Northpower

Pricing Methodology

1 April 2024 – 31 March 2025

1 Introduction

Northpower owns and operates the electricity distribution network covering the Whangārei and Kaipara regions, delivering electricity to more than 62,500 homes and businesses. The network covers a large geographic area from Pouto in the south to Bland Bay in the north, and includes key population centres of Whangārei and Dargaville, and growth areas of Mangawhai and One Tree Point.

As a supplier of an essential service and as a consumer owned network, we seek to set fair and reasonable prices for consumers that have shared access to our network. This document outlines the pricing methodology Northpower uses to determine its prices.

This document applies to the pricing of all electricity lines services regulated under Part 4 of the Commerce Act 1986.

2 Our Distribution Network

Northpower connects to the national grid at three grid exit points (GXPs) which are located at Maungatapere (MPE), Bream Bay (BRB), and Maungaturoto (MTO):

- The Maungatapere GXP services the majority of our network. Connecting customers from Bland Bay in the north to Pouto in the south, it connects Whangārei and Dargaville, as well as Golden Bay Cement, the Marusumi chip mill, and Fonterra's Kauri dairy factory.
- The Bream Bay GXP services the One Tree Point, Ruakākā, and Waipu areas, including Channel Infrastructure's fuel storage and pipeline facility, and Carter Holt Harvey's LVL plant.
- The Maungaturoto GXP services the lower Kaipara region, from Ruawai across to Mangawhai, and including Fonterra's Maungaturoto dairy factory.
- There are currently two large embedded generators on the network. Northpower's Wairua hydro power station is connected via MPE, and Manawa Energy's diesel generators connect via BRB.

Key statistics are outlined below:

Load (anytime maximum demand) by consumer group and GXP

GXP	Mass market load (MW)	Large industrial load (MW)	Total load (MW)
Maungatapere	97.8	18.8	116.6
Bream Bay	12.1	6.9	19.0
Maungaturoto	18.9	3.2	22.1
Total	**128.8**	**29.0**	**157.7**

Customer type by GXP

Map of the Northpower network

GXP	Total consumers	Urban %	Residential %
Maungatapere	45,231	57%	84%
Bream Bay	5,964	53%	84%
Maungaturoto	11,179	22%	81%
Total	**62,374**	**51%**	**84%**

We are wholly owned by the Northpower Electric Power Trust, which is a consumer trust. As such, we are effectively owned by our consumers.

3 Regulatory Context

3.1 Commerce Act

The Commerce Commission (**the Commission**) regulates electricity distribution services under the Commerce Act 1986 (**the Act**). Under the Act, Northpower is subject to information disclosure regulation, which is where we must complete annual disclosure of information relating to our business and performance as set out in the Electricity Distribution Information Disclosure Determination 2012.

Northpower is not subject to price-quality regulation, as it meets the definition of an exempt consumer owned Electricity Distribution Business (EDB). However, we still use the Commerce Commission's building block model (BBM) to determine our target revenue, and to benchmark our returns as if we were subject to price-quality regulation.

3.2 Low Fixed Charge Regulations

We must comply with the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (**the Low Fixed Charge Regulations**). These regulations require us to offer residential consumers a price option at their principal place of residence, with a fixed price of no more than 60c per day (excluding GST), and where the sum of the annual fixed and volumetric charges on that price option equals any other price option available to those consumers when they use 8,000kWh per annum.

The Low Fixed Charge Regulations are now being phased out. Originally capped at 15c a day, the cap will increase by 15c a day each year for 5 years, and when it reaches 90c a day it will be removed altogether. This reflects that most network costs are fixed, and with 84% of ICPs on our network being residential, it was not possible to implement cost-reflective pricing with the Low Fixed Charge Regulations in place.

3.3 Electricity Authority pricing principles

We are also guided by the Electricity Authority's pricing principles, its 2022 Practice Note (Second Edition v2.2, its 2019 Practice Note, and its October 2022 guidance on transmission charge pass through (https://www.ea.govt.nz/documents/299/Distribution_pricing_practice_note.pdf). While compliance with the pricing principles is voluntary, the Disclosure Determination requires us to either demonstrate consistency with the principles or explain the rationale for any inconsistency.

In addition, the Electricity Code has specific pricing principles in Part 6 which limit us to recovering only our incremental costs from distributed generation customers. These specific principles are legally binding, and effectively limit us to recovering only the additional costs resulting from distributed generation.

4 Industry Context

Electricity networks are like roads in that they can become congested at peak times of the day. Cost-reflective pricing uses price signals to demonstrate when there is capacity in our network (through lower prices), and when the network is more congested (through higher prices).

Unlike traffic on roads, electricity cannot sit in a queue and wait its turn. If there is more demand for electricity at peak times than the network can handle, the network will trip and there will be a power outage. As such, if we get close to the capacity of the network (and cannot reduce that demand through a price signal or other means) we have to upgrade the capacity in that area.

The additional cost of upgrading capacity is recovered in two ways:

- The cost of new connections or increasing the capacity of existing connections is recovered through capacity charges.
- The cost of existing connections increasing their usage of the network (within their allocated capacity) is recovered through lines charges.

In the same way that roads are not built large enough to handle every car which consumers own at the same time, electricity networks cannot handle every consumer using their allocated capacity at the same time. Both roads and electricity network rely on diversity of demand – that consumers will use the roads, or the electricity networks, at different times. This is why increases in consumer usage of an electricity network, even within their allocated capacity, can drive increases in network capacity and corresponding cost increases.

Technology changes, such as more affordable rooftop solar, batteries, and electric vehicles will increasingly have an impact on the way that networks perform. For example, electric vehicles will increase the loads on networks, potentially meaning we need to incur cost to complete upgrades. Rooftop solar injected at low voltage, can also exceed the capacity of the distribution transformer, and create voltage swings as generation ramps up and down, requiring costly upgrades.

These changes in network use are making well-designed network pricing increasingly important. This is driving reform across New Zealand (and in countries such as Australia and the UK) toward cost-reflective pricing (CRP). Figure 2 below describes CRP in more detail.

What is cost-reflective pricing (CRP)?

After allocating costs to pricing areas...

1. Signal *future* network costs

At peak times, set prices that reflect the cost of adding network capacity to meet growing demand.

At times when there is ample capacity headroom, set low prices

→ Customers pay less by using the network off-peak. That reduces investment pressure, which lowers the costs for everyone longer-term.

2. Allocate residual costs

Prices that signal future costs of meeting new demand won't recover enough revenue to meet todays fixed costs.

Recover residual costs through prices designed to avoid deterring usage, or creating cross-subsidies between different types of consumers.

→ The fixed costs of the network are recovered in a way that is fair and doesn't discourage off-peak usage.

Northpower is committed to implementing good practice pricing arrangements that play a constructive role in encouraging efficient network use and investment, for the long-term benefit of our consumers. By efficient use, we mean increasing the use of the network within its existing capacity, including by shifting load outside of peak periods, and incentivising new load to also go onto the network outside of peak periods. More energy delivered across the network without incurring costly upgrades means a lower cost per unit of energy delivered for all of us.

Transitioning to CRP is a major shift that will take time to implement. We began our transition four years ago, and while we have updated the pricing structure of almost every price plan, rebalancing prices will take time in order to mitigate the impact on consumers.

The pricing structures that we have initially adopted to improve cost reflectivity may change and evolve over time, particularly as technology evolves and markets which can respond to new and more dynamic price signals develop. For now, our focus is on Time of Use pricing for residential, small, and medium-sized enterprises (SME) consumers, capacity based pricing for large commercial and industrial consumers, and asset based pricing for very large industrials.

5 Our Network

5.1 Current pricing

Like most distributors in New Zealand, there is room to improve how our existing pricing arrangements signal future costs. For example, for residential:

- 53% of revenue is recovered through variable (kWh) based prices (down from 61% in the prior year), which has improved but still does not align with our costs which are largely fixed. Re-balancing of fixed and variable prices is the key pricing reform that we are continuing to implement over the coming years.
- 7% of revenue is recovered through off-peak and controlled variable prices (down from 11% on prior year). This is good but can still be improved. Driven by the LFC regulations, it requires us to increase controlled charges for Low Users as we increase the Fixed Charges for Standard Users, which discourages use during times where there is capacity to consume more electricity across the network without driving network costs.

High variable charges, and in particular high off-peak and controlled variable charges, incentivise consumers to inefficiently invest in alternate forms of technology to avoid lines charges. Some examples include wood burners, gas instant hot water heaters, batteries, and solar panels.

Not all of these investments will be inefficient. Inefficient investments are investments where the customer is saving more money from their investment in alternate technologies, than the network is saving from the customer shifting their usage away from the network. When an investment is inefficient, the network is left with the same or similar costs after a customer leaves, but less people to share those costs. This increases lines charges for the consumers who are left, who can't afford investments such as batteries and solar panels to avoid lines charges. And as a whole community – the consumers who invested in alternate technologies, plus the consumers who remain paying for the network – we all end up spending more to deliver the energy we need than we otherwise would have.

Batteries and solar panels have a role to play in increasing New Zealand's renewable generation, which in turn can help lower energy prices and help meet our zero carbon aspirations. However, in weighing whether to invest in these technologies, consumers should have the right price signals and information to assess whether the value of the energy generated from the solar panels exceeds the cost of the solar panels.

Another example of the issues that current pricing can create is the impact on EV owners. Currently EV owners can pay up to 5-6c per kWh in lines charges for charging at home during off-peak hours (plus energy costs), even though off-peak or interruptible charging could be accommodated on our network at no incremental cost. These prices might deter consumers from investing in electric vehicles, which would be counterproductive to achieving New Zealand's zero carbon ambitions.

Pricing changes take years to develop and implement, with multi-year transitions often needed to limit bill shock. Signals then take time to flow to customer investment decisions and behaviours. As such, the focus for pricing reform should be on investment pressures 7+ years from today. Over that timeframe, price signal misalignment could drive outcomes such as:

- **Inefficient EV charging.** EV uptake will grow rapidly and could cause significant network investment pressure if charging adds to peak demand. At the same time, usage charges for off-peak or interruptible demand may deter usage that would not drive any new network costs.

- **Electricity rationing.** Usage-based charges at times when there is ample network capacity deters consumption, contributing to under-heated or under-cooled homes, and suppress electrification.
- **Unnecessary network investment.** Over time, well targeted pricing should produce flatter network demand profiles, supporting deferral of reinforcement work and potentially avoid altogether a wave of low voltage (LV) reinforcement that may otherwise be needed to accommodate EVs or high solar uptake.

There is also a policy and regulatory focus on network pricing that reinforces the case for CRP and adds some elements:

- **Low Fixed Charges.** The Government is phasing out the Low Fixed Charge Regulations. This will enable the increase of fixed daily charges to residential consumers, and allow variable costs to reduce, reflecting the fixed cost nature of the service we provide. This enables consumers to access the unutilised capacity in our network at off-peak times, at lower cost.
- **Pricing reform.** The Electricity Authority is driving a focus on pricing reform to improve the cost reflectivity of network pricing, thereby encouraging more efficient outcomes.

These factors shape the impetus for reform, and the direction of our reform strategy set out in Section 6.

5.2 Current constraints

For the majority of our network we have no capacity constraints which we need to signal to consumers. We have provided detailed substation level information relating to current capacity utilisation, constraints, and planned works to alleviate these constraints in Appendix 3. Our Asset Management Plan (AMP) also provides further detail.

Our key emerging challenges are summarised below:

Helena Bay

Helena Bay and surrounding areas may (based on modelling) experience congestion issues around holiday periods due to the high proportion of holiday homes and associated influx of holiday makers, leading to additional network demand for short periods of time. This is compounded by the remote location, meaning it is a significant distance from the nearest substation.

Mangawhai

Mangawhai has historically been fed from a single 33kV circuit with back-feeding capability via the 11kV network, reflecting its historical status as a small seaside village. Over the last few years we have received a significant volume of new connection requests in this area, including one large development, which is equivalent to almost the entire capacity of the existing substation.

As such, we need to both increase our capacity into the area to supply the new connections, and increase the security of supply to N-1 to provide a quality of service commensurate with that expected by consumers in what has now developed into a large and growing township.

To address these requirements, we are currently constructing a new substation that is due to be commissioned in March 2024. The investment in the new substation has been triggered by the large development outlined above, which will not be able to connect the majority of its load until the new substation is completed. We did explore non-network alternatives, but were unable to identify options that met the security of supply and capacity requirements at a lower cost. The developer's timeframes meant that we were not able to go to market and had to rely on our internal analysis.

The new connections at Mangawhai enabled by the new substation will be subject to capacity charges, which are a cost-reflective pricing signal as to the cost of creating the capacity for a new connection on the network. As such, while we did not have time to go to market for a non-network alternative, the developer is incentivised by the capacity charge to employ a non-network alternative if it is a lower cost than connecting to the grid, and as such an effective pricing signal has been deployed in relation to this constraint. The developer did not identify any lower cost opportunity to supply electricity to their development.

A second 33kV line is in the early stages of planning, and may require easements across private land, which could be time consuming to acquire. As such, we continue to invite any providers who can supply a non-network alternative at a lower cost to the new line to contact us.

Dargaville

Multiple distributed generators have applied to connect to the network in the Dargaville region, which means that effectively the entire western part of the network is now constrained from a generation point of view. Future large-scale connections in this area will need to fund upgrades on an incremental cost basis, which provides a cost reflective signal to construct generation on parts of the network where capacity remains available where it is economic to do so.

There are options to increase the capacity on the existing line from Maungatapere to Dargaville to enable significant additional generation. If this is of interest, please contact us.

EV uptake

We currently have around 1,172 EVs registered within our network area and are not seeing any capacity issues so far as a result. However, without access to power quality information from smart meters, we cannot accurately monitor constraints on the low voltage network and rely on high level network studies or consumers to notify us if they believe there may be an issue. We are working through obtaining access to this information to improve our network visibility.

Very large industrial

We have one large industrial consumer who has materially reduced their peak demand, which has resulted in surplus capacity at the Bream Bay GXP. We are aware that there are currently interested parties looking at utilising this surplus capacity at Bream Bay GXP.

Non-network alternatives

We actively consider non-network alternatives as part of making investment decisions, but at this time have not been able to identify solutions for the above, or for the planned upgrades set out in Appendix 3, that are more cost effective than traditional solutions.

If any non-network providers are able to provide cost efficient solutions to these constraints, or would like more information about these constraints, we invite them to contact Andrew Camuso (andrew.camuso@northpower.com).

5.3 Supporting infrastructure

The electricity which you consume in your home or business is measured by your electricity meter, which is provided by a metering equipment provider (MEP). The readings are provided to your retailer, who uses them to bill you, and also to provide us with data so that we can bill the retailer for our lines services. The MEP who provides your metering is selected by your retailer.

To implement cost-reflective pricing, we need consumption data to set prices, and to bill for our services, under those new pricing structures. We are therefore reliant on metering providers to measure the right data, and retailers to then provide us that data.

Smart meters

Cost-reflective pricing requires smart meter data. Currently 92% of residential ICPs and 75% of general ICPs on our network have communicating smart meters. To increase the availability of cost-reflective pricing to all consumers, we need retailers to finish their smart meter rollouts and MEPs to upgrade their mesh networks and meter communications to decrease the number of meters that are out of communication range.

Retailer data

We implemented Time of Use pricing four years ago for most residential and general consumers. We consider such timeframe to be sufficient time for retailers to adapt their systems to provide us with time-sliced data (i.e. consumption data in a peak/shoulder/off-peak format) for billing purposes, and to enter into agreements with metering equipment providers for the supply of data. As such, same as the prior year, for 2024-2025 the only exceptions from Time of Use pricing will be:

- ICPs which have a legacy meter, or a non-communicating smart meter installed
- GBUG ICPs. Mercury Energy uses the GBUG participant code for its Glow Bug prepay offering. While it has not updated their pre-pay specific systems to supply Time of Use data, it is currently the only retailer on our network which offers a pre-pay option. As such, if another retailer commences to offer pre-pay, we will review this exception.

Currently we have 88% of residential and 69% of general ICP's on Time of Use pricing.

6 Pricing Roadmap and Strategy

Our pricing strategy is to transition network pricing to be appropriately cost-reflective and responsive to the evolving market and the changing ways that consumers are using electricity.

Our pricing roadmap sets out how we are going to implement our strategy:

#	Action	Status
1	**Test and learn:** research cost-reflective pricing options, engage in stakeholder consultation, implement trials.	Complete
2	**Strategy:** update our pricing strategy to reflect the cost-reflective pricing principles.	Complete
3	**Pricing structures:** review and implement updated pricing structures.	Complete
4	**Pricing methodology:** review and implement changes to pricing methodology and supporting modelling.	Complete (but ongoing)
5	**Phased implementation:** phase price point changes to mitigate the impact on consumers and avoid bill shock.	In progress
6	**Review:** consider the effectiveness of pricing strategies, new technology, and how we can further our pricing reform.	Ongoing

6.1 Test and learn

Consumers

We considered consumer research (including that undertaken for the ENA and overseas) that found that while consumers were interested in lower cost electricity, they did not want to change how they used it. In particular, they did not want to have to think about how they used electricity – they simply want it there when they turn the light switch on.

The outcome of the research into customer views was that any new pricing structures had to be clear, understandable, and able to be responded to by consumers in the event they were passed through. We also needed to take them on the journey of why pricing reform was necessary and how it would benefit them, to address their hesitation towards change.

Retailers

We also consulted retailers, who are our direct customers, and upon whom we rely on to provide the data for billing. Without retailer cooperation, it is impossible to implement cost-reflective pricing.

Retailer feedback has been varied but initially many were reluctant to implement change, and to provide the data required to complete analysis, set prices, and bill new pricing structures. Most were clear that they do not for the most part see that consumers want cost-reflective pricing, and therefore indicated they were unlikely to pass it through to consumers.

Analysis

We also conducted analysis into the customer level impact of pricing change, in the event it was passed through. We assessed that, while we were only recovering the same amount of revenue, re-distributing this revenue would create ‘winners’ and ‘losers’. We decided that phasing of changes would be a key change management strategy, to mitigate the impact on consumers, and give them time to adjust their behaviours. However, signalling the changes early was also important, so that consumers could consider the impact of pricing changes on investment decisions that could potentially be inefficient.

Outcome

As a result of our research we developed the following principles which governed our approach to implementing cost-reflective pricing:

(1) Changes needed to be phased to mitigate the impact on consumers in the event prices were passed through.

(2) Price structures needed to be clear, understandable, and able to be responded to by consumers in the event they were passed through.

(3) Change needed to be accompanied by messaging which conveyed why and how pricing was changing.

6.2 Strategy

Following the research phase, we developed a new pricing strategy:

> *Our pricing strategy is to transition network pricing to be appropriately cost reflective and responsive to the evolving market and the changing ways that consumers are using electricity.*

6.3 Pricing structures

6.3.1 Residential and general

In 2018 we assessed the various cost-reflective pricing structures identified by the Electricity Networks Association and used in other jurisdictions, to identify the best options which would meet the above principles.

We considered a number of pricing structures, including Customer Peak Demand, Network Peak Demand, Installed Capacity, and Nominated Capacity. We assessed these options against a number of criteria, including their ability to:

- Manage peak loads
- Improve utilisation of network assets
- Signal the best time to charge EVs
- Ensure all consumers contribute fairly to fixed and variable costs
- Reduce incremental cost to consume electricity
- Reduce undesirable cross subsidies
- Give consumers the ability to manage their bill (where retailers pass through transparently)
- Be simple for consumers to understand
- Manage our revenue risk.

Demand based pricing

Demand based pricing is not easy for customers to understand or respond to. Consumers are attuned to thinking about their total electricity consumption, not how many appliances they have on at once. One instance of turning on their oven at the same time as their air conditioning or electric car could send their lines charges soaring. They can't easily tell what their demand is at any time without installing specialist equipment. We also weren't able to get data to bill this option, as smart meters generally do not collect capacity demand data, or measure consumption in intervals more frequently than 30 minutes.

Capacity based pricing

Installed capacity pricing was also not suitable for a number of reasons. Unlike with fibre for example where broadband speeds can be electronically throttled, there is no electronic way to control a customer's available capacity. It requires a truck roll to change the fuse in the pillar or on the power pole. It would incentivise customers to reduce their fuse size to reduce their lines charges, which would make blowing a fuse more likely, and replacing a fuse requires a truck roll. Also, some customers have a 2 phase or 3 phase connection to balance the load particularly outside of urban areas, and there is no practical way to limit these customers to the equivalent of a standard 1 phase connection. It would be unfair to charge them for 2 phases simply because of a network requirement to balance load. In addition, we don't hold complete data on installed fuse sizes, and checking the capacity of all fuses across the network would be expensive and impractical, requiring an outage. As such, this option was also ruled out.

Time of Use pricing

We selected Time of Use as our preferred cost-reflective pricing methodology following feedback that this option was preferred by consumers and retailers, that it was the easiest option for consumers to understand and respond to (in the event retailers passed it through) and the most practical option for retailers to implement.

It enables us to increase prices at times when there is congestion on the network, and reduce them at times when there is plenty of capacity. This sends a price signal to transfer load outside of congestion periods, and incentivises growth in consumption at times when there is no incremental cost for us to deliver the additional energy.

For example, it enables us to set the off-peak price at nil, because there is no incremental cost for us to deliver energy at that time. This incentivises electric car owners to charge off-peak when there is plenty of capacity in the network, and no cost for us means no cost for them.

It also enables us to set higher prices during peak times, to signal that if you wish to consume at that time we might need to upgrade the network. You can choose to consume at those times, pay the additional cost, and we will upgrade the network. Or you can choose to shift your consumption, which will result in both you and us saving money.

Implementation

We selected Time of Use pricing in 2018 as our preferred cost-reflective pricing methodology for residential and general consumers. We then implemented a trial in 2019, and after its success, rolled out Time of Use pricing to all consumers in 2020.

The time-bands for peak, shoulder, and off-peak were selected based upon the times that peaks occur on our network. We also aligned our time bands with Top Energy, to provide consistency and efficiencies for retailers operating across Northland.

Previously, we allowed retailers exemptions from Time of Use where they were in the process of updating their systems to enable them to supply us data for Time of Use billing purposes, or they were reaching agreements with metering equipment providers for them to supply the required data to retailers. However, retailers have now had four years to achieve both of these things, and as such we have decided that these exemptions will no longer be allowed.

As such, Time of Use pricing is now mandatory for all consumers where the customer has a communicating smart meter. This pricing only relates to how we charge the retailer; retailers are able to determine what and how they charge their customers.

6.3.2 Large commercial & industrial

We reviewed our Large Commercial and Industrial pricing structures in 2020, and decided to implement new structures which were more cost reflective. This means that:

- Customers with a dedicated transformer would be charged a capacity charge, reflecting the network capacity made available to them (and generally requested by them at time of connection) irrespective of their utilisation of that connection.
- High voltage customers would be charged a slightly lower capacity charge, reflecting the lower cost incurred by the network from not having to provide them with a distribution transformer. The capacity charge reflects the network capacity available to them.
- Customers on shared transformers can opt for either a capacity or volume based pricing structure.

Broadly customers with dedicated assets are now charged based on the capacity available to them through those assets. This is cost reflective because our costs do not change whether they have high or low utilisation of those assets.

6.3.3 Very large industrial

Our very large industrial consumers (consumers with significant load and/or dedicated assets) are charged based on the specific assets deployed to provide services to them. In addition, transmission charges are passed through transparently by replicating the Transpower charges as closely as possible. As this was already very cost reflective, we have not made any significant changes to their pricing structures.

6.4 Pricing methodology

6.4.1 2020 review

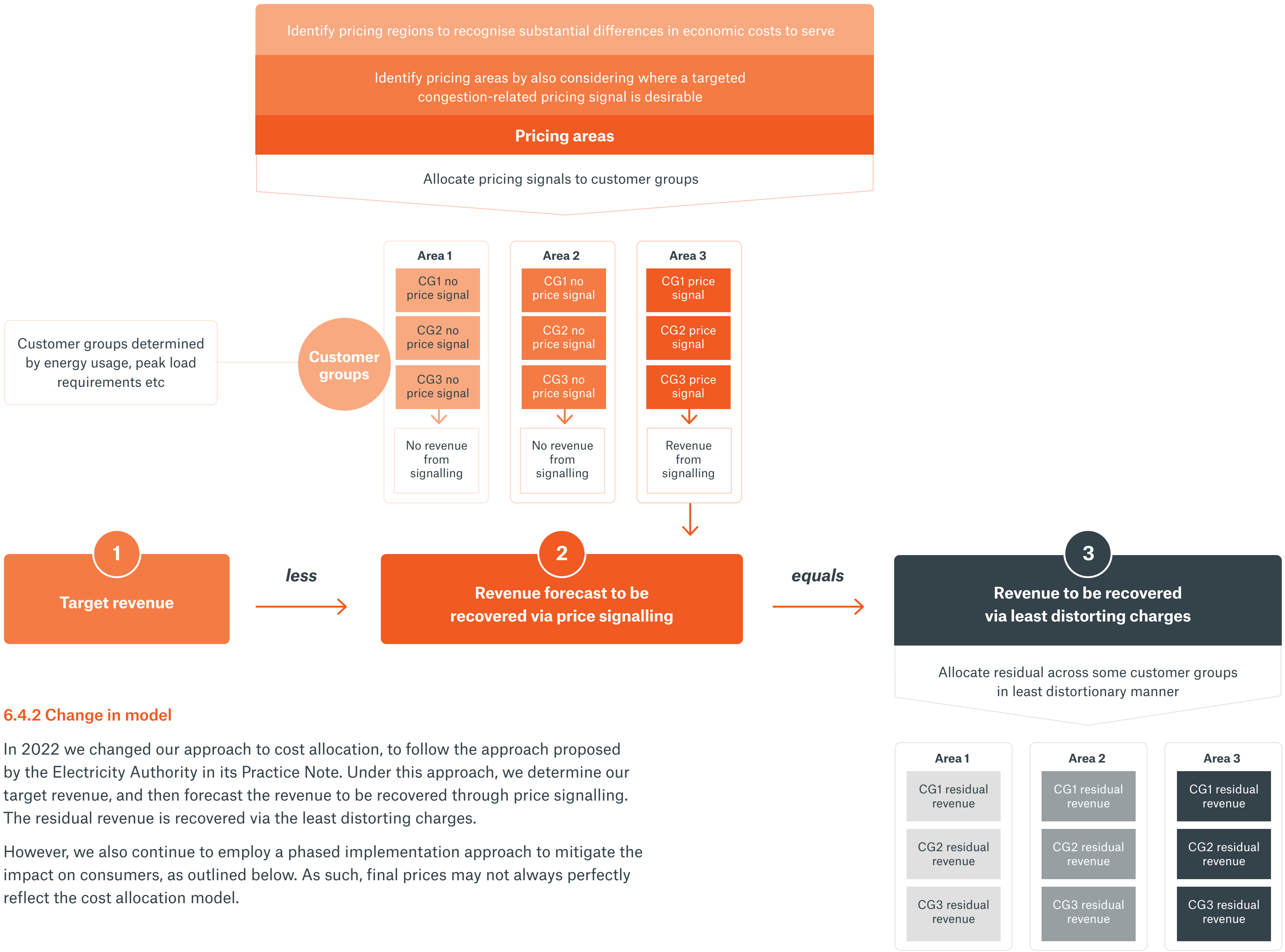
In 2020 we had our pricing methodology reviewed by an external economist, who largely agreed with our approach (noting it had not yet been updated to align with the structure suggested in the Authority's 2019 Practice Note) but proposed a change to the allocator that we use to allocate non-asset related fixed overhead costs, which was previously allocated using an arbitrary estimate.

To determine a more appropriate allocator, we reviewed three options and selected peak demand as the most appropriate allocator, that was least likely to result in distortionary outcomes:

Number of ICPs	We have 6 very large industrial consumers who represent on circa 18% of the peak demand on our network and 26% of the electricity consumed. This has materially changed from 42% and 48% respectively, due to the closure of the Marsden Point oil refinery. These customers and their associated assets demand significantly more dedicated network engineering, operations and management resource and support than an average consumer or business. As such, we considered number of ICPs would under-allocate cost to large consumers.
MWh consumption	As we do not sell energy across our network, we did not think MWh was the best allocator of our costs. In addition because some customers use their assets more efficiently than others to consume electricity, there is a risk that MWh consumption might over-allocate cost to large consumers.
Peak demand (adopted)	This was adopted as it most closely correlates with the service we provide (distribution is a pipe or capacity service as opposed to the sale of energy). Further, we considered this was most likely to result in non-distortionary outcomes.

To prevent consumers from changing their behaviour to avoid a peak demand charge, we use a 10 year rolling average. The exception to this is channel infrastructure, which we have allowed a reset due to the material change in their business model.

This change in allocator in line with the pricing principles has had the effect of re-allocating costs from mass market consumers to large industrials. We are phasing the change over 5 years, to mitigate the impact on large industrial consumers. 2024/2025 is the fourth year of the phased implementation.



6.4.2 Change in model

In 2022 we changed our approach to cost allocation, to follow the approach proposed by the Electricity Authority in its Practice Note. Under this approach, we determine our target revenue, and then forecast the revenue to be recovered through price signalling. The residual revenue is recovered via the least distorting charges.

However, we also continue to employ a phased implementation approach to mitigate the impact on consumers, as outlined below. As such, final prices may not always perfectly reflect the cost allocation model.

6.5 Phased implementation

We are cognisant of the impact of price shock on consumers from changing prices too quickly, but equally we are concerned as to the risk of uneconomic outcomes if we do not change prices. In particular, there is a risk that if consumers do not receive cost-reflective pricing signals (or it is not signaled how prices are changing) and they make uneconomic investments in alternate technologies, they will subsequently be adversely impacted when prices do change.

As such, we are phasing our price changes over time to mitigate the impact on consumers, but will also signal how pricing is changing. Our general approach is to phase changes over 5 years, and this aligns with the time period introduced to phase out the LFC regulations. However, we generally look to limit fixed daily charge increases to around 30c each year (and are limited to 15c each year under the LFC transition) and as such when inflation is driving price increases as it is now, this may extend the amount of time to reach the transition end point.

There are two types of price changes which require phasing:

(1) Fixed/variable prices: fixed prices need to increase, and variable prices decrease, to reflect the fixed cost nature of the service we provide. This enables consumers to tap unutilised capacity in the network at little to no additional cost. Outside of residential where the LFC regulations apply, we began implementing these changes in 2019/2020 and will continue increasing fixed daily charges at the rate of around 30c p.a. (and holding or reducing variable charges accordingly) until they reflect our cost structure.

(2) Peak/shoulder/off-peak prices: Our off-peak prices are now nil or close to nil in most cases (except where the LFC regulations prevent us from doing so), reflecting our minimal incremental costs to deliver electricity during periods where there is no congestion on the network. Peak and shoulder prices generally need to reduce (or increase at a much slower rate) as the daily price increases, until the price signal is circa 11c/kWh during the peak period, and approximately 3-5c/kWh in the shoulder. These reductions can only be achieved as the fixed prices slowly ramp up over time.

6.6 Review

We continually review our pricing structure to improve cost reflectivity and keep up with market developments. We are also looking at guidance from the Electricity Authority and industry developments both in New Zealand and globally.

While we have implemented ToU, we don’t see this as the end point for the evolution of pricing. However, we expect that further change will be triggered by technological development and new markets, which enable electricity consuming devices to respond in real time. For example, pricing might dynamically change in real time based on congestion, and your electric car might automatically respond to those pricing signals (and the time you have indicated you wish to depart) to determine the best time to charge. Based on consumer feedback, we do not see how dynamic price signals can realistically be responded to manually by consumers, so we see further cost-reflective pricing reform being largely contingent on the further development and adoption of technology to automate demand management.

7 2024/2025 Network Pricing

7.1 Approach

Northpower's pricing methodology is designed to support an efficient level of investment in our network for the long-term benefit of customers, to comply with the Electricity Authority's pricing principles (Appendix A), and its latest Pricing Practice Note. Prices are set to signal the underlying costs of supplying services, allowing customers to make efficient decisions about how they connect to, and use, our network. This allows Northpower to plan and operate our network assets efficiently, safely, and reliably. In setting customer prices for 2024-2025 we followed the approach outlined in section Figure 1 of the latest Practice Note:

7.2 Target revenue

Northpower calculates its target annual revenue using the Commerce Commission's building block model, to benchmark its returns as if it were subject to price-quality regulation.

The model results in target revenue of $96.1m, an increase of $11.8m on prior year target revenue.

Type	Component	2024 $M	2025 $M	YoY $M
Distribution	Operating Expenditure	33.9	38.9	5.0
	Depreciation	13.9	14.3	0.4
	Regulatory tax allowance	4.2	3.5	(0.7)
	Revaluations	(7.1)	(9.5)	(2.4)
	Other regulated income	(1.1)	(1.1)	0.0
	Return on investment (ROI)	21.9	30.1	8.2
Pass through	Transmission	18.2	19.4	1.2
	Rates	0.1	0.1	0.0
	Levies	0.3	0.4	0.1
Total		**84.3**	**96.1**	**11.8**

This revenue is shown gross of (or including) the discount to be paid during the year, which is $15.8m (i.e. the target revenue net of the discount will be $80.3m). The discount is included in the ROI for the purposes of applying the BBM framework.

7.3 Identify pricing regions

The second step in the pricing process is to identify pricing regions where there are substantial differences in economic costs to serve.

There are a variety of ways in which pricing regions could be determined:

- The network could be split based on the 3 GXPs which service it. The 33kV networks which extend from each GXP do not currently connect, although there are some 11kV connections.
- The network could be split based on the connection type, such as rural vs urban.

We consider that if the network was to be split into pricing regions, it would best be done by GXP. This is because there are effectively separate networks emanating from each GXP, and because they cover different geographic areas. In addition, GXP connection costs are for some GXPs a substantial cost.

We then considered whether there are substantial differences in economic costs to serve between the areas, based on GXP. For the purposes of the below we have excluded our Very large industrial consumers, as these customers are already charged on a cost reflective basis based on the actual assets that they use, as well as a transparent pass-through of their transmission costs.

	Maungatapere	Bream Bay	Maungaturoto	Average
Average cost per customer	$1,283	$1,282	$1,374	$1,300
Difference to average (%)	-1%	-1%	+6%	0%
Difference to average ($)	-$16	-$18	+$74	$0

Maungatapere and Bream Bay have nearly the same cost to serve while Maungaturoto (MTO) has moved to the highest average cost to serve due to a new substation added to Mangawhai Central. Large growth is expected in this region which will bring down the difference between GXP's over time.

We do not consider that regional pricing is appropriate for MTO at this time because increasing the charges at MTO could dis-incentivise growth, and that growth will help to lower the average cost to serve at MTO by spreading the fixed cost over more connections. Furthermore, the relatively small numbers of ICPs at MTO will likely make it uneconomic (due to transaction costs) to develop separate pricing.

7.4 Identify pricing

The next step is to consider areas where a targeted congestion-related pricing signal is desirable.

The key areas of constraint on our network are set out in Appendix 3. We plan to address these through pricing signals as follows.

Helena Bay

The network can manage existing demand, but growth in demand through new connections may trigger network upgrades. As such, we are using our capital contribution policy to send a strong price signal to customers wishing to connect to the network as to the costs to build capacity for them to do so. There are no indications that existing consumers are materially increasing their load on a per connection basis.

Mangawhai

We are using our capital contributions policy to send a strong price signal to customers wishing to connect to the network as to the cost to build capacity for them to do so. Therefore, they are incentivised to consider non-network solutions, and will only connect if upgrading the network is lower cost than the alternatives available.

Dargaville

We charge any further distributed generation connections the incremental cost to connect them, under Part 6 of the Code. This is an extremely cost reflective price signal, that will ensure these connections consider whether there are alternate locations that they could connect at with a lower overall cost.

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

8 Determine Consumer Groups

We have divided our consumers into two groups, based on their energy usage, security of supply, and asset requirements.

Customers are allocated to price category codes based on the method of connection to the network, the type of customer, the size of their connection, the metering configuration, and in consultation with the retailer and/or consumer. Price category codes roll up into consumer groups.

Very large industrial

Very large industrial is made up of 6 large industrial consumers, who have significant Northpower assets dedicated to their supply. In most cases, they have a dedicated feeder from a Northpower substation to their site, and in many cases they have dedicated backup feeders to provide N-1 security.

These customers receive a higher level of service, reflecting their reliance on electricity to operate critical industrial processes. This includes access to our control room, key operational and engineering staff, and senior management.

Mass market

Mass market is made up of all other connections, including residential, businesses, large commercial and industrial sites, and non-commercial sites. These sites are generally connected via shared assets.

9 Allocating Price Signals to Customer Groups

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

A price signal should be applied where, if a customer places more demand on the network, the costs to the network will increase. The below sets out the costs that are variable and therefore could increase if a customer places more demand on the network, and the price signals we will use to recoup the costs from customers.

Interconnection

Transpower charges us interconnection, which is our contribution towards the shared part of the national grid. Prior to 2023-2024, this was allocated based on our share of the total load in the Upper North Island during the 100 half hour periods with the highest load for the prior 12-month period. We calculated the load of the different consumer groups during the same half-hour periods used to allocate the Transpower interconnection cost.

The way in which Transpower charges its customers has changed effective from 2023-2024, and it now utilises a benefit based approach which seeks to identify the beneficiaries of investments, allocate the costs of investments to the beneficiaries, and lock those allocations in for the life of the investment. This is designed to avoid consumers taking actions to inefficiently avoid transmission charges. As such, interconnection charges are now fixed in nature, and in line with Electricity Authority guidance we will recoup these costs using fixed charges where possible. Therefore, we will not include interconnection in the calculation of price signaling revenue.

ACOT

We also paid avoided cost of transmission (ACOT) to eligible generators who inject into the Northpower network during the 100 highest peaks, calculated as the amount that we would have otherwise paid to Transpower under the RCPD calculation. Under the new TPM it is not possible to calculate ACOT in the same way as previous. In addition, ACOT often result in inefficient additional costs for consumers, because while distributors had to pay the transmission that they theoretically saved to generators, the generators were not always saving Transpower the same amount of cost, and therefore consumers paid twice. As such, the Electricity Authority has decided that distributors are no longer required to pay ACOT, and we therefore ceased to do so from 1 April 2023.

System growth

We have used the existing capacity growth investments set out in our AMP to forecast our Long Run Marginal Cost (LRMC) to build additional capacity into the network. This currently reflects only the cost to increase the “size of the pipe” or the capacity that our network can deliver at a high voltage level – not to extend the pipe to new areas to allow for new subdivisions and connection growth, or to upgrade LV networks due to increased peak demand.

We are using Long Run Marginal Cost rather than Short Run Marginal Cost because networks are made up of long-term investments, and generally we can absorb growth for a long period of time, but when capacity is reached material cost is incurred for upgrades. As such, we want to signal the cost of additional capacity when consumers add to peak load, so consumers can make efficient and rationale investment decisions in EVs, electrical appliances, solar panels, and other connected technologies. Long Run Marginal Cost is calculated by looking at the capacity growth investments we intend to make over the term of our AMP (10 years) and the capacity those investments will give us and calculating an average cost of capacity over the 10 year period. Improvements to our AMP this year have continued to refine our LRMC calculation, and we expect these will further improve in coming years.

We considered using Short Run Marginal cost. However, this would mean very low variable charges now, and then very material increases to our variable charges when a constraint crystallises in the future and an investment is required. This is likely to cause consumers to invest into connected technologies based on very low variable prices, and when they increase in the future their investment may be inefficient. For example, electrification might make sense now, but in 2 years when prices increase due to us running out of capacity, suddenly the investment does not make sense. Consumers are often making long term investment decisions, and as such the horizon timeframe of our pricing needs to reflect that.

Our Long Run Marginal Cost to build new capacity on the network is currently circa $147 per kW. This is calculated in a different way to our Capacity Charge, including only incremental costs (whereas the Capacity Charge averages out costs, and recoups costs already incurred to build capacity in anticipation of new connections). Variable charges to signal congestion intersect with capacity charges at the point that you need to upgrade the capacity of your connection – variable charges signal congestion up to the existing capacity of your connection (because networks leverage diversity of demand and therefore have a lower capacity than the sum of all of the individual capacities) and the capacity charge signals the cost of upgrading the physical capacity of your connection. $147 per kW equates to 11c per kWh consumed during peak periods (calculation included in Appendix 4).

In effect, this converts the LRMC into a price signal – if a consumer is willing to pay 11c/kWh to consume during peak periods, it is economic to build more capacity when we reach constraints. If a customer does not place 11c/kWh of value on consuming during peak periods and would prefer to shift their load, we should not build the additional capacity.

Electricity Authority levies

The Electricity Authority charges us levies of $0.0001562 per kWh. We on-charge this to VLI consumers based on their actual consumption, and we include this in our variable charges for mass market consumers.

Forecast signaling revenue

As outlined above, we are aiming to recover 11c/kWh in peak periods, to signal our LRMC. The cost of interconnection is no longer collected as part of signalling revenue, as under the new TPM it is now a fixed cost. In addition, we recover EA levies through variable charges

We therefore target price signalling revenue of $9.6m for 2024-2025:

Cost	Mass market price signal	VLI price signal	Mass market signalling revenue	VLI signalling revenue
Capacity Growth	$11c/kWh in peak periods	Customer must enter into an agreement with us to construct and fund new assets for their use.	$9.5m	$0.0m
EA levies	$0.0001562 per kWh	$0.0001562 per kWh	$0.1m	$0.0m
Total			**$9.6m**	**$0.0m**

10 Allocating Residual Revenue

The residual revenue balance to be recovered is $86.6m. This is to be recovered via the least distorting charge, which means the charge that consumers are least able to avoid by changing their behaviour.

We use our Cost of Supply model ("CoS model") to first allocate the residual revenue to the consumer groups. The allocators reflect how the different consumer groups drive the cost components.

Connection

Transpower charges us for our share of the costs for the grid exit points ("GXPs") that we use, based on the value of the assets and our usage of those assets. The total of these charges have increased by 3% compared to the prior year.

Connection charges are allocated to consumer groups based on their contribution to the peak demand at each GXP over the last 10 years, reflecting that GXP assets are fixed in nature and are unable to be quickly flexed to reflect change in demand from connected consumers.

Consumer group	FY25 contribution to peak demand (kW)	FY24 Cost	FY25 Cost	YoY
VLI	59,592	2.1	2.1	0.0
Mass market	114,075	1.0	1.1	0.1
Total	173,667	3.1	3.2	0.1

As each GXP has different connection charges, and we allocate connection charges at a GXP level, the percentage of a consumers group's contribution to peak demand may vary from the percentage of cost allocated to them.

Interconnection

Interconnection charges have been allocated by Transpower to transmission customers for 2024-2025 using their new Benefit based methodology. This methodology splits charges into 3 categories:

TPM component	FY24 Cost ($m)	FY25 Cost ($m)	YoY
Benefit based charge	7.3	8.3	1.0
Residual charge	7.7	7.9	0.2
Transitional Cap	0.1	0.0	(0.1)
Total	**15.1**	**16.2**	**1.1**

The cost of interconnection is up $1.1m this year, mainly driven by Benefit based charges for which Transpower have increased their opening Regulatory Asset Base values due to improvement of assets for which we receive benefits.

Guidance

The Authority has provided high level guidance that distributors should:

(a) Map transmission charges to pricing areas

(b) Use fixed charges where possible

(c) Pass step changes through

(d) Use proportionate allocation methods (i.e. more complex methods for larger customers and simpler methods for smaller customer)

(e) Manage remaining differences by exception

Allocation:

Our interconnection charges for 2024-2025 by GXP are below:

TPM component	Bream Bay	Maungatapere	Maungaturoto	Total
Benefit based charge	1.8	5.7	0.8	8.3
Residual charge	0.9	5.9	1.1	7.9
Transitional cap	0.0	0.0	0.0	0.0
Total	2.7	11.6	1.9	16.2

We are provided with a split of these charges by GXP by Transpower, except for the transitional cap. The allocation of the transitional cap is discussed below.

We then allocate the GXP level transmission charges to the 6 individual VLI consumers. We have adopted the below approach to mirror the TPM as closely as possible, noting that the modelling for >$20m Benefit based charge investments is completed in proprietary software which we do not have access to. As such, we have had to adopt the allocators we consider the most appropriate, and have considered the Electricity Authority's guidance in doing so.

The individual VLI consumer charges are then summed to form the total for the VLI consumer group, and the balance is allocated to the Mass market consumer group.

TMP component	Allocation approach
Benefit based charge	The Electricity Authority states that Benefit based charges are intended to be allocated between users in proportion to the **net private benefits** each user is expected to derive from the investment. <$20m Transpower allocates Benefit based charges for investments under $20m to a regional demand group, and then allocates the total for each regional demand group to transmission customers within the group based on **average power flows between 1 Sep 2016 and 31 Aug 2021, with a reset every 5 years**. We have therefore allocated it to VLI customers using their average power flows during the same time period. >$20m The Benefit based calculation methodology used by Transpower for investments over $20m depends on the type of benefit the investment provides to the grid. Investments with market related benefits are calculated use proprietary software which cannot be replicated by transmission customers. As such we have adopted the following approach: • The 7 'Appendix A' investments are a retrospective reallocation of costs and benefits associated with these historic investments that pre-date the TPM. The allocation of these investments was completed by the EA. As we cannot replicate the modelling of these re-allocations, we have used average power flows between 1 July 2014 – 30 June 2018 as our allocator. This is the same period that Transpower proposes to use for pre-commencement adjustments in relation to these investments. • There have been three new investments over $20m since the TPM was implemented – CUWLP, POLE2 HVDC and WUNIVM 1a. Further details of these investment projects can be found on Transpower's website at https://www.transpower.co.nz/our-work/industry/grid-pricing/transmission-pricing-methodology/tpm-benefit-based-investment. Transpower's modelling allocates the benefit to regions, and then to customers within the regions based on average offtake between a 5 year period depending on the final investment decision date for the investment . We have therefore used average consumption between the same dates as our allocator. For CUWLP, the measurement period is 1 September 2014 to 31 August 2019. For POLE2 HVDC and WUNIVM 1a, the period is 1 September 2015 to 31 August 2020.
Residual charge	The Electricity Authority states that residual charges are intended to be allocated among load customers in a way which reflects their size (as a proxy for ability to pay) but does not influence usage. Residual charges are allocated to transmission customers based on **the average of their highest peak in each of the 12 month periods between 1 July 2014 – 30 June 2018, adjusted by the ratio of their average of their annual gross energy consumption between 4 to 8 years ago (for 2024-2025, this is 1 July 2016 – 30 June 2020) compared to the baseline period (1 July 2014 – 30 June 2018)**. We have used the same calculation as our allocator.
Transitional cap	We have allocated the transitional cap based on historic power flows (average of consumption between 4 to 8 years ago), because it is a relatively small amount, and because this aligns with the Authority's guidance below.

We have opted to replicate the TPM as closely as possible for the purpose of allocating transmission costs to consumer groups and to individual VLI consumers, because it achieves the most efficient, accurate, and cost reflective outcome possible.

Where we have not been able to replicate the TPM exactly (eg. for Benefit based investments > $20m, and the transitional cap) we use the most appropriate allocator depending on the charge type:

- For benefit based investments, this depends on the benefit type of the specific investment, how it has been allocated by Transpower, and what data is available to allocate the benefit. As such the allocation depends on the individual investment, but we will also consider the guidance from the Authority.
- Where a logical allocator is not available (such as for the Transitional Cap) we will use lagged total energy flows as our default allocator. The Electricity Authority considers total energy flow (kWh) is best at providing a “fixed like” allocation outcome because this allocator is least likely to inefficiently influence usage. Peak demand allocators (kW) are ‘less good’ because they can incentivise inefficient load shifting. The use of a lagged or historic metric further increases the ‘fixed like’ nature of the charge and makes it more difficult to avoid through behavior changes.

Allocation outcomes

The outcomes of the allocation process are below:

TPM component	VLI	Mass market	Total
Benefit based charge	3.3	5.0	8.3
Residual charge	1.7	6.2	7.9
Transitional cap	0	0	0
Total	**5.0**	**11.2**	**16.2**

Asset costs

The costs to maintain and repair network assets are allocated to consumer groups based on the degree to which each of the consumer groups use or have access to the underlying assets. Assets have been allocated using the allocators below:

Asset	Allocator	VLI	Mass market
Dedicated sub-trans mission (33kV) lines/cables	Customer allocation	100%	0%
Sub-transmission (33kV) lines/cables	Distance between GXP and substation 10 year coincidental peak demand	2%	98%
Zone substations	# circuit breakers at substation 10 year coincidental peak demand	17%	83%
Distribution substations and transformers	Total installed transformer capacity (kVA)	6%	94%
Distribution and LV lines	Dedicated line length	0%	100%
Distribution and LV cables	Dedicated line length	0%	100%
Distribution switchgear	10 year coincidental peak demand	17%	83%
Other network assets	Asset allocation	0%	100%
Non-network assets	Adjusted 10 year peak demand	25%	75%
Weighted total	Total allocated asset value	6%	94%

There are only very small changes in most asset allocations compared to prior year, as the Mass market related assets slowly grow with new connections.

Non-network assets are allocated using an adjusted 10 year peak demand. The adjustment relates to the 10 year peak demand for one VLI customer who had a material change in their business model and therefore materially reduced their peak demand. We have allowed an adjustment for their peak demand in relation to non-network assets. We have not made the same adjustment in relation to network assets, because shared network assets cannot be flexed quickly if a customer decides to change its demand levels at short notice, and because the customer has not relinquished any of its dedicated assets.

Preventative maintenance is allocated based on the weighted total value of assets utilised by the consumer group, as all assets require periodic maintenance. Reactive maintenance (i.e. fault call outs) is primarily driven by incidents which affect power lines and poles (for example trees falling on lines, cars hitting poles, diggers hitting buried cables) and as such is allocated based upon the value of lines/cables allocated.

Operational costs relating to running and maintaining the core assets in our network are allocated based on the cost allocator assigned to the asset type they support. For example, substation related running costs are assigned based on 10 year coincidental peak demand, which is also used to allocate substation asset costs.

Operational costs which generally relate to the physical assets of the network, such as the engineers who design extensions and upgrades, and plan for the future, are allocated based on the share of assets as they generally support assets.

Non asset costs

Non Asset costs are the overhead costs to operate and maintain the network. They include the engineers who monitor the performance of the network, the customer services teams, operations teams who monitor the network 24/7 and manage outages, health and safety, finance, commercial and billing functions. These costs are allocated based on adjusted 10 year peak demand.

Cost	Allocator	VLI	Mass market
Non asset costs	Peak demand	24.6%	75.4%

Return on investment, depreciation, regulatory tax allowance, and revaluations

These costs are where we recover the depreciation on the assets which make up our network, the cost of tax, and a return on our investment in network assets. This component is important because it allows us to replace assets as they reach the end of their lives, and to invest in new assets as the network expands, in new technology, and improve the performance and reliability of the network.

These costs relate to the underlying network assets, and are therefore allocated to the consumer groups based on the total assets that each consumer group uses as described above.

Cost	Allocator	VLI	Mass market
ROI	Total asset allocation	5.5%	94.5%
Regulatory tax allowance	Total asset allocation	5.5%	94.5%
Depreciation	Total asset allocation	5.8%	94.2%
Revaluations	Total asset allocation	5.8%	94.2%
Other regulated income	Mass market only	0%	100%

The VLI allocation for ROI and Regulatory Tax Allowance is lower than the other categories due to the inclusion of some large distributed generators in these groups. While we can claim depreciation on our assets from this group, we cannot earn a return on our investment under Part 6 of the Code, resulting in a lower allocation for the first two categories.

Residual revenue allocated to each consumer group

Using the allocators described above, we allocate the residual revenue to each of the consumer groups. The target amount that we intend to recover from each group is outlined below:

	Component	2024 VLI $m	2024 Mass market $m	2024 Total $m	2025 VLI $m	2025 Mass market $m	2025 Total $m
Distribution	Operating Expenditure	4.9	29.0	33.9	5.6	33.3	38.9
	Depreciation	0.8	13.1	13.9	0.8	13.5	14.3
	Regulatory tax allowance	0.2	4.0	4.2	0.2	3.3	3.5
	Revaluations	(0.4)	(6.7)	(7.1)	(0.5)	(9.0)	(9.5)
	Other regulated income	0.0	(1.1)	(1.1)	0.0	(1.1)	(1.1)
	Return on investment	1.3	20.6	21.9	1.6	28.5	30.1
Pass through	Transmission	6.5	11.8	18.3	7.2	12.2	19.4
	Rates	0.0	0.1	0.1	0.0	0.1	0.1
	Levies	0.1	0.2	0.3	0.1	0.3	0.4
Total		**13.4**	**71.0**	**84.4**	**15.0**	**81.1**	**96.1**
***Less* signalling revenue**		**0.0**	**8.2**	**8.2**	**0.0**	**9.6**	**9.6**
Residual revenue		**13.4**	**62.8**	**76.2**	**15.0**	**71.5**	**86.5**

11 Setting Prices to Recover Residual Revenue

The following sections explain how we set our prices to recover the Residual Revenue allocated to each consumer group. It explains what types of prices are used, and how the prices are set.

11.1 Very large industrial

We offer non-standard pricing to very large industrial consumers who would like us to own and operate assets of significant value which are dedicated to their supply. We currently have six consumers in this consumer group, all of whom now are supplied under the Default Distributor Agreement we have with their retailer.

The pricing is based on the assets that the customer uses and the services that they receive, to ensure Northpower recovers the costs of the dedicated and shared assets, an appropriate return on investment, and the associated operating and maintenance costs. Transmission costs are passed through in a transparent manner.

The revenue target for these consumers is $15.0m for 2024-2025. We forecast that actual revenue recovered from these consumers will be $13.5m, as we are phasing the impact of changing the allocator for non-asset related costs over a 5 year period to mitigate the impact on these consumers.

Of the $13.5m total forecast revenue from this consumer group, $50k is signaling revenue (EA levies) and the balance is residual revenue. All of the residual revenue will be charged by way of a fixed price, which is calculated to a customer level using the same allocation approach as in our Cost of Supply model. The outputs of the modelling will be limited by the phasing and the fixed price agreement discussed above.

VLI prices have changed compared to the prior year due to the continued phasing of the change in allocator (+$1.4m), and new transmission allocations driven by the implementation of the new TPM (+$0.6m).

11.2 Mass market

For our mass market consumers, the least distortionary charge is generally a fixed charge, because a consumer is unable to alter their behaviour to avoid it. To make the fixed charge cost reflective, we vary the price depending on the capacity of the connection, because this is a key driver of cost to us. For example, business fixed charges are higher than residential consumers because these generally have a higher capacity connection, and large industrials are charged capacity charges because they generally have substantially higher capacity connections.

We set our prices by forecasting how many 'units' of each price type we will 'sell', and adjusting the price to recover our residual revenue. Ideally we would recover all of our residual revenue from just the fixed daily and capacity charges, however to mitigate the impact on consumers we are phasing the changes. This generally means increases to daily charges of around 30c per annum, except for residential consumers subject to the LFC regulations, where we are limited to 15c increases. As fixed prices gradually increase, variable charges that do not signal congestion reduce accordingly to ensure we only collect the residual revenue.

This may mean that for example prices are 11c peak, 5c shoulder, and 0c off-peak – maintaining that 11c differential between peak and off-peak. Then as the fixed price goes up, shoulder, can further reduce.

11.3 Distributed generation

Distributed generation less than 1MW

Distributed generation less than 1MW will continue to be charged 1c per kWh exported, reflecting the incremental costs of supporting export generation for this group of consumers. We incur costs to manage and review applications, to check that distributed generation will not adversely impact the network, provide approvals where there is capacity, and provide advice on network upgrades required where there is not capacity on the network. We are also starting to incur costs to study the impact of distributed generation on the network, and the impact it has on the quality of our service supplied to load customers. The 1c per kWh is forecast to recover $76k this year, which will partly cover these costs.

We have a price category for DG of less than 1MW, recognising that we are now starting to see dedicated DG sites of this size (for example, dedicated solar sites, as opposed to solar panels on a load site). This new price category ensures that we only charge incremental costs to dedicated DG sites.

Distributed generation over 1MW

Distributed generators over 1MW are part of the VLI consumer group, and are charged incremental costs on an individual basis, based on the assets that are employed and the costs we incur to provide the ongoing connection service.

Where there is demonstrable cost saving to Northpower as a result of distributed generation, these may be passed through to the distributed generator as network support. To produce cost savings for us, generation generally needs to coincide with peak periods on our network, to be injected at locations where there are network constraints, and to be material enough to defer or avoid investment. As such we will review connections over 1MW to determine whether there are cost savings resulting to the network. For connections under 1MW we do not consider that any cost savings will result.

12 Responsibilities to Very Large Industrial Consumers

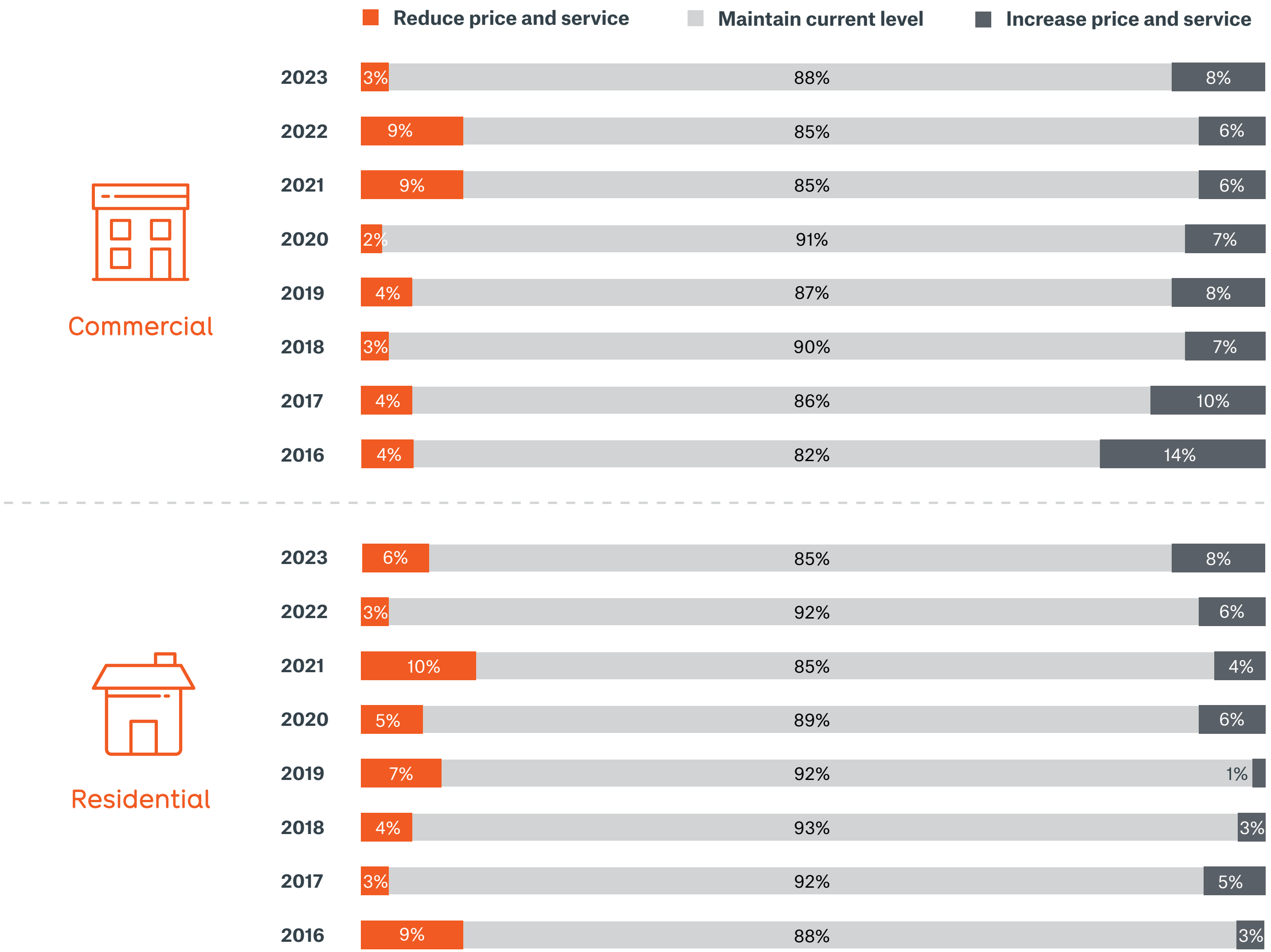
VLI consumers are able to input into their supply configuration, and as such they sometimes opt to duplicate assets to increase security of supply. For example, some VLI sites elect to have two incoming feeders, each capable of supplying the entire load for the site, to ensure they have a backup if one feeder fails. They also often have assets which are dedicated to their supply, such as dedicated feeders.

The non-standard pricing offered to our VLI consumers reflects the assets which they use, and as such their contribution towards target revenue covers the additional cost of the duplication of assets to improve security of supply.

13 Consultation

We consult with a range of stakeholders including consumers, retailers, and the Northpower Electric Power Trust on behalf of our consumer owners, on a range of issues including their views on pricing, quality, and the desirable level of trade-off between these two factors. For example, the below question is from our 2023 annual survey of consumers. The majority of consumers are satisfied with the current levels of service and would prefer that these are maintained rather than the price level adjusted. We are starting to see slight increase in residential customers who would like an increase in both price and service. We factor these views into our investment planning, which flows into our target revenue and ultimately prices.

Preferred level of service



NOTES:

1. Sample: 2023: Total Residential n=300, Residential urban n=205, Residential rural n=95, Residential Whangārei n=164, Residential Kaipara n=136; Total Commercial n=100, Commercial urban n=80, Commercial rural n=20, Commercial Whangārei n=56, Kaipara n=44.

2. PV4. Northpower's level of service is based on reliability of supply, supply quality and response times to faults. Changes in service levels might require changes in price. If you had to choose which one of the following best describes what you prefer?

- The chart shows historical trends for preferred level of service.

We also consulted extensively with retailers on the changes made to 2024-2025 pricing, through our joint consultation with Top Energy.

Appendix 1: Proportion of target revenue by price component

Price component code	%	Price component code	%
02	1.5%	1450	1.1%
03	0.1%	1451	2.6%
04	0.8%	1452	0.5%
05	1.7%	1550	0.5%
06	3.0%	1551	0.9%
07	0.1%	1552	0.3%
11	0.2%	200RP	0.0%
12	0.0%	210CAP	0.7%
19	0.0%	210EXD	0.0%
24	0.2%	210PKD	0.0%
25	0.0%	210RP	0.0%
32	0.7%	220CAP	5.5%
33	2.1%	220EXD	0.0%
46	0.0%	220PKD	0.0%
47	0.0%	220RP	0.0%
53	0.0%	230CAP	0.1%
55	0.2%	230EXD	0.0%
92	0.1%	230PKD	0.0%
93	0.0%	230RP	0.0%
105	0.0%	A	2.1%
201	0.0%	ATOU	7.1%
211	0.0%	B	0.1%

Price component code	%	Price component code	%
221	0.0%	BTOU	0.8%
231	0.0%	C	0.7%
1050	3.5%	CTOU	6.2%
1051	7.9%	G	0.1%
1052	1.6%	H	0.6%
1106	0.0%	HHHVC	0.0%
1107	0.0%	HHLVC	0.1%
1150	0.3%	HHLVT	0.2%
1151	0.4%	HHLVV	0.1%
1152	0.0%	IND	14.1%
1206	0.0%	K	1.4%
1207	0.0%	KTOU	12.3%
1250	2.6%	M	0.2%
1251	3.4%	P	0.1%
1252	0.0%	T	0.2%
1350	1.8%	W	0.6%
1351	4.3%	WTOU	3.8%
1352	0.4%		

Appendix 2: Glossary

Term	Definition
AMD	Anytime Maximum Demand. The highest half-hour demand, usually in kVA, during a one-year period.
Avoided Cost of Transmission (ACOT)	A reduction in the transmission costs payable by distributors to Transpower (usually in the context of embedded generation).
Code	Electricity Industry Participation Code 2010 and subsequent amendments.
Commission	Commerce Commission.
Consumer	A person or an entity whose electricity installation is connected to the electricity network.
Consumer group	A broad category of electricity consumers.
Controlled	An option where consumers elect to have part of their electricity supply subject to interruption at Northpower's discretion. The most common example is control of electrically heated hot water.
Demand	Electricity load, measured in either kW or kVA, usually averaged over a half-hour period.
Distributor (EDB)	An entity other than Transpower which owns an electricity network other than an embedded network. Often denoted as an Electricity Distribution Business (EDB).
Distributed generation (DG)	An electricity generator connected directly to an electricity distribution network (rather than to the transmission grid). Also called Embedded Generation.
EDIDD	Electricity Distribution Information Disclosure Determination 2012 published by the Commerce Commission as Decision NZCC 22 dated 1 October 2012, as subsequently amended.
Electricity Industry Act (EIA)	Electricity Industry Act 2010.
Half-hour metered	An ICP with metering that records electricity consumption in half-hour intervals.
ICP	Installation Control Point. An individual connection to an electricity distribution network.
kVA	Kilovolt-amp. Measure of total apparent power.
kVAr	Reactive power.

Term	Definition
kW	Kilowatt. Measure of true power.
kWh	Kilowatt-hour. Rate of energy flow.
Low Fixed Charge Regulations (LFC)	Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
Non-principal place of residence	A residential premise that is not the principal place of the consumer in the context of clause 3 of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
Non-standard contract	A contract that is not a standard contract in terms of the EDIDD 2012. (Refer to definition of Standard contract below.)
Point of Connection (PoC)	The connection between the transmission grid and a distribution network. Also called a Grid Exit Point (GXP).
Power factor	kW/kVA
Pricing principles	The distribution pricing principles published by the former Electricity Commission in 2010, adopted by the Electricity Authority, and amended from time to time.
Principal place of residence	In the context of clause 3 of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
Regional Coincident Peak Demand (RCPD)	The average demand at the times of the hundred highest half-hour regional demands.
Residential consumer	A consumer at a residential ICP which satisfies the definition of “domestic premises” in Section 5 of the Electricity Industry Act 2010.
Standard contract	EDIDD 2012 defines a standard contract as one where the price for electricity line services is determined solely by reference to a publicly disclosed schedule of prescribed terms and conditions, or a contract which covers at least five persons, none of which is a related party to the EDB or each other.
TPM	Transmission pricing methodology – the methodology defined in accordance with Part F (subpart 4) of the Code by which transmission prices are allocated to participants with connections to the national electricity grid.
Transmission grid	The national electricity grid owned and operated by Transpower.
Upper North Island (UNI)	The area of the North Island north of Huntly.

Appendix 3: Network constraints

The below table refers to N-1 capacity, therefore substations running over 100% means that to the extent the peak load is above 100%, the substation is operating at N security. The theoretical maximum performance of a substation (at N security) is therefore 200%.

Zone/regional substations	Load type and implications	Utilisation of installed firm capacity (%)	Utilisation of installed firm capacity in 5 years (%)
Kensington Regional Sub	Supplies most of the Zone Substations in Whangārei city. Ongoing upgrade to be completed within 5 years to meet load growth demand.	130%	71%
Alexander Street	Supplies the Whangārei City CBD with mostly commercial and residential loads	68%	72%
Hikurangi	Supplies Hikurangi township and some industrial load in the town	64%	69%
Kamo	Supplies northern boundary of Whangārei City, with a mixture of industrial, commercial, residential and rural load	87%	93%
Ngunguru	Supplies mostly residential load on the Ngunguru township, Tutukaka, and Matapouri areas.	63%	74%
Onerahi	Supplies the suburb of Onerahi with mainly residential and some commercial load	48%	53%
Parua Bay	Supplies the Parua Bay, McLeod's Bay, Whangārei Heads and Pataua areas comprising of mainly residential type load.	74%	85%
Tikipunga	Supplies the residential areas to the north of the CBD as well as the rural area to the north-east of Whangārei, which includes a large sawmill load.	87%	95%
Bream Bay	Supplies mixture of industrial commercial and residential customers.	50%	81%
Ruakākā	Supplies the Ruakākā township and the surrounding rural dairying area, Waipu township and the south-east coast holiday resort area	86%	102%
Maungatapere Regional Sub	Supplies 2 Zone Substations in Maungatapere and 3 Zone Substations plus 2 large industrial Substations in Whangārei. Ongoing upgrade to be completed within 5 years to meet load growth demand.	148%	48%

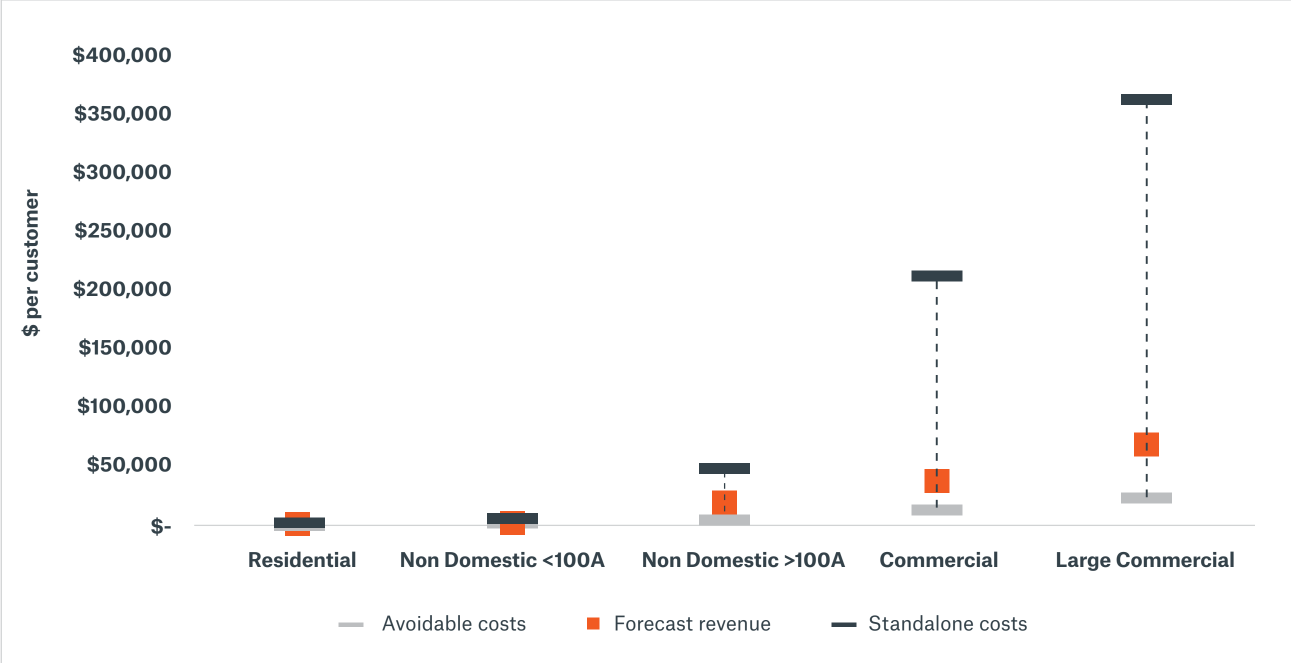
Zone/regional substations	Load type and implications	Utilisation of installed firm capacity (%)	Utilisation of installed firm capacity in 5 years (%)
Maungatapere	Supplies a predominantly rural area (dairy and fruit farming) around Maungatapere village which includes Maungakaramea, Poroti, Tangiteroria, Puwera and Mangapai.	77%	89%
Maunu	Supplies a predominant residential area to the west of Whangārei City.	37%	46%
Kioreroa	Supplies heavy industry with associated light industry and commercial loads.	44%	45%
Poroti	Supplies a predominantly rural region with no significant urban centres other than Titoki village.	61%	68%
Whangārei South	Supplies a mixture of residential, commercial and light industrial load. 11kV backfeed will maintain security. Proposed to be upgraded within 10 years to meet load growth demand.	106%	114%
Dargaville	Supplies some industrial loads and a large rural area (mainly dairy farming) centred around the Dargaville township.	81%	86%
Maungaturoto	Load on this substation is dominated by the local dairy factory, which accounts for approximately 75% of the substation's maximum demand.	75%	79%
Ruawai	Supplies Ruawai Town with demand dominated by the surrounding rural dairy farming area.	67%	71%
Kaiwaka	Supplies Kaiwaka Township and surrounding rural area, which is predominantly dairy farming.	55%	58%
Mangawhai	Significant load growth due to residential, commercial and industrial development. New Mangawhai Central Substation to be completed within 5 years to meet load growth demand.	76%	59%
Mareretu	Supplies predominantly rural dairy farming with no significant urban centres other than Paparoa Village.	69%	73%

Where a non-network solution provider believes that they could provide a solution to defer or avoid a network upgrade, at a lower cost and the same quality of service as a substation upgrade, we invite them to contact us at andrew.camuso@northpower.com.

Appendix 4: Consistency with Electricity Authority pricing principles

Pricing principle	Consistency of Northpower pricing methodology
(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); ii. reflecting the impacts of network use on economic costs; iii. reflecting differences in network service provided to (or by) consumers; and iv. encouraging efficient network alternatives	Our approach to setting prices is: 1) We determine our signaling prices with regard to our variable costs and LRMC, and forecast our signaling revenue. 2) We determine our residual revenue, and allocate this to consumer groups. 3) We set our remaining prices, with a view to collecting our entire residual revenue through fixed charges, while also phasing the change over time to mitigate the impact to consumers. This approach reflects the structure set out in the EA's 2022 Practice Note, albeit that we are phasing the impacts on pricing to mitigate the impact on consumers. **Subsidy free** The costs that we incur can be categorised as: • **Incremental costs:** these are costs incurred specifically for that customer, for example the cost of dedicated feeders for a VLI consumer. • **Shared costs:** these are costs which would still be incurred if any consumer group existed on a standalone basis, but when multiple consumer groups exist these costs can be shared. To be subsidy free, our forecast revenue for each consumer group should fall between avoidable costs (i.e. incremental costs) and standalone costs (incremental plus the full shared costs). Overall we are forecasting to recover our incremental costs plus a portion of the shared costs from each consumer group, and therefore our pricing meets the subsidy free test in the Distribution Pricing Practice Note. To provide further breakdowns and details, modelling has been completed for each key customer category to compare the forecast revenue against avoidable costs (costs that can be avoided by not serving that customer category) and standalone cost (estimation of off-grid solar and battery power system), based on current market information. The graph below demonstrates that the revenue for each customer category is within the subsidy free range.

Appendix 4: Consistency with Electricity Authority pricing principles (Contd)

Pricing principle	Consistency of Northpower pricing methodology
	 **Reflecting the impacts of network use on economic costs** Northpower's costs are largely fixed, driven by the physical footprint of the network, and long term nature of investment decisions. Variable costs are limited to EA levies, and the cost of building capacity if consumption exceeds our network capacity.

Appendix 4: Consistency with Electricity Authority pricing principles (Contd)

Pricing principle	Consistency of Northpower pricing methodology
	Mass market Our Mass market pricing has historically had a high per kWh rate and low daily connection rate, which does not correlate closely to our costs drivers. To address this we have: • Increased the differential between peak and off-peak prices to ~11c/kWh, which reflects our LRMC to build capacity. As mentioned under Section 9, our currently LRMC is circa $147 per kW. Based on that, the differential between peak and off-peak is calculated as: $\textit{Peak differential} = \dfrac{\textit{LRMC (\$/kW)}}{\textit{Peak hours per year}} = \dfrac{147}{1{,}300} = \textit{\$0.1131 per kWh}$ *Peak hours per year = Peak hours per day × Number of Peak Days = 5 × 260 = 1,300 hours* • Continued rebalancing our fixed and variable prices, within the limitations of the Low Fixed Charge Regulations. With the changes to the LFC regulations, we have been able to increase the fixed charge for residential low users from 15c to 60c per day. This will help us to bring the average amount paid by low users and standard users closer together, to reflect there is little cost difference in providing our service to these consumers. We have not created separate pricing for geographical regions, on the basis of transaction costs (because 2 of our GXPs have relatively low numbers of consumers) and because the average cost to serve is not dissimilar at each of the GXPs. *Very large industrial* Our pricing for VLI consumers is set based on the costs allocated to them, and therefore there is a direct correlation between their prices and our cost to provide the service to them. If they vary the service they require or the way they use our network, and this changes our costs, this has a direct impact on their costs. For example, the transmission costs, and the costs of assets dedicated to their supply, are passed through directly. Costs of shared assets and network management costs are passed through based on an appropriate cost driver.

Appendix 4: Consistency with Electricity Authority pricing principles (Contd)

Pricing principle	Consistency of Northpower pricing methodology
	Differences in network services *Mass market* Our Mass market price category codes reflect the service that consumers receive: • We have different pricing depending on the capacity of the customer's connection to the network, as this is a key cost driver for us. This includes differentiated pricing for consumers connecting at high voltage where we do not need to supply a transformer. • We offer lower per kWh rates for supplies where the consumer agrees that we may control the load for a period during the day to manage load on the network. For us this predominantly relates to hot water load control, and most residential dwellings in our network that have electric hot water have a ripple controller installed. These consumers receive a lower price in relation to their controlled load, reflecting that there are little to no incremental costs to provide this supply outside of network peak periods. • We offer lower off-peak kWh rates, reflecting that there is also little to no risk of consumption driving incremental costs through congestion at these times. *Very large industrial* Our VLI pricing is a direct charge through of the costs we incur to provide them with the service, as such it inherently reflects the differences in the service they receive. For example, most VLI consumers have dedicated feeders, some with N-1 security. The costs of the assets are charged back to them, reflecting the differentiated service they receive in terms of dedicated assets and increased security of supply. These consumers also receive a higher level of personalised service compared to the average consumer. For example, they have direct access to our 24/7 control room in the event of an outage, receiving direct updates, control room to control room coordination, and priority restoration. Another example is that we liaise around Northpower and Transpower maintenance schedules to avoid their busy periods and where possible to coincide with planned maintenance windows. The allocation of non-asset related fixed overhead costs based on customer peak (as opposed to for example the number of ICPs) reflects that these customers require a higher level of service commiserate with their larger load on the network.

Appendix 4: Consistency with Electricity Authority pricing principles (Contd)

Pricing principle	Consistency of Northpower pricing methodology
	Encouraging efficient network alternatives *Distributed Generation/Storage* We use our capital contributions policy to encourage efficient network alternatives. This policy effectively incentivises consumers to consider network alternatives such as off-grid solutions if they can do so at a lower cost than we can grow the capacity in our network to supply them. We don't believe that our prices dis-incentivise efficient network alternatives. Rather, we think there is a risk that where fixed prices are too low and don't sufficiently reflect the fixed cost nature of our service, there is a risk that pricing can subsidise inefficient network alternatives. This is because consumers can avoid lines charges through alternate investments such as solar and batteries, but our costs don't reduce accordingly. This simply transfers network costs to other consumers, who can't afford the alternate technologies. If a network prices its daily connection prices below its actual fixed costs to connect a consumer to the network, and recoups the balance of its fixed costs through variable charges, this creates an incentive for the consumer to invest in distributed generation and distributed storage to reduce their variable charges. The result is that the network receives less in revenues than its costs to provide the connection, and other consumers have to pay the shortfall through their variable charges. It also means that the electricity network is under-utilised, whilst the consumer has purchased equipment to duplicate the electricity network functions, which is inefficient. Through our re-weighting of fixed prices we are solving this issue, however it is important we phase the changes to reduce the impact on consumers. The Low Fixed Charge Regulations have also inhibited this re-balancing, however the regulations have now been updated and 2024-2025 is the third of 5 years over which they will phase out. As 84% of our consumer base is residential, this will have a significant impact in removing the potential for this type of inefficient subsidisation. *Demand Response/Interruptible demand* As described above, we offer discounted pricing for controlled load and Time of Use pricing. These price signals incentivise consumers to shift load and adjust their demand at certain times of the day when we might experience congestion, in order to avoid investment in transmission or distribution upgrades.

Appendix 4: Consistency with Electricity Authority pricing principles (Contd)

Pricing principle	Consistency of Northpower pricing methodology
(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.	Our approach is that the shortfall (residual revenue) is used to determine our fixed prices which least distort network use. However, we are phasing the change over time to mitigate the impact on consumers.
(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.	**Reflect the economic value of services** Our VLI consumers are able to negotiate directly with us to achieve prices which are cost reflective and fair to both parties, and as such are unlikely to curtail demand, disconnect, or not connect due to facing standard prices. We continue to adjust our peak, shoulder, and off-peak prices, to signal the economic costs of consuming at peak, and remove incentives to inefficiently curtail demand outside of peak periods. For larger commercial and industrial consumers who might disconnect or not connect in the first place if faced with standard per kWh pricing, we offer capacity based charging which reflects the service they receive. **Price/quality trade offs** Our VLI consumers have individually negotiated arrangements, where they can determine the various service quality aspects of their connection and their pricing is adjusted accordingly based on the cost to us to provide that service. For example, some VLI consumers opt to have dedicated feeders so they have guaranteed capacity and improved security of supply, underground their feeders to further increase security of supply, and to have multiple feeders to provide N-1 security. Some opt to connect at 33kV and provide their own transformers, whilst others opt for Northpower to provide and maintain transformers. It is practically difficult to provide Mass market consumers with options to vary their level of service quality (reliability, resilience, etc.) at an individual or price plan level, as they are using shared assets. However, our pricing does, where practical, include options which relate to service quality, for example consumers can opt for a controlled 18 hour or night only price plan where they receive a lower price in exchange for reduced availability of supply. They can also opt to trade off when they consume with price, shifting load off-peak to reduce cost, or paying peak prices if they value consuming at that time. We do survey consumers to understand their views on price, service levels, and the trade-off between these factors. This is factored into our price setting processes.

Appendix 4: Consistency with Electricity Authority pricing principles (Contd)

Pricing principle	Consistency of Northpower pricing methodology
(d) Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.	**Transparency** Our development of pricing is transparent, in that we describe our approach and the strategic changes we are making to pricing in our pricing methodology. We also communicate key changes and messaging as part of our public disclosure of pricing. **Transaction costs, consumer impacts, and uptake incentives** Our pricing is not yet perfectly cost reflective, because we are phasing price changes over a number of years in order to mitigate the impact on consumers. We have also made some decisions to not be perfectly cost reflective due to transaction costs, for example: • We have aligned our Peak, Shoulder, and Off-Peak time periods with Top Energy to create one standard pricing structure for residential and small to medium business across Northland. While this is not perfectly cost reflective as we have slightly different peaks, it mitigates the impact on and creates efficiencies for retailers. • We have not implemented locational pricing within our network as we consider the transaction costs currently outweigh the benefits, noting that the regional nature of EDBs already implicitly creates locational pricing across NZ. We have conducted analysis which shows the cost to serve differential is not material, so we do not consider the benefits would outweigh the transaction costs.

Schedule 17: Certification of year-beginning disclosures

(Distribution pricing methodology for the year commencing 1 April 2024)

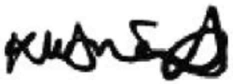
Clause 2.9.1

We, **Mark Trigg**, and **Kerry Friend**, being Directors of Northpower Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Northpower Limited prepared for the purposes of clauses 2.4.1 to 2.4.5 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.

Mark Trigg, Chair



Kerry Friend, Director

Date: 21 February 2024