TOP ENERGY LIMITED

PRICING METHODOLOGY DISCLOSURE

2022-2023

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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 33,900 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 2022. 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 2022-23
- **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
- **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
- **Appendix 5** details distribution prices that will apply from 1 April 2022

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 2022-23.

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.

2023 Target Revenue

We have determined 2023 target revenue based on recovery of costs, limited to the regulated revenue cap we are subject to.

Communicate and monitor

We have published our 2023 prices and pricing methodology. We will continue to monitor developments and adjust our strategy as required.

Consult

We have consulted with Retailers on the 2023 Pricing changes and structural changes. We will also consult with consumers and retailers on our wider pricing strategy as work progresses.

2023 Prices

Target revenue is allocated to consumer groups and pricing options to determine 2023 prices.

2023 Consumer Groups and Pricing Options

We have implemented the first year of phasing out the Low Fixed Charge Tariff and further increased fixed cost recovery through higher capacity pricing for Large Commercial customers in line with the changes developed in our strategy. A new charge for distributed generation greater than 1 MW has been introduced to recover network management costs where and when appropriate.

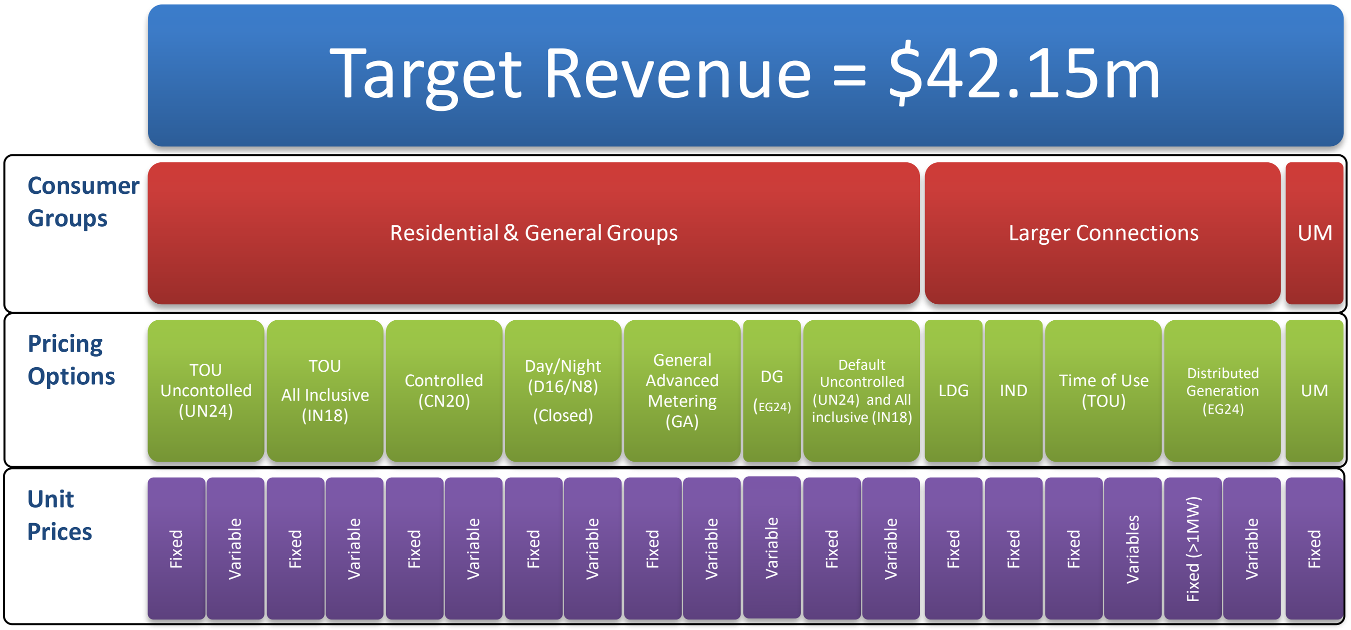
2.2. How prices are calculated

Prices have been set to recover our 2022-23 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 2022-23

We have continued the focus on our pricing methodology. The key highlights to date are:

- Separation of Residential and General Commercial customers and extension of Commercial TOU pricing (2016).

- Alignment with the industry with reference to the ENA's Distribution Pricing Guides (August 2015 and revised September 2016) and the new EA pricing principles (June 2019) and practical notes (August 2019) to improve the efficiency and effectiveness of our pricing.
- Implementation of Residential and General Commercial TOU prices from 1 April 2020. This was assisted by acquiring a subset of TOU smart meter data for mass market customers.
- 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.

This year we are introducing one significant change to our price structure. From 1 April 2022 a new charge will be introduced for distributed generation greater than 1MW to cover incremental costs to actively manage and monitor power flows in areas where congestion exists. Initially this will be set at zero as no new distributed generation greater than 1MW requiring monitoring and management has been connected to date.

There will also be a significant change to our Residential prices with the first step in phasing out the Low Fixed Charge Tariff (LFCT) for Residential customers. From 1 April 2022, the daily charge on all Low User Residential pricing categories will increase to 30 c/day. This is the maximum allowed in the first year of the phase out. The variable prices for Residential customers have been adjusted to ensure that our revenue recovery from Residential customers reflects their proportion to our costs. Top Energy intends to continue to phase out the LFCT over the next four years which will accelerate our move to cost-reflective distribution pricing through higher fixed cost recovery.

We are continuing to phase in capacity and demand pricing for our large TOU Commercial customers. These structures will better reflect the connection cost of various consumers, the fixed nature of these costs and their demand on the network. The capacity price will increase from $0.02 kVA / day to $0.05 kVA / day. The demand charge will remain at $0/kVA/day given congestion pricing is not required at present but does signal this will be introduced when congestion pricing is required.

The variable charge for export to the grid from distributed generation will remain at 0.5 c/kWh. This is to cover their contribution to Transpower connection charges and the incremental costs of understating the impact of solar export on our LV network which has been steadily increasing as solar growth continues across the network. This will continue to be reviewed annually.

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 2023.

Distribution prices have decreased by 2.0% on average including the posted discount to recover net allowable revenues permitted under the revenue cap regulation. These decreases 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 prices have decreased by 9% after accounting for all pass through and recoverable costs and including the discount. Appendix 5 provides further detail on prices.

3. Pricing considerations

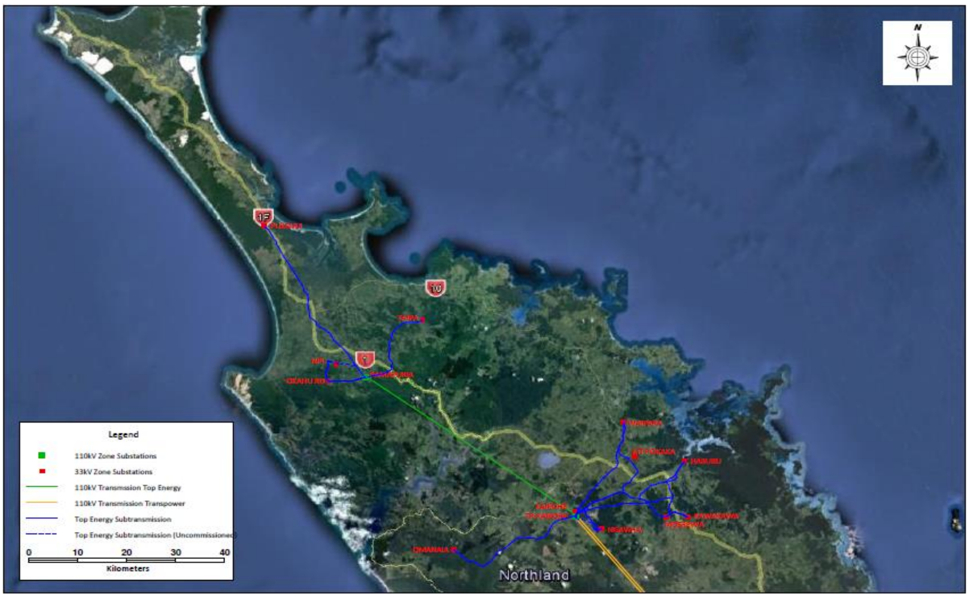
3.1. Business considerations

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 sales 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 generation at Ngawha. 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 10MW 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 now occurring in the Bay of Islands and Kerikeri as well as the East Coast peninsulas. This is where the existing infrastructure is weakest.

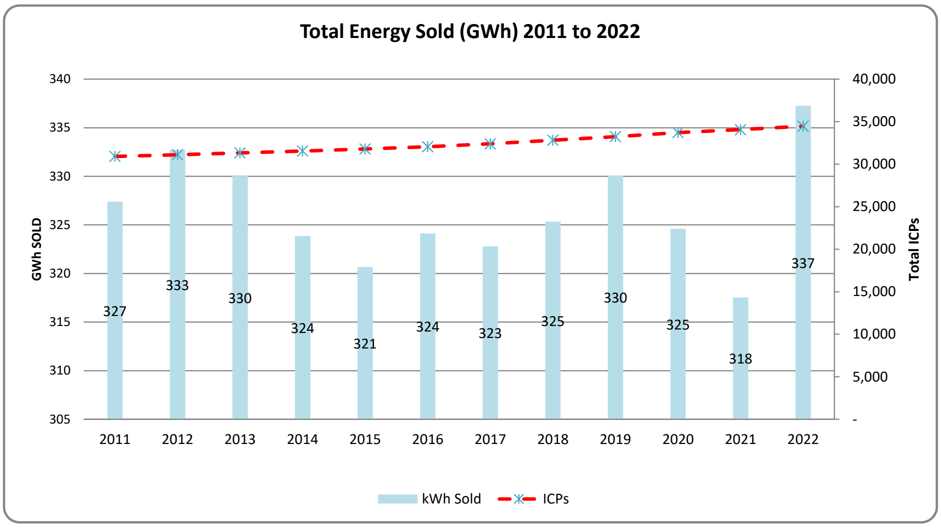
Many existing lines now require extensive rebuilding and refurbishment. Many assets are located in sparsely populated rural areas which remain uneconomic in some circumstances. However, Top Energy is required by legislation to maintain a power supply to consumers that were connected to these lines prior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

3.1.2 Network consumption and peak demand

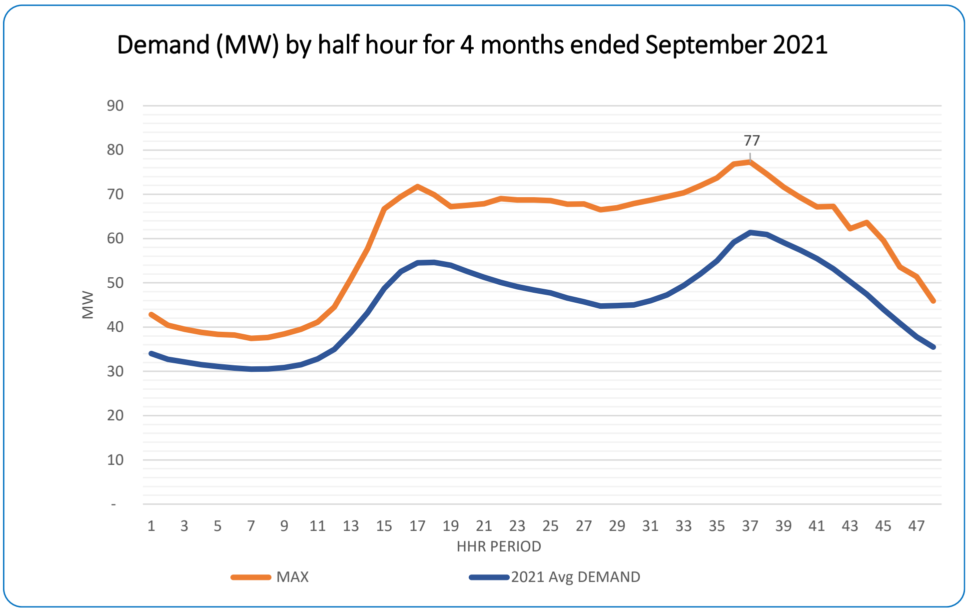
The utilisation of the network is heavily weighted towards small consumers, representing 99% of connections and over 78% of maximum demand. This is evidenced by the fact that average consumption is the one of the lowest in the country at approximately 10,000kWh/consumer. Top Energy's pricing structures 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 last year however it has been relatively stable over the last decade despite a steady increase in connections.

Figure 3: Consumption and peak demand



The key drive for future investment on the network is maximum demand in aggregate and substation level. Maximum demand on the network was approximately 77MW up from 75MW in 2021 due to growth in connections. This is nearly 10% higher than in 2019. Further growth is forecast due to increased general connections and the possibility of additional industrial load from the potential Ngawha Industrial Park.

Figure 4: Demand on Top Energy network by time of day



Although no major capacity constraints exist on the sub-transmission 33kV network, when all network elements are in services, 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. The table below shows current and forecast (5 year) utilisation of the network by substation and implications.

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.	54%	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.	100+%	75%	6.25 MVA Firm (n-1)	Operating over 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.	54%	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	25% 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.
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	50% 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.	40% of Firm	45% of Firm	10 MVA Firm	Future energy needs are anticipated to be within current capacity.

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 managed is required.

Since introducing TOU pricing for Residential and Commercial consumers there has been no material change in customer behaviour as shown in the table below. This is due to a very limited number of customers being charge on price structures which reflect our TOU pricing bands. Furthermore, under 50% of connections are currently able to be charged on TOU rates to retailers due to non HHR meters and exemptions due to retailer system limitations. These results strengthen the requirement for Top Energy to implement price signals now for future peak management. The balance of future price signalling and impact on current customer behaviour will continue to monitor and adjustments made if necessary.

	2021	Estimated pre TOU pricing from data
Peak	19%	20%
Shoulder	56%	54%
Off-peak	24%	26%

The most pressing capacity constraints on the Top Energy network are 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. Future growth in demand on these lines will require additional investment. This can be managed through increasing the capacity, optimisation of existing asset or smoothing demand through price signals.

3.1.3 Technology

Emerging new technologies are beginning to impact upon the traditional electricity industry, 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. Our 5-year pricing strategy has been updated to further reflect this. Network implications and opportunities are currently under investigation.

The network has the second highest penetration of solar in the country at 4.0% of connections (1,343 customers with installed capacity of 7.1MW). This is 23% 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 networks. 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.

Last year Top Energy increased the distribution generation export charge to 0.5c/kWh from nil. 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.

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 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 is working with Transpower and Northpower on potential options to accommodate further generation in Northland with a Renewable Energy Zone.

Electric Vehicles have the potential to change consumption patterns and are also a consideration for network management however penetration is still minimal. There is currently only 1,150 Electric Vehicles registered in Northland which Top Energy is a subset.

3.2. Consumer views

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. This was completed via a telephone survey.

The survey results established that 80% of consumers wished to see network reliability improve. There was overwhelming support from community organisations for the construction of a second 110 kV circuit to secure the electricity supply to the Kaitaia region. 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.

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.

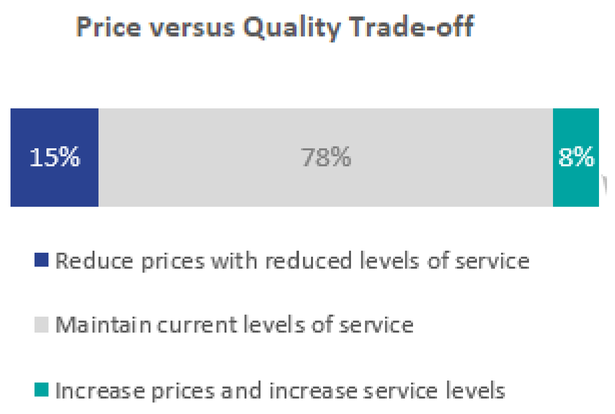
Over the last four years, Top Energy has completed comprehensive annual telephone satisfaction surveys to understand Residential and Commercial customer satisfaction and experience with the services provided. In addition, we have introduced monthly customers surveys which measure customer satisfaction with our faults and new connections divisions.

The key results were:

- Customer satisfaction with faults and new connections divisions has averaged 86% over the last 12 months
- Customers are reasonably open to adopting solar generation however electric vehicle and battery adoption remains low. Solar panels remain the most likely new technology to be adopted in the near future.
- Only 10% of customers said that they changed power companies in the last 12 months although 22% of customers said that they used Powerswitch website to determine the best power company. This is down from 14% last year and reflects a reduction of retailers actively acquiring customers.

The survey also measures the current levels of satisfaction with levels of price and quality. Feedback from the last four 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. This was demonstrated most recently in the 2021 customer survey, with the results shown below.

Figure 5: Price quality trade-off



Source: Key Research customer survey 2021

Surveys will continue to be completed to provide a benchmark of customer satisfaction and preferences over time.

To compliment the telephone surveys, Top Energy has also run focus groups to provide in-depth discussion with customers on their views about the electricity sector and different pricing structures to recover distribution costs. In addition, trials of new products e.g. Residential TOU have been completed. The Residential TOU trial in 2019 enabled us to get an insight into a small subset of customers behaviour on cost reflective pricing. The key findings have been that TOU prices does attract and reward customers with suitable consumptions profiles.The annual surveys and focus groups continue to assist us in our review of our current pricing and future developments.

3.3.Regulatory considerations

Top Energy is subject to regulations which influence our pricing decisions as well provide guidance on how prices should be set. These are summarised in Figure 6. There has been one change this year with the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Amendment Regulations 2021 introduced. This regulation amends the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.

The Commerce Commission determines the lines charge revenue which it considers is sufficient to recovery 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 for consultation (2021), and we have considered the extent to which our pricing methodology aligns with these pricing principles in Appendix 4.7.

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 2021 pricing methodology and pricing roadmap.

Top Energy was placed sixth highest out 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 introduction of the scorecard, Top Energy will continue align our pricing strategy with our pricing objectives e.g. not differentiate between rural and urban customers based on consumer views.

The 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 annually 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 6: 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 30 cents for the 1 April 2022 to end of 31 March 2023 period. Over the next 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.

3.4. 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.

Over September 2021 and November 2021 Top Energy, in conjunction with Northpower, undertook consultations on further cost reflective distribution pricing. The consultation focussed on feedback on the TOU pricing for Residential and General Commercial customers introduced on 1 April 2020, billing of unmetered sites, recover of incremental costs for monitoring and managing distributed generation >1MW and emerging issues and new technology.

Retailers continued to be supportive of the new TOU price structures implemented on 1 April 2020 for Residential and General Commercial customers and open to discuss emerging issues and potential solutions.

Retailers reiterated the need for the TOU pricing to allow for legacy meters, non-communicating advanced meters and retailers who unable to provide data and or bill TOU. Retailers were in favour of our proposal to continue to accommodate these practical issues by offering, on request, a 12-month exemption for non-punitive single default prices for the following:

- legacy meters or non-communicating advanced meters (automatic)
- Specific meter providers due to system constraints or contractual issues
- Billing system limitations or
- other issues considered on a case by case basis.

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 24 retail brands with customers on the Top Energy network, this was down one from last year.

4. Pricing Decisions

4.1. 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:

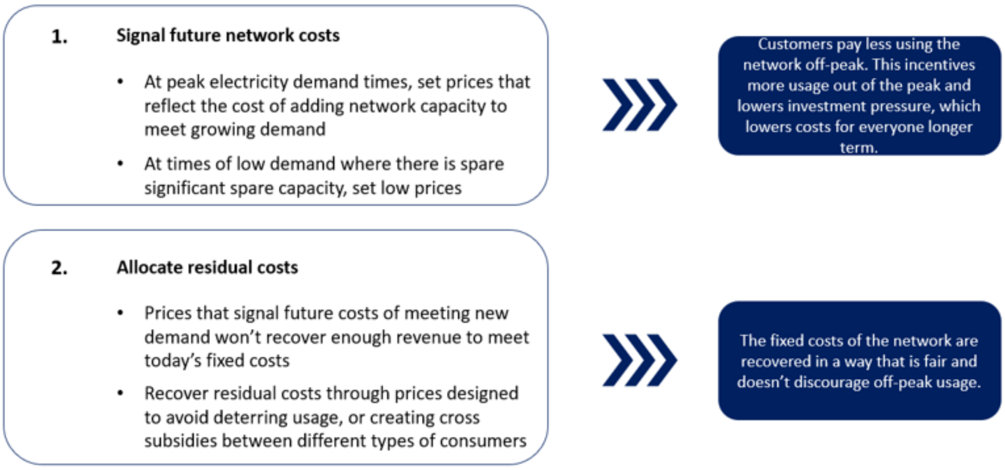
- To allocate costs fairly between consumer groups
- To establish a range of price options that reflect consumer requirements e.g. new Residential and General Commercial TOU pricing
- That prices reflect the potential demand and capacity required by consumers
- To comply with regulatory requirements
- To appropriately recover pass through costs
- To achieve a rate of return acceptable to shareholders.

4.2. Five-year pricing strategy

Top Energy has developed a plan and strategy to continue our transition towards more efficient pricing and continually evolve our pricing structures. 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. A key driver of this is the management of maximum demand which has increased by nearly 10% compared to 2019. Maximum demand, and localised demand is forecast to continue to increase as outlined in our Asset Management Plan with low voltage constraints e.g. street and suburb level, the most immediate risk. The main drivers for growth are expected to be from an increase in connections, adoption of new technologies e.g. electric vehicles and there is a potential for step change growth due to large-scale projects e.g. Ngawha Industrial Park.

Although no major constraints exist currently, these changes in network use are making network pricing increasingly important. This is driving reform across New Zealand toward cost-reflective pricing which will increase utilisation of the network and lower future costs meaning lower line charges. Figure 7 below describes this in more detail.

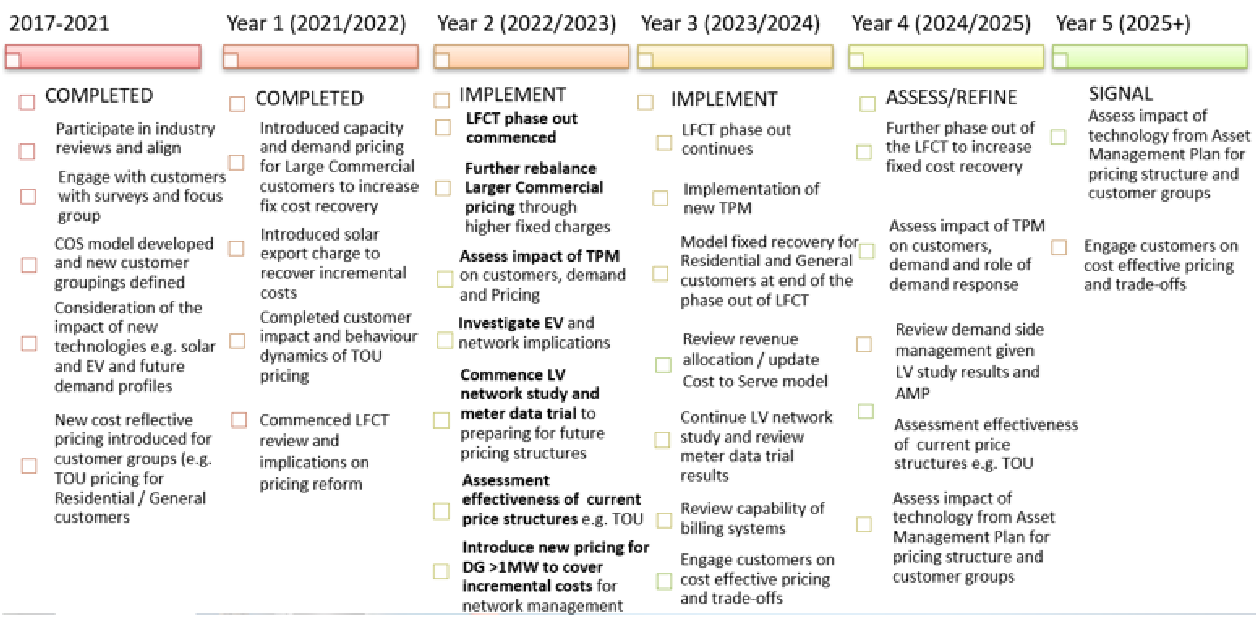
Figure 7: Cost reflective pricing principle



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 has been completed and the strategy and roadmap updated to reflect Top Energy's next steps in pricing reform and transition to efficient pricing.

The five-year pricing strategy outlined continues to see more cost reflective pricing implemented and will position Top Energy to better manage its network and investment in the future. The approach outlined below will also enable Top Energy to manage the impact on customers while adapting the approach, if 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 including ripple control will continue to be used in conjunction with pricing signals.

Figure 8: Top Energy's pricing strategy



A key focus of the strategy in the coming year will be the implementation of two major industry changes:

1. The phase out of the LFCT for Residential customers over 5 years and
2. Implementation of the new Transmission Pricing Methodology

The phase out of the LFCT tariff will commence on 1 April 2022 with the daily charge increasing to 30 c/day. At this point Top Energy intends to increase the daily charge by the maximum allowable under the regulations. However, Top Energy will complete a cost allocation review in 2023/2024 to review revenue allocation target for Residential and Commercial customers. This combined with consumer consultation will inform Top Energy's approach to fixed cost allocation when the legislation ends.

Over the next year Top Energy will determine its pricing approach to implement the new TPM on 1 April 2023. This is subject to it commencing on 1 April 2023 which has not been finalised. This will include the allocation of Transmission costs across customer groups, given the change in approach, and will have consideration for the customer impact. The impact on peak demand will be analysed to see the implications for network congestions and pricing over time.

In parallel, Top Energy is aiming to address data constraints for assessing current network capability to enable further pricing reform. This includes

- Internal low voltage physical study of network to commence in 2023 year to understand capacity and connectivity.
- Negotiate 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.

In addition, Top Energy will continue to phase in cost reflective pricing. This includes

- Continuing to increase the capacity charge introduced last year for large TOU Commercial customers and review whether a demand charge is required given current congestion on the network
- Exploring the implication of distributed generation on the network and associated costs. This includes distribution system operation and voltage flows
- Role of demand management on managing the network and associated pricing implications.

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.

A key issue identified in implementing our price strategy is still the roll out of smart meters to all our customers. In the EA consultation paper "More efficient distribution prices - 11 December 2018" the availability of smart meter data was central to pricing reform. Currently, only 70% of connections have smart meters installed and these are concentration in populated areas. See table below.

Figure 9: HHR Penetration based on Advanced Metering Flag

Density	Advanced Metering penetration (%)
REMOTE	43%
RURAL	67%
URBAN	77%

The availability of smart meters and data issues identified by Retailers, limits our ability to offer new pricing structures and for customers to potentially benefit. This has been addressed by offering a default non-punitive single rate for customers without smart meters and providing Retailers an option to apply for an exemption due to operational issues e.g. non-communicating meters, contractual issues with meter providers. 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.

ROADMAP

Top Energy's future pricing roadmap has been updated to incorporate the changes in the 5-year strategy. The Roadmap shows that significant progress has been achieved, multi year activities which are interlinked and the key timelines.

Figure 10: Top Energy's future pricing roadmap (as of 31 March 2022)

Future Pricing Roadmap EDB : *Top Energy Limited* *31/03/2022*

Key: C Completed; X To be completed

Roadmap Stages	Activities	2017/19	2019/20	2020/21	2021/22	2022/23	23/24	24/25	25+
1. Initiate pricing reform									
Identify objective, update strategy and plan, consult with stakeholders and industry and basic data gathering for analytics		Completed							
2 Develop detailed plans for pricing reform									
Develop detailed plans, including customer consultation, data analysis to assess impacts on customers and transition plans		Completed							
Access to data for analysis including half hour data from Retailers for Analysis			Completed						
Develop trials of new pricing structures including TOU, establish feedback loops through Retailer consultation and educate			Completed						
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)		Completed						
New Mass Market pricing structures	New pricing structures for all mass market customers with retailer exemption for technical reasons			Completed					
Export Distribution Generation charge	Cost to cover incremental costs from distributed generation				Completed				
New pricing for TOU customers	Implementation Demand and Capacity pricing for TOU Commercial customers				Completec	X	X	X	
LFCT phase out	Phase out of the LFCT and increase fixed charge recovery					1-Apr	X	X	X
Distributed Generation management	Incremental charges for monitoring and managing DG where required					1-Apr	X	X	
3b. Observation and adjustment									
Implement transition strategies	Incentivise and manage take-up over time for retailers and customers			C	C	X	X	X	
Adopt risk management approach	Identify and manage risks to markets, customers, EDBs *(eg political and financial risks)*		C	C	C	Continuous			
Review progress and make adjustments	Actively consider progress towards outcomes over time			C	C	Continuous			
Review Pricing Methodology	Review and implement changes to pricing methodology and supporting modelling.					X			
Ongoing customer interactions	Monitor customer responses and manage as required			C	C	Continuous			
4. Enabling future reform									
Understand LV network	Low Voltage study and meter trial to prepare for future pricing reform					X	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					X			
- Network demand	Understand change in network demand and long term impact on AMP and pricing						X	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	X		
Cost / quality trade off	Further engage consumers on cost effective pricing and trade offs						X	X	
5. Future pricing reforms									
Strategic review of pricing	Review of pricing strategy for next 5 years				C		C		
- Analysis, understand and Trial						Continuous			
- implementation, observation, and adjustment.						Continuous			

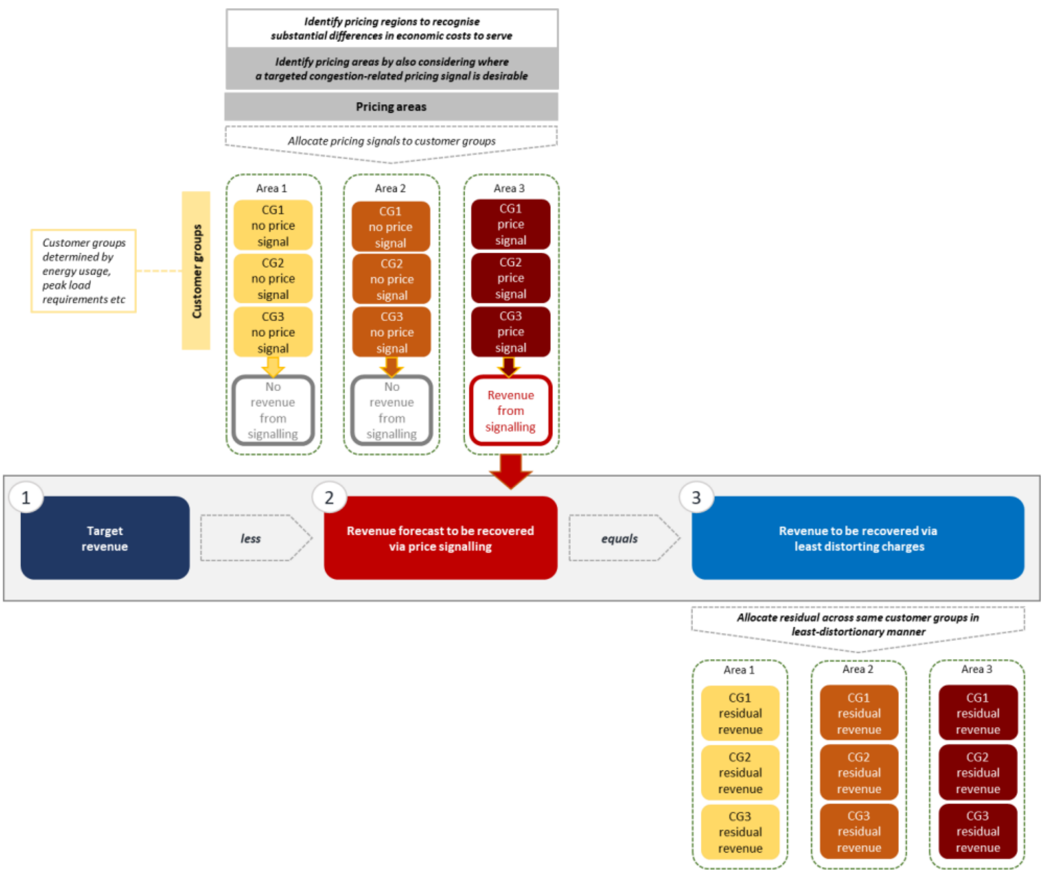
4.3.Pricing review

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.

To better reflect the service we provide and our underlying cost structure (i.e. network capacity) and assist in managing future network capacity constraints outlined in the background section, 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 EA has released for consultation in its Updated Practical Notes (2021). This is outlined below. Since completing our pricing the EA has released final Updated Practical Notes (December 2021).

Figure 11: Electricity Authority Practical note diagram



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
- Consideration of the options outlined in the ENAs 2017 paper "A Guideline Paper for Electricity Distributors on new pricing options" which covered five network pricing types that either on their own or in combination that could be used to meet the pricing objectives
- 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

There are four key pricing focuses this year:

Strategic driver	Explanation	Actions
LFCT regulations phase out	Increase fixed charge recovery to be more cost reflective.	Increase Residential daily charge to 30c/day.
Recover incremental costs from Distributed Generation greater than 1MW)	Applications for large scale solar have reached capacity in some areas of the network. Once build this will require active monitoring and system operation. An allocation of Transpower connections charges will also be included.	Introduce a fixed daily charge to recover Distribution System Operator incremental costs and Transpower connection charges once they occur.

Increase fixed charge recovery to be more cost reflective	Continuation of our move to cost reflective pricing by increasing fixed proportion of consumers charges.	Reduction in prices achieved through reducing variable charges. Increase kVA Capacity charges for large TOU Commercial customers.
Introduction of new pricing for Ngawha Innovation Park	Top Energy has agreed to provide Ngawha Industrial Park connections individual pricing for a limited time.	New pricing introduced for Ngawha Industrial Park customers. Note there are no connections at present.

Pricing signals (Mass Market TOU)

TOU Pricing signals are design to recover costs that are or will be incurred if customers place more demand on the system. For the Top Energy network these include:

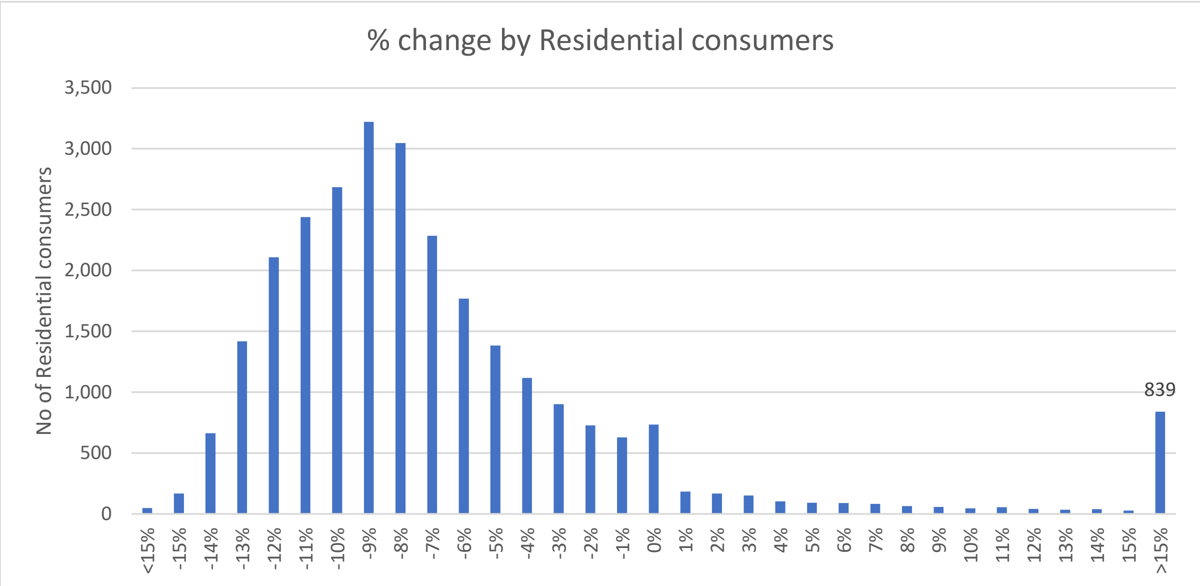
Cost	Approach
Interconnection Transmission costs	Interconnection charges are fully variable and so will be passed through to Industrial customers based on their RCPD, and other customers as part of their peak variable charges. These charges are based on the contribution of demand of consumer groups in 100 half hour periods which are used by Transpower to set RCPD. For our mass market customers our "peak" time (Under our Time of Use Pricing structure) usually covers 90% of the RCPD 100 half hour periods. As such, we aim to recover mass market's share of the interconnection and ACOT charges from their consumption during peak periods.
Avoided Costs of Transmission (ACOT)	ACOT is paid to one generator based on their injection into Top Energy's network as at RCPD peaks and is fully variable and is allocated the same as Interconnection Transmission costs
Transmission Connection costs	Connection charges are fixed, but if demand rises above current capacity, then upgrades could be required. However, based on Asset Management Plan and Distributed Generation Applications this will not occur, so no price signal is required.
EA levies	These are fully variable however are not material
Growth asset capital costs	Additional demand growth can drive the new asset investment to increase the capacity of areas of the network. Note industrial customers will be charged incremental costs directly.

In the long run our aim is for the pricing bands to reflect the underlying economic costs of using the network. An initial analysis shows that a differential of up to 15 c/ KWh between Peak and Off-peak would send an appropriate signal to consumers currently. A transitional approach has been taken to setting Residential and General Commercial TOU pricing to manage the impact on customers, current level of congestion, and the potential change in the Transmission Pricing Methodology which could reduce price signals through the removal of the Regional Coincidental Peak Demand (RCPD) variable charge. In addition with only 50% of connections migrated to TOU pricing a key focus is working with retailers to migrate the remaining eligible customers.

Consumer impact

The impact of the change in the LFCT daily charge to 30 c/day combined with the overall price decrease for Residential consumers is shown below. Overall, only ~2,250 consumers are expected to get an increase in line charges per year to $109.50 per year. The number of customers getting an increase has been reduced due to the overall reduction in prices.

Figure 12: Price change % for residential customers



5. 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: 2022-23 Breakdown of Target

COMPONENTS OF TARGETED REVENUE			
	(1 April 2020 to 31 March 2023)	(1 April 2020 to 31 March 2022)	% change
Transpower Charges	1,682,738	4,828,652	-65.2%
Avoided Cost of Transmission (ACOT)	2,392,836	2,409,885	-0.7%
Pass-through Costs	349,677	269,241	29.9%
Other recoverable Costs	- 617,485	366,754	-268.4%
Pass Through subtotal	**3,807,765**	**7,874,532**	-51.6%
Network Maintenance Costs	6,324,000	6,299,000	0.4%
Overheads	12,786,000	11,230,000	13.9%
Depreciation	10,000,000	8,719,000	14.7%
Pre tax ROI charge	16,701,000	16,302,000	2.4%
Distribution subtotal	**45,811,000**	**42,550,000**	7.7%
Annual Revenue Requirement	**49,618,765**	**50,424,532**	-1.6%
DPP Compliance Adjustment	- 7,467,650	- 4,072,381	83.4%
TOTAL TARGET REVENUE*	**42,151,116**	**46,352,151**	-9.1%

The total Target Revenue has decreased by $4.2m (9.1%). This is driven by the increase in Top Energy's net allowable forecast revenue under the new 2020 Default Price Path (DPP) Determination of $0.785m which was offset by a decrease in Pass through costs of $4.07m mainly due to the $3.15m reduction in Transpower charges, a reduction in IRIS washups of $0.67m and reduction in Quality incentive adjustment of $0.3m.

5.1. 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 2022-23 is $42.15m complying with the default price path (DPP) and based on consumption and connections forecasts. The methodology for forecasting consumption and connections is outlined in Top Energy Annual Price-Setting Compliance Statement – 2023 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 $7.12m for the year, representing 14% of target revenue before the discount.

Under the 2020 DPP Determination, Top Energy was required to decrease revenue by 17.4% in the 2020-2021 year and then increase prices by CPI in the four subsequent pricing years. In addition, Top Energy is allowed to recover pass-through and recoverable costs including transmission charges, Avoided Transmission, Avoided Distribution, rates and levies. For the 2022–2023-year, revenue has decreased by 9.1% ($4.2m). This includes a decrease in pass through and recover costs of $4.1m, an increase in Forecast allowable revenue of $0.785m and a decrease of $1m due to washups. 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).

5.2.Transpower charges

Top Energy passes through all transmission charges at cost in accordance with the DPP and its own pricing principles. The transmission charge is equitably distributed across all customers. Transmission charges include:

- Connection Charges – Transpower charges for use of Kaikohe GXP connection assets to which Top Energy's network connects to the national grid
- Interconnection Charges – Transpower charges for use of core grid assets based on Top Energy's share of Regional Coincident Peak Demand (RCPD) in Transpower's Upper North Island demand measurement region
- New investment charges – Transpower contractual charges for grid connection capacity and security upgrades determined by agreement between Transpower and Top Energy.

5.3.Avoided Transmission – Distributed generation

Avoided transmission and voltage support charges may be payable to embedded generators of greater than 1MW output when suitable terms have been negotiated with Top Energy. Avoided interconnection charges are paid in recognition of a generator's contribution to reducing Top Energy's share of Transpower RCPD peaks.

5.4.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.

5.5.Other Pass-through costs

This includes rates and regulatory levies.

5.6. Other recoverable costs

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

5.7.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.

5.8. 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.

5.9. Depreciation

Depreciation represents the return of Top Energy's asset investment and is estimated using 2020 Regulatory Asset Base (RAB) roll-forward.

5.10. 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.

6. 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. Consumers' peak usage of existing network capacity is therefore a key driver of future costs. For instance, the network potentially faces 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. Recently, as part of our Cost to Serve model update, we 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. For similar reasons, we have decided not to distinguish between the Eastern, Western and Northern networks.

Therefore, while circuit length is a relevant cost driver, 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. 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.

Pricing distinctions could also be made based on network regions (discussed above), use of the high voltage network only, and use of dedicated transformers. However, our review of pricing suggests there is little benefit for Top Energy in disaggregating prices to reflect these costs.

6.2. Consumer Groupings

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

The number of Consumer Groups has been set at four 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 14: Consumer Groups

Consumer Group	Criteria	Rationale	Pricing and commercial terms
Larger	Large Commercial and Industrial loads consuming >275,000kWh per annum, with a fuse capacity of 110kVa or greater	Pricing incentivises the efficient use of network capacity by large loads through variable charges levied on peak, shoulder and off-peak time of use periods for Large Commercial and capacity charge based on kVA installed.	Standard
		Industrial loads are distinguished by much larger load size, time of use metering and Transpower and Top Energy's distribution costs can be identified for each consumer.	Non-Standard
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
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. Summary of pricing options

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

Figure 15: Pricing Options

Price Code	Description and rationale	MWh	ICPs
Industrial **(IND)**	Fixed price recovery of costs associated with industrial loads consuming >3,000,000kWh per annum and a fuse capacity of 110kVa or greater.	45,450	3
Large Generation **(LDG)**	Fixed price recovery of costs associated with the connection of large-scale distributed generation into the distribution network.		4
Micro Generation **(DG)**	Variable price recovery of costs associated with the connection of small-scale distributed generation into the distribution network. This is set at 0.5c/kWh	3,782	
General Advanced Metering **(TOU) and (GA)**	TOU is the default code for all customers with 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	46,332	106
Residential	Residential ICP's can have the following metering configurations: Uncontrolled, All inclusive, Day/Night (Closed) and Controlled.	157,646	28,013

Meter configuration	Total usage (MWh)
Uncontrolled	31,989
All Inclusive	122,100
Day (Closed)	2,314
Night (Closed)	918
Controlled	325
Total	157,646

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. In addition, Retailers can apply for an exemption to TOU pricing. 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. In addition, Retailers can apply for an exemption to TOU pricing. 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.

Day/Night (D16, N8): This plan includes a fixed price for each day connected and two variable consumption prices during a day (7am to 11pm) and night period (11pm-7am). This tariff is closed to new customers from 31 March 2020.

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.

General	General ICP's can have the following metering configurations: Uncontrolled, All inclusive, Day/Night (Closed) and Controlled **Meter configuration** / **Total usage (MWh)**: Uncontrolled: 60,214 All Inclusive: 9,834 Day: 7,615 Night: 3,627 Controlled: 2910 Total: 84,199 See above for definitions.	84199	5,480
UM	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.	1,000	2,564

Meter configuration	Total usage (MWh)
Uncontrolled	60,214
All Inclusive	9,834
Day	7,615
Night	3,627
Controlled	2910
Total	84,199

6.4. 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 Connection charges
- Transpower Interconnection Charges
- Avoided transmission charges payable to embedded generators
- 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)
- Coincident peak demand (i.e. to directly allocate Transpower charges)

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 may introduce non-standard pricing for specific regional development initiatives e.g. Energy park

6.5. 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

6.6. Residential/General

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

- a 30 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 $1.35 per day is applied to all Residential consumers who do not meet the low user criteria
- A $1.50 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.

6.7. Unmetered

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

6.8. 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 large scale generators (greater than 1MW). For large scale generators 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.

Avoided Cost of Transmission (ACOT) payments can no longer be paid to new generation connected to Top Energy's network. This reflects recent changes to the distribution generation regulations under Part 6 of the Electricity Industry Participation Code (the Code). New distributed generation customers will have to directly approach and contract with Transpower to receive ACOT payments. Top Energy will continue to pay existing ACOT arrangements for distributed generation connected to the network on 6 December 2016 and which are on the Electricity Authority's published list of eligible Upper North Island distributed generation.

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 will be 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.

Avoided interconnection charges may be paid to generators that are connected to the Top Energy's network and which have actively contributed to reducing Top Energy's contribution to RCPD peaks, used to set Transpower's interconnection charges. Avoided transmission and voltage support charges are calculated based on the notified Transpower charges for the applicable pricing period. This requires appropriate metering facilities at each site, so that the contribution to RCPD or voltage support charge reductions can be verified.

Other distributed generation

Top Energy considers that other distributed generation customers (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.

6.9. Discounts

The discount will continue to be posted and is based on consumption from 1 April 2022 to 31 March 2023 which covers the entire assessment period. Discounts calculated on this basis represent approximately $7.12m and will be processed through the retailers to be applied to consumer invoices after the 31 March 2023.

6.10. 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. Standard charges and requirements apply to typical connection configurations.

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

7. Calculation of Prices

Tariffs are calculated by allocating costs to consumer groups and prices, based on assumed splits between fixed and variable tariffs. Figure 16 summarises the allocators used to allocate target revenue and the rationale for these decisions.

Figure 16: Summary of cost allocators used to set prices

Cost Category	Allocator used	Rationale
Transmission costs	*Interconnection charges and ACOT - DG:* Coincident share of RCPD (kW) for industrial consumers and Anytime Maximum Demand (AMD) for other connections	Allocation of interconnection charges aligns with Transpower's use of RCPD to apportion charges at a national level.
	Connection charges and ACOT - Transmission: Share of AMD	Connection charges represent investment in GXP capacity. AMD broadly represents usage of this capacity.

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 17: Cost allocation results

				Pass through $000s	Distribution $'000's					Revenue		
Consumer Group	Regulatory Asset Base 2022($m)	Number of ICPs	Energy Consumption and export Forecast 2023 (GWh)	Transmission, Other Pass-through and Recoverable Costs 2023	Network Costs (Maintenance)	Non-Network Costs (Overheads)	Depreciation	Posted Discount	Pre tax WACC	Annual Revenue Requirement	DPP compliance Adjustment	Total 2023 Target Revenue
IND	9,683	3	45.5	300	208	423	330	(26)	578	1,813	(498)	1,315
GG,GU,GC	55,520	5,480	84.2	863	1,194	2,423	1,895	(1,139)	4,304	9,539	3,580	13,119
GA	4,245	45	7.2	141	91	185	145	(28)	270	805	(3)	802
TOU	9,006	61	39.1	472	194	393	307	(104)	618	1,880	723	2,603
LDG	1,999	4	-	0	43	87	68	-	114	312	465	777
DG			3.8		22				-	22	(3)	19
Unmetered'	520	264	1.0	-	11	23	18	-	30	81	313	394
Total Commercial									-		-	-
LR	104,167	17,344	79.7	1,001	2,240	4,546	3,555	(3,607)	9,545	17,279	(6,194)	11,085
SR	107,861	10,668	77.9	1,031	2,320	4,707	3,681	(2,218)	8,366	17,887	(5,849)	12,037
Total Residential												
Total	**293,000**	**33,869**	**338.4**	**3,808**	**6,324**	**12,786**	**10,000**	**(7,123)**	**23,824**	**49,619**	**(7,468)**	**42,151**

Appendix 5 summarises the resulting prices for 2022-2023 which are also located on the Top Energy website;

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

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, Euan Richard Krogh and David Alexander Sullivan, 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.

____________________ ____________________

E R Krogh D A Sullivan

28 March 2022

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.
RPDP	Regional Peak Demand Period, relates to an Upper North Island defined by Transpower where Top Energy is located. The half hour in which any of the 100 highest regional demands occurs during the capacity measurement period for the relevant pricing year.
RCPD	Regional Coincident Peak Demand, relates to the customer's offtake at the connection location during a regional peak demand period.
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).
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 2022.
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 have increased by a decreased by 9% when comparing 2022 and 2023 pricing schedules. See section 2.3 Changes in target revenues are described in Section 5.
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 6.4 and 6.8
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 2020 and 2021 (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 2022.
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 5.
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 5.

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 6.2.
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 4.2
2.4.4(2)	Explain how and why prices for each consumer group are expected to change as a result	See section 4.2
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 6.4 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 6.4

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 6.8
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

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	We interpret 'avoidable cost' as 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. Over the last ten years a new connection has contributed approximately $300 per annum (real) to operating expenditure. An uncontrolled consumer (UN) would need to consume less than **1,000kWh** in a year for prices to fall below this incremental cost (i.e. based on the 30 cents per day fixed charge and existing UN prices). This highlights that the application of the 30 cents per day low fixed charge creates cross-subsidisation at very low levels of consumption. Top Energy considers 'stand alone 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. For example, a 7kW solar system, 15kW battery system with diesel generator can cost more than $40,000 to install. We estimate this would cost $0.70/kWh over a 15-year period and the installation is funded by a mortgage. This is significantly more expensive than the average 42.97c/kWh charge Top Energy's consumers pay (source: MBIE quarterly survey of electricity prices, 15 November 2021). Nevertheless, the cost of installing these systems is falling rapidly and Top Energy will continue to keep a watch on this market and respond appropriately through pricing.
(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 directly based on their contribution to RCPD • 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 \$1.35/day and \$1.50/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 \$0.30/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: (i) reflect the economic value of services and; (ii) enable price/quality trade-offs	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).
(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.

Appendix 5 - Network Line Charges 2022 – 2023

TOP ENERGY
Te Puna Hihiko

2022/23 Electricity Price Schedule

Effective from 1 April 2022. All prices exclude GST

KEY CHANGES

Overall, Top Energy lines charges are dropping by 9%. The key driver is a decrease in charges from Transpower due to the investment in the new Ngāwhā Geothermal plant by Top Energy.

The Low User daily rate is increasing to 30c, in accordance with the recent changes in the Electricity (Low fixed charge option) Amended Regulations 2021.

Your Top Energy Lines Discount of up to $250 will be paid to consumers each May. You are eligible if you were connected to the Top Energy network on 31 March, and you have used more than 1 kilowatt hour of power between 1 April and 31 March each year.

		Current from 1 April 2022							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 ($/kWh)	Maximum combined kWh's eligible for Discount per ICP	Daily Price ($/day) from 1.4.2021	Total ($/kWh) from 1.4.2021	Distribution 12 month Discount Component	Maximum Combined Eligible Discount kWh
												RESIDENTIAL
Low User Non-TOU (LR) for customers using less than 8,000kWh per year : 8,427 users (excludes holiday homes, ancillary buildings and meters)												
LRF	Fixed price	0.3000		0.1373		0.1627			0.1500		0.1373	
LUC	Uncontrolled (no load controlling applied)		0.1893		0.1481		0.0412			0.2288	0.1481	
LA	All inclusive (3kW loading)		0.1482		0.1481		0.0001	1,130		0.1817	0.1481	1,130
LD	Day (7am - 11pm)		0.1953		0.1481		0.0472			0.2228	0.1481	
LN	Night (11pm - 7am)		0.0906		-		0.0906	-		0.0996		-
LFC	Controlled 20 (10kW loading)		0.0744		-		0.0744	-		0.0887		-
DG	Exported Micro generation		0.0050		-		0.0050	-		0.0050		-
Low User Time of Use Uncontrolled (LU) for customers who have no load controlling applied to their line : 1,738 users												
LUF	Daily Price on Half Hourly Read Uncontrolled	0.3000		0.1373		0.1627			0.1500		0.1373	
LU1	Peak (7am - 9.30am & 5.30pm - 8pm, excluding weekends and public holidays)		0.2510		0.1481		0.1029			0.3008	0.1481	
LU2	Shoulder (9.30am - 5.30pm & 8pm - 10pm or 7am - 10pm, weekends and public holidays)		0.1797		0.1481		0.0316	1,130		0.2199	0.1481	1,130
LU3	Off Peak (10pm - 7am)		0.1707		0.1481		0.0226			0.1963	0.1481	
LFC	Controlled 20 (10kW loading)		0.0744		-		0.0744	-		0.0887	-	-
DG	Exported Micro generation		0.0050		-		0.0050	-		0.0050	-	-
Low User Time of Use All inclusive (LC) for customers who do have load controlling applied to their line : 7,179 users												
LCF	Daily Price on Half Hourly Read Controlled (3kW loading)	0.3000		0.1373		0.1627			0.1500		0.1373	
LC1	Peak (7am - 9.30am & 5.30pm - 8pm excluding weekends and public holidays)		0.1873		0.1481		0.0392			0.2419	0.1481	
LC2	Shoulder (9.30am - 5.30pm & 8pm - 10pm or 7am - 10pm weekends and public holidays)		0.1553		0.1481		0.0072	1,130		0.1647	0.1481	1,130
LC3	Off Peak (10pm - 7am)		0.1483		0.1481		0.0002			0.1528	0.1481	
LFC	Controlled 20 (10kW loading)		0.0744		-		0.0744	-		0.0887		-
DG	Exported Micro Generation		0.0050		-		0.0050	-		0.0050		-
Standard User (SR) for customers using more than 8,000kWh per year : 5,512 users												
SRF	Daily Price	1.3500		0.3402		1.0098			1.350		0.3402	
SUC	Uncontrolled (no load controlling applied)		0.1419		0.0825		0.0594			0.1745	0.0825	
SA	All inclusive (3kW loading)		0.1013		0.0825		0.0188	1,130		0.1272	0.0825	1,130
SD	Day (7am - 11pm)		0.1360		0.0825		0.0535			0.1542	0.0825	
SN	Night (11pm - 7am)		0.0797		-		0.0797	-		0.0879	-	-
SFC	Controlled 20 (10kW loading)		0.0554		-		0.0554	-		0.0674	-	-
DG	Exported Micro Generation		0.0050		-		0.0050	-		0.0050	-	-
Standard User Time of Use Uncontrolled (SU) for customers who have no load controlling applied to their line : 1,656 users												
SUF	SUF Daily Price on Half Hourly Read Uncontrolled	1.3500		0.3402		1.0098			1.350		0.3402	
SU1	Peak (7am - 9.30am & 5.30pm - 8pm excluding weekends and public holidays)		0.2007		0.0825		0.1182			0.2455	0.0825	
SU2	Shoulder (9.30am - 5.30pm & 8pm - 10pm or 7am - 10pm weekends and public holidays)		0.1374		0.0825		0.0549	1,130		0.1682	0.0825	1,130
SU3	Off Peak (10pm - 7am)		0.1217		0.0825		0.0392			0.1424	0.0825	
SFC	Controlled 20 (10kW loading)		0.0554				0.0554	-		0.0674	-	-
DG	Exported Micro Generation		0.0050				0.0050	-		0.0050		-
Standard User Time of Use All inclusive (SC) for customers who do have load controlling applied to their lines : 3,500 Users												
SCF	SCF Daily Price on Half Hourly Read Controlled (3kW loading)	1.3500		0.3402		1.0098			1.350		0.3402	
SC1	Peak (7am - 9.30am & 5.30pm - 8pm excluding weekends and public holidays)		0.1658		0.0825		0.0833			0.1800	0.0825	
SC2	Shoulder (9.30am - 5.30pm & 8pm - 10pm or 7am - 10pm weekends and public holidays)		0.1048		0.0825		0.0223	1,130		0.1178	0.0825	1,130
SC3	Off Peak (10pm - 7am)		0.0864		0.0825		0.0039			0.0878	0.0825	
SFC	Controlled 20 (10kw loading)		0.0554		-		0.0554	-		0.0674	-	-
DG	Exported Micro Generation		0.0050		-		0.0050	-		0.0050	-	-
POSTED DISTRIBUTION DISCOUNT NOTES												
	The Discount will only be provided to ICP's connected on 31 March 2023 (eligibility date) with an active customer and have used more than 1kWh during the 12 month period ending 31 March 2023.											
	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 2023 and 31 May 2023.											

COMMERCIAL PRICING

		Current from 1 April 2022							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 ($/kWh)	Maximum combined kWh's eligible for Discount per ICP	Daily Price ($/day) from 1.4.2021	Total ($/kWh) from 1.4.2021	Distribution 12 month Discount Component	Maximum Combined Eligible Discount kWh
				For payment timing and eligibility, see previous page notes								
General User (GG) for businesses that use less than 45,000 kWh per year, and builder connections : 3,816 Users												
GGF	Daily Price	1.5000		0.3402		1.1598			1.5000		0.3402	
GGUC	Uncontrolled (no load controlling applied)		0.1455		0.0825		0.0630			0.1680	0.0825	
GGA	All inclusive (3kW loading)		0.1066		0.0825		0.0241	1,130		0.1224	0.0825	1,130
GGD	Day (7am-11pm)		0.1321		0.0825		0.0496			0.1476	0.0825	
GGN	Night (11pm-7am)		0.0740		-		0.0740	-		0.0787		-
GGFC	Controlled 20 (10kW loading)		0.0569		-		0.0569	-		0.0649		-
DG	Exported Micro generation		0.0050		-		0.0050	-		0.0050		-
General User Time of Use Uncontrolled (GU) : 1,314 users												
GUF	Daily Price on Half Hourly Read Uncontrolled	1.5000		0.3402		1.1598			1.5000		0.3402	
GU1	Peak (7am-9.30am & 5.30pm-8pm, excluding weekends and public holidays)		0.2016		0.0825		0.1191			0.2263	0.0825	
GU2	Shoulder (9.30am-5.30pm & 8pm-10pm or 7am-10pm, weekends and public holidays)		0.1397		0.0825		0.0572	1,130		0.1574	0.0825	1,130
GU3	Off Peak (10pm-7am)		0.1230		0.0825		0.0405			0.1308	0.0825	
GGFC	Controlled 20 (10kW loading)		0.0569		-		0.0569	-		0.0649	-	-
DG	Exported Micro generation		0.0050		-		0.0050	-		0.0050	-	-
General User Time of Use All Inclusive (GC) : 350 users												
GCF	Daily Price on Half Hourly Read Controlled (3kW loading)	1.5000		0.3402		1.1598			1.5000		0.3402	
GC1	Peak (7am-9.30am & 5.30pm-8pm excluding weekends and public holidays)		0.1582		0.0825		0.0757			0.1761	0.0825	
GC2	Shoulder (9.30am-5.30pm & 8pm-10pm or 7am-10pm weekends and public holidays)		0.1000		0.0825		0.0175	1,130		0.1161	0.0825	1,130
GC3	Off Peak (10pm-7am)		0.0826		0.0825		0.0001			0.0881	0.0825	
GGFC	Controlled 20 (10kW loading)		0.0569		-		0.0569	-		0.0649		-
DG	Exported Micro Generation		0.0050		-		0.0050	-		0.0050		-
General Advanced User (GA) for businesses that use 45,000 to 275,000kWh per year : 45 users												
GAF	Daily Price on Half Hourly Read	9.1462		0.5500		8.5962			9.1462		0.5500	
G1	Peak (7am-9.30am & 5.30pm-8pm)		0.1445		0.0038		0.1407	1,092,500		0.1662	0.0038	1,092,500
G2	Shoulder (9.30am-5.30pm & 8pm-10pm)		0.0983		0.0038		0.0945			0.1129	0.0038	
G3	Off Peak (10pm-7am)		0.0550		-		0.0550	-		0.0592	-	-
DG	Exported Micro Generation		0.0050		-		0.0050	-		0.0050	-	-
Larger User Time of Use (TOU) for business that use over 275,000 kWh per year : 68 users												
TOUF	Daily Price	26.3220		0.5500		25.7720			26.3220		0.5500	
TOUDVD	Daily Distrubtion Demand Price	-				-			-			
TOULVFD	Daily Distribution LV Capacity price $/day/kVA	0.0500				0.0500			0.0200			
TOU1	Peak (7am-9.30am & 5.30pm-8pm)		0.0738		0.0038		0.0700	1,092,500		0.1222	0.0038	1,092,500
TOU2	Shoulder (9.30am-5.30pm & 8pm-10pm)		0.0502		0.0038		0.0464			0.0832	0.0038	
TOU3	Off Peak (10pm-7am)		0.0092			-	0.0092			0.0100		
DG	Exported Micro Generation < 1MW		0.0050				0.0050			0.0050		
TOUTXF	Fixed Price	26.3220		0.5500		25.7720			26.3220		0.5500	
TOUTXD	Daily Distribution Demand Price					-						
TOUTXT	Daily Distribution LV Capacity price $/day/kVA	0.0500				0.0500			0.0200			
TOUTX1	Peak (7am-9.30am & 5.30pm-8pm)		0.0738		0.0038		0.0700	1,092,500		0.1222	0.0038	1,092,500
TOUTX2	Shoulder (9.30am-5.30pm & 8pm-10pm)		0.0502		0.0038		0.0464			0.0832	0.0038	
TOUTX3	Off Peak (10pm-7am)		0.0092				0.0092			0.0100		
DG	Exported Micro Generation < 1MW		0.0050				0.0050			0.0050		

UNMETERED PRICING: Fixed charges only. No variable charge.

Price Code	Description	NEW 1 April 2022 Daily Price $/day	OLD Total ($/kWh) from 1.4.2021 to 31.3.2022
Unmetered supply - Closed for New Connections 01.04.16 : 73 Users			
UMINT	Intermittent supply consisting of Fire Sirens, Railway Crossing Lights, Traffic Counters	0.2400	0.2400
UMGL	Intermittent supply consisting of Community Lighting, Convenience Lighting, Jetty Lights, Under Verandha Lighting	0.1500	0.1500
Unmetered supply - For New Connections after 01.04.16 : 2,427 Users			
UMLF	Streetlights (STL)	0.4400	0.4400
UML	Streetlights (STL)	-	-
UMGF	General Connection (UM)	0.4400	0.4400
UMG	General Connection (UM)	-	-
NIL	Tsunami Warning Alarms	-	-

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