Electricity Pricing Methodology

1 April 2026 – 31 March 2027

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

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 34,088 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.

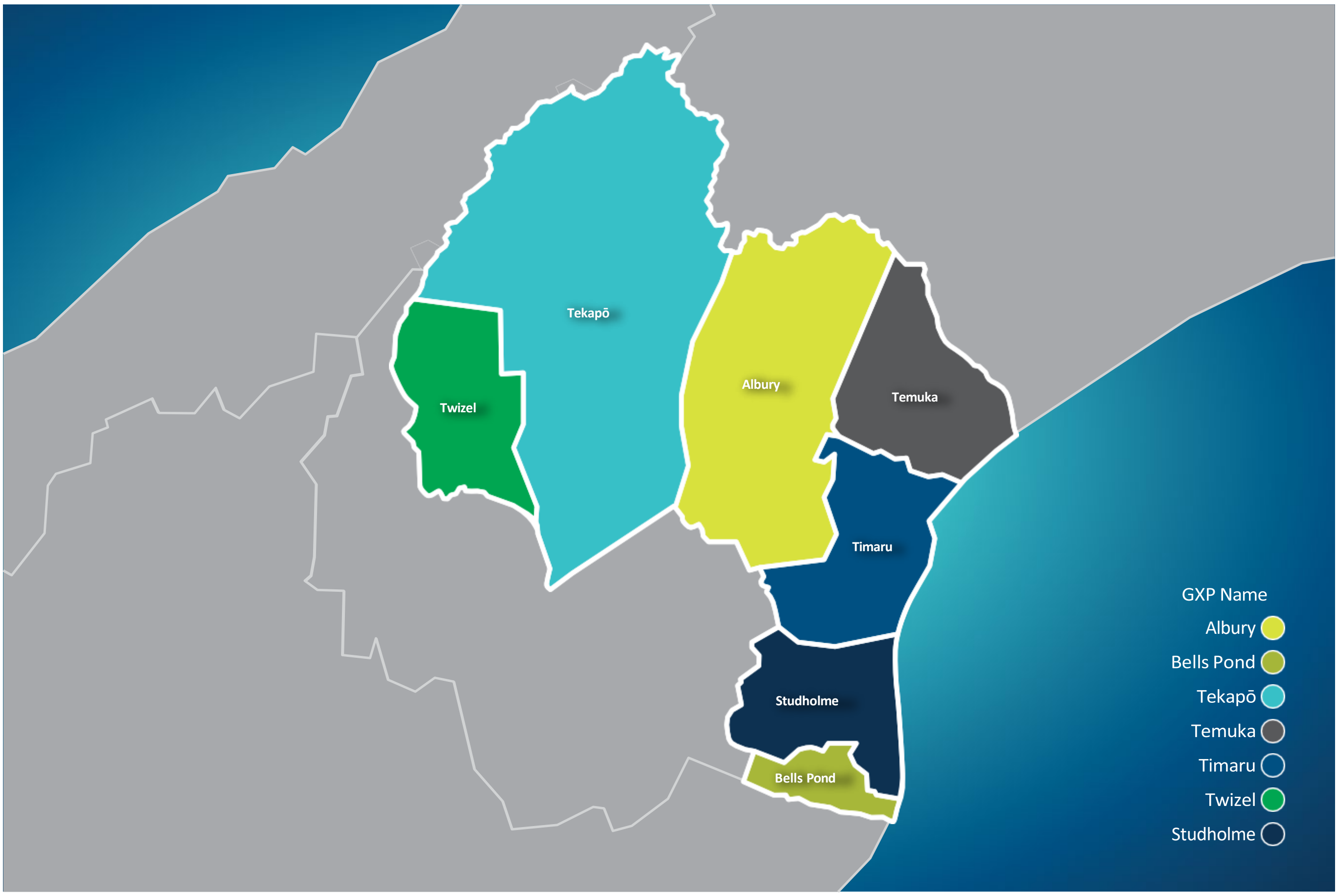

Figure 1: Our network

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.

Purpose

This Pricing Methodology outlines our approach to setting delivery prices to apply from 1 April 2026.

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, which reflect our regulated revenue set by the Commerce Commission
- 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 km^2, 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 five 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	16,288	47.78%
Waimate	3,751	11.00%
Temuka	3,504	10.28%
Geraldine	3,157	9.26%
Twizel	1,822	5.34%
Pleasant Point	1,274	3.74%
Fairlie	1,225	3.59%
Lake Tekapo	925	2.71%
Pareora	482	1.41%
Orari	314	0.92%
Glenavy	273	0.80%
St Andrews	234	0.69%
Winchester	223	0.65%
Cave	205	0.60%
Albury	184	0.54%
Makikihi	118	0.35%
Mount Cook	109	0.32%
Total	**34,088**	**100%**

Table 1: Total ICP count and percentage of total by region on 31 December 2025

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 for pricing are that we:

- set prices to below the revenue allowed by the Commerce Commission's *Electricity Distribution Services Default Price-Quality Determination 2025* (DPP Determination/DPP4).
- disclose information about our pricing approach and prices by the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 (ID Determination).
- set efficient and cost-reflective prices consistent with the Electricity Authority's Distribution Pricing Principles.
- set prices for distributed generators connecting to and using our network according to Part 6 of the Electricity Industry Participation Code 2010 (Part 6 of the Code).
- offer primary residence consumers a low fixed charge tariff option (of $0.90 /day) by the Electricity (Low Fixed Charge (LFC) Tariff Option for Domestic Consumers) Regulations 2004 (the LFC Regulations). The Electricity Authority monitors and enforces the regulations.

Section 2: Current pricing and future pricing plans

Introduction

Our pricing reflects the network, consumer, and regulatory factors relevant to our operations. The outcome of our pricing strategy is to

- align the cost of delivering services to prices faced by each customer group.
- encourage efficient network use by signalling the cost of network congestion to consumers.
- incentivising injection on network during peak period when network is constrained.

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.

Pricing structure

Low capacity connections (mostly residential and small business)

Our pricing has a three-part structure for most residential and small commercial connections.

Our LOW, 015, 030 and 045 price categories have:

- a fixed daily price component;
- 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).

Each customer group has a target revenue figure. Within each group, the fixed component averages 80% with 20% variable. This aligns with our cost structure. This balance also 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.

Larger capacity connections (commercial, agricultural and industrial)

Larger connections with theoretical capacity larger than 45 kVA fall into ASS, TOU400 or TOU11 price categories. These price categories have a four-part structure:

- a fixed daily price component;
- a volume-based price for daytime usage (7 am to 11 pm);
- a volume-based price for night-time usage (11 pm to 7 am); and
- a kW/day demand (capacity) price component.

Connections in the assessed (ASS) price category have a capacity size range of 45 kW – 435 kW (2 x 10 Amp – 3 x 630 Amp) and generally have non-half hour metering. The chargeable demand component for a connection on this price category is based on fuse size. A customer may vary the demand component by physically varying the fuse size of their connection if they want to increase or decrease their demand.[1] Assessed connections also have a high-cost or low-cost differential applied.

TOU400 connections are typically larger connections (3 x 800 Amp (555 kW), 3 x 1000 Amp (695 kW), 3 x 1350 Amp (935 kW), 3 x 1600 Amp (1110 kW)) supplied from the low voltage network. TOU11 connections

[1] For ICPs on ASS price category, we require retailers to submit us the consumption data in EIEP1 format.

are supplied from the high voltage (11 kV) network. Connections on both price categories must have half-hourly smart metering.[2] We assess the chargeable kW component of these connections using the latest 12-months' consumption profiles at the time of our price review. The process is:

- Calculate the anytime maximum demand (AMD) in any half-hour period.
- Two values are calculated: A = AMD incurred during business hours (7am – 10pm) and B = 0.5xAMD incurred between non-business hours (10pm – 7am)
- Max(A,B) is the chargeable capacity (kW) for next pricing year.

This approach provides an incentive to large commercial and industrial customers to shift load to off-peak hours where the congestion is lowest on our network. The chargeable capacity component is fixed for the pricing year. The customer may see the benefit of their reduced load on their capacity charges for the next year when we review the AMD modelling.

For new and altered ASS and TOU connections which occur within the year, our approach to capacity charging is:

- ASS – fused capacity determined at time of connection, and change to capacity charging, customers are required to physically upgrade/downgrade fuse size via a Connection Application (available on our website)

- TOU – capacity will be determined in consultation with customer, and for first year of connection, capacity costs will be applied at a rate of 60% of anticipated kVA. At the next annual pricing review, customer's actual consumption will be assessed for the period they have been connected, and capacity costs will be based on the above methodology.

Other pricing factors

We also apply price differentials to connections based on whether we can control hot water load using ripple control technology, and whether the connection is in a high-cost or low-cost area. Section 4 provides more detail on how we allocate connections.

Table 2 provides an overview of the price structure and components for each consumer group for the 2026-2027, excluding the directly billed consumers, who are charged only a daily fixed rate. Additional details for each consumer group can be found in Section 6.

[2] We require retailers to submit us the consumption data for ICPs on this price code in EIEP3 format.

Consumer group	Forecast # ICPs	Description	Fixed daily component	Capacity component	Variable day volume component	Variable night volume component	Peak Export Tariff
			$/day	$/kW/day	$/kWh	$/kWh	$/kWh
LOWHCA	2,313	Households using <9000kWh/ year, controlled, high-cost area	$0.9000	$0.0000	$0.1270	$0.1249	-$0.0300
LOWLCA	10,838	Households using <9000kWh/ year, controlled, low-cost area	$0.9000	$0.0000	$0.1156	$0.1135	-$0.0300
LOWUHCA	29	Households using <9000kWh/ year, uncontrolled, high-cost area	$0.9000	$0.0000	$0.1305	$0.1284	-$0.0300
LOWULCA	69	Households using <9000kWh/ year, uncontrolled, low-cost area	$0.9000	$0.0000	$0.1191	$0.1170	-$0.0300
015HCA	6,004	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, controlled, high-cost area	$3.6211	$0.0000	$0.0176	$0.0155	-$0.0300
015LCA	11,564	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, controlled, low-cost area	$3.3318	$0.0000	$0.0176	$0.0155	-$0.0300
015UHCA	47	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, uncontrolled, high-cost area	$3.7052	$0.0000	$0.0176	$0.0155	-$0.0300
015ULCA	57	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, uncontrolled, low-cost area	$3.4157	$0.0000	$0.0176	$0.0155	-$0.0300
030HCA	9	Commercial, 16 to 30 kW connection, no TOU metering, controlled, high-cost area	$8.0420	$0.0000	$0.0176	$0.0155	-$0.0300
030LCA	4	Commercial, 16 to 30 kW connection, no TOU metering, controlled, low-cost area	$7.2750	$0.0000	$0.0176	$0.0155	-$0.0300
030UHCA	2	Commercial, 16 to 30 kW connection, no TOU metering, uncontrolled, high-cost area	$8.2007	$0.0000	$0.0176	$0.0155	-$0.0300
030ULCA	3	Commercial, 16 to 30 kW connection, no TOU metering, uncontrolled, low-cost area	$7.4499	$0.0000	$0.0176	$0.0155	-$0.0300
045HCA	526	Commercial, 3-phase, 60-amp connection, no TOU metering, controlled, high-cost area	$12.5390	$0.0000	$0.0176	$0.0155	-$0.0300
045LCA	743	Commercial, 3-phase, 60-amp connection, no TOU metering, controlled, low-cost area	$11.2981	$0.0000	$0.0176	$0.0155	-$0.0300
045UHCA	14	Commercial, 3-phase, 60-amp connection, no TOU metering, uncontrolled, high-cost area	$12.7761	$0.0000	$0.0176	$0.0155	-$0.0300
045ULCA	16	Commercial, 3-phase, 60-amp connection, no TOU metering, uncontrolled, low-cost area	$11.5540	$0.0000	$0.0176	$0.0155	-$0.0300
ASSHCA	1,313	Commercial, capacity > 15kVA, no TOU metering, high-cost area	$6.6044	$0.2931	$0.0176	$0.0155	$0.0000
ASSLCA	422	Commercial, capacity > 15kVA, no TOU metering, low-cost area	$5.9879	$0.2612	$0.0176	$0.0155	$0.0000
TOU400HCA	37	Households and small commercials connected to LV network, TOU metering, high-cost area	$6.3555	$0.6513	$0.0127	$0.0105	$0.0000
TOU400LCA	101	Households and small commercial connected to LV network, TOU metering, low-cost area	$5.7968	$0.5841	$0.0127	$0.0105	$0.0000
TOU11HCA	6	Commercial, connected to 11kV network, TOU metering, high-cost area	$6.3555	$0.5993	$0.0127	$0.0105	$0.0000
TOU11LCA	5	Commercial, connected to 11kV network, TOU metering, low-cost area	$5.8013	$0.5308	$0.0127	$0.0105	$0.0000

Table 2: Overview of price structure and price components for each load group for 1 April 2026 – 31 March 2027

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.

The structure and level of prices can affect how electricity is used on our network.

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 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 tax; and
- Pass-through and recoverable costs, including transmission prices.

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

- Low user prices are based on the Low Fixed Charge Regulations.
- Mass market prices 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.
- Prices for 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.
- Prices for directly billed customers are determined on a case-by-case basis. The pricing is negotiated with these customers based on their conveyance agreements which recover the cost of investment that we have made in these large connections, reflect their contribution of transmission costs, and additional service requirements specific to them.

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.

Consumer group (Load group)	Revenue recovered by fixed & capacity prices %	Revenue recovered by variable prices %
LOWHCA	29%	71%
LOWLCA	33%	67%
015HCA	88%	12%
015LCA	89%	11%
030HCA	89%	11%
030LCA	87%	13%
045HCA	93%	7%
045LCA	89%	11%
ASSHCA	89%	11%
ASSLCA	87%	13%
TOU400HCA	88%	12%
TOU400LCA	82%	18%
TOU11HCA	71%	29%
TOU11LCA	93%	7%
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 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 as circumstances change for our network and for how our customers use it. The energy sector is evolving in response to new consumer demands, new technologies and decarbonisation. Our Asset Management Plans includes forecasts of significant increases in network investment required over the next 10 years compared to the past. This will translate to an increase in revenue to deliver. Pricing is a critical lever for ensuring these investments are made at the right time.

Our Pricing Strategy and Roadmap outlines our long-term pricing objectives including alignment with the Electricity Authority's distribution pricing reform programme. Our Pricing Strategy and Roadmap are available on our website at www.alpineenergy.co.nz. Our focus until 2030 is transitioning towards more transparent and equitable pricing structures that better reflect network usage and costs. Key milestones include:

- **phase out of the Low Fixed Charge (LFC)** 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.

- **negative injection price** introduced from 1 April 2026 for consumers who export electricity to our network during peak periods. In line with Electricity Authority guidelines, this price applies to customers with a connection capacity of 45 kVA or less, and a maximum deliverable generation capacity of 45kW. Eligible price categories include LOW, 015, 030 & 045. Our network load profiling has identified two daily peak-congestion periods: 9.30 am – 4.30 pm and 4.30 pm – 9.00 pm. During these periods consumers who inject electricity into our network will receive a credit rate of -$0.03/kWh. At this stage, the negative injection price applies across all seasons and days of the week. We will monitor uptake and seasonal and half-hourly load patterns and may adjust the injection pricing approach as new insights emerge.

- **developing and implementing time-of-use (TOU) pricing** to encourage more efficient electricity usage by providing price signals tied to demand. TOU pricing provides stronger and more cost-reflective signals by aligning prices with network demand patterns, particularly during periods of congestion. This initiative is currently in the research & analysis phase as we evaluate network data, customer behaviour and operational implications. In implementing TOU pricing, we will align our off-peak and controlled charges load charges with our long-run marginal costs (LRMC) to encourage demand shifting and EV charging when network capacity is available.

- **investigating several foundational changes** to our billing and pricing systems. These include simplifying our pricing structures and progressing the transition from GXP-level billing to ICP-level billing. This will provide us flexibility and agility to introduce and implement new pricing structures in the future.

- **standardise our approach to allocating distribution and transmission costs** across mass-market consumers, large commercial customers and embedded generators (DGs). As the first phase of this work, we will undertake review of transmission cost allocation methodologies, including industry practices Transpower's TPM. Our objective is to implement allocation method that are cost reflective, aligns with industry norms, fulfil Electricity Authority's Distribution Pricing Principles and ensures that costs are passed through to consumers in a transparent and consistent way.

- **consumer and retailer engagement** to ensure that any future changes are well-communicated, practical to implement and inclusive of stakeholder feedback.

We believe that our long-term strategic direction will promote efficient network use and align prices more closely with the cost of service.

Strategy implementation and review

Successful implementation of changes to our pricing approach will be transparent and involve consultation with retailers and relevant consumer groups and stakeholders. We will conduct regular reviews of the outcomes and provide regular progress reports within this document to ensure transparency and continuous improvement.

Section 3: Pricing changes for 2026/27

Introduction

We are changing delivery prices in 2026-27 as follows:

- The overall revenue we recover through prices will increase by 6.9%.
- We have introduced a new negative injection price for residential and small business customers who supply electricity at peak times.

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.

The Commerce Commission reviews spending forecasts of EDBs to ensure that revenue increases are justified. It also regulates revenue growth and adopts a gradual approach to price increases, aiming to balance affordability with the delivery of a safe, reliable, and resilient electricity network. Electricity distribution and transmission costs have increased due to

- External factors, such as inflation and rising interest rates since the last regulatory period
- Network drivers, such as the need for greater investment to replace aging assets, improve resilience against extreme weather, and enable growth.

The total forecast revenue from prices (i.e., the total revenue we are allowed to collect in the second regulatory year under the DPP4 Determination) is $87.27 million for 2026/27. This represents an overall increase of 6.8% on the $81.63million forecast revenue from prices for 2025/26. The average increase in our delivery prices (distribution and pass-through, and recoverable costs which include transmission prices) across all consumer groups is 6.56% (excluding our five directly billed customers).

For an average residential consumer (on LOW and 015 consumer groups), representing more than 30,000 of our ICPs, the projected average monthly lines charge is $103, an increase of about $5 per month compared to last year.

Transpower's transmission charges to Alpine Energy increased by 19% from 2025/26 to 2026/27, and this increase will be passed through to all customers in alignment with the Transmission Pricing Methodology.

The change in revenue for each consumer group and average delivery price change from the resulting changes to price levels are detailed in Table 4.

Consumer group	Avg. Annual delivery prices for 2025/26	Avg. Annual delivery prices for 2026/27	$ Change	% Change
LOWHCA	1,005	1,063	58	5.8%
LOWLCA	940	997	57	6.0%
015HCA	1,023	1,083	60	5.9%
015LCA	958	1,017	59	6.2%
030HCA	1,415	1,479	64	4.5%
030LCA	1,313	1,374	61	4.6%
045HCA	1,442	1,510	68	4.7%
045LCA	1,342	1,404	63	4.7%
ASSHCA	3,222	3,371	149	4.6%
ASSLCA	2,952	3,091	139	4.7%
TOU400HCA	3,277	3,429	152	4.6%
TOU400LCA	3,011	3,155	143	4.8%
TOU11HCA	4,798	5,017	219	4.6%
TOU11LCA	4,359	4,564	204	4.7%

Table 4: Change in forecast revenue and average delivery prices between 2025/26 and 2026/27

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 6.

Changes to the price structure – negative injection charges

In 2025, the Electricity Authority introduced new regulations for all Electricity Distribution Businesses (EDBs). From 1 April 2026 EDBs are required to offer negative charges (credits) to customers supplying power at peak periods[3]. It is required to be offered to residential and small industrial customers with business consumers connection capacity of equal to 45 kVA or less, with a maximum deliverable generation capacity of 45kW.

The intended regulatory purpose is to provide a pricing signal to encourage consumers to provide energy at the peak periods by investing in battery and other flexible resources. It could potentially reduce the network congestion during the peak periods and therefore reducing or the deferring network upgrades and promoting energy resilience over time.

Based on the EA's guidance notes, the process to calculate the negative injection charge was:

Step 1: Determining the pricing window using load profiles for the negative export charges

Using zone-substation-level consumption data for residential & small connections we develop daily load profiles for residential and small commercial customers. Based on the analysis of that consumption data and using a 90% threshold to identify periods of sustained high demand, the data indicated two peak-congestion periods as below:

a. Peak period is 6:30 am – 9:30 am and 4:30 pm – 9:00 pm

b. Off-peak period: from 9:30 am – 4:30 pm and 9:00 pm – 6:30 am the next morning

[3] Please refer to Electricity Authority's Distribution Pricing Practice Note (2A_Final_Negative_Charge_Guidance_Document_for_Distributors.pdf).

Step 2: Estimating Long Run Marginal Cost (LRMC)

We estimate the Long Run Marginal Cost (LRMC) on a per peak kWh basis. We used a standard LRMC model developed by Electricity Network Association (ENA). We applied a Long Run Average Incremental Cost (LRAIC) approach, to determine incremental costs to providing additional network capacity. Forecasts of system growth and demand driven capital investment were taken from our latest draft AMP. The model adjusts these figures with the Reserve Bank of New Zealand's long-run target inflation rate of 2%, incorporates forecasts of incremental OPEX and calculates the Net Present Value (NPV) of demand-driven CAPEX using DPP4 post-tax WACC. The NPV of cumulative annualised CAPEX/OPEX is $31,724,000 and NPV of cumulative incremental demand equals 178 MW.

Our resulting LRMC is approximately $179/kW per year, which equates to $0.07/kWh during peak periods (step 1).

Step 3: Forecasting the export volumes at peak periods

To estimate the total export charges during peak periods, we forecast the export volumes from residential and small commercial consumers. As retailers currently do not provide export data split into peak and off-peak periods, we rely on our own modelling to estimate these volumes.

Using hourly solar generation data, we forecast the expected solar generation output per kW installed capacity of solar PV for the Timaru region across a full year. This provides a reliable 24-hours solar production profile based on South Canterbury's climate and sunshine hours[4]. From this modelling, we estimate that 24.6% of total annual solar generation occurs within defined peak period windows.

The volumes of solar generation at the customer level does not mean that it is exporting onto our network, as generation may be being consumed onsite or stored in batteries. To estimate the volumes of solar generation exported on Alpine's network we analysed six years of Registry data, comparing the solar generation at customer level (using past 6-years of solar capacity) and actual network level injection. This analysis indicates that 33% of customer-level solar generation is exported to our network. Based on these assumptions and a current installed solar capacity of 5,130 kW, we forecast that 630,478 kWh will be exported onto our network during peak periods.

Step 4: Forecast for negative injection charges & determining an appropriate adjustment factor

The Electricity Authority guidance allows EDBs to apply an adjustment factor to scale the injection charges down from the raw avoidable cost value calculated in step 2. This is intended to balance two objectives: incentivising greater DG injection and adoption of technologies promoting injection at peak periods, while also managing the risk that excessive injection could create network instability and voltage issues.

An adjustment factor of 57% has been applied for 2026/27 pricing year. We believe this adjustment results in a negative injection change set at a conservative level while still providing a meaningful price signal that is in line with other comparable EDBs charges. We may change the adjustment factor in future years. Future adjustments will be informed by actual export patterns, customer feedback, network performance insights from our engineering teams and emerging industry practices & technologies. We also consider it is easier to reduce the adjustment factor over-time than to increase it, given consumer expectations once price signals are established.

The outcome is a peak injection charge of -$0.03/kWh, with total credits expected to remain below $20k for the year.

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[4] sourced from *www.profilesolar.com*

Future refinements

This is the first year of applying this method. Potential refinement areas include:

- Definition of peak & off-peak windows
- Forecasts for solar export volumes as we begin receiving the actual peak/off-peak export splits
- Forecast accuracy using half-hourly injection volumes
- refining the 'adjustment factor'. Future adjustments will be informed by actual export patterns, customer feedback, network performance insights from our engineering teams and emerging industry practices & technologies.

Section 4: How prices are set

In setting the prices we have followed the steps below:

Defining our consumer groups

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	16 – 30 kW; 1 x 80 Amp fuse, 2 x 60 Amp fuses; or 3 x 32 Amp fuses – high-cost area
030LCA	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 45kVA – high-cost area
ASSLCA	Assessed capacity over 45kVA – 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

Load density is a primary cost factor for Alpine. Capital expenditure costs and operating expenditure costs to service connections are generally higher in rural areas (high-cost areas with lower load density) than servicing clustered connections (low-cost areas with higher load density) in the urban areas.

We will review our high-cost / low-cost areas over the next two years to ensure they reflect network development over recent years.

Allocation of consumers to load groups

Consumers 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; or two phase 60 A; or three-phase 32 A connection)
    - 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.

Consumers are allocated to load groups based on the following criteria:

Low fixed charge load group

Wea are compliant with the LFC Regulations, which state that we must offer a fixed tariff for "domestic consumers" of no more than $0.90 per day for the pricing year beginning 1 April 2026. A domestic consumer is defined by the regulations as a person who purchases electricity for their 'principal place of residence'.[5]

This is the final year of the government's phase out of the LFC regulations. We will not offer a low fixed charge consumer group next year.

Mass market load groups

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

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

Consumers in the 015 load group are single-phase and have a maximum capacity of 15 kVA (60 A). Consumers 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.

Assessed capacity load group

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.

[5] Clause 4 (1), Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 https://www.legislation.govt.nz/regulation/public/2004/0272/latest/dlm283614.html

Time of use load groups

The TOU400 are typically larger connections: 3 x 800 A (555 kW), 3 x 1000 A (695 kW), 3 x 1350 A (935 kW), 3 x 1600 A (1110 kW) supplied from our low voltage network, and ICPs on TOU11 price plan are supplied from our high voltage (11 kV) network. Consumers in this group must have TOU meters installed.

IND load group (non-standard)

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
- 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 non-standard customers, including distributed generators.

Determine target revenue

Alpine Energy is subject to price-quality regulation under Part 4 of the Electricity Act. The Commerce Commission reset the Default Price-Quality Path (DPP4) for the period 1 April 2025 to 31 March 2030 for regulated electricity distribution businesses in November 2024. 2026/27 is the second year of DPP4.

Our target revenue from prices for 2026/27 is determined based on the allowable revenue we can recover from lines charges, consistent with the DPP Determination.[6] Our calculations are published in a separate regulatory document (Annual Price-setting Compliance statement) and is available on our website.

Table 6, and the commentary below 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., in line with the DPP4 regulations.

Cost component	$ '000
Operating expenditure	37,716
Depreciation	13,796
Return on investment	25,496
Regulatory tax	5,955
Revaluation	-8,019
Transpower charges	20,263
Other pass-through costs and recoverable costs	2,915
Revenue Foregone (as per undertakings with the Commerce Commission)	($10,878)
Target revenue from prices	**$87,244**[7]

[6] https://www.comcom.govt.nz/__data/assets/pdf_file/0027/363276/5BFINAL5D-Electricity-Distribution-Services-Default-Price-Quality-Path-Determination-2025-5B20245D-20-November-2024.pdf

[7] This is lower than the $87.27m on page 13 because prices do not need to recover other regulated income of $23k.

Table 6: 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 based on our latest Asset Management Plan operating expenditure forecasts and are in line with the Commerce Commission's DPP4 operating expenditure allowances.

Depreciation

Reflects the reduction 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.

Regulatory tax

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

Revaluation

Change in value of existing assets and forecasted commissioned assets in the regulatory year, 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 investment contract charges, connection charges, benefit-based charges, residual charges and other transmission provisions. These charges are passed onto our consumers at cost.

Other pass-through and recoverable costs

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

Revenue Foregone

As part of our undertakings of historical overcharge with the Commerce Commission, we will return the remainder of the part of the 2025 wash-up amount that represents an overcharge to consumers by reducing our revenue from prices in 2027 assessment period. For more details about our historical pricing error, please refer to Historical pricing error explanation on Alpine Energy's website. A copy of our undertakings to the Commission can be found on the Commission's website.

Allocating revenue/costs to specific consumer groups

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

The allocation of transmission costs to the load groups for 2026/27 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 costs 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 costs for non-standard consumers are allocated using an interim methodology introduced to accommodate the 2023 Transmission Pricing Methodology. Under this approach, we adjust each non-standard customer's transmission charges by applying the same percentage increase or decrease as the year-on-year change in Transpower's charges to Alpine Energy.

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 target revenue allocated to each consumer group for 2025/26 is shown in Table 13 below. The allocation is based on the methodology described in Section 4.

Consumer group	Year ending 31 March 2026 ($'000)	Year ending 31 March 2027 ($'000)	Change ($'000)	Change (%)
LOWHCA	2,417	2,455	38	1.6%
LOWLCA	9,952	10,789	836	8.4%
LOWUHCA	27	31	4	16.1%
LOWULCA	58	70	12	21.5%
015HCA	8,509	8,869	360	4.2%
015LCA	15,117	15,863	746	4.9%
015UHCA	65	71	6	9.2%
015ULCA	76	80	4	5.6%
030HCA	33	30	-2	-7.0%
030LCA	44	12	-32	-72.0%
030UHCA	-	7	7	-
030ULCA	-	9	9	-
045HCA	2,462	2,634	171	6.9%
045LCA	3,182	3,387	204	6.4%
045UHCA	65	71	6	10.0%
045ULCA	81	74	-7	-8.1%
Peak Export Tariffs	-	-19	-19	-
ASSHCA	16,812	17,999	1,187	7.1%
ASSLCA	5,065	5,242	177	3.5%
TOU400HCA	2,230	2,563	333	15.0%
TOU400LCA	5,882	6,393	511	8.7%
TOU11HCA	2,966	2,420	-546	-18.4%
TOU11LCA	934	1,824	890	95.2%
IND	*5,649*	*6,369*	*720*	*12.7%*
Total	***81,625***	***87,244***	***5,618***	***6.9%***

Table 7: Target revenue by consumer group

Determine the delivery prices for each load group

Other factors can influence our approach to pricing including the level of price changes, maintaining logical relationships between price categories, compliance with 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 examine multiple scenarios to balance impacts on consumer groups and alignment with the pricing principles.

The analysis resulted in the following pricing outcomes:

- Fixed prices for all load groups except LOW load groups are 80% (on average), with variable prices making up the residual 20% (on average).
- Transmission prices are passed through 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 2026/27. The fixed distribution price is $0.90 as stipulated in the Low Fixed Charge Regulations.

The resulting delivery prices, by load group for distribution and recoverable and pass-through cost (including transmission prices), for 2065/27 are shown in Table 8 below.

Load group	Distribution					Recoverable and pass-through costs (incl. transmission prices)				
	Fixed per day	Variable Day per kWh	Variable Night per kWh	Peak Export Tariff per kWh	Capacity per kW/day	Fixed per day	Variable Day per kWh	Variable Night per kWh	Peak Export Tariff per kWh	Capacity per kW/day
LOWHCA	$0.9000	$0.0950	$0.0929	$-0.0300	$0.0000	$0.0000	$0.0320	$0.0320	$0.0000	$0.0000
LOWLCA	$0.9000	$0.0836	$0.0815	$-0.0300	$0.0000	$0.0000	$0.0320	$0.0320	$0.0000	$0.0000
LOWUHCA	$0.9000	$0.0951	$0.0930	$-0.0300	$0.0000	$0.0000	$0.0354	$0.0354	$0.0000	$0.0000
LOWULCA	$0.9000	$0.0837	$0.0816	$-0.0300	$0.0000	$0.0000	$0.0354	$0.0354	$0.0000	$0.0000
015HCA	$3.0059	$0.0176	$0.0155	$-0.0300	$0.0000	$0.6152	$0.0000	$0.0000	$0.0000	$0.0000
015LCA	$2.7166	$0.0176	$0.0155	$-0.0300	$0.0000	$0.6152	$0.0000	$0.0000	$0.0000	$0.0000
015UHCA	$2.9907	$0.0176	$0.0155	$-0.0300	$0.0000	$0.7145	$0.0000	$0.0000	$0.0000	$0.0000
015ULCA	$2.7012	$0.0176	$0.0155	$-0.0300	$0.0000	$0.7145	$0.0000	$0.0000	$0.0000	$0.0000
030HCA	$7.0481	$0.0176	$0.0155	$-0.0300	$0.0000	$0.9939	$0.0000	$0.0000	$0.0000	$0.0000
030LCA	$6.2811	$0.0176	$0.0155	$-0.0300	$0.0000	$0.9939	$0.0000	$0.0000	$0.0000	$0.0000
030UHCA	$7.0036	$0.0176	$0.0155	$-0.0300	$0.0000	$1.1971	$0.0000	$0.0000	$0.0000	$0.0000
030ULCA	$6.2528	$0.0176	$0.0155	$-0.0300	$0.0000	$1.1971	$0.0000	$0.0000	$0.0000	$0.0000
045HCA	$11.1666	$0.0176	$0.0155	$-0.0300	$0.0000	$1.3724	$0.0000	$0.0000	$0.0000	$0.0000
045LCA	$9.9257	$0.0176	$0.0155	$-0.0300	$0.0000	$1.3724	$0.0000	$0.0000	$0.0000	$0.0000
045UHCA	$11.0965	$0.0176	$0.0155	$-0.0300	$0.0000	$1.6796	$0.0000	$0.0000	$0.0000	$0.0000
045ULCA	$9.8744	$0.0176	$0.0155	$-0.0300	$0.0000	$1.6796	$0.0000	$0.0000	$0.0000	$0.0000
ASSHCA	$5.5656	$0.0176	$0.0155	-	$0.2700	$1.0388	$0.0000	$0.0000	-	$0.0231
ASSLCA	$4.9498	$0.0176	$0.0155	-	$0.2381	$1.0381	$0.0000	$0.0000	-	$0.0231
TOU400HCA	$5.0087	$0.0127	$0.0105	-	$0.6208	$1.3468	$0.0000	$0.0000	-	$0.0305
TOU400LCA	$4.4545	$0.0127	$0.0105	-	$0.5536	$1.3423	$0.0000	$0.0000	-	$0.0305
TOU11HCA	$5.0087	$0.0127	$0.0105	-	$0.5720	$1.3468	$0.0000	$0.0000	-	$0.0273
TOU11LCA	$4.4545	$0.0127	$0.0105	-	$0.5035	$1.3468	$0.0000	$0.0000	-	$0.0273

- Table 8: 2026/27 delivery prices for all standard load group

Different prices 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 each load group's forecast 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 ($0.90 per day in 2026/27).
- 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.

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).

In all consumer groups, the average cost per ICP is greater than avoidable costs and less than standalone costs, demonstrating that our pricing meets the Electricity Authority's subsidy free principle.

	Low	015	030	045	ASS	TOU400	TOU11	IND
Stand-alone cost ($)	582.35	204.97	62,400.54	1,152.02	521.44	10,734.96	2,298.97	1,466.33
$/kW cost of supply	205.63	152.73	115.15	100.44	91.40	74.21	72.87	73.30
Avoidable cost ($)	44.99	48.07	16.43	17.17	17.32	12.16	12.08	12.35
Average cost ($/ICP)	71.81	93.05	101.89	147.98	285.13	317.84	336.87	456.15

Table 9: Subsidy-free range for network price

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.

The prices for 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.

Transmission charges for non-standard customers are allocated using an interim approach that aligns their charges with the same year-on-year percentage change in Transpower's charges to Alpine Energy.

The delivery prices for directly billed customers are set out in Table 10 below, showing a comparison with the prior year's prices.

Component	2025/26 ($'000)	2026/27 ($'000)
Forecast distribution prices	3,475	3,782
Transmission prices	2,174	2,587
Total	**5,649**	**6,369**

Table 10: Total revenue allocated to directly billed customers in the IND load group

With directly billed customers having forecast delivery costs set at $6,369 million, the remaining revenue to be allocated between all other load groups is $80,875 million.

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) 65th percentile figure of 7.10% recommended for EDB industry during DPP4, 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 charges for non-standard consumers are allocated using an interim methodology introduced to accommodate the 2023 Transmission Pricing Methodology. Under this approach, we adjust each non-standard customer's transmission charges by applying the same percentage increase or decrease as the year-on-year change in Transpower's charges to Alpine Energy

Distributed generation on our network

Our network enables distributed generators (DGs) of all types and sizes to convey electricity to end-users. We are seeing strong and growing interest from potential DGs wishing to connect to our network.

Pricing for distributed generators is set by the Part 6 of the Electricity Industry Participation Code. Under the Pricing Principles in Part 6 of the Code, charges for large DGs must be based on the incremental costs that arise from connecting & operating the DG on Alpine Energy's network. This allows us to apply certain upfront charges as well as ongoing charges where they reflect incremental costs.

A key component of incremental cost is incremental transmission charges. These are triggered when a large DG connects to an EDB network and Transpower adjusts the transmission charges following an adjustment event. If such an event occurs, Alpine Energy will pass these incremental transmission costs through to the DG. As an interim approach, Alpine Energy will calculate the proportion change in its overall transmission charges because of the first adjustment event and apply this proportion to allocate transmission charges for future years when allocating transmission charges to DGs. In the long run we intend to develop a model to calculate these incremental costs to highest level of granularity.

Other potential incremental costs at the distribution level may include but not limited to:

- O&M Charges associated with maintenance of DGs assets.
- Consumption charges for the energy consumed from Alpine's network.
- Any other identifiable incremental costs arising because of the DG connection.

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.

Connection Pricing

In line with new Electricity Authority requirements, we have updated our pricing for customers connecting to our network or upgrading existing connections. Our Connection Pricing Methodology sets out:

- Our connection charges for standard connections that meet network criteria (posted rates)
- our approach to pricing 'minimum schemes' (least-cost technically acceptable),
- how we allocate the costs of enhancements to a minimum scheme (to either the network or the customer)
- how we manage 'pioneer schemes' in instances where a customer funds a network extension that later customers can subsequently connect to (mitigating first mover disadvantage)

Our Connection Pricing Methodology is available on our website.

Section 6: Assessing Consumer Impacts

Introduction

We assess the impact on customer groups from changes to the price structure and price level. We account for:

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

Assessing the impacts of price changes

The Commerce Commission has set Alpine Energy's revenue path for 2026-30, including the rules for other costs that can be passed through, e.g. transmission cost. Our forecast revenue has increased by 6.9% compared to our 2025/26 forecast. Prices increase for the average consumer in each pricing category excluding directly billed customers is slightly different and depends on their consumption profiles. An overall increase of 6.9% in delivery prices translate to about a 5.2% rise in the overall cost of electricity for residential consumers with an average consumption profile. This translates to a $5 monthly price increase. For an average Commercial & Agriculture/Large Commercial customer this increase is 4.6% ($15 monthly) and 5.8% ($60 monthly) increase.

The table below summarises the average price increase for customer groups. These price change percentages are calculated relative to prices set at 1 April 2025.

Customer Group Total	kWh	ICP$	Average Yearly Revenue 2025/26	Average Yearly Revenue 2026/27	Average Monthly Revenue 2025/26	Average Monthly Revenue 2026/27 ($)	$ Change	% Change
Residential	60,384	30,921	$,180	$ 1,241	$ 98	103	5	5.2%
Commercial	206,353	1,317	$ 3,869	$ 4,048	$ 322	$ 337	$ 15	4.6%
Agriculture/Large Commercial	187,656	1,735	$ 12,363	$ 13,086	$ 1,030	$ 1,091	$ 60	5.8%
TOU	12,701,834	149	$ 216,422	$ 225,483	$ 18,035	$ 18,790	$ 755	4.2%
Directly Billed Customers	-		$ 5,649,363	$ 6,368,710	$ 470,780	$ 530,726	$ 59,946	12.7%

Table 11: Average consumer impact

Consumer engagement

In 2025, we surveyed 400 of our consumers across all seven GXPs to assess perceptions of reliability, outages and notifications, pricing, and uptake of new technologies and electric vehicles.

Key pricing related insights included:

- 31% of customers as somewhat willing, willing or very willing to pay more to have a more reliable power supply and fewer unplanned outages.
- 87% of respondents would prefer to maintain current levels instead of increasing or reducing prices with associated changes to service.
- 37% of respondents believed their lines charges were value for money, an increase from 33% the prior year.

The survey also revealed that our consumers have little willingness for increased delivery prices to improve the reliability of service provided 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, Tony King and Stephen Lewis, 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.

Tony King	Stephen Lewis
26.03.2026	26.03.2026

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:	
i) 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 4.
ii) 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 4.
iii) 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.
iv) 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 4.	
b) Prices should be responsive to the requirements and circumstances of end-users by allowing negotiation to:	
i) 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.
ii) Enable price/quality trade-offs	We regularly engage with consumers to test price/quality preferences via surveys, refer to section 6. We also enable consumers to make price/quality trade-offs by offering controlled and uncontrolled prices. Non-standard contracts are negotiated to reflect price/quality trade-offs. It includes 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 6 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 2025/26 to 2026/27.
(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 6 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.	
We publicly disclosed the inclusion of a new negative injection charge at least 20 working days prior to taking effect.	
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 5.
(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 to Appendix A.
(3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	Refer to Section 4,
(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 4,
(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 4.
(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 4.
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. 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.

(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 2025 was 3.4%%.

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.