account for changes in ICP numbers within each load group, and scaled for the actual revenue requirements from Transpower.

Due to the short lead times from receiving the final transmission prices and implementation, the allocation of costs to the load groups for 2025/26 is based on the historical allocations, adjusted to account for changes in ICP numbers within each load group, and scaled for the actual revenue requirements from Transpower.

Transmission prices are allocated to standard consumers based on the price category of the connection, with no variable component, to align it with the fixed nature of the transmission pricing methodology. Transmission prices for the low fixed cost residential consumers are variable components to ensure compliance with the relevant regulations.

Transmission prices are allocated to non-standard consumers based on the same rules used by the transmission pricing methodology - a five-year average historic pricing period, scaled to the actual Transpower prices.

Allocating pass-through and recoverable costs

When calculating load group prices to recover annual pass-through and recoverable costs, we use forecast rates and levies from local authorities, the Commerce Commission, and the Electricity Authority.

We allocate forecast pass-through and recoverable costs to load groups, by multiplying the forecast annual pass-through and recoverable cost by the number of ICPs in a load group to total ICPs on the network.

The different prices (charges) explained

The different prices that make up the full delivery price for each load group are explained below.

Fixed daily prices

Fixed daily prices are calculated by multiplying the total load group revenue requirement by the load group's fixed-to-variable ratio and then dividing the fixed portion by load group ICP numbers. With ASS and TOU load groups, the fixed portion of the revenue requirement is multiplied by a capacity price ratio to calculate the portion of costs recovered through a capacity price.

The capacity price itself is calculated by dividing the total load group costs recovered from a capacity price, by either the load group's assessed capacity (in the case of the assessed groups) or the load group's after diversity maximum demand (for TOU groups).

Low fixed charge group prices

We calculate tariffs for the LOW load groups using a three-step process.

- We deduct from the LOW load group revenue requirement; the total fixed price we can recover under the Low Fixed Charge Regulations ($0.75 per day).
- We then calculate the LOW day-night variable prices using the corresponding 015 load group fixed and variable prices, so that the total annual price for an average consumer (consuming 9000 kWh p.a.) in the LOW load groups, is not higher than an average consumer would pay in the corresponding 015 groups.
- We allocate the excess low user revenue requirement that we cannot recover under regulation to the remaining load groups.

Calculating pass-through and recoverable prices

The pass-through and recoverable costs are calculated to reflect the pass-through and recoverable prices excluding the cost of transmission but including the allowable wash-up recovery or pay-back. The balance between fixed and variable was proportionally adjusted starting with the previous year's arrangements.

Section 7: Assessing Consumer Impacts

Introduction

We assess the impact on consumers of each change to the price structure and price level. We take account of:

- The potential that the price change will result in bill shock for consumers or a consumer group
- Whether the price structure is practicable for retailers to adopt and apply
- The transaction costs associated with applying the price structure.

Assessing impacts of price changes

Moving from the DPP3 to the DPP4 regulatory period has driven the main price adjustments impacting consumers for 2025/26. The Commerce Commission has set Alpine Energy's revenues for FY26-30, including the rules for other costs that can be passed through, e.g. transmission. A characteristic of the Commission's decision is for a significant step change in FY26, with revenues escalating at the consumer price index for the following four years. The Commission estimates that the annual impact will be around $5/month over this period.

Our forecast revenue has increased by around 18% compared to our original FY25 revenue forecast, and 25% relative to the lower forecast as a result of the June 2024 price reduction. The impact on distribution prices for consumer groups varies because prices reflect forecasts of consumer connections and consumption, cost allocation of revenue between consumer groups, and the terms for directly billed customers.

Our distribution prices are passed to a consumer's retailer who incorporates them into electricity charges that include other parts of the supply chain, e.g. electricity supply costs. The impact of Alpine's 2025/26 distribution prices relative to the lower June 2024 prices is $22/month, approximately a 9% increase in an energy bill that was based on those prices. Relative to April 2024 prices the impact is around $16/month (18% monthly energy bill impact). Relative to June 2024 prices, a commercial consumer with a monthly electricity bill of $870 will see an increase of 9.7%, and an agricultural consumer with a monthly electricity bill of $2,930 will see a 7.7% increase.

Customer engagement

Between 5 August and 13 September 2024, Key Research surveyed 427 of our consumers across all seven GXPs to assess perceptions of reliability, outages and notifications, pricing, and uptake of new technologies and electric vehicles.

The survey revealed that areas with the largest proportion of satisfied consumers included:

- Delivering a safe power supply (75%)
- Providing a reliable power supply (72%)
- Notifying you of planned shutdowns (71%)
- Minimising the number of outages (70%)
- Overall reliability of power supply (70%).

This highlights our ongoing commitment to maintaining a safe and reliable network while prioritising consumer satisfaction through quality service.

Areas with the largest proportion of dissatisfied consumers included:

- Delivery prices being good value (20% dissatisfied)
- Overall handling of enquiry (20% dissatisfied)
- How well they communicate about the things they are doing (19% dissatisfied)
- Overall image and reputation (17% dissatisfied)
- They deal with consumer issues in a timely manner (17% dissatisfied).

These responses reinforce what we know about increasing consumer expectations for real-time information about network outages and planned work, as well as greater expectations for more proactive communications across all business activities.

The survey also revealed that our consumers have little willingness for increased delivery prices to improve the reliability of service provided; with 85% preferring to maintain current levels instead of increasing or reducing prices with associated changes to service. This result is consistent with our previous survey responses and is an important input when determining the level of network investment into reliability-associated projects and the required pricing structures to support this.

We set prices that are practicable for retailers to adopt and apply

We consider the impact on retailers when adopting complex price structures. We, therefore, attempt to keep our pricing structure as uncomplicated and limited to as few categories as possible to reduce the need for retailers to interpret complex pricing or the need to upgrade their systems.

We continue to consult on any pricing changes with retailers, ensuring that our pricing remains easy to interpret. This helps reduce the burden on retailers to navigate complex structures and manage system upgrades. Additionally, we consider retailers' ability to pass through distribution pricing signals and access smart meter data for pricing purposes.

Section 8:
Do you have any questions?

Introduction

We are happy to answer any questions about our Pricing Methodology and Pricing Strategy that you might have. We can be contacted on 0800 661 177 or email us at mailbox@alpineenergy.co.nz

After a copy of our Pricing Strategy and Roadmap?

To get a copy of our Pricing Strategy and Roadmap you can:

- Go to our website at: www.alpineenergy.co.nz
- Call us at 0800 661 177, and we can email you a copy
- Visit our offices at 24 Elginshire Street, Washdyke between 8:30 am and 4:30 pm.

Complaints process

If you have a complaint about our service, please contact us on 0800 661 177. We will respond to your complaint by:

- Acknowledging the complaint within 2 working days
- Confirming with you that you are making a formal complaint and what outcome you expect
- Aim to resolve your complaint within 20 working days.

If we can't resolve your complaint, you can contact Utilities Disputes Ltd, formerly known as the Electricity and Gas Complaints Commissioner, at http://www.utilitiesdisputes.co.nz or 0800 22 33 40. This is a free and independent complaint resolution service.

Certification for the Year Beginning Disclosures

Clause 2.9.1

We, Melissa Clark-Reynolds and Kevin Winders, being directors of Alpine Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

- The following attached information of Alpine Energy Limited prepared for the purposes of clause 2.4.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.
- The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

Melissa Clark-Reynolds
27 March 2025

Kevin Winders
27 March 2025

Appendix A: Alignment with Electricity Authority's Pricing Principles

Pricing Principles	Our Alignment to the Principles
Prices are to signal the economic costs of service provision by:	
1. Being subsidy-free (equal to or greater than avoidable costs, and less than or equal to stand-alone costs)	The prices for each load group are less than stand-alone costs. Prices for each load group are above the long-run incremental cost of supply. Refer to Section 7.
2. Reflecting the impacts of network use on economic costs;	Prices for each load group signal the impacts of network use on economic costs using TOU pricing (including day/night). Prices for commercial and industrial consumers also signal economic costs of network use with a capacity price which can vary annually based on changes to consumer connection capacity or peak demand. Most network costs are fixed and do not vary based on network use in the short term (i.e., hourly, daily). Work is planned to identify which network costs vary according to network use to confirm the correlation between fixed and variable costs and fixed and variable prices. Refer to Section 2.
3. Reflecting differences in the network service provided to (or by) consumers	Prices reflect the difference in the network service provided to consumers. We offer non-standard contracts for consumers with non-standard service requirements. Refer to Section 5 for a discussion of the approach to supply standards for consumers with non-standard contracts. We define our load groups to reflect differences in network service provided, based on location and capacity prices for each load group are developed based on the cost to deliver the relevant network service. Refer to Section 4.
4. Encouraging efficient network alternatives	Network alternatives are considered as part of asset management planning.
a) Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use	
Most network costs are fixed and do not vary based on network use in the short term. Work is planned to identify which network costs vary according to network use to confirm the correlation between fixed and variable costs and fixed and variable prices. Refer to Section 2.	
b) Prices should be responsive to the requirements and circumstances of end-users by allowing negotiation to:	
1. Reflect the economic value of services	We offer non-standard contracts to consumers who have non-standard network connection and operation requirements to appropriately reflect the economic value of the network service. Refer to Section 5.
2. Enable price/quality trade-offs	We regularly engage with consumers to test price/quality preferences via surveys. We also enable consumers to make price/quality trade-offs by offering controlled and uncontrolled prices. Refer to Section 7. Non-standard contracts are negotiated to reflect price/quality trade-offs. Refer to Section 5 for a discussion of the approach to supply standards for consumers with non-standard contracts.
c) Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives	
We regularly engage with consumers, retailers, and shareholders on the construction of our delivery prices. In particular, we seek feedback from retailers on the practical implications of our pricing approach and any changes to pricing structures. We are managing the transaction costs on retailers by discussing pricing with other EBDs to help with the standardisation of tariffs, thereby reducing transaction costs for retailers and consumers. We consider the impact of price changes on households and design our pricing to avoid bill shocks by ensuring by load group that the average bill in each load group is checked for reasonableness in comparison to the previous year. Increases to our delivery prices have been and will continue to be, consistent with the limits placed on us under the DPP Determination by the Commerce Commission. Refer to Section 7 for a discussion of the approach to assessing consumer impacts and engaging with retailers.	

Appendix B: Alignment with information disclosure requirements

Pricing Principles	Our Alignment to the Principles
2.4.1 Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which:	
1. Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the prices payable or to be payable;	Refer to the description of the approach in this document.
2. Describes any changes in prices and target revenues;	Refer to Section 3 for a description of the change in forecast revenue and average delivery prices for each consumer group between 2024/25 to 2025/26.
3. Explains, in accordance with clause 2.4.5 below, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any);	Refer to Section 5 for a description of the pricing approach for non-standard contracts and distributed generation.
4. Explains whether, and if so how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.	Refer to Section 7 for a description of how we sought the views of consumers on price and quality expectations and how these views inform the pricing approach.
2.4.2 Any change in the pricing methodology or adoption of a different pricing methodology, must be publicly disclosed at least 20 working days before prices are determined in accordance with the change or the different pricing methodology takes effect.	
N/a – we have not changed our pricing model from the prior year.	
2.4.3 Every disclosure under clause 2.4.1 above must:	
1. Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group;	Refer to Sections 4 and 6.
2. Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;	Refer Appendix A.
3. State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	Refer to Section 6, Table 11.
4. Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;	Refer to Section 6, Table 11.
5. State the consumer groups for whom prices have been set, and describe– a. the rationale for grouping consumers in this way; b. the method and the criteria used by the EDB to allocate consumers to each of the consumer groups;	Refer to Section 4.
6. If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons;	Refer to Section 3.
7. Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way;	Refer to Section 6, Table 13.
8. State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	Refer to Section 6, Table 13.

Pricing Principles	Our Alignment to the Principles
2.4.4 Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy:	
1. Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set;	Refer to Section 2 for a description of how we plan to evolve our pricing over the coming years. The key objective is gradually rebalancing the proportion of costs recovered using fixed and capacity prices and variable prices by reducing the level of variable volume components. More detail on the nature and timing for achieving this objective is being worked on.
2. Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy;	Refer to Section 2. Our goal is to work towards a pricing structure for all consumer groups (excluding directly billed customers) that recovers costs and revenue and reflects economic costs to the extent practicable. Specific consumer impacts will be assessed as part of our future pricing work plan.
3. If the pricing strategy has changed from the preceding disclosure year, identify the changes, and explain the reasons for the changes.	Refer to Section 2. Our pricing approach has not fundamentally changed from the preceding disclosure year. However, we have more clearly identified the objectives through the development of our pricing work plan. This is now reflected in the pricing methodology document.
2.4.5 Every disclosure under clause 2.4.1 above must:	
1. Describe the approach to setting prices for non-standard contracts, including– a. The extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts;	Refer to Section 5 for a description of the pricing approach for non-standard contracts. For the period ending 31 March 2024, we had six directly billed customers with 12 ICPs connected to our network at present. Refer to Table 8 for the expected target revenue to be recovered from non-standard contract customers.
b. How the EDB determines whether to use a non-standard contract, including any criteria used;	Refer to Section 5 for a description of the pricing approach for non-standard contracts, including the criteria used. The decision to place a new connection onto a directly billed contract is made on a case-by-case basis.
c. Any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles;	Refer to Section 5 for a description of the pricing approach for non-standard contracts, including the approach to cost allocation and determining pricing. Prices for non-standard contracts are developed to be consistent with the pricing principles. Price structures for non-standard contract consumers reflect a close alignment between fixed and variable costs.
2. Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain: a. The extent of the differences in the relevant terms between standard contracts and non-standard contracts; b. Any implications of this approach for determining prices for consumers subject to non-standard contracts;	Refer to Section 5 for a description of the service levels available to consumers subject to non-standard contracts, including the extent of differences to standard consumers.

Pricing Principles	Our Alignment to the Principles
3. Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the: a. Prices; and b. Value, structure, and rationale for any payments to the owner of the distributed generation.	Refer to section 5 for a description of the approach to developing prices for network services provided to consumers with distributed generation.

Appendix C: Loss factors

Losses represent the percentage of electricity entering the network that is lost during the delivery to ICPs. The quantity of electricity metered at ICPs is net of losses. To determine each retailer's purchase responsibilities, the electricity measured at the consumer's meter is multiplied by a 'loss factor'. There are two main components to loss factors:

- Fixed component due to the standing losses of the zone substation and distribution transformers.
- Variable components arising from the heating effects of the resistive losses in the delivery conductors.

The loss percentage reported under the information disclosure requirements for the year ended 31 March 2024 was 3.2%.

The following loss factors are applied by us:

- 33kV dedicated–1.02
- 11KV general–1.019
- 400V general–1.049.

Glossary

ADMD	After Diversity Maximum Demand—the simultaneous maximum demand of a group of consumers with similar power requirements.
Capacity	The maximum power supplied by a network asset in respect of consumer capacity, it refers to the size of the network assets directly connected to the consumer.
Code	The Electricity Industry Participation Code 2010.
Consumer	A person that consumes electricity supplied by our network.
Commerce Commission	A government body tasked with regulating our price and quality of service.
CPD	Coincident Peak Demand—relates to the consumer's off-take at the connection location during a peak demand period.
CPI	Consumer Price Index—a measure of the change of a weighted average of prices in a basket of consumer goods and services.
Customer	A legal entity with which we have a direct contractual relationship, in the form of a use of supply agreement (e.g. retailers and large consumers).
Delivery prices	Prices that recover distribution, transmission, pass-through, and recoverable costs.
Demand	The amount of electricity required to power equipment at a point in time, expressed in kilowatts (kW) or kilovolt amperes (kVA).
Distributor	Alpine Energy Limited as the operator and owner of the electricity distribution network.
Distributed Generation	Electricity generation that is connected and distributed within the distribution network, the electricity generation being such that it can be used to avoid or reduce transmission demand costs. Also referred to as 'embedded generation'.
Distribution costs	Costs associated with building and maintaining our electricity network.
Distribution network	The network of electricity assets that distribution network companies such as Alpine Energy Limited own and operate, to deliver electricity from the transmission network to consumers.
DPP	Default Price-Quality Path—with which non-exempt suppliers of electricity line services comply under Part 4 of the Commerce Act 1986.
EDB	Electricity Distribution Business—a business that is responsible for delivering electricity from the national grid to consumers.
Electricity Authority (EA)	A government body tasked with promoting efficiency in the electricity industry and who make changes to the Electricity Industry Participation Code, which we must comply with.
Fixed prices	Prices that do not vary with the number of kWh consumed
GIS	Geographic Information System—is used to isolate assets on a network and to identify low-cost and high-cost areas.
GXP	Grid Exit Point—a point of connection between Transpower's transmission system and our distribution network.
HCA	High-cost area - an area of the network that has higher distribution costs per ICP than the LCA due to lower ICP density.
High voltage (HV)	Network assets that supply electricity at or above 11,000 V.
ICP	Installation Control Point—a point of connection on the Distributor's network, which the Distributor nominates as the point at which a retailer is deemed to supply electricity to a consumer.

LCA	Low-cost area – an area of the network that has lower distribution costs per ICP than the HCA due to higher ICP density.
Load group	A group of consumers with similar network connection characteristics such as location or capacity requirements.
Low user	A consumer in the LOW load group.
Low voltage (LV)	Network assets that supply electricity at 400 V.
Long-run incremental costs	LRIC is the increase in cost from an increase in network capacity that has occurred over time, long enough for all costs to be variable.
Mass market	The majority of electricity consumers, predominantly residential and small businesses.
Network asset	An asset that is primarily used to transport electricity between the national transmission grid and local consumers of electricity.
Part 4	Part 4 of the Commerce Act 1986 governs the regulation of EDBs as administered by the Commerce Commission.
Pass through and recoverable costs	Costs that are charged to us are then 'passed through' consumers. Costs include: • Rates • Commerce commission levies and other industry levies • Transmission costs.
Pricing Principles	Guidelines published by the Electricity Authority that specify the information that a Distributor should make available.
RAB	Regulatory Asset Base - The value our network assets would have in a competitive market if this existed, as determined by the Commerce Commission.
Required revenue	The revenue we require to cover the annual costs of providing electricity distribution services.
TOU	Time Of Use—is a consumer that is metered according to their electricity consumption for a particular period (usually half-hourly) allowing pricing that varies depending on the time of day and measurement of peak demands.
Transmission costs	The cost of maintaining the national electricity grid. Transmission costs are charged to distribution companies who recover these costs from users of the network through delivery prices.
Uncontrollable Load	The load that we are not able to control i.e., not able to switch off during periods of high demand such as electrical water heating.
Vanilla WACC	The weighted average of the pre-corporate tax cost of debt and the cost of equity.
Variable prices	Prices that vary with the number of kWh consumed.
WACC	Weighted Average Cost of Capital—is the regulated rate of return on the company's assets.

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