TOP ENERGY LIMITED

PRICING METHODOLOGY DISCLOSURE

2026-2027

TABLE OF CONTENTS

1. Introduction

Top Energy Limited (Top Energy) is the electricity distribution network in the Mid and Far North of the Northland region. The network distributes 328,000,000 kWh of electricity to 34,500 electricity consumers who own the company through the Top Energy Consumer Trust (TECT).

This pricing methodology document outlines our key considerations and approach to setting distribution prices, effective April 1, 2026. It also sets out our plans and pricing strategy.

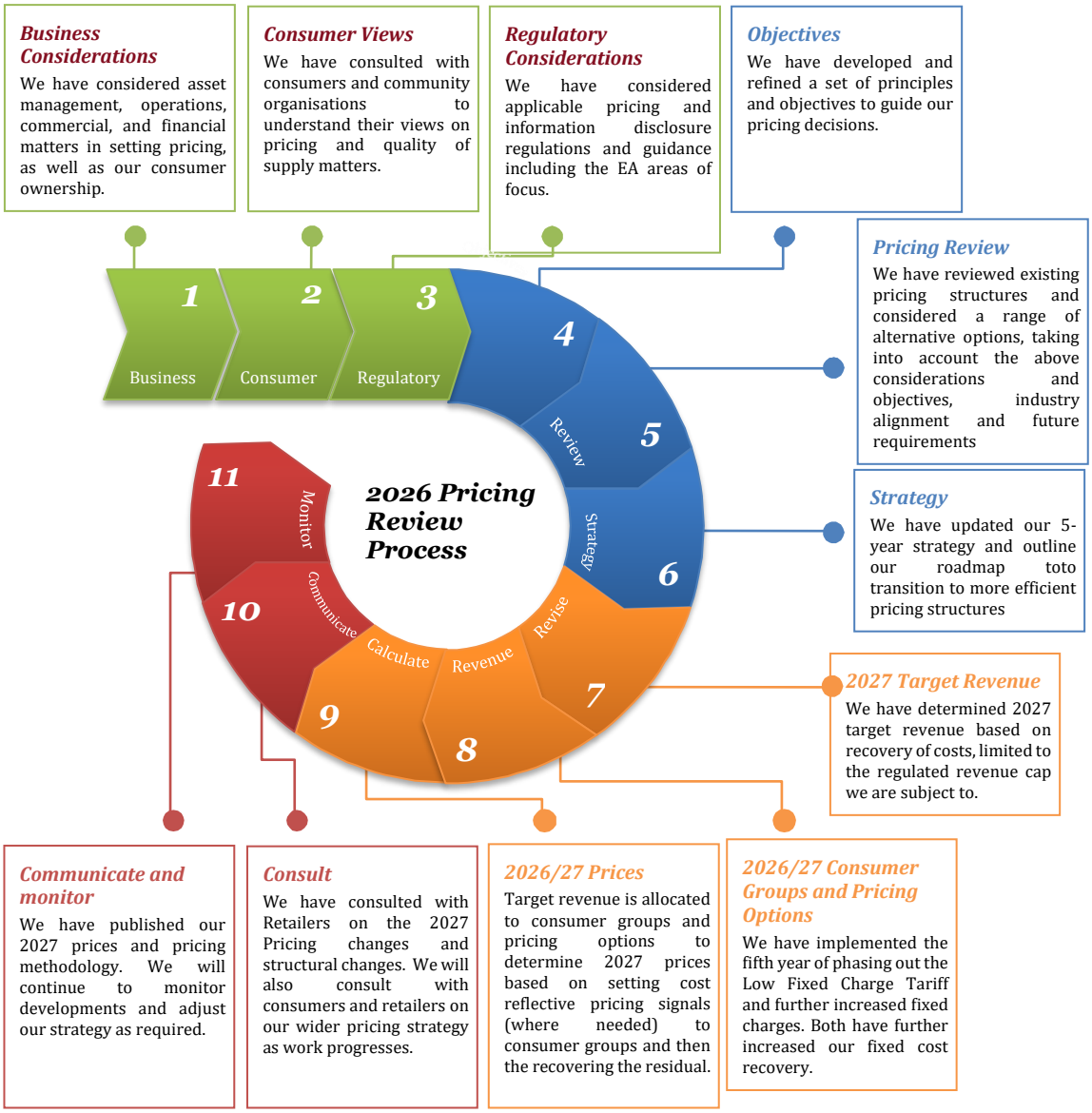
The pricing methodology is structured as follows:

- **Section 2** summarises our approach and key decisions for setting prices in 2026-27
- **Section 3** summarises key considerations we have considered in making decisions on pricing.
- **Section 4** details our principles and objectives, recent review, and plans and strategy for pricing.
- **Sections 5 to 7** provide further details on how prices are set, including:
  - How target revenue is determined
  - key decisions on consumer groups and available pricing options
  - how target revenue is allocated to each consumer and price option including for price signals
- **Appendix 1** provides director certification of this pricing methodology.
- **Appendix 2** provides a glossary of standard terms used in this document.
- **Appendix 3** maps compliance against section 2.4 of the ID Determination
- **Appendix 4** describes how this pricing methodology is consistent with the Electricity Authority's pricing principles published in June 2019. It also shows our progress on the current ten areas of focus.
- **Appendix 5** details distribution prices that will apply from 1 April 2026
- **Appendix 6** shows the current and forecast Utilisation of the network by substation.
- **Appendix 7** Payment for injection methodology and calculation

2. Summary of how prices are set

2.1.Process for setting prices

The following diagram illustrates Top Energy's process for reviewing and setting prices in 2026-27



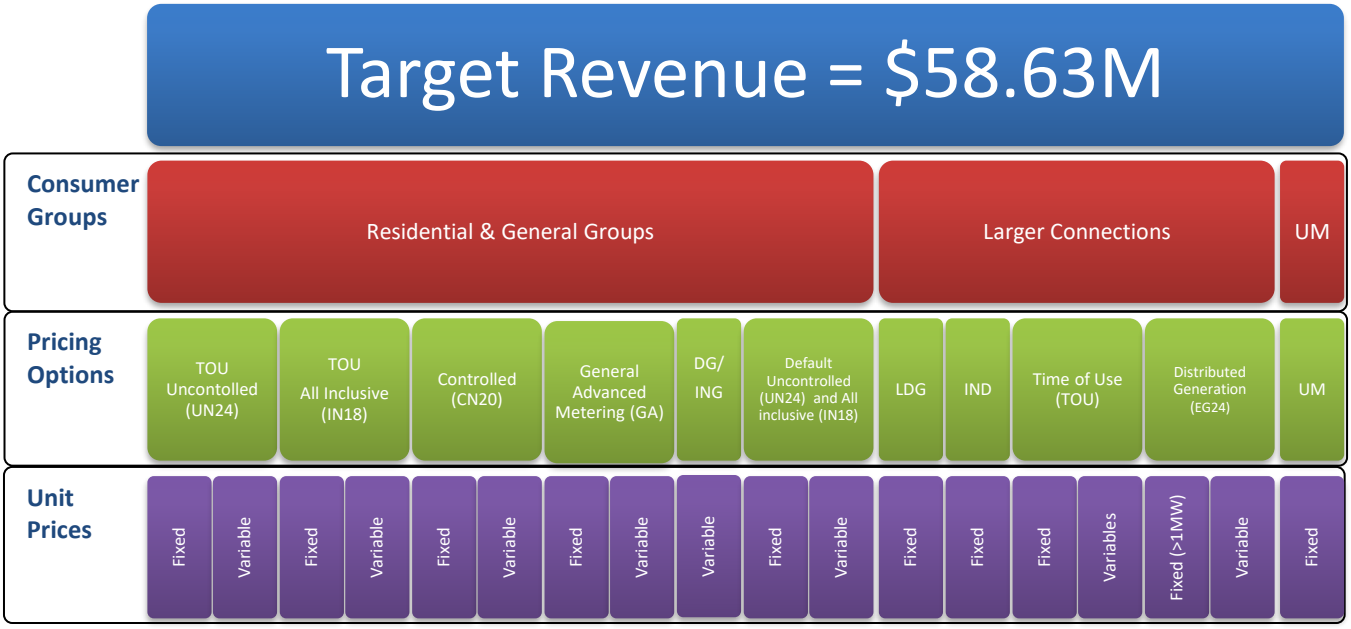
2.2. How prices are calculated

Prices have been set to recover our 2026-27 target revenue. Target revenue is calculated to recover our forecast costs and is limited by a revenue cap determined by the Commerce Commission. This year is the second under DPP4. This revenue covers the cost of our local electricity distribution network and pass-through costs (including Transmission, levies and rates). Unit prices (comprising a daily fixed charge and/or a consumption-based variable charges and /or capacity charges) are calculated for each pricing option we offer by allocating target revenue:

- directly to a consumer, where costs are known for specific consumer groups.
- based on revenue from price signaling if applicable and
- using cost allocators for shared costs, which are based on consumer numbers or usage characteristics.

Figure 1 illustrates how target revenue is allocated to consumer groups and prices.

Figure 1: Calculation of prices

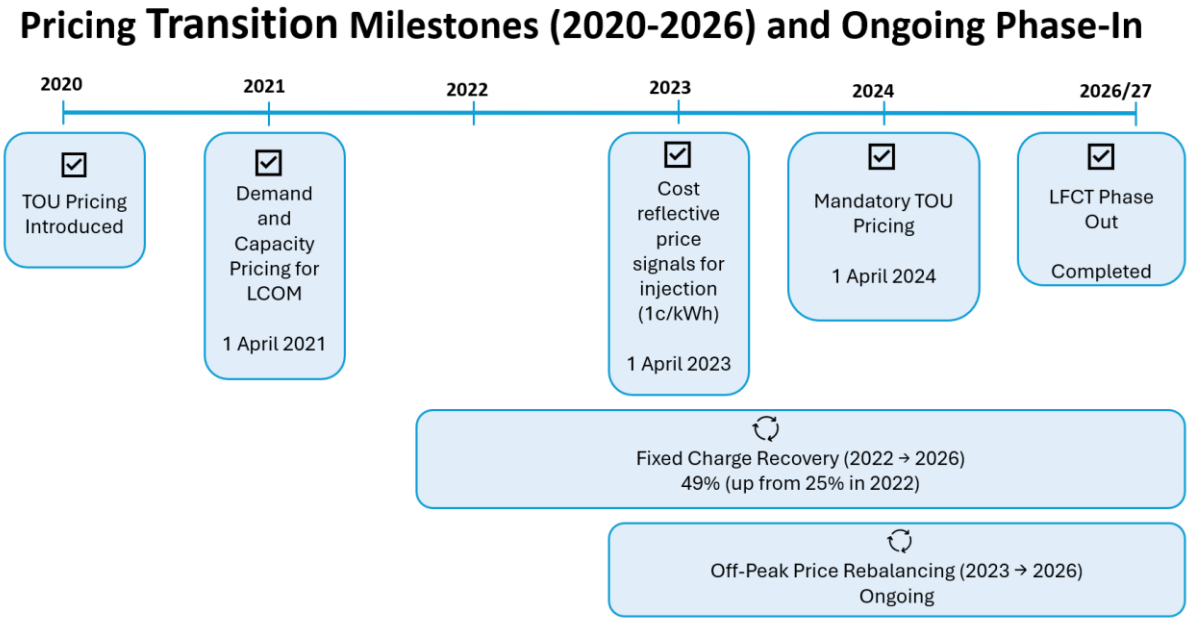


Notes: UM: Unmetered, IND: Industrial, DG: Distributed Generation

Top Energy's prices are used to charge electricity retailers in the Far North. Electricity retailers determine how to package these charges together with energy, metering and other costs when setting retailer prices that are charged.

2.3. Key changes to prices in 2026-27

We have continued to focus on our pricing methodology and built upon previous reforms implemented, as outlined in our roadmap. The key highlights over the last five years are:



This year, there are three changes to pricing structures. The first is due to a change in regulations, and the other two are based on further rationalising our prices to reflect our operations and network. This year, we have continued our focus on increasing the efficiency of the existing pricing by phasing in cost-reflective pricing, including increasing fixed charge recovery and lowering off-peak prices.

The key changes in 2026-2027 are:

- Introduced a price code for customers injecting electricity as required under the new Code amendment effective 1 April 2026. This applies to all Residential and General connections (>99%) and has been set at 0 c/kWh. This reflects that the total forecast growth spends, which is not committed, is only $0.5M over the next 10 years.
- Discontinued our Building Temporary Supply Price Category, which has no customers.
- Closed Controlled 20 Pricing Code to new customers.
- Completed the phase-out of the LFCT for residential customers. From 1 April 2026, the daily charge on all Low User Residential pricing categories will increase to 90 c/day. This is the final year that the LCFT regulations apply. Starting next year, pricing will no longer be restricted.
- Increasing fixed charge recovery from 43% to ~49% and lowering off-peak charges

The discount paid by Top Energy will continue to be a posted discount and will be included in the price schedule. This is based on consumption over the pricing year and will be paid in May 2027.

Distribution prices have increased by 4.6% on average, including the posted discount. This results in revenue being $84M below the Forecast allowable revenue permitted under the revenue cap regulation. These increases will be applied across all consumer groups except Industrial and Large Generation. Industrial (IND) consumers will continue to be assessed based on the specific assets they use. Overall headline prices have increased by 6.3%, accounting for all pass-through and recoverable costs but before the discount. After the discount 6.9%. This includes a 17% increase in Transmission costs. Appendix 5 provides further details on prices.

3. Pricing considerations

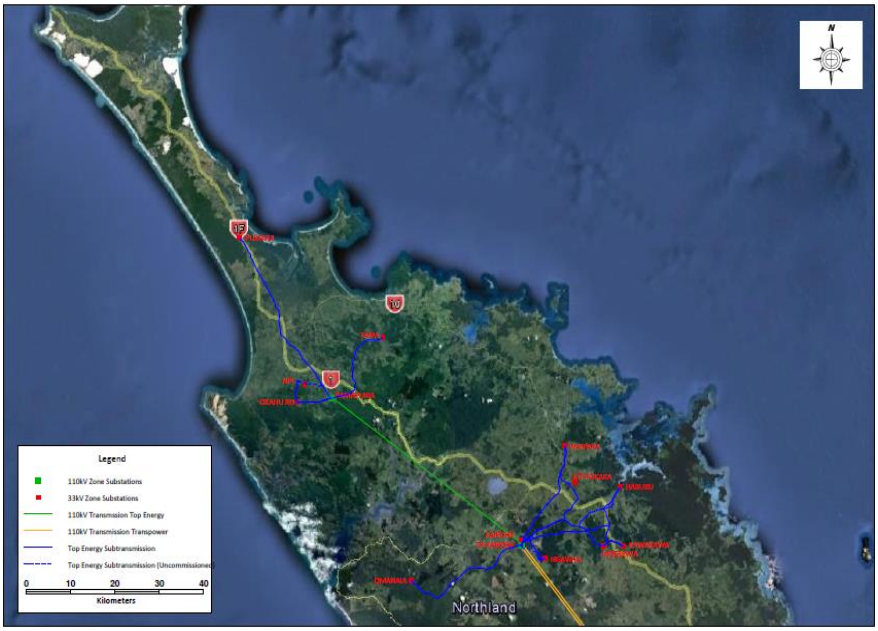
3.1. Business considerations

3.1.1 Background – Our Network

Top Energy is the local electricity distribution network in the Mid and Far North of the Northland region. Top Energy's network begins in Hukerenui, approximately 25km north of Whangarei, and ends at Te Paki, 20 km south of Cape Reinga. It spans from the East Coast to the West Coast. The supply area is sparsely populated with no dominant urban centre and is recognised as one of the more economically depressed areas of the country.

The company is an integral part of the Far North community. It is owned by its customers through TECT. Consumer trust ownership means that surpluses not required for the operation and development of the network are returned to consumers via line discounts on electricity bills and through a dividend from TECT. Top Energy also employs more than 190 people and is one of the largest employers in the Far North.

Figure 2: Map of Top Energy's Network



The network receives supply from the national grid at the Kaikohe substation and from local geothermal generation at Ngawha and three solar farms in Kaitaia. Two of these were commissioned in 2025. The Kaikohe substation supplies the southern part of the network directly, while the northern part is supplied from a single transmission circuit to Kaitaia. Electricity is then distributed to consumers across long distribution feeders supplied from a limited number of zone substations. To improve the quality of supply and maintain supply for planned outages for Kaitaia, over 15MW of Diesel generators have been installed just outside the township.

This configuration is a legacy of a network design focused on providing electricity to a sparsely populated, economically deprived area, at a time when cost rather than reliability was the main driver for network development. Over 35% of

Top Energy's lines were originally built using subsidies provided by the Rural Electrical Reticulation Council (RERC). This levy assisted post-war farming development in remote areas and enabled the supply of electricity to consumers located in sparsely populated rural areas, which would otherwise have been uneconomic to service.

The original network infrastructure was also developed at a time when Kaikohe and Kaitaia were the dominant urban centres. This is no longer the case, with growth subsequently occurring in the Bay of Islands and Kerikeri as well as the East Coast peninsulas.

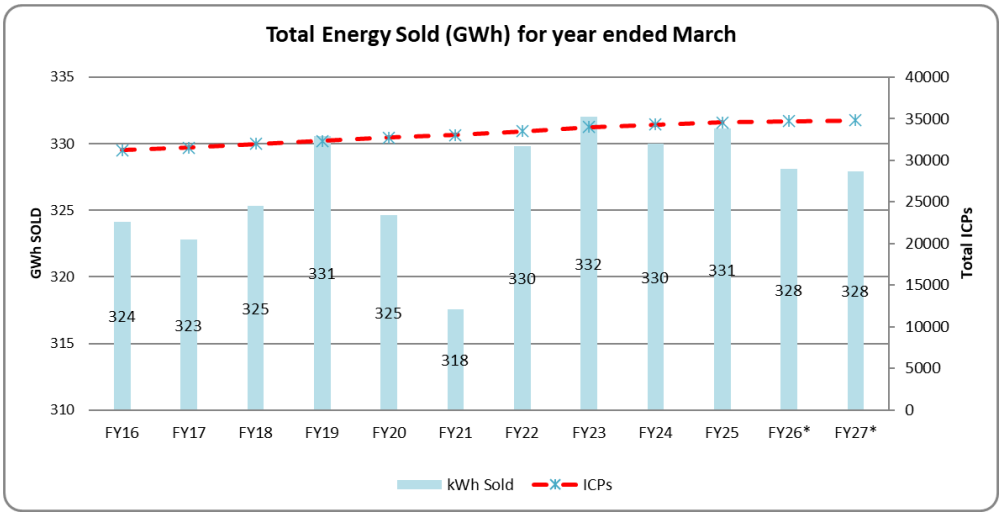
Many existing lines now require extensive rebuilding and refurbishment. Many assets are located in sparsely populated rural areas, which remain uneconomic in some circumstances. However, Top Energy is required by legislation to maintain a power supply to consumers who were connected to these lines before 1993.

Within this environment, Top Energy has had to invest to meet growth in new areas, while maintaining an appropriate level of service in existing high-cost network areas. The costs of these investments need to be reflected in prices.

3.1.2 Network consumption and peak demand

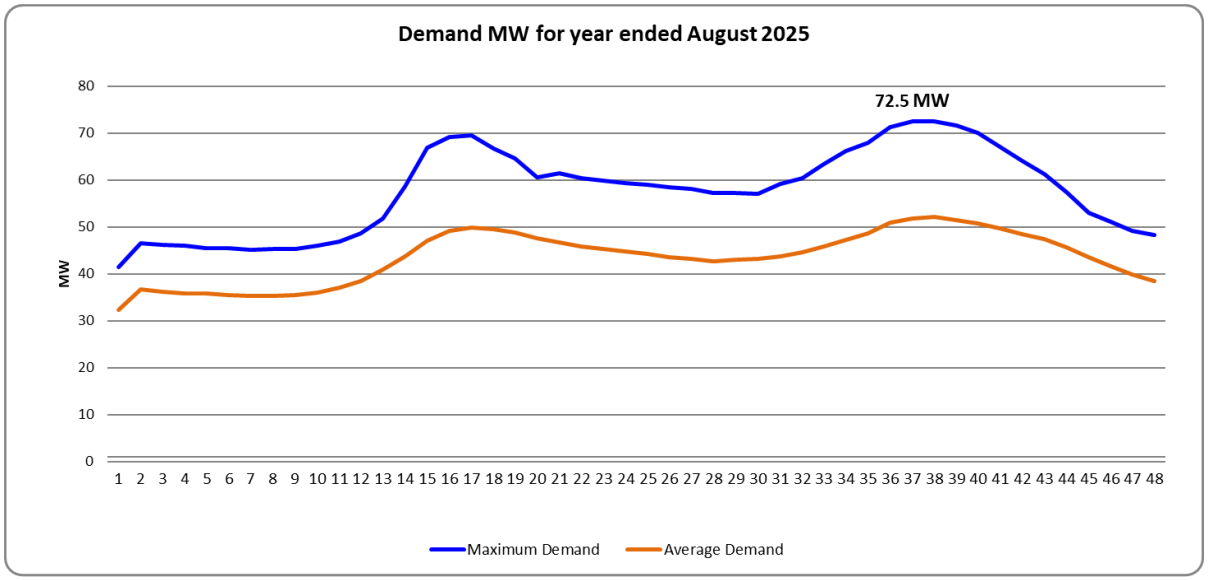
The utilisation of the network is heavily weighted towards small consumers, representing 99% of connections and over 80% of maximum demand. This is evidenced by the fact that average consumption is one of the lowest in the country at approximately 9,500kWh/consumer. Top Energy's pricing structures are therefore strongly focused on the needs of the Residential and General consumer groups, with only a few significant connections. The total energy sold on the network is shown below and has fallen over the last five years, despite an increase in the number of connections.

Figure 3: Consumption and number of connections



The key driver for future investment in the network is the maximum demand at both the aggregate and substation levels. Maximum demand on the network was approximately 72MW, up 1MW from 2024. This is still significantly lower than the high of 78MW in 2023 and is at 2019 levels.

Figure 4: Demand on Top Energy network



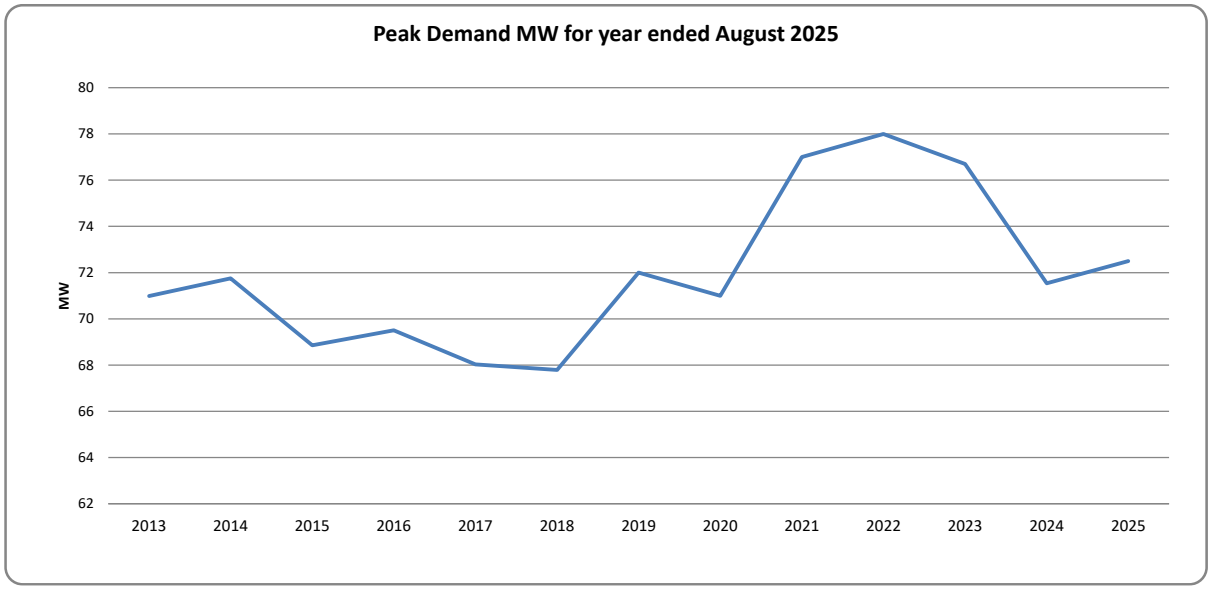
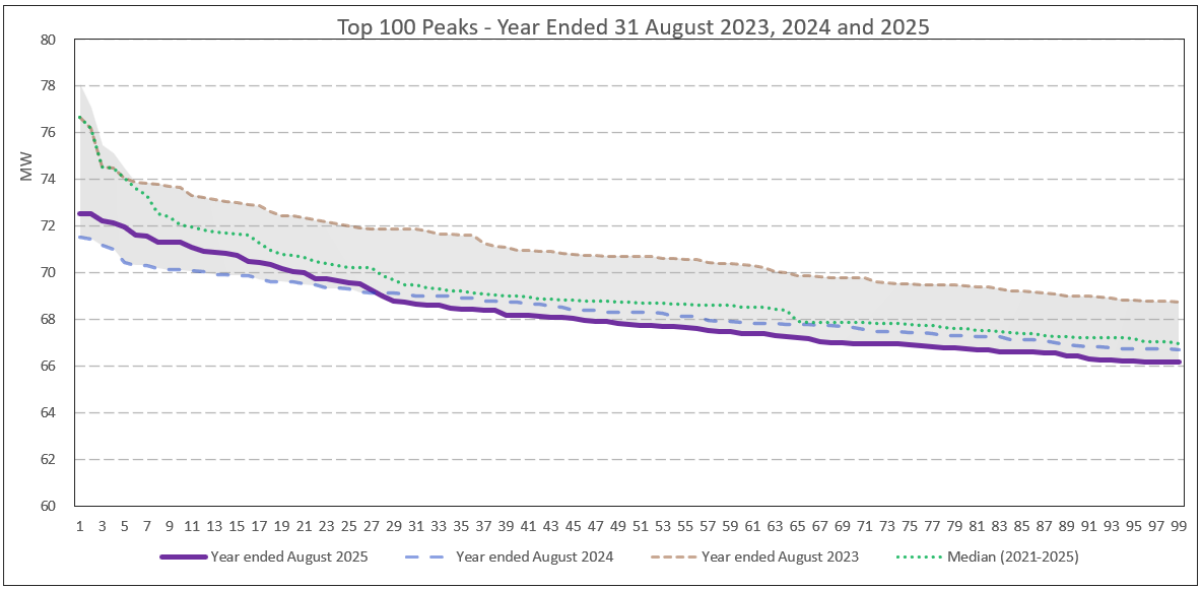


Figure 5 below shows the Top 100 peaks for the years 2021 to 2025. This indicates that the fall in peak demand is not just at the maximum level but across the top 100 peaks. Demand response, due to tight wholesale market conditions and tighter economic conditions, may have contributed. We will continue to monitor this and the impact on our demand forecasts.

Figure 5: Demand on Top Energy network

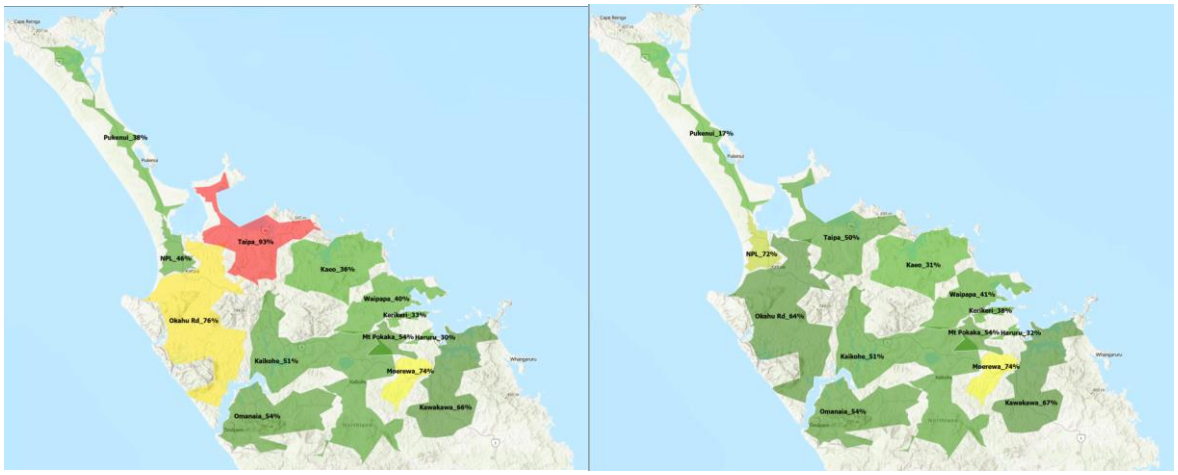


3.1.3 Current Constraints and responding to future congestion

No significant capacity constraints exist on the sub-transmission 33kV network when all network elements are in service. The only potential constraint is at Taipa, which is being addressed next year with the end-of-life replacement of a transformer. The AMP growth CAPEX has been reviewed and now shows that over the next 10 years, there will be $8.5M of growth CAPEX (4% of total CAPEX), of which $8M is fully committed in the next couple of years.

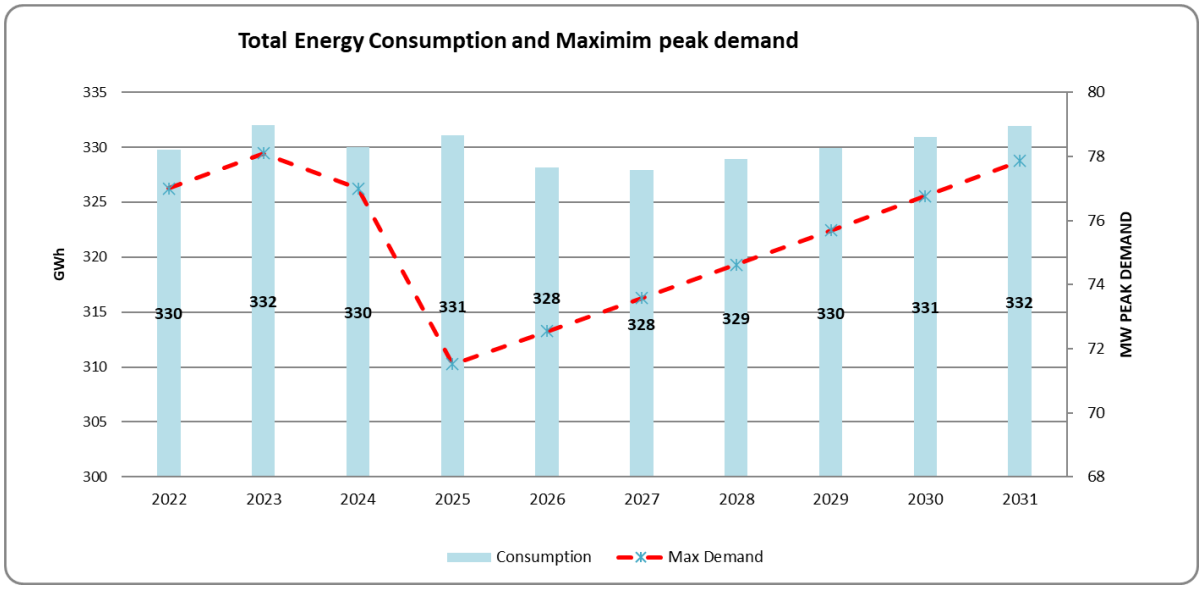
The graphs below show the current utilisation by station now and in 5 years. A more detailed assessment and future implications are shown in Appendix 6.

Figure 6: Current Utilisation by Substation Utilisation by substation in 5 years



Our Asset Management Plan further highlights that demand and consumption growth are expected to be subdued over the next five years. Peak demand is not likely to recover to the 2023 level by 2031/2032.

Figure 7: Total Energy Consumption and maximum peak demand



Any emerging constraint on the network would be at the distribution level. Both at Distribution transformers and the low-voltage network, which is typically at the street and suburban level. Network Capacity constraints have historically been the result of growth in consumer demand. However, network constraints are now being caused by the demand for connecting renewable generation rather than the growth in consumer demand.

Traditionally, it has been hard to assess the impact on the LV network as we did not have access to voltage information from smart meters. However, we have just concluded a trial that has successfully resulted in the adoption of the Hiko LV smart meter visibility tool with access to SmartCo meter data.

Future infrastructure spending on the LV network may be delayed due to the change in Code, increasing our voltage drop threshold from 6% to +/-10%. This is seen as a low-cost enabler to accommodate an increase in demand for both load and generation on LV Networks across New Zealand.

Beyond the above quality thresholds, demand increases can be accommodated by increasing capacity, utilising non-network solutions, and optimising existing assets, or by smoothing demand through price signals.

Despite experiencing limited capacity constraints, Top Energy introduced TOU pricing for Residential and General consumers in 2021. By offering price signals now, this will enable retailers to build the appropriate systems and offer TOU pricing to customers and for customers to become accustomed to these future price structures. The TOU signal has been reduced this year to reflect the change in growth forecast from the AMP update. A TOU signal has been maintained to provide customers with continuity in pricing and manage impact.

To date, no change in behaviour has been seen due to very limited pass-through to end customers. To further embed these price signals, Top Energy removed retailer exemptions last year and migrated all eligible customers with capable meters to TOU pricing. This is now required under the code from 1 April 2026. Periodic reviews are conducted to ensure that connections are maintained at the correct pricing. Price signals for demand management will continue to be refined, e.g., more targeted, and this could include further trials.

3.2 Industry Context

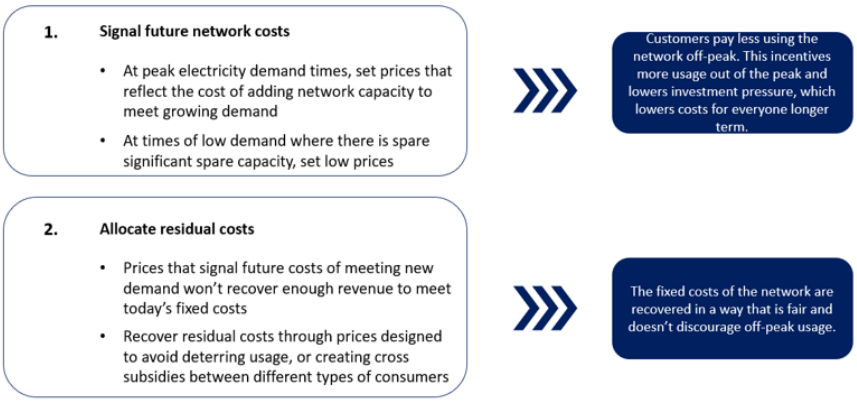
Decarbonisation and the emergence of new technologies are expected to have a significant impact on the traditional electricity industry, not only increasing demand but also changing customers' use of the network and, in some cases, providing alternatives to grid connection. Emerging technologies include:

- Distributed generation e.g. Photovoltaic generation
- Battery storage and management systems
- Household Management Systems and
- Electric Vehicles

The overall combined impact of these technologies is uncertain; however, the impact of technology will have a direct effect on our pricing structures, and we need to ensure that network utilisation can be maximised. Electrification of existing industrial processes will be limited, as we only have two Industrial customers with little energy transition required. Future Industrial growth will be evaluated on an individualised basis.

Top Energy is committed to implementing good pricing practices that encourage efficient network use and investment for the long-term benefit of our consumers. This includes moving towards cost reflective pricing and closely aligning with the Electricity Authority's guidance. This is a reform across New Zealand with the objective to increase utilisation of the network and lower future costs, meaning lower line charges. Figure 8 below provides a more detailed description of this.

Figure 8: Cost reflective pricing principle



Our 5-year pricing strategy has been updated to reflect this further and continues to be refined. Network implications and opportunities are an initial focus on distributed generation and electric vehicles. A Distribution System Operator has been employed to assist in managing this.

3.2.1 Distributed Generation

The network has the third-highest penetration of small solar in the country, at 7.3% of connections (2,545 customers with installed capacity of 15MW). This represents a 16% increase over the same period last year, and growth is expected to continue. This excludes large distribution generation. The potential impact of Distribution Generation was outlined in the background,

Top Energy has a distribution generation charge of 1 cent per kWh, which is unchanged. The revenue recovered seeks to recover some of the incremental costs of investigating issues, developing solutions, and other administrative costs. These costs only relate to additional expenses incurred due to distributed generation, rather than additional network infrastructure costs. This charge is separate from the injection, which is required under the Code from 1 April 2026.

We now have three large-scale solar generators connected at Kaitaia (67.7MW). Larger-scale Distributed Generation, for the purpose of export, is expected to cause capacity constraints at all levels in the future, including the national transmission grid. Given the maximum possible export capacity of the Kaikohe to Kaitaia 110 kV line circuit is 53MVA, Top Energy will no longer approve applications unless upgrades are financially supported. In addition, there are potential transmission constraints on the Kaikohe and Maungatapere 110kV line, with Top Energy having approved applications for 132MVA, with several other interested parties showing interest and at various stages of discussion. To accommodate these applications Top Energy has worked with Transpower to implement a Special Protection Scheme, which has doubled the capacity of the line. However, even with this upgrade, it is anticipated that the remaining capacity will be allocated in the short term. Top Energy has been working with Transpower and Northpower on options to accommodate further generation in Northland.

3.2.3 Electric Vehicles

Electric Vehicles have the potential to change consumption patterns e.g. peak demand and are also a consideration for network management. We currently have around 578 EVs (BEV, PHEV as of February 2026), up from 477, registered within our network area and are not seeing any network issues. However, we do acknowledge the actual number using our network is higher due to a high level of tourists visiting the district. As uptake increases, we do expect to see isolated constraints appearing which will require additional price signals to manage demand. However, the lack of pass-through from retailers of current price signals, e.g., TOU prices, could limit our ability to signal this and result in higher investment than otherwise required.

3.3 Consumer views

3.3.1 Price and Quality

In 2009, Top Energy consulted with consumers on our proposed network developments and consumer expectations for prices and the quality of service they receive. The survey results established that 80% of consumers wished to see network reliability improve. Accordingly, we embarked on a programme to improve security of supply in which $180 million would be spent over 10 years, the single largest expansion in the history of the network.

In 2022, Top Energy consulted customers again regarding their price and quality perspectives. This was done through a separate survey of 1,000 consumers. This was repeated in November 2024, and the results were consistent with the 2022 survey. The key findings were:

- Six out of ten customers (64%) consider Top Energy's current power supply reliability to be acceptable (compared to 68% in 2022), with over one-third (35%) stating that the power supply has improved over the last 12 months.
- A significant proportion of customers (79%) would not be prepared to pay more for an improved level of power supply (compared to 81% in 2022).
- Over eight of ten customers (81%) agree to move from a high cost to a low-cost company by 2030 would require reliability of supply to remain at the current level. This is up from 74% in 2022.

These results are consistent with our annual survey, which measures current satisfaction with price and quality. Feedback from the last five surveys indicates that both Residential and Commercial consumers are generally satisfied with the current levels of service, with the majority not willing to pay higher prices for increased reliability. The 2024 customer survey results are shown below.

Figure 9: Price quality trade-off

Source: Key Research customer survey 2024

3.3.2 Customer satisfaction

Since 2018, Top Energy has completed comprehensive annual telephone satisfaction surveys to understand Residential and Commercial customer satisfaction and experience with the services provided. In addition, we complete monthly customer surveys which measure customer satisfaction with our faults and new connections divisions.

The key results over the last few years have been:

- Customer satisfaction with faults and new connections divisions remains strong and has averaged 80%
- Adoption of *New technologies* by customers remained steady with Commercial customers more inclined to adopt new technologies than Residential customers. This included electric vehicles, solar and batteries. However, in 2024 the number of customers who are likely to purchase an EV in the next 12 months fell from 14% to 9%. This is due to the removal of the subsidy and the introduction of road user charges.

This year, rather than running the annual telephone survey, we formed an in-person consumer panel to provide more in-depth consumer feedback on topical issues. Consumers were asked to apply, and then a cross-section of consumers was chosen. The key topics covered were:

- Pricing
- Sustainability
- Communication
- Network Resilience

The insights provided by the Panel enabled us to better understand consumers' views and the impact of our decisions.

3.2.Regulatory considerations

Top Energy is subject to regulations that influence our pricing decisions as well as provide guidance on how prices should be set. These are summarised in Figure 10.

The Commerce Commission determines the lines charge revenue it considers sufficient to recover our reasonable costs and appropriate return on investment. This is outlined in the Default Price-Quality Path Determination 2025 (DPP4). The 2026/2027 year is the second year of DPP4. We must also publish a range of information on our prices and pricing methods. This pricing methodology is prepared pursuant to these requirements (see Appendix 3).

The Electricity Authority's (EA) pricing principles and information disclosure guidelines also provide useful guidance on setting economically efficient prices. The EA published pricing principles (June 2019), and Updated Practical notes V2.1 (2022), and we have considered the extent to which our pricing methodology aligns with these pricing principles in Appendix 4.

To encourage and support distributors to adopt more efficient distribution prices, the EA developed and published scorecards for each distributor based on an assessment of their pricing methodology and pricing roadmap. The last scorecard was completed for the 2023/24 year, as the Authority decided not to produce them based on the 2024/25

and 2025/26 years. In addition to scorecards, the Authority has published 10 focus areas for distribution pricing. These are outlined in Appendix 4, which shows our progress to date.

Top Energy scored 4.1 / 5 in 2023/2024, a significant increase from the 2021 score of 3.3 / 5. This placed Top Energy in the top 35% of all distribution companies in New Zealand, reflecting our pricing reform to date on cost-reflective pricing and our future pricing strategy. Despite the scorecard, Top Energy will continue to align our pricing strategy with our pricing objectives, e.g., not differentiating between rural and urban customers, as this is based on consumer feedback.

Figure 10: Summary of relevant regulations

Regulation	How this affects Top Energy's prices
Electricity Distribution Services Default Price-Quality Path Determination 2020 (DPP)	Forecast revenue from prices must not exceed forecast allowable revenues determined by the Commerce Commission
Section 2.4 of the Electricity Distribution Information Disclosures Requirements (ID)	Requires Top Energy to publish certain information on prices and pricing methods
Distribution Pricing Principles and Information Disclosure Guidelines (Pricing Principles)	Provides guidance on: • economic principles and market considerations for setting prices. • information that should be made available to support pricing methodologies
The Electricity (Low Fixed Charges Options for Domestic Consumers) Regulations 2004 (LFC Regulations) and The Electricity (Low Fixed Charges Options for Domestic Consumers) Amendment Regulation 2021	This requires Top Energy to offer a price option to domestic consumers that has a fixed daily price not exceeding 90 cents for the 1 April 2026 to end of 31 March 2027 period. This regulation is revoked on 31 March 2027.
The Electricity Industry Participation Code, Part 6 - pricing of distributed generation.	Limits prices for distributed generation to the incremental costs of connecting generation to the network, considering any avoided costs.
The Electricity Industry Participation Code, Part 12A.	Top Energy must consult with retailers in relation to any changes to pricing structures.

3.3.Stakeholder (Retailer) considerations

In accordance with the requirements of the Electricity Industry Participation Code, Top Energy has engaged with all retailers with connections on our Network when we have intended to make changes to our pricing structures.

During October 2025, Top Energy, in conjunction with Northpower, undertook consultation on further cost-reflective pricing. The consultation focused on:

- Structural change with the introduction of a negative tariff for injection
- Pricing approach after the phase-out of the Low Fixed Charge Tariff regulations
- Smart meter deployment plans, given our low penetration and the shutdown of 2G and 3G networks
- Future technology trials and our interest to participate e.g. Electric Vehicles and

In addition to this formal notification, Top Energy has engaged stakeholders through attendance at industry workshops (e.g. ENA Strategic Pricing Working Group, Joint Retailer and ENA workshop), informal discussions and face to face meeting with retailers. There were 18 retail brands with customers on the Top Energy network, which is unchanged since last year.

Pricing Decisions

The Statement of Corporate Intent (SCI) of Top Energy Consumer Trust outlines the overall objectives of Top Energy Limited. Our Pricing objectives and strategy align with this. Of relevance are:

D. To operate in an environmentally sustainable manner, to be responsive to the social needs of our community and have a well-defined corporate governance system to support the long-term strategy

E. To minimise the total delivered cost of electricity to our consumers

3.4.Pricing objectives

Top Energy has adopted the following six pricing objectives, informed by the above considerations:

1. Prices provide an adequate return to the shareholder within the restrictions of the Commerce Commission's price control regime.
2. Prices are economically efficient, transparent, and simple to understand, but also recognise the socio-economic needs of consumers and the region.
3. Prices reflect a fair and efficient allocation of costs, regardless of actual volumes of electricity consumed.
4. Prices provide consumers with opportunities to reduce their charges where they can make changes in their usage of the network to reduce Top Energy's long-run marginal costs.
5. Price stability and certainty is maintained by signaling changes in advance and by transitioning these changes over an appropriate timeframe to avoid price shock.
6. Prices do not differentiate between urban and rural consumers.

These objectives are informed by the key considerations discussed in the previous section, including business considerations, consumer feedback, industry and regulatory guidance (in particular the Electricity Authority pricing principles).

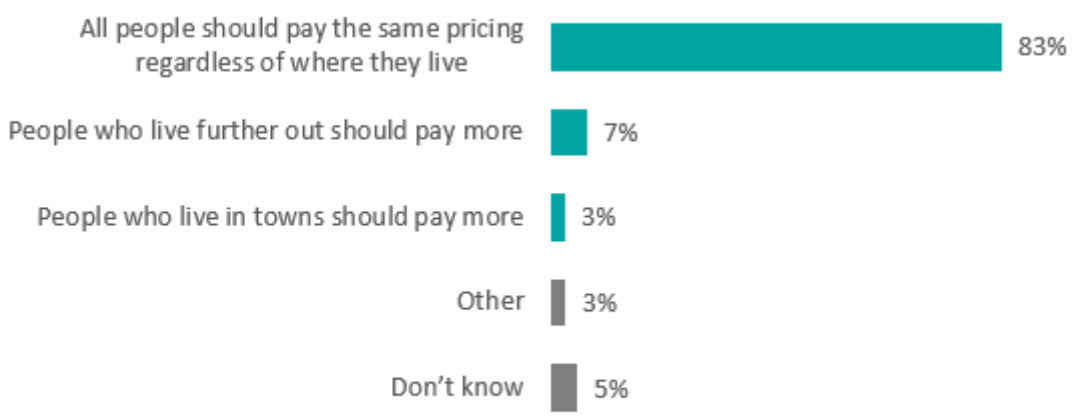
Trade-off exists across these objectives which must be balanced. Our current focus in meeting these objectives is:

- To allocate costs fairly between consumer groups
- To establish a range of price options that reflect consumer requirements e.g. Residential and General Commercial TOU pricing.
- Those prices reflect the potential demand and capacity required by consumers and are recovered in a cost reflective manner e.g. increase fixed charges.
- Complying with regulatory requirements
- To appropriately recover pass-through costs
- To achieve a rate of return acceptable to shareholders.

These are reviewed periodically. The last change was made in 2023.

Top Energy surveyed its customers as part of the annual consumer survey in 2022 to determine if consumers agreed with pricing principle 6 – Prices do not differentiate between urban and rural customers. This was completed again in 2023 with similar results. The chart below shows our consumers strongly hold this view, with more than eight out of ten customers (83%, up 2%) believe all people should pay the same pricing regardless of where they live and only approximately one in fifteen customers (7%, down 4%) would like people who live further out to pay more. Therefore, the objective will remain.

Figure 11: Survey results on locational pricing



3.5. Five-year pricing strategy and Roadmap

All key activities for 2025/2026 have been completed or are in progress. Our 5-year strategy has been reviewed, and the transition to more cost-reflective pricing has been further outlined in the pricing road map. The review of our capital contributions policy has been incorporated into the Authority's Distribution Connection Pricing Code amendments work stream. See section 7.11.

Strategy

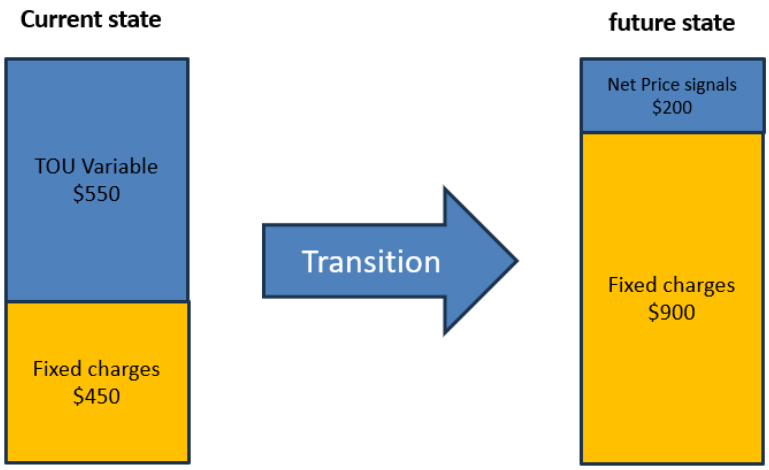
Our pricing strategy has been reviewed this year. The review is timed to align with the removal of the LFCT regulations on 31 March 2027, an update to the Asset Management Plan, and the end of our current five-year strategy period. This review ensures that our roadmap will deliver the strategic objectives of focusing on efficient cost recovery and preparing for emerging trends.

Our strategy aligns with the Authority's pricing principles. Under this strategy, we determine our target revenue and then forecast the revenue to be recovered through price signalling. The residual is then recovered via the least distorting charges.

Figure 12 illustrates our end-state strategy for the Residential customers. The strategy is to recover target revenue through fixed charges, except when price signals are appropriate. These price signals will be tailored directly to the desired outcome (now and in the future) and include payments and charges to retailers, which could be applied network-wide, to localised areas, or to specific individuals. Some examples are below:

1. Network-wide price signals
    - Consumption signals, e.g. TOU prices, winter/summer peak prices, ripple control to manage peak demand or signal future congestion/behaviour.
    - Injection peak signals e.g. new negative injection price at peak to manage peak demand
    - Injection charges e.g. charge for injection to cover the incremental cost associated with network management
2. Localised area price signals
    - Holiday home peak signals e.g. Summer injection payment in rural holiday hotspots e.g. Russell
3. Individual price signals
    - Demand management signals e.g. monthly payment for control of load to manage peak demand ($/month to control EV)
    - Flexibility services (either individual or aggregate)

Figure 12: Top Energy's Residential pricing strategy



This strategy will be applied to other segments; however, the signals and mechanisms to recover the residual revenue will differ. In addition to efficient cost recovery, our strategy also focuses on preparing for emerging trends that may impact outside the 5-year strategy timeframe.

Preparedness for emerging trends

Top Energy is addressing data and other constraints to assess current network capability and enable further pricing reform. This includes:

- An internal low-voltage physical study of the network to understand capacity and connectivity. The project has commenced and is expected to take 5 years. This will allow more capacity-based fixed charge pricing.
- We have just concluded a trial that has successfully resulted in the adoption of the Hiko LV smart meter visibility tool with access to SmartCo meter data.
- Employing a dedicated Distribution System Operator to understand and manage:
    - Impacts of distributed generation on the network and associated costs. This includes distribution system operation and voltage flows.
    - Developing the role of demand management for managing the network and associated pricing implications.
    - Monitor EV uptake.
- Surveying consumers' intentions and expectations.

The impact of the electrification of large industrial processes is expected to be limited, as only two Industrial customers are on our network.

Other mechanisms to manage maximum demand, when required, including ripple control, will continue to be used in conjunction with pricing signals. The pricing strategy is one component of the wider strategy to manage our network assets and investment for the long-term benefit of our existing and future consumers.

Top Energy also acknowledges that pricing reform will be an ongoing process and has incorporated the development and modelling of further cost-reflective pricing, including new technologies, into the pricing strategy. This has been complemented by further consultation with retailers, including an offer to participate in trials that retailers are considering conducting.

Roadmap

Top Energy's future pricing roadmap sets out how we will achieve our strategy. As a part of our strategy review, our pricing roadmap has been changed. The previous roadmap outlined our progress from the start of pricing reform. A summary of the roadmap and a more detailed plan are below.

Figure 13: Summary of Top Energy's pricing roadmap to 31 March 2026

Stages	Action	Status
1	**Test and understand:** Identify objectives, consult with stakeholders and industry, undergo trials, and gather data for analytics	Completed
2	**Develop strategy and roadmap:** Update pricing strategy to reflect cost-reflective pricing principles for Top Energy.	Periodic review and update this year.
3	**Enable price reform through pricing structures**: Implement and price structures required to achieve the strategy.	Completed and ongoing
4	**Phased Implementation:** Phased in of price signals to manage price shock on consumers within regulations.	In Progress
5	**Observe and refine:** Review the effectiveness of the pricing strategy, new technology and alignment with the AMP.	Ongoing
6	**Enable future pricing and alternatives:**	Ongoing

The new detailed roadmap is below. It outlines our plan to achieve our Strategic objectives, along with their corresponding timelines. This will continue to evolve.

Figure 14: Top Energy's future pricing roadmap (as of 31 March 2026)

Strategy component	Previous 5-year strategy	Year 1 (2026/27) *Implement*	Year 2 (2027/28)	Year 3 (2028/29)	Year 4+ (2029+)
Achieve cost reflective pricing Cost reflective fixed charge recovery.	• Continued journey to **cost reflective fixed charge recovery,** subject to LFCT and impact on consumers. • Increase fixed charges • Introduce TOU capacity pricing • Increase from **x% to x%**	• Implement the last year of the LFCT (90c/day) • Continue to increase in fixed charges (xx%) • Determine migration timeline of LFCT customers to standard pricing	• Accelerated fixed charge recovery through starting to phase out LFCT	• Accelerated fixed charge recovery • Potentially complete migration of all customers to the standard pricing, subject to decision in 2026/27	Complete the strategy of **fixed revenue recovery with price signals only where:** • network signals are required (or to be signaled) or • where targeted/ localised signals are required and • Assists in transitioning to non-distortionary recovery of residual revenue Review allocations based on network requirements
Network Price signals	• Introduced and **refined price signals** e.g. mandatory TOU reflecting long-term AMP	• Review LRMC when EA guidance is released • Reduce off-peak pricing	• Introduce Summer /Winter TOU pricing • LRMC calculation	• Refine pricing to align with the signal required for peak management	
Targeted price signals (Locational or segment)	• Introduced DG price signals to reflect the specific cost to be recovered • Demand pricing	• Introduce injection pricing under regulations on 1 Apr 26 • Close CN20 as signal no longer required	• Base injection pricing on LRMC (Regulation)	• Annual review of pricing signals	
Customer impact	• Manage customer impact on the road to cost reflective pricing and efficient cost allocation				
Regulatory compliance	• LFCT phase out • Align EA pricing principles and areas of focus • Capital contributions				
Efficient Cost allocation	• Completed COSM model in 2023/24	• Update COSM and review our revenue segment allocation based on EA guidance			
Enabling future pricing and alternatives	• LV connection study • Reviewed requirements for DSO and established plan	• Consultation with stakeholders, including pass through of signals • Review billing system is fit for purpose • Assess impact of technology from AMP for pricing structure and customer groups			DSO functionality when re

Limitations on strategy

Despite these efforts, there are still some barriers to achieving our strategy.

Despite having mandatory TOU pricing, there has been no material change in customer behaviour, as shown in Figure 15. This is due to a lack of pass-through by retailers, which has removed the pricing signals to end consumers. The requirement for retailers to offer TOU pricing may assist.

With limited ability to influence Retailers to pass through line costs or install TOU meters, it makes further signalling through prices difficult. This could lead to inefficient network investment, which is not in the best long-term interest of consumers. We are working with other EDBs to explore future options e.g. EV pricing.

Figure 15: Consumption proportion by TOU time bands

Time band	2025	2024	2023
Peak	20%	19%	19%
Shoulder	52%	55%	54%
Off-peak	27%	27%	26%

Another key issue identified in implementing our price strategy is the rollout of smart meters to all our customers. Currently, only 78% of connections have smart meters installed. Our consultation with Retailers continues to push for further deployment of smart meters.

Figure 16: HHR Penetration based on Advanced Metering Flag

Density	Advanced Metering Penetration (%)
Remote	65%
Rural	78%
Urban	85%

The availability of smart meters limits our ability to offer new pricing structures, and for customers to potentially benefit. The concentration of non-smart meters in remote low-socioeconomic areas is of concern as our most vulnerable customers may not only be able to benefit but could also be negatively impacted as more network costs are allocated to those without smart metering.

3.6.Pricing review 2026/2027

Top Energy's pricing strategy has provided the framework for activity over the last few years and for the changes made this year. To assist in the delivery of the framework, Top Energy has continued to be a part of the ENA's Distribution Pricing Working Group (DPWG), to better understand and be involved in industry discussions on pricing and assist in industry alignment with the transition from a historical pricing structure. In addition, Top Energy and Northpower have continued to work closely together to delivery common pricing structures for Northland and adopt industry consistency where possible. This includes joint consultation of retailers, implementation, and analysis of TOU pricing for mass market customers and demand and/or capacity pricing structures for larger Commercial customers.

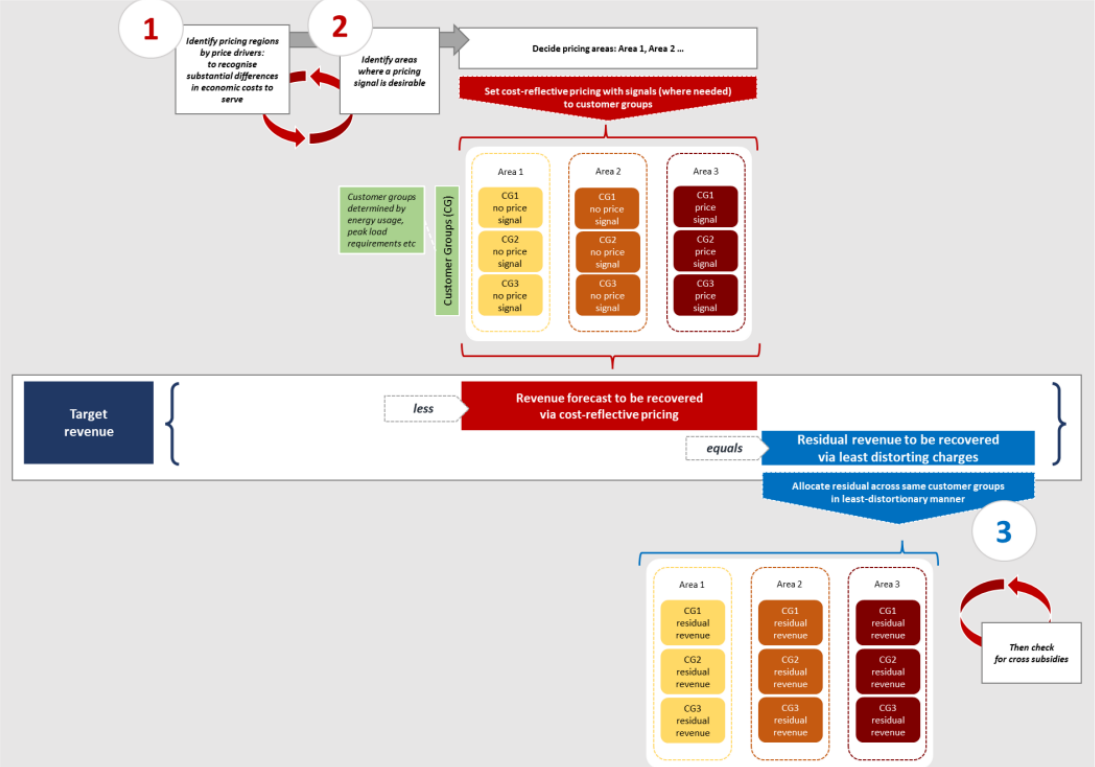
The main changes and activities to date are:

- Modernising the pricing structure to achieve better industry alignment e.g. ENAs distribution pricing guidelines, Residential consumer group with Low User and Standard User category and the introduction of TOU pricing for non-Residential customers.
- Evaluation of pricing options and potential impact on customers through analysis using customer half-hour meter, updating our cost to serve model and focus group insights.
- Introduction of TOU pricing for Residential and General Commercial customers from 1 April 2020
- Introduction of capacity and demand pricing for TOU Commercial customers from 1 April 2021
- Introduction of Distributed generation export charges to cover incremental costs from 1 April 2021

- Commence the phase out of the LFCT from 1 April 2022
- Pass through of the new Transmission Pricing methodology from 1 April 2023
- Increased recovery of costs through fixed charges – ongoing and lower off-peaks rates
- Updated our cost-to-serve model in 2023.
- Migrating all eligible connections to TOU pricing with no exemptions on 1 April 2024.

To better reflect the service, we provide and our underlying cost structure (i.e. network capacity) and assist in managing future network capacity constraints, Top Energy has commenced implementing new more cost reflective pricing signals with the objective of moving from largely consumption-based pricing towards prices based on demand/capacity-utilisation with time of use consumption charges. This change is in line with the cost reflective framework that the EA has released for consultation in its Updated Practical Notes (2022).

Figure 17: Electricity Authority Practical note diagram



There are three changes to pricing structures this year, which are:.

- Introduced a price code for customers injecting electricity during the winter peak as required under the regulation
- Discontinued our Building Temporary Supply Price Category, which has no customers
- Closed Controlled 20 Pricing Code to new customers

This year, the phase-in of lower off-peak prices and increased fixed cost recovery continues. Our fixed cost recovery strategy will be further refined to align with the phase-out of the LFCT regulations. The fixed charge recovery rate increased to 49% from 43% in the previous year. There are three key pricing focus areas this year, and these are shown in Figure 18:

Figure 18: Key pricing focus for 2026-27

Strategic driver	Explanation	Actions
LFCT regulations phase-out	Increase fixed charge recovery to be more cost reflective.	Increase the Residential daily charge to 90c/day.
Regulation for Injection Negative Charge	Distributors are required, under the code, to implement a price code that reflects the value of injecting into the grid at peak times.	Introduced a new price code. Price based on the LRMC model from ENA.
More cost-reflective pricing	Continuation of our move to cost reflective pricing by increasing the fixed proportion of consumers' charges and lowering off-peak charges where constraints do not exist.	Continued increase in fixed cost recovery and reducing off-peak price signals through a phased approach to manage rate shock.

4. Target revenue

The first step in the pricing process is establishing the total target revenue to be recovered through prices. Distribution prices are set to generate sufficient revenue for Top Energy to recover its costs, subject to DPP allowable revenues. These costs are discussed in further detail:

COMPONENTS OF TARGETED REVENUE			
	(1 April 2026 to 31 March 2027)	(1 April 2025 to 31 March 2026)*	% change
Transpower Charges*	9,738,017	8,353,354	16.6%
Avoided Cost of Transmission (ACOT)	-	-	
Other Pass-through Costs	378,870	377,519	0.4%
Other Recoverable Costs	- 3,000,523	- 5,916,825	-49.3%
Pass Through subtotal	**7,116,364**	**2,814,048**	152.9%
		-	
Network Maintenance Costs	10,572,000	10,252,834	3.1%
Overheads	22,621,000	20,114,000	12.5%
Depreciation	14,498,000	15,279,000	-5.1%
Pre tax ROI charge	32,931,621	31,575,992	4.3%
Distribution subtotal	**80,622,621**	**77,221,826**	4.4%
Annual Revenue Requirement	**87,738,985**	**80,035,874**	9.6%
DPP Compliance Adjustment	- 29,104,651	- 25,776,276	12.9%
TOTAL TARGET REVENUE	**58,634,333**	**54,259,598**	8.1%

* Published as last year, except for Transmission, due to BBI adjustment event. Total Target Revenue has been adjusted accordingly.

The total Target revenue has increased by $4.4m (8.1%).

4.1.Revenue cap regulation

Top Energy's revenue under the 2025 Default Price Path (DPP) Determination is based on a revenue cap. Total target revenue for 2026-2027 is $58.6m, complying with the default price path (DPP) and based on consumption and connections forecasts. This is $8.4m below the Forecast Allowable Revenue of $67.07m. The methodology for forecasting consumption and connections is outlined in Top Energy Annual Price-Setting Compliance Statement – 2027 Assessment period. The target revenue is after any posted line charge discounts that are paid to consumers through a reduction in their electricity bill. Posted discounts are forecast to be in the vicinity of $5.9m for the year, representing 10% of target revenue before the discount.

For the 2026-27-year, targeted distribution revenue has increased by 6.5% ($3.0m). Despite this increase, Top Energy is under-recovering revenue by $19.6m. This consists of $8.4m under-recovery from Forecast Allowable Revenue and

$11.2m from Wash-ups, which is not being recovered. The allowable return on investment for the 2026-27 regulatory period is 7.1% (65th percentile vanilla Weighted Average Cost of Capital (WACC).

4.2.Transpower charges

From 1 April 2025, Transmission has been reclassified as a pass-through rather than a recovery cost. Top Energy passes through all transmission charges at cost in accordance with the DPP and its own pricing principles. From 1 April 2023, Transpower has implemented a new Transmission Pricing Methodology (TPM). The key aspect of the new TPM is a benefit-based approach. The EA states "Those who benefit from Transmission will pay for them, through fixed like charges". The new TPM has three charges:

- Connection Charges – Transpower charges for use of Kaikohe GXP connection assets to which Top Energy's network connects to the national grid. This is relatively unchanged.
- Benefits Based charges (BBC) – allocates the cost of new and certain historical grid investments to consumers in proportion to their benefits
- Residual charge – recovers Transpower's remaining costs that are not recovered through other charges.

In addition, there is also a transition cap to manage price shock. This is only an interim charge. In 2025-2026, our BBI charges were recalculated based on a new connection that met the >10MW reopener criteria. The incremental change was passed through to the new connection.

Top Energy has used the following methodology to allocate Transmission costs to consumer groups. These allocators are in line with the EA's guidelines that allocators should be "fixed like" and not materially impacted by customers' future behaviour. Top Energy will charge this as a fixed costs in line with the EA guidance. The phase in was completed last year.

Figure 19: TPM allocation and pass-through methodology

Charge Type	Basis of Costs	Transpower allocator	Charged by Transpower	Allocation by Top Energy to Pricing Groups	Top Energy Long-term Charging Methodology
Connection Charges	Connection Investments	Primary: Connection Secondary: AMD/AMI	Fixed	Lagged coincidental AMD (3 years) as a proxy for capacity then lagged kWh for Residential and Small Commercial	Fixed
Benefits Based	Interconnection Assets	Primary: Regional benefit Secondary: GXP Average kWh	Fixed	<$20M TPM simple allocation method updated every 5 years >20M historical kWh (2014-2018)	Fixed
Residual	Remaining recoverable revenue	Primary: Historical average AMD Secondary: Historical Average kWh Tertiary: Lagged system average kWh	Fixed	Match Transpower methodology	Fixed
Transitional Cap	Transition management	See TPM	Fixed	Same as connection given only $20k	Fixed

4.3.Avoided Transmission – Distributed Generation

From 1 April 2023, the Authority has decided that payments by distributors to eligible distributed generation for avoided cost of transmission (ACOT) are no longer required.

4.4.Avoided Distribution – Distributed Generation

Avoided distribution may be payable to embedded generators of greater than 1MW output when suitable terms have been negotiated with Top Energy.

4.5.Other Pass-through costs

This includes rates and regulatory levies.

4.6. Other recoverable costs

This includes quality incentive and Incremental rolling incentive scheme (IRIS) adjustments.

4.7.Network costs

Network costs comprise mainly maintenance costs. These are derived from the network maintenance programme which provides consumers with acceptable levels of safety and reliability, including an allowance for repairs following faults. The amount is determined in conjunction with Top Energy's Asset Management Plan.

4.8. Non-Network costs

These are costs incurred in managing the day-to-day operations of the business, including management, finance and administration costs, as well as system operations and network support.

4.9.Depreciation

Depreciation represents the return of Top Energy's asset investment and is estimated using 2025 Regulatory Asset Base (RAB) roll-forward.

4.10. Pre-Tax WACC

A pre-tax return on investment is derived by applying a pre-tax weighed average cost (WACC) to Top Energy's regulatory asset base (RAB). Our 2027 WACC estimate of 8.37% is based on the DPP WACC (7.10%) expressed on a pre-tax basis.

5. Identify pricing regions and pricing signals

The second step in the pricing process is to identify pricing regions where there is a substantial difference in economic cost to serve. There are several ways in which pricing regions could be determined:

- Split by GXP

- Connection types such as rural and urban
- Geographical regions

To assist in this process, we use our Cost Serve model. This model investigated the merits of adopting pricing sub-regions, reflecting urban, rural and remote and Northern, Eastern and Western network supply areas, respectively. While some cost differences were evident across these regions, potentially justifying different prices, consumers have sent a clear message that rural and remote consumers should pay no more than urban areas (See Section 4 Pricing principles). This aligns with our pricing objectives that prices do not differentiate between Rural and Urban customers.

The third step is to consider areas were a target congestion-related pricing signal is desirable. The key areas of constraint on our network are set out in Appendix 6.

Taipa substation

Taipa substation feeds 4,500 consumers and is operating near capacity, with future growth predicted. This issue is being addressed through the end-of-life replacement of the transformers. The new transformers will alleviate the constraint. The project has been approved and is scheduled to commence in 2027.

Kaitaia 110KV

The constraint on the Kaitaia 110kV is for large-scale distributed generation. Currently, the approved applications of 67MVA consume the full export capacity of this line. Therefore, we will charge any further large DG connections the incremental costs to connect them under Part 6 of the Code. This is an extremely cost-reflective price signal.

As such, there are no areas on our network that require a targeted congestion-related signal for the coming year.

6. Determining Consumer Groups and Pricing Options

The next stage is to determine Consumer groups and pricing options.

6.1.Cost drivers

We have sought to align our consumer groups and pricing options to reflect differences in the key drivers of our costs. Approximately, 75% of our costs are associated with directly investing in, maintaining, and operating the network, as well as receiving supply from Transpower. The remaining 25% is attributed to general management and business administration. Top Energy considers that our network cost drivers are:

- peak demand
- the length of the circuit required to supply consumers.
- the number of consumer connections
- dedicated asset costs.

The cost drivers that are relevant to Top Energy's current pricing methodology are peak demand, the number of connections, and dedicated asset costs, as discussed below.

Peak demand

Top Energy builds capacity in the network to meet forecast demand. As demand increases, Top Energy must consider further investments in capacity or alternatives. Consumers' peak usage of existing network capacity is a key driver of future costs. For instance, the network faced capacity constraints in some growth areas (as identified in 3.1 Business considerations) and Top Energy has undertaken a large investment programme in these areas to meet forecast demand. The introduction of TOU pricing and full migration of eligible connections may assist in deferring future investment once these signals have been passed through to customers by retailers.

Circuit length

The distance between a consumer's premises and the point of supply to the network influences the length of lines and cables required to deliver electricity to consumers. Thus, consumers further away from the Kaikohe GXP create relatively higher costs for Top Energy.

In our view, it is not practical, or necessarily fair, to distinguish individual consumers by circuit length. However, groups of consumers within network sub-regions can be distinguished, as noted in section 2. Given the clear message from consumers that rural and remote consumers should pay no more than urban areas, Top Energy has decided not to reflect this in pricing other than for Industrial customers.

Consumer connections

New connections create investment and ongoing operations and maintenance costs. Top Energy's policy is for consumers to contribute towards capital costs in an upfront capital contribution. Remaining connection-related costs must therefore be recovered through pricing.

Consumer specific costs

As a general principle, costs that are specific to individual consumers or groups of consumers should be directly recovered from these consumers, where practical. Example of these include:

- The provision of street lighting and community lighting is an example of a cost only caused by a specific group.
- Transmission and asset costs for large industrial consumers can also be identified, and prices set to reflect these costs through non-standard contracts.
- Transformer capacity for larger commercial consumers.

6.2.Consumer Groupings

Primarily consumers' connections are classified into Consumer Groups according to their capacity requirements and connection profiles. Capacity is seen as a good proxy for Consumer groups with similar peak demand and, therefore, incur similar network costs.

The number of Consumer Groups has been set at five, reflecting that 99.5% of the customer base is made up of mass market customers, and the balance between minimising complexity and ensuring costs are allocated appropriately between consumers.

Figure 20: Consumer Groups

Consumer Group	Criteria	Rationale	Pricing and commercial terms
Larger	Large Commercial and Industrial loads, with a fuse capacity of 110kVa or greater	Pricing incentivises the efficient use of network capacity by large loads through variable charges levied on peak, shoulder and off-peak time of use periods for Large Commercial and capacity charge based on kVA installed.	Standard
		Industrial loads are distinguished by much larger load size, time of use metering and Transpower and Top Energy's distribution costs can be identified for each consumer.	Non-Standard

		Embedded networks are typically large loads and are distinguished by individualised requirements which are required to considered on a case-by-case basis	Non-Standard
Residential	Loads have similar capacity with a common load profile which is often controllable	Recognises the large majority of small load connections with or without access to time of use meters and providing compliance for low user regulations.	Standard
General	All connections that do not fit within other consumer groups	Same pricing options as 'standard Residential' are available. In addition, pricing incentives through General Advanced variable charges levied on peak, shoulder and off-peak TOU periods. Also recognises that some connections will be without TOU meters.	Standard
Generation only <1MW	Connection which is less than <1MW and is a generation only	Ensure that connections whose sole purpose is generation only pay incremental costs. Note >1MW are individual priced	Standard
Unmetered	Street and community lighting and other unmetered connections	This group recognises the unique cost and network usage profile of street and community lighting.	Standard

6.3. Allocating price signals to consumer groups

The next step is to determine which consumer groups should receive a price signal and the strength of that signal to determine the revenue forecast to be recovered via price signalling.

System Growth

We have utilised the existing capacity growth investment in our AMP to forecast our Long-Run Marginal Cost (LRMC), enabling us to build additional capacity into the network. This only reflects the cost to increase the capacity that our network can deliver and does not include new connections or subdivisions. Only non-committed Capex is included.

The AMP growth Capex has been reviewed. The growth capex for the next 10 years has decreased significantly to $8.5m. This reflects the demand forecast in the background section. Of the $8.5m, $8m has been committed to projects

that have commenced delivery. Therefore, there is only $0.5m of forecasted growth capex over the next 10 years. This occurs in year 10. This has resulted in our LRMC being less than $1 per kVA. This calculation was made using the model from Electricity Networks Aotearoa. The assumptions and methodology are in Appendix 7.

Residential and General connections

TOU Pricing signals were introduced in 2021 and were based on future system growth. Despite the reduction in LRMC to near zero, we will maintain TOU pricing to ensure that price signals are embedded for the future. However, we have reduced the differential between Peak and Off-Peak by nearly half. This will be reviewed again next year, taking into account the impact on customers.

Residential and General connections peak injection negative price

Under section 12A.7 of the Code, distributors are required to make payments for injection for Residential and Business customers from 1 April 2026, where there is a benefit. This has been applied to all Pricing Categories that meet the definition in the Code (>99.5% of customers).

Top Energy has set the price based on the long-run marginal cost of peak demand approach – 12A.7 (1)(b)(i). The peak injection charge has been set at zero.

The LRMC has been calculated at $0.80/kW, and the calculated negative injection price for the peak period chosen (winter peak) is $0.0005/kWh. Based on our estimate of injection in the winter peak for the year ended 2027, the value is minimal. Based on 12A.7(c) Top Energy will set the injection charge at zero due to regard for transaction costs and consumer impact of setting a price signal, which will not incentivise uptake.

The calculation and methodology, as required under the Code 12A.7(3), are in Appendix 7. This is in line with the guidance provided by the Authority – Pricing for Distribution Peak Export Tariffs.

Top Energy will continue to review this each year. Retailers have been consulted on this approach.

Large TOU commercial and Industrial customers

- Large commercial price signals are lower than Mass Market due to higher fixed cost recovery and higher usage. These will continue to be reviewed as we increase cost recovery through fixed costs.
- Industrial pricing aims to recover Top Energy's costs to service these consumers. It is fully fixed with no price signal, as any capacity growth requirements are directly charged to these customers.

6.4.Test for cross-subsidisation

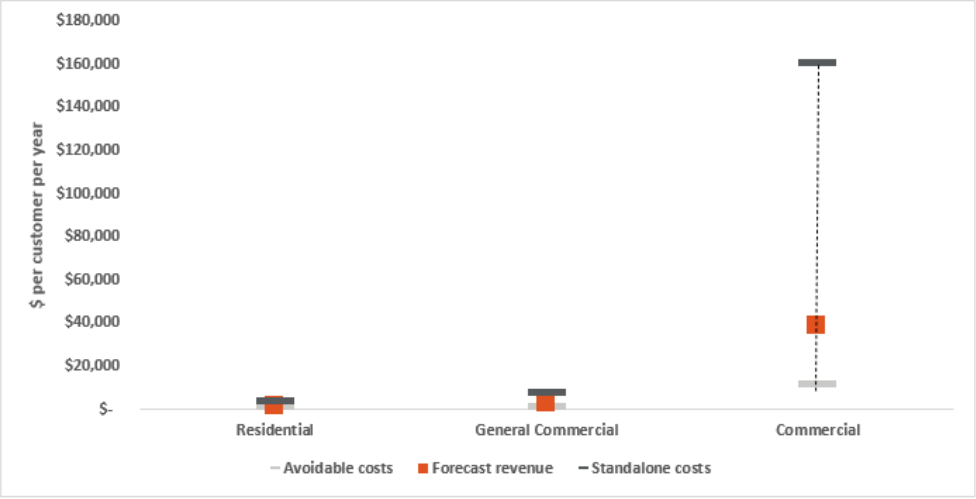
To help ensure the consumer groups are free from cross-subsidisation, we test whether revenue collected from prices is less than the stand-alone cost and greater than the avoidable cost (the cross-subsidy free range), for each consumer group.

Avoidable cost: are the additional costs of connecting a consumer, comprising connection costs, network upgrades, and incremental operating costs. Top Energy requires a capital contribution for new connections and asset upgrades if the expected line charge revenue from the connection is less than the associated incremental capital cost (i.e. an uneconomic connection). Accordingly, distribution prices will typically be in addition to incremental capital costs. Remaining incremental operating costs resulting from a new connection will be recovered through distribution prices. A new connection is estimated to contributed approximately $400 per annum (real) to operating expenditure.

Standalone cost: means the cost for a consumer to disconnect from the distribution network and install onsite generation. Solutions do exist for small loads to disconnect from the network through installation of onsite solar generation and batteries. However, these systems are relative expensive when compared to distribution supply. Given the geographic characteristics of our network these are calculated on an individual basis.

The graph below compares avoided costs, stand-alone costs and revenue from prices. Residential and General connections cover more than 99% of customers. This shows the revenue is within the subsidy-free range established by stand-alone and avoidable costs. Industrials are priced individually on a cost basis.

Figure 21: Avoidable and standalone costs by segment



For example, a 10kW solar system, 15kW battery system with a diesel generator can cost around $40,000 to install. We estimate this would cost 60 c/kWh over a 15-year period and the installation is funded by a mortgage. This is lower than last year, however, is significantly more expensive than the average 46c/kWh charge Top Energy's consumers pay after discount (source: MBIE quarterly survey of electricity prices, 15 August 2025). Top Energy will continue to keep watch on this market and respond appropriately through pricing.

6.5.Summary of pricing options

Top Energy offers the following pricing options within the above consumer groups.

Figure 22: Pricing Options

Price Code	Description and rationale	MWh	ICPs
Industrial (IND)	Fixed price recovery of costs associated with industrial loads consuming >3,000,000kWh per annum and a fuse capacity of 110kVa or greater.	39,765	3
Large Generation (LDG)	Fixed price recovery of costs associated with the connection of large-scale distributed generation into the distribution network.		4
Generation <1MW	Costs are set only to recover incremental costs.		
Micro Generation (DG)	Variable price recovery of costs associated with the connection of small-scale distributed generation into the distribution network. This is set at 1c/kWh. This applies to non-communicating meters only.	7,683	
Net Charge for export	The Net Charge for Export is calculated as the Charge for Export (as above) less the negative injection charge, if applicable. The negative variable charge rewards Residential and Small Commercial for injecting electricity back into the network at peak times when demand is likely to, on average and over time, drive future network investment. This has been set at zero and the TOU bands are the same as the Residential and General connections Price categories This is only available for customers with a communicating TOU meter and a connection of 45kVA or less and who export up to 45kW. The Credit for Network Benefit is set at 0 c/kWh for all TOU periods. The Net Charge for export is 1 c/kWh.		
General Advanced Metering (TOU) and (GA)	TOU is the default code for all customers with 110kVA using less than 3,000,000kWh (TOU). Total charges for this plan include a fixed price for each day connected, a connection charge for installed capacity on a kVA per day and a variable consumption price based on kWh consumption during three pricing periods, representing peak, shoulder and off-peak demand periods, as follows: GA Advanced metering is for small Commercial connections (<110kVA) with pricing beneficial for customers using over 45,000 kWh Both have pricing in the following time periods. • Peak: 07:00-9:30 and 17:30-20:00 • Shoulder: 09:30-17:30 and 20:00-22:00 • Off-peak: 22:00-07:00	44,201	107

Residential	Residential ICP's can have the following metering configurations: Uncontrolled, All-inclusive and Controlled.	157,921	28,718

Meter configuration	Total usage (MWh)
Uncontrolled	38,895
All Inclusive	118,343
Controlled	538
Total	157,776

Where:

Uncontrolled (UN24): This plan includes a fixed price for each day connected and a variable consumption price based on kWh consumption during three pricing periods, representing peak, shoulder and off-peak demand periods, as follows:

Weekdays (excluding weekends and public holidays)

- Peak: 07:00-9:30 and 17:30-20:00
- Shoulder: 09:30-17:30 and 20:00-22:00
- Off-peak: 22:00-07:00

Weekends and public holidays

- Shoulder: 07:00 - 22:00
- Off-peak: 22:00 - 07:00

A single price default option is available for customers with legacy meters or non-communicating smart meters as indicated by "N" in the AMI flag field of the Metering Attributes section in the EA registry. Variable prices are set higher than other controlled codes to incentivise consumers to take up controlled prices.

All Inclusive (IN18): This plan includes a fixed price for each day connected and a variable consumption price based on kWh consumption during three pricing periods, representing peak, shoulder and off-peak demand periods, as above. A single price default option is available for customers with legacy meters or non-communicating smart meters as indicated by "N" in the AMI flag field of the Metering Attributes section in the EA registry. This requires that Top Energy can control load for up to 6 hours per day. The load offered must be at least 3 kW (e.g. a hot water cylinder). Variable prices are set higher than other controlled codes as the supply is a single meter and therefore it is not possible to determine the actual portion of controlled and uncontrolled load.

Controlled 20 (CN): Top Energy can control load for up to 4 hrs per day and the load offered must be at least 10 kW. This is available to customers in conjunction with other configurations. Prices are lower than under the UN and IN price options to encourage consumers to offer up large interruptible loads.

<table>
<tr><td>General</td><td>General ICP's can have the following metering configurations: Uncontrolled, All inclusive, and Controlled

<table>
<tr><th>Meter configuration</th><th>Total usage (MWh)</th></tr>
<tr><td>Uncontrolled</td><td>70,155</td></tr>
<tr><td>All Inclusive</td><td>11,681</td></tr>
<tr><td>Controlled</td><td>2,331</td></tr>
<tr><td>Total</td><td>84,168</td></tr>
</table>
See above for definitions.</td><td>82,118</td><td>5,575</td></tr>
<tr><td>UM</td><td>Prices for streetlights (UML) are based on a price per lamp equivalent. Other connections (UMG) are supplied with continuous supply less than 500watts. Prices are wholly fixed.</td><td>1,130</td><td>2,519</td></tr>
</table>

6.6. Industrial (Non-Standard)

Industrial pricing aims to recover Top Energy's costs to service these consumers. To meet these consumers' requirements, Top Energy charge a wholly fixed annual price divided into twelve equal payments. There is no variable component. This fixed charge comprises the following individual charge items:

- Transpower charges which include Connection charges, Benefits based charges, Residual charge and Transition Charge
- Avoided distribution charges payable to embedded generators if applicable
- Top Energy connection and interconnection charges for its sub-transmission assets
- Top Energy operations and maintenance charges

The charges have been calculated consistent with network cost drivers on the basis of:

- Asset usage (e.g. no low voltage or distribution level costs are assigned to these consumers as they connect directly to the sub-transmission system)
- Transmission methodology outlined in section 5.2.

Top Energy has introduced non-standard pricing for specific regional development initiatives e.g. Ngawha Innovation Park and may introduce non-standard pricing for new embedded networks depending on its characteristics.

6.7.TOU and General Advanced Metering

Pricing comprises of a fixed, capacity for TOU and variable component. Fixed prices have been set to maintain historical linkages, reduce stranding risk associated with larger connections, as well as reflect the proportion of asset used

compared to other pricing options. Capacity prices reflect the individual assets used by customers and will be phased in over time to reflect the underlying related costs.

Variable rates are set relatively higher during periods of peak demand and progressively lower during shoulder and off-peak demand periods. These time periods have been designed:

- To align with typical demand periods on the network
- To encourage consumers to shift demand from peak periods to shoulder periods and from shoulder to off-peak periods.
- To maintain consistency with industry standard TOU periods

6.8.Residential/General

Pricing comprises of a daily fixed and variable component. A daily fixed price is levied on these plans as follows:

- A 90 cent per day is applied to all Residential consumers who meet the criteria of being a low user (LR) to comply with the low user fixed charge regulations and the Retailer has requested the low user (LR) code.
- A $2.85per day is applied to all Residential consumers who do not meet the low user criteria.
- A $3.60 per day is applied to all other consumers who are not Residential.

The increase in the daily fixed charge for the Low Users continues Top Energy's strategy to move towards more cost reflective pricing however, this is limited by the low fixed charge regulations phase out timeline. Variable rates are set relatively higher during periods of peak demand and progressively lower during shoulder and off-peak demand periods. Discounts to the standard Uncontrolled price are applied to Controlled plans (All Inclusive and Controlled 20), to incentivise consumers to offer up controllable load.

6.9.Unmetered

Unmetered pricing is wholly fixed. Fixed charges have historically been set with reference to historical amounts and have not changed in recent years.

6.10.Distributed generation

Under Part 6 of the Electricity Industry Participation Code, Top Energy must price distributed generation at no more than the incremental cost of connecting this generation, considering any avoided costs.

Top Energy has developed separate charges for distributed generation based on c/kWh exported to the grid. These charges only cover incremental cost directly associated with distributed generation and apply to all customers except generators. For large-scale generators (>1MW), Top Energy has negotiated avoided transmission, avoided distribution and voltage support payments. This is dependent on these generators being able to demonstrate on an annual basis that they are making a material contribution towards Top Energy avoiding additional transmission costs.

Negative charge for injection

The Authority introduced new requirements in the Code, from 1 April 2026, for Distributors to offer negative charges for injection, if there is a benefit. This is applied across the network to reward Residential and Small Commercial for injecting electricity back into the network at peak times when demand is likely to, on average and over time, drive future network investment. This has been set as variable c/kWh. Appendix 7 outlines the methodology and how it meets the new requirements in section 12.7.

Existing large-scale distributed generation (>1MW)

Connection charges have been set to recover the costs through a non-standard contract. Initially, this has been set at zero as no distributed generation >1MW requiring monitoring and management has been connected to date. Direct costs associated with Transmission Connection charges will also be recovered.

Other distributed generation

Top Energy considers that other distributed generation customers with load (e.g. small-scale solar PV) already receive a significant benefit through reduced distribution consumption prices, to the extent that electricity generated on site reduces the amount of electricity delivered via the network. Conversely, the cost to Top Energy of servicing these connections (i.e. an average domestic connection) is not reduced by the presence of the distributed generation, especially if the connection requires access to the network at times of peak demand. Accordingly, we believe that some connections with distributed generation are paying less than the incremental cost of providing the connection to that consumer.

The introduction of a distributed generation based on c/kWh exported to the grid, the planned move to demand / capacity pricing and a higher proportion of fixed charges will ensure that consumers with distributed generation pay a fair share of costs, to satisfy cost recovery and fairness considerations under Top Energy pricing objectives.

6.11.Discounts

The discount will continue to be posted and will be based on consumption from 1 April 2026 to 31 March 2027, which covers the entire assessment period. Discounts calculated on this basis represent approximately $5.9m and will be processed through the retailers to be applied to consumer invoices after 31 March 2027.

6.12.Capital contributions

A customer may be required to make an upfront contribution to the cost of extending or upgrading the network (e.g. arising from connecting to the network). This contribution pre-funds Top Energy's investment, with these costs excluded from line charges.

In July, the Electricity Authority released two decision papers on Connection pricing:

- Distribution connection pricing Code amendments and
- Network connections project – stage 1.

From 1 April 2026, Top Energy's capital contribution policy and procedures have been amended to align with the Code changes. Further changes will be implemented by April 1, 2027, as outlined in the decision papers.

The key changes are:

- **Connection enhancement cost allocation** – Top Energy must set prices with reference to a 'minimum scheme', and any enhancement costs are paid by whichever party requires it (distributor or customer).
- **Pioneer scheme policy** – Top Energy must publish a policy for establishing 'pioneer schemes. Pioneer schemes ensure that the applicant who funds a network extension receives rebates from those who follow and utilise the same network.
- **Connection charge reconciliation** – Top Energy must prepare a reconciliation that breaks down their quoted connection charge into incremental cost, incremental revenue and network cost components. This improves transparency in how costs are allocated to new connections.

The fourth requirement, for connection applications received from 1 April 2027, is:

- **Capacity costing** – if a distributor chooses to allocate upstream capacity costs, they must do so using published rates that allocate costs as capacity is consumed –not when it is built.

Top Energy already had connection cost allocation, a pioneer scheme, and Capacity cost charges. These have been aligned with the Code changes.

The full details of the methodology for determining capital contributions are publicly disclosed on the website www.topenergy.co.nz/network/network-disclosures/

7. Calculation of Prices and Customer Impact

Tariffs are calculated by allocating costs to consumer groups and prices, based on assumed splits between fixed and variable tariffs. Figure 23 summarises the allocators used to allocate target revenue and the rationale for these decisions.

Figure 23: Summary of cost allocators used to set prices

Cost Category	Allocator used	Rationale
Transmission costs	**Connection Charge and Transition charges:** 3-year Lagged AMD as a proxy for Capacity	Connection charges represent investment in GXP capacity. AMD broadly represents usage of this capacity.
	Benefits Based charges:	**Same as TPM Method**

	Project <20M: TPM Simple methodology Project >$20M; historical kWh (2014-2018) **Residual charges:** Historical average AMD (2014-2018) and Historical average kWh (2018-2022)	Aligns with Residual allocation and is fixed like allocator **Same as TPM calculation**
Network Costs	Customer group demand on the system as a percentage of ORC	Spreads maintenance cost weighted by the replacement cost of assets (recognising higher maintenance is usually attributed to higher cost assets).
Non-Network Costs	Regulatory Asset Base (RAB)	Spreads costs that are relatively static with the size of a customer's **asset base, per feeder**.
Depreciation	IND: Demand (kW) General Advanced: RAB Residential/General/UM: RAB	Allocation based on utilisation of asset utilisation, which broadly corresponds with depreciation representing use of capital.
Pre-tax ROI	RAB	Allocates return in proportion to value of assets RAB, consistent with regulatory framework.

The above allocation approach results in the following allocations of target revenue to consumer groups.

Figure 24: Cost allocation results

				Pass through $000s		Distribution $'000's					Revenue		
Consumer Group	Regulatory Asset Base 2026($m)	Number of ICPs	Energy Consumption and export Forecast 2026 (GWh)	Transmission, Other Pass-through Costs 2026	Recoverable Costs 2026	Network Costs (Maintenance)	Non-Network Costs (Overheads)	Depreciation	Posted Discount	Pre tax WACC	Annual Revenue Requirement	DPP compliance Adjustment	Total 2026 Target Revenue
IND	13,483	4	41	1,001	(103)	360	775	497	(21)	1,149	3,658	(1,423)	$2,235
GG,GU,GC	62,020	5,560	83	2,649	(473)	1,654	3,566	2,285	(936)	6,127	14,872	3,488	$18,360
GA	5,700	47	6	21	(43)	152	328	210	(24)	502	1,145	(179)	$966
TOU	12,093	63	40	904	(92)	323	695	446	(100)	1,112	3,288	289	$3,577
LDG	2,684	5	-	134	(20)	72	154	99	-	225	663	294	$957
DG			7	-	-	76				-	76	-	$76
Unmetered	2,327	254	1	34	(18)	62	134	86	-	195	493	59	$552
Total Commercial										-		-	
LR, LU, LC	175,755	16,883	75	3,161	(1,340)	4,688	10,105	6,476	(2,841)	17,552	37,801	(22,903)	$14,898
SR, SU, SC	119,387	11,815	82	2,212	(910)	3,185	6,864	4,399	(1,988)	11,981	25,742	(8,730)	$17,013
Total Residential													
Total	**393,448**	**34,631**	**335**	**10,117**	**(3,001)**	**10,572**	**22,621**	**14,498**	**(5,910)**	**38,841**	**87,739**	**(29,105)**	**$58,634**

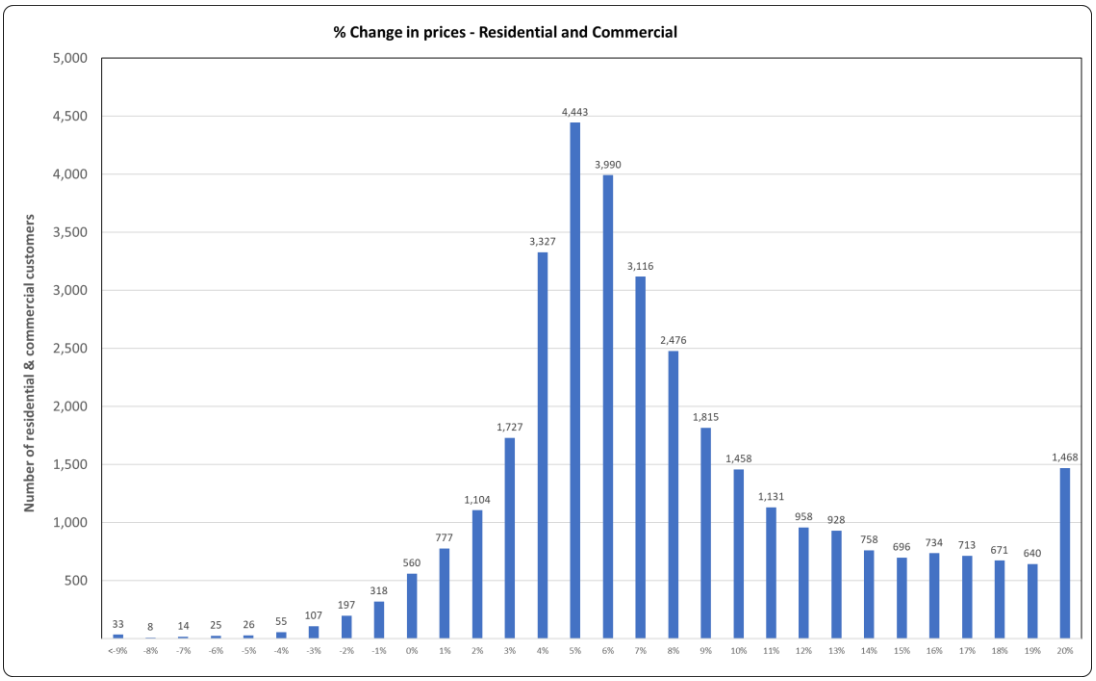
Appendix 5 summarises the resulting prices for 2026-2027, which are also located on the Top Energy website.

www.topenergy.co.nz/network/network-disclosures/

Consumer impact

A key consideration of our pricing is to manage customer impact for our consumers. The impact of the change in the LFCT daily charge, completing the fixed pass-through of the new Transmission pricing methodology and other price changes for Residential and General commercial consumers is shown below. The increases greater than 5% are due to an increase in fixed charge recovery and low consumption.

Figure 25: Price change % before the discount for residential and General commercial customers



Appendix 1 – Certification for Year Beginning Disclosures

Certification for Year-beginning Disclosures

Pursuant to Schedule 17

Clause 2.9.1 of section 2.9

Electricity Distribution Information Disclosure Determination 2012

We, David Alexander Sullivan and Matthew Peter Todd, being directors of Top Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge –

a) The following attached information of Top 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.

b) The prepective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

D A Sullivan

M P Todd

24 March 2026

Appendix 2 - Glossary

ACOT	Avoided Cost of Transmission
ACOD	Avoided Cost of Distribution
AMD	Anytime Maximum Demand, which is defined as the average of the 12 highest off-take quantities for the customer at the connection location during the Capacity Measurement Period.
Capacity Measurement Period	12-month period starting 1 September and ending 31 August inclusive, immediately prior to the commencement of the pricing year.
Consumer	A purchaser of electricity from the Retailer where the electricity is delivered via the distribution network and is interchangeable with customer.
Consumption Data	Data provided by the Retailer to the Distributor as required under the Use of System Agreement, showing details of the measured electricity consumption on the distribution network.
Code	The Electricity Industry Participation Code 2010.
Demand	The rate of expending electrical energy expressed in kilowatts (kW) or kilovolt amperes (kVA).
Distributor	Top Energy as the operator and owner of the distribution network.
Distributed Generation (DG)	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.
ENA	Electricity Networks Association
GXP	Grid Exit Point, a point of connection between Transpower's transmission system and Top Energy's distribution network.
GST	Goods and Services Tax as defined in the Goods and Services Tax Act 1985.
HV	High Voltage, voltage above 1,000 volts.
ICP	Installation Control Point. 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.
IND	Industrial Customer defined by Top Energy.
Installed Capacity	The capacity of each customer's connection to the Top Energy Network charged based on the capacity recorded by the Network in the Registry as at the end of the month. Low Voltage: Fuse capacity

	Transformer: Transformer capacity
Line Prices	The prices levied by Top Energy on Consumers for the use of the Network as described in this Pricing Methodology.
Load Control Equipment	The equipment (which may include, but is not limited to, ripple receivers and relays) which is from time to time installed in a consumer's premises for the purpose of receiving load management service signals.
LV	Low voltage. Voltage up to 1,000 volts, generally 230 or 400 volts for supply to most Consumers.
Pricing Year	12-month period from 1 April to 31 March the following year.
Retailer	The supplier of electricity to Consumers with installations connected to the distribution network.
ToU	Time of Use Customer, who is metered according to their electricity consumption for a particular period (usually half-hourly).
TPM	Transmission Pricing Methodology
Transpower	Transpower (NZ) Limited
UN	Uncontrolled

Appendix 3 – Compliance with ID determination

ID Clause	Information Disclosure requirement	Pricing Methodology Reference
2.4.1	Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which:	This Pricing Methodology will be published on our website prior to 1 April 2026.
2.4.1(1)	Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the prices payable or to be payable;	See below for document references to compliance against clause 2.4.3.
2.4.1(2)	Describes any changes in prices and target revenues;	Prices after the discount have increased 6.9% when comparing 2026 and 2027 pricing schedules. See section 2.3. Changes in target revenues are described in Section 4.
2.4.1(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);	See sections 6.6 and 6.10
2.4.1(4)	Explains whether, and if so how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.	Public consultation was completed during 2025 (see section 3.2)

2.4.2	Any change in the pricing methodology or adoption of a different pricing methodology must be publicly disclosed at least 20 working days before prices determined in accordance with the change or the different pricing methodology take effect.	Any changes were disclosed by 1 March 2026.
2.4.3	Every disclosure under clause 2.4.1 above must-	
2.4.3(1)	Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group;	Top Energy considers this document to provide sufficient information on how prices have been set but will continually review for improvements.
2.4.3(2)	Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;	See Appendix 4 TEL considers our pricing is broadly consistent with the pricing principles, but we also discuss how potential changes to our pricing methodology will align more closely with these principles.
2.4.3(3)	State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	See section 4.
2.4.3(4)	Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;	See section 4.

2.4.3(5)	State the consumer groups for whom prices have been set, and describe- • the rationale for grouping consumers in this way; • the method and the criteria used by the EDB to allocate consumers to each of the consumer groups;	See Section 6.5.
2.4.3(6)	If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons;	See section 2.3 and Appendix 5
2.4.3(7)	Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way;	See tables in Section 7.
2.4.3(8)	State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	See tables in Section 7.
2.4.4	Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy-	
2.4.4(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;	Our pricing strategy is discussed in section 3.5
2.4.4(2)	Explain how and why prices for each consumer group are expected to change as a result	See section 3.5
2.4.5	Every disclosure under clause 2.4.1 above must-	

2.4.5(1) (a), (b), (c)	Describe the approach to setting prices for non-standard contracts, including- • 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; • how the EDB determines whether to use a non-standard contract, including any criteria used • any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology is consistent with the pricing principles;	See Section 6.6 and appendix 5
2.4.5(2)	Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain- • the extent of the differences in the relevant terms between standard contracts and non-standard contracts • any implications of this approach for determining prices for consumers subject to non-standard contracts.	See Section 6.6

2.4.5(3)	Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the- • prices; and • value, structure and rationale for any payments to the owner of the distributed generation.	See Section 6.10
2.9.1	Where an EDB is required to publicly disclose any information under clause 2.4.1, clause 2.6.1 and sub-clauses 2.6.3(4) and 2.6.5(3), the EDB must at that time publicly disclose a certificate in the form set out in Schedule 17 in respect of that information, duly signed by 2 directors of the EDB.	Completed and attached as Appendix 1

Appendix 4 – EA Pricing Principles and focus areas

Pricing principles	Extend to which pricing methodology is consistent with pricing principle
(a) Prices are to signal the economic costs of service provision, including by:	
(i) being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs	See section 6.4
(ii) reflecting the impacts of network use on economic costs	Top Energy's primary service is to provide capacity in the distribution network. To further reflect the impact of network use on economic costs Top Energy has implemented Residential and General Commercial TOU pricing from 1 April 2020 (which are mandatory with no exemptions) and demand/capacity for larger Commercial customers from 1 April 2021. This aligns pricing more closely with the impacts of network use on economic costs. In addition to the changes above, current pricing structures recognise the differences in network services provided to (or by) customers as follows: • Consumer groups recognise different load sizes. • Many network and transmission related costs are allocated to consumer groups in proportion to demand. • Capital contributions help fund the uneconomic proportion of new investments in capacity.

(iii) reflecting differences in network services provided to (or by) consumers and	• Industrial sites (IND) are charged for specific asset usage and therefore the capacity these assets provide and are apportioned transmission charges. • TOU/Advanced Metering structures encourage consumers to optimise the usage of the network across all time periods. • Controlled prices encourage consumers to offer up controllable load which Top Energy can use to manage congestion during interruptions to supply, when the network may be constrained. • Residential and Small Business customers, Peak injection charge set to reflect the value of the network from deferred investment. For the same reasons discussed above, Top Energy's pricing structures reflect differences in network services provided to (or by) customers. The introduction of TOU pricing for Residential and General Commercial customers and demand and capacity for larger Commercial customers have improved these signals.
(iv) Encouraging efficient network alternatives	Avoided transmission, avoided distribution and voltage support charges may be payable to embedded generators of greater than 1MW output. This may help justify investments in local generation. The introduction of TOU pricing for Residential and General Commercial customers provides better signals for investment in new technology e.g. electric vehicles, distributed generation and batteries. Further analysis has been included in our pricing strategy.

(b) Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use	This principle suggests that the short fall should be made up of prices which don't impact usage behaviour e.g. higher fixed charges or that consumers with a higher willingness to pay should pay relatively more than consumers with a lower willingness to pay. Top Energy has increased its standard daily charge for Residential and General Commercial since 2016 from \$0.15/day to \$2.85 /day and \$3.60 /day, respectively. However, this approach is limited by regulatory constraints e.g. Low Fixed Charge Tariff regulation as over 60% of Residential customers are on lower user charge of \$0.90/day. Top Energy considers pricing based on willingness to pay should be linked to the level of service provided. This is a common pricing practice in many competitive markets. For instance, the UN24 and CN20 pricing options give consumers a choice over whether heating loads are interrupted. Consumers that are unwilling to have supply interrupted pay relatively more than a customer that is willing to accept a slightly lower level of service. Similarly, consumers on TOU pricing options that do not want to shift load to off peak periods pay more for using electricity at times that suits them.
(c) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to: (i) reflect the economic value of services and	Capital contributions and non-standard contracts provide a mechanism where a consumer can request assets that provide a higher level of service. The costs of specific assets are either recovered upfront through a capital contribution or within specific pricing. Consumers can also request alternative pricing structures under non-standard contracts to address their own risks (e.g. IND prices are wholly fixed).

(ii) enable price/quality trade-offs	
(d) Development of prices should be transparent, and have regard to transaction costs, consumer impacts, and uptake incentives	The pricing strategy explained in this document provides stakeholders with an overview of Top Energy's plans for prices over the next several years. We plan to continue to consult with consumers and retailers to seek their feedback on any changes which will be incorporated into any pricing decisions. Learnings from the TOU trial and retailer consultation enabled us to understand the transaction costs and operational policies for the implementation of TOU for Residential and General Commercial customers from 1 April 2020. The approach of the new TOU prices applying to all customers with automatic exemptions for non-communication meters e.g. legacy meters and retailer's ability to apply for exemptions due to operational issues reflect this. Exemptions were removed this year after retailers had sufficient time to manage operational issues. The TOU price differentials are being phased in over time to manage rate shock and reduce revenue risk. As important it will allow further modelling as more consumption information becomes available, which will assist in getting the final price differentials more accurate. The new demand and capacity pricing for large Commercial customers implemented on 1 April 2021 incorporated feedback from retailers with the initial focus on implementing new structures and operational policies. The price signal will be phased in over time to manage rate shock and depend on network constraint requirements.

Initial Focus areas	Extent to which pricing methodology is consistent with Focus areas
Distributors Roadmaps responding to future network congestions	We have actively considered the impacts of future congestion and set out time-limited plans for responding in our roadmap. This includes our review of CAPEX growth expenditure in our AMP. See section 3 and Appendix 6.
Distributors response to any significant first mover disadvantages issues	Top Energy has had a capital contribution policy which ensures for connection assets first movers are charged based on the cost required to supply them and that these first movers are rebated fairly if subsequent mover connects within a time limit. See sections 6.12. The Authority released a decision on capital connections contributions in 2025. This is being implemented within the timeframes required, including a Pioneer scheme which replaces the current scheme.
The extent to which distributors are following the Authority's guidance on pass-through of new transmission changes	Top Energy has followed the Authority's guidelines in the pass-through. Where possible this matches the TPM methodology. See section 4.2 and 4.3
Whether distributors are increasing their use of fixed charges to match the phase-out path of the LFCT regulations	Top Energy has increased the fixed charge for low users by the maximum allowed under the phaseout regulations. See section 3.5, 3.6 and Appendix 5.

Distributors avoiding or transitioning away from recovery of costs that are fixed in nature through use-based charges	Top Energy does not charge non-direct billed customers based on AMD or similar. There is a demand charge for TOU (61 customers), but this is set at zero as there is no current congestion. Our 2 Industrial are allocated shared asset costs on their use of that asset.
Allocate revenue transparently	Reviewed current revenue allocation as part of our cost to serve update in 2023. Have reviewed our pricing methodology to ensure transparency. Waiting for further guidance from the Authority.
Assign all ICPs to time-varying distribution tariffs (limited exemptions)	Completed on 1 April 2024. There are no exceptions. Periodically review ICPs on non-ToU tariffs to ensure that they meet the criteria.
Set peak rates on a measure of Long-Run Marginal Cost	Introduced in last year's pricing. Further refinement and standardisation with industry the focus going forward.
Reduce off-peak prices and controlled rates	In progress. Higher price levels than other EDBs mean that the transition will be longer.
Follow up on AMP reporting on readiness for increase electrification	Completed by 31 August 2024

Appendix 5 - Network Line Charges 2026 – 2027

TOP ENERGY® TePuna Hihiko

2026/27 Electricity Price Schedule

Effective from 1 April 2026. All prices exclude GST

KEY CHANGES

From 1 April 2026, our prices will increase by 6.3% to continue to replace aging equipment and infrastructure to ensure continued reliability. This increase consists of a 4.6% increase in Top Energy's costs and the remainder is an increase in Transmission costs from Transpower.

The Low User daily rate is increasing from 75c to 90c per day, in accordance with changes in the Electricity (low fixed charge option) Amended Regulations 2021.

This year, the Electricity Industry Participation Code 2010 requires distributors to offer a credit for exporting electricity at peak times if there was a benefit to the distributor. Top Energy has no power constraints on our network, therefore, there is no benefit and this is set at 0c/kWh. The export charge remains unchanged at 1c/kWh. This charge helps cover the extra costs involved in managing electricity that flows back into the network.

In May, customers will receive a Top Energy Lines Discount of up to $200 on their power bill.

		Current from 1 April 2026							Previous Year			
Price Code	Description	Daily Passthrough and Distribution Price ($/day)	Unit Price $/kWh	Distribution Discount Component ($/day)	Distribution Discount Component ($/kWh)	Daily charge after Discount Component ($/day)	Unit Price after distribution Discount Component ($/kWh)	Maximum combined Eligible Discount per KWh per ICP	Daily Price ($/day) from 1.4.25 to 31.3.26	Total ($/kWh) from 1.4.25 to 31.3.26	Distribution 12 month Discount Component	Maximum combined Eligible Discount per KWh per ICP
RESIDENTIAL												
Low User Non-TOU (LR) for customers using less than 8,000kWh per year : 3,486 users (excludes holiday homes, ancillary buildings and meters)												
LRF	Fixed price	0.9000		0.1555		0.7445			0.7500		0.1555	
LUC	Uncontrolled (no load controlling applied)		0.1912		0.1037		0.0875	1,130		0.1876	0.1037	1,130
LA	All inclusive (3kW loading)		0.1612		0.1037		0.0575			0.1576	0.1037	
LFC	Controlled 20 (10kW loading)		0.0620		-		0.0620	-		0.0643		-
DG	Charge for export		0.0100		-		0.0100	-		0.0100		-
Low User Time of Use Uncontrolled (LU) for customers who have no load controlling applied to their line : 3,574 users												
LUF	Daily Price on Half Hourly Read Uncontrolled	0.9000		0.1555		0.7445			0.7500		0.1555	
LU1	Peak (7am - 9.30am & 5.30pm - 8pm, excluding weekends and public holidays)		0.2631		0.1037		0.1594	1,130		0.2614	0.1037	1,130
LU2	Shoulder (9.30am - 5.30pm & 8pm - 10pm or 7am - 10pm, weekends and public holidays)		0.1831		0.1037		0.0794			0.1814	0.1037	
LU3	Off Peak (10pm - 7am)		0.1280		0.1037		0.0243			0.1307	0.1037	
LFC	Controlled 20 (10kW loading)		0.0620		-		0.0620	-		0.0643	-	-
DG-TOU	Net charge for export		0.0100		-		0.0100	-		0.0100	-	-
Low User Time of Use All Inclusive (LC) for customers who do have load controlling applied to their line : 9,823 users												
LCF	Daily Price on Half Hourly Read Controlled (3kW loading)	0.9000		0.1555		0.7445			0.7500		0.1555	
LC1	Peak (7am - 9.30am & 5.30pm - 8pm excluding weekends and public holidays)		0.2189		0.1037		0.1152	1,130		0.2172	0.1037	1,130
LC2	Shoulder (9.30am - 5.30pm & 8pm - 10pm or 7am - 10pm weekends and public holidays)		0.1600		0.1037		0.0563			0.1583	0.1037	
LC3	Off Peak (10pm - 7am)		0.1037		0.1037		0.0000			0.1037	0.1037	
LFC	Controlled 20 (10kW loading)		0.0620		-		0.0620	-		0.0643		-
DG-TOU	Net charge for export		0.0100		-		0.0100	-		0.0100		-
Standard User (SR) for customers using more than 8,000kWh per year : 2,499 users												
SRF	Daily Price	2.8500		0.3527		2.4973			2.3750		0.3527	
SUC	Uncontrolled (no load controlling applied)		0.1056		0.0400		0.0656	1,130		0.1182	0.0400	1,130
SA	All inclusive (3kW loading)		0.0753		0.0400		0.0353			0.0881	0.0400	
SFC	Controlled 20 (10kW loading)		0.0437		-		0.0437	-		0.0437	-	-
DG	Charge for export		0.0100		-		0.0100	-		0.0100	-	-
Standard User Time of Use Uncontrolled (SU) for customers who have no load controlling applied to their line : 3,145 users												
SUF	SUF Daily Price on Half Hourly Read Uncontrolled	2.8500		0.3527		2.4973			2.3750		0.3527	
SU1	Peak (7am - 9.30am & 5.30pm - 8pm excluding weekends and public holidays)		0.1263		0.0400		0.0863	1,130		0.1768	0.0400	1,130
SU2	Shoulder (9.30am - 5.30pm & 8pm - 10pm or 7am - 10pm weekends and public holidays)		0.1100		0.0400		0.0700			0.1146	0.0400	
SU3	Off Peak (10pm - 7am)		0.0648		0.0400		0.0248			0.0668	0.0400	
SFC	Controlled 20 (10kW loading)		0.0437		-		0.0437	-		0.0437	-	-
DG-TOU	Net charge for export		0.0100		-		0.0100	-		0.0100		-
Standard User Time of Use All inclusive (SC) for customers who do have load controlling applied to their lines : 6,171 Users												
SCF	SCF Daily Price on Half Hourly Read Controlled (3kW loading)	2.8500		0.3527		2.4973			2.3750		0.3527	
SC1	Peak (7am - 9.30am & 5.30pm - 8pm excluding weekends and public holidays)		0.0995		0.0400		0.0595	1,130		0.1500	0.0400	1,130
SC2	Shoulder (9.30am - 5.30pm & 8pm - 10pm or 7am - 10pm weekends and public holidays)		0.0800		0.0400		0.0400			0.0846	0.0400	
SC3	Off Peak (10pm - 7am)		0.0400		0.0400		0.0000			0.0400	0.0400	
SFC	Controlled 20 (10kw loading)		0.0437		-		0.0437	-		0.0437	-	-
DG-TOU	Net charge for export		0.0100		-		0.0100	-		0.0100	-	-

POSTED DISTRIBUTION DISCOUNT NOTES	
	The Discount will only be provided to ICP's connected on 31 March 2027 (eligibility date) with an active customer and have used more than 1kWh during the 12 month period ending 31 March 2027.
	Variable discounts will be applied to consumption up to the KWh Discount Cap, as outlined in the price schedule above. Additional consumption above this cap will not receive a discount.
	Discounts will be applied by your Retailer on your first bill between 1 May 2027 and 31 May 2027.

TOP ENERGY® TePuna Hihiko

Price Code	Description	Current from 1 April 2026							Previous Year			
		Daily Passthrough and Distribution Price ($/day)	Unit Price $/kWh	Distribution Discount Component ($/day)	Distribution Discount Component ($/kWh)	Daily charge after Discount Component ($/day)	Unit Price after distribution Discount Component ($/kWh)	Maximum combined Eligible Discount per KWh per ICP	Daily Price ($/day) from 1.4.25 to 31.3.26	Total ($/kWh) from 1.4.25 to 31.3.26	Distribution 12 month Discount Component	Maximum combined Eligible Discount per KWh per ICP
				For payment timing and eligibility, see previous page notes								
												GENERAL PRICING
General User (GG) : 1,700 Users												
GGF	Daily Price	3.6000		0.3527		3.2473			3.0000		0.3527	
GGUC	Uncontrolled (no load controlling applied)		0.1513		0.0400		0.1113	1,130		0.1535	0.0400	1,130
GGA	All inclusive (3kW loading)		0.1223		0.0400		0.0823			0.1235	0.0400	
GGFC	Controlled 20 (10kW loading)		0.0437		-		0.0437	-		0.0437		-
DG	Charge for export		0.0100		-		0.0100	-		0.0100		-
General User Time of Use Uncontrolled (GU) : 3,312 users												
GUF	Daily Price on Half Hourly Read Uncontrolled	3.6000		0.3527		3.2473			3.0000		0.3527	
GU1	Peak (7am-9.30am & 5.30pm-8pm, excluding weekends and public holidays)		0.1910		0.0400		0.1510	1,130		0.2042	0.0400	1,130
GU2	Shoulder (9.30am-5.30pm & 8pm-10pm or 7am-10pm, weekends and public holidays)		0.1583		0.0400		0.1183			0.1525	0.0400	
GU3	Off Peak (10pm-7am)		0.0804		0.0400		0.0404			0.0830	0.0400	
GGFC	Controlled 20 (10kW loading)		0.0437		-		0.0437	-		0.0437	-	-
DG-TOU	Net charge for export		0.0100		-		0.0100	-		0.0100	-	-
General User Time of Use All Inclusive (GC) : 548 users												
GCF	Daily Price on Half Hourly Read Controlled (3kW loading)	3.6000		0.3527		3.2473			3.000		0.3527	
GC1	Peak (7am-9.30am & 5.30pm-8pm excluding weekends and public holidays)		0.1610		0.0400		0.1210	1,130		0.1742	0.0400	1,130
GC2	Shoulder (9.30am-5.30pm & 8pm-10pm or 7am-10pm weekends and public holidays)		0.1291		0.0400		0.0891			0.1233	0.0400	
GC3	Off Peak (10pm-7am)		0.0504		0.0400		0.0104			0.0531	0.0400	
GGFC	Controlled 20 (10kW loading)		0.0437		-		0.0437	-		0.0437		-
DG-TOU	Net charge for export		0.0100		-		0.0100	-		0.0100		-
General Advanced User (GA) for businesses that generally use more than 70,000kWh : 45 users												
GAF	Daily Price on Half Hourly Read	17.9932		0.5500		17.4432			14.9943		0.5500	
G1	Peak (7am-9.30am & 5.30pm-8pm)		0.1705		0.0032		0.1673	1,092,500		0.1708	0.0032	1,092,500
G2	Shoulder (9.30am-5.30pm & 8pm-10pm)		0.1067		0.0032		0.1035			0.1069	0.0032	
G3	Off Peak (10pm-7am)		0.0531		-		0.0531	-		0.0531	-	-
DG-TOU	Net charge for export		0.0100		-		0.0100	-		0.0100	-	-
Larger User Time of Use (TOU) for businesses with connection size 110KVA or greater : 71 users												
TOUF	Daily Price	49.1580		0.5500		48.6080			40.9650		0.5500	
TOUDVD	Daily Distrubtion Demand Price	-				-			-			
TOULVFD	Daily Distribution LV Capacity price $/day/kVA	0.1500					0.1500		0.1250			
TOU1	Peak (7am-9.30am & 5.30pm-8pm)		0.0621		0.0032		0.0589	1,092,500		0.0716	0.0032	1,092,500
TOU2	Shoulder (9.30am-5.30pm & 8pm-10pm)		0.0409		0.0032		0.0377			0.0432	0.0032	
TOU3	Off Peak (10pm-7am)		0.0060		-		0.0060			0.0085		
DG	Charge for export		0.0100		-		0.0100			0.0100		
TOUTXF	Daily Price	49.1580		0.5500		48.6080			40.9650		0.5500	
TOUTXD	Daily Distribution Demand Price	-				-			-			
TOUTXT	Daily Distribution LV Capacity price $/day/kVA	0.1500					0.1500		0.1250			
TOUTX1	Peak (7am-9.30am & 5.30pm-8pm)		0.0621		0.0032		0.0589	1,092,500		0.0716	0.0032	1,092,500
TOUTX2	Shoulder (9.30am-5.30pm & 8pm-10pm)		0.0409		0.0032		0.0377			0.0432	0.0032	
TOUTX3	Off Peak (10pm-7am)		0.0060		-		0.0060			0.0085		
DG	Charge for export		0.0100		-		0.0100			0.0100		

UNMETERED PRICING: Fixed charges only. No variable charge.

Price Code	Description	NEW 1 April 2026 Daily Price $/day	NEW 1 April 2026 Unit Price $/kWh	OLD 1 April 2025 Daily Price $/day	OLD 1 April 2025 Unit Price $/kWh
Unmetered supply - For New Connections after 01.04.16 : 2,835 Users					
UMLF	Streetlights (STL)	0.5278	-	0.5038	-
UMGF	General Connection (UM)	0.5278	-	0.5038	-
UMCF	General Connection (3000-6000kWh)	2.5008	-	2.3817	-
NIL	Tsunami Warning Alarms	-	-	-	-

Net Charge for Export

Net Charge for Export is calculated as Charge for Export less Credit for Network Benefit. This is only available for customers with a TOU meter with a connection of 45kVA or less and who export up to 45kW. The Credit for Network Benefit is set at 0 c/kWh for all TOU periods. The Net Charge for Export is 1 c/kWh.

Appendix 6 – Current Constraints by Substation

Main Substation	Load Type	Utilisation of Installed Capacity (%)	Forecast Utilisation of Installed Capacity in 5 years (%)	Maximum Capacity	Implications
Kaikohe	Urban and Rural with a mix of Domestic, Commercial and Agricultural load. An Industrial Park being developed.	51%	51%	17 MVA Firm (n-1)	Future energy needs are anticipated to be within current capacity, subject to load locations.
Kawakawa	Urban and Rural with a mix of Domestic, Commercial and Agricultural load.	66%	67%	6.25 MVA Firm (n-1)	Movement of Russell loads from Kawakawa Zone Sub to Haruru Zone Sub has reduced utilisation
Moerewa	Urban and Rural with a mix of Domestic, Commercial and Agricultural load. Static growth.	74%	74%	5 MVA Firm (n)	Future energy needs are anticipated to be within current capacity.
Waipapa	Urban and Rural with mainly Commercial, Industrial and Agricultural loads. Load is growing.	40%	41%	23 MVA Firm (n-1)	Future energy needs are anticipated to be within current capacity.
Omanaia	Urban and Rural with a mix of Domestic, Commercial and Agricultural load.	54%	54%	5 MVA (n)	Future energy needs are anticipated to be within current capacity.
Haruru	Urban and Rural with an industrial load centre. Increasing demand growth	30%	32%	23 MVA Firm (n-1)	Future energy needs are anticipated to be within current capacity.
Okahu Rd	Urban and Rural with a mix of Domestic, Commercial and Agricultural load. Static growth.	76%	64%	11.5 MVA Firm (n-1)	Future energy needs are anticipated to be within current capacity.
Taipa	Urban & Rural with Domestic, Commercial and Agricultural loads. Medium growth	93%	50%	6.25 MVA (n)	New Transformer project commenced.
Pukenui	Dominantly Rural with Domestic and agricultural loads. Slow growth.	36%	40%	5 MVA (n)	Future energy needs are anticipated to be within current capacity.
NPL	Urban and Rural with Domestic, Commercial, Agricultural & Industrial loads. Falling demand due to reduced output from our largest industrial customer	46%	72%	23 MVA Firm (n-1)	Future energy needs are anticipated to be within current capacity.
Kaitaia 110KV	Bulk Supply at 33kV. Supply to Okahu Rd, Taipa, Pukenui & NPL Zone Substations.	126%	139%	20 MVA (n-1)	Issue going forward is new distributed generation, not load. Second 110kV planned

Kaikohe 110kV	Bulk Supply at 33kV to Kaikohe, Kawakawa, Moerewa, Waipapa, Omanaia, Haruru, Kerikeri & Kaeo Zone Substations.	155%	157%	30 MVA Firm (n-1)	Planned reduction in Utilisation due to 33kV Load transfer (Mt Pokaka, Waipapa, Kerikeri, Kaeo Zone Substations) to Wiroa.
Mt Pokaka	Rural with Domestic, Agricultural, and Industrial loads.	54%	54%	5 MVA (n)	Future energy needs are anticipated to be within current capacity.
Kerikeri	Urban load with Domestic, Commercial & Industrial. Township Increasing demand.	33%	38%	23 MVA Firm (n-1)	Future energy needs are anticipated to be within current capacity.
Kaeo	Rural with Domestic, light commercial, light industrial loads & Agricultural loads.	36%	37%	10 MVA Firm	Future energy needs are anticipated to be within current capacity.

Appendix 7 – Payment for injection methodology and calculation

Under section 12A.7 of the Code, distributors are required to make payments for injection for Residential and Business customers from 1 April 2026, where applicable. Top Energy has set the price based on the long-run marginal cost (LRMC) of peak demand approach – 12A.7 (1)(b)(i). Below outlines our methodology to meet our requirements under 12A.7(3). This is in line with the guidance provided by the Authority – Pricing for Distribution Peak Export Tariffs.

1. LRMC Calculation methodology (12.A.7(3)(a)

This LRMC calculation is based on the ENA's model, which uses the Average Incremental Cost Approach. A timeframe of 10 years has been chosen to align with our Asset Management Plan (AMP). The key inputs are below:

- Real Capital expenditures for growth as the 2026 AMP. Only non-committed Growth CAPEX has been included in the calculation.
- Forecasted increases in Peak demand from the AMPs mid-scenario with a Power factor of 0.95.
- WACC from DPP4
- Related OPEX and Average asset life estimate from AMP.

The table below shows the key inputs over the 10-year period

Input	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
System growth capex (constant prices, $000) - Committed	$4,584	$1,575	$1,829	$0	$0	$0	$0	$0	$0	$0
System growth capex (constant prices, $000) - Forcast	$0	$0	$0	$0	$0	$0	$0	$0	$0	$504
System growth capex (constant prices, $000) -Total	$4,584	$1,575	$1,829	$0	$0	$0	$0	$0	$0	$504
Demand forecast (MW)	74	75	76	77	78	79	80	81	82	83

2. Form of charge and conversions to negative charge (12.A.7(3)(a), 12.A.7(3)(c))

The LRMC is converted into a negative charge for injection by the following methodology:

Step	Decision	Explanation
Consumers	All categories except TOU, TOUTX, IND, and Unmetered. >99.5% of Customers	This meets the new definition of customers with connection capacity up to 45kVA and who export up to 45kW.
The form of a negative charge	Variable c/kWh	Aligns with Guidance
Period applies	Current peak period in winter e.g. 0700:09:30 and 17:30 -20:00 from 1 April to 30 Sept	Aligns with the current consumption winter peak and is the period most likely to drive future investment. All other TOU periods have been set to zero.
Conversion to a negative charge	(NPV growth cost / cumulative growth kW)/Number of hours in peak period	Based on ENA model
Adjustment factor	None	An adjustment factor has not been calculated due to the minimal value of the calculation.

3. Important assumptions relied (12.A.7(3)(d))

- Non-pricing measures are used to ensure network stability.

4. Criteria to be eligible (12.A.7 (1))

This has been applied to all Pricing Categories that meet the definition in the Code. This is customers with connection capacity up to 45kVA who export up to 45kW. The only customers that don't meet the criteria are large TOU and , Industrial customers, Large Distributed generation and Unmetered. This has been included in the Price schedule.

5. Publications

Our injection charges are included in the pricing schedules posted in accordance with the Commerce Commission's Information Disclosure requirements.