PRICING METHODOLOGY

Pursuant to the Electricity Distribution Information Disclosure Determination 2012, clause 2.4.1

and

Electricity Authority Distribution Pricing Principles and Information Disclosure Guidelines

For the Period: 1 April 2025 – 31 March 2026

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Certification for Year-Beginning Disclosures

Pursuant to Schedule 17

Clause 2.9.1 of section 2.9

Electricity Distribution Information Disclosure Determination 2012

We, Michael J. de Buyzer and Robert T. Caldwell being directors of Network Waitaki Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Network Waitaki Limited prepared for the purposes of clause 2.4.1, disclosure of pricing methodologies, 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.

Michael J. de Buyzer

Date: 31 March 2025

Robert T. Caldwell

Date: 31 March 2025

Contents

Executive Summary

Network Waitaki supplies approximately 13,500 electricity connections to households and businesses in the supply area covering North Otago and parts of South Canterbury. The company is 100% owned by the Waitaki Power Trust.

Due to its ownership structure the company is an exempt Electricity Distribution Business (EDB) under Part 4 of the Commerce Act and is not subject to price-quality regulation that sets a revenue cap for 16 of the country's EDBs. However, Network Waitaki is subject to Information Disclosure requirements. In accordance with those disclosure requirements, this document describes how we have determined our prices and required revenue for the period 1 April 2025 to 31 March 2026.

There have been no material changes to Network Waitaki's pricing methodology, approach and rationale since the last methodology was published in March 2024. We continue to apply a pricing structure for most customers that includes a fixed daily charge (which varies according to the capacity of the connection) and a kWh charge that varies by Day and Night. We have also introduced a volumetric Distributed Generation export charge at 0 c/kWh.

Network Waitaki, following direction set from the Electricity Authority, is committed to cost-reflective, service-based pricing to support efficient use of the network. Our costs are largely fixed and the network is generally unconstrained. As a result, we seek to recover most of our revenue requirement from fixed daily charges.

We have been rebalancing fixed and variable charges over time towards a target of 80% of our revenue being recovered through fixed charges, with the remaining 20% from variable charges. When the *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004* (LFC Regulations) are terminated effective 1 April 2027 this target will have been achieved. Our off-peak price for general customers is close to zero ($0.00373) and our peak price is close to our estimate of the forward-looking economic cost of peak usage (the long-run marginal cost/LRMC).

We set our required revenue using a bottom-up calculation of our costs which mimics the approach used by the Commerce Commission when setting revenue caps for regulated networks. The calculation includes the capital costs and operating costs of our distribution network as well as the costs of being connected to the national grid (transmission costs).

For 2025/26 our revenue requirement is $33.5 million before discount. The impact on bills faced by individual customers will vary, but the weighted average price increase will be approximately 19%. We continue our policy of providing a $1 million discount to our customers.

1 Introduction

Under section 2.4 (pricing and related information) of the *Electricity Distribution Information Disclosure Determination 2012*[1], Network Waitaki must publicly disclose, before the start of each disclosure year, a pricing methodology which:

- Describes the methodology used to calculate prices payable or to be payable;
- Describes any changes in prices and target revenues;
- Explains the approach taken with respect to pricing in non-standard (IND) contracts and distributed generation; and
- Explains whether, and if so how, we have sought the views of customers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable.

Network Waitaki's pricing methodology is consistent with the Electricity Authority's 2019 Distribution pricing principles[2] (EA Principles) as outlined in Appendix B.

A detailed summary of how Network Waitaki complies with the Information Disclosure Determination 2012 and which sections of this pricing methodology comply with each regulatory requirement can be found in Appendix C.

Appendix D contains Network Waitaki's pricing reform status against the ten focus areas that the Electricity Authority circulated in open letters during September 2022 and May 2024 respectively.

Network Waitaki also complies with the LFC Regulations. Residential Low User (RL) customers at the 9,000 unit average domestic household consumption threshold level for the Lower South Island will pay no more than standard price plan customers.

The following sections:

- Provide context on our customers and network (section 2)
- Set out our pricing strategy and objectives (section 3)
- Show how we calculate our revenue requirement based on our cost to serve (section 4)
- Define our pricing load groups and the price structures we use for each group (section 5)
- Describe how we allocate the target revenue to each customer load group and determine prices that deliver the allocated revenue (section 6)
- Discuss technical and non-technical losses (section 7)
- Describe our approach to pricing for distributed generation connections (section 8)

[1] Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024

[2] Electricity Authority (April 2022). Distribution Pricing: Practice Note. Second Edition v2.1, 2022.

2 Our network and customers

2.1 Our customers

Network Waitaki has about 13,500 connected customers, and its supply area is dominated by residential customers making up 79% of the customer base that contributes about 42% of revenue and 24% of energy used on the network.

Agriculture, commercial and industrial customers make up the balance of 21% of the customer base, with agriculture generating about 29% of revenue and industry and commercial customers the other 29%. Agriculture varies from year to year due to irrigation's volatility associated with rainfall levels.

2.2 Overview of Network Waitaki

The network has a footprint of approximately 8,400 square kilometres. The number of Installation Connection Points (ICPs) currently connected to and active on the network is approximately 13,500, the maximum coincident system demand is approximately 70 MW and the annual delivered energy after losses is about 308 GWh.

Within our network area, the distribution network includes 19 zone substations, approximately 1,939 km of lines and cables, and 3,009 distribution transformers of which about 823 have a capacity of more than 100 kVA. Network Waitaki's distribution assets are dispersed over a large area and the company services a mix of towns, rural land and remote farmland.

The network has a strong rural character, with low load density measured in kVA per km of line: Network Waitaki records 126 kVA of network capacity per km of line, against a New Zealand average of 155 kVA/km. Although 79% of ICPs on our network are residential connections and only close to 11% of ICPs are agricultural connections, irrigation (as the major driver for agricultural use of electricity) consumes on average a third of annual energy, similar to residential consumption. Retail, hospitality, industrial, commercial and social services combined make up the balance of the ICP numbers.

2.3 Network demand

The size and capacity of the network is driven by the peak demand for electricity by our customers[3]. Peak demand on our network occurs in the summer when demand for irrigation is at its highest. This differs from most other electricity networks, which typically experience demand peaks in the winter when residential heating demands are at their highest.

Over the last decade irrigation schemes have been the biggest driver of demand growth with Network Waitaki's maximum demand growing from 50 MW to a high of 70 MW in FY2024. Irrigation contributed about 45% to the total network maximum demand in FY2025. Some additional irrigation growth is still expected over the next decade including projects relating to conversion from border dyke to spray irrigation, but no further growth is expected after this as most viable land will then be irrigated.

In terms of commercial and industrial load growth, we expect the main driver to be decarbonisation of process heat.

The Asset Management Plan contains detailed analysis around process heat conversion opportunities and other demand drivers including Electric Vehicles and Distributed Generation[4] the impact of which is expected to be small in the next year or so. At the time of writing, Electric Vehicles (battery and plug in hybrid) have a 1.0% penetration rate in the Network Waitaki supply area, which is approximately half the national penetration rate of Electric Vehicles (at 2.5%).

Table 1 below illustrates the characteristics for each of the Network Waitaki Grid Exit Points (GXP) in FY2025.

Table 1: Grid Exit Point characteristics

GXP	Load type and forecast capacity adequacy	Pricing implications
Oamaru: **11,216 customers** **12 Zone substations** **Capacity: 45 MVA** **Peak demand: 44 MW** **Energy: 223 GWh**	Main supply area. Predominantly residential, commercial and farming connections. Variations occur between winter and summer demand mainly because of irrigation. Forecasts for the medium term suggest irrigation, along with process heat decarbonisation loads will lead to capacity and security constraints on the Oamaru GXP, and upstream Transpower Transmission network requiring major investment.	Progressing with significant investments in the transmission grid (including a new GXP) as well as subtransmission assets (for both capacity and security of supply) - to enable regional decarbonisation initiatives, electrification of industry and domestic process heat, and transportation electrification. Capacity pricing strategy to continue as a proxy for demand pricing that best signals the cost of supply.
Waitaki: **1,608 customers** **4 Zone substations**	Mostly residential customers with demand peaking in Otematata over the December holiday period.	No material growth with adequate capacity – capacity pricing strategy to continue.

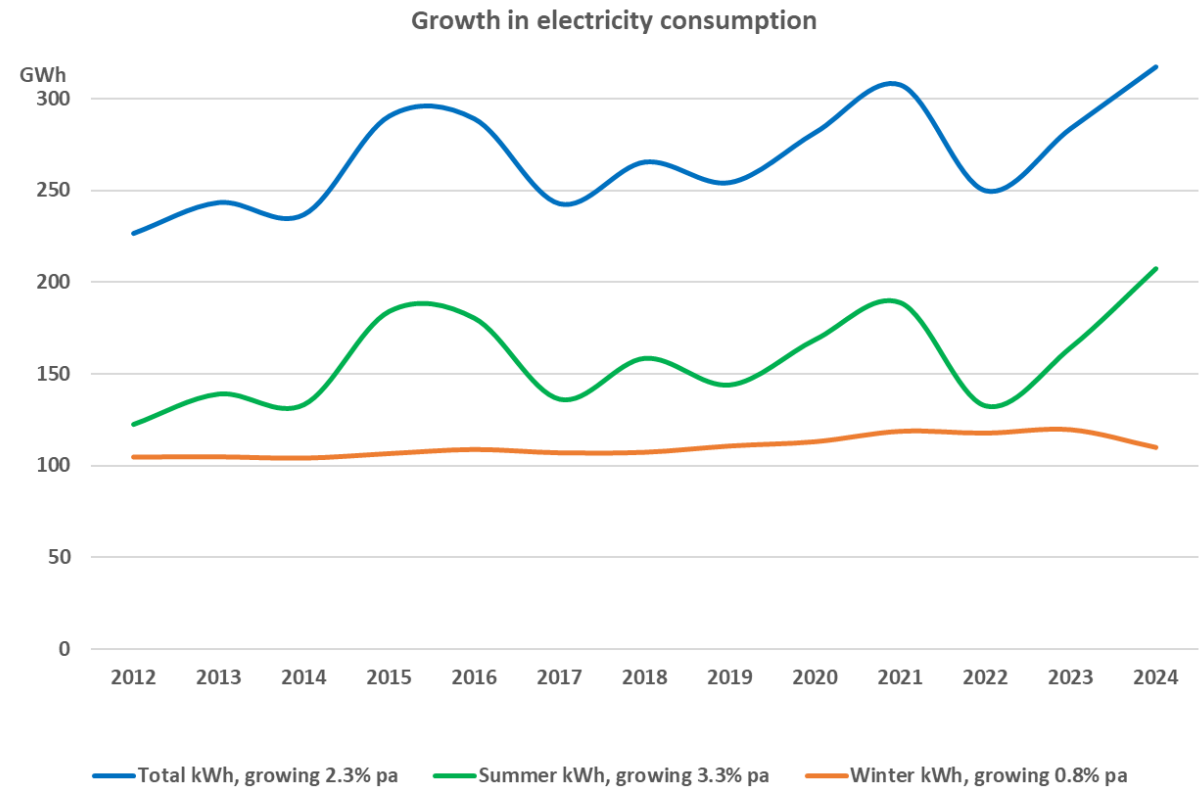
[3] In this methodology we use the term "customer" to refer to electricity end consumers. We consider the terms to be interchangeable and recognise that "consumer" (rather than "customer") is the defined term as per clause 2.4.1(4) in the Commerce Commission, Decision NZCC 22: Electricity Distribution Information Disclosure Determination 2012.

[4] Updates in Network Waitaki Asset Management Plan. 2025-2035 (https://www.networkwaitaki.co.nz/company/regulatory-disclosures/asset-management-plan/)

GXP	Load type and forecast capacity adequacy	Pricing implications
Capacity: 24 MVA **Peak demand: 13 MW** **Energy: 46 GWh**	Demand also varies between summer and winter due to irrigation.	
Twizel: **687 customers** **3 Zone substations** **Capacity: 27 MVA** **Peak demand: 4 MW** **Energy: 17 GWh**	Mostly residential and irrigation customers as well as the Ohau lodge and snowfield. Demand varies between winter and summer due to irrigation load.	No material growth forecast, with adequate capacity. Capacity pricing strategy to continue.
Black Point **1 customer** **0 Zone substations** **Capacity: 25 MVA** **Peak demand: 17 MW** **Energy: 39 GWh**	Dedicated supply for the North Otago Irrigation Company (NOIC).	Separate pricing arrangement.

Figure 1 below shows the long-term trends in energy consumption over ten years to 2024. The figure shows the volatility in summer volumes (due to irrigation) which supports the move to capacity-based pricing. Shifting away from volume-based pricing reduces the impact of volatile annual volumes and the associated revenue risk as well as removing a pricing signal that does not serve a purpose but is a remnant of historic pricing practices.

Figure 1: Electricity volume trend over the last 10 years



3 Pricing strategy

Our pricing methodology is aimed at setting prices that, as far as practicable, achieve Network Waitaki's identified pricing objectives, recover the full cost to operate the network efficiently and over time reflect the cost of serving different customer load groups better to encourage efficient use of the network.

3.1 Our pricing strategy

The aim of Network Waitaki's **pricing strategy** is to:

- Reflect the cost of service of the company more accurately through an approximately 80% capacity-based fixed and 20% volume-based pricing structure (subject to impact of constraints such as LFC regulations);
- Ensure revenue adequacy and reliability through implementation of this cost-reflective price structure;
- Maintain pricing signals through discounts on controllable load to manage congestion where necessary;
- Limit negative impacts of price rebalancing on customers as far as is practicable;
- Minimise the impact of price rebalancing by communicating with and advising customers of mitigating actions; and
- Continuously monitor wider regulatory developments to ensure the direction of price structure development is aligned with industry and regulatory developments.

3.2 Pricing objectives

Network Waitaki has identified pricing objectives of revenue reliability, efficiency, fairness, simplicity, transparency, innovation, and supporting of regional economic growth through future price direction and the ability to provide an annual discount to customers.

3.2.1 Revenue reliability

Network Waitaki must generate sufficient revenue to:

- meet the costs associated with the use of the Transpower national grid, the cost of transmission alternatives, and other pass through costs;
- meet the costs associated with providing a safe, reliable and efficient network to meet customer service levels, and fulfil its contractual obligations for the delivery of energy over its distribution network;
- comply with statutory requirements on health and safety, environmental protection, and quality of supply;
- provide for new network investment; and
- provide a rate of return on assets that is acceptable to its owners.

To meet the revenue requirement, Network Waitaki uses the following principles in setting prices:

- Prices should be simple to understand and administer and must comply with regulations;
- Maintain the stability of historic pricing structures in order to lessen price shocks to customers;
- Prices should not differentiate between urban and rural customers;

3.2.2 Discount to consumers

Network Waitaki has a policy of paying discounts to qualifying consumers towards the end of each year. Except when noted otherwise, all revenues stated in this pricing methodology are before the payment of any discount. Network Waitaki's discount to consumers consists of a fixed component.

The discount is announced in November of every year and the discount allocation methodology is available on Network Waitaki's website.

3.2.3 Efficiency

For Standard Contracts this applies as follows:

From an economic efficiency perspective:

- A rebalancing of capacity-based fixed prices and volume prices to reflect the cost structure of the business;
- Off-peak usage is encouraged through differentiated day and night volume pricing.

From a technical and operational efficiency perspective:

- Monitoring of power factors;
- Maintaining loss factors;
- Load control to manage peak system demand within supply constraints; and
- Emergency load shedding schemes to cope with transmission and generation constraints.

From an administrative efficiency perspective:

- Network Waitaki applies a 'GXP billing' approach where volume charges are based on electricity volumes measured at the three injection points (Transpower grid exit points) into the Network Waitaki network for each retailer in aggregate rather than per ICP. Chargeable quantities attributed to each retailer are determined by the wholesale electricity market reconciliation process.

For non-standard contracts efficiency is promoted as follows:

- Efficient investment in the network by large customers through passing through the cost of different size connections using predominantly capacity and to a lesser extent demand prices.
- Ongoing efficient operation of the network by signalling mainly the capacity costs of the delivery of electricity to each customer of this type.

3.2.4 Fairness

As a supplier of essential services Network Waitaki is continuously striving to set fair and reasonable prices for each customer load group. Fairness is a contentious subject and customers might disagree about what is fair and what is not.

Having prices with a dominant volume base makes achievement of fair prices complex as the resultant charge is in most cases not reflective of the cost to supply the customer. Network prices are becoming fairer as the cost of supply is increasingly reflected in it over time as per our pricing strategy and with the phasing out of the LFC Regulations.

Non-standard prices are more reflective of customers' use of network assets together with the associated transmission costs.

3.2.5 Simplicity

Network Waitaki has a simplistic, "easy to understand" two-part pricing structure with a fixed component and a day/night volume component applicable to each customer load group.

Except for the RL customers, all customer load groups have the same day/night volume prices. Appendix A contains the delivery price schedule for Network Waitaki.

3.2.6 Transparency

Network Waitaki follows a philosophy of setting prices such that they increasingly reflect costs and allow customers to have choices and the ability to respond to price signals. This philosophy will be continued and is part of Network Waitaki's future pricing directions, i.e. to reflect the fixed cost nature of the company accurately through re-balancing of the capacity-based fixed and volume components of electricity distribution prices (subject to constraints such as LFC regulations).

3.2.7 Innovation

Network Waitaki's prices support innovation through retailers making decisions as part of a competitive market on how they present Network Waitaki's pricing structures to customers. Non-standard customers similarly can decide how to respond to price structures especially going forward as prices become more capacity-based with less variation, promoting better price stability for customers.

3.2.8 Supporting regional growth

Network Waitaki supports regional growth by investing in infrastructure to meet expected load growth requirements. Network Waitaki's capital contributions policy outlines how this investment is funded with growth investments partially funded upfront through capital contributions and connection levies and partially funded over time through distribution pricing.

3.3 Pricing that reflects economic cost

3.3.1 Why fixed capacity-based pricing?

The cost to operate our network is predominantly driven by the size (capacity) of the network required to meet peak demand. The volume of electricity conveyed across our network has no material impact on the cost of operating the network.

Capacity-based pricing effectively charges customers for the size of their connection rather than the volume of electricity conveyed. This aligns the pricing for connecting to the network with the cost of providing the connection which provides an effective price signal to customers. This price signal incentivises customers to optimise their contracted capacity which in turn enables Network Waitaki to optimise the size of the network.

Optimising the size of the network ultimately results in an optimised cost to customers of connecting to the network. Consequently, capacity-based pricing is the most appropriate pricing mechanism because:

- It represents the long-term cost driver related to capital spending that is based on the customer's connected capacity.
- It provides for customer choice with a direct influence on cost and is a known quantity for each customer.
- Capacity is a known variable that we can use in pricing without any need for estimation or approximation.
- It is the only customer driven factor that the customer has direct control over due to customer's choice of capacity.
- A contractual capacity limit will be a stronger incentive to control maximum demand than an ex-post measurement of maximum demand, for all cases where the maximum demand is close to the contracted capacity plan limit.

In time, as smart meter functionality and data become more readily available, a capacity-based pricing approach could become more granular allowing a larger range of installed capacity options to customers.

Capacity-based pricing is favoured for reasons of simplicity, data availability and most importantly cost reflectiveness. The contracted capacity provides the bulk of the information that determines the cost of supply for each customer.

3.3.2 The long-term objective – delivery of peak demand

Network Waitaki must provide infrastructure that meets the need of customers' peak demand individually at their point of consumption and diversified across the network. Success is measured by being able to supply peak loads at the required security and reliability levels demanded by customers.

To be able to deliver peak demand Network Waitaki requires sufficient capacity from the Transmission Grid, sufficient capacity on the Sub-Transmission network and sufficient capacity on the distribution component of the network.

The Transmission Grid capacity used by Network Waitaki is the fully diversified demand requirements of our customers and this value is metered by Transpower and the bulk half-hour (HHR) values at GXP level are known, thus Network Waitaki plans for GXP capacity accordingly. As is shown in Table 1 and in the Asset Management Plan there is a Transmission constraint into Oamaru. The current solution is to construct a new GXP as the best technical and economic solution to provide future capacity and security for our customers. The new 220kV GXP infrastructure would be owned by Transpower and costs will be funded via a Transpower Works Agreement.

In the last two decades Network Waitaki has experienced significant load growth due to dairy and irrigation conversion and more recently process heat electrification. The capacity of the 110kV Transpower Transmission supplying Oamaru GXP has required tactical projects to manage the connection of new load during the summer period for several years. All tactical options have now been exhausted and demand projections indicate a requirement to invest in additional capacity to the National Grid. We are at a point where the option to invest in a new GXP is considered the most cost-effective long-term solution to ensure our customers have the supply they need, when they need it.

Demand on the sub-transmission network is based on locational After Diversity Maximum Demand (ADMD) values and these values are known on a zone substation level for planning purposes.

Measuring demand on parts of the distribution network (especially on low voltage networks) is challenging as real-time metering data at ICP level is owned by retailers and not readily available[5]. Demand on parts of the high voltage distribution network can be obtained from substation SCADA systems, however this is an aggregation of all downstream customer demand. As a result, catering for peak demand of customers is based on incomplete information. To provide a network capable of delivering the peak demand a proxy of customer demand must be used.

Our cost basis once infrastructure is in place is fixed and does not respond to volume – our cost is fundamentally driven by our estimate of peak demand which is calculated from contracted capacity.

3.3.3 Peak demand features of our network

The main peak demand features of our network are as follows:

- A moderate winter peak based on residential consumption.
- A high summer peak based on irrigation consumption which also determines Network Waitaki's annual maximum demand.

[5] Our largest retailer has in the past been helpful in providing past ICP level data in accordance with Appendix C requirements of the Default Distributor Agreement, however this is not real time and unable to be used for operations purposes.

- Load control measures available through ripple controlled hot water to manage peaks by time shifting residential hot water load. This is also available for emergency load reduction.

3.3.4 Price signal for peak demand

While the peak demand and volume usage is mostly weather dependent each year, Network Waitaki up to now had to build infrastructure to cater for a dry year when demand and volume are at its highest. Going into the future, new technologies such as Electric Vehicles, decarbonisation initiatives and Distributed Generation are coming into the planning mix – the forecasted impact on the network has been shown in Table 1 and is also discussed in detail in Network Waitaki's Asset Management Plan.

In terms of pricing, variable weather and the resultant fluctuation in annual volumes transported is irrelevant for cost and thus for pricing.

To produce a long-term pricing signal related to the peak demand capacity and cost of the network requires a pricing variable that captures the long-term impact of each customer on the network peak demand. The pricing variable that best captures this long-term impact relates to the size of connection as chosen by the customer, within the available connection size options made available by Network Waitaki. This variable does not change from year to year through short term considerations that impacts on annual consumption of a customer.

The most appropriate pricing signal for Network Waitaki, within current constraints are related to capacity (volume agnostic) which defines the long-term stable maximum demand of a customer.

Consideration of Long Run Marginal Cost

Using the system growth investments and optimised customer demand growth scenario as set out in the AMP we have calculated and considered Long Run Marginal Cost (LRMC). LRMC provides a measure of the forward-looking economic cost of network use. It can be used to formulate price signals about the costs that will be incurred in future because of network use.

The bulk of our forecast system growth expenditure relates to the construction of a new 220 kVA GXP infrastructure (referred to in par. 3.3.2). As explained above the new GXP is our preferred solution. Once a new GXP is in place, we would welcome electrification and usage of the network as there will be significant capacity "headroom". The system growth capital expenditure that arises because of the new GXP will occur regardless of actual demand growth.

Hence, two scenarios were considered when applying an average incremental cost methodology to estimate LRMC. One, where the forecast capital expenditure related to the new GXP and associated infrastructure has not been included in the LRMC calculation with a resultant LRMC of $39.79/kW. Assuming that all network peaks fall in the 'day' period this result in peak price of 0.68 c/kWh. If the new GXP and associated infrastructure are included then the resultant LRMC price is circa $159.69/kW (or about 2.8 c/kWh which is close to the day volume price of 3.3 c/kWh as shown in the price schedule in Appendix A).

This analysis has provided comfort that our current pricing is within the LRMC scope and hence no changes are required to prices as a result.

3.3.5 What is the optimal capacity / volume pricing ratio?

When providing price signals to customers, it is essential that the customer can respond to such signals. Electricity distribution charges represent around a quarter of the cost of electricity and a small portion of a household's expenditure. Splitting the signal between more than one pricing component, risks the signal being ignored by customers.

A pricing structure based on the core functionality of Network Waitaki's service is more effective. The biggest driver of cost is capital invested in the network, and this is based on the maximum demand of a customer (which is limited by the contracted capacity of the customer) at the time when the system is constrained. With maximum demand data not available in real-time to Network Waitaki, the contracted capacity is the best indicator of cost which is accurate and available for use in pricing.

To use a dynamic pricing signal which will convince customers to switch off load when a constraint occurs is challenging as experience has shown that customers easily ignore dynamic real time pricing signals from the distribution network. This is further exacerbated because retailers do not necessarily pass these price signals on to their customers.

Effective management of constraints is thus better managed through the ability of Network Waitaki to dynamically switch off controllable loads during high load periods and emergencies. Through differentiation of price plans, like the current Network Waitaki pricing regime, a customer can choose to allow the control of their load during pre-defined periods and conditions and the arrangement can be enhanced to include an agreed schedule and specific rules.

As indicated earlier, Network Waitaki currently does not have real-time access to smart meter data to allow information on individual ICPs, nor does it have access to the switching function of smart meters. These limitations reduce the ability of Network Waitaki to implement optimal control measures on the network. The current set-up with day and night rates and switching of certain loads with a single relay on-site at the ICP is the only measure available for use by Network Waitaki currently.

A predominantly fixed pricing structure is, currently, the best cost-reflective structure for the following reasons:

- A high-level cost of supply review has shown that Network Waitaki's cost to supply electricity is largely fixed, even though actual operational expenses may vary somewhat from year to year, e.g. vegetation, maintenance or even administration costs such as labour and IT, it is still a fixed component not affected by volume of electricity used.
- As network prices form a small part of the total electricity bill, even an 80/20 capacity-based/volume-based charge, though a big improvement from the historic state, dilute the pricing signal required to encourage customers to contract to the most appropriate price plan for their usage patterns.
- Provides mitigation of revenue risk due to volume and future technology innovations that is predicted to become more affordable sooner rather than later.
- It complements the Transmission Pricing Methodology guidelines of prices that are largely designed to be unavoidable.
- It reduces the likelihood of windfall profits during high electricity consumption years ensuring the company remain within regulatory limits, earning adequate but not excessive revenue.

A 20% volume-based component will contribute towards signalling and recovery of cost related to the 20% slightly less fixed cost components of operational expenditure, namely asset relocations, system growth, vegetation management and service interruptions and emergencies.

In addition, achieving an 80/20 (fixed capacity / volume) ratio will be a major step forward towards cost reflectivity considering the 10/90 (fixed capacity / volume) ratio of a few years back.

3.4 Implementation progress

Network Waitaki has been re-balancing fixed capacity-based and volume prices since 2017 to achieve a predominantly cost reflective pricing structure in FY2026 to:

- mitigate revenue uncertainty due to volume risk (weather and emerging technologies) as well as
- provide customers with the right information through pricing signals to invest in the appropriate connection that will satisfy their electricity demand requirements.

The approval by government in 2021 to phase out the Low Fixed Charge (LFC) regulations was a positive development in achieving cost-reflective prices. The regulations require Network Waitaki to offer residential consumers a price option at their primary place of residence, with a fixed price for FY2026 of no more than 75c per day (excluding GST), and where the sum of the annual fixed and volume charges on that price option equals any other price option available to those consumers when they use 9,000kWh per annum. Network Waitaki has been adjusting low-user prices since 1 April 2022 in accordance with this decision.

The price adjustment applicable to the pricing year 2025-2026 will result in a change in the capacity / volume make-up of prices to an overall 75/25 ratio (which include LFC prices). Hence, should LFC prices be phased out today the 80/20 ratio would in effect have been achieved.

3.5 Impact on customers

Network Waitaki customers will individually be affected differently. Some customers will be favourably affected (typically those that have relatively high utilisation of their contracted capacity) and some negatively.

Figure 2 and Figure 3 below provides an illustration of different % impacts customers may experience:

- Figure 2 shows that customers on controlled 15kVA price plans (mostly residential and small commercial) will face an increase of between $230 and $400 per year – average of between 19% and 25% depending on the customer's usage patterns.
- Figure 3 shows that most customers on uncontrolled 15kVA price plans will face an increase of between $185 and $350 – average of 15% to 16%.

The % increases in the controlled vs uncontrolled price plans differ due to a reduction in the differential between controlled and uncontrolled price plans. This is in support of customers who wish to move off controlled prices to take up third party flexibility offerings.

Figure 2: Impact of price adjustment on small customers (0 – 15kVA Controlled price group)

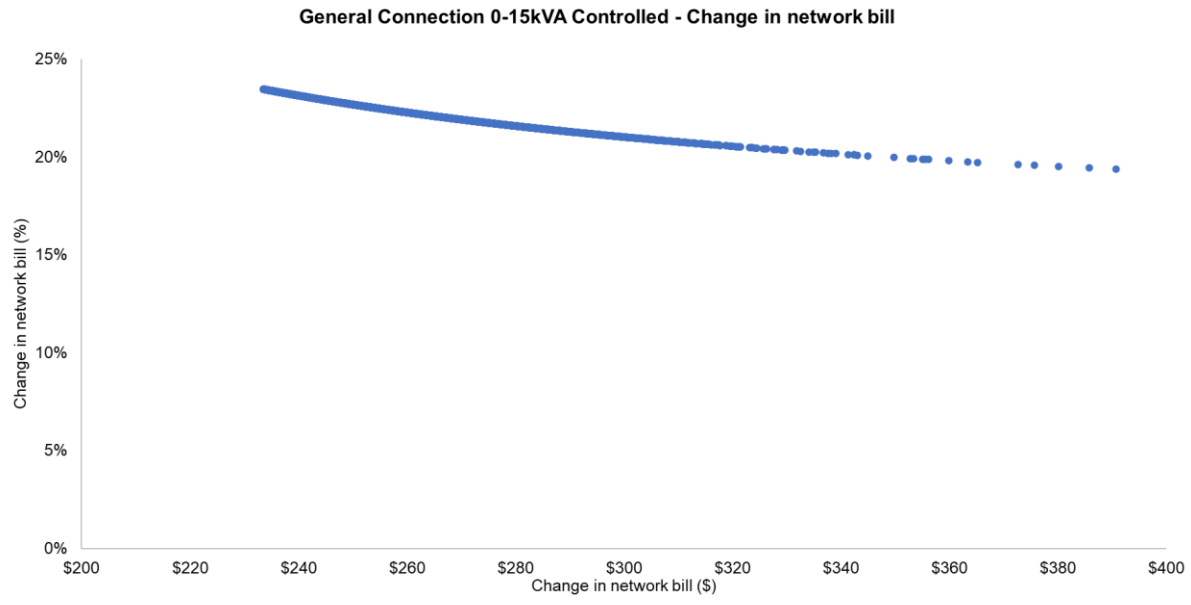
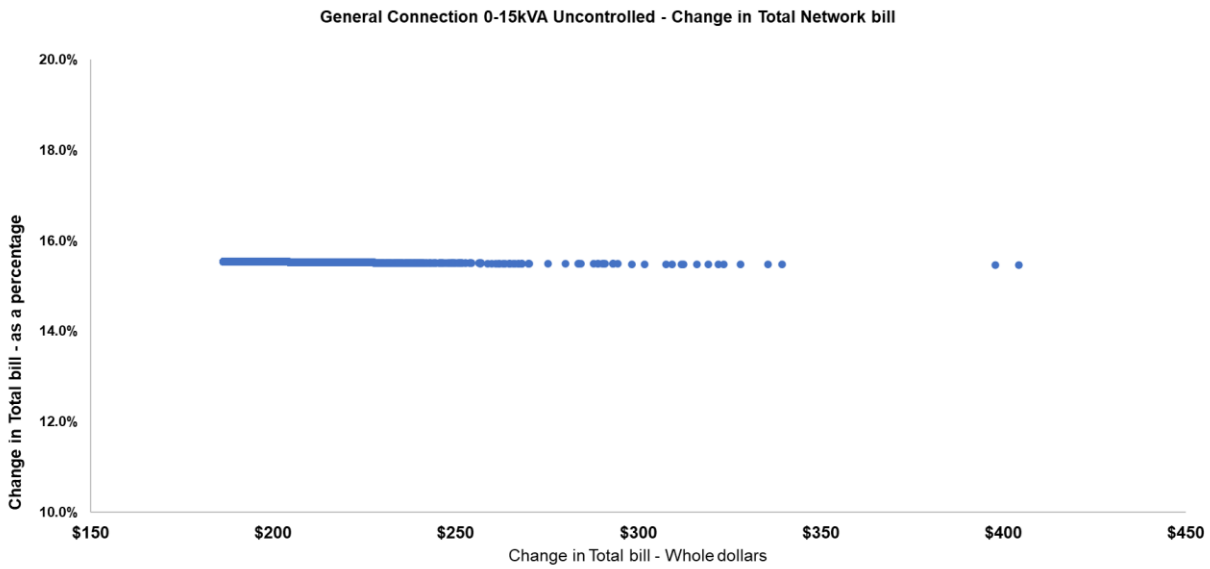


Figure 3: Impact of price adjustment on small customers (0 – 15kVA Uncontrolled price group)



3.6 Roadmap going forward

As per our strategy we have achieved an 80% fixed capacity-based / 20% volume-based pricing structure if allowance is made for removal of LFC prices. While the LFC pricing structure is still in place, we plan to achieve 75% fixed capacity-based / 25% volume-based pricing structure overall (including LFC prices).

Our roadmap going forward will focus on the following actions:

a) Maintaining an approximately 80/20 ratio between capacity-based (fixed) / volume-based charges with our main pricing signal being our fixed capacity-based price components

b) Maintain load control pricing plans (lower fixed charge relative to uncontrolled for the same capacity) but in support of flexibility services reduce the differential between controlled and uncontrolled price plans.

c) Continuous consideration from a technical perspective of making available a greater range of capacity options to customers when LFC regulations are removed from 1 April 2027, and the necessary technology is in place to better address and manage 'low user' pricing.

d) Putting in place various communication approaches to inform our customers about significant investments in the network (for both capacity and security of supply) to enable regional decarbonisation initiatives, including electrification of industry and domestic process heat, along with transportation electrification.

e) On an ongoing basis, we are continuing to assist customers in FY2026 where required to ensure they are on the most appropriate pricing plans.

The largest benefits of this strategy are:

a) Cost reflective and service-based pricing structure containing improved price signalling to better align customer behaviour with key cost to supply drivers;

b) Discounts on controllable load to manage congestion where necessary;

c) Reduction in revenue volatility;

d) Adoption of a pricing strategy consistent with EA guidance; and

e) Preparation for the anticipated removal of LFC regulations.

3.7 Customer Survey

In February 2023, Network Waitaki carried out a comprehensive survey to understand consumers' experiences on a range of issues. Issues covered in the survey included overall satisfaction with Network Waitaki's management of outages, price and reliability balance, awareness of company ownership, image and reputation, core service delivery, familiarity with and views on future energy activities such as electric vehicles, decarbonisation and other emerging technologies.

This survey was completed in two parts, as follows:

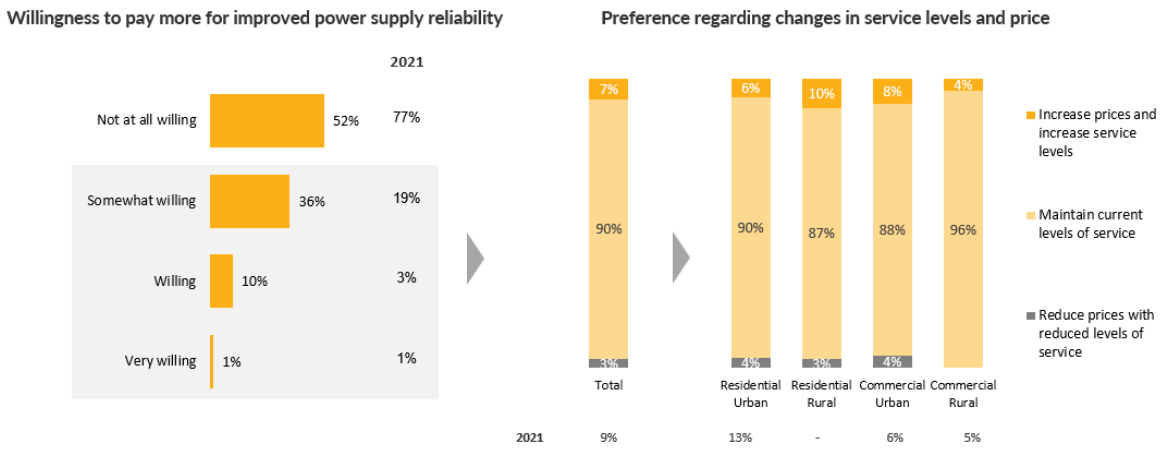
- An online survey was undertaken with 648 Network Waitaki customers between 10 February and 20 March 2023.
- Face-to-face interviews with fifteen of our large key customers.

The specific objectives of this research were:

- To understand customers' perceptions of the organisation and its reputation, including price/quality trade-off.
- To understand satisfaction with the services provided by Network Waitaki.
- To identify the key drivers of perceptions.
- To identify priority opportunities to enhance customer satisfaction.

Key findings were that:

- 74% of those surveyed are satisfied with the *Overall Performance of Network Waitaki,* and 100% of the key customers surveyed are satisfied which is consistent with the 2021 results.
- 60% of those surveyed online are satisfied with the Overall Value for Money.
- Reliability of power supply was the area achieving the highest rating.
- Opportunities highlighted for improvement with the 648 surveyed online included Overall Communication, and Lines Charges Being Good Value. Value for Money remains the most influential attribute for customers' overall satisfaction and retains a similar performance rating to that of the 2021 study.
- Out of the 15 key customers 93% were satisfied with our Overall Communication, up 16% on 2021.
- Regarding customers willingness to pay more for improved power supply reliability – of those surveyed online, 52% are not at all willing to pay more, 36% are somewhat willing, 10% willing and 1% very willing. And 90% of customers would prefer that we maintain the current levels of service, which is in line with the results from 2021.



The next customer survey will be conducted during FY2026.

4 Calculation of Cost to serve

We calculate our required revenue using a cost-to-serve calculation, which sums operation and maintenance cost, depreciation, return on investment, administration cost, and pass-through cost.

4.1 Cost to serve components

4.1.1 Distribution network costs

The components of our distribution network costs are:

Operations and Maintenance costs: Maintenance costs are based on the programmes and expenditure levels outlined in the 10-year Asset Management Plan (AMP). Operational costs include all other direct and indirect network expenses excluding administration costs.

Depreciation: Depreciation on network assets is based on the standard life for each asset category.

Return on investment: Return on Investment provides for a return to the business and the shareholder, which is used to fund growth and development, fund renewals in excess of depreciation and provide a return to the shareholder or allow for a discount to customers.

Administration costs: A provision for a share of costs associated with the administration of the business, and the full cost of support services related to the management and operation of the network.

4.1.2 Recoverable and Pass-Through Cost

Recoverable and Pass-through cost consists of transmission prices charged by Transpower, avoided transmission cost and new investment contracts as well as local authority rates, Electricity Authority levy, Commerce Commission levy, Fire and Emergency levy (FENZ) and Utilities Disputes levy.

Transmission prices charged by Transpower consists of the following price components:

- Connection Charge: This charge represents the fixed costs associated with the dedicated assets at each GXP. Shared assets are allocated based on each Transpower off-take customer's share of the 12 highest half-hour demand peaks measured at the GXP.
- Avoided transmission costs are associated with transmission assets that have been provided by Network Waitaki rather than by Transpower.
- New Investment Contracts relate to improvements to the Grid undertaken by Transpower to meet Network Waitaki's supply requirements.

- Benefit-based charge: This charge represents the capital costs and applicable operating costs associated with all new and some historic interconnection investments. The charge is allocated to each Transpower customer based on the extent to which a customer is an expected beneficiary of those investments.
- Residual charge: This charge applies to each customer's gross load, whether it is supplied from the grid or from embedded generation, and regardless of season or its time-of-use.
- Transitional cap charge: A transitional cap applies to distributors and grid-connected consumers' benefit-based charges and residual charges. The cost of this transitional cap is spread among distributors, generators and direct-connect customers in the form of a transitional cap charge.

4.2 Calculation of the required revenue

The revenue required to cover the costs and return on investment of Network Waitaki's business activities for 2025-2026 amounts to $33.5 million and is shown in Table 2 below.

Table 2: Revenue Requirement

Revenue Requirement	2025-2026
Operation and Maintenance	$7,831,778
Depreciation	$5,638,985
Administration	$4,655,000
Return on Regulatory Assets	$8,213,202
Transmission	$6,898,359
Pass-through costs	$284,000
Revenue Requirement	**$33,521,324**
Fixed Discount	(1,000,000)
Net Revenue Requirement	**$32,521,324**

Our Cost of Supply model (CoSM) and pricing design model follow a bottom-up approach and provide a platform for setting cost-reflective and efficient prices.

5 Customer load groups and pricing structures

Customer load groups fall into two main categories, namely:

- Standard customer load groups where network costs are recovered by means of a fixed annual price (based on connection capacity) applicable to the customer load group, and a day/night volume (kWh) price as shown in the schedule of delivery prices in Appendix A. Most Network Waitaki customers are on standard price plans which mean that they have a supply contract with a retailer and not with Network Waitaki.
- Non-standard customers where network costs are recovered by means of a fixed annual price based on the individual customer's asset usage, capacity requirements, and to a smaller extent their contribution towards the system peak demand.

5.1 Standard customer load groups

Customer load groups are based on the standard distribution transformer capacities used on the network, with no distinction being made between a single-phase and three-phase connection.

The minimum connection capacity for a single-phase supply is 15kVA, while the minimum connection capacity for a three-phase supply is 30kVA.

Customers are allocated into the various load groups based on their contracted connection capacity, with no distinction being made between residential and non-residential connections except for the RL categories which is available only to low use primary domestic supplies.

Load groups are differentiated based on kVA as it is a measure of service capacity and load density and is reflective of the costs incurred to serve each group. The following table describes each of our customer load groups.

Table 3: Customer load groups

Load Group	Description	Maximum Fuse Rating
RLC	Residential Low User 15C	1x 63A fuse
RLU	Residential Low User 15U	1x 63A fuse
15C	0 - 15kVA controlled	1 x 63A fuse
15U	0 - 15kVA Uncontrolled	1 x 63A fuse
30C	16 - 30kVA Controlled	1 x 100A fuse or 3 x 40A fuses
30U	16 - 30kVA Uncontrolled	1 x 100A fuse or 3 x 40A fuses
50C	31 - 50kVA Controlled	3 x 80A fuses
50U	31 - 50kVA Uncontrolled	3 x 80A fuses
100	51 - 100kVA	3 x 160A fuses
200	101 – 200kVA	3 x 315A fuses
300	201 – 300kVA	3 x 400A fuses
500	301 – 500kVA	NA
750	501 – 750kVA	NA
LC	750kVA +	NA
IND	Non-standard	NA

Street lighting is a specialist load group which utilises dedicated LV assets and is covered by a non-standard plan.

5.2 Distribution fixed prices: Standard customer Load Groups

5.2.1 0 – 50kVA Load Groups

Customers in the 15, 30, and 50kVA groupings are typically domestic or small commercial installations which may have water-heating or other loads that can be controlled.

Network Waitaki will continue to use the control options for those customers that foster economic use of the network assets and enable load to be moved to off-peak periods. In recognition of this, the fixed prices for installations that provide year-round access to controllable load are lower than for installations with no controlled load. However, as stated in par. 3.6 (b) we are reducing the differential between controlled and uncontrolled fixed prices to support flexibility services.

In addition, controlled installations can utilise two-rate, day/night metering, which enables customers to benefit from the cheaper night prices that apply between 11:00pm and 7:00am.

An RL option is also available in accordance with the *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulation 2004*. This option is cost-neutral for a customer using 9,000 kWh per annum before and after a discount has been applied.

5.2.2 51 – 750kVA Load Groups

Installations in the 100 – 750kVA load groups are predominantly commercial, light industrial, or farming, and as generally high consumption customers they will most likely benefit from the future move to fixed capacity-based prices. These customers do not usually have loads that can be controlled externally and load control is therefore not generally available for these load groups. These installations are normally supplied from a dedicated transformer and therefore do not utilise the same range of network assets as small low-voltage connections.

With costs being allocated on a predominantly fixed basis rather than volume prices the fixed cost nature of Network Waitaki's business is reflected.

5.2.3 Large Commercial Load Group

This load group requires connections larger than 750kVA. Pricing for this group is similar to the pricing method applied for non-standard price plans. The costs associated with the network assets are recovered as a fixed price based on contracted capacity and contribution to network system demand. Like other load groups, the fixed capacity price component portion will progressively form a bigger component of the price structure to reflect costs appropriately.

5.3 Distribution prices for Non-standard Load Groups

Non-standard customer pricing is driven from the main cost drivers, namely contracted capacity and to a small extent contribution to network system demand.

Network Waitaki currently has 12 customers on non-standard connections.

5.4 Volume prices: Standard customer Load Groups

Volume prices for standard customer load groups are based on GXP volumes and individual customer usage. Day volume prices apply to all units transported over the network between 7:00am and 11:00pm and night volume prices to all units transported over the network between 11:00pm and 7:00am.

Night volume prices are lower than day volume prices to encourage retailers to develop prices that reward customers for off-peak usage. Volume prices have increased in the pricing period as the volume / fixed capacity ratio will reach 25/75 in 2025-2026 and once the LFC regulations are terminated the 20/80 target will be achieved.

5.5 Transmission prices: Standard customer Load Groups

Transpower's charges are fixed asset-based costs and are allocated between customer load groups based on the group capacity requirements. These costs are recovered through mostly fixed prices.

5.6 Transmission prices for Non-standard Load Groups

Transpower's connection charges and new investment charges are recovered by means of a fixed price based on the capacity (kVA) requirements of each customer adjusted annually in accordance with the approved price adjustment.

Transpower's benefit-based, residual and transitional cap charges are recovered through a fixed price and allocated based on the adjusted lagged Anytime Maximum Demand (AMD) of each customer.

5.7 Settlement Residual Allocation

In accordance with clause 12A.3 of the Code Network Waitaki has published a Settlement residual Allocation methodology. This methodology provides the rationale on which Network Waitaki passes through settlement residue rebates received from Transpower to the payers of transmission charges.

5.8 Distributed Generation

A Distributed Generation volume price is applicable to distributed generator connections for exportation of electricity over the Network Waitaki network. The price is currently set at 0c/kWh. Revenue from these prices will recover the incremental costs of connecting the distributed generation, which includes network and overhead costs.

6 Price-setting approach

When we set our prices, we follow two high-level steps:

Step 1: The CoSM allocates the revenue requirement as follows:

- Firstly, the revenue requirement is allocated to the four GXPs that Network Waitaki' s network connects to, namely Oamaru, Waitaki, Twizel and Black Point.
- Secondly, the revenue requirement for each GXP is allocated to the eleven consumer load groups.

Step 2: The pricing design model sets the required revenue by:

- Setting distribution and pass-through prices, by GXP, within each consumer group based on a designated split between fixed / volume-based charges.
- Rolling the distribution and pass-through prices up to set uniform delivery charges, i.e. not split by GXP.

6.1 Overview of approach to allocating the revenue requirement

6.1.1 Allocation of revenue requirement to GXPs

The CoSM firstly allocates the revenue requirement across the four GXPs that Network Waitaki's network connects to namely, Oamaru, Waitaki, Twizel and Black Point, based on the principal drivers of the cost components of the required revenue. There are eight drivers of cost that could be used at each GXP:

- Number of ICPs
- Installed Capacity
- Regulatory Asset Base
- Consumption
- Peak Demand
- Regulatory Asset Base - depreciation
- Line length
- Anytime Maximum Demand

Cost drivers are allocated to each GXP as shown in Table 4.

Table 4: Allocation to GXP by cost driver

Cost driver	Oamaru	Waitaki	Twizel	Black Point
No. of ICPs	83%	12%	5%	0%
Consumption	69%	14%	5%	12%
Installed Capacity	74%	14%	5%	6%
Peak Demand	58%	17%	4%	21%
Anytime Maximum Demand	70%	14%	5%	11%
Line Length	80%	12%	8%	0%
RAB	70%	22%	8%	0%
RAB – Depreciation	73%	20%	7%	0%

The eight cost drivers have been selected as it is information that is available, although in some instances assumptions are made, e.g. peak demand values are not available at load group level. We expect that the input into the model will continuously evolve and improve over time.

The allocation of the revenue requirement to each GXP by cost component and cost driver is shown in Appendix E.

6.1.2 Allocation of revenue requirement to consumer groups

Using the allocated required revenue by GXP, the CoSM next allocates the revenue requirement by GXP to consumer groups based on the driver of cost to serve each consumer group. The allocation is done in three steps, namely:

Step 1: High-level allocation of cost to standard and non-standard consumer groups (Table 12, Appendix F) using the following cost drivers:

- Installed Capacity
- Peak Demand
- Anytime Maximum Demand

Step 2: Allocation of cost to the different standard consumer groups using the following cost drivers:

- Number of ICPs
- Consumption
- Line length
- Installed Capacity
- Peak Demand
- Anytime Maximum Demand

Step 3: Allocation of cost to the non-standard consumer and Large Commercial groups using the following cost drivers

- Installed Capacity
- Peak Demand
- Anytime Maximum Demand

The cost drivers consist of historical quantities (information from billing, EIEP files and information disclosures) that are allocated to each consumer group.

Tables 12 to 16 in Appendix F show the % allocation of each cost driver per consumer load group per GXP. Tables 17 to 20 (in Appendix G) shows the actual cost driver values used for each load group at each GXP.

6.1.3 Resulting required revenue by consumer groups

Based on the outcome of the CoSM the required revenue to ideally be recovered from each load group is shown in Table 5 below.

Table 5: Allocation of revenue requirement by consumer group

Breakdown of revenue requirement for 2025 – 2026				
	Distribution	**Pass-through**	**TOTAL**	**Proportion**
Small: RLU, RLC, 15U, 15C	$13,335,996	$2,737,717	$16,073,713	48%
Medium: 30U, 30C, 50U, 50C	$3,652,047	$890,595	$4,542,642	14%
Large: 100, 200, 300, 500, 750	$6,543,507	$1,770,370	$8,313,878	25%
IND: Non-standard	$2,807,415	$1,783,677	$4,591,092	14%
Total Revenue Requirement	**$26,338,965**	**$7,182,359**	**$33,521,324**	**100%**

6.2 Setting pricing to recover required revenue from consumer groups

Through a smoothing approach the pricing design model sets the prices from which the target revenue for each consumer group will be recovered over the pricing year. The pricing design model, based on the revenue requirement, first sets distribution and transmission prices for each consumer group by GXP as well as a uniform distribution and transmission price for each consumer group across all GXPs.

Uniform delivery charges

Network Waitaki continues to apply a uniform delivery charge that is indifferent to location and includes both distribution and pass-through charges. Approximately 83% of Network Waitaki

customers are supplied through the Oamaru GXP showing that the market is relatively concentrated. As illustrated in Figure 4, 9% of connections are more than 11km way from their point of supply.

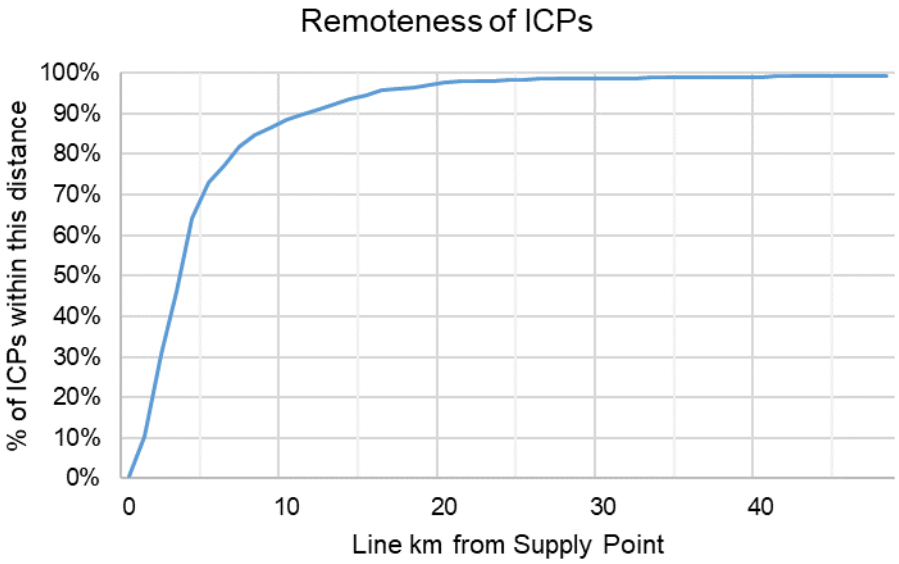
At this point the complexity and possible ambiguity of applying locational prices to 9% of remote rural customers do not justify this pricing, and the inherent security-of-supply/cost trade-off between urban and rural customers tend to equalise the situation.

Urban customers supplied from Chelmer Street and Redcastle substations enjoy a higher level of security due to the N-1 status of these substations. Also, the higher level of interconnectivity in the urban areas provides alternative supply routes in the event of a fault or planned outage.

The Authority recognised the importance of weighing the cost vs. benefits of adopting greater granularity in its Practice Note—

"Granularity matters. The prices and regulated charges for electricity services vary significantly at different times and in different locations in electricity networks. Progressively improving the temporal and locational granularity of prices and charges can deliver increased social welfare; **however, these benefits must be balanced against the costs, complexity, and potential equity concerns of implementation**."[6] [Emphasis added]

Figure 4: Illustration of remoteness of ICPs



Setting a fixed / volume-based split

In accordance with Network Waitaki's pricing strategy an overall fixed / volume-based split of 80/20 is used.

Setting fixed and volume-based prices

The fixed and volume-based prices to achieve the required revenue shown in par. 6.1.3, Table 5 above within each consumer group is set using the following formula –

[6] Electricity Authority. Distribution Pricing: Practice Note Second Edition v2.2 (2022). Paragraph 81, page 15

(CoSM allocated required revenue per consumer group x fixed/volume split) / quantity

Each standard consumer group has one fixed price and uniform day/night volume-based charges apply across all standard consumers in that group.

Smoothing prices for compliance

Prices per consumer group are then smoothed to meet the obligations of the LFC regulations and to avoid bill shocks as prices become more cost reflective.

A three-step process is followed:

- Initial fixed/volume-based allocations based on pricing strategy to achieve an 80/20 (fixed/volume) ratio.
- Adjustment to prices to comply with LFC regulations.
- Spreading the under-recovered revenue across consumer load groups in a fair manner and to achieve the LFC regulation cross-over obligations.

Forecast quantities to set prices

A forecast of quantities per consumer group is used to set prices. Volumes are forecasted using an average of the previous three years' average volume throughput and a growth factor is applied to the number of ICPs per consumer group based on the average year-on-year growth over the previous 5 years.

Calculation of target revenue

Target revenue per consumer group is calculated using the following formula –

Smoothed Price x forecast quantity = Target revenue

Table 6 provides a breakdown of the target revenue by consumer group and the proportion of each consumer group's target revenue to the total target revenue.

Table 6: Target revenue

Consumer Group	Target revenue	Proportion
RLU (Residential Low User 15U)	$871,521	2.6%
RLC (Residential Low User 15C)	$4,538,610	13.5%
15U (0-15kVA Uncontrolled)	$2,963,750	8.8%
15C (0-15kVA Controlled)	$5,915,655	17.6%
30U (16-30kVA Uncontrolled)	$1,199,348	3.6%
30C (16-30kVA Controlled)	$461,727	1.4%
50U (31-50kVA Uncontrolled)	$2,595,802	7.7%
50C (31-50kVA Controlled)	$615,978	1.8%
100 (51-100kVA)	$3,588,904	10.7%
200 (101-200kVA)	$2,519,455	7.5%
300 (201-300kVA)	$1,504,254	4.5%
500 (301-500kVA)	$1,337,551	4.0%
750 (501-750kVA)	$929,264	2.8%

LC (750kVA+)	$146,338	0.4%
IND (Non-Standard)	$4,333,167	12.9%
Total Target revenue	**$33,521,324**	100.0%

Variance between required revenue and target revenue within consumer groups

Smoothing of prices cause a variance between the required revenue and target revenue within consumer groups.

Table 7 below compares the revenue requirement and target revenue by consumer group.

Table 7: Comparison of Required Revenue and Target Revenue by Consumer Group

Consumer Group	Required revenue	Target revenue	Variance	
RLU (Residential Low User 15U)	$1,334,061	$871,521	-$462,540	-54%
RLC (Residential Low User 15C)	$6,130,553	$4,538,610	-$1,591,942	-35%
15U (0-15kVA Uncontrolled)	$2,795,546	$2,963,750	$168,204	6%
15C (0-15kVA Controlled)	$5,813,554	$5,915,655	$102,101	2%
30U (16-30kVA Uncontrolled)	$1,152,303	$1,199,348	$47,045	4%
30C (16-30kVA Controlled)	$467,390	$461,727	-$5,663	-1%
50U (31-50kVA Uncontrolled)	$2,343,768	$2,595,802	$252,034	10%
50C (31-50kVA Controlled)	$579,181	$615,978	$36,797	6%
100 (51-100kVA)	$2,954,277	$3,588,904	$634,627	18%
200 (101-200kVA)	$2,118,585	$2,519,455	$400,870	16%
300 (201-300kVA)	$1,247,339	$1,504,254	$256,915	17%
500 (301-500kVA)	$1,081,797	$1,337,551	$255,754	19%
750 (501-750kVA)	$758,672	$929,264	$170,593	18%
LC (750kVA+)	$153,207	$146,338	-$6,869	-5%
IND (Non-Standard)	$4,591,092	$4,333,167	-$257,925	-6%
Total	**$33,521,324**	**$33,521,324**	$0	0%

6.3 Impact on prices

For the period 1 April 2025 to 31 March 2026 the overall impact of the price adjustment is a weighted average increase of 19% in network prices. The price adjustment is allocated as described in the following table.

Table 8: Price adjustment 2025-2026

Price adjustment	% Adjustment
Distribution fixed (Standard and Non-standard)	20.0%
Distribution volume	18.9%
Recoverable and pass-through fixed (Standard and Non-standard)	23.1%
Recoverable and pass-through volume	10.6%
Weighted average price increase	**19.3%**

This price adjustment is in accordance with the pricing strategy. Increases to volume prices include LFC price changes where increase to fixed price components is capped.

6.4 Applying the subsidy-free test

The Electricity Authority's Distribution Pricing Principles state that:

> *Prices are to signal the economic costs of service provision, including by:*
>
> *i. being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs);*

We estimated avoidable and standalone costs for each of our 4 key load groups and found that for each group, our target revenue lies between avoidable and standalone costs, satisfying the subsidy-free test, as shown in the following tables and chart.

Table 9 Avoidable costs by load group

	Up to 50kVA	51-750 kVA	Large Customer	Individually Priced
Avoidable opex ($000)	$3,549	$993	$12	$438
Avoidable transmission ($000) (BBC + Residual)	$1,735	$3,625	$1,912	$973
Avoidable cost ($000)	**$5,283**	**$2,014**	**$14**	**$514**
Revenue ($000)	**$19,159**	**$9,879**	**$146**	**$4,333**
Revenue > Avoidable cost?	Yes	Yes	Yes	Yes

Table 10 Standalone costs by load group

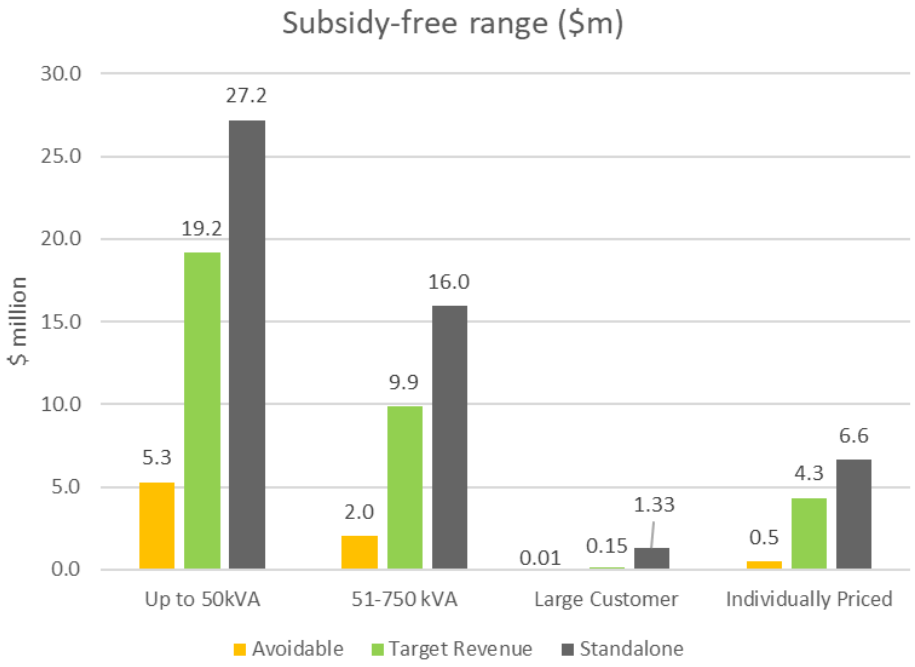
	Up to 50kVA	51-750 kVA	Large Customer	Individually Priced
Depreciation	$4,230	$2,461	$10	$346
Return on capital (pre-tax)	$10,415	$6,332	$25	$916
Opex	$9,510	$3,973	$608	$2,405
Transmission	$3,041	$3,196	$683	$2,962
Total Standalone Cost	**$27,195**	**$15,962**	**$1,327**	**$6,629**
Revenue	**$19,159**	**$9,879**	**$146**	**$4,333**
Is Revenue < Standalone cost?	Yes	Yes	Yes	Yes

To estimate avoidable cost we first identify which types of assets could be abandoned if each consumer group was no longer being supplied. We then used data published in our information disclosures to estimate the avoidable costs associated with abandoning those assets.

To estimate the standalone asset costs for each customer load group, we:

a. Identify which asset classes most resemble common assets, where the value of the assets needed to serve an individual customer load group are similar to value of assets needed to serve all customer load groups. Identify the RAB value of those assets, by asset class for each customer load group
b. For asset classes that are more attributable to individual load groups (rather than being common to the supply of multiple customer groups), we allocate the RAB value to each customer load group
c. For each customer load group, calculate the depreciation and return on capital on common assets and allocated attributable assets to estimate the standalone asset costs

Figure 5 Subsidy-free test



7 Losses

Losses represent the percentage of electricity entering the network that is either consumed or lost in the delivery process between the Grid Exit Points and the customer installation metering points and can be categorised as either technical losses or non-technical losses.

Technical losses comprise:

- standing losses arising from zone and distribution transformers; and
- variable losses arising from resistive losses in conductors. Resistive losses are proportional to the square of the current passing through the conductor.

Non-technical losses comprise:

- losses arising from metering faults or errors; and
- losses arising from electricity theft etc.

The energy measured at customers' installations is therefore after losses and must be multiplied by the overall "loss factor" to determine each energy retailer's purchase quantities at each GXP.

7.1 Low Voltage and High Voltage connection

Most customers take supply and are metered at low voltage (400/230V) and the loss factor applied to these sites must account for distribution transformer and low voltage reticulation losses. A small group of customers take supply and are metered at 11,000V and the loss factor applied to these customers does not include distribution transformer and LV reticulation losses.

7.2 Loss factor allocation

The average loss factor for the network is calculated from data supplied by the National Reconciliation Manager. This information is compared with the GXP data to determine the long run overall loss factor.

8 Distributed Generation

Network Waitaki is always keen to work with customers and to advise them of distribution alternatives such as Distributed Generation (DG) from wind or solar. We encourage any customer interested in DG to get in touch to discuss the opportunity further.

DG in our region is predominantly small-scale photovoltaic panels and this continues to grow. There are currently 290 DG connections approved on the network, comprising 1.8% (or 2.9 MW) of all connections. The average domestic photovoltaic DG installation size is 4.7 kW. Generation by DG connections make up about 0.4% of total energy consumption on the network.

Network Waitaki offers connection to DG by the standard terms defined by the Electricity Authority. The standard terms are easy to understand and are consistent with most distributors across the country. These terms can be found on the "*Solar and other distributed generation*" page on Network Waitaki's website: www.networkwaitaki.co.nz

We do not currently charge DG customers for injecting into our network. A Distributed Generation volume price is applicable to distributed generator connections for exportation of electricity over the Network Waitaki network. The price is currently set at 0c/kWh.

In future, there may be a need to charge for this, but it would be set at a level that does not discourage DG and relevant stakeholders will be consulted at the time. Revenue from these prices will recover the incremental costs of connecting the distributed generation, which includes network and overhead costs.

Any connections and payments must be carried out in accordance with Part 6 of the Electricity Industry Participation Code 2010, which is administered by the Electricity Authority.

9 GLOSSARY

ADMD	After Diversity Maximum Demand
AMP	Asset Management Plan
CoSM	Cost of Supply Model
EA	Electricity Authority
EDB	Electricity Distribution Business
GXP	Grid Exit Point
ICP	Interconnected Control Point
IND	Non-Standard
kVA	kilo Volt Ampere
kW	kilo Watt
kWh	kilo Watt hour
LV	Low Voltage
RL	Residential Low User
LFC Regulations	Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004
RLC	Residential Low User Controlled
RLU	Residential Low User Uncontrolled
WPT	Waitaki Power Trust

APPENDIX A – Delivery Price Schedule

DELIVERY PRICE SCHEDULE FOR NETWORK WAITAKI

Effective from 1 April 2025

The prices in this schedule are used to charge electricity retailers for the delivery of electricity in the Waitaki region serviced by Network Waitaki. Electricity retailers determine how to allocate this cost together with energy, metering and other retail costs when setting the retail prices that appear on an end consumer's power account.

			Effective 1 April 2024			Effective 1 April 2025			
Code	Description	Units	Distribution	Pass-through	Delivery price	Distribution	Pass-through	Delivery price	No. of Consumers
RESIDENTIAL LOW FIXED CHARGE CONNECTIONS / Price category code: RL (0 - 15 kVA)									
RLU	0 - 15kVA - Uncontrolled	$/connection/day	0.4624	0.1376	0.6000	0.5849	0.1651	0.7500	965
RLC	0 - 15kVA - Controlled	$/connection/day	0.4624	0.1376	0.6000	0.5849	0.1651	0.7500	4,506
RLUD	Day Volume - Uncontrolled	$/kWh	0.12453	0.03426	0.15879	0.14391	0.03848	0.18239	
RLCD	Day Volume - Controlled	$/kWh	0.11178	0.02207	0.13385	0.13378	0.02881	0.16259	
RLUN	Night Volume - uncontrolled	$/kWh	0.01257	0.01231	0.02488	0.01247	0.01025	0.02272	
RLCN	Night Volume - Controlled	$/kWh	0.01128	0.00227	0.01355	0.01247	0.00270	0.01517	
GENERAL CONNECTIONS / Price category code: GC									
15U	0 - 15kVA - Uncontrolled	$/connection/day	2.5142	0.7721	3.2863	2.9294	0.8677	3.7971	1,945
15C	0 - 15kVA - Controlled	$/connection/day	2.2554	0.4706	2.7260	2.7369	0.6289	3.3658	4,025
30U	16-30kVA Uncontrolled	$/connection/day	3.9716	1.3602	5.3318	4.7075	1.5965	6.3040	465
30C	16 - 30kVA - Controlled	$/connection/day	3.6009	0.9483	4.5492	4.4270	1.2469	5.6739	192
50U	31-50kVA Uncontrolled	$/connection/day	6.4040	1.6507	8.0547	7.6948	1.9645	9.6593	600
50C	31-50kVA Controlled	$/connection/day	5.9100	1.1607	7.0707	7.3380	1.5306	8.8686	150
100	51-100kVA	$/connection/day	14.0926	2.2999	16.3925	16.7692	2.8853	19.6545	373
200	101-200kVA	$/connection/day	28.1756	4.5697	32.7453	33.5269	5.7327	39.2596	135
300	201-300kVA	$/connection/day	42.1968	6.9620	49.1588	50.2112	8.7340	58.9452	56
500	301-500kVA	$/connection/day	70.7097	12.5452	83.2549	84.1395	15.7382	99.8777	27
750	501-750kVA	$/connection/day	107.8642	18.7126	126.5768	128.3506	23.4753	151.8259	13
WATAD	Day volume	$/kWh	0.02322	0.00584	0.02906	0.02769	0.00584	0.03353	
WATAN	Night volume	$/kWh	0.00259	0.00064	0.00323	0.00309	0.00064	0.00373	
DGD	Distributed Generation export (Day volume)	$/kWh	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	
DGN	Distribution Generation export (Night volume)	$/kWh	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	
LARGE COMMERCIAL / Price category code: LC (750 kVA +)									
LC	Daily fixed price	$/connection/day	2.6238	0.0000	2.6238	5.6160	0.0000	5.6160	1
LCCAP	Daily capacity price	$/kVA/day	0.1675	0.1018	0.2693	0.1917	0.1030	0.2947	
LCDEM	Daily demand price	$/kW/day	0.0751	0.0510	0.1261	0.0630	0.0153	0.0783	
INDIVIDUALLY ASSESSSED / Price category code: IND									
IND	Individually Priced								12

Note: All prices are exclusive of GST.

NOTES:

1. All Charges are GST exclusive. GST is payable in addition to the charges.

2. The price movement amounts to an average overall 19.3% increase mainly as a result of increased operational and capital expenditure. This increase is necessary to allow Network Waitaki to operate efficiently and target a secure and reliable supply of electricity through appropriate levels of investment.
For more information on how prices are determined is published in our pricing methodology which is available on the Network Waitaki website (www.networkwaitaki.co.nz).

3. Eligibility for the "Residential Low Fixed Charge" price category requires that the premises must be the consumer's principal place of residence as defined by the Electricity Industry Act 2010.

4. Volume (kWh) prices are based on volumes metered at the Grid Exit Points supplying the network. All metered loads should be grossed up using the appropriate loss factor to arrive at the chargeable GXP volume.
Different rates are applied for "day volume" (07:00 a.m. until 11:00 p.m.) and for "night volume" (11:00 p.m. until 07:00 a.m. the next morning).

5. Large Commercial (LC) load group with connections higher than 750kVA: Daily capacity prices are based on contracted capacity. Daily demand prices are applied to an assessed demand level that is available on request.
Capacity and demand prices accrue on a daily basis at the rate of 1/365th of the annual amount due, or 1/366th during a financial year that includes a leap day.

6. Distribution and Pass-through prices are charged in respect of each site and electricity retailers are invoiced monthly in arrears. Fixed prices accrue on a daily basis at the rate of 1/365th of the annual amount due, or 1/366th during a financial year that includes a leap day.

7. Pass-through prices consist of transmission prices, rates and regulatory levies.

8. Where an ICP is disconnected for seasonality reasons and reconnected in the same 12 month period, Network Waitaki reserves the right to charge the fixed charges that would have been due over the period of disconnection had the consumer not seasonally disconnected.

9. Network Waitaki pays an annual discount to consumers. Discounts will be payable based on the number of days the installation has been connected within a specific load group. The discount methodology is available on the Network Waitaki website.

10. Distributed Generation (DG) export prices apply to the volume of energy (kWh) exported from a connection point into Network Waitaki's network for delivery to other network connections. The installation of small scale generation requires a meter capable of recording both imported and exported volume data

Network Waitaki

APPENDIX B – Compliance with the Electricity Authority's Distribution Pricing Principles

This section demonstrates the extent to which Network Waitaki's pricing methodology is consistent with the Electricity Authority's pricing principles.

Pricing Principles		Network Waitaki alignment to EA principles
(a) Prices are to signal the economic costs of service provision, by:		
(i)	**being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs);**	A subsidy-free test was done showing forecast total revenue for load groups fall between standalone and avoidable costs.
(ii)	**reflecting the impacts of network use on economic costs;**	In moving away from the volume dominated pricing regime and correcting the imbalance between capacity-based fixed and volume pricing, customers are presented with a 'price signal' that more accurately conveys the cost of electricity transportation. The key driver of economic cost consists of a load group's contracted network capacity and circuit length. A fixed price based on contracted capacity allows the customer to contract for an appropriately sized connection, and similarly allows Network Waitaki to provide suitable assets to honour the contract. Capacity-based prices signal to customers the cost of providing the connection and hence the impact of network use on economic cost. Our current controlled load price plans encourage customers to make load available for control. This benefits the network as it provides an ability to move load whenever the need arise to ensure supply stability and reliability, and to manage maximum demand.
(iii)	**reflecting differences in network service provided to (or by) customers; and**	Price reflects differences in network services. Network Waitaki offers discounted prices for customer load groups (up to 50kVA price plans) who opt for controlled prices. Both distribution and transmission fixed prices are lower for controlled prices compared to the equivalent uncontrolled prices to signal the benefits of load control. Load control systems are effective in reducing demand at peak times by deferring non-critical electricity usage. The benefits of controlled load include greater predictability of the magnitude of peak demands and potential to defer transmission and distribution capacity upgrades.
(iv)	**encouraging efficient network alternatives**	In moving to a cost-reflective pricing structure, that reflects the underlying cost structure through a mainly capacity-based fixed price component, customers are encouraged to consider efficient network alternatives where it makes economic sense. Capacity-based pricing for delivery supports the decision-making process through price signals that indicate the economic cost of the grid connection.

	Electricity distribution is a small component of the electricity bill of a customer and diluting signals with other components (e.g. Time of Use) results in customers not being incentivised to optimise their contractual capacity size and so limit the cost of connection. For example, customers connected to capacity sizes larger than their demand requirements as well as investment in distributed generation.

(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.

Current price structures signal economic cost through the capacity-based fixed price component. The volume-based component applicable to LFC customers dilute an efficient signal and subjects Network Waitaki to revenue risk and potential under-recovery of target revenue, mainly due to weather volatility.

Network Waitaki has not experienced any shortfalls on target revenue, but any potential shortfall will be recovered through price increases to the capacity component that least distort network use. A predominantly capacity-based pricing structure reflects the impact of network use on economic cost and is least distortionary as those customers requiring larger capacities with less elasticity are allocated higher cost.

Marginal pricing signals on the short term is not part of our long-term pricing approach, as the main impact on our business is providing for long-term capacity to ensure we supply customers' peak demand when required. This will be achieved through a mostly single pricing signal, aligned with the major cost driver of the business, to influence customer behaviour. Marginal pricing signals will in most cases not have an impact as distribution prices make up about 30% of the total electricity bill and the impact of marginal pricing signals on customer behaviour is negligible. Also please see par. 3.3.4 regarding consideration of LRMC.

Capacity-based pricing enhances the ability to obtain customer reaction and to reduce network cost, while reducing the customer's price.

Pricing for non-standard customers is already mostly fixed (and thus least distortionary). Prices are calculated as an annually recalculated fixed price with the contracted capacity component over 80% and the contribution the customer's installation makes to system demand less than 20% to the price in FY2026.

In time, through reflecting the business cost structure in pricing and by not being subject to uncontrollable variables, such as rainfall, under-recovery of target revenues should not be a major issue.

(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	Network Waitaki does have non-standard customers, that were historically considered and negotiated on a case-by-case basis according to the specific needs of the customer. Pricing was tailored to reflect the cost to supply the unique needs of the customer. Care is taken to ensure prices are above avoidable cost and below stand-alone cost. Network Waitaki has 12 customers on non-standard price plans. For standard load groups our pricing strategy explains the process of achieving a pricing structure that results in prices that reflect the economic cost of service provision. The pricing structure with a dominant fixed capacity-based component (applicable to all price plans, including LFC once terminated) will provide customers with options and an appropriate signal to ensure they are on appropriate connection sizes for the electricity usage they have.

(ii)	**enable price/quality trade-offs**	Network Waitaki is 100% owned by the Waitaki Power Trust (WPT). Trustees of the WPT represent the interests of customers and engage with Network Waitaki to ensure the company makes appropriate price/quality trade-offs. In addition, for non-standard customers, Network Waitaki has in the past negotiated a service tailored to the requirements of the individual customer, making a price-quality trade-off appropriate for that customer. Non-standard price plans with quality aspects will continue to be available in future but only for those customers that do not fit into any of the standard load groups and have special and unique requirements.

(d) Development of prices should be transparent and have regard to transaction costs, customer impacts, and uptake incentives.

The pricing methodology of Network Waitaki is transparent, with a focus on limiting negative impacts on customers and incentivising efficient usage through development of cost reflective pricing. Price structure realignment has occurred at a slow and steady pace over the past few years with no change to current price structures itself, i.e. capacity-based fixed prices and day/night volume-based prices are still in place. The intent is to keep prices structures simplistic and understandable while offering choices to customers to encourage the most efficient use of the network.

Price structure rebalancing has been done in such a way to limit major impacts on customers. Network Waitaki has developed a pricing information sheet to explain price changes and have engaged with customers to discuss their options with a view of limiting transaction cost. Furthermore, through its ownership by WPT, and the regular engagement with Trustees of the WPT (who represent the interests of customers), Network Waitaki ensures that network prices are transparent to WPT and have full regard to the impact network prices have on customers. Any rebalancing of current and future price design is and will be accompanied by careful analysis of bill impacts on all customers.

Network Waitaki's prices do not favour one retailer over another. The pricing methodology and applicable prices are identical across all retailers, with no discrimination regarding available price plan options, applicable prices, calculation methodology, or discounts.

As Network Waitaki is not considering structural changes to its current price structures assignment policies such as opt-in, opt-out and event-based will not be that relevant but will be considered on a continuous basis. Currently, except for LFC price plans, the cost-reflective price structure has been achieved.

APPENDIX C – Information Disclosure Compliance Checklist

The table below contains a check list that summarises compliance to all the pricing and related information requirements as per section 2.4. of the Information Disclosure Guidelines.

Clause in Determination	Reference in Pricing Methodology
2.4.1 Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which-	
Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the prices payable or to be payable;	
Describes any changes in prices and target revenues;	Appendix A for changes to prices. Paragraph 6.2 for changes to target revenues.
Explains, in accordance with clause 2.4.5 below, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any);	Paragraphs 5.3 and 5.6 Paragraph 8 for a discussion on Distributed Generation.
Explains whether, and if so how, the EDB has sought the views of customers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of customers, the reasons for not doing so must be disclosed.	Paragraph 3.7 for an explanation of Network Waitaki's customer Engagement.
2.4.2 Any change in the pricing methodology or adoption of a different pricing methodology, must be publicly disclosed at least 20 working days before prices determined in accordance with the change or the different pricing methodology take effect.	There have been no material changes to the pricing methodology since publication of the last methodology in 2024.
2.4.3 Every disclosure under clause 2.4.1 above must-	
Include sufficient information and commentary to enable interested persons to understand how prices were set for each customer group, including the assumptions and statistics used to determine prices for each customer group;	Section 5 explain how prices were set for each customer group, for both standard and non-standard plans. Paragraph 6.1 provide more detail on allocation of revenue requirement.
Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;	Appendix B details the consistency of Network Waitaki's pricing methodology with the Electricity Authority Pricing Principles.
State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	Paragraph 6.2 shows the target revenue to be collected in the disclosure year 2025-2026
Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision	Paragraph 4.2 shows the components of target revenue to be collected in the disclosure year 2025-2026

Clause in Determination	Reference in Pricing Methodology
of electricity lines services. Disclosure must include the numerical value of each of the components;	
State the customer groups for whom prices have been set, and describe (a) the rationale for grouping customers in this way; (b) the method and the criteria used by the EDB to allocate customers to each of the customer groups;	Section 5 details customer groups and the rationale for grouping customers this way and the method and criteria that Network Waitaki has used to allocate customers to each group.
If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons;	Note 2 in Appendix A provides the details.
Where applicable, describe the method used by the EDB to allocate the target revenue among customer groups, including the numerical values of the target revenue allocated to each customer group, and the rationale for allocating it in this way;	Section 6.
State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	Network Waitaki's revenue is targeted across customer groups as stipulated in paragraph 6.2
2.4.4 Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy-	Section 3.1 outlines Network Waitaki's thinking on price reform.
Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set;	Section 3 outlines Network Waitaki's thinking on price reform.
Explain how and why prices for each customer group are expected to change as a result of the pricing strategy;	Section 3 outlines Network Waitaki's thinking on price reform.
If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.	Not applicable.
2.4.5 Every disclosure under clause 2.4.1 above must-	
Describe the approach to setting prices for non-standard contracts, including-	
the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from customers subject to non-standard contracts;	There are 12 customers on non-standard contracts. The value of target revenue from non-standard contracts is depicted in paragraph 6.2.
how the EDB determines whether to use a non-standard contract, including any criteria used;	Network Waitaki has several historic non-standard customers. However, it will only consider non-standard plans to new customers when there are particular and compelling reasons for doing so.

Clause in Determination	Reference in Pricing Methodology
any specific criteria or methodology used for determining prices for customers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles;	The methodology for determining prices for non-standard contracts is detailed in paragraphs 5.3 and 5.6.
Describe the EDB's obligations and responsibilities (if any) to customers subject to non-standard contracts in the event that the supply of electricity lines services to the customer is interrupted. This description must explain-	This is not applicable as Network Waitaki does not treat interruptions to non-standard contract customers any differently to those on standard contracts.
the extent of the differences in the relevant terms between standard contracts and non-standard contracts;	Not applicable as above.
any implications of this approach for determining prices for customers subject to non-standard contracts;	Not applicable as above.
Describe the EDB's approach to developing prices for electricity distribution services provided to customers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the-	Section 8
prices; and	Par. 5.8 and Section 8
value, structure and rationale for any payments to the owner of the distributed generation	Section 8

APPENDIX D – Compliance with the Electricity Authority's areas of focus

In two open letters (September 2022 and May 2024) to Distributors the Electricity Authority identified ten areas of focus for distribution pricing reform. Network Waitaki has considered these areas of focus and found it to be similar to the high-level themes of its own pricing strategy.

The focus areas are addressed as follows in the pricing strategy:

1. **Distributors' roadmaps responding to future network congestion**

Network Waitaki's strategy in section 3 has as its main aim signalling to customers the cost of providing a distribution service and maintaining load control pricing plans to incentivise customers to make load available for control when required. Our network is generally unconstrained and once the new GXP is operational we would encourage usage. An appropriate fixed capacity-based / volume-based ratio has been achieved (except for LFC price plans) reflecting the fixed cost nature of the business. Our customers will through this approach obtain the greatest value from their use of electricity with investments being made at the right time and place.

2. **Distributors' response to any significant first mover disadvantage (FMD) issues facing customers seeking to connect to their networks (new and expanded connections).**

Network Waitaki's capital contribution policy, clause 5.2 on "*Reapportionments*" provides for this type of situation where reapportionment of direct network extension costs may apply in the instance of a customer connecting to assets which other customers have paid for within the previous five years.

"Deep" connection network infrastructure investment such as a new GXP or zone substation are funded by Network Waitaki and the cost socialised across all customers, except where a single user (or small group of users) is the main beneficiary of such an investment.

3. **The extent to which distributors are following the Authority's guidance on pass-through of new transmission charges.**

Network Waitaki has followed the Authority guidance on pass-through of transmission charges, i.e. that it should be fixed-like and not incentivise behaviour that influence usage.

4. **Whether distributors are increasing their use of fixed charges to match the phase-out path of the low fixed charge tariff regulations.**

Network Waitaki have increased fixed charges to match the phase-out path of the LFC regulations.

5. **Distributors avoiding, or transitioning away from, recovery of costs that are fixed in nature through use-based charges, such as charges based on a customer's Anytime Maximum Demand (AMD).**

Network Waitaki continues to transition away from recovery of costs that are fixed in nature through volume-based charges.

6. **Allocate revenue transparently**

Section 6 describes how we allocate costs to each customer load group and describes the subsidy-free test that we have applied. Details on the allocators used to determine target revenue for each customer load group are illustrated in Appendices F and G.

7. **Assign all ICPs to time-varying distribution tariffs (limited exceptions only)**

Network Waitaki charges for usage (kWh) based on measurements made at the GXP, and applies a time of day structure to all kWh that are charged for.

8. Set peak rates based on a measure of Long-Run Marginal Cost

Network Waitaki has set its peak (day) rate to a level that is within the estimated LRMC range. Our off-peak (night) rate is close to zero.

9. Reduce off-peak and controlled rates

We have set our off-peak (night) rate close to zero.

The way that our pricing differentiates between controlled and uncontrolled services is through a difference in the fixed daily charge, rather than through usage charges (kWh).

10. Follow up on Asset Management Plan reporting on readiness for increased electrification due to decarbonisation

Further to the 2021 Asset Management Plan (AMP), and as explained in section 4.3 of the 2025-2035 AMP, to ensure we are ready for increased electrification our strategy is to increase network capacity, understand real-time constraints, model future scenarios and plan timely solutions. We have four initiatives underway, namely:

- Increase in network capacity: We are working towards the construction of a new GXP in conjunction with Transpower to enable process heat and transport decarbonisation.
- LV monitoring: Since 2022, from trialling the monitoring of ten transformers we are now monitoring 105 transformers and 240 LV feeders. This covers 50% of Oamaru residential customers with the aim of increasing coverage to 90% over the next three years. This will allow us to understand existing LV hosting capacity, monitor trends, protect assets, and plan timely investment.
- Network model enhancement: From development of a load flow model in 2022 to syncing with the GIS system – planned for 2026. This allows us to model future energy scenarios, understand future constraints and plan timely investment.
- Smart meter data trial: Trial underway of an analytics system using smart meter data procured from MEPs. This trial will allow us to evaluate benefits from this data to augment our LV monitoring program

APPENDIX E – Breakdown of required revenue by GXP

Table 11 shows the allocation of the revenue requirement by cost component and cost driver to the four Network Waitaki GXPs.

Table 11: Required revenue allocated to GXP by cost component and cost driver for the pricing year

Cost description	Price recovery category	Cost Driver	Required revenue				
			Oamaru	Waitaki	Twizel	Black Point	Total
Service Interruptions and Emergencies	Distribution	Line Length	$557,572	$84,637	$57,791	$0	$700,000
Vegetation Management	Distribution	Line Length	$612,157	$92,923	$63,449	$0	$768,528
Routine and Corrective Maintenance	Distribution	Line Length	$1,185,877	$180,011	$122,914	$0	$1,488,802
Asset Replacement and Renewal	Distribution	RAB	$197,592	$60,580	$23,276	$0	$281,448
System Operations and Network Support	Distribution	No. of ICPs	$3,812,084	$550,218	$230,356	$342	$4,593,000
Business Support	Distribution	No. of ICPs	$3,863,543	$557,645	$233,466	$346	$4,655,000
Depreciation - Network Assets	Distribution	RAB – Depreciation	$4,014,041	$1,073,882	$412,077	$0	$5,500,000
Depreciation - Non-network Assets	Distribution	RAB – Depreciation	$101,434	$27,137	$10,413	$0	$138,985
Cost of Capital	Distribution	Installed Capacity	$6,111,885	$1,172,960	$416,221	$512,136	$8,213,202
Rates	Pass-through	No. of ICPs	$120,356	$17,372	$7,273	$0	$145,000
Commerce Act Levies	Pass-through	No. of ICPs	$20,751	$2,995	$1,254	$0	$25,000
Electricity Authority Levies	Pass-through	No. of ICPs	$55,613	$8,027	$3,361	$0	$67,000
FENZ Levies	Pass-through	No. of ICPs	$30,711	$4,433	$1,856	$0	$37,000
Utilities Disputes Levies	Pass-through	No. of ICPs	$8,300	$1,198	$502	$0	$10,000
New investment charges	Pass-through	Attributable	$53,075	$63,974	$0	$158,270	$275,319
Avoided cost of Transpower charges	Pass-through	Attributable	$0	$311,085	$0	$0	$311,085
Connection Charge	Pass-through	Attributable	$689,047	$208,369	$291,596	$16,976	$1,205,988
Benefit-based charges (BBC)	Pass-through	Attributable	$648,399	$85,683	$34,570	$100,471	$869,123
Residual Charge	Pass-through	Attributable	$3,093,179	$555,650	$177,453	$407,779	$4,234,062
Transitional Cap	Pass-through	Attributable	$2,019	$539	$225	$0	$2,783
Total Revenue Requirement			**$25,177,637**	**$5,059,315**	**$2,088,053**	**$1,196,319**	**$33,521,324**

APPENDIX F – Allocation of cost drivers to consumer groups

The following table shows the high-level allocation of cost drivers to standard consumer groups and non-standard consumer groups for the four GXPs.

Table 12: Allocation of cost drivers to standard and non-standard consumer groups

ALLOCATION OF COST DRIVERS TO STANDARD AND NON-STANDARD CONSUMER GROUPS FOR OAMARU GXP

Consumer group	Installed capacity	Peak demand	Anytime Maximum Demand
Standard consumer group	91%	76%	76%
Non-standard consumer group	9%	24%	24%

ALLOCATION OF COST DRIVERS TO STANDARD AND NON-STANDARD CONSUMER GROUPS FOR WAITAKI GXP

Consumer group	Installed capacity	Peak demand	Anytime Maximum Demand
Standard consumer group	96%	98%	99%
Non-standard consumer group	1%	2%	1%

ALLOCATION OF COST DRIVERS TO STANDARD AND NON-STANDARD CONSUMER GROUPS FOR TWIZEL GXP

Consumer group	Installed capacity	Peak demand	Anytime Maximum Demand
Standard consumer group	97%	96%	93%
Non-standard consumer group	3%	4%	7%

ALLOCATION OF COST DRIVERS TO STANDARD AND NON-STANDARD CONSUMER GROUPS FOR BLACK POINT GXP

Consumer group	Installed capacity	Peak demand	Anytime Maximum Demand
Standard consumer group	0%	0%	0%
Non-standard consumer group	100%	100%	100%

From this high-level allocation each consumer group are allocated cost drivers in proportion to each consumer group's share of the cost driver. This allocation is shown in the tables below. No allocation of cost drivers to standard consumer groups are applicable for Black Point GXP, as this GXP only has NOIC as a customer.

Table 13: Allocation of cost drivers to standard consumer groups for Oamaru GXP

ALLOCATION OF COST DRIVERS TO STANDARD CONSUMER GROUPS FOR OAMARU GXP

Consumer group	No. of ICPs	Consumption	Line Length	Installed Capacity	Peak Demand	Anytime Maximum Demand
RLU	6%	2%	7%	4%	2%	2%
RLC	37%	15%	34%	24%	13%	15%
15U	12%	5%	13%	8%	3%	5%
15C	31%	20%	30%	20%	13%	20%
30U	3%	2%	3%	4%	2%	2%
30C	1%	1%	1%	2%	1%	1%
50U	4%	9%	5%	10%	12%	10%
50C	1%	3%	1%	3%	2%	3%
100	2%	17%	3%	11%	17%	17%
200	1%	10%	1%	7%	10%	10%
300	0.3%	6%	0.4%	5%	6%	6%
500	0.1%	7%	0.2%	3%	17%	6%
750	0.1%	3%	0.1%	2%	4%	3%

Table 14: Allocation of cost drivers to standard consumer groups for Waitaki GXP

ALLOCATION OF COST DRIVERS TO STANDARD CONSUMER GROUPS FOR WAITAKI GXP

Consumer group	No. of ICPs	Consumption	Line Length	Installed Capacity	Peak Demand	Anytime Maximum Demand
RLU	9%	1%	9%	4%	1%	1%
RLC	17%	3%	16%	8%	3%	3%
15U	24%	4%	25%	11%	3%	4%
15C	28%	8%	27%	12%	7%	8%
30U	6%	2%	6%	5%	2%	3%

ALLOCATION OF COST DRIVERS TO STANDARD CONSUMER GROUPS FOR WAITAKI GXP

Consumer group	No. of ICPs	Consumption	Line Length	Installed Capacity	Peak Demand	Anytime Maximum Demand
30C	2%	1%	1%	2%	1%	1%
50U	4%	5%	4%	6%	6%	5%
50C	1%	1%	1%	1%	1%	1%
100	5%	22%	6%	14%	18%	23%
200	2%	19%	3%	14%	18%	19%
300	1%	8%	1%	8%	5%	8%
500	0.4%	10%	1%	7%	13%	10%
750	0.4%	15%	0.2%	8%	22%	13%

Table 15: Allocation of cost drivers to standard consumer groups for Twizel GXP

ALLOCATION OF COST DRIVERS TO STANDARD CONSUMER GROUPS FOR TWIZEL GXP

Consumer group	No. of ICPs	Consumption	Line Length	Installed Capacity	Peak Demand	Anytime Maximum Demand
RLU	7%	1%	8%	4%	2%	1%
RLC	14%	3%	14%	7%	4%	3%
15U	32%	8%	35%	17%	5%	8%
15C	26%	10%	26%	13%	10%	10%
30U	7%	6%	6%	7%	3%	6%
30C	1%	1%	1%	1%	1%	1%
50U	6%	9%	5%	10%	10%	9%
50C	0.2%	0.3%	0.2%	0.3%	0.5%	0.3%
100	3%	18%	3%	11%	15%	18%
200	2%	26%	1%	13%	24%	26%
300	0.5%	4%	1%	5%	5%	4%

ALLOCATION OF COST DRIVERS TO STANDARD CONSUMER GROUPS FOR TWIZEL GXP

Consumer group	No. of ICPs	Consumption	Line Length	Installed Capacity	Peak Demand	Anytime Maximum Demand
500	1%	13%	0.4%	11%	21%	13%
750	0%	0%	0%	0%	0%	0%

Table 16: Allocation of cost drivers to non-standard and LC consumer groups

ALLOCATION OF COST DRIVERS TO NON-STANDARD AND LC CONSUMER GROUPS FOR OAMARU GXP

Consumer group	Installed Capacity	Peak Demand	Anytime Maximum Demand
LC (750+)	5%	3%	3%
Non-standard	95%	97%	97%

ALLOCATION OF COST DRIVERS TO NON-STANDARD AND LC CONSUMER GROUPS FOR WAITAKI GXP

Consumer group	Installed Capacity	Peak Demand	Anytime Maximum Demand
LC (750+)	0%	0%	0%
Non-standard	100%	100%	100%

ALLOCATION OF COST DRIVERS TO NON-STANDARD AND LC CONSUMER GROUPS FOR TWIZEL GXP

Consumer group	Installed Capacity	Peak Demand	Anytime Maximum Demand
LC (750+)	0%	0%	0%
Non-standard	100%	100%	100%

ALLOCATION OF COST DRIVERS TO NON-STANDARD AND LC CONSUMER GROUPS FOR BLACK POINT GXP

Consumer group	Installed Capacity	Peak Demand	Anytime Maximum Demand
LC (750+)	0%	0%	0%
Non-standard	100%	100%	100%

APPENDIX G – Historical quantities used for cost drivers

Table 17 shows the quantities used for each load group of each cost driver to allocate required revenue to the Oamaru GXP.

Note: Line length cost driver for each price plan is the sum of the distance (km) of each ICP in that price plan to the respective GXP from which it is supplied.

Table 17: Quantities used to allocate required revenue to the Oamaru GXP for the pricing year

Consumer group	No. of ICPs	Consumption	Line Length	Installed Capacity	Peak Demand	Anytime Max Demand	RAB	RAB depreciation
		MWh	km	MVA	MW	MW	$'000	$'000
RLU (Residential Low User 15U)	709	3,566	15,756	11	1	3		
RLC (Residential Low User 15C)	4,100	25,216	75,242	61	4	20		
15U (0-15kVA Uncontrolled)	1,311	7,634	29,302	20	1	6		
15C (0-15kVA Controlled)	3,451	33,636	65,393	52	4	26		
30U (16-30kVA Uncontrolled)	333	3,436	6,497	10	1	3		
30C (16-30kVA Controlled)	157	1,996	2,693	5	0	2		
50U (31-50kVA Uncontrolled)	497	15,893	10,268	25	4	13		
50C (31-50kVA Controlled)	134	4,861	2,185	7	1	4		
100 (51-100kVA)	270	29,006	7,325	27	6	23		
200 (101-200kVA)	85	16,631	2,384	17	3	13		
300 (201-300kVA)	38	9,537	878	12	2	8		
500 (301-500kVA)	15	11,121	329	8	6	9		
750 (501-750kVA)	7	5,566	187	5	1	4		
LC (750kVA+)	1	1,749	25	1	0	1		
IND (Non-Standard)	50	52,909	892	26	10	41		

Consumer group	No. of ICPs	Consumption	Line Length	Installed Capacity	Peak Demand	Anytime Max Demand	RAB	RAB depreciation
Total	**11,160**	**222,757**	**219,355**	**286**	**42**	**175**		
Network (Distribution and LV Cables)							$7,815	$341
Network (Distribution and LV Lines)							$29,469	$1,139
Network (Distribution Substations and Transformers)							$15,567	$581
Network (Distribution Switchgear)							$10,675	$412
Network (Subtransmission Cables)							$1,723	$33
Network (Subtransmission Lines)							$8,085	$157
Network (Zone Substations)							$13,741	$430
Network (Other)							$3,296	$115
Non-network (Non-network)							$3,728	$457
Total							**$94,100**	**$3,665**

Table 18 shows the quantities used for each load group of each cost driver to allocate required revenue to the Waitaki GXP.

Table 18: Quantities used to allocate required revenue to the Waitaki GXP for the pricing year

Consumer group	No. of ICPs	Consumption	Line Length	Installed Capacity	Peak Demand	Anytime Max Demand	RAB	RAB depreciation
		MWh	km	MVA	MW	MW	$'000	$'000
RLU (Residential Low User 15U)	148	556	3,064	2	0	0		
RLC (Residential Low User 15C)	274	1,376	5,236	4	0	1		
15U (0-15kVA Uncontrolled)	387	1,611	8,316	6	0	1		
15C (0-15kVA Controlled)	442	3,486	8,947	7	1	3		
30U (16-30kVA Uncontrolled)	89	1,107	1,969	3	0	1		
30C (16-30kVA Controlled)	28	429	466	1	0	0		
50U (31-50kVA Uncontrolled)	69	2,338	1,312	3	1	2		

Consumer group	No. of ICPs	Consumption	Line Length	Installed Capacity	Peak Demand	Anytime Max Demand	RAB	RAB depreciation
50C (31-50kVA Controlled)	16	547	198	1	0	0		
100 (51-100kVA)	78	10,063	1,880	8	2	8		
200 (101-200kVA)	39	8,500	1,007	8	2	7		
300 (201-300kVA)	14	3,725	378	4	1	3		
500 (301-500kVA)	7	4,445	182	4	2	3		
750 (501-750kVA)	6	6,849	69	5	3	5		
LC (750kVA+)	0	0	0	0	0	0		
IND (Non-Standard)	15	526	273	0	0	0		
Total	**1,611**	**45,558**	**33,297**	**55**	**12**	**35**		
Network (Distribution and LV Cables)							$2,496	$109
Network (Distribution and LV Lines)							$7,521	$291
Network (Distribution Substations and Transformers)							$2,658	$99
Network (Distribution Switchgear)							$2,652	$102
Network (Subtransmission Cables)							$0	$0
Network (Subtransmission Lines)							$6,828	$132
Network (Zone Substations)							$5,948	$186
Network (Other)							$351	$12
Non-network (Non-network)							$397	$49
Total							**$28,850**	**$980**

Table 19 shows the quantities used for each load group of each cost driver to allocate required revenue to the Twizel GXP.

Table 19: Quantities used to allocate required revenue to the Twizel GXP for the pricing year

Consumer group	No. of ICPs	Consumption	Line Length	Installed Capacity	Peak Demand	Anytime Maximum Demand	RAB	RAB depreciation
		MWh	km	MVA	MW	MW	$'000	$'000
RLU (Residential Low User 15U)	49	186	1,664	1	0	0		
RLC (Residential Low User 15C)	93	528	3,056	1	0	0		
15U (0-15kVA Uncontrolled)	211	1,243	7,692	3	0	1		
15C (0-15kVA Controlled)	172	1,501	5,786	3	0	1		
30U (16-30kVA Uncontrolled)	45	945	1,300	1	0	1		
30C (16-30kVA Controlled)	8	132	287	0	0	0		
50U (31-50kVA Uncontrolled)	38	1,377	1,189	2	0	1		
50C (31-50kVA Controlled)	1	52	33	0	0	0		
100 (51-100kVA)	21	2,828	576	2	0	2		
200 (101-200kVA)	12	3,936	232	2	1	3		
300 (201-300kVA)	3	613	176	1	0	1		
500 (301-500kVA)	4	1,974	89	2	1	2		
750 (501-750kVA)	0	0	0	0	0	0		
LC (750kVA+)	0	0	0	0	0	0		
IND (Non-Standard)	17	1,210	655	1	0	1		
Total	**674**	**16,526**	**22,736**	**20**	**3**	**13**		
Network (Distribution and LV Cables)							$1,389	$61
Network (Distribution and LV Lines)							$2,538	$98
Network (Distribution Substations and Transformers)							$1,595	$60

Network (Distribution Switchgear)	$1,505	$58
Network (Subtransmission Cables)	$0	$0
Network (Subtransmission Lines)	$2,772	$54
Network (Zone Substations)	$1,166	$36
Network (Other)	$56	$2
Non-network (Non-network)	$63	$8
Total	**$11,085**	**$376**

Table 20 shows the quantities used for each load group of each cost driver to allocate required revenue to the Black Point GXP.

Table 20: Quantities used to allocate required revenue to the Black Point GXP for the pricing year

Consumer group	No. of ICPs	Consumption	Line Length	Installed Capacity	Peak Demand	Anytime Maximum Demand	RAB	RAB depreciation
		MWh	km	MVA	MW	MW	$'000	$'000
RLU (Residential Low User 15U)	0	0	0	0	0.0	0.0		
RLC (Residential Low User 15C)	0	0	0	0	0.0	0.0		
15U (0-15kVA Uncontrolled)	0	0	0	0	0.0	0.0		
15C (0-15kVA Controlled)	0	0	0	0	0.0	0.0		
30U (16-30kVA Uncontrolled)	0	0	0	0	0.0	0.0		
30C (16-30kVA Controlled)	0	0	0	0	0.0	0.0		
50U (31-50kVA Uncontrolled)	0	0	0	0	0.0	0.0		
50C (31-50kVA Controlled)	0	0	0	0	0.0	0.0		
100 (51-100kVA)	0	0	0	0	0.0	0.0		
200 (101-200kVA)	0	0	0	0	0.0	0.0		
300 (201-300kVA)	0	0	0	0	0.0	0.0		

500 (301-500kVA)	0	0	0	0	0.0	0.0		
750 (501-750kVA)	0	0	0	0	0.0	0.0		
LC (750kVA+)	0	0	0	0	0.0	0.0		
IND (Non-Standard)	1	38,719	0	24	15	29		
Total	**1**	**38,719**	**0**	**24**	**15**	**29**		
Network (Distribution and LV Cables)							$0	$0
Network (Distribution and LV Lines)							$0	$0
Network (Distribution Substations and Transformers)							$0	$0
Network (Distribution Switchgear)							$0	$0
Network (Subtransmission Cables)							$0	$0
Network (Subtransmission Lines)							$0	$0
Network (Zone Substations)							$0	$0
Network (Other)							$0	$0
Non-network (Non-network)							$0	$0
Total							$0	$0