TOP ENERGY LIMITED

PRICING METHODOLOGY DISCLOSURE

2024-2025

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 some 335,000,000 kWh of electricity to 34,000 electricity consumers, who also own the company through the Top Energy Consumer Trust (TECT).

This pricing methodology document describes our key considerations and approach to setting distribution prices effective 1 April 2024. 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 2024-25
- **Section 3** summarises key considerations we have taken account of in making decisions on pricing.
- **Section 4** details our principles and objectives, recent review, and plans and strategy for pricing.
- **Section 5 to 7** provides further detail 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 common 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 outlines our progress on their current 5 areas of focus.
- **Appendix 5** details distribution prices that will apply from 1 April 2024
- **Appendix 6** shows current and forecast Utilisation of the network by substation.

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 2024-25

Business Considerations

We have considered asset management, operations, commercial, and financial matters in setting pricing, as well as our consumer ownership.

Consumer Views

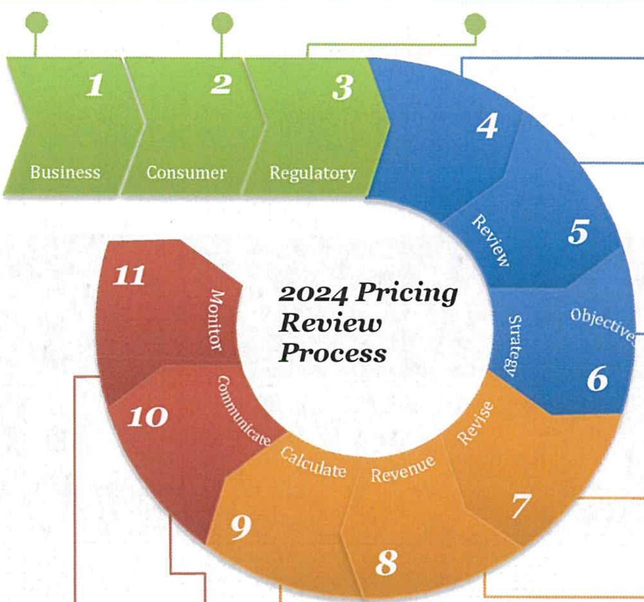
We have consulted with consumers and community organisations to understand their views on pricing and quality of supply matters.

Regulatory Considerations

We have considered applicable pricing and information disclosure regulations and guidance.

Objectives

We have developed and refined a set of principles and objectives to guide our pricing decisions.



Pricing Review

We have reviewed existing pricing structures and considered a range of alternative options, taking into account the above considerations and objectives, industry alignment and future requirements

Strategy

We have revised our plan and strategy to continue to transition to more efficient pricing structures over a 5-year period.

2025 Target Revenue

We have determined 2025 target revenue based on recovery of costs, limited to the regulated revenue cap we are subject to.

Communicate and monitor

We have published our 2025 prices and pricing methodology. We will continue to monitor developments and adjust our strategy as required.

Consult

We have consulted with Retailers on the 2025 Pricing changes and structural changes. We will also consult with consumers and retailers on our wider pricing strategy as work progresses.

2025 Prices

Target revenue is allocated to consumer groups and pricing options to determine 2025 prices based on setting cost reflective pricing signals (where needed) to consumer groups and then the recovering the residual.

2024 Consumer Groups and Pricing Options

We have implemented the third year of phasing out the Low Fixed Charge Tariff and completed the recovery of transmission through fixed charges. Both of these have further increased our fixed cost recovery.

2.2. How prices are calculated

Prices have been set to recover our 2024-25 target revenue. Target revenue is calculated to recover our forecast costs and is limited by a revenue cap determined by the Commerce Commission. This revenue covers the cost of our local electricity distribution network, pass through costs (including levies and rates) and costs associated with national transmission grid. 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 except two direct connect customers. 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 2024-25

We have continued the focus on our pricing methodology and build on previous reforms that have been implemented as outlined in our roadmap.

The key highlights to date are:

- Separation of Residential and General Commercial customers and extension of Commercial TOU pricing (2016). This commenced a programme to increase the recovery of costs through fixed charges.
- Implementation of Residential and General Commercial TOU prices from 1 April 2020.
- Implementation of capacity and demand pricing for our large TOU Commercial customers from 1 April 2021.
- Implementation of a distributed generation export variable charge of 0.5c/kWh to cover incremental costs from 1 April 2021.
- New Price Code for DG >1MW to cover incremental costs for Distribution System Operation from 1 April 2022.
- Implementation of the phase out of the LFCT regulations from 1 April 2022.
- Updating of the 5-year pricing strategy in 2022.

After significant change over the last three years there are no changes to our pricing structures this year. The focus on this year is on increasing the efficiency of the existing pricing through continuing the phasing in of cost reflective pricing including increasing fixed charge recovery and lowering off-peak prices.

There is also a significant change to our recovery of costs through prices due to two major regulatory changes. These are:

- Continued phase out of the Low Fixed Charge Tariff (LFCT) for Residential customers. From 1 April 2024, the daily charge on all Low User Residential pricing categories will increase to 60 c/day. This is the maximum allowed in the third year of the phase out. Top Energy intends to continue to phase out the LFCT over the next two years which will accelerate our move to cost-reflective distribution pricing through higher fixed cost recovery.
- Completion of the implementation of the new Transmission Pricing Methodology (TPM) which came into effect from 1 April 2023. Top Energy has followed the Electricity Authority's guidance and, where possible, these have been recovered through fixed charges, subject to price shock. This year we have completed the two-year phase in of fully recovering Transmission costs through fixed charges. This has also accelerated our move to cost-reflective distribution pricing through higher fixed cost recovery.

These changes have resulted in fixed charges to increase from 34% to nearly 40%.

The discount paid by Top Energy will continue to be a posted discount and included in the price schedule. This is based on consumption over the pricing year and will be paid in May 2025.

Distribution prices have increased by 9.9% on average including the posted discount. This results in revenue being \$4.77M below the net 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 specific assets used. Overall headline prices have increased by 8.4% accounting for all pass through and recoverable costs but before the discount. Appendix 5 provides further detail 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 lines discounts on electricity bills and through a dividend to TECT. Top Energy also employs more than 155 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. From late 2023 the network also receives supply from a solar farm in Kaitaia. The Kaikohe substation supplies the southern part of the network directly, with the northern part of the network 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 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.

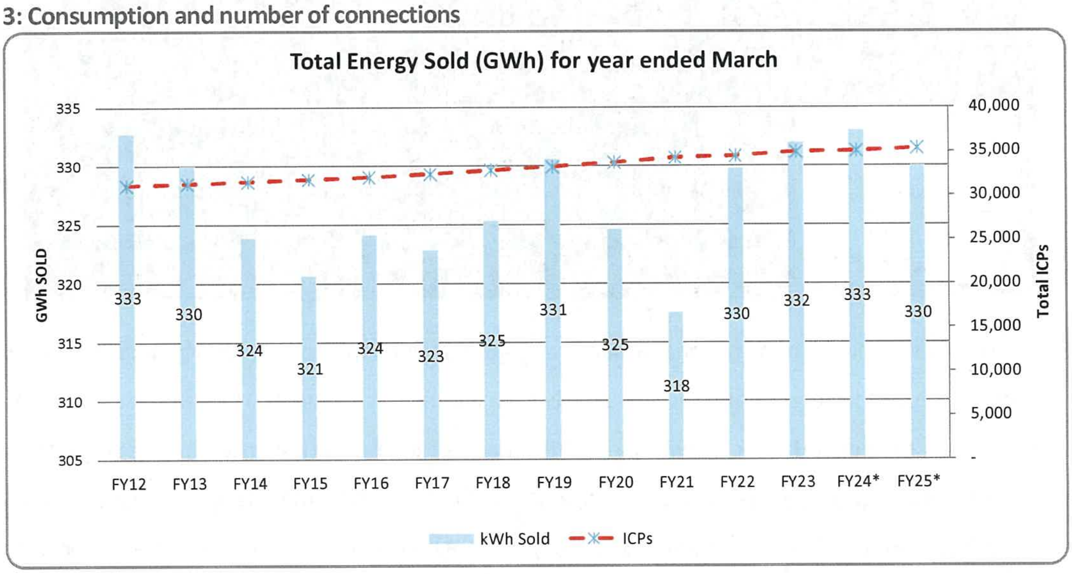
Many existing lines now require extensive rebuilding and refurbishment. Many assets are located in sparsely populated rural areas which remain uneconomic in some circumstances. However, Top Energy is required by legislation to maintain a power supply to consumers that were connected to these lines prior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

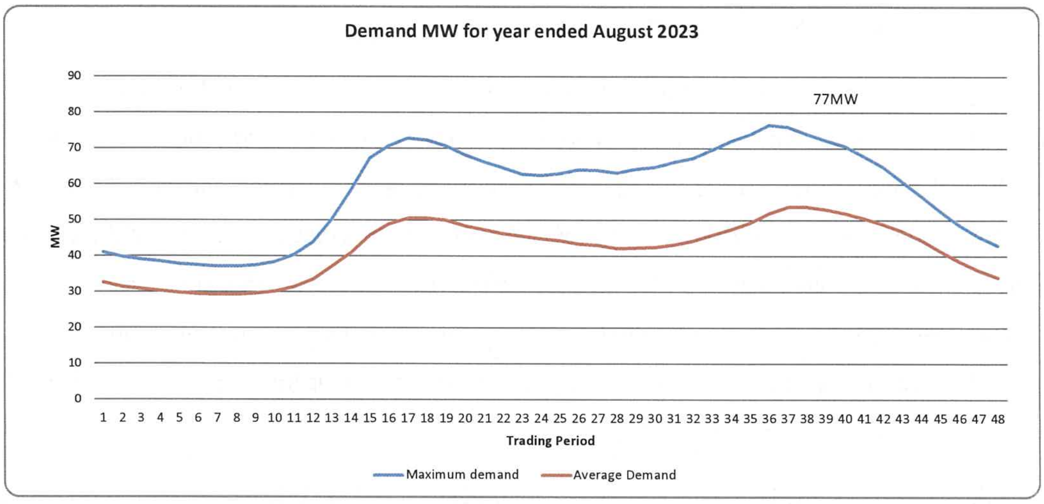
The utilisation of the network is heavily weighted towards small consumers, representing 99% of connections and over 80% of maximum demand. This is evidenced by the fact that average consumption is the one of the lowest in the country at approximately 10,000kWh/consumer. Top Energy's pricing structures are therefore strongly focussed on the needs of the Residential and General consumer groups, with only a few large connections. Total energy sold on the network is shown below and has increased significantly over the couple years however it has been relatively stable over the last decade despite a steady increase in connections.

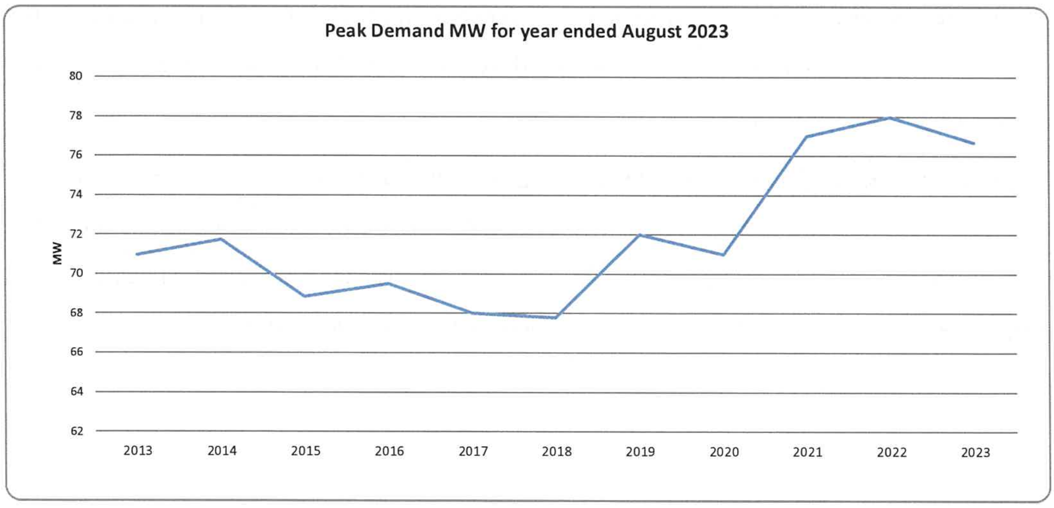
Figure 3: Consumption and number of connections



The key driver for future investment on the network is maximum demand in aggregate and substation level. Maximum demand on the network was approximately 77MW down from 78MW in 2023. Despite the fall this year, peak demand is nearly 10% higher than in 2019. Section 3.1.3 below shows that despite the maximum demand falling, due to higher temperatures, underlying peak demand has increased significantly since the removal of the TPM. Further growth is forecast due to increasing general connections, electrification and the possibility of additional industrial load from the potential Ngawha Industrial Park.

Figure 4: Demand on Top Energy network





3.1.3 Current Constraints and responding to future congestion

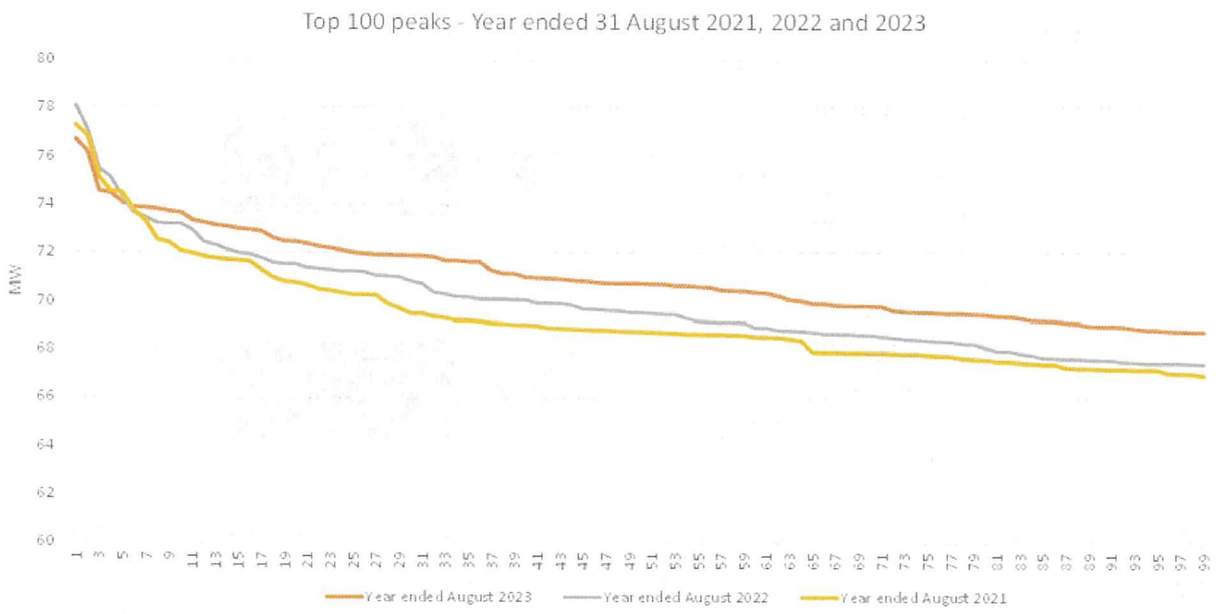
No major capacity constraints exist on the sub-transmission 33kV network when all network elements are in services. However, our Asset Management Plan has signalled that additional load growth would result in the load at risk continuing to increase and therefore more difficult to mitigate. This assessment is based on the utilisation of our network by substation. Appendix 6 shows current and forecast (5 year) utilisation of the network by substation and implications e.g. future congestion. A five-year period has been considered as it balances delivery time to address potential issues with uncertainty of future network demands.

The most pressing capacity constraints on the network is on the lower voltage network (11kV and less) which is typically at street and suburb level. These constraints are predominately in rural areas but also include some urban areas. To date it has been hard to assess the impact on the LV network as we don't have access to voltage information from smart meters. We have an ongoing trial looking at addressing this. Future growth in demand on these lines may require additional investment. This can be managed through increasing the capacity, non-network solutions and optimisation of existing asset or smoothing demand through price signals.

Despite experiencing limited capacity constraints currently, Top Energy has introduced TOU pricing for Residential and Commercial consumers as we see congestion is sufficiently proximate. By offering price signals now this will enable retailers to build the appropriate systems and offer TOU price structures to customers and for customers to become accustomed to these future price structures as peak demand management is required. 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 has removed retailer exemptions, except in exceptional circumstances e.g. Prepay, and migrated the remaining eligible customers with capable meters to TOU pricing. Price signals for demand management will continue to be refined e.g. more targeted and this could include further trials.

These price signals have become increasing important with the removal of peak demand transmission pricing (RCPD) and the removal of Avoided Cost of Transmission (ACOT) payments from 1 April 2023. Without these signals Distribution Generation in our network has no incentive to generate when demand is high e.g. winter nights and consumers will have less incentive to reduce demand.

An initial review of the impact of the removal of RCPD has been completed. The graph below shows the Top100 peaks for the years ended August 2021, 2022, and 2023. This shows a clear increase in peak demand. Peak demand between 2021 and 2023 increased 2.5% despite higher temperatures. This is consistent with Transpower observations that peak demand has increased 1.5-2% over the last couple of years. We will continue to monitor this and the impact on our demand forecasts.



3.2 Industry Context

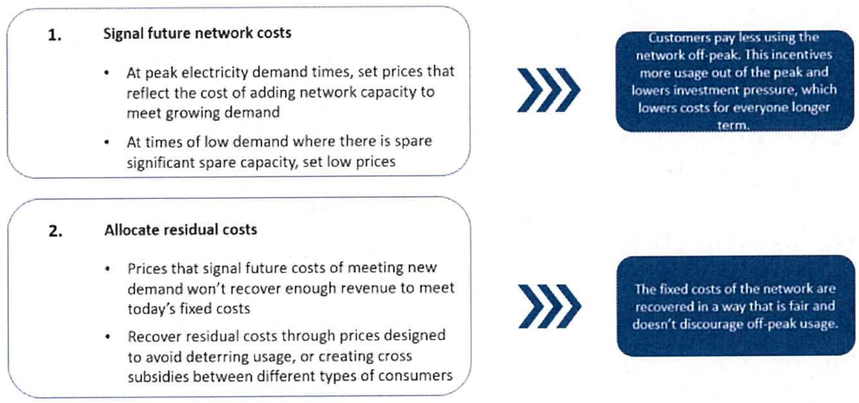
Decarbonisation and the emergence of new technologies are expected to have significant impact upon the traditional electricity industry, not only increasing demand but also changing customers use of the network and in some cases providing alternatives to grid connection. Emerging technologies include:

- 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 grow 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 which has the objective to increase utilisation of the network and lower future costs meaning lower line charges. Figure 5 below describes this in more detail.

Figure 5: Cost reflective pricing principle



Our 5-year pricing strategy was updated to further reflect this and continues to be refined. Network implications and opportunities are currently under investigation with the initial focus on Distributed generation and electric vehicles.

3.2.1 Distributed Generation

The network has the third highest penetration of small solar in the country at 5.6% of connections (1,932 customers with installed capacity of 11.2MW). This is 20% higher than a year ago with growth expected to continue to increase.

The key immediate issue with solar is localised clustering e.g. at street level especially in the Eastern part of the network. A high penetration of solar within a street or suburb results in voltage issues and potential capacity constraints. To date this has been managed with the existing infrastructure but the future impact on the network requires investigation and management. It is anticipated that the increasing prevalence of exporting distributed generation will drive long term incremental costs on the network through demand for additional capacity, initially in the low voltage network.

Top Energy has a distribution generation charge of 1 c/kWh which is unchanged. The revenue recovered seeks to recover some of the incremental costs of investigating issues, developing solutions and other administration costs. These costs only relate to additional costs due to distributed generation rather than additional network infrastructure costs.

Our first large scale solar (32MW) connected in the Kaitaia region in November 2023. Larger scale Distributed Generation, for the purpose of export, is expected to cause capacity constraints at all levels in the future and this includes the national transmission grid. Currently Top Energy had approved applications for 67MWA for solar around Kaitaia. Given the maximum possible export capacity of the Kaikohe to Kaitaia 110 kV line circuit is 66MVA, Top Energy will no longer approve applications unless upgrades are financially supported. In addition, there is potential transmission constraints on 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 is working with Transpower on a low cost run back scheme with the costs to be recovered by new connecting generation. 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 potential options to accommodate further generation in Northland through a Renewable Energy Zone.

3.2.2 Battery trial

Batteries could assist in the management of the network especially at peak demand. A battery trial with a third party started in 2023 with the aim to understand the potential and how effectively the technology can be utilised. The battery was installed at Taipa in December 2023 which was chosen as it is operating at capacity and is requiring reinforcement and use of distributed generation (diesels).

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 350 EVs (BEV, PHEV), up from 250, 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

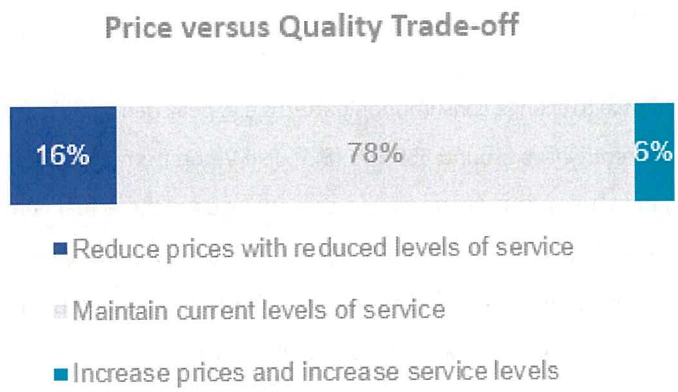
To inform our decisions regarding the above investments, in 2009 Top Energy consulted with consumers on our proposed network developments and consumer expectations for prices and the quality of service they receive. The survey results established that 80% of consumers wished to see network reliability 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 on their price and quality perspective. This was done through a separate survey of 1,000 consumers. The key findings were:

- Seven out of 10 customers consider Top Energy's current power supply reliability to be acceptable, with almost one-third (32%) stating that the power supply has improved over the last 12 months.
- A significant proportion of customers (81%) would not be prepared to pay more for an improved level of power supply.
- Almost three-quarters of customers (74%) 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.

These results are consistent with our annual survey which measures the current levels of satisfaction with levels of 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 2023 customer survey results are shown below.

Figure 6: Price quality trade-off



Source: Key Research customer survey 2023

3.3.2 Customer satisfaction

Since 2009, regular telephone surveys and focus groups have been completed to gauge customer views on our progress and incorporate any new insights into asset management planning and pricing approaches.

Over the last five years, 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 customers surveys which measure customer satisfaction with our faults and new connections divisions.

The key results were:

- Customer satisfaction with faults and new connections divisions remains strong and has averaged 80% over the last 12 months, this includes a drop to 56% during cyclone Gabrielle.
- Adoption of *New technologies* by customers remains similar to 2022 with Commercial customers more inclined to adopt new technologies than Residential customers. This included EV, solar and batteries. Overall, 14% of participant stated they were likely to purchase and EV in the next 5 years.

Only 12% of customers said that they changed power companies in the last 12 months although 26% of customers said that they used Powerswitch website to determine the best power company. Surveys will continue to be completed to provide a benchmark of customer satisfaction and preferences over time.

3.2. Regulatory considerations

Top Energy is subject to regulations which influence our pricing decisions as well as provide guidance on how prices should be set. These are summarised in Figure 7.

The Commerce Commission determines the lines charge revenue which it considers is sufficient to recover our reasonable costs, as well as an appropriate return on investment. In the new Default Price-Quality Paths Determination 2020, the methodology has changed to setting an allowable revenue rather than allowable prices. 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 has developed and published scorecards for each distributor based on an assessment of their 2023 pricing methodology and pricing roadmap. The EA has highlight criteria including their 5 key areas of focus. These are also outlined in Appendix 4 with our progress to date.

Top Energy scored 4.1 / 5 which was a significant increase from 2021 score of 3.3 / 5. This placed Top Energy in the top 35% of all distribution companies in New Zealand which reflects 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 differentiate between rural and urban customers, as this is based on consumer feedback.

The scorecard assessment is aimed to complement industry-led efforts to promote more efficient distribution pricing, by analysing different pricing options, and offering frameworks and tools. The EA assessments will be repeated periodically to track progress, identify good practice, and provide constructive feedback where progress lags. Top Energy has met with EA to better understand good practice, identify gaps and discuss suggested improvement opportunities. Feedback from this session and the scorecard has been incorporated into this year's pricing strategy and pricing methodology.

Figure 7: 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 60 cents for the 1 April 2024 to end of 31 March 2025 period. Over 5 years this can increase by 15 c/day each year to 90c /day for 1 April 2026 to end of 31 March 2027. Thereafter, the regulation is revoked.
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 that have connections on our Network when we have intended to make changes to our pricing structures.

During September 2023, Top Energy in conjunction with Northpower undertook consultation on further cost reflective pricing. The consultation focused on:

- Removal of TOU exemptions for Residential and General consumers
- Smart meter deployment plans given our low penetration and
- Future technology trials and our interest to participate e.g. Electric Vehicles

Retailers continued to be supportive of the new TOU price structures implemented on 1 April 2020 for Residential and General Commercial customers and there was only one retailer that expressed concern with the removal of exemptions and this has been worked through.

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, or when new retailers sign up for a Use of System Agreement. There were 20 retail brands with customers on the Top Energy network, this is three down from last year.

Pricing Decisions

The Statement of Corporate Intent (SCI) of the Top Energy Consumer Trust sets out the overall objectives of Top Energy Limited. Our Pricing objectives and strategy and align to 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 cost, regardless of actual volumes of electricity consumed.
4. Prices provide consumers with opportunities to reduce their charges where they are able to 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 urban and rural consumers.

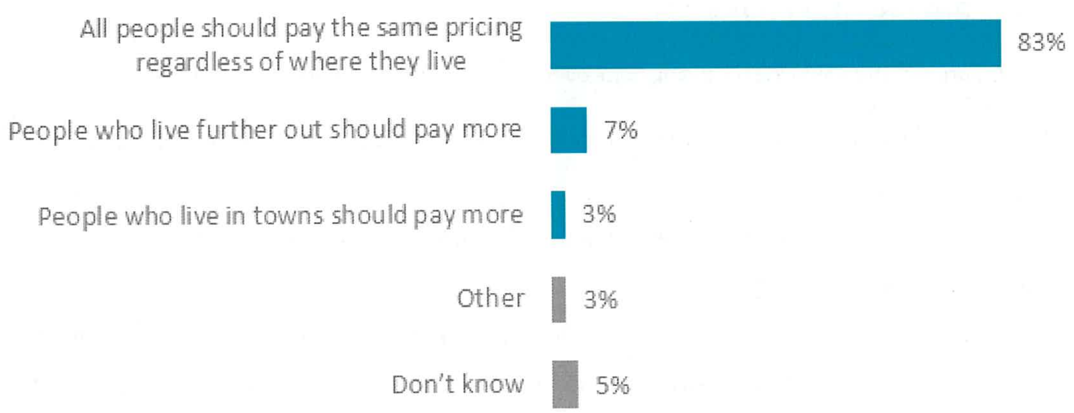
These objectives are informed by the key considerations discussed in the previous section, including business considerations, consumer feedback, industry and regulatory guidance (in particular the Electricity Authority pricing principles).

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. new Residential and General Commercial TOU pricing.
- That prices reflect the potential demand and capacity required by consumers and are in recovered in a cost reflective manner e.g. increase fixed charges.
- To comply with regulatory requirements
- To appropriately recover pass through costs
- To achieve a rate of return acceptable to shareholders.

Top Energy surveyed its customers as a part of the annual consumer survey in 2022 to establish if consumers agreed with pricing principle 6 – Prices do not differentiate 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 8: Survey results on locational pricing



3.5. Five-year pricing strategy and Roadmap

After implementing significant price reform over the last five years and achieving the key deliverables of our original five-year strategy and roadmap, a review was completed in 2022 and the strategy and roadmap updated to reflect Top Energy's next steps in pricing reform and ongoing transition to efficient pricing. This has been further refined to align our pricing to the rural network scenario map outlined in the Authority's Distribution Pricing: Practice Note Second Edition v2.2, 2022 and developments in the industry.

Top Energy's future pricing roadmap sets out how we are going to achieve our strategy and shows that significant progress has been achieved to date and includes multi-year activities which are interlinked and the key timelines. For the 2023/2024 all the key activities have been completed or are in progress. The fixed cost recovery strategy has been extended out to incorporate the end of the LFCT regulations and the reset of DPP which will be published in November 2024. Top Energy's capital contributions policy (refer to section 7.11) means significant first mover advantages are avoided. The EA published Target Reform of Distribution Pricing – issues paper (July 2023) which included consultation of Capital Contributions. Top Energy's next step is to work with the Authority and Industry to progress this.

Figure 10: Top Energy's future pricing roadmap (as of 31 March 2024)

Future Pricing Roadmap EDB : Top Energy Limited 31/03/2025

Key: C Completed; X To be completed

Roadmap Stages	Activities	2018/20	2020/21	2021/22	2022/23	23/24	24/25	25/26	26+
1. Initiate pricing reform									
Identify objective, update strategy and plan, consult with stakeholders and industry and basic data gathering for analytics		C							
2 Develop detailed plans for pricing reform									
Develop detailed plans, including customer consultation, data analysis to assess impacts on customers and transition plans		C							
Access to data for analysis including half hour data from Retailers for Analysis		C							
Develop trials of new pricing structures including TOU, establish feedback loops through Retailer consultation and educate		C							
3. Manage roll out of new pricing options									
3a. Implementation of new pricing options									
Trial Mass Market pricing structures	New pricing structures available to Residential customers (Optional)	C							
New Mass Market pricing structures	New pricing structures for all mass market customers with retailer exemption for technical reasons		C						
Export Distribution Generation charge	Cost to cover incremental costs from distributed generation			C	C				
New pricing for large TOU customers	Implementation Demand and Capacity pricing for TOU Commercial customers			C	C	C	X		
LFCT phase out	Phase out of the LFCT and increase fixed charge recovery				C	C	X	X	X
Distributed Generation management	Incremental charges for monitoring and managing DG where required				C	C	X	X	
3b. Observation and adjustment									
Implement transition strategies	Incentivise and manage take-up over time for retailers and customers		C	C	C	C	X		
Adopt risk management approach	Identify and manage risks to markets, customers, EDBs *(eg political and financial risks)*		C	C	C	C	Continuous →		
Review progress and make adjustments	Actively consider progress towards outcomes over time including effective of price signals		C	C	C	C	Continuous →		
Review Pricing Methodology	Review and implement changes to pricing methodology and supporting modelling.				C	X	X		
Ongoing customer interactions	Monitor customer responses and manage as required		C	C	C	Continuous →			
4. Enabling future reform									
Understand LV network	Low Voltage study and meter trial to prepare for future pricing reform				C	C	X	X	
Impact of TPM	Access the impact on the network and consequences for pricing for removal of RCPD price signal								
- Impact on Industrial customers	Determine pass through method and consult with Industrial customers before 1 April 2023				C				
- Network demand	Understand change in network demand and long term impact on AMP and pricing					C	X	X	
- Demand side management	Evaluate the role of demand side management including ripple control						X	X	
Billing system	Evaluate capability of Axos for future price reform with the other EDBs (Axos User group)						X		
Cost / quality trade off	Further engage consumers on cost effective pricing and trade offs				C	C			
Future pricing reforms									
Revenue recovery cost reflective pricing signal	Refine price signals to further reflect costs e.g lower offpeak prices					Continuous	X	X	X
Revenue recovery via least distorting charges	Increase fixed recovery to align with under cost structure			C		Continuous	X	X	X
Strategic review of pricing	Review of pricing strategy for next 5 years			C		C		X	
Upstream First Mover Disadvantage	Review potential for FMD on our network						X		
Decarbonisation	Impact on future pricing allocations and structures						X	X	
Further trials	Technology trials with partners e.g. batteries and Electric Vehicles						X	X	X

Strategy

Top Energy acknowledges that there is further room to improve our existing pricing to signal future costs and to respond to future network congestion. For example:

- 61% of revenue is recovered through variable (kWh) based prices, which does not align to our costs which are largely fixed. Re-balancing of fixed and variable revenue recovery continues to be a key pricing reform and fixed cost recovery has increased this year.
- Our initial TOU pricing signals, if passed through, could be more targeted so they don't discourage consumers from using electricity during times where there is capacity available and does not drive additional network costs. This has started to be addressed through lower off-peak TOU prices.

The 5-year strategy outlined below will also enable Top Energy to manage the impact on customers while adapting the approach, as required, to changing requirements, technologies or timing of change. This could include incorporation of new technologies and network alternatives by customers. 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 acknowledge that pricing reform will be an ongoing process and have incorporated the development and modelling of further cost reflective pricing including new technologies in the pricing strategy. This has been complemented by more consultation with retailers. This includes offering to be part of trials which retailers are considering operating.

Figure 8: Top Energy's pricing strategy

Pre 2022	Year 1 (2022/2023)	Year 2 (2023/2024)	Year 3 (2024/2025)	Year 4 (2025/2026)	Year 5 (2026+)
COMPLETED	COMPLETED	COMPLETED	IMPLEMENT	ASSESS/REFINE	SIGNAL
Participate in industry reviews and align Engage with customers with surveys and focus group COS model developed and new customer groupings defined Monitor new technology and introduce price signals e.g. solar New cost reflective pricing introduced for customer groups (e.g. TOU and Capacity pricing for LCOM Increased fixed cost recovery in mass market and LCOM segments	LFCT phase out commenced Further rebalance LCOM pricing through higher fixed charges Assessed impact of New TPM and defined methodology Commence LV network study and meter data trial to preparing for future pricing structures Assessment effectiveness of current price structures e.g. TOU Introduce new pricing for DG >1MW to cover incremental costs for network management Completed extensive Price vs Quality survey	LFCT phase out continues Implement new TPM pass through and assess impact on demand Define fixed cost recovery strategy and pathway at end of LFCT Continue LV network study and review meter data trial Complete cost to Serve model Battery trial at Taipa substation learnings Review Upstream First Mover Disadvantage issues	LFCT phase out continues and increase fixed charge recovery Assess impact of TPM on customers, demand and role of demand response Optimise price signals including reducing off-peak rates and removing exemptions for TOU Continue LV network study Review Upstream First Mover Disadvantages issues with industry Review capability of billing systems Define fixed cost recovery strategy with DPP4 reset and LFCT end	Further phase out of the LFCT to increase fixed cost recovery Continue to optimise price signals including reducing off-peak rates Assess impact of technology from Asset Management Plan for pricing structure and customer groups Engage customers on cost effective pricing and trade-offs Review demand side management and fixed cost recovery mechanisms given findings of the LV study	LFCT Tariff phase out complete Transitioned to non-distortionary recovery of residual revenue Annual review of requirement for cost reflective price signals Review Cost to serve model

Our pricing strategy focuses on three key areas:

1. Efficient cost recovery
2. Responses to current and future network congestion
3. Preparedness for emerging trends

Efficient cost recovery

Costs are recovered in a manner which reflects the underlying costs to Top Energy which are predominately fixed. Top Energy's strategy is to transition to fixed charges except where price signals are required while managing consumer impact and future signalling requirements for congestion. This has commenced including increasing fixed cost recovery and reducing off-peak pricing signals.

The fixed cost recovery strategy after the end of the LFCT will be further defined after the DPP4 reset. A quantitative analysis that establishes a link between network conditions and peak signal strength has also been included in section 7.3 Allocating price signals to consumer.

Responses to current and future network congestion

3.1.3 outlines the current constraints on our network. Despite experiencing limited network capacity constraints currently, Top Energy has introduced TOU pricing for Residential and Commercial consumers as we see congestion is sufficiently proximate.

By offering price signals now this will enable retailers to build the appropriate systems and offer TOU price structures to customers and for customers to become accustomed to these future price structures as peak demand managed is required. It is expected as constraints arise price signals will become more targeted.

These price signals have become increasing important with the removal peak transmission pricing (RCPD) and the removal of Avoided Cost of Transmission (ACOT) payments from 1 April 2023. Without these signals Distribution Generation in our network has no incentive to generate when demand is high e.g. winter nights and consumers will have less incentive to reduce demand. An analysis of the impact of these is in section 3.1.3.

Preparedness for emerging trends

Top Energy is aiming to address data and other constraints for assessing current network capability to 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 3 years. This will allow more capacity based fixed charge pricing.
- Negotiating access to low voltage network usage data including demand and voltage to understand real AMD. The initial step is a trial to understand the value of the data which has commenced.
- Exploring the implication 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. This is especially important given the removal of the RCPD signal by Transpower and subsequent increase in peak demand.
- Monitor EV uptake and surveying consumers intentions.

The impact of electrification of large industrial processes is expected to be limited as there is only two Industrial customers on our network. However, future work is required on upstream First Mover issues.

Limitations on strategy

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

Since introducing TOU pricing in 2020 for Residential and Commercial consumers there has been no material change in customer behaviour as shown in Figure 9. This is due to lack of pass through by retailers which has removed the pricing signals to end consumers. Furthermore, only 50% of connections are currently able to be charged on TOU rates due to retailers not installing HHR meters and / or exemptions due to retailer system limitations. Despite Retailers not having passed through pricing signals, Top Energy has removed retailer exemptions (with minimal exemptions e.g. Prepay) to maximise the number of Connections on TOU pricing. This follows the Authority's advice.

With limited ability to influence Retailers to pass through line costs or install TOU meters, it does make 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 9: Consumption proportion by TOU time bands

Time band	2023	2022
Peak	19%	19%
Shoulder	54%	56%
Off-peak	26%	24%

Another key issue identified in implementing our price strategy is still the roll out of smart meters to all our customers. Currently, only 72% of connections have smart meters installed. Our consultation with Retailers continues to push for further deployment of smart meters.

Figure 10: HHR Penetration based on Advanced Metering Flag

Density	Advanced Metering Penetration (%)
Remote	50%
Rural	71%
Urban	82%

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 benefit but could also be negatively impacted as more network costs are allocated onto those without smart metering.

3.6. Pricing review

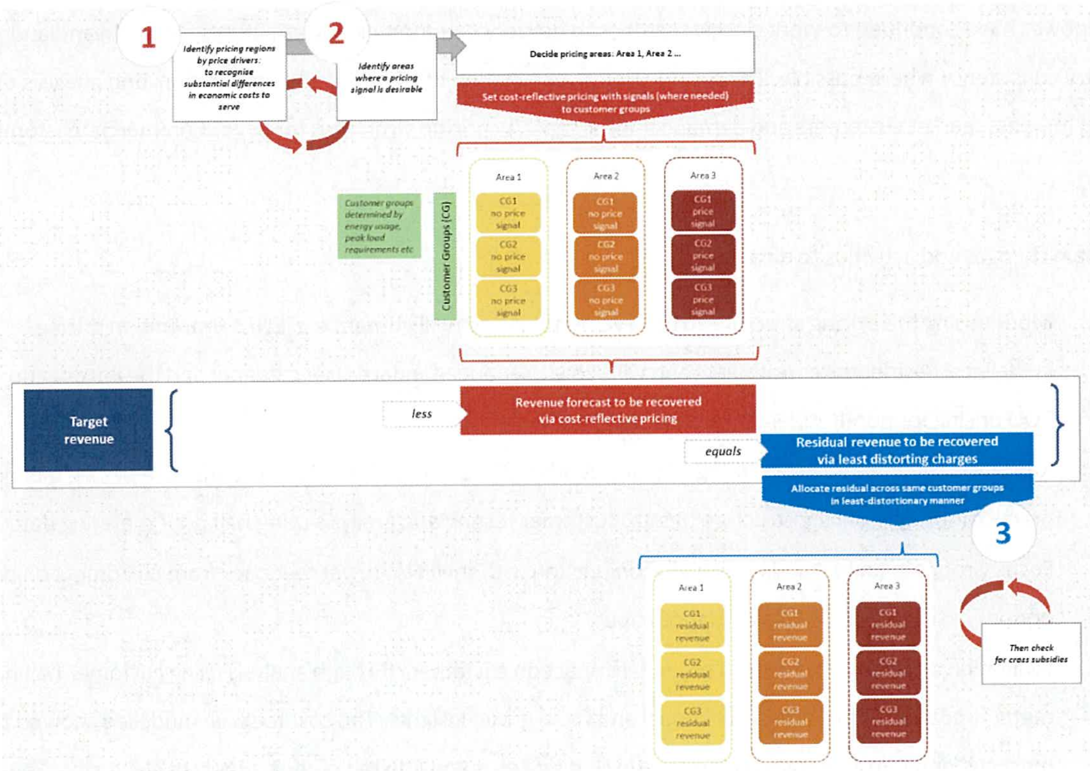
Top Energy's pricing strategy has provided the framework for activity over the last few years and for the changes being made this year. To assist in the delivery of the framework, Top Energy has continued to be a part of the ENA's Distribution Pricing Working Group (DPWG), to better understand and be 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.
- Representation on the ENA Strategic Pricing Working Group to look at what cost effective pricing means in practice including pricing structure design, customer testing and analysis using half hour metering data.
- Focus Groups in Kaitaia and Kerikeri, in conjunction with the ENA, to get feedback from customers on pricing options outlined in the ENAs Guidance paper.
- 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. The cost to serve modelled showed that, most customer groups covered the cost (excluding Return on Capital) of their supply of electricity. The main exceptions were Low User customers in rural areas across the network.
- Development of a trial Residential TOU pricing, in collaboration with Northpower and retailers
- 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
- Updated our cost to serve model in 2023.

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 11: Electricity Authority Practical note diagram



There are three key pricing focus areas this year and these are shown in Figure 12:

Figure 12: Key pricing focus for 2024-25

Strategic driver	Explanation	Actions
LFCT regulations phase out	Increase fixed charge recovery to be more cost reflective.	Increase Residential daily charge to 60c/day.
Complete pass through of new TPM as fixed charges	New TPM is effective from 1 April 2023 and removes the RCPD price signal and moves to a benefits-based methodology	Complete transition to fixed charge recovery
More cost reflective pricing	Continuation of our move to cost reflective pricing by increasing fixed proportion of	Continued increase in fixed cost recovery and reducing off-peak price

	consumers charges and lower off-peak charges where constraints do not exist.	signals through a phased approach to manage rate shock. Updated of COSM model

After significant change over the last three years there are no changes to pricing structures. The focus is on improving efficiency under the current structures.

The phase in of lower off-peak prices has commenced with off-peak prices reduced across Price Categories. The phase in approach will be defined as part of the fixed cost recovery strategy which incorporates the end of the LFCT and DPP4 reset.

4. Target revenue

The first step in the pricing process is to establish 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:

Figure 13: 2024-2025 Breakdown of Target

COMPONENTS OF TARGETED REVENUE			
	(1 April 2024 to 31 March 2025)	(1 April 2023 to 31 March 2024)	% change
Transpower Charges	7,007,294	6,005,653	16.7%
Avoided Cost of Transmission (ACOT)	-	-	
Pass-through Costs	386,403	392,920	-1.7%
Other recoverable Costs	- 567,029	573,028	-199.0%
Pass Through subtotal	**6,826,668**	**6,971,601**	-2.1%
Network Maintenance Costs	7,939,000	7,463,000	6.4%
Overheads	16,013,000	15,491,000	3.4%
Depreciation	13,946,000	13,237,000	5.4%
Pre tax ROI charge	19,897,166	19,329,889	2.9%
Distribution subtotal	**57,795,166**	**55,520,889**	4.1%
Annual Revenue Requirement	**64,621,834**	**62,492,490**	3.4%
DPP Compliance Adjustment	- 17,655,367	- 19,788,792	-10.8%
TOTAL TARGET REVENUE*	**46,966,467**	**42,703,698**	10.0%

The total Target Revenue has increased by $4.26m (10%). This is the maximum allowed under DPP.

4.1. Revenue cap regulation

Top Energy's revenue under the 2020 Default Price Path (DPP) Determination is based on a revenue cap. Total target revenue for 2024-2025 is $46.97m complying with the default price path (DPP) and based on consumption and connections forecasts. This is $4.77m below the Forecast Allowable Revenue of $51.74m. The methodology for forecasting consumption and connections is outlined in Top Energy Annual Price-Setting Compliance Statement – 2025 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 $5.8m for the year, representing 11% of target revenue before the discount.

For the 2024-25 year, revenue has increased by 10% ($4.26m). This includes a decrease in pass through and recover costs of $0.15m, an increase in Forecast allowable revenue of $0.8m and an increase in washups of $3.4m. Even through revenue has increased by $4.26m, Top Energy is under recovering revenue by $4.77m compared to our regulatory allowable revenue. This decision was based on an allowable return on investment for the 2021-2025 regulatory period of 4.57% (67th percentile vanilla Weighted Average Cost of Capital (WACC).

4.2. Transpower charges

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.

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 has been completed this year.

Figure 14: 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 2023 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 2023 WACC estimate of 5.70% is based on the DPP WACC (4.57%) 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 type such as rural and urban
- Geographical regions

To assist in this process our Cost Serve was updated in 2023. 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 at near capacity with future growth predicted. The immediate growth in peak demand will be met through an existing distribution generation solution owned by Top Energy (4.5MW Diesel generation). Alternative solutions are being considered. This includes a battery trial with a third party. The battery (100kW) has been installed and results will be analysed.

Kaitaia 110KV

The constraint on the Kaitaia 110kV is for large 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 extremely cost reflective price signal.

As such, there is 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 is associated with directly investing in, maintaining and operating the network, as well as receiving supply from Transpower. The remaining 25% is associated with general management and administration of the business. Top Energy considers that our network cost drivers are:

- peak demand
- the length of 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 therefore 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 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. Effectively, consumers that are 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 that is only caused by a specific group.
- Transmission and assets 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. With the removal of RCPD charges these consumers groups will be reviewed. This will be part of the impacts of the new TPM workstream in the pricing strategy.

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

Figure 15: 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	Non-Standard

		Energy's distribution costs can be identified for each consumer. 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.

Residential and Commercial

- TOU Pricing signals are design to recover costs that are or will be incurred if customers place more demand on the system. This is primarily driven by system growth.

System Growth

We have used the existing capacity growth investment in our AMP to forecast our Long Run Marginal Cost (LRMC) 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. LMRC has been chosen because networks are made up of long-term investments and is consistent with other networks which we work closely with e.g. Northpower.

Our LRMC is currently estimated to be $129 per KVA. This is used to establish a link between network conditions and the peak signal strength by deriving a peak differential.

The peak differential is calculated as:

$$Peak\ differential = \frac{Value\ of\ demand\ management\ (per\ annum)}{Peak\ hours\ per\ year} = \frac{129}{1{,}250} = \$0.10 \text{ per kWh}$$

Where $Peak\ hours\ per\ peak\ day \times Peak\ days\ per\ year$ ($5 \times 250 = 1{,}250\ hours$)

Based on this calculation the differential has been set at approximately 10c per kWh for our standard Residential and General Price categories.

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 be continued to be reviewed as we increase cost recovery through fixed costs.
- Industrial pricing aims to recover Top Energy's costs to service these consumers. These are fully fixed with no price signal as any capacity growth requirements is directly charges to these customers.

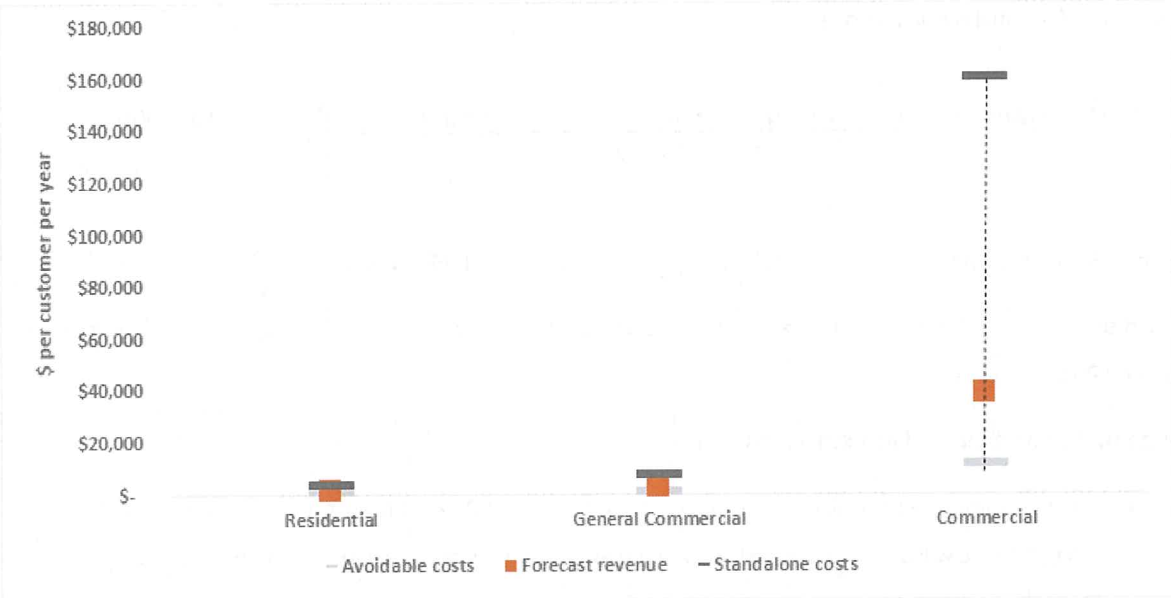
6.4. Test for cross-subsidisation

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 cost 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.



For example, a 7kW solar system, 15kW battery system with diesel generator can cost more than $45,000 to install. We estimate this would cost 65-70 c/kWh over a 15-year period and the installation is funded by a mortgage. This is significantly more expensive than the average 43c/kWh charge Top Energy's consumers pay (source: MBIE quarterly survey of electricity prices, 15 November 2023). Top Energy will continue to keep a watch on this market and respond appropriately through pricing.

6.5. Summary of pricing options

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

Figure 16: Pricing Options

<table>
<tr><th>Price Code</th><th>Description and rationale</th><th>MWh</th><th>ICPs</th></tr>
<tr><td>Industrial

(IND)</td><td>Fixed price recovery of costs associated with industrial loads consuming >3,000,000kWh per annum and a fuse capacity of 110kVa or greater.</td><td>42,715</td><td>3</td></tr>
<tr><td>Large Generation

(LDG)</td><td>Fixed price recovery of costs associated with the connection of large-scale distributed generation into the distribution network.</td><td></td><td>4</td></tr>
<tr><td>Generation <1MW</td><td>Costs set to only recover incremental costs</td><td></td><td></td></tr>
<tr><td>Micro Generation

(DG)</td><td>Variable price recovery of costs associated with the connection of small-scale distributed generation into the distribution network. This is set at 1c/kWh</td><td>7,028</td><td></td></tr>
<tr><td>General Advanced Metering

(TOU) and (GA)</td><td>TOU is the default code for all customers with 110kVA connection or greater and typically have an annual consumption appropriately of 275,000kWh but less than 3,000,000kWh (TOU). Total charges for this plan include a fixed price for each day connected, 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 connection with pricing beneficial for customers using between 45,000 and 275,000 kWh (GA) per annum depending on capacity.

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</td><td>44,749</td><td>106</td></tr>
<tr><td>Residential</td><td>Residential 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>39,796</td></tr><tr><td>All Inclusive</td><td>120,235</td></tr><tr><td>Controlled</td><td>296</td></tr><tr><td>Total</td><td>160,327</td></tr></table></td><td>160,327</td><td>28,630</td></tr>
</table>

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>66,758</td></tr>
<tr><td>All Inclusive</td><td>11,951</td></tr>
<tr><td>Controlled</td><td>2,041</td></tr>
<tr><td>Total</td><td>80,751</td></tr>
</table>
See above for definitions.</td><td>80,751</td><td>5,597</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>1,141</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 charge, Benefits based charges, Residual charge and Transition Charge
- Avoided distribution charges payable to embedded generators
- 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 into the sub-transmission system)
- Transmission methodology outlined in section 5.2.

Top Energy does not have additional obligations or responsibilities regarding interruptions to supply for non-standard connections beyond those incorporated in its standard contracts. While additional circuit redundancy and specialist equipment is provided to these consumers in some circumstances, which is sometimes beyond what is provided to many standard connections, these consumers pay for this enhanced level of security on a cost recovery basis.

Top Energy has introduced non-standard pricing for specific regional development initiatives e.g. Energy 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 incentivise 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 60 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 $1.90 per day is applied to all Residential consumers who do not meet the low user criteria.
- A $2.40 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, taking into account 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.

Existing large-scale distributed generation (>1MW)

Connection charges have been set to recover the costs through a non-standard contract. From 1 April 2022 a new charge was introduced for distributed generation >1MW to cover incremental costs to actively manage and monitor power flows in areas where congestion occurs. Initially this will be set at zero as no distributed generation >1MW requiring monitoring and management has been connected to date. Direct cost 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 is based on consumption from 1 April 2024 to 31 March 2025 which covers the entire assessment period. Discounts calculated on this basis represent approximately $5.8m and will be processed through the retailers to be applied to consumer invoices after the 31 March 2025.

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.

The value of the Capital Contribution is calculated from the total cost of extension work and reduced by the value of the Top Energy connection subsidy. The contribution represents the uneconomic cost of constructing the line but does not grant any ownership rights; Top Energy retaining ownership, and responsibility for repairs and refurbishment of the reticulated extension.

Capital Contributions may be non-refundable or refundable depending on the circumstances. A refund may be applicable should a new customer connect to the Network extension within a 5-year period from the date of payment by the applicant that made the original contribution. This assists in addressing the First Mover disadvantage issue. Standard charges and requirements apply to typical connection configurations.

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 17 summarises the allocators used to allocate target revenue and the rationale for these decisions.

Figure 17: 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: Project <20M: TPM Simple methodology Project >$20M; historical kWh (2014-2018)	**Same as TPM Method** Aligns with Residual allocation and is fixed like allocator
	Residual charges: Historical average AMD (2014-2018) and Historical average kWh (2016-2020)	**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 18: Cost allocation results

				Pass through $000s	Distribution $'000's					Revenue		
Consumer Group	Regulatory Asset Base 2024($m)	Number of ICPs	Energy Consumption and export Forecast 2025 (GWh)	Transmission, Other Pass-through and Recoverable Costs 2025	Network Costs (Maintenance)	Non-Network Costs (Overheads)	Depreciation	Posted Discount	Pre tax WACC	Annual Revenue Requirement	DPP compliance Adjustment	Total 2025 Target Revenue
IND	11,963	3	43	537	271	549	478	(21)	703	2,517	(771)	$1,746
GG,GU,GC	55,025	5,597	81	1,547	1,248	2,524	2,198	(929)	4,065	10,654	3,649	$14,303
GA	5,057	46	6	253	115	232	202	(9)	297	1,090	(255)	$835
TOU	10,729	61	38	847	243	492	429	(96)	708	2,623	317	$2,940
LDG	2,381	5	-	0	54	109	95	-	136	394	366	$761
DG			7		22				-	22	48	$70
Unmetered'	2,064	254	1	-	47	95	82	-	118	342	52	$394
Total Commercial									-		-	$0
LR	155,932	17,366	79	1,794	3,537	7,153	6,230	(2,885)	11,774	27,601	(15,207)	$12,395
SR	105,922	11,264	82	1,848	2,402	4,859	4,232	(1,870)	7,907	19,378	(5,855)	$13,523
Total Residential												
Total	**349,073**	**34,596**	**337**	**6,827**	**7,939**	**16,013**	**13,946**	**(5,810)**	**25,707**	**64,622**	**(17,655)**	**$46,966**

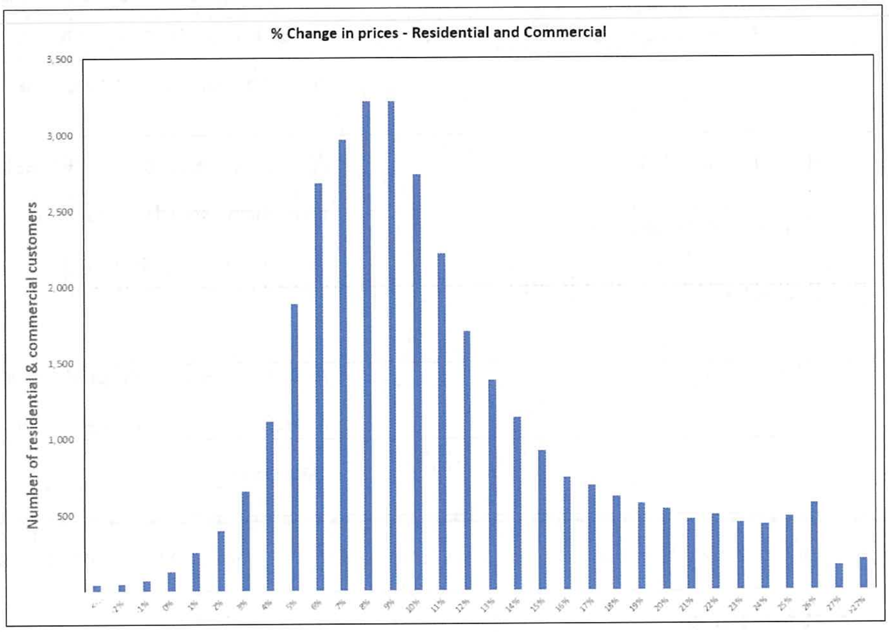
Appendix 5 summarises the resulting prices for 2024-2025 which are also located on the Top Energy website.

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, completion the fixed pass through of new Transmission pricing methodology and other price change for Residential and General commercial consumers is shown below. The majority of customers getting >15% increases are very low residential users whose daily charge is increasing from 45c/day to 60 c/day.

Figure 19: Price change % before the discount for residential and General commercial customers


% Change in prices - Residential and Commercial
Number of residential & commercial customers
3,500
3,000
2,500
2,000
1,500
1,000
500
-2%
-1%
0%
1%
2%
3%
4%
5%
6%
7%
8%
9%
10%
11%
12%
13%
14%
15%
16%
17%
18%
19%
20%
21%
22%
23%
24%
25%
26%
27%
>27%

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 Jon Edmond Nichols, 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 prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

D A Sullivan

J E Nichols

26 March 2024

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 2024.
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 when comparing 2024 and 2025 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 section 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 2023 (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 2024.
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 provides 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	Extent 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 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.

	• 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 maybe constrained.
(iii) reflecting differences in network services provided to (or by) consumers and	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 provide 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 by 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 \$1.90/day and \$2.40/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 \$0.60/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 time that suits them.
(c) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:	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).
(i) reflect the economic value of services and;	

(ii) enable price/quality trade-offs	
(d) Development of prices should be transparent, and have regard to transaction costs, consumer impacts, and uptake incentives	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 for all customers with automatic exemptions for non-communication meters e.g. legacy meters and retailer's ability to apply for exemptions due to operation issues reflect this. 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 depending on network constraint requirements.

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. See section 3 and Appendix 6.
Distributors response to any significant first mover disadvantages issues	Top Energy has 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 limited. See sections 6.12. The EA published Target Reform of Distribution Pricing – issues paper (July 2023) which included consultation of Capital Contributions. Top Energy's next step is to work with the Authority and Industry to progress this.
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 guideline 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 and intends to continue this over the 5 years. 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.

Appendix 5 - Network Line Charges 2024 – 2025

TOP ENERGY®
Te Puna Hihiko

2024/25 Electricity Price Schedule

Effective from 1 April 2024. All prices exclude GST

KEY CHANGES

Our prices are increasing by 8.4%. This is because transmission prices for the Far North have doubled over the last two years, costs of materials continue to climb locally and globally, and we are increasing our network resiliance, accentuated by 2 years of extreme weather.

The Low User daily rate is increasing from 45c to 60c per day, in accordance with changes in the Electricity (low fixed charge option) Amended Regulations 2021.

Other daily charges are also increasing, mainly due to passing through of the new transmission pricing. While prices will likely increase in coming years, we remain committed to our focus on affordable energy.

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

		Current from 1 April 2024							Previous Year			
Price Code	**Description**	**Daily 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 1.4.2023**	**Total ($/kWh) from 1.4.2023**	**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 : 4,346 users (excludes holiday homes, ancillary buildings and meters)												
LRF	Fixed price	0.6000		0.1373		0.4627			0.4500		0.1373	
LUC	Uncontrolled (no load controlling applied)		0.1716		0.1094		0.0622	1,130		0.1702	0.1094	1,130
LA	All inclusive (3kW loading)		0.1416		0.1094		0.0322			0.1402	0.1094	
LFC	Controlled 20 (10kW loading)		0.0643		-		0.0643	-		0.0658		-
DG	Exported Micro generation		0.0100		-		0.0100	-		0.0100		-
Low User Time of Use Uncontrolled (LU) for customers who have no load controlling applied to their line : 3,100 users												
LUF	Daily Price on Half Hourly Read Uncontrolled	0.6000		0.1373		0.4627			0.4500		0.1373	
LU1	Peak (7am - 9.30am & 5.30pm - 8pm, excluding weekends and public holidays)		0.2374		0.1094		0.1280	1,130		0.2244	0.1094	1,130
LU2	Shoulder (9.30am - 5.30pm & 8pm - 10pm or 7am - 10pm, weekends and public holidays)		0.1574		0.1094		0.0480			0.1531	0.1094	
LU3	Off Peak (10pm - 7am)		0.1374		0.1094		0.0280			0.1441	0.1094	
LFC	Controlled 20 (10kW loading)		0.0643		-		0.0643	-		0.0658	-	-
DG	Exported Micro generation		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 : 9,920 users												
LCF	Daily Price on Half Hourly Read Controlled (3kW loading)	0.6000		0.1373		0.4627			0.4500		0.1373	
LC1	Peak (7am - 9.30am & 5.30pm - 8pm excluding weekends and public holidays)		0.1952		0.1094		0.0858	1,130		0.1816	0.1094	1,130
LC2	Shoulder (9.30am - 5.30pm & 8pm - 10pm or 7am - 10pm weekends and public holidays)		0.1343		0.1094		0.0249			0.1271	0.1094	
LC3	Off Peak (10pm - 7am)		0.1094		0.1094		0.0000			0.1141	0.1094	
LFC	Controlled 20 (10kW loading)		0.0643		-		0.0643	-		0.0658		-
DG	Exported Micro Generation		0.0100		-		0.0100	-		0.0100		-
Standard User (SR) for customers using more than 8,000kWh per year : 2,755 users												
SRF	Daily Price	1.9000		0.3402		1.5598			1.5000		0.3402	
SUC	Uncontrolled (no load controlling applied)		0.1162		0.0437		0.0725	1,130		0.1231	0.0437	1,130
SA	All inclusive (3kW loading)		0.0861		0.0437		0.0424			0.0931	0.0437	
SFC	Controlled 20 (10kW loading)		0.0437		-		0.0437	-		0.0468	-	-
DG	Exported Micro Generation		0.0100		-		0.0100	-		0.0100	-	-
Standard User Time of Use Uncontrolled (SU) for customers who have no load controlling applied to their line : 2,905 users												
SUF	SUF Daily Price on Half Hourly Read Uncontrolled	1.9000		0.3402		1.5598			1.5000		0.3402	
SU1	Peak (7am - 9.30am & 5.30pm - 8pm excluding weekends and public holi-days)		0.1705		0.0437		0.1268	1,130		0.1751	0.0437	1,130
SU2	Shoulder (9.30am - 5.30pm & 8pm - 10pm or 7am - 10pm weekends and public holidays)		0.1133		0.0437		0.0696			0.1120	0.0437	
SU3	Off Peak (10pm - 7am)		0.0705		0.0437		0.0268			0.0951	0.0417	
SFC	Controlled 20 (10kW loading)		0.0437		-		0.0437	-		0.0468	-	-
DG	Exported Micro Generation		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 : 5,604 Users												
SCF	SCF Daily Price on Half Hourly Read Controlled (3kW loading)	1.9000		0.3402		1.5598			1.5000		0.3402	
SC1	Peak (7am - 9.30am & 5.30pm - 8pm excluding weekends and public holi-days)		0.1437		0.0437		0.1000	1,130		0.1451	0.0437	1,130
SC2	Shoulder (9.30am - 5.30pm & 8pm - 10pm or 7am - 10pm weekends and public holidays)		0.0832		0.0437		0.0395			0.0820	0.0437	
SC3	Off Peak (10pm - 7am)		0.0437		0.0437		0.0000			0.0651	0.0437	
SFC	Controlled 20 (10kw loading)		0.0437		-		0.0437	-		0.0468	-	-
DG	Exported Micro Generation		0.0100		-		0.0100	-		0.0100	-	-
BTS Time of Use Uncontrolled (BTSU) for builder temporary connections : 0												
BTSUF	Fixed Price	2.4000		0.3402		2.0598			1.900	-	0.3402	-
BTSU1	Peak (7am - 9.30am & 5.30pm - 8pm excluding weekends and public holi-days)		0.1867		0.0437		0.1430	1,130	-	0.1872	0.0417	1,130
BTSU2	Shoulder (9.30am - 5.30pm & 8pm - 10pm or 7am - 10pm weekends and public holidays)		0.1350		0.0437		0.0913		-	0.1252	0.0437	
BTSU3	Off Peak (10pm - 7am)		0.0867		0.0437		0.0430		-	0.1072	0.0437	
POSTED DISTRIBUTION DISCOUNT NOTES												
	The Discount will only be provided to ICP's connected on 31 March 2025 (eligibility date) with an active customer and have used more than 1kWh during the 12 month period ending 31 March 2025.											
	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 2025 and 31 May 2025.											

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Price Code	Description	Current from 1 April 2024: Daily 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 ($/kWh)	Maximum combined Eligible Discount per KWh per ICP	Previous Year: Daily Price ($/day) from 1.4.2023	Total ($/kWh) from 1.4.2023	Distribution 12 month Discount Component	Maximum combined Eligible Discount per KWh per ICP
				For payment timing and eligibility, see previous page notes								
COMMERCIAL PRICING												
General User (GG) for businesses : 1,990 Users												
GGF	Daily Price	2.4000		0.3402		2.0598			1.9000		0.3402	
GGUC	Uncontrolled (no load controlling applied)		0.1410		0.0437		0.0973	1,130		0.1346	0.0437	1,130
GGA	All inclusive (3kW loading)		0.1110		0.0437		0.0673			0.1046	0.0437	
GGFC	Controlled 20 (10kW loading)		0.0437		-		0.0437	-		0.0546		-
DG	Exported Micro generation		0.0100		-		0.0100	-		0.0100		-
General User Time of Use Uncontrolled (GU) : 3,061 users												
GUF	Daily Price on Half Hourly Read Uncontrolled	2.4000		0.3402		2.0598			1.9000		0.3402	
GU1	Peak (7am-9.30am & 5.30pm-8pm, excluding weekends and public holidays)		0.1867		0.0437		0.1430	1,130		0.1872	0.0437	1,130
GU2	Shoulder (9.30am-5.30pm & 8pm-10pm or 7am-10pm, weekends and public holidays)		0.1350		0.0437		0.0913			0.1252	0.0437	
GU3	Off Peak (10pm-7am)		0.0867		0.0437		0.0430			0.1072	0.0437	
GGFC	Controlled 20 (10kW loading)		0.0437		-		0.0437	-		0.0546	-	-
DG	Exported Micro generation		0.0100		-		0.0100	-		0.0100	-	-
General User Time of Use All Inclusive (GC) : 546 users												
GCF	Daily Price on Half Hourly Read Controlled (3kW loading)	2.4000		0.3402		2.0598			1.9000		0.3402	
GC1	Peak (7am-9.30am & 5.30pm-8pm excluding weekends and public holidays)		0.1568		0.0437		0.1131	1,130		0.1572	0.0437	1,130
GC2	Shoulder (9.30am-5.30pm & 8pm-10pm or 7am-10pm weekends and public holidays)		0.1058		0.0437		0.0621			0.0952	0.0437	
GC3	Off Peak (10pm-7am)		0.0568		0.0437		0.0131			0.0772	0.0437	
GGFC	Controlled 20 (10kW loading)		0.0437		-		0.0437	-		0.0546		-
DG	Exported Micro Generation		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	11.9954		0.5500		11.4454			9.9962		0.5500	
G1	Peak (7am-9.30am & 5.30pm-8pm)		0.1558		0.0032		0.1526	1,092,500		0.1369	0.0032	1,092,500
G2	Shoulder (9.30am-5.30pm & 8pm-10pm)		0.0919		0.0032		0.0887			0.0910	0.0032	
G3	Off Peak (10pm-7am)		0.0572		-		0.0572	-		0.0572	0.0032	-
DG	Exported Micro Generation		0.0100		-		0.0100	-		0.0100	-	-
Larger User Time of Use (TOU) for businesses with connection size 110KVA or greater : 69 users												
TOUF	Daily Price	32.7720		0.5500		32.2220			27.3100		0.5500	
TOUDVD	Daily Distrubtion Demand Price	-				-			-			
TOULVFD	Daily Distribution LV Capacity price $/day/kVA	0.1000				0.1000			0.0700			
TOU1	Peak (7am-9.30am & 5.30pm-8pm)		0.0696		0.0032		0.0664	1,092,500		0.0756	0.0032	1,092,500
TOU2	Shoulder (9.30am-5.30pm & 8pm-10pm)		0.0420		0.0032		0.0388			0.0456	0.0032	
TOU3	Off Peak (10pm-7am)		0.0085		-		0.0085			0.0085		
DG	Exported Micro Generation < 1MW		0.0100		-		0.0100			0.0100		
TOUTXF	Daily Price	32.7720		0.5500		32.2220			27.3100		0.5500	
TOUTXD	Daily Distribution Demand Price					-						
TOUTXT	Daily Distribution LV Capacity price $/day/kVA	0.1000				0.1000			0.0700			
TOUTX1	Peak (7am-9.30am & 5.30pm-8pm)		0.0696		0.0032		0.0664	1,092,500		0.0756	0.0032	1,092,500
TOUTX2	Shoulder (9.30am-5.30pm & 8pm-10pm)		0.0420		0.0032		0.0388			0.0456	0.0032	
TOUTX3	Off Peak (10pm-7am)		0.0085		-		0.0085			0.0085		
DG	Exported Micro Generation < 1MW		0.0100		-		0.0100			0.0100		

UNMETERED PRICING: Fixed charges only. No variable charge.

Price Code	Description	NEW 1 April 2024 Daily Price $/day	NEW 1 April 2024 Unit Price $/kWh	OLD 1 April 2023 Daily Price $/day	OLD 1 April 2023 Unit Price $/kWh
Unmetered supply - Closed for New Connections 01.04.16 : 84 Users					
UMINT	Intermittent supply consisting of Fire Sirens, Railway Crossing Lights, Traffic Counters	0.3000	-	0.2400	-
UMGL	Intermittent supply consisting of Community Lighting, Convenience Lighting, Jetty Lights, Under Verandha Lighting	0.2000	-	0.1500	-
Unmetered supply - For New Connections after 01.04.16 : 2,435 Users					
UMLF	Streetlights (STL)	0.4360	-	0.4000	-
UMGF	General Connection (UM)	0.4360	-	0.4000	-
UMCF	General Connection (3000-6000kWh) - NEW	2.0710	-	1.9000	-
NIL	Tsunami Warning Alarms	-	-	-	-

For more information visit www.topenergy.co.nz or call 0800 867 373

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.	49%	61%	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.	87%	75%	6.25 MVA Firm (n-1)	Operating near firm capacity in winter peak periods. Movement of Russell loads from Kawakawa Zone Sub to Haruru Zone Sub planned
Moerewa	Urban and Rural with a mix of Domestic, Commercial and Agricultural load. Static growth.	50%	55% of Firm	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.	42% of Firm	64% of Firm	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.	49%	55%	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	19% of Firm	37% of Firm	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.	73% of Firm	75% of Firm	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	100%	125% of Firm	6.25 MVA (n)	Requiring reinforcement and use of distributed generation. Battery trial underway with third party
Pukenui	Dominantly Rural with Domestic and agricultural loads. Slow growth.	40%	45%	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	39% of Firm	50% of Firm	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.	100% of Firm	100% - 175% of Firm	20 MVA (n-1)	Issue going forward is new distributed generation, not load. Second 110kV planned

					but delayed due to environment court
Kaikohe 110kV	Bulk Supply at 33kV to Kaikohe, Kawakawa, Moerewa, Waipapa, Omanaia, Haruru, Kerikeri & Kaeo Zone Substations.	100% of Firm	100% of Firm	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.	50%	55%	5 MVA (n)	Future energy needs are anticipated to be within current capacity.
Kerikeri	Urban load with Domestic, Commercial & Industrial. Township Increasing demand.	25% of Firm	30% of Firm	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.	34% of Firm	45% of Firm	10 MVA Firm	Future energy needs are anticipated to be within current capacity.