Methodology for deriving delivery prices

For prices applying from 1 April 2026

Issued 25 February 2026

We are pleased to present our Pricing Methodology Disclosure for prices effective 1 April 2026 to 31 March 2027 (the Pricing Methodology).

Purpose Statement

The purpose of this Pricing Methodology is to outline the approach used in setting our prices for electricity distribution lines services effective from 1 April 2026 to 31 March 2027 (the pricing year).

Before 1 April each year, we publish our Pricing Methodology, as is required by section 2.4, Pricing and Related Information, of the *Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024 [2024] NZCC 31* (the ID Determination).

Our goal, every pricing year, is to set prices that signal the efficient use of our electricity distribution network (the network) for the long-term benefit of consumers. We signal the efficient use of our network through prices that reflect our costs to serve, and signal future investments needed on our network. Efficient pricing is particularly important as New Zealand embarks on its journey to be Net Zero Carbon by 2050.

Our pricing approach

Our pricing objective is to strike the right balance between the prices consumers pay and the provision of a reliable and resilient electricity supply that meets the needs and expectations of our central Canterbury community. Like roads, electricity networks have limited capacity and our 'rush hour' typically occurs on very cold winter mornings and evenings. Our priority is to ensure our network can sustain these demand peaks, even though they are typically only for short periods of time.

We have options as to how we meet peak demand. One option is to increase our network's capacity, much like making the roads bigger to handle an increased volume of traffic. This option, however, is expensive and would require increases in prices to cover the expansion cost. A second option is to actively promote mechanisms such as ripple control, through consumers taking up controlled prices or responding to control signals, whereby congestion on the network can be alleviated during periods of high or 'peak' electrical demand by shifting some consumption to an off-peak period.

We prefer the second option as this is the least cost option and keeps prices and services at levels our consumers expect. Accordingly, we use 'price signals' — charging higher prices during periods of high electricity demand and lower prices during low demand periods — to support and reward consumers managing their use in this way. Ways in which consumers do this include:

- Having hot water cylinders peak load controlled, which means hot water load can be switched off and on by us
- Heating hot water only at night
- Investing in more efficient forms of heating such as heat pumps, which produce much more heat output for the same electrical input
- Moving consumption to a different time of day, or reducing the level of consumption when signalled

Peak and off-peak pricing

Determining the peak periods price differential is complicated. Some parts of our network cost more than others, and different parts are used to deliver electricity to more than 233,000 individual consumer connections. Individual consumer pricing is simply not feasible for all connections.

To recognise the key differences in the usage and cost of our network, we separate consumer connections into various connection categories:

- Residential and small business connections – where electricity use peaks in winter.
- Major customer and embedded network connections – businesses that are large electricity consumers or embedded networks.
- Irrigation connections – for farms with significant irrigation requirements.
- Street lighting connections – for private and publicly owned dedicated lighting connections supplied from a separate lighting network.
- Large capacity connections – for very large businesses with significant load for which we negotiate an individual price due to their size and impact on the local network.

More detail on how we apply our prices and how the chargeable quantities are calculated for each connection category, can be found in our Pricing Policy document, which is available on our website.[1]

[1] https://www.oriongroup.co.nz/our-story/pricing

Orion

Glossary

Abbreviation / Term	Definition or description
2026/27 Disclosure of Prices	Orion New Zealand Disclosure of Prices
Annual Price Setting Compliance Statement	Discloses how much revenue a network can collect and demonstrates that forecast prices are set at a level to collect that revenue
Capacity	The maximum amount of energy that a part of the network is able to carry at any point in time
CER	Consumer Energy Resources
Commerce Commission	New Zealand Commerce Commission
Consumer	A person, residential or business, that uses electricity or acquires electricity lines services
Consumer group	The category of consumer used by the Electricity Distribution Business (distributor's) for the purpose of setting prices
Controlled load	An amount of electrical load which a consumer makes available to the distributor's load control system to turn off during periods of network congestion or to assist in restoring supply
CPI	Consumer Price Index inflation
CPP	The Commerce Commission sets a price-quality path for each regulated lines company – a price path is the maximum total revenue a lines company can recover from its consumers and the quality path is the minimum level of quality of service that it must provide. A customised price path (CPP) is a unique price-path used to deliver a specific programme of work
Delivery price	The total delivery price for both distribution and transmission services (also known as lines charges)
Demand	Maximum amount of energy demanded from the network at any given time
DER	Distributed Energy Resources
Distributed generator	Any person who owns or operates equipment that is connected to our distribution network, including through a consumer installation, which is capable of injecting electricity into the network

Distribution Network	A distribution network is the network of equipment that carries electricity from the high voltage transmission grid to industrial, commercial, and domestic users
Distribution pricing practice note	2022 distribution pricing practice note 2nd edition provides guidelines to help distributors interpret and apply the distribution pricing principles. This can be found on the Electricity Authority's website
DPP	The Commerce Commission sets a price-quality path for each regulated lines company – a price path is the maximum total revenue a lines company can recover from its consumers and the quality path is the minimum level of quality of service that it must provide. A default price path (DPP) is a low cost, standard method of calculating the price-quality path for lines company's not on a CPP.
DPP Determination 2025	Electricity Distribution Services Default Price-Quality Path Determination 2025, [2024] NZCC 28 – 20 November 2024
Electricity Authority	The Electricity Authority is an independent Crown entity responsible for the efficient operation of the New Zealand electricity market. It is the electricity market regulator
Electricity distribution services	Electricity distribution services are the conveyance of electricity on lines from the transmission GXP to consumers ICPs
EV	Electric Vehicle
Flexibility services	Services which use consumer smart devices to move electricity demand away from congested periods on the network
GXP	A point of supply to [our] distribution network from Transpower's national transmission grid
HV	High Voltage – equipment or supplies at voltages of 11kV, 22kV or 33kV
ICP	An Installation Control Point (ICP) is a physical point of connection on a local network or an embedded network that the distributor nominates as the point at which a retailer will be deemed to supply electricity to a consumer
ID Determination	Electricity Distribution Information Disclosure Determination (amendments related to IM Review 2023) Amendment Determination 2024, [2024] NZCC 31 — 27 November 2024
IM Determination	Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023, [2023] NZCC 35 — 13 December 23

LCT	Low Carbon Technologies
LFC Regulations	Electricity (Low Fixed Charge Price Option for Domestic Consumers) Regulation 2004 and Electricity (Low Fixed Charge Price Option for Domestic Consumers) Amendment Regulations 2021
Lines charges	Refer to Delivery price
LRMC	Long Run Marginal Costs
LV	Low Voltage – equipment of supply at a voltage of 220V single phase or [415V] three phases
Network	The electricity distribution equipment owned by us for the conveyance of electricity. Network assets include substations, lines, poles, transformers, circuit breakers, switchgear, cabling etc.
Point of connection	A point at which a consumer's fittings interconnect with the Network as described in our Network Connection Standard
Power Factor (PF)	A measure of the ratio of real power to total power of a load. The relationship between real, reactive and total power is as follows: PF= Real Power (kW)/Total Power (kVA) Total Power kVA=$(kW^2+kVAr^2)^{0.5}$
Pricing Methodology	Orion New Zealand Pricing Methodology Disclosure Document
Pricing Principles	The Electricity Authority Distribution Pricing Principles. Guidance as to how to apply these pricing principles is provided in "Distribution Pricing: Practice Note – second edition v2.2, 2022. This can be found on the Electricity Authority's website
RAB	Regulated Asset Base – is the regulated value of the distribution assets that we use to provide full line function services
Regulatory Period	A regulatory period is the period that a price quality path determination applies to; usually five years.
Regulatory Year	A regulatory year is the 12-month period from 1 April to 31 March
TPM	Transmission Pricing Methodology is the methodology and approach, set by the Electricity Authority and implemented by Transpower, to allocate transmission costs to the user of grid services, including distributor's

1. Introduction

1.1 Who is Orion New Zealand Limited

We own and operate the electricity distribution infrastructure in central Canterbury, including Ōtautahi Christchurch city and Selwyn District. Our network is rural and urban and extends over 8,000 square kilometres from the Waimakariri River in the north to the Rakaia Rivers in the south: from the Canterbury coast to Arthur's Pass. We deliver electricity to more than 233,000 homes and businesses and are New Zealand's third largest electricity distributor.

New Zealand's South Island

We convey electricity across our network of distribution assets to consumers. We do not generate, buy or sell electricity; we deliver it to homes and business who are the customers of the electricity retailers operating in our area. Electricity retailers, in turn, include our charges in the electricity bills to their customers. Our delivery charges amount to approximately 24.5% of an average household's electricity bill.[2]

Our network is entirely within the boundaries of the two local councils: Christchurch City Council and Selwyn District Council. We are owned by these councils with Christchurch City Council holding 89.3% and Selwyn District Council 10.7% of the shares respectively.

1.2 Contributing to New Zealand's decarbonised future

We are committed to making a positive contribution to the successful delivery of New Zealand's Net Zero future. In January 2021, He Pou a Rangi, the Climate Change Commission released its vision of a

'…thriving, climate-resilient and low emissions Aotearoa where our children thrive.'

The ambitious report calls for a transformational and lasting change across society, with a strong economic focus on reducing emission at the source. The Climate Change Commission considers that transport and industrial heat electrification will significantly contribute to New Zealand realising its carbon zero targets by 2050.

Transpower's long-term strategic plan Whakamana i te Mauri Hiko predicts that demand for electricity could double by 2050. If this assumption is proven, we could see an additional 114 megawatts of load added to our network over the next 25 years. This load growth is substantial and represents significant challenges and potential opportunities. Not least of all, the need to spend capital upfront to offset future security of supply risk with no guaranteed return on investment, i.e., the need to install additional capacity in advance of its utilisation.

We are committed to managing and operating our network to deliver electricity safely, resiliently and reliably so that it meets consumers' expectations now and in a decarbonised future. Cost reflective pricing gives us the foundation for success in our commitment to support New Zealand's decarbonised future by signalling the impact of network use on consumers today and in the future.

[2] More information about the components of your power bill can be found on the Electricity Network Aotearoa website.

2. Our Network Characteristics

Pricing and asset management investments are inextricably linked and somewhat symbiotic. Pricing provides signals that inform consumer behaviour, influencing network utilisation, and signalling constraints on the network revealing the potential for future infrastructure investment. Infrastructure investment is a key cost driver and operating expenditure, over time, are reflected in the prices consumers pay, and the quality of supply they receive.

In addition to our price signalling, with a particular focus on price-quality trade-offs we look to stakeholder consultation and harnessing constraint information that is undertaken as part of our asset management plan (AMP) process. Our AMP provides detailed information on the constraint and capacity status of our network from the eight grid exit points (GXP) down to low voltage (LV) network level.

To meet our future infrastructure investment challenges, we are implementing initiatives, including use of new digital technologies, that increase our understanding of the network. We are investing in systems that fully utilise the data sources at our disposal thereby optimising short and long-term decision making, planning, and operation of our network. Enabling us to deliver electricity distribution services that are reliable and affordable to the long-term benefit of our consumers and central Canterbury.

Like roads, electricity networks have ‘rush hours’ where loading levels peak and capacity is heavily utilised. One solution to cope with these relatively short periods of high loading is to expand our network's capacity, much like making roads bigger to handle more traffic. However, building this additional capacity could be more expensive than other alternatives. To ensure our network investments represent good value for money, we explore other, more least cost alternatives, optimising existing asset utilisation before investing in traditional reinforcement of our network. These may be to:

- influence or control demand using flexibility, load management, and smart digital and control network solutions which can benefit consumers through more efficient network utilisation and therefore price
- optimise the existing network configuration and enable the measured release of capacity through switching
- other forms of demand response.

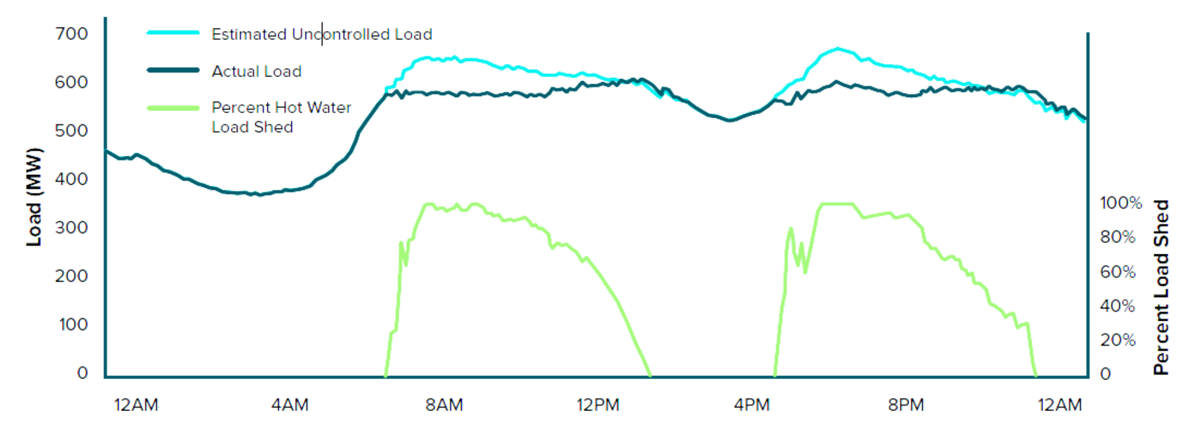
2.1 Load management

Our load management system allows us to control non-essential customer loads, such as hot water and irrigation. Enabling load deferral during peak times, reducing the need for asset investment. The load management system also provides a means to shed non-essential load during system contingencies, helping us maintain essential customer loads during such events.

The load management system comprises a range of signalling plant, hardware and software platforms and it remains an integral part of our distribution system. In 2023, we upgraded our load management software and integrated it within our ADMS[3] system. Our investment plan for this asset class includes asset management of the hardware and software of the Upper South Island (USI) load management master station which coordinates load management for the electricity lines businesses in the Upper South Island region. Load management therefore has the ability to reduce costs to our customers across the supply chain- transmission, distribution and retail costs.

Load management systems support our asset management objectives by minimising peak load using deferrable load control to improve the efficiency, reliability, and sustainability of our distribution network. Figure 1 gives an example of a winter peak day demand profile showing the hot water load that was shed corresponding with peak periods.

Figure 1*: Example of a winter peak day demand profile*



Note: uncontrolled load is our estimate of the loading levels that would have occurred if we had not controlled load.

The objectives for our load management system are to—

- implement load shedding or demand response plans to lower peak demand during high-load periods, reducing network investment requirements
- optimise network asset usage by effectively managing loads, prolonging the lifespan of equipment, and minimising the need for costly infrastructure upgrades
- contribute towards SAIDI and SAIFI targets through load reduction during critical load periods by reducing the likelihood of power outages
- support continual automation to manage aggregated load to a limit and control existing ripple plant accordingly
- ensure compliance with regulatory standards and mandates related to load management, grid operation, and energy efficiency.

Currently, the primary mechanism used to facilitate load management on our network is through ripple control relays. We use ripple control to manage load in two ways.

[3] Automated distribution management system

- Peak hot water cylinder control—when network loading is high, usually on the colder winter weekday mornings and evenings, we can temporarily turn off hot water heating to reduce peak demand. Enabling consumers to take advantage of cheaper retail pricing plans and contributes approximately 50MW of peak load deferment.
- Fixed time control—employ fixed time control to permanently shift load away from periods of peak demand and to also enable customers to take advantage of the lower electricity costs at other times of the day e.g., nights or lower cost Time-of-Use price periods. Fixed time control is mainly applied to larger hot water cylinders and contributes an estimated 75MW peak reduction.

In the future, ripple control technology is likely to be displaced by alternative systems such as smart appliances or meters responding to signalling over cellular or fibre telecommunications infrastructure. We are currently working with retailers to trial dual control of hot water cylinders.

2.2 Drivers of growth on our network

Our network feeds both high density Christchurch city loads and diverse rural loads on the Canterbury Plains and Banks Peninsula. Growth in electricity consumption in Christchurch and Banks Peninsula has historically matched growth in population, including the holiday population for Banks Peninsula however we have experienced growth higher than this in recent years. Peak electricity consumption growth on the Canterbury Plains has been driven by changes in land use rather than population growth.

Changes in Technology and customer behaviour, the drive to decarbonise, and recent housing intensification, mean forecasting growth in peak network demand, and where the growth will occur, has more facets to it. As most of these facets carry uncertainties, accurate forecasting of peak future demand is more difficult. We are now incorporating more sophisticated scenario planning, where we attempt to predict the many possible paths for demand growth and make asset investment decisions based on least regret actions or best predicted scenarios.

Network development is primarily driven by growth in peak demand, along with energy conveyed in respect of local renewable generation. The peak demand capability of our network is defined by network component capacities. For this reason, we concentrate on forecasting peak demand across all levels of our network rather than energy usage.

To support some of the growth we see, we have planned significant projects which we describe in more detail in our AMP.

2.3 Our network maximum demand

Maximum demand is the major driver of investment in our network so it's important for us to be as accurate as possible. The measure can be volatile and normally varies by up to 10% depending on winter weather.

Our network maximum half hour demand, based on load through the Transpower GXPs, for the 2025 winter period was 697MW during the peak that occurred on 3 July 2025.

In the medium-term maximum network demand is influenced by difficult to predict factors such as underlying population trends, new customers joining the network, growth in the commercial/ industrial sector, changes in rural land use, climate changes and changes in customer behaviour.

2.3.1 What issues do we take account of when planning our network?

Some of the emerging technologies we need to consider when we do are our network planning include—

Electric vehicles—uncertainties with EVs including uptake rates, what proportion of drivers will charge at home or at public charging facilities and when, the diversity of home charging and what size charger will be used.

Consumer actions—how consumers will respond to signals of high-cost power or high CO^2 emissions are unknown. A focus on decarbonisation could lead to improved home insulation, greater appliance efficiency, and consumers responding to reduce peak load.

Coal boiler conversions—We have engaged with boiler users to gain insight into their decarbonisation plans. The absence or presence of Government incentives has an impact on the rate of conversion along with trade-offs between fuel options.

Solar photovoltaics—the uptake rate, and size of solar installations.

Batteries—battery uptake rates and how our consumers will use batteries. Consumers may discharge batteries at expensive evening peak times, and recharge the batteries at cheaper times, or may discharge their batteries when they get up in the morning and through the day – meaning evening electricity usage may still be from the network.

2.3.2 We have developed demand scenarios

Given the range of impacts the emerging technologies above will bring for the energy sector, we can no longer rely only on maximum demand forecasts based primarily on historical growth. We have moved to scenario-based demand forecasting:

Business as usual—an extrapolation of existing electrification trends, in a low growth world. Low change in technology uptake results in low economic growth and high climate change impact.

Progress—where electrification and change in consumer behaviour accelerates but does not result in full transition of the energy sector by 2050. There is some increased uptake of new technology and optimisation with medium economic and population growth.

System transition—a centrally led transition of the energy sector is achieved through high uptake of new technology, but minimal shift in consumer engagement in the energy sector. Economic growth and population growth are medium. Climate change impacts are towards best case scenarios.

Consumer and place-based transition—where consumer and place-based optimisation combined with technology change achieves energy sector transition. Climate change impacts are towards best case scenario.

Central Scenario—high growth across the region, while electrification doesn't accelerate considerably until after 2035. The scenario assumes some optimisation of charging demand and place-based optimisation but low levels of EDB controlled flexibility. The Central scenario is the scenario we use for asset management planning, as our best / least regrets view of load growth over the next 10 years.

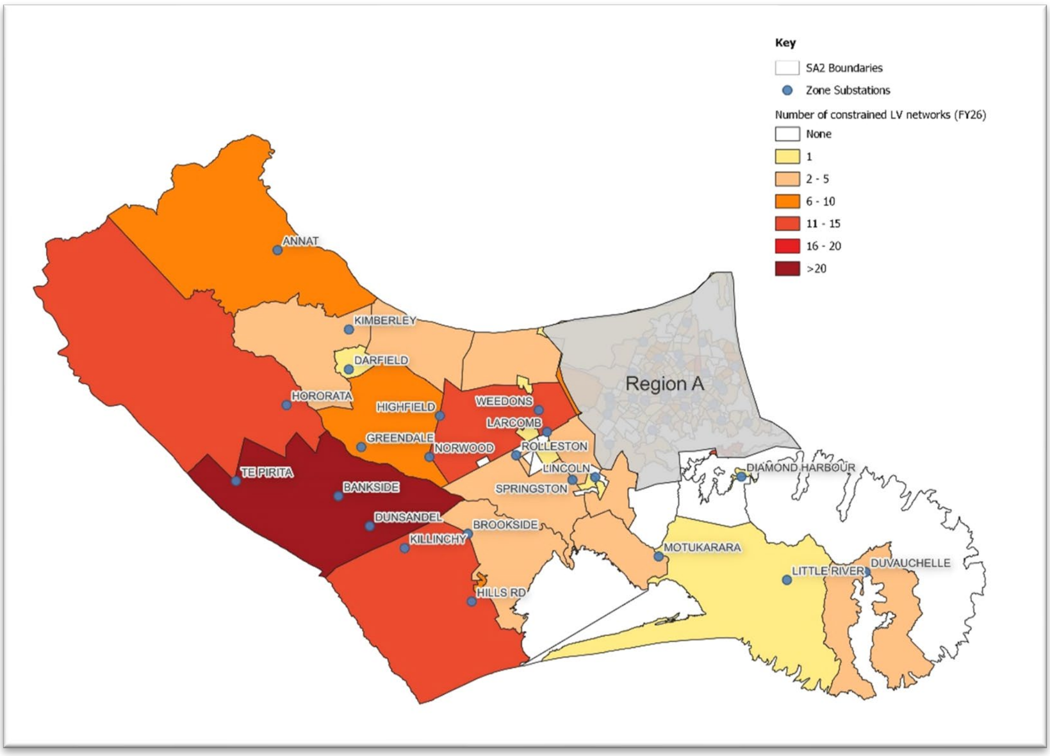
The outputs of the above scenario's inform potential risk and what drives the differences between the scenarios. The modelling shows system peak demand growth between 10% and 42% over the next 10-year planning period. Network wide peak demand is an indicator of the load growth we expect to see on the network. Table 1 lists the scenario demand assumptions that apply to each scenario.

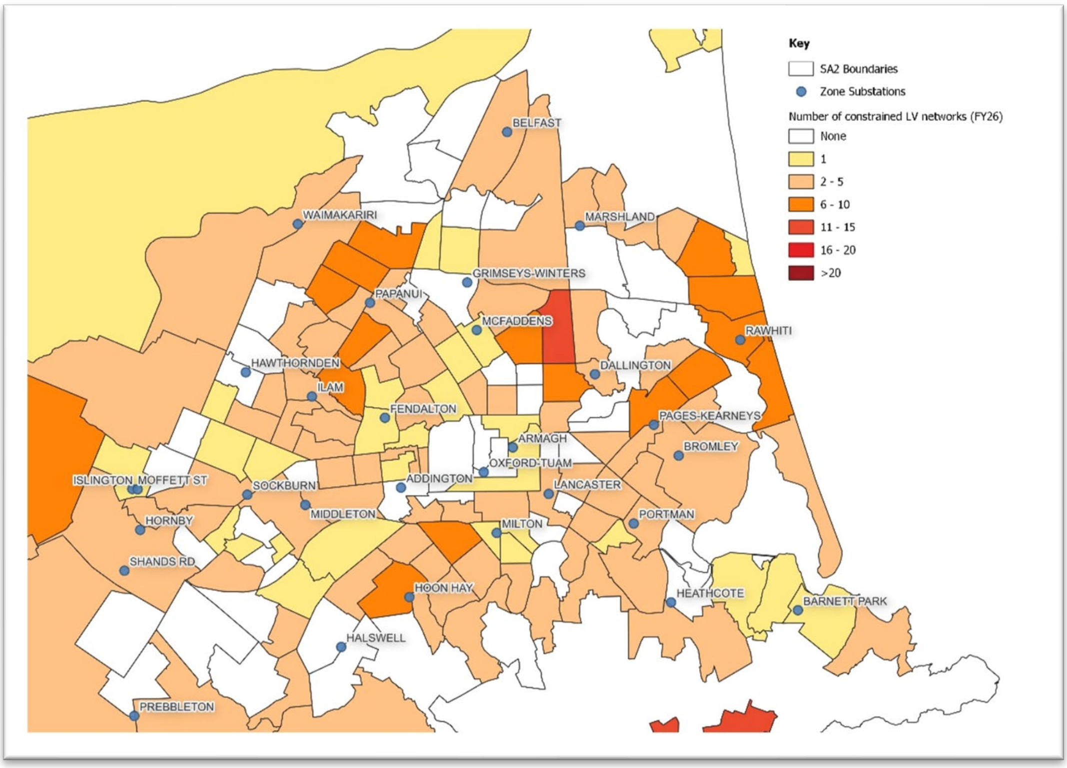
Table 1: Scenario demand assumptions 2036-2050

	2036			2050		
	Maximum demand (MW)	**Growth (MW)**	**% Change**	**Maximum demand (MW)**	**Growth (MW)**	**% Change**
Business as Usual	786	104	15%	827	145	21%
Progress	828	150	22%	989	311	46%
System transition	987	313	46%	1,266	593	88%
Consumer and place-based transition	900	220	32%	953	273	40%
Central Scenario	939	258	38%	1,158	476	70%

Different areas of the network and assets on the network will see load growth differently between timing and varying levels of existing capacity. Figure 2 shows the projected low voltage urban network constraints for the disclosure year.

Figure 2: Projected low voltage urban network constraints





2.4 Developing our LV capability

Historically, LV networks were planned for reasonably stable passive household loads with one-way power flow. However, more consumers are adopting technologies such as electric vehicles (EVs) which can place significant additional demand on a street's LV system. Given our LV network supplies mostly residential consumers, developing the visibility and capability of these networks is becoming increasingly important to efficiently manage our networks and facilitate consumer choice. We are doing this by:

- Leveraging LV monitor data to create improved visibility of our assets and activity on our network, particularly Distributed Energy Resources (DER) and Low Carbon Technologies (LCT).
- Leveraging analytics tools to derive power system insights such as system constraints, network performance improvements and efficiency through optimal investment.
- Developing improved forecasting and modelling techniques to increase accuracy of the LV level.
- Investigating options for unlocking latent capacity in our network which becomes available using improved visibility, smart technology, and non-traditional solutions.

These initiatives will develop our LV networks and help us to:

- Provide information to guide our operational, planning and investment activities.

- Facilitate customer choice by better-enabling customers to charge batteries during off-peak times and potentially export power into our network at peak times, thereby lowering their net cost of electricity.
- Improve customer service through real-time identification and location of faults.
- Identify poor performing feeders and quality of service to individual customers, which will then allow us to target actions to improve customer experience.
- Reduce capital and operational costs by early warning of power quality problems, such as phase imbalance.
- Enhance safety as real- or near-time monitoring provides measurements which will better inform us of what is live, de-energised, and outside of regulatory limits.
- Display constraints in our network online, enabling others to participate in developing solutions.
- Ensure we can host increasing DER and LCT connections while maintaining the required network safety, stability and resilience in an efficient and cost-effective way.
- Maximise the two-way throughput of energy across our network.

3. Our pricing aims and objectives

We aim to set prices that are cost-reflective, effective, and appropriate. Each pricing year, we assess our prices against the Authority's measure of cost-reflective pricing to ensure that:

- we signal the economic cost to serve on our network; and
- where a revenue shortfall occurs, we recover the shortfall in a way that least distorts network use.

With these aims in mind, we set prices to:

- establish a fair range of changes,
- allocate our cost to serve fairly between connection categories,
- appropriately recover our pass-through costs (i.e., rates, levies and transmission charges[4]) and recoverable costs (i.e., incentives, penalties and rewards),
- provide appropriate demand-based pricing signals, when necessary,
- avoid bill shock where possible by having a pricing approach that is certain, transparent, and understandable,
- offer pricing that, is comparable in form to other electricity distributors and
- be consistent with the intent of the Pricing Principles.

In delivering on our aims and objectives, our pricing approach is subject to inherent limitations, including:

- the need to comply with regulatory requirements relating to fixed daily charges under the current low user fixed charge regulations and
- a lack of ability to control how prices are passed onto consumers by their respective electricity retailers.

[4] In its December 2023 input methodology decision, the Commerce Commission reclassified transmission-related recoverable costs as pass-through costs

Despite the inherent limitations faced, we are committed to evolving our pricing approach to better meet the Pricing Principles and have used the Authority's Practice Note to guide our transitional journey.

3.1 Three priorities of our long-term pricing strategy

Our pricing objective acknowledges our current position and our goals focusing on three long-term strategic priorities—

1. Cost Recovery and Reflectivity—prices must recover efficient supply costs from each consumer segment, reflecting cost drivers.
2. Price Reform Enablement—establish pricing systems, data, and processes that:
    - support efficient price structures
    - empower consumers to react to price signals.
3. Price Signalling and Behavioural Response—prices should be tailored to consumer type based on their response capability and cost-benefit opportunities. Our prices should:
    - send actionable signals
    - promote efficient network use amid increasing electrification and bidirectional energy flows
    - foster a flexible services market
    - utilise utility-mode control where oversight and the scale of benefits incentivise participation.

Figure 3: Our Pricing strategy and roadmap

Pricing strategy & roadmap

	Now (2026-2027) 1-2 years	Strategy Refresh — Next (2027-2030) 3-4 years	Future (2030+) +5 years
Cost recovery & reflectivity	• Improved data points and modelling to inform cost allocation across consumer segments. • Progressively address over or under recovery across consumer segments within Orion's self-imposed 10% rebalancing constraint. • Align peak import and injection pricing with ENA LRMC model. • Review the Asset Building Block Approach (ABBA) for Large Connection Customers (LCC). • Monitor locational and temporal cost drivers, including control period signals	• Monitor locational and temporal cost drivers, including control period signals. • Monitor if injection congestion occurs on the network and drives costs and requires pricing signals	• Monitor if injection congestion occurs on the network and drives costs and requires pricing signals • Monitor locational and temporal cost drivers, including control period signals
Price reform enablement	• Manage transition from low user fixed charge regulations and standardised retailer consumer groups. • Introduce injection tariffs for residential and small business price categories. • Review and alignment of business price categories with industry and connections standards while introducing tariff structures with a view to provide further incentives for flexibility and DG. • Commence mass-market flexibility trials to target critical peak periods and better understand customer responsiveness and behavioral drivers. • Alignment of hot water control value with LRMC. • Connection agreements establish dynamic control rights	• Introduce opt-in tariffs from flexibility trials that provide value to consumers who shift peak load or export generation during critical peaks on Orion's network.	• Establish dynamic control network capability for mass market
Signalling & behavioural response	• Trial price mode demand flexibility, by repurposing our major customer peak period signal • Monitor retailer responses to existing tariff changes and levels consumer response	• Activate C&I demand management and response with reward tariffs | Establish variable demand pricing, demand exceedance tariffs • Look at moving price driven demand flexibility tariff as an opt-in for whole of network.	• Support flexibility innovators | Implement opt-in variable demand pricing and interruptible supply tariffs for aggregators

More information about our pricing strategy can be found in Appendix G of this Pricing Methodology.

4. Implementing future pricing

We develop and maintain our prices to support our group purpose:

powering a cleaner and brighter future with our community

Against this purpose we have identified focus areas important to our purpose delivery, and within this framework we have identified that the key initiatives that our pricing can support are:

1. Facilitating decarbonisation and hosting capacity at lowest cost, and
2. Investing to maintain a safe reliable, resilient network at lowest total lifecycle cost.

Building on these two initiatives—

- The structure of our pricing influences customer behaviour relating to use of our infrastructure and the consequent investment needed, the adoption and sharing of renewable energy resources, the electrification of transport and process heat, and the level of non-renewable generation that is needed at times of peak consumption.
- We recognise the impact that our pricing and pricing changes have on vulnerable customers (including those in energy hardship) who do not have the resources to cope with change or adapt their behaviour. Alongside our pricing transition, we are seeking alternative approaches that might provide targeted assistance for vulnerable customers and more broadly look at ways to optimise network use to manage the cost impact, of the drive to decarbonise.

Alongside these initiatives we also have a range of practical, economic, regulatory and equitability considerations to include. There is often a trade-off between these various considerations.

4.1 Cost-reflective pricing

Cost-reflective prices are considered fairer because consumers are charged based on how and when they use the network. Peak and off-peak rates better reflect the costs of distributing electricity on our network at different times of the day and year. Prices that reflect these time-based costs allow consumers to make better decisions about how to manage their electricity consumption, enabling them to save on their bills.

When consumers make small changes to how they use the network, this can help to reduce peak demand. Over time, this will help to reduce how much additional investment is required to deliver a reliable service, helping to keep network costs down for all consumers. Cost-reflective prices result in lower prices in the middle of the day during 11am-5pm when demand for electricity and use of the network is low. Conversely, there will be higher prices in the mornings and evening on weekdays from 7am – 11am and 5pm-10pm when the demand for electricity is high, and the network is at its busiest.

4.2 Decarbonisation

The Climate Change Commission, Ministry for Environment and others have identified that electrification of our transport fleet provides the greatest opportunity and least cost means for our community to decarbonise. A resilient electricity supply with stable pricing will facilitate this transition and providing attractive off-peak charging options will accelerate the transition and improve the efficient use of our network.

Our pricing for industrial customers can also support the electrification of process heat.

Looking further forward, we aim to help consumers share their local renewable energy resources and utilise the energy stored in batteries (be they standalone or electric vehicle (EV) batteries via vehicle-to-grid (V2G)) to stabilise the energy system.

Traditional volume-based pricing approaches can discourage electrification of transport and process heat, and act as a barrier to consumers using our network to share their local renewable resources. Volume-based pricing approaches also encourages customers to make inefficient investments in technology, including expensive forms of renewable generation and devices that avoid sharing of energy resources (such as batteries and hot water diverters). Our strategy includes a transition away from the current level of volume-based pricing.

4.3 Affordability

We recognise the vulnerable within our community, those who do not have the resources to accommodate additional costs, nor to adapt their usage to mitigate the additional cost. We observe that more than 20% of our residential consumers live in areas with a high deprivation index. Within this group, we have higher usage customers that may live in energy hardship (spending more than 10% of their income on electricity), but also a large proportion (approximately 70%) with lower-than-average usage.

Any change in pricing structure creates winners and losers. There is direct impacts when changes affect customers that are not contributing to an area of concern and/or are not able to respond.

Orion

Of particular concern, we have identified that a greater proportion of our vulnerable customers sit within the lower consumption bands. While a shift away from volume-based pricing will provide lower cost outcomes in the long term, it also shifts more of the cost burden onto these consumers.

The main tools to mitigate this impact is to implement a staged transition, spreading the change over several years and to provide pricing options throughout the day. This provides more opportunity for vulnerable consumers to adapt and for support mechanisms to adjust[5], and for consumers to tailor usage at lower cost times.

We also intend to look for ways we can provide targeted relief to customers in need, and we are supporting the industry initiative to set up a support fund that operates alongside the removal of the low fixed charge regulations.

4.4 Economic considerations

In terms of the structure of our pricing, we aim to ensure that our pricing is economically efficient, which means that:

- consumers choosing to use our network should face the appropriate cost of that decision and be incentivised to weigh up the value of the service and the cost of alternatives, and consequently
- investments in our network over time will be at an appropriate level and in the interest of consumers.

4.5 Even-handedness and practical considerations

Through our pricing we take account of the need for even-handedness and practicality in determining customer groupings (categories), cost allocations and the structure of our pricing.

Specifically, we:

- apply price averaging over connection categories, because it is generally not practical to single out individual connections for cost-specific delivery pricing. However, where it is practical, we do allocate assets and associated costs only to the connections or connection categories that use them.
- recognise that all consumers should share in the benefits of greater utilisation of shared assets and other enhanced economies of scale (new customers are not gifted existing capacity, instead the costs of significant upgrades are contributed to by new customers with existing consumers sharing in the cost of shared assets that benefit all).
- recognise that consumers change their demand behaviour over time, and it is important that we provide compelling and consistent pricing incentives aimed at maximising the efficient utilisation of our assets.
- seek to make our price signals effective by balancing strong price signals with easily understood application and measurement,
- treat connections with similar electrical attributes consistently,

[5] Such as those initiatives highlighted in the Energy Hardship Expert Panel report on Energy Hardship: The challenges and a way forward https://www.mbie.govt.nz/dmsdocument/27831-energy-hardship-the-challenges-and-a-way-forward-energy-hardship-expert-panel-report-to-minister-pdf

Orion

- set prices that are the same for all retailers, providing a “level playing field” to promote retail competition.

4.6 Our 1 April 2027 pricing goals

Progressively increase the proportion of fixed charge revenue recovered from consumers to achieve an equitable fixed / variable split:

- Work through the phase-out of the low fixed charge regulations and incrementally increase the proportion of fixed charge revenue recovered from residential connections.

Progressively rebalance how peak pricing signals are recovered:

- Alignment of our residential and small business peak TOU variable pricing with LRMC (ENA standardised LRMC model).
- Implement pricing learnings from flexibility trials to become opt-in pricing categories.
- Introduce peak demand charges for large business (>69kVA)
- Explore Distribution Energy Resources (“DER”) and Customer Energy Resources (“CER”) on our network around dynamic pricing and operating envelopes

Transparently manage our key transition constraints by:

- complying with the Electricity Authority’s distribution pricing principles and guidance on these
- administering the phase-out of the low fixed charge price regulation
- managing bill impacts of the default price path for the 2026/27 to 2029/30 pricing periods
- retaining transmission pass through as regulated
- scaling of new billing system functionality and retailer interfaces for ICP 30-minute interval data
- accommodating legacy accumulation meters by introducing a default charge component and implementing capability within our billing system of profiling of consumption to ensure we remain compliant with EA code changes.
- supporting our asset management strategy (including demand response controls) and investment plans as these evolve.

5. Changes made for 1 April 2026

We have made several material changes to our prices effective 1 April 2026. The changes we have made to our pricing approach are listed in Table 2.

Table 2: Summary of the changes made to our pricing approach effective 1 April 2026

Consumer Category	Description of the changes made effective 1 April 2026
Residential Low User	The general fixed daily supply charge will increase from 75 cents to 90 cents as per the phase out of the low fixed charges. More information on the low fixed charge regulations and their phase-out can be found in Appendix D.

Consumer Category	Description of the changes made effective 1 April 2026
	From 1 April 2026, we have transitioned the fixed/variable split from 31% fixed / 69% variable split to 33% fixed / 67% variable. We were able to make this change while: • Making small immaterial changes to our pricing methodology • Avoiding perverse impacts on consumers • Remaining compliant with the low fixed charge regulations With the 1 April 2026 pricing year marking the final year of the low fixed charge regulations, we will review our allocation of costs between fixed and variable charges from 1 April 2027. Our aim is to ensure a smooth transition while continuing to maintain strong peak price signals through our variable charges.
Residential Standard User **Small - GEN (GC1)** **Medium - GEN(GC2)**	From 1 April 2026 Orion has introduced peak injection tariff for winter months only (1 May to 31 August). The prices for injection have been set based on Orion's LRMC, while incorporating an adjustment factor. We've reviewed our peak pricing for this group and are starting a transition to align with Orion's LRMC.
Large - GEN(GC3)	We've reviewed our peak pricing for this group and are starting a transition to align with Orion's LRMC. Orion will conduct a review of peak injection tariffs for large business connections throughout 2026.
Two-way power flow	With the introduction of peak injection tariffs on residential and small business (<=69kVA) as required by the Electricity Authority decision and Code change. Orion is removing the 2WAY price categories. Retailers haven been notified of the ICPs and the new applicable pricing category.

Delivery charges effective 1 April 2026 and a comparison with the delivery charges effective 1 April 2025 is included in Appendix C.

5.1 We have decided to retain uniform pricing

We have decided to continue applying a uniform delivery charge for the foreseeable future. While we calculate locational prices and prices for both distribution and transmission, our analysis supports application of a uniform delivery charge that is indifferent of location and inclusive of both distribution and transmission prices.

We do calculate granular prices, however, applying those prices would add significant costs to billing without a discernible benefit to consumers. Accordingly, the cost versus benefit does not support us moving away from uniform delivery charges for this pricing year.

More information on our approach to setting uniform delivery charges can be found in section 10 of this Pricing Methodology.

5.2 We have taken the next steps to evolve our pricing

The context under which we set our pricing is constantly evolving. We last refreshed our pricing strategy in June 2024.

We developed our new pricing strategy with stakeholder and consumer engagement conducted in late 2023. This strategy informed our current pricing roadmap.

The Electricity Authority Te Mana Hiko has also evolved its expectations on our pricing practices, designs and evidence base. Since our 2021 pricing strategy the authority has published a practice note in 2022, progressed broad industry pricing consultation across 2023 and published open letters of its expectations in 2023 and 2024. Our new strategy also addressed the Electricity Authority's expectations, signalled through updated pricing practice notes and pricing consultations during 2022 and 2023. The Government Taskforce[6] decisions of 2025 also influenced our pricing shifts for 2025.

Figure 4 illustrates the approach we have taken to refresh our pricing strategy, and how we intend to implement and refine it over the roadmap horizons. We have retained the horizons from our existing roadmap.

We recognise that how we transition our pricing is important to the effectiveness of our pricing strategy in realising our pricing objectives.

Our transition principles are our commitment to our consumers for how we intend to implement and refine our roadmap over time.

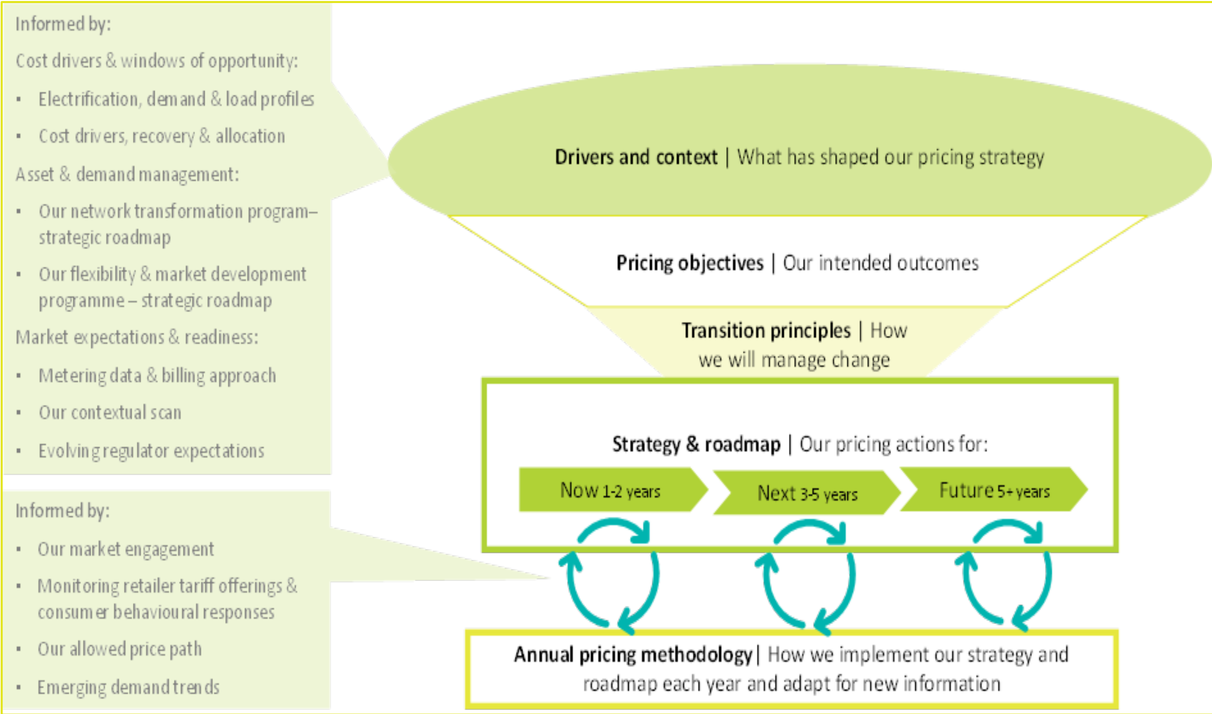
Our overarching transition principles:

Our roadmap seeks to:

- develop prices transparently and consider transaction costs, consumer impacts, and uptake incentives
- provide predictability for consumers to make investments with certainty and for retailers and aggregators to design market offers
- use the right tool for each consumer segment's required behaviours and controls, including simplicity where possible
- acknowledge the market value stacking opportunities and materiality when designing prices for cost recovery and behavioural response by understanding the interaction of our prices with the rest of the supply chain costs benefits and market signals
- ensure consumers outcomes are equitable and appropriate.

Figure 4: Our approach to reviewed pricing strategy and roadmap

[6] Energy Competition Task Force | Our projects | Electricity Authority



Our consumer segment specific principles: We recognise that some consumers will have specific needs amid pricing transitions. Our roadmap seeks to:

- consider impacts on vulnerable consumers within our residential connection's community
- provide signals for electrification and decarbonisation, particularly for commercial and industrial connections and EV charging
- provide signals to flexibility stakeholders who can access multiple value streams to attract coordinated and two-way CER connections.

5.3 Network Price Structure

Network prices are how consumers are charged for their network service and energy usage. We charge our network prices to retailers, who then pass them onto their consumers. These prices enable us to recover the revenue needed to build, operate and maintain our network to transport electricity to our consumers. The underlying principles to our approach to prices are outlined in Figure 5.

Figure 5: Underlying principle to our approach to pricing

Transparent Prices are simple and transparent	**Empowered** All consumers are empowered to take control of their bills and make efficient consumption and technology choices
Predictable Prices are predictable and stable over time	**Fair** Prices are reflective of consumers' network costs

We engaged with stakeholders, including end-consumers and consumer advocates in developing our pricing strategy and roadmap. We undertook formal consultations with retailers, a range of external stakeholders and other market participants, who could pool and sell energy generated and exported back to the distribution network by our consumers from rooftop solar, batteries or electric vehicles.

Efficient network pricing requires a clear and causal link between network use and the costs that exports impose. We engaged with our stakeholders on how costs could be most efficiently reflected in and impacted by prices. This requires an estimation of the forward-looking efficient costs, or long- run-marginal-cost (LRMC), for both imports and exports. Our estimates of LRMC include those components of forward-looking network expenditure that could be avoided through a change in the timing of consumption or generation.

5.4 Withdrawing the Two-way power flow price categories

Last year we made the bold step of introducing two-way power flow pricing for residential and commercial consumers. With peak injection tariffs now mandatory by regulation across all residential and small business price categories, we are closing the two-way power flow price categories.

6. Measuring consumer Impact

We are mindful that a change in pricing approach can impact consumers differently. Over the longer term, consumers will pay their true costs to serve because prices are efficient. Efficient prices send the right signals and reduce the overall costs to serve all consumers (compared to the costs that would have arisen had inefficient prices driven up the costs to serve).

We attempt to fully mitigate perverse year-on-year outcomes as far as practicable. Otherwise, we risk sending the wrong signals to consumers and encouraging inefficient network use, thereby driving up costs. More details on our approach to smoothing prices can be found in subsection 10.4.3 of this Pricing Methodology.

The changes to this pricing year's low fixed charge regulations resulted in a 20% increase to residential consumers' fixed daily charges. We considered it fair and reasonable to start transitioning prices so that residential consumers pay more of their true cost to serve in this pricing year and avoided bill shock from a sudden and unexpected increase in price by keeping variable prices unchanged. The impact on annual charges for a typical residential connection was an increase of +$117 or +13.7%.

The impact on the average SME connection was +$398 or +15.5% per annum, and +$17,216 or +15.8% for major connections. Our impact analysis indicated that the change to a capacity-based approach impacted connections with mismatched connection capacity and usage profiles the most. This is not a perverse outcome as we intend to send a strong signal to the consumers on our network that are best placed to effect change.

Our pricing changes last year continued the transition toward collecting a greater portion of revenue through fixed daily charges. The increase in fixed charges for UNGENC3 and GENGC3 did result in some customers with installed capacity exceeding their current needs experiencing bill shock, leading to a number of downgrade requests.

During this period, Orion also identified discrepancies in price category allocations across our SME connections. We have since completed a detailed audit and worked with retailers to realign affected connections to the appropriate price categories.

SME consumers can affect their lines charges by right sizing their connection to meet their individual needs. Any consumer who thinks they might have a larger connection than what they currently need or are likely to need in the future should consider applying to downgrade the connection. A connection downgrade could be as simple as changing the fuses and performed on request.

Our network charges amount to approximately 24.5% of an average consumers' total electricity bill. The other 76.5% comprises electricity generation charges, retailer charges, levies and metering costs, transmission, and GST. We have no control over how retailers pass our network charges on to consumers. Questions about how the changes to our network charges will affect a consumer's total electricity bill are better directed to that consumer's electricity retailer.

7. Standard connection contracts

We supply electricity distribution services to consumers via Retailers[7] under the terms in our Default Distribution Agreement, our standard connection contract. We have 20 retailers (28 including sub-brands) trading on our network.

7.1 How we assign consumers to price categories

Consumers are assigned to one of nine price categories based on the consumer's utilisation of our network. The rationale and method/criteria are demonstrated in Table 3. Revenue is recovered from consumers through fixed daily charge and variable time-based prices.

Table 3: Consumer groups and network charge categories effective 1 April 2026

[7] A list of retailers operating on our network can be found at https://www.oriongroup.co.nz/consumers/about-electricity/industry-structure/retailers/

Consumer Group	Fixed and Variable Charges
Streetlighting	Fixed charge – per lamp, per day
Residential Low User Residential Standard User Small General Connection Medium General Connection Large General Connection (injection not included)	*Uncontrolled Charge* Fixed Daily Charge – per ICP, per day Weekends (Saturday and Sunday) – per kWh Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) – per kWh Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) – per kWh Off Peak (Mon to Fri, 10:00pm to 3:00am) – per kWh Super Off Peak (Anytime between 3:00am and 5:00am) – per kWh Winter Injection Peak (May to Aug only - Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) – per kWh Injection Off Peak (all other times) – per kWh *Controlled Charges* Fixed Daily Charge – per ICP, per day Weekends (Saturday and Sunday) – per kWh Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) – per kWh Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) – per kWh Off Peak (Mon to Fri, 10:00pm to 3:00am) – per kWh Super Off Peak (Anytime between 3:00am and 5:00am) per kWh Winter Injection Peak (May to Aug only - Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) – per kWh Injection Off Peak (all other times) – per kWh
Irrigation Connections	Capacity Charge – per kW, per day* Power factor correction rebate – per kVAr, per day* Interruptibility rebate – per kW, per day* Weekends (Saturday and Sunday) – per kWh Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) – per kWh Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) – per kWh Off Peak (Mon to Fri, 10:00pm to 3:00am) – per kWh Super Off Peak (Anytime between 3:00am and 5:00am) per kWh *Applied to 1 October to 31 March only
Major Customer and Embedded Network Connections	Fixed charge – per ICP, per day Fixed Charge (additional connections) – per ICP, per day Extra switches – per switch, per day 11kV Metering equipment – per ICP, per day 11kV Underground cabling – per km, per day 11kV Overhead lines – per km, per day Transformer capacity – per kVA, per day Peak charge (control period demand) – per kVA, per day Nominated maximum demand – per kVA, per day Metered maximum demand – per kVA, per day
Large Capacity Connections	Individually assessed prices advised and charged directly to the customers

8. Non – standard pricing

8.1 Extent of non-standard contract use

Orion's use of non-standard contracts is limited to two large capacity load customers. We expect an increase in non-standard contracts as existing customers electrify and as the pipeline of utility scale generation moves to implementation and commissioning.

8.2 Determining need for non-standard contract use

Non-standard arrangements normally apply to industrial and commercial consumers or utility scale generation consumers. We offer individualised pricing arrangements in conjunction with separate contractual arrangements (non-standard contracts)

These arrangements are typically applied where a consumer:

- has a high-capacity connection—generally installed capacity of more than 5MVA;
- requires significant capital investment or a substantial increase in network capacity to support supply; or
- poses a risk of uneconomic network bypass that can be mitigated through a tailored pricing arrangement.

Information about these contracts are disclosed in our *Disclosure of prescribed contracts* document which is available on our website[8].

8.3 Obligations and responsibilities to consumers in event of interruption

Arrangements for obligations and responsibilities in the event of interruption are individually negotiated with customers within the bounds of our responsibilities to the System Operator and our security of supply standards.

In general, where agreed with the consumer we may:

- provide uninterrupted supply security against a range of faults by maintaining duplicate supply assets;
- prioritise restoration of supply following outages; and
- to the extent reasonably practicable, not include all of the connections for "automatic under frequency load shedding", nor "automatic under voltage load shedding".

This supply security may be greater than our standard undertakings which are set out in our "security of supply standard" in our published asset management plan. The key difference is that for a range of faults, power is off for the duration of the repair time (often up to 4 hours) under our normal security of supply standard.

With only two consumers presently in the large capacity connection category, commercial sensitivity prevents us from providing any load profile for this category.

[8] https://www.oriongroup.co.nz/our-story/regulatory-disclosures

8.4 Implications for determining prices (if any)

Under an Asset-based Building Block Approach the operational arrangements relating to interruptions has no direct impact on determining prices except to the extent security of supply arrangements are higher which may impact the extent of assets involved in the connection.

8.5 Approach to setting pricing and consistency with pricing principles

Our non-standard pricing applies to customers whose energy use or connection needs are significantly different from most others. These customers usually have larger point loads or special supply arrangements that require a tailored approach.

Because their prices are negotiated individually and may include commercially sensitive information about their business or energy use, we don't publish these prices in our standard pricing schedule.

We regularly review non-standard prices to make sure they still reflect the actual cost of supplying each customer and remain consistent with both regulatory requirements and the terms of their agreements.

Our approach aims to balance fairness, transparency, and efficiency, following the Electricity Authority's pricing principles and similar practices used across other New Zealand distribution networks. This gives large customers confidence that their charges are based on the true cost of their supply, while ensuring the network continues to be sustainable and affordable for everyone.

We align with the Electricity Authority's pricing principles set out in Appendix E.

8.6 Load Customers

Prices for non-standard load customers are determined using the asset-based building block approach (ABBA). ABBA provides a transparent, consistent, and economically efficient framework for setting prices for non-standard customers. It ensures that charges reflect each consumer's contribution to network investment and operation.

This method mirrors the cost-of-service model used in regulated price settings and ensures that each customer's price reflects their share of the network's underlying costs and capacity usage.

The ABBA approach comprises five core components—

- Return on and of capital — whereby a rate of return is applied to the distribution assets dedicated and shared to the customer, based on the regulated post-tax weighted average cost of capital (WACC) and depreciation allocated according to those assets' remaining life and contribution to service delivery.
- Operating and maintenance costs — allocated for both transmission and distribution components based on the customer's use of the relevant network section (e.g., GXP or zone substation) and the kVa value of assets supplying their load.
- Indirect costs — shared costs (e.g., administration, network management, system operations, etc.) allocated in proportion to the assets utilised by the customers in proportion to the total Orion assets.
- Transmission costs — Transpower's charges are passed through to consumers based on the components of the TPM charges and the customer-installed or contracted capacity as a proportion of the capacity of the GXPs that they utilise.

8.7 How cost to serve is determined and allocated

Costs to serve large non-standard customers are determined based on each customer's relative contribution to network capacity requirements and transmission capacity utilisation. Specifically, we use —

- Capacity is used to allocate zone substation assets and transmission-related costs. Allocation is based on each customer's contracted or installed capacity as a proportion of the total capacity available at the relevant zone substation or grid exit point (GXP). This ensures that costs are recovered in proportion to the capacity Orion is required to reserve to supply each customer.
- Peak coincident demand to allocate sub-transmission costs, reflecting each customer's demand at the time of the network's overall system peak. This approach ensures that customers who contribute more to peak loading bear a proportionate share of the costs associated with providing and maintaining sub-transmission assets.

8.8 Generation customers (if any)

We use the Asset-based Building Block Approach (ABBA), and the requirements outlined in Part 6 of the Code relating to distributed generation to set fair, transparent prices for large generator consumers. The key principle applied is that we may only apply incremental charges for transmission and distribution.

Refinement of our approach to non-standard pricing for utility scale generation is evolving.

9. Calculation of our costs to serve

9.1 Calculation of the Required Revenue

The required revenue represents the forecast costs incurred over the pricing year. Through our prices effective 1 April 2026, we intend to recover the required revenue of $351.3 million over the pricing year. Table 5 provides a breakdown of our required revenue for the pricing year.

Table 5: Breakdown of our Required Revenue

Description	Amount ($'000)
Operations and Maintenance Costs	33,533
Administration and Corporate Costs	61,582
Regulatory depreciation charges	68,000
Regulatory return on investment	91,977
Transpower Charges	82,617
Regulatory Cost / Levies	8,775
Recoverable costs	4,591
Total Revenue Recovered from Prices	351,342
Large connection contracts	-
Other regulated income	4,516
Total required revenue	**355,591**

9.1.1 Calculation of the Operations and Maintenance Costs

Our forecast Operations and Maintenance costs for the year are $33.5 million. Table 6 provides a breakdown of our forecast operations and maintenance costs for the pricing year.

Table 6: Breakdown of our Forecast Operations and Maintenance Costs

Description	Amount ($'000)
Service Interruptions and Emergencies	12,607
Vegetation Management	6,968
Routine and Corrective Maintenance	13,957
Asset Replacement and Renewal	0
Total Operations and Maintenance Costs	**33,533**

9.1.2 Calculation of the Administration and Corporate Costs

Our forecast Administration and Corporate Costs for the pricing year are $61.6 million. Table 7 provides a breakdown of our forecast administration and corporate costs for the pricing year.

Table 7: Breakdown of our Forecast Administration and Corporate Costs

Description	Amount ($'000)
System Operations and Network Support	21,852
Business Support	39,730
Total Administration and Corporate Costs	**61,582**

9.1.3 Calculation of the Depreciation Charges

Our forecast Depreciation Charges for the pricing year are $68.0 million. The Depreciation Charges reflect the annual charge to the accounts for depreciation on network system assets and related fixed assets costs as communications equipment and network-related software. As per the company's management accounts, our forecast is equal to the budgeted depreciation charges for the network business between 1 April 2026 and 31 March 2027. Table 8 provides a breakdown of our forecast depreciated charges for the pricing year.

Table 8: Breakdown of our Forecast Depreciation Charges

Description	Amount ($'000)
Non-System Fixed Assets	4,859
System Fixed Assets	63,141
Total Depreciation Charges	**68,000**

9.1.4 Calculation of Transpower charges and Regulatory costs

Transpower charges are the contracted Transmission costs of the national grid operator Transpower for the pricing year. Our notified transmission charges effective 1 April 2026 to 31 March 2027 are $82.6 million.

Regulatory costs / levies include amounts charged by the Authority, Commission, Ministry of Economic Development, and the Utilities Disputes scheme. Our forecast regulatory costs / levies for the pricing year are $8.8 million.

9.2 Change in Required Revenue

Our required revenue has increased by $38.6 million (or +12.2%) for the 1 April 2026 pricing year when compared against the prior pricing year 1 April 2025. Table 9 provides the movement in required revenue between the pricing years.

Table 9: Movement in revenue requirement between pricing years

Description	1 April 2026 ($'000)	1 April 2025 ($'000)	Movement ($'000)	Percent
Operations and Maintenance Costs	33,533	*33,906*	(373)	-1%
Administration and Corporate Costs	61,582	*52,572*	9,010	17%
Depreciation charges	68,000	*58,914*	9,086	15%
Return on Investment	91,977	*81,912*	10,065	12%
Transpower charges	82,617	*70,179*	12,438	18%
Rates/Levies	8,775	*10,407*	(1,632)	-16%
Recoverable costs	4,591	*4,986*	(394)	-8%
Total Revenue Recovered from Prices	***351,075***	***312,876***	***38,200***	***12.2%***
Large Connection Contract	-	-	-	0%
Other Regulated Income	4,516	4,100	416	10%
Total Required Revenue	**355,591**	**316,976**	**38,616**	**12.2%**

9.2.1 Change in Operations & Maintenance Costs

Our operations and maintenance costs are forecast to decrease by -$0.37 million (or -1%) for the 1 April 2026 pricing year when compared against the prior pricing year 1 April 2025. Table 10 provides a comparison of our operations and maintenance costs expenditure, by cost component, between pricing years.

Table 10: Comparison of operations and maintenance costs between pricing years

Description	1 April 2026 ($'000)	1 April 2025 ($'000)	Movement ($'000)	Percent

Service Interruptions and Emergencies	12,607	9,856	2,751	28%
Vegetation Management	6,968	4,933	2,035	41%
Routine and Corrective Maintenance	13,957	16,032	(2,075)	-13%
Asset Replacement and Renewal	-	3,085	(3,085)	0%
Total Operations and Maintenance Costs	**33,533**	**33,906**	**(373)**	**-1%**

The movement reflects the significant upward pressure on input costs experienced during the past year, primarily in service interruptions and emergencies, and vegetation. But this is offset by the reduction in maintenance, replacements and renewals.

9.2.2 Change in Administration and Corporate Costs

The Administration and Corporate costs have increased by ($9.0) million (or 17%). Table 11 compares administration and corporate costs expenditure between pricing years.

Table 11: Comparison of Administration and Corporate Costs between pricing years.

Description	1 April 2026 ($'000)	1 April 2025 ($'000)	Movement ($'000)	Percent
System Operations and Network Support	21,852	21,534	318	1%
Business Support	39,730	31,038	8,692	28%
Total Administration and Corporate Costs	**61,582**	**52,572**	**9,010**	**17%**

9.2.3 Change in Depreciation Costs

The increase in Depreciation Charges of +$9.1 million (or +15%) reflects the increasing value of our electricity network assets, which are subject to annual regulatory revaluation. Table 12 compares depreciation charges between pricing years.

Table 12: Comparison of Depreciation charges between pricing years.

Description	1 April 2026 ($'000)	1 April 2025 ($'000)	Movement ($'000)	Percent
System Fixed Assets	63,141	53,914	9,227	17%
Non-system Fixed Assets	4,859	5,000	(141)	-3%
Total Depreciation Costs	**68,000**	**58,914**	**9,086**	**15%**

9.2.4 Change in Transpower costs

The increase in transmission costs of +$12.4 million (or +18%) is due to an increase in charges as per Transpower's notification to consumers. Transpower sets its prices per the Transmission Pricing Methodology (TPM) administered by the Authority. More information on the TPM can be found on the Authority's website.[9]

9.3 Recovery of Required Revenue from consumer groups

We recover our required revenue from consumers through prices. Table 13 provides a breakdown of the required revenue we recover through prices by consumer group for the pricing year.

[9] https://www.ea.govt.nz/operations/transmission/transmission-pricing

Table 13: Required Revenue by connection grouping for the pricing year

Consumer Group	Required Revenue ($'000)	Proportion of total Required Revenue
Street Lighting	610	0%
Residential Low User	125,524	36%
Residential Standard User	57,533	16%
Small General Connections	10,340	3%
Medium General Connections	33,509	10%
Large General Connections	41,205	12%
Irrigation Connections	18,297	5%
Major Customer and Embedded Network Connections	59,620	17%
Large Capacity Connections	4,438	1%
Total Revenue Recovered from Prices	**351,075**	**100%**

As discussed, our pricing approach aims to set efficient and appropriate prices. We set prices to recover the total required revenue over the pricing year to meet our aims and objectives.

9.4 Calculation of long-run marginal cost

From 1 April 2026, Orion has adopted the long-run marginal cost (LRMC) model developed through Electricity Networks Aotearoa (ENA). This standardised model is used by the majority of electricity distribution businesses (EDBs) in New Zealand and replaces Orion's previously applied long-run average incremental cost (LRAIC) model used for export credits.

The ENA LRMC model was developed to support the introduction of peak injection charges, which are mandated from 1 April 2026. Orion has applied the LRMC framework consistently across:

- Peak injection charges
- Peak consumption charges
- Major customer export credits

Orion will continue to apply LRMC for peak-related charges, as it provides efficient price signals that reflect the incremental cost of network investment required to accommodate growth.

Orion's model has calculated LRMC at $233 per kW, and this value is used in the setting of relevant tariffs.

9.4.1 Model inputs and calculations

1. General assumptions

	Value
Pricing year	2027
Constant dollar year of forecasts	2025
Last year of capex forecasts	2035
Inflation rate	2.0%
Years of inflation to be applied	2.00
EDB Cost of capital	8.94%
Average expected asset life of new demand-driven capex	50
Distribution Network Opex as a % of Capital Expenditure	1.6%

2. Incremental distribution network expenditure

	NPV	2027	2028	2029	2030	2031	2032	2033	2034	2035
System growth capex (2025 dollars)			38,963	42,995	41,906	44,138	36,811	43,440	45,227	52,307
System growth capital contributions (2025 dollars)			-	-	-	-	-	-	-	-
Demand-driven connections capex (2025 dollars)			-	-	-	-	-	-	-	-
Other demand-driven capex (2025 dollars)			-	-	-	-	-	-	-	-
Total demand-driven capex (2025 dollars)			38,963	42,995	41,906	44,138	36,811	43,440	45,227	52,307
Total demand-driven capex (2027 dollars)			40,537	44,732	43,599	45,921	38,298	45,195	47,054	54,420
Cumulative demand-driven capex			40,537	85,269	128,868	174,789	213,087	258,282	305,337	359,757
Annualised cumulative capex			3,677	7,734	11,688	15,853	19,326	23,425	27,693	32,628
NPV of cumulative annualised capex	88,431									
Incremental opex			645	1,356	2,050	2,780	3,389	4,108	4,856	5,722
NPV of incremental opex	15,508									

4. Demand forecasts

	NPV	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand on system for supply to consumers' connection points		715	733	752	772	793	814	836	858	881
Demand increment			18	19	20	21	21	22	22	23
Cumulative incremental demand			18	37	57	78	99	121	143	166
NPV of cumulative incremental demand	446									

5. LRMC calculation

	Units	Value
LRMC per kW per year	$/kW	$233
For TOU consumption pricing		
Peak hours per year	hrs	2340
LRMC per peak kWh	$/kWh	$0.100
Adjustment factor		0%
Adjusted LRMC per kWh	$/kWh	$0.100
For injection rebate		
Peak hours per year	hrs	780
LRMC per peak kWh	$/kWh	-$0.30
Adjustment factor		80%
Adjusted LRMC per kWh	$/kWh	-$0.060

10. Our Approach to setting prices

To set prices, we use a bottom-up approach that includes two steps.

- Step 1 – allocate the required revenue (cost to serve) by location to each consumer group
- Step 2 — set prices for each consumer group to recover that required revenue through our prices (target revenue).

10.1 Step 1 –allocate the revenue requirement by location and to consumer group

Using our cost of supply model (CoSM) we allocate the required revenue by location and then to consumer group. Our network is connected to eight grid exit points (GXP's). Several of those GXP's are tied, which means if consumers cannot be supplied by the closet GXP to them they can be supplied through another by switching. We consider GXP to be appropriately granular for the purposes of our CoSM and accordingly we allocate costs to the eight GXP's to which our network connects—

- Arthurs Pass
- Castle Hill
- Hororata
- Kimberley
- Bromley
- Coleridge
- Islington
- Norwood

Then we allocate the costs to our nine consumer groups. We consider consumer group to be sufficiently representative of the consumers on our network. Consumers are assigned to a consumer group based on how they use our network, size of their connection and primary function. Table 14 provides a list of our eight consumer groups.

Table 14: List of our nine consumer groups

Streetlighting
Residential Low User
Residential Standard User
Small General Connection
Medium General Connection
Large General Connection
Irrigation Connections
Major Customers and Embedded networks Connections
Large Customer Connections

10.2 Step 2—set the prices by which we recover our Target Revenue

We set the prices for each consumer group using our pricing design model. The model takes the cost to serve allocated by location and consumer group and derives distribution, pass-through and transmission prices from which we recover our Target Revenue.

We have two price types:

- fixed based on the type of connection and are static (e.g., kW, kVA, kVAr, meters, etc); and

- volumetric based on consumption and vary depending on when the consumer consumes or injects electricity (kWh).

The mix of fixed charges is shown in Figure 10 and the mix of variable charges is shown in Figure 11.

Figure 10: Mix of fixed prices

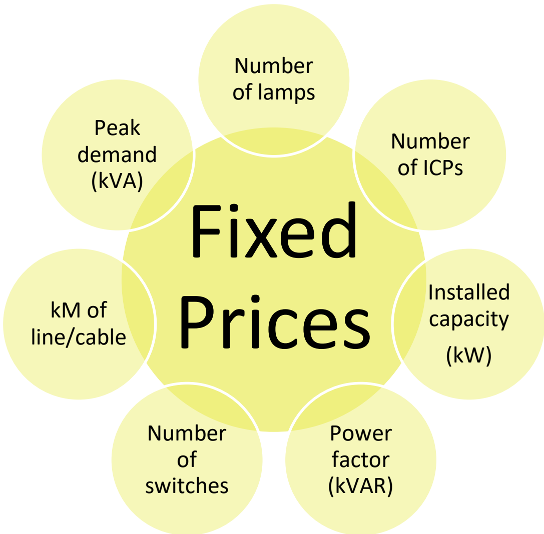


Figure 11: Mix of Variable prices

While we calculate distribution, pass-through, and transmission prices and locational prices, we do not bill those. Instead, we roll the distribution, pass-through and transmission prices up to set uniform delivery charges that apply no matter where the consumer is on our network.

10.2.1 Why do we apply a uniform delivery charge

We have elected to continue applying a uniform delivery charge, that is indifferent of location and inclusive of distribution, pass-through, and transmission prices for this pricing year.

Our current billing approach is simple and cost-effective; changing that approach to accommodate non-standard prices would add significant costs to billing, without a traceable benefit to consumers.

The Authority recognised the importance of weighing the cost versus benefits of adopting greater granularity in its Practice Note as follows:

'Granularity matters. The prices and regulated charges for electricity services vary significantly at different times and in…'

We will reconsider applying uniform delivery charges before setting prices each year. When consumers realise the benefits of more granular prices, we will change our approach and take the necessary steps to implement more granular prices.

10.3 Overview of our approach to allocating the Revenue Requirement

10.3.1 Allocate the Revenue Requirement at the GXP to consumer groups

As discussed in the previous section the CoSM firstly allocates our Revenue Requirement across the eight GXPs that our network connects to, based on the principal drivers of the cost components of the Required Revenue. The eight drivers of cost we use at each GXP are shown in Table 15

Orion

Table 15: The allocation to each GXP by cost driver

GXP	Arthurs Pass	Bromley	Castle Hill	Coleridge	Hororata	Islington	Kimberly	Norwood
No. of ICPs	0.1%	24.8%	0.1%	0.1%	2.0%	71.6%	0.4%	1.0%
Installed capacity (kW)	0.1%	21.7%	0.1%	0.1%	3.1%	73.0%	0.5%	1.5%
Asset Utilisation	0.1%	21.7%	0.1%	0.1%	3.1%	73.0%	0.5%	1.5%
Consumption (kWh)	0.0%	19.8%	0.1%	0.0%	3.1%	74.7%	0.4%	1.9%
Assessed Peak Demand (kW)	0.0%	19.6%	0.1%	0.0%	4.3%	73.2%	0.4%	2.4%
Line Length (LV/HV)	0.1%	21.9%	0.2%	0.1%	2.9%	72.9%	0.7%	1.3%
Regulated Asset Base ($)	0.1%	21.7%	0.1%	0.1%	3.1%	73.0%	0.5%	1.5%
Regulated Asset Base Depreciation ($)	0.1%	21.7%	0.1%	0.1%	3.1%	73.0%	0.5%	1.5%

1 April 2026 is the third year we are using this approach. Before 1 April 2024, costs were allocated to consumer groups based on ∑ AMD, after diversified maximum demand (ADMD) and average regulatory value (RIV). Last pricing year, we moved to a more granular approach apportioning costs in support of cost reflective pricing. The five cost drivers above were chosen as we have readily available information for these drivers. Making the approach straightforward, appropriate, and fair.

10.3.2 Allocate the Revenue Requirement at the GXP to consumer groups

Using the allocated Required Revenue by GXP, the CoSM next allocates the Revenue Requirement by GXP to the consumer groups, again based on the driver of the cost to serve each consumer group. Table 34 to Table 41, at Appendix F, show the five drivers that we use to allocate costs to the consumer groups, and the allocation of costs to each GXP.

10.3.3 Historical quantities to allocate the Required Revenue

We use historical quantities to allocate the required revenue to each consumer group by the GXP. The historical quantities used to allocate the Required Revenue for the pricing year is shown at Table 16. Table 42 to Table 49, at Appendix G, show the historical quantities that we have used to allocate the required revenue for each consumer group at each GXP

Table 16: Quantities used to allocate the Required Revenue for the pricing year

Consumer Group	**ICPs / Supplies** (Number)	**Consumption** (kWh)	**Installed capacity** (kVA)	**Asset utilisation** (kW)	**Line length** (meters)	**Assessed Demand** (kW)	**RAB** ($)	**RAB Depreciation** ($)
Streetlighting	464	7,353,895	3,704	2,593	8,172	1,190		
Residential Low User	157,921	1,088,018,205	2,413,198	1,689,239	5,628,567	231,852		
Residential Standard User	44,731	516,687,727	740,841	518,588	1,705,040	109,727		
Small General Connection	9,680	79,597,412	127,438	89,207	343,532	19,642		
Medium General Connection	12,703	276,850,218	609,923	426,946	1,555,363	62,406		
Large General Connections	2,877	420,457,546	587,678	411,375	1,424,456	78,756		
Irrigation Connections	1,054	103,316,460	104,848	73,394	668,384	43,033		
Major Customer Connections	560	850,335,295	342,151	239,506	759,083	117,889		
Total	**229,990**	**3,342,616,759**	**4,929,782**	**3,450,847**	**12,092,598**	**664,497**		
Network	Sub transmission Lines						92,114,000	3,239,000
	Sub transmission Cables						108,518,000	3,286,000
	Zone Substation						195,545,000	9,011,000
	Distribution LV Lines						175,478,000	6,637,000
	Distribution LV cables						496,871,000	16,659,000
	Distribution substations and transformers						177,936,000	5,124,000
	Distribution switchgear						210,879,000	8,055,000
	Other network assets						47,647,000	2,437,000
Non-Network	Non-Network assets						61,066,000	4,816,000
Total							**1,566,054,000**	**59,264,000**

Orion

10.4 Overview of our approach to setting Target Revenue

The pricing design model sets out how we recover our Target Revenue for each consumer group over the pricing year. The pricing design model first sets distribution and transmission prices for each consumer group by GXP and then a uniformed delivery charge.

10.4.1 Determine the fixed / variable split

Historically we have set delivery charges with a low fixed and high variable component as we have applied a consumption-based approach to pricing. As we transition our prices to become use-based, we will increase the fixed component and decrease the variable to improve cost reflectivity while retaining a level of variable price signalling. Table 17 compares the fixed and variable split applied in this pricing year to the prior pricing year. This year the proportion of revenue collected from fixed has reduced slightly as we have required rebalancing to ensure our peak prices align with updated LRMC.

Table 17: Comparison of the fixed / variable split between pricing years

Consumer Group		**1 April 2026**		**1 April 2025**	
		Fixed	**Variable**	**Fixed**	**Variable**
Streetlighting	LIG	100%	-	100%	-
Residential Low User	LOW	32%	68%	25%	75%
Residential Standard User	STN	35%	65%	41%	59%
Small General Connection	GEN(GC1)	56%	44%	59%	41%
Medium General Connection	GEN(GC2)	46%	54%	51%	49%
Large General Connections	GEN(GC3)	37%	63%	62%	38%
Residential Two-way Power Flow	2WAYRES	Withdrawn		21%	79%
Commercial Two-way Power Flow	2WAYSME	Withdrawn		37%	63%
Irrigation Connections	IRR	65%	35%	69%	31%
Major Customer and Embedded Network Connections	MCC	100%	-	100%	-
Large Capacity Connections	LCC	100%	-	100%	-

10.4.2 Calculate and set the fixed and variable charges

We set the fixed and variable charges within each consumer group by using the following formula

((CoSM allocated Required Revenue x split) x allocation to price / quantities)

Each connection group has one fixed charge:

- Residential and SME connection have a per-day ICP charge
- Irrigation connections have a per day, per chargeable capacity kVA charge
- Major customers have a per day, per chargeable capacity kVA charge
- Street Lighting connections have a per lamp per day charge

Table 18 shows the proportion of the Target Revenue recovered through fixed charges for each consumer group.

Table 18: Breakdown of Target Revenue recovered through fixed and variable revenue.

Consumer Group		Fixed Revenue ($'000)	Variable Revenue ($'000)	Target Revenue ($'000)
Streetlighting	LIG	1,826	-	1,826
Residential Low User	LOW	45,128	97,311	142,439
Residential Standard User	STN	20,082	37,774	57,856
Small General Connection	GEN(GC1)	6,519	5,118	11,637
Medium General Connection	GEN(GC2)	14,089	16,425	30,514
Large General Connections	GEN(GC3)	12,779	21,863	34,642
Irrigation Connections	IRR	8,761	4,710	13,471
Major Customer and Embedded Network Connections	MCC	54,252	-	54,252
Large Capacity Connections	LCC	4,438	-	4,438
	Total	**167,874**	**183,202**	**351,075**

Each connection category (excluding Major and LCC connections) have five variable prices - weekend, peak, shoulder, off-peak, super off-peak units per kWh as shown in Table 19. Accordingly, the costs are allocated to variable charges across each consumer group's variable price components.

Table 19: Allocation of variable prices (i.e. TOU) for the pricing year

Consumer Group		Weekend	Peak	Shoulder	Off Peak	Super Off Peak	Winter Peak Injection
Streetlighting	LIG						
Residential Low User	LOW	27%	31%	20%	16%	5%	1%
Residential Standard User	STN	27%	32%	21%	15%	6%	0%
Small General Connection	GEN(GC1)	23%	31%	29%	12%	5%	0%
Medium General Connection	GEN(GC2)	21%	32%	33%	9%	5%	0%
Large General Connections	GEN(GC3)	21%	32%	31%	11%	6%	0%
Irrigation Connections	IRR	28%	27%	24%	13%	7%	0%
Major Customer and Embedded Network Connections	MCC						
Large Capacity Connections	LCC						

10.4.3 We smooth prices to avoid bill shock

We use the allocation to variable prices to smooth end prices so we can:

- meet our regulatory requirements (e.g., transition arrangements of low fixed charge regulations) by capping fixed daily charges for residential consumers to recover our Required Revenue
- avoid bill shock to consumers as we evolve our prices to be more cost reflective.

We use a four-step process to smooth variable prices

Step 1 — Set the peak consumption and winter peak injection prices at LRMC

Step 2 — Set the residual required revenue across all other TOU charge components.

Step 3 — Adjust prices to comply with the transition arrangement of low fixed charge regulations.

Step 4 — Spread the under-recovered revenue from applying step 2 across the consumers in a fair manner that avoids bill shock to the consumers in those consumer groups.

10.4.4 We use forecast year-end quantities to set prices

We use year-end forecast quantities when setting our prices. Quantities are forecast for each consumer group based on the prior year's quantities multiplied by a growth factor. We use a combination of quantities to set prices:

- No of ICPs / Lamps
- Installed capacity (kVA)
- Demand (kVA)
- Consumption weekend (kWh)
- Winter peak injection (kWh)
- Consumption Peak (kWh)
- Consumption Shoulder (kWh)
- Consumption Off-Peak (kWh)
- Consumption Super off-peak (kWh)

Table 20 shows the forecast quantities we used for each consumer group to set this year's prices.

Orion

Table 20: Forecast quantities for this pricing year

	Streetlighting LIG	Residential Low User LOW	Residential Standard user STN	Small General Connection GEN(GC1)	Medium General Connection GEN(GC2)	Large General Connection GEN(GC3)	Irrigation Connections IRR	Major Customer Connections MCC
Number of ICPs/ lamps	54,750	158,269	47,902	10,207	12,783	2,892		560
Consumption Weekend (MWh)		48,720	20,706	13,763	48,231	82,223.5	38,975	
Consumption Peak (MWh)		314,950	146,149	24,315	88,169	139,148.8	36,844	
Consumption Shoulder (MWh)		327,643	159,439	25,134	93,577	136,616.1	33,748	
Consumption Off Peak (MWh)		216,150	100,352	12,311	35,164	54,133.8	18,588	
Consumption Supper Off Peak (MWh)		163,479	70,774	6,111	16,008	26,125.1	10,321	
Injection (MWh)		3,927	983	31	76			
Installed capacity (kVA)							76,393	390,928
Power factor correction rebate							23,775	
Interruptibility rebate							48,731	
Extra switches								113
11kV Assets								61
Demand (kVA)								688,654

Orion

10.4.5 Target Revenue is derived by multiplying prices by forecast quantities

The target revenue for each consumer group is set by using the following formula –

Price x Forecast quantities = Target Revenue

Table 21 provides a breakdown of the Target Revenue for each consumer group and the proportion of total revenue that consumer group equates to.

Table 21: Allocation and proportion of the Target Revenue between connection groups

Consumer Group		**Target Revenue** ($'000)	**Proportion of Total Target Revenue**
Streetlighting	LIG	1,826	1%
Residential Low User	LOW	142,439	41%
Residential Standard User	STN	57,856	16%
Small General Connection	GEN(GC1)	11,637	3%
Medium General Connection	GEN(GC2)	30,514	9%
Large General Connections	GEN(GC3)	34,642	10%
Irrigation Connections	IRR	13,471	4%
Major Customer and Embedded Network Connections	MCC	54,252	15%
Large Capacity Connections	LCC	4,438	1%
	Total	**351,075**	**100%**

10.5 Change in Target Revenue

Target Revenue has increased by $38.2 million (or+12.2%) for this pricing year. Table 22 shows the movement in Target Revenue by consumer group between pricing years.

Table 22: Movement in Target Revenue within connection groups between pricing years

Consumer Group		**1 April 2026** ($'000)	**1 April 2025** ($'000)	**Movement** ($'000)	Percent
Streetlighting	LIG	1,826	1,565	261	17%
Residential Low User	LOW	142,439	108,707	33,732	31%
Residential Standard User	STN	57,856	73,310	(15,454)	-21%
Small General Connection	GEN(GC1)	11,637	10,636	1,001	9%
Medium General Connection	GEN(GC2)	30,514	22,894	7,620	33%
Large General Connections	GEN(GC3)	34,642	29,964	4,678	16%
Residential Two-way Power Flow	2WAYRES	Withdrawn	2,521	(2,521)	-100%
Commercial Two-way Power Flow	2WAYSME	Withdrawn	144	(144)	-100%
Irrigation Connections	IRR	13,471	11,727	1,744	15%
Major Customer and Embedded Network Connections	MCC	54,252	46,474	7,778	17%
Large Capacity Connections	LCC	4,438	4,933	(495)	-10%
	Total	**351,075**	**312,876**	**38,200**	**12.2%**

10.6 Payments for injection

For the pricing year beginning 1 April 2026, we have adopted the LRMC approach to base the negative peak injection charge. Refer to section 9.4 for the calculation of Orion's LRMC.

We use a three-step process to calculate the negative peak injection charge

10.6.1 Calculation of negative peak injection charge

Step 1: Calculate Orion's LRMC, section 9.4.

Step 2: Determine the pricing window for the negative peak injection charge

The peak time periods for the negative charge aligns with our consumption tariffs, being 7am to 11am and 5pm to 10pm weekdays. However, for the negative charge, the pricing window is narrowed to winter months only (1 May to 31 August). This is because:

- For load customers, the goal is to enable behavioural change. To achieve that, simple, broad and consistent pricing signals are required, rather than periodic signals.
- For the negative charge for peak injection, as per the guidance, the goal is to determine the periods when demand on our network is at its greatest and when additional demand is likely to drive future network investment. Our network peak occurs in winter only and our future network investment is driven by the growth in our peak demand, therefore we believe narrowing the pricing window for the negative charge to winter months only is appropriate, which aligns with the guidance's principles.

Step 3: Determine an appropriate adjustment factor

As allowed under subclause (1)(c) in Part 12A.7 of the Code, we have adopted an 80% adjustment factor to negative charges. This scales the negative charge down to reflect the specific risks and characteristics of injection with regard to consumer impacts, uptake incentives, network stability, and variations in AMP forecasts. Further to this Orion is initiating flexibility trials this year with the goal of working with aggregators and retailers to offer stronger price signals and value to consumers for generation during Orion's the critical peaks in winter. These considerations are outlined below.

At the outset, as suggested by the Authority in the guidance, we have been prudent to begin with a relatively high adjustment factor (and therefore lower negative charge), and will fine-tune it over time as better data and consumer feedback become available.

Consumer impacts

This consideration has prompted us to adopt a conservative approach initially at setting the negative charge, because:

- As suggested by the Authority in the guidance, to avoid price shock, this means setting a negative charge at a relatively conservative rate initially, which increases over time, rather than setting it too high and discovering it needs to be lowered. This allows distributors to test and learn while sufficient visibility into our LV network is not available.
- Starting conservatively will also minimise the risks where the benefits from peak injection do not eventuate and some network investments are still required, leading to existing load consumers cross subsidising the negative charges.

Uptake incentives

This consideration also relates to us adopting a simple and broad approach. By not having a granular and complex set up, it facilitates retailers to pass them through efficiently.

Network stability

Injection at the wrong time/place may not only provide no network benefits but may incur additional network costs by causing localised export congestion or voltage issues. This is also one of the reasons why we have adopted a conservative approach to avoid a sudden spike in generation leading to congestion. As we learn and gather more data throughout this journey, it will allow us to finetune the negative charge amount to drive the best outcome for both the consumers and the network.

AMP forecast variations

When running six years of historic AMP investment forecasts for growth through our LRMC model, we observed a 170% spread in LRMC values, ranging from $75/kW to $501/kW (relative to the average outcome). This degree of variability highlighted the need to adopt a conservative adjustment factor to support predictable and consistent pricing outcomes for consumers over the long term. While the past three years have shown relative stability in forecast outcomes, we consider it prudent to maintain a conservative approach as we progress our CPP application.

Flexibility trials

Orion is continuing to work with retailers on flexibility trials to better understand how value can be created from distributed generation on our network during critical peak periods. These trials take a dynamic approach and are designed to integrate with retailers to reward consumers for the value they provide to the wider electricity system, including network services.

This approach is expected to deliver more precise price signals during the limited winter periods each year when the network requires additional injection and load reduction. As Orion continues to build understanding of customer behaviour through these trials, we expect to further refine our pricing approach, including the role of the current static negative peak injection price.

10.6.2 Form and the time periods in which it applies

As a result of the consultation with retailers, new pricing component codes will be created for retailers to be able to submit injection volume for peak and off-peak time band, and negative charges will apply accordingly to winter peak only.

For time periods, as mentioned above, the peak time periods for the negative charge aligns with our consumption tariffs, being 7am to 11am and 5pm to 10pm during workdays. However, for the negative charge, the pricing window is narrowed to winter months only (1 May to 31 August).

10.6.3 Important assumptions relied upon

All assumptions have been outlined above.

11. Loss Factors

Losses are the percentage of electricity entering the network lost during the delivery to consumer's connections (i.e., ICPs). The quantity of electricity metered at ICPs is net of losses. The consumption proportion assigned to each retailer at the GXP is determined by the electricity measured at the consumer's meter multiplied by a loss factor.

There are two components to loss factors on our network:

- Fixed component due to the standing losses of the distribution transformers; and
- Variable component arising from the heating effect of resistance on the lines.

Orion continue to undertake reviews of loss factors using the methodology outlined in the Electricity Authority's guideline. The revised and updated loss factors for the pricing year are provided in Table 23. The new loss factors will be effective 1 April 2026.

Table 23: Loss factors for the pricing year

Code	Loss Factor	Description
LVL	1.0452	Low voltage metered connections (230v or 400v)
11L	1.0229	11kV metered connections
SLL	1.0068	Connection specific factors (HV)
FSL	1.0068	Connection specific factors (HV)

12. Distributed Generation

Interest in utility-scale solar connections has significantly increased since 2022. Inquiries indicate potential for 400MW of solar PV/wind generation to be added within Region B. We have 7,937 small photovoltaic installations under 10kW at 1 December 2025.

Summer peaks sometimes occur after 7pm when solar radiation is reduced. Together with cloud cover the solar generation can be less than 5% of nameplate capacity at the time of peak load. We plan to monitor the output of these solar connections so their contribution can be excluded from our peaks which will reveal the change in underlying load. Standard forecasting methodology can be applied to this underlying load, with the solar output reported separately.

Currently, no distributed generation feeds in at high voltage onto our network.

12.1 Solar 10kW or less

Systems of this size are typically installed in homes and small businesses whereas systems greater than 10 kilowatts are typically used by larger businesses.

Distributed generation must meet all relevant statutory and regulatory requirements and comply with all applicable safety standards. As there is no incremental cost associated with the connection of small distribution generation load, we currently charge a nominal application fee.

12.2 Business 10kW or more

Distributed generators, also known as 'embedded generators', are located at a home or business to produce electricity for that home or business's own use. They may also be capable of putting surplus energy back into our distribution network. These generators can take several forms: solar panels, wind or micro-hydro turbines and diesel generators are the most common. These systems are usually three-phase, and are typically installed at industrial, commercial or rural sites.

Our policies relating to the connection of distributed generation can be found on our website at Solar or diesel generation | The Orion Group.

13. Export Credits

Distributed generation that reliably generates during peak demand times can provide an economical alternative to electricity delivery and we provide export credits in recognition of this benefit to the network. Our export credits do not represent the purchase of electricity, and consumers are able to separately negotiate to sell exported energy with other parties, usually with their electricity retailer.

Payments to generators are a cost incurred in providing our delivery service and, as with all other delivery costs, must be recovered from the consumers that use our network.

We do not specifically charge consumers for exporting electricity to our network; however, consumers would be expected to fund any costs associated with situations where our network needed to be upgraded to accommodate the exported electricity. Separately, the nominated maximum demand charge for major customers, which broadly reflects the sizing of network delivery assets near the consumer, is based on export demands where this is more than double the load demands, so excess peak export can increase delivery charges.

13.1 How are export credit prices calculated?

Export credits are based on the amount of electricity injected into our network during peak loading periods. The cost of delivery during peak loading is represented by our assessment of LRMC which we calculate as $233 per kW[10] per year. The approach that we take to derive the LRMC is shown in section 9.

Some of the costs represented in this LRMC are not alleviated via export for example, the required size for distribution transformers and low voltage systems is usually unchanged when generation is installed. Further, some network areas experience peaks that are not aligned with the timing of our signalled peak periods, and we reduce the standard credit price to reflect this divergence as well. Combining these factors, the distribution credit price is set below the full LRMC. While we continue to optimise our approach to LRMC, we have applied a 20% increase to export credit prices this year.

We then separate the credit between real (kW) and reactive (kVAr) components of export, and we cap the amount of reactive export that is eligible for credits, to encourage appropriate levels of each.

Different categories are maintained to generally reflect the different metering information available from different sites, and standard credits are capped at 750kW of generation – above this level we individually consider the benefits to the network and apply specific pricing. We set a lower credit price for export that includes PV and where the metering arrangement only records total monthly export (referred to as “non-half-hour metering”) rather than the actual time that energy was exported. The lower price reflects average coincidence between export from PV generation, and our network peak

[10] Assumes a power factor of 1.

demands (usually occurring on cold winter days and evenings) that we observe at connections that do have the necessary metering for this assessment.

Exporting generators also reduce our exposure to Transpower's charges if they generate during Transpower's peak demand periods. The Electricity Authority has revised the rules so that we are only able to reflect this savings in the credits applied to customers for generating connections that they approve, and at the date of this publication, no connections have been approved by the Electricity Authority.

Orion

Appendix A –Price Schedule effective 1 April 2026

Electricity delivery price schedule for Orion NZ Ltd
(applicable from 1 April 2026)

This schedule lists the prices that Orion uses to charge electricity retailers and directly contracted customers for the electricity delivery service in Orion's network area. This delivery service includes the transmission and distribution of electricity to homes and businesses but does not include the cost of electricity itself. Please refer to your retailer for details of retail electricity prices.

All prices exclude GST	**Price Category Code [2]**	**Price Component Code [2]**	**Distribution Price** (D)	**Pass-through & Recoverable Price** (P&R)	**Transmission Price** (T)	**Delivery Price** (D+P&R+T)	**Unit of measure**
Streetlighting	LIG						
Fixed Daily Charge	54,750	LIGFXD	$0.0828	$0.0012	$0.0073	$0.0913	$/lamp/day
Residential Low User							
Uncontrolled Charges	**URES**						
Fixed Daily Charge	26,624	URESUFXD	$0.7810	$0.0811	$0.0379	$0.9000	$/con/day
Weekend		URESUWKD	$0.04500	$-	$-	$0.04500	$/kWh
Peak		URESUP	$0.09960	$-	$0.07291	$0.17251	$/kWh
Shoulder		URESUSH	$0.09217	$-	$0.00794	$0.10011	$/kWh
Off Peak		URESUOP	$0.00829	$-	$-	$0.00829	$/kWh
Super Off Peak		URESUSOP	$-	$-	$-	$-	$/kWh
Winter Injection Peak		URESUDGI	$(0.06000)	$-	$-	$(0.06000)	$/kWh
Controlled Charges	**URES**						
Fixed Daily Charge	131,645	RESCFXD	$0.6574	$0.0811	$0.0187	$0.7572	$/con/day
Weekend		RESCWKD	$0.04500	$-	$-	$0.04500	$/kWh
Peak		RESCP	$0.09960	$-	$0.07291	$0.17251	$/kWh
Shoulder		RESCSH	$0.09217	$-	$0.00794	$0.10011	$/kWh
Off Peak		RESCOP	$0.00829	$-	$-	$0.00829	$/kWh
Super Off Peak		RESCSOP	$-	$-	$-	$-	$/kWh
Winter Injection Peak		RESCDGI	$(0.06000)	$-	$-	$(0.06000)	$/kWh
Residential Standard User							
Uncontrolled Charges	**RSU**						
Fixed Daily Charge	9,243	RSUUFXD	$0.7867	$0.1265	$0.3369	$1.2501	$/con/day
Weekend		RSUUWKD	$0.03636	$-	$-	$0.03636	$/kWh
Peak		RSUUP	$0.09960	$-	$0.04232	$0.14192	$/kWh
Shoulder		RSUUSH	$0.06613	$-	$0.01380	$0.07993	$/kWh
Off Peak		RSUUOP	$0.00657	$-	$-	$0.00657	$/kWh
Super Off Peak		RSUUSOP	$-	$-	$-	$-	$/kWh
Winter Injection Peak		RSUUDGI	$(0.06000)	$-	$-	$(0.06000)	$/kWh
Controlled Charges	**RSC**						
Fixed Daily Charge	38,659	RSCCFXD	$0.7417	$0.1265	$0.2561	$1.1243	$/con/day
Weekend		RSCCWKD	$0.03636	$-	$-	$0.03636	$/kWh
Peak		RSCCP	$0.09960	$-	$0.04232	$0.14192	$/kWh
Shoulder		RSCCSH	$0.06613	$-	$0.01380	$0.07993	$/kWh

All prices exclude GST	Price Category Code [2]	Price Component Code [2]	Distribution Price (D)	Pass-through & Recoverable Price (P&R)	Transmission Price (T)	Delivery Price (D+P&R+T)	Unit of measure
Off Peak		RSCCOP	$0.00657	$-	$-	$0.00657	$/kWh
Super Off Peak		RSCCSOP	$-	$-	$-	$-	$/kWh
Winter Injection Peak		RSCCDGI	$(0.06000)	$-	$-	$(0.06000)	$/kWh
Small General Connection up to 15 kVA							
Uncontrolled Charges	**UGENGC1**						
Fixed Daily Charge	8,173	UGENGC1UFXD	$1.1439	$0.1063	$0.5307	$1.7809	$/con/day
Weekend		UGENGC1UWKD	$0.02754	$-	$-	$0.02754	$/kWh
Peak		UGENGC1UP	$0.09960	$-	$0.01788	$0.11748	$/kWh
Shoulder		UGENGC1USH	$0.06429	$-	$-	$0.06429	$/kWh
Off Peak		UGENGC1UOP	$0.00507	$-	$-	$0.00507	$/kWh
Super Off Peak		UGENGC1USOP	$-	$-	$-	$-	$/kWh
Winter Injection Peak		UGENGC1UDGI	$(0.06000)	$-	$-	$(0.06000)	$/kWh
Controlled Charges	**GENGC1**						
Fixed Daily Charge	2,034	GENGC1CFXD	$0.9899	$0.1063	$0.5284	$1.6246	$/con/day
Weekend		GENGC1CWKD	$0.02754	$-	$-	$0.02754	$/kWh
Peak		GENGC1CP	$0.09960	$-	$0.01788	$0.11748	$/kWh
Shoulder		GENGC1CSH	$0.06429	$-	$-	$0.06429	$/kWh
Off Peak		GENGC1COP	$0.00507	$-	$-	$0.00507	$/kWh
Super Off Peak		GENGC1CSOP	$-	$-	$-	$-	$/kWh
Winter Injection Peak		GENGC1CDGI	$(0.06000)	$-	$-	$(0.06000)	$/kWh
Medium General Connection 16 kVA to 69 kVA							
Uncontrolled Charges	**UGENGC2**						
Fixed Daily Charge	11,081	UGENGC2UFXD	$1.2853	$0.2687	$1.4874	$3.0414	$/con/day
Weekend		UGENGC2UWKD	$0.02337	$-	$-	$0.02337	$/kWh
Peak		UGENGC2UP	$0.09960	$-	$0.00828	$0.10788	$/kWh
Shoulder		UGENGC2USH	$0.05457	$-	$-	$0.05457	$/kWh
Off Peak		UGENGC2UOP	$0.00418	$-	$-	$0.00418	$/kWh
Super Off Peak		UGENGC2USOP	$-	$-	$-	$-	$/kWh
Winter Injection Peak		UGENGC2UDGI	$(0.06000)	$-	$-	$(0.06000)	$/kWh
Controlled Charges	**GENGC2**						
Fixed Daily Charge	1,702	GENGC2CFXD	$1.2571	$0.2687	$1.3511	$2.8769	$/con/day
Weekend		GENGC2CWKD	$0.02337	$-	$-	$0.02337	$/kWh
Peak		GENGC2CP	$0.09960	$-	$0.00828	$0.10788	$/kWh
Shoulder		GENGC2CSH	$0.05457	$-	$-	$0.05457	$/kWh
Off Peak		GENGC2COP	$0.00418	$-	$-	$0.00418	$/kWh
Super Off Peak		GENGC2CSOP	$-	$-	$-	$-	$/kWh
Winter Injection Peak		GENGC2CDGI	$(0.06000)	$-	$-	$(0.06000)	$/kWh
Large General Connection >70 kVA							
Uncontrolled Charges	**UGENGC3**						
Fixed Daily Charge	2,628	UGENGC3UFXD	$2.6555	$1.4884	$7.9845	$12.1284	$/con/day

Orion

All prices exclude GST	Price Category Code [2]	Price Component Code [2]	Distribution Price (D)	Pass-through & Recoverable Price (P&R)	Transmission Price (T)	Delivery Price (D+P&R+T)	Unit of measure
Weekend		UGENGC3UWKD	$0.01843	$-	$-	$0.01843	$/kWh
Peak		UGENGC3UP	$0.09064	$-	$0.00736	$0.09800	$/kWh
Shoulder		UGENGC3USH	$0.04510	$-	$-	$0.04510	$/kWh
Off Peak		UGENGC3UOP	$0.00345	$-	$-	$0.00345	$/kWh
Super Off Peak		UGENGC3USOP	$-	$-	$-	$-	$/kWh
Winter Injection Peak		UGENGC3UDGI	$-	$-	$-	$-	$/kWh
Controlled Charges	**GENGC3**						
Fixed Daily Charge	264	GENGC3CFXD	$2.4951	$1.4884	$7.9015	$11.8850	$/con/day
Weekend		GENGC3CWKD	$0.01843	$-	$-	$0.01843	$/kWh
Peak		GENGC3CP	$0.09064	$-	$0.00736	$0.09800	$/kWh
Shoulder		GENGC3CSH	$0.04510	$-	$-	$0.04510	$/kWh
Off Peak		GENGC3COP	$0.00345	$-	$-	$0.00345	$/kWh
Super Off Peak		GENGC3CSOP	$-	$-	$-	$-	$/kWh
Winter Injection Peak		GENGC3CDGI	$-	$-	$-	$-	$/kWh
Irrigation Connections	IRR						
	1,067						
Capacity Charge		IRRCAP	$0.3071	$0.0511	$0.3423	$0.7005	$/kW/day*
Power factor correction rebate		IRRPFC	$(0.1500)	$-	$-	$(0.1500)	$/kVAr/day*
Interruptibility rebate		IRRIRR	$(0.0372)	$-	$-	$(0.0372)	$/kW/day*
Weekend		IRRWKD	$0.01423	$-	$-	$0.01423	$/kWh
Peak		IRRP	$0.07969	$-	$-	$0.07969	$/kWh
Shoulder		IRRSH	$0.03467	$-	$-	$0.03467	$/kWh
Off Peak		IRROP	$0.00266	$-	$-	$0.00266	$/kWh
Super Off Peak		IRRSOP	$-	$-	$-	$-	$/kWh
* applied to 1 October to 31 March only							
Major Customer and Embedded Network Connections							
	MCC						
Fixed charge	430	MCFXD	$27.9997	$-	$-	$27.9997	$/con/day
Fixed charge (additional connections)		MCFXDA	$20.9998	$-	$-	$20.9998	$/con/day
Extra switches		EQESW	$5.4999	$-	$-	$5.4999	$/switch/day
11kV Metering equipment		EQMET	$7.4319	$-	$-	$7.4319	$/con/day
11kV Underground cabling		EQUGC	$7.0025	$-	$-	$7.0025	$/km/day
11kV Overhead lines		EQOHL	$5.2205	$-	$-	$5.2205	$/km/day
Transformer capacity		EQTFC	$0.01735	$-	$-	$0.01735	$/kVA/day
Peak charge (control period demand)		MCCPD	$0.20799	$0.03130	$0.18698	$0.42627	$/kVA/day
Nominated maximum demand		MCNMD	$0.13166	$0.00062	$0.00369	$0.13597	$/kVA/day
Metered maximum demand		MCMMD	$0.05686	$0.00995	$0.05946	$0.12627	$/kVA/day

Large Capacity Connections

Individually assessed prices advised and charged directly to the customers

Time Periods

Weekend means all trading periods on a Saturday and Sunday except for Super Off Peak between 3am -5am.

Peak periods are Monday to Friday, 7:00am to 11:00am and 5:00pm to 10:00pm

Shoulder periods are Monday to Friday, 5:00am to 7:00am and 11:00am to 5:00pm

Off Peak period is Monday to Friday, 10:00pm to 3:00am

Super Off Peak period is any day between 3:00am to 5:00am

Distributed generation injection credit is payable during the Winter Peak Period only, which is 1 May to 31 August, Monday to Friday, 7:00am to 11:00am and 5:00pm to 10:00pm

Notes

1. Full details on how we apply these prices are included in our Pricing Policy document, available on our website.
2. The applicable price category is recorded against each connection ICP on the Electricity Authority's registry, and the price component is used in our mandatory 'electricity information exchange protocol' files.
3. If an ICP kWh value cannot be submitted under the required TOU time bands, DEF24 must be used as the price component code.

Appendix B – Export Credits Schedule effective 1 April 2026

Electricity export credit schedule for Orion NZ Ltd
(applicable from 1 April 2026)

This schedule lists the credit prices that we use to credit electricity retailers or directly contracted customers for exports or contributions from their distributed generation. The credits do not represent the purchase of electricity. They are a recognition of the value to Orion in providing its delivery service. Credits are only available for generation approved by Orion and customers must apply in advance.

For exporting generators that were in place prior to 6 December 2016 and approved by the Electricity Authority an additional credit reflecting any actual savings in Transpower charges is available (at the date of issue of this schedule, no exporting generators have been approved by the Electricity Authority). In addition to applying for our distribution credit, exporting customers can approach Transpower (for example, under Transpower's demand response program) for recognition of any transmission benefit, and approach their electricity retailer for recognition of the value of energy exported.

Export credits are based on electricity exported only during specific time periods and exclude GST.

Generator rated output	Period applied	Credit prices	Price Component Code[3]	Unit of measure
30 - 750kW Control period credits[4]				
- real power, plus	Chargeable control period	(0.1068)	EXPCP1	$/kW/day
- reactive power[5]		(0.0352)	EXPCP2	$/kVAr/day
above 750kW	*Individually assessed prices provided on application*			

Appendix C – Change in prices between pricing years

		Delivery Prices (excl GST)	
Connection categories and price components	**Units**	**1 April 2025**	**1 April 2026**
Streetlighting connections (approx 54,750 lamps)			
Fixed Daily Charge	$/lamp/day	0.0789	0.0913
Residential Low User (approx 158,269 connections)			
Uncontrolled Charges			
Fixed Daily Charge	$/con/day	0.7500	0.9000
Weekend	$/kWh	0.03913	0.04500
Peak	$/kWh	0.15611	0.17251
Shoulder	$/kWh	0.09101	0.10011
Off Peak	$/kWh	0.00721	0.00829
Super Off Peak	$/kWh	-	-
Winter Peak Injection	$/kWh	-	(0.06000)
Controlled Charges			
Fixed Daily Charge	$/con/day	0.6078	0.7572
Weekend	$/kWh	0.03913	0.04500
Peak	$/kWh	0.15611	0.17251
Shoulder	$/kWh	0.09101	0.10011
Off Peak	$/kWh	0.00721	0.00829
Super Off Peak	$/kWh	-	-
Winter Peak Injection	$/kWh	-	(0.06000)
			-
Residential Standard User (approx 47,902 connections)			
Uncontrolled Charges			
Fixed Daily Charge	$/con/day	1.1613	1.2501
Weekend	$/kWh	0.03109	0.03636
Peak	$/kWh	0.12458	0.14192
Shoulder	$/kWh	0.07260	0.07993
Off Peak	$/kWh	0.00582	0.00657
Super Off Peak	$/kWh	-	-
Winter Peak Injection	$/kWh	-	(0.06000)
Controlled Charges			
Fixed Daily Charge	$/con/day	1.0191	1.1243
Weekend	$/kWh	0.03109	0.03636
Peak	$/kWh	0.12458	0.14192
Shoulder	$/kWh	0.07260	0.07993
Off Peak	$/kWh	0.00582	0.00657
Super Off Peak	$/kWh	-	-
Winter Peak Injection	$/kWh	-	(0.06000)
Small General Connection (approx 10,207 connections)			
Uncontrolled Charges			
Fixed Daily Charge	$/con/day	1.5338	1.7809
Weekend	$/kWh	0.02550	0.02754
Peak	$/kWh	0.10216	0.11748

Connection categories and price components		Units	Delivery Prices (excl GST) 1 April 2025	1 April 2026
	Shoulder	$/kWh	0.05953	0.06429
	Off Peak	$/kWh	0.00477	0.00507
	Super Off Peak	$/kWh	-	-
	Winter Peak Injection	$/kWh	-	(0.0600)
	Controlled Charges			
	Fixed Daily Charge	$/con/day	1.3967	1.6246
	Weekend	$/kWh	0.02550	0.02754
	Peak	$/kWh	0.10216	0.11748
	Shoulder	$/kWh	0.05953	0.06429
	Off Peak	$/kWh	0.00477	0.00507
	Super Off Peak	$/kWh	-	-
	Winter Peak Injection	$/kWh	-	(0.06000)
Medium General Connection (approx 12,783 connections)				
	Uncontrolled Charges			
	Fixed Daily Charge	$/con/day	2.7204	3.0414
	Weekend	$/kWh	0.02124	0.02337
	Peak	$/kWh	0.08511	0.10788
	Shoulder	$/kWh	0.04961	0.05457
	Off Peak	$/kWh	0.00398	0.00418
	Super Off Peak	$/kWh	-	-
	Winter Peak Injection	$/kWh	-	(0.06000)
	Controlled Charges			
	Fixed Daily Charge	$/con/day	2.5840	2.8769
	Weekend	$/kWh	0.02124	0.02337
	Peak	$/kWh	0.08511	0.10788
	Shoulder	$/kWh	0.04961	0.05457
	Off Peak	$/kWh	0.00398	0.00418
	Super Off Peak	$/kWh	-	-
	Winter Peak Injection	$/kWh	-	(0.06000)
Large General Connection (approx 2,892 connections)				
	Uncontrolled Charges			
	Fixed Daily Charge	$/con/day	11.9824	12.1284
	Weekend	$/kWh	0.01755	0.01843
	Peak	$/kWh	0.07033	0.09800
	Shoulder	$/kWh	0.04099	0.04510
	Off Peak	$/kWh	0.00329	0.00345
	Super Off Peak	$/kWh	-	-
	Winter Peak Injection	$/kWh	-	-
	Controlled Charges			
	Fixed Daily Charge	$/con/day	11.8382	11.8850
	Weekend	$/kWh	0.01755	0.01843
	Peak	$/kWh	0.07033	0.09800
	Shoulder	$/kWh	0.04099	0.04510
	Off Peak	$/kWh	0.00329	0.00345
	Super Off Peak	$/kWh	-	-
	Winter Peak Injection	$/kWh	-	-

Orion

Connection categories and price components	Units	Delivery Prices (excl GST) 1 April 2025	1 April 2026
Irrigation Connection (approx 1,067 connections)			
Capacity Charge	$/kW/day*	0.6397	0.7005
Power factor correction rebate	$/kVAr/day*	(0.1359)	(0.1500)
Interruptibility rebate	$/kW/day*	(0.0336)	(0.0372)
Weekend	$/kWh	0.0135	0.01423
Peak	$/kWh	0.0541	0.07969
Shoulder	$/kWh	0.0315	0.03467
Off Peak	$/kWh	0.0025	0.00266
Super Off Peak	$/kWh	-	-
* applied from 1 October to 31 March only			
Major customer and embedded network connections (approx 1,067 connections)			
Fixed charge	$/con/day	23.8045	27.9997
Fixed charge (additional connections)	$/con/day	17.8534	20.9998
Extra switches	$/switch/day	4.6419	5.4999
11kV Metering equipment	$/con/day	6.3082	7.4319
11kV Underground cabling	$/km/day	5.5941	7.0025
11kV Overhead lines	$/km/day	4.1658	5.2205
Transformer capacity	$/kVA/day	0.0140	0.01735
Peak charge (control period demand)	$/kVA/day	0.3664	0.42627
Nominated maximum demand	$/kVA/day	0.1181	0.13597
Metered maximum demand	$/kVA/day	0.1113	0.12627
Export credits (approx 12 connections)			
30 - 750kW Control period credits			
- real power, plus	$/kW/day	(0.0890)	(0.1068)
- reactive power5	$/kVAr/day	(0.0293)	(0.0352)

Orion

Appendix D – Overview of the regulatory framework

D1. Regulatory background

We are a supplier of electricity distribution lines services. Accordingly, our revenues and prices are regulated by the Commerce Commission (the economic regulator) and the Electricity Authority (the electricity market regulator). Table 25 provides a summary of how these two regulators give effect to how much revenue we can earn and how we set our prices

Table 25: Summary of the regulatory functions around revenues and prices by the regulators

Regulator	Regulation	Purpose	Regulatory mechanism
Commerce Commission	Part 4 of the Commerce Act	Sets the price and quality path (how much revenue a distributor can collect)	Price Path Determination
		Sets reporting and disclosure requirements (the information about prices that a distributor must publicly disclose)	Information Disclosure Determination
Electricity Authority	Electricity Industry Act 2010	Provides terms and conditions for applying prices to retailers	The Electricity Participation Code and Default Distribution Agreement
		Provides guidance on developing pricing structures to reflect the true costs of providing distribution services	Distribution Pricing Principles

D2. Commerce Act 1986

Electricity distribution is a regulated service under Part 4 of the Commerce Act 1986 (the Act) the Commission regulates markets where competition is limited, including electricity distribution services. The purpose of Part 4 is to promote the long-term benefits of consumers by fostering outcomes consistent with competitive markets thereby ensuring that distributors have incentives to innovate, invest, improve efficiency, and provide services at a quality that consumers demand. Table 26 summarises the two ways the Commission regulates revenues of distributors.

Table 26: How the Commission regulates revenues for electricity distribution services

Price-quality regulation	The Commission regulates the price (how much a consumer pays for the service) and quality (the level of quality it must provide) to ensure distributors face incentives that exist in a workably competitive market. The Commission sets a price-quality path determination which provides how much revenue a distributor can collect and the service quality it must provide.

Information disclosure	The Commission regulates what information distributors must publicly disclose about its operating and business performance. This allows the Commission, stakeholders, and the public to judge whether the purpose of Part 4 of the Commerce Act are being met. The information that distributors must disclose publicly is prescribed by the Commission through the Information Disclosure Determination. This Pricing Methodology is a requirement of that determination.

D2.1 Price-quality regulation

We are subject to price and quality regulation under the Electricity Distribution Services Default Price-Quality Path Determination 2025 (DPP Determination 2025) for the 5-year regulatory period from 1 April 2025 to 31 March 2030. Table 27 provides an overview of the three components of the price path.

Table 27: Overview of the three components of the price path

Component of the price path	What the price component recovers
Distribution price component	The cost of operating the electricity distribution network and providing electricity distribution services.
Pass-through price component	The costs for other external services that the distributors then pass through to consumers. These costs include council rates, electricity regulation levies and transmission costs. These costs are largely outside the control of the distributors.
Recoverable price component	Recoverable costs are in-period adjustments to distribution service costs. Recoverable costs include incentive payments and penalties, wash-ups for differences between forecasts and actual pricing inputs, delayed recovery of revenue from price smoothing and approved innovation allowances cost recovery.

Before the start of each regulatory period, the Commission determines the total amount of allowable revenue that a non-exempt distributor is allowed to collect from its consumers. Allowable revenue comprises of 'building blocks' which include operating expenditure, asset depreciation, tax expenses and an industry benchmarked rate of return on capital employed. Once the building blocks are determined for each year of the regulatory period, the annual cost amounts are aggregated and smoothed over the regulatory period as forecast net allowable revenue.

The DPP Determination 2025 sets our forecast net allowable revenue to be collected from distribution prices for each year of the regulatory period starting 1 April 2025 and ending 31 March 2030. A mechanism at the end of each pricing year allows for any differences between forecast allowable revenue and actual revenue to be washed-up in subsequent years with a time value of money adjustment.

Pass-through price components recover the actual pass-through and recoverable costs that we incur. A mechanism at the end of each pricing year allows for any differences between pass-through and recoverable costs and pass-through price revenues to be washed up in subsequent years with a time value of money adjustment.

The prices provided in this Price Methodology are compliant with the DPP Determination 2025 for the second Assessment Period, i.e., the year commencing 1 April 2026.

D2.2 Information disclosure

We are also subject to information disclosure regulation under Part 4[11] of the Act. The purpose of information disclosure regulation is to ensure that interested persons have sufficient information readily available for them to assess whether the purpose of Part 4 of the Act is being met. Each year before the regulatory year begins and after it ends, we make several disclosures prescribed by the ID Determination: including publicly disclosing a pricing methodology before the start of the disclosure year commencing 1 April. The requirements of the ID Determination relating to pricing methodologies are set in Appendix C.

D3. Electricity Industry Act 2010

The Electricity Act 2010 provides the framework for the regulation of the electricity industry. The Act is enacted via The Electricity Industry Participation Code 2010 (Code) which provides the rules that govern the New Zealand electricity market. The Authority is the regulator of the Electricity Industry Act 2010 and the Code.

D3.1 Electricity Authority's price reform

The Electricity Authority is reforming prices for transmission and distribution services.[12] The intent of the reform is to provide prices that are fully cost reflective of the underlying costs of providing lines services to consumers. Prices influence people's and businesses' use of electricity and the investments they, distributors, Transpower and others in the sector make. Cost-reflective price signals support consumers and the industry to make efficient infrastructure investments which will help reduce the size of any future price increases.

Ensuring efficient investments in infrastructure will be especially important as New Zealand Emissions Reduction Programme increases electricity demand and future investment requirements.

D3.1.1 Transmission Pricing Methodology (TPM)

In April 2022 the Authority completed its review of the Transmission Pricing Methodology (TPM). The TPM, effective from 1 April 2023, determines how Transpower recovers its maximum allowable revenue from its transmission customers through transmission charges.[13] Distributors pass through these transmission costs to retailers and direct billed consumers by replicating as close as is practicable the allocation methodology used to assign the transmission costs to them.[14]

---

[11] Section 54F of the Commerce Act 1986

[12] The Electricity Authority's price reform is for methods used to calculate the unit price which pass costs on to consumers, not the total amount of revenue that is allowed to be collected, which is provided by the Commerce Act 1986 and is the responsibility of the Commission.

[13] Transpower's maximum allowable revenue is set by the Commerce Commission to reflect the annual cost of owning and operating the national electricity transmission network (the grid).

[14] More information about the TPM can be found in the Transpower New Zealand's, Guide to the TPM, available on its website.

D3.1.2 Distribution Pricing Reform

To assist distributors, interpret and apply the distribution pricing principles (discussed in more detail in Appendix C) the Authority also publish a Distribution Pricing Practice Note[15]. Further, the Authority developed a scorecard to 'monitor and comment on distributor's pricing structure and pricing reform.' The most recent scorecard assessed the progress of 1 April 2023 pricing.[16] In that scorecard we were assessed at an overall score of 4.1 out of 5, with five specific expectations of progress identified—

- Focus area 1: Roadmaps responding to future network congestion
- Focus Area 2: First mover disadvantage in new and expanded connections
- Focus Area 3: Pass-through of new transmission charges
- Focus Area 4: Phase-out of low fixed charge (LFC) regulations
- Focus Area 5: Recovery of fixed costs through use-based charges[17]

We put a strong focus on pricing reforms to progress these five areas for our 1 April 2024 prices. Table 28 provides a snapshot of the progress we have made on meeting the Authority's pricing reforms in 2024.

Table 28: Snapshot of our progress on meeting the Authority's expected pricing reforms in 2024

Authority's Expectation	How we align
Distributors' roadmaps responding to future network congestion	Our roadmap initially targets congestion reducing measures for our largest consumer segments first, including: • *Now* | Support price mode innovators by trialling retailer aggregation prices for residential connections • *Next* | Activate commercial and industrial consumer demand management and response with reward prices by establishing variable demand pricing
Distributors' response to first mover disadvantage (FMD) issues	As part of phase 2 of our new connections and extensions methodology, we are implementing a Pioneer Scheme for consumer-funded network extension assets to overcome first mover disadvantage via rebates from subsequent connections that occur within a reasonable period. This will involve a comprehensive assessment of technical, financial, and regulatory aspects. Additionally, we will address regulatory compliance, risk management strategies, and implement effective communication channels to keep stakeholders informed and engaged throughout the process.
Pass-through of transmission charges	We will continue to apply transmission pass through per our transition constraint identified in *Our 1 April 2027 pricing goals* at section 4.6.
The phase-out of the low fixed charge (LFC) price regulations	We are in the process of transitioning our legacy residential LFC prices under the regulated phase-out timeline, per our transition constraint identified in *Our 1 April 2027 pricing goals* at section 4.6 and *B4. Low Fixed Charge Regulations* below on page 62.

[15] Electricity Authority, Distribution Pricing: Practice Note, Second Edition v 2.w, 2022 — October 2002.

[16] Electricity Authority, Distribution pricing scorecards 2023, Information paper, 10 October 2023.

[17] Electricity Authority, Orion — Distribution pricing scorecard 2023, 10 October 2023.

Authority's Expectation	How we align
	In our 2023 pricing methodology we introduced the disaggregation of our general connections consumer segment to allow better targeting of the transition, by segmenting into: • Residential connections • General Group 1 (GC1) Small business • General Group 2 (GC2) Small and medium enterprises (SMEs) • General Group 3 (GC3) Commercial and industrial (C&I) In 2024 moved to time-of-use pricing and retired our Weekdays (Mon to Fri, 7am – 9pm) and Nights & weekends (Sat & Sun) prices. To further support the transition, this pricing year, we have introduced a new general pricing category Residential Standard User with a higher fixed daily price and lower volumetric price than the Residential Low User general pricing category.
Moving away from recovery of fixed costs through use-based charges	Moving away from recovering fixed costs through usage-based charges involves transitioning to pricing models where fixed capital and operational costs are not solely dependent on consumption volume. Instead, these costs can be offset through fixed fees (nominated capacity charge for Major Customers, Embedded Networks and Large Capacity Connections and nameplate rating for Irrigation) or tiered pricing structures reflecting the value of service access rather than just usage. This shift can promote fairness by guaranteeing that all users contribute to the maintenance of essential services, regardless of their consumption levels. Furthermore, it stabilises revenue streams, easing the financial strain on consumers with high usage and encouraging more efficient and equitable utilisation of resources.

The Authority has not completed a scorecard since 2023, so we are unclear as to the Authority's views as to the progress of our pricing reform.

In May 2024 the Authority released its Open Letter to Distributors[18] giving five new areas of focus for distributors, which were additional to those communicated in 2022. Table 29 provides a snapshot of our further progress on meeting the Authority's expected pricing reforms in 2025.

Table 29: Snapshot of our further progress on meeting the Authority's expected pricing reforms in 2026

Expectation	How we align
Allocate revenue transparently	Our current pricing methodology provides quantified details of our revenue allocations and our revenue outcomes relative to the calculated subsidy-free range.
Assign all ICPs to time-varying distribution prices (limited exceptions only)	All our general connections, streetlighting connections, and irrigation connections currently have prices with time-varying energy (kWh) charges. The price reform enablement limb of this pricing strategy is continuing our transition to greater use of 30-minute ICP interval data to improve consumers' ability to benefit from responding to our time-varying distribution price signals. Our limited exceptions are our major customers and embedded network connections for whom we are less able to diversify the capacity utilisation risk

[18] A copy of the Authority's open letter can be found on its website at https://www.ea.govt.nz/documents/4980/Open_letter_to_distributors_distribution_pricing_reform.pdf

Expectation	How we align
	on our network. These consumers' prices have maximum demand charges based on their nominated demand, metered demand and peak control-period demand.
Set peak rates based on a measure of Long-Run Marginal Cost	By aligning our peak rates with Long-Run Marginal Cost (LRMC), our pricing communicates the true cost of using the network during peak hours. This ensures that prices truly correspond to any additional expenses due to increased demand, such as the need for additional capacity or investments. Consumers will receive clear signals to shift their usage to off-peak periods, easing strain on the network. This promotes efficient resource allocation and encourages sustainable investment by ensuring sufficient recovery of peak-time usage, tested against our assumptions when setting peak prices.
Reduce off-peak and controlled rates	Our 2024 off-peak rates are well below our peak rates, and at 1.844 c/kWh are lower than the sector's 2024 weight average cited in the authority's letter. We consider this price differential is sufficient to motivate behavioural change whilst still spreading the recovery of our fixed costs in an equitable manner. As noted above, we will continue to monitor the table-up of ICP-based time-variable prices and the level of consumer load shifting behaviour we see and will adapt our prices if needed.
Improve price signalling	Our 2025 pricing methodology introduces further disaggregation of our general connection consumer segment to allow better targeting of price signals, and price shock management as LUFCR transition, by segmenting into: • Residential Standard User Controlled • Residential Standard User Uncontrolled • Residential Low User Controlled • Residential Low User Uncontrolled We also transitioned to ICP based pricing.
Follow up on Asset Management Plan (AMP) reporting on readiness for increased electrification	These updates are provided separately to our pricing strategy; however, the LV system visibility measures we are pursuing within our AMP form part of the data set we are monitoring to identify future opportunities for our pricing design to support patterns of least cost electrification and distribution generation uptake.

We look forward to the Authority's 2026 assessment and gaining further insight into the progress of our pricing reforms.

D3.2 Default Distribution Agreements

The Default Distribution Agreement (DDA) provides the terms and conditions for the provision of distribution services to electricity retailers. The Code requires all distributors publish a default agreement with standardised terms for access to their networks.[19] Our DDA can be found on our website[20]. When a retailer negotiates with us to trade on our network, we offer them the DDA in the

[19] Part 12 A, Distributor agreements, arrangements, and other provisions.

[20] https://www.oriongroup.co.nz/assets/Our-story/Regulatory-disclosures/Orion-default-distributor-agreement-v2-25-Nov-2024.pdf

first instance. We can negotiate an alternative agreement, and the parties have 20 business days to execute that agreement, or the DDA applies automatically.

Amongst other operations, the DDA prescribes the terms and conditions around the process that distributors must take when changing their prices, allocating price categories and price options to ICPs, and changing their pricing structures. The DDA requires us to consult with retailers on any material changes to our pricing structure including, the introduction of a new price category.

This year we have removed the residential and commercial two-way power flow categories, while introducing peak injection tariffs on residential and small business price categories. We consulted with retailers on these changes and limited feedback was provided given the changes were regulated.

D4. Low Fixed Charge Regulations

The Low Fixed Charge Regulations[21] require distributors to offer a pricing plan unique to residential consumers based on 9,000kWh per annum (deemed to be low users). This low-user pricing plan restricts the structure of prices for residential consumer by—

- allowing only one fixed charge
- capping the quantum of that fixed daily price, excluding GST
- requiring prices be set so that low users pay no more per year on a low-user plan than they would pay on any other price plan available to a residential user consuming 9,000kWh per annum
- prohibiting the use of tiered or stepped variable charges
- denying fees for special service, rebates, or discounts that are inconsistent with those offered to other consumers on our network.

In November 2021, the amendment regulations[22] came into force. The amendment regulations intend to phase out the low fixed charges over five years by allowing the regulated distributor tariff option to increase each year by 15 cents, as shown in Table 30.

In September 2025, the regulations where further amended[23] to allow for the new regulated injection tariffs. These changes excluded the injection tariffs from the low user revenue tests.

Table 30: Timetable for the phasing out of the low fixed charges

Year	Pricing Year	Permissible change to fixed charges
1	1 April 2022 to 31 March 2023	15 cents increase to 30 cents
2	1 April 2023 to 31 March 2024	30 cents increase to 45 cents
3	1 April 2024 to 31 March 2025	45 cents increase to 60 cents
4	1 April 2025 to 31 March 2026	60 cents increase to 75 cents
5	**1 April 2026 to 31 March 2027**	**75 cents increase to 90 cents**

[21] Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.

[22] Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Amendment Regulations 2021

[23] Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Amendment Regulations 2025

The phase-out of the low fixed charges has been an enabler in meeting the Authority's pricing reform expectations. Allowing distributors to increase the fixed charge has enabled us to pass-through transmission charges, increase the fixed proportion of cost recovery, and increase peak differentials, thereby sending stronger pricing signals to consumers.

The regulations will be revoked on 1 April 2027, which will further support us in completing our transition to more cost-reflective and efficient pricing.

D5. Related Pricing documents

In addition to this Pricing Methodology disclosure, the documents listed at Table 31 supports our prices and price setting process. Each can all be found on our website:[24]

Table 31: Other documents that support our Pricing Methodology

Document	Purpose
Annual Compliance Statement	Confirms that we have met revenue and quality expectations set out by the price quality path.
Annual Price Setting Compliance Statement	Confirm that our forecast prices have been set at a level to collect the allowances determined by the price-quality path set by the Commission.
Connections and Extensions Methodology	We collect revenue from our network lines charges (delivery prices) or from the consumer contributions paid towards new connections. The Extension and Connections Methodology is a regulatory disclosure which sets out how we calculate a consumer's contribution towards a new connection.
Network Pricing Schedule	The Network Pricing schedules provide stakeholders with our network lines charges and the terms and conditions of their application. Specifically, the Network Pricing Schedule provides: (a) Pricing structure (b) Pricing categories, and the eligibility criteria for each price category (c) Price options (if any) and (d) Unit prices.
Disclosure of prices	The disclosure of prices provides stakeholders (consumers, retailers and regulators) with prices and any price changes for the upcoming regulatory year. The disclosure of prices is a regulatory Information Disclosure requirement.
Line Charge Notices	The Line Charge Notice informs stakeholders of our prices for the upcoming regulatory year. We publish the Line Charge Notice on news websites, in print and on our website[25].
Pricing Roadmap	The Pricing Roadmap updates stakeholders about our intended pricing structures and/or prices changes, together with expected timeframes and progress updates.

[24] https://www.oriongroup.co.nz/our-story/pricing

[25] https://www.oriongroup.co.nz/our-story/pricing

Appendix E – Demonstrating that we meet the Authority's Pricing Principles

The Authority's Distribution Pricing Principles 2019 provides pricing principles for distributors to apply when developing their pricing structures.

- Prices are to signal the economic costs of service provision, including by:
    - being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs);
    - reflecting the impacts of network use on economic costs;
    - reflecting differences in network service provided to (or by) consumers; and
    - encouraging efficient network alternatives.
- Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.
- Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:
    - reflect the economic value of services; and
    - enable price/quality trade-offs.
- Development of prices should be transparent and have regard to transaction costs, consumer impacts and uptake incentives.

In accordance with the ID Determination, we demonstrate our approach to setting prices are consistent with these Pricing Principles.

E1. Signalling the economic costs to serve

(a) Prices are to signal the economic costs of service provision, including by:

(i) being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs);

(ii) reflecting the impacts of network use on economic costs;

(iii) reflecting differences in network service provided to (or by) consumers; and

(iv) encouraging efficient network alternatives."

In line with the principle, we price to reflect the economic costs of providing our delivery service. We estimate the Long Run Average Incremental Cost (LRAIC) of investment in our network (see Table 24 above on page 52 for more detail on our approach) and we set a peak load-based price which reflects this.

We consider that the peak load based incremental cost of our current network provides a suitable surrogate for the incremental cost of meeting future load growth, in the long term. The fact that we must apply other additional price components, over and above the component that reflects the LRAIC, shows that our prices are greater than avoidable costs thereby meeting the first 'subsidy free' requirement in principle (a)(i).

Equally, prices are demonstrably lower than stand-alone costs on the basis that we provide a shared delivery service sized to meet the diversified load of customers, which is much smaller than the sum of individual load peaks. For example, we observe an average residential customer peak of 7.4 kW, but when looking at an entire residential suburb, the network peak equates to just 2.3 kW per household. An alternative approach to the assessment of stand-alone costs is also set out in the paragraphs below.

E1.1. Standalone subsidy free test

The Authority's 2019 Practice Note sets out an alternative basis for the subsidy free test. It focuses on consumer groups (or connection categories) rather than individual consumers. It also identifies avoidable cost as the costs that would reduce if a consumer group was not supplied with electricity, and the standalone costs as energy alternatives that would supply groups of consumers (such as micro-grids).

In this context we provide the estimated the avoidable and standalone cost boundaries for each consumer group at Table 32.

The estimated costs per kWh used in the stand-alone cost assessments are broadly based on information taken from recent economic assessments. Actual costs of these alternatives will vary from location to location, but the magnitude of the stand-alone cost shows that the subsidy free test is not sensitive to inaccuracies in this metric. The forecast revenue is taken from section 9.

In all cases, the revenue we receive is greater than avoidable costs and less than standalone costs, demonstrating that our pricing meets the subsidy free requirement in principle (a)(i).

Our cost allocation weights the allocation of assets that are installed for security of supply using the value that consumers place on "lost load". This helps us reflect the different willingness to pay for these back-up assets between different connection categories. We also provide a specific rebate scheme for irrigation consumers that elect to be first off following a capacity constraint caused by damage to or failure of our network.

We allocate Transpower's charges to each connection category based on our assessment of each category's use of the transmission system. Our distribution network load is characterised by summer (rural) and winter (urban) seasonal peaks. To the level of the lower summer peak, the transmission system is in place to meet both seasonal loads, and it would not be reasonable to view either winter or summer loads as "free" marginal additional loads. So, to the extent that all connection categories use the transmission service, we have split the costs equally between summer and winter peak demands. We then allocate the additional cost of meeting the higher winter peak only to connection categories that contribute to the winter peak. As a result, our price structure carries a lower winter demand price than Transpower applies to us but provides a more equitable (in terms of cost sharing) and stable structure.

Looking ahead, one of the primary strategic objectives we have established as part of our revised pricing strategy is to transition our pricing to enable consumers to efficiently use our network to share their local renewable energy resources.

Table 32: Avoidable and standalone costs

Consumer Group	Avoidable cost	($'000)	Forecast revenue ($'000)	Standalone cost	($'000)
Streetlighting	*Assuming that the separate lighting network assets could be abandoned*			*Reflecting geographic spread of load, an individual PV/Battery basis is assumed for each light*	
	Repair and maintenance costs	147			
	Cust. Service, billing, and admin	42		Estimated cost per lamp/per day	$0.08
	Transpower charges	54		Forecast number of lamps	54,332
	Total cost	**243**	**1,565**	**Total cost**	**4,287**
Residential Low User	*Assuming that the majority of the low voltage network assets could be abandoned*			*Based on subdivision sized micro-grid estimate of shared PV and battery*	
	Repair and maintenance costs	11,734			
	Cust. Service, billing, and admin	19,702		Estimated cost per kWh*	$0.42
	Transpower charges	25,620		Annual volume (MWh)	925,625
	Total cost	**57,056**	**107,707**	**Total cost**	**390,669**
Residential Standard User	*Assuming that the majority of the low voltage network assets could be abandoned*			*Based on subdivision sized micro-grid estimate of shared PV and battery*	
	Repair and maintenance costs	7,823			
	Cust. Service, billing, and admin	13,135		Estimated cost per kWh*	$0.42
	Transpower charges	17,080		Annual volume (MWh)	617,084
	Total cost	**38,038**	**71,805**	**Total cost**	**260,446**
Small General Connection	*Assuming that the majority of the low voltage network assets could be abandoned*			*Based on subdivision sized micro-grid estimate of shared PV and battery*	
	Repair and maintenance costs	812			
	Cust. Service, billing, and admin	1,195		Estimated cost per kWh*	$0.42
	Transpower charges	1,621		Annual volume (MWh)	78,563
	Total cost	**3,628**	**7,377**	**Total cost**	**33,158**

Consumer Group	Avoidable cost	($'000)	Forecast revenue ($'000)	Standalone cost	($'000)
Medium General Connection	*Assuming that the majority of the low voltage network assets could be abandoned*			*Based on subdivision sized micro-grid estimate of shared PV and battery*	
	Repair and maintenance costs	3,203			
	Cust. Service, billing, and admin	5,068		Estimated cost per kWh*	$0.42
	Transpower charges	6,836		Annual volume (MWh)	245,513
	Total cost	**15,107**	**28,333**	**Total cost**	**103,621**
Large General Connection	*Assuming that the majority of the low voltage network assets could be abandoned*			*Based on subdivision sized micro-grid estimate of shared PV and battery*	
	Repair and maintenance costs	4,505			
	Cust. Service, billing, and admin	7,909		Estimated cost per kWh*	$0.42
	Transpower charges	10,268		Annual volume (MWh)	299,384
	Total cost	**22,682**	**40,763**	**Total cost**	**126,358**
Two-way Power Flow	*Assuming that the majority of the low voltage network assets could be abandoned*			*Based on subdivision sized micro-grid estimate of shared PV and battery*	
	Repair and maintenance costs	225			
	Cust. Service, billing, and admin	415		Estimated cost per kWh*	$0.42
	Transpower charges	580		Annual volume (MWh)	17,482
	Total cost	**1,220**	**2,234**	**Total cost**	**7,342**
Irrigation connections	*Assuming that distribution transformers and associated LV network assets can be abandoned*			*Reflecting geographic spread load, an individual PV/Battery is basis is assumed for each installation*	
	Repair and maintenance costs	915			
	Cust. Service, billing, and admin	1,092		Estimated cost per kWh*	$0.28
	Transpower charges	1,705		Annual volume (MWh)	46,124
	Total cost	**3,712**	**6,021**	**Total cost**	**12,978**

Consumer Group	Avoidable cost	($'000)	Forecast revenue ($'000)	Standalone cost	($'000)
Major customer connections	*Assuming that distribution transformers and associated LV network assets can be abandoned*			*Based on industrial subdivision sized micro-grid estimate of shared PV and battery, with supplementary diesel generation*	
	Repair and maintenance costs	4,149			
	Cust. Service, billing, and admin	3,424		Estimated cost per kWh*	$0.28
	Transpower charges	4,237		Annual volume (MWh)	843,976
		11,810	**42,138**	**Total cost**	**237,472**
Large capacity connections	*Assuming that all dedicated assets can be abandoned*			*Based on large scale rurally located PV with battery storage*	
	Repair and maintenance costs	763			
	Cust. Service, billing, and admin	380		Estimated cost per kWh*	$0.14
	Transpower charges	2,178		Annual volume (MWh)	300,468
		3,321	**4,933**	**Total cost**	**42,272**

* An estimate of the savings associated with avoiding purchasing energy at the wholesale rate of 12c/kWh has been deducted from this cost to provide a basis that is comparable with the delivery cost.

E2. Recovery of Target Revenue shortfalls

(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.

We set fixed and volume prices for general connections, and maximum demand-based prices for major customers, to collect the balance of our revenue requirement.

With the phasing out of the low fixed charge regulations, we will be gradually transitioning away from using volume-based pricing to collect the balance of our revenue requirement and instead recover a higher proportion from fixed charges. We have restructured the general connection fixed charges to ensure larger connections continue to contribute an equitable amount towards our overall revenue requirement.

Our capacity charge for major customers is based on the consumer's own peak, which is less subject to demand response than other measures.

E3. Price should reflect economic value and price/quality trade-offs

(c) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:

(i) reflect the economic value of services; and

(ii) enable price/quality trade-offs.

We may recognise an alternative opportunity available to a major customer in close proximity to a grid exit point and may reduce the chargeable demands to approximate the lower-than-average cost to distribute over the shorter distance.

We also individually negotiate the pricing and charge structure directly with large capacity consumers. These connections have a significant impact on the network to which they connect such that significant additional investment by us is required. Consumers that elect to go ahead with the supply will do so on the basis that the service provides economic value.

Consumers in our major customer price category have the option to provide a range of their own connection equipment (transformers, switchgear, metering interfaces). Consumers that elect to use our service will do so on the basis that they provide economic value in comparison with the alternatives available. These factors align with principle (c)(i).

We also provide the opportunity to tailor the quality of the service to the specific needs of the consumer for major customer and large capacity connections. Major customers can elect to use additional connections and/or additional connection equipment which can provide enhanced security of supply. Services for large capacity connections are provided with specific security undertakings which are required by the consumer considering the costs associated with the services. These options align with principle (c)(ii).

As additional examples of our alignment with principle (c)(ii)—

- General consumers have options to select from a range of water heating options, each providing a different level of service, and coming at a different effective cost (based on varying contributions to our time-of-use (TOU) and weekend volume prices).

- Irrigation consumers can choose to allow us to turn off their pumps during system emergencies, and the lower service level is reflected in credits that we pay.

More generally, all consumers are free to invest in ways of achieving a higher quality service than that provided by our network. For example:

- some larger consumers have on-site backup generation capacity to achieve higher reliability than that provided by our network, and
- other consumers invest in relatively low-cost UPS devices (uninterruptible power supplies) for their critical loads, such as computers and cash registers.

E4. Price should be transparent

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

We openly disclose our pricing methodology and actively works to promote a stable and long-term pricing basis, recognising the impact on consumers and the impact on investment decisions they have made in response to our pricing. We also recognise that any material changes to pricing structure can impose costs (including transaction costs) on stakeholders, and in particular retailers. In relation to this:

i. our structure for major customers has been in place for more than 25 years while any other changes to are applied in a transitioned way;

ii. any significant changes are widely consulted on, and only made where we consider they will improve economic outcomes;

iii. material cost allocation changes are spread over a number of years to ease the impact on consumers; and

iv. price changes are only enacted after stakeholder consultation.

Our asset management plan sets out our longer-term plans for the network and this includes indications of key cost drivers. We conduct periodic major customer connections seminars at which pricing and other network related matters are discussed.

In terms of uptake incentives, when prices reflect costs, consumers are rewarded for their elections (such as loading levels, water heating options, election to participate in rebate schemes) at an appropriate level, and the uptake incentive is inherent in the prices.

Pricing development is primarily focussed on achieving efficient outcomes for the long-term benefit of consumers, but where possible we reduce retailer transaction costs. In recent years we have introduced a range of changes to simplify the application of our pricing.

Appendix F — Information disclosure requirements

Table 33 references where in this Pricing Methodology, we have provided the information prescribed by the Commission in the ID Determination and by the Electricity Authority under Part 12A of the Code.

Table 33: Information Disclosure Requirements Compliance Matrix

Commerce Commission Information Disclosure requirements	
IDD Section	**Description of how addressed in this document**
2.4.1 (1)	See IDD 2.4.3 below.
2.4.1 (2)	See sections 9, 10, and Appendix A to C.
2.4.1 (3)	See section 8 for non-standard contracts. See sections 10.6, 12 and 13 for distributed generation.
2.4.1 (4)	See section 5.2, 5.3 and Appendix G.
2.4.2	The methodology is publicly disclosed before the end of February each year for prices that apply from 1 April each year.
2.4.3 (1)	See sections 7 through 13, Appendix H and I.
2.4.3 (2)	See Appendix E.
2.4.3 (3)	See sections 9 and 10.
2.4.3 (4)	See section 9.
2.4.3 (5) (a) & (b)	See sections 7, 8 and 10.
2.4.3 (6)	See sections 5, 9.2 and 10.
2.4.3 (7)	See section 10.
2.4.3 (8)	See section 10.
2.4.4 (1) to (3)	See sections 3, 4, 5, 6, 9.3 and Appendix G.
2.4.5 (1) (a) to (c)	See section 8.
2.4.5 (2) (a) & (b)	See section 8.
2.4.5 (3) (a) & (b)	See sections 5, 10.6, 12, 13 and Appendix A to B.
Disclosure requirements under Part 12A of the Code	
Clause	**Description of how addressed in this document**
12A.7(1) (a) to (c)	See section 5 and 10.6
12A.7(2)	See section 5
12A.7(3) (a) & (b)	See section 9.4
12A.7(3) (c) & (d)	See section 9.4 and 10.6

Orion

Appendix G – Pricing Strategy

G1. Our pricing strategy

The Board approved our refreshed pricing strategy in July 2024.

This pricing strategy and implementation roadmap set out how we intend to segment our consumers and structure our prices to them over coming years. This structure allows us to recover our permitted costs under the revenue allowance set by the Commerce Commission.

We intend this strategy to help retailers, consumers, new energy market participants, and other stakeholders understand how we are adapting our prices to:

- recover our efficient costs of servicing different consumer types
- empower consumers to respond to price signals that benefit them and all our consumers by helping lower our network costs, and
- support decarbonisation transition within our community.

G2. How we developed our pricing strategy

G2.1 Why we have refreshed our pricing strategy

Our pricing context is evolving. We last refreshed our pricing strategy in April 2021. Since that time the expectations of increased electrification of our consumers' energy needs, and the scale of benefits available from sending more targeted pricing signals have increased.

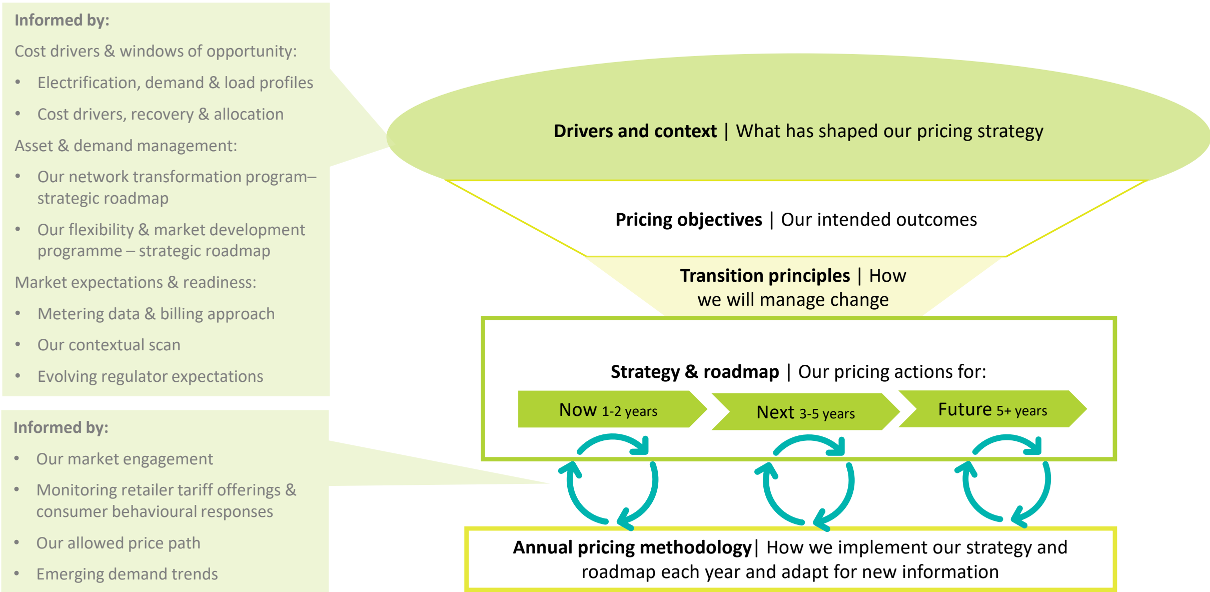
We sought to test and understand these trends through our stakeholder, consumer and consumer scan conducted in late 2023, which has informed this refreshed pricing strategy.

The Electricity Authority Te Mana Hiko has also evolved its expectations on our pricing practices, designs and evidence base. Since our 2021 pricing strategy the authority has published a practice note in 2022, progressed broad industry pricing consultation across 2023 and published open letters of its expectations in 2023 and 2024. Our new strategy addresses these expectations, and we set out in Table 28 the things we will monitor during implementation to dynamically refine our pricing actions for new information.

G2.2 How we have developed and will implement this pricing strategy

Figure 12 illustrates the methodical approach we have taken to refresh our pricing strategy, and how we intend to implement and refine it over the roadmap horizons. We have retained the horizons from our existing roadmap.

Figure 12: Our pricing strategy framework



G3. Our pricing objectives

Our pricing objectives recognise where we are now and where we need to get to. Our pricing objectives therefore seek to target 3 priorities:

1. Cost recovery and cost reflectivity | First we need prices that recover our allowed efficient cost of supply from each consumer segment in a manner reflecting our cost drivers.

2. Price reform enablement | Second, we need to establish pricing systems, data and processes that:

- support efficient price structures
- empower consumers and consumers to respond to price signals.

3. Price signalling and behavioural response | Finally, we need to ensure our prices are targeted by consumer and consumer type based on ability to respond and scale of the available cost and benefit sharing opportunities. Our prices should:

- send signals that can be responded to
- support efficient network utilisation amid growing electrification and two-way energy flows
- foster a growing flexibility services market
- leverage utility-mode control, where we have sight of the energy load or device, and the scale of benefits for sharing is sufficient to incentivise consumer choice to participate in control.

G3.1 Our transition principles

We recognise that how we transition our pricing is important to the effectiveness of our pricing strategy in realising our pricing objectives.

Our transition principles are our commitment to our consumers and consumers for how we intend to implement and refine our roadmap over time.

Our overarching transmission principles | Our roadmap seeks to:

- develop prices transparently and consider transaction costs, consumer impacts, and uptake incentives
- provide predictability for consumers to make investments with certainty and for retailers and aggregators to design market offers
- use the right tool for each consumer segment's required behaviours and controls, including simplicity where possible
- acknowledge the market value stacking opportunities and materiality when designing prices for cost recovery and behavioural response by understanding the interaction of our prices with the rest of the supply chain costs, benefits and market signals
- treat consumers and consumers equitably and ethically.

Our consumer segment specific principles | We recognise that some consumers will have specific needs amid pricing transitions. Our roadmap seeks to:

- consider impacts on vulnerable consumers within our residential connection's community
- provide signals for electrification and decarbonisation, particularly for commercial and industrial connections and EV charging
- provide signals to flexibility stakeholders who can access multiple value streams to attract coordinated and two-way CER connections.

G3.2 Our transition constraints

We intend to also transparently show how our pricing actions in the roadmap have been designed to address key transition and compliance constraints. Key constraints that will affect how we transition our prices are that our pricing should:

- comply with the Electricity Authority's distribution pricing principles and guidance on these
- comply with the phase-out of the low fixed charge price regulation until 1 April 2027
- manage bill impacts of the default price path for the 2025-26 to 2029-30 pricing period
- retain transmission pass through as regulated
- manage orderly scaling of new billing system functionality and retailer interfaces for ICP 30-minute interval data
- accommodate legacy accumulation meters out to 2030 which require legacy prices using our existing GXP deemed load profiles
- support our asset management strategy (including demand response controls) and investment plans as these evolve.

G4. Our roadmap by objective area

Our roadmap actions have been designed to respond to our drivers and context, advance our objectives, and take an orderly sequence considering our transition principles and constraints. The actions for each priority areas are set out below for each of our strategy horizons: Now—2026-2026, Next—2027-2030, and Future—2030+.

G4.1 Cost recovery and reflectivity

Now	• Improved data points and modelling to inform cost allocation across consumer segments. • Progressively address over or under recovery across consumer segments within Orion's self-imposed 10% rebalancing constraint. • Align peak import and injection pricing with ENA LRMC model. • Review the Asset Building Block Approach (ABBA) for Large Connection Customers (LCC). • Monitor locational and temporal cost drivers, including control period signals
Next	• Monitor locational and temporal cost drivers, including control period signals. • Monitor if injection congestion occurs on the network and drives costs and requires pricing signals
Future	• Monitor if injection congestion occurs on the network and drives costs and requires pricing signals • Monitor locational and temporal cost drivers, including control period signals

G4.2 Price reform enablement

Now	• Manage transition from low user fixed charge regulations and standardised retailer consumer groups. • Introduce injection tariffs for residential and small business price categories. • Review and alignment of business price categories with industry and connections standards while introducing tariff structures with a view to provide further incentives for flexibility and DG. • Commence mass-market flexibility trials to target critical peak periods and better understand customer responsiveness and behavioral drivers. • Alignment of hot water control value with LRMC. • Connection agreements establish dynamic control rights
Next	• Introduce opt-in tariffs from flexibility trials that provide value to consumers who shift peak load or export generation during critical peaks on Orion's network.
Future	• Establish dynamic control network capability for mass market

G4.3 Price signalling and behavioural response

Now	• Trial price mode demand flexibility, by repurposing our major customer peak period signal • Monitor retailer responses to existing tariff changes and levels consumer response
Next	• Activate C&I demand management and response with reward tariffs | Establish variable demand pricing, demand exceedance tariffs • Look at moving price driven demand flexibility tariff as an opt-in for whole of network
Future	• Support flexibility innovators | Implement opt-in variable demand pricing and interruptible supply tariffs for aggregators

G5. Things we will monitor during implementation

Our roadmap is intended to foreshadow both what we currently plan to do, and what we intend to monitor and respond to. This iterative approach will allow us to dynamically refine our pricing actions for new information and evolving market, consumer and regulator behaviours and expectations.

The monitoring and refinement aspect of our strategy will consider:

- Market dynamics, including:
  - retailer responses to existing price changes and levels of consumer response
  - the number of consumers billed on 30-minute interval ICP data
  - the level of retail price offering alignment to our time-varying distribution prices.
- Decarbonisation trends, including:
  - renewable distributed generation connections and their export and import profiles
  - patterns of high thermal load electrification among our major users
  - public EV charging connections and load profile, and willingness to participate in demand response.
- Network loads, constraints and utilisation trends, including:
  - whether and if so where and at what scales reverse power flows are driving costs and require pricing signals
  - locational and temporal cost drivers, including levels of consumer or aggregators response to control period signals versus uncontrolled time-variable price signals.

Appendix H – Allocation of the Revenue Required by GXP

Table 34: Allocation to the consumer group by cost driver at the Arthurs Pass GXP for the pricing year

Description	LIG	LOW	STN	GEN(GC1)	GEN(GC2)	GEN(GC3)	IRR	MCC
No. of ICPs	1%	64%	6%	16%	13%	0%	0%	0%
Line Length (meters)	0%	53%	4%	12%	31%	0%	0%	0%
Installed capacity (kW)	0%	53%	4%	12%	31%	0%	0%	0%
Asset Utilisation	0%	53%	4%	12%	31%	0%	0%	0%
Consumption (kWh)	2%	28%	3%	21%	46%	0%	0%	0%
Assessed Peak Demand (kW)	1%	34%	3%	20%	43%	0%	0%	0%

Table 35: Allocation to the consumer group by cost driver at the Bromley GXP for the pricing year

Description	LIG	LOW	STN	GEN(GC1)	GEN(GC2)	GEN(GC3)	IRR	MCC
No. of ICPs	0%	72%	18%	4%	5%	1%	0%	0%
Line Length (meters)	0%	55%	15%	2%	12%	11%	0%	5%
Installed capacity (kW)	0%	55%	15%	2%	12%	11%	0%	5%
Asset Utilisation	0%	55%	15%	2%	12%	11%	0%	5%
Consumption (kWh)	0%	40%	17%	3%	8%	10%	0%	21%
Assessed Peak Demand (kW)	0%	44%	18%	3%	10%	10%	0%	14%

Table 36: Allocation to the consumer group by cost driver at the Castle Hill GXP for the pricing year

Description	LIG	LOW	STN	GEN(GC1)	GEN(GC2)	GEN(GC3)	IRR	MCC
No. of ICPs	1%	68%	9%	13%	8%	2%	0%	0%
Line Length (meters)	0%	54%	6%	8%	19%	13%	0%	0%
Installed capacity (kW)	0%	54%	6%	8%	19%	13%	0%	0%
Asset Utilisation	0%	54%	6%	8%	19%	13%	0%	0%
Consumption (kWh)	1%	26%	5%	16%	17%	36%	0%	0%
Assessed Peak Demand (kW)	0%	41%	9%	24%	15%	11%	0%	0%

Table 37: Allocation to the consumer group by cost driver at the Coleridge GXP for the pricing year

Description	LIG	LOW	STN	GEN(GC1)	GEN(GC2)	GEN(GC3)	IRR	MCC
No. of ICPs	1%	62%	7%	13%	16%	1%	0%	1%
Line Length (meters)	0%	48%	9%	8%	31%	4%	0%	1%
Installed capacity (kW)	0%	48%	9%	8%	31%	4%	0%	1%
Asset Utilisation	0%	48%	9%	8%	31%	4%	0%	1%
Consumption (kWh)	0%	25%	7%	10%	23%	8%	0%	26%
Assessed Peak Demand (kW)	0%	38%	1%	0%	16%	19%	0%	26%

Table 38: Allocation to the consumer group by cost driver at the Hororata GXP for the pricing year

Description	LIG	LOW	STN	GEN(GC1)	GEN(GC2)	GEN(GC3)	IRR	MCC
No. of ICPs	0.07%	55%	15%	11%	11%	3%	6%	0.1%
Line Length (meters)	0.02%	31%	9%	4%	14%	11%	30%	2%
Installed capacity (kW)	0.02%	31%	9%	4%	14%	11%	30%	2%
Asset Utilisation	0.02%	31%	9%	4%	14%	11%	30%	2%
Consumption (kWh)	0.17%	18%	7%	3%	10%	16%	40%	6%
Assessed Peak Demand (kW)	0.04%	12%	5%	2%	5%	8%	66%	3%

Table 39: Allocation to the consumer group by cost driver at the Islington GXP for the pricing year

Description	LIG	LOW	STN	GEN(GC1)	GEN(GC2)	GEN(GC3)	IRR	MCC
No. of ICPs	0.19%	68%	20%	4%	5%	1%	0%	0.3%
Line Length (meters)	0.08%	48%	16%	2%	12%	12%	1%	8%
Installed capacity (kW)	0.08%	48%	16%	2%	12%	12%	1%	8%
Asset Utilisation	0.08%	48%	16%	2%	12%	12%	1%	8%
Consumption (kWh)	0.23%	32%	16%	2%	8%	13%	1%	28%
Assessed Peak Demand (kW)	0.18%	35%	17%	3%	10%	13%	2%	20%

Table 40: Allocation to the consumer group by cost driver at the Kimberley GXP for the pricing year

Description	LIG	LOW	STN	GEN(GC1)	GEN(GC2)	GEN(GC3)	IRR	MCC
No. of ICPs	0.20%	63%	15%	10%	8%	2%	2%	0%
Line Length (meters)	0.07%	46%	12%	4%	14%	13%	11%	0%
Installed capacity (kW)	0.07%	46%	12%	4%	14%	13%	11%	0%
Asset Utilisation	0.07%	46%	12%	4%	14%	13%	11%	0%
Consumption (kWh)	0.61%	35%	15%	3%	9%	25%	12%	0%
Assessed Peak Demand (kW)	0.20%	31%	15%	2%	7%	7%	38%	0%

Table 41: Allocation to the consumer group by cost driver at the Norwood GXP for the pricing year

Description	LIG	LOW	STN	GEN(GC1)	GEN(GC2)	GEN(GC3)	IRR	MCC
No. of ICPs	0%	47%	11%	10%	13%	3%	15%	0.1%
Line Length (meters)	0%	26%	7%	4%	16%	10%	34%	2%
Installed capacity (kW)	0%	26%	7%	4%	16%	10%	34%	2%
Asset Utilisation	0%	26%	7%	4%	16%	10%	34%	2%
Consumption (kWh)	0%	13%	5%	2%	9%	12%	52%	6%
Assessed Peak Demand (kW)	0.03%	9%	4%	1%	4%	5%	74%	3%

Appendix I – Historical quantities by GXP

Table 42: Quantities used to allocate the Required Revenue to the Arthurs Pass GXP for the pricing year

Consumer Group		ICPs / Supplies (Number)	Consumption (kWh)	Installed Capacity (kVA)	Asset utilisation (kW)	Line length (meters)	Assessed Peak Demand (kW)	RAB ($)	RAB Depreciation ($)
Streetlighting		1	20,200	5	3	22	2		
Residential Low User		105	291,460	1,492	1,044	6,841	53		
Residential Standard User		10	30,327	113	79	519	4		
Small General Connection up to 15 kVA		27	224,273	325	228	1,491	31		
Medium General Connection 16 kVA to 69 kVA		21	484,065	854	598	3,916	68		
Large General Connection >70 kVA		-	-	-	-	-	-		
Irrigation Connections		-	-	-	-	-	-		
Major Customer and Embedded Network Connections		-	-	-	-	-	-		
	Total	**164**	**1,050,324**	**2,788**	**1,952**	**12,789**	**159**		
Network	Subtransmission lines							52,103	1,832
	Subtransmission cables							61,382	1,859
	Zone substations							110,608	5,097
	Distribution and LV lines							99,257	3,754
	Distribution and LV cables							281,050	9,423
	Distribution substations and transformers							100,648	2,898
	Distribution switchgear							119,281	4,556
	Other network assets							26,951	1,378
Non-network	Non-network Assets							34,541	2,724
	Total							**885,821**	**33,522**

Table 43: Quantities allocated to the Required Revenue at the Bromley GXP for the pricing year

Consumer Group		ICPs / Supplies (Number)	Consumption (kWh)	Installed Capacity (kVA)	Asset utilisation (kW)	Line length (meters)	Assessed Demand (kW)	RAB ($)	RAB Depreciation ($)
Streetlighting		134	1,267,822	890	623	1,606	285		
Residential Low User		40,941	266,687,238	587,597	411,318	1,060,093	57,080		
Residential Standard User		10,339	114,221,216	158,754	111,128	286,410	24,053		
Small General Connection up to 15 kVA		2,149	17,408,855	26,586	18,610	47,964	4,417		
Medium General Connection 16 kVA to 69 kVA		2,831	55,445,483	131,389	91,972	237,041	12,798		
Large General Connection >70 kVA		536	68,497,293	114,115	79,881	205,877	13,032		
Irrigation Connections		-	-	-	-	-	-		
Major Customer and Embedded Network Connections		96	137,521,881	51,057	35,740	92,113	18,837		
Total		**57,026**	**661,049,787**	**1,070,388**	**749,272**	**1,931,104**	**130,501**		
Network	Subtransmission lines							20,000,424	703,274
	Subtransmission cables							23,562,173	713,479
	Zone substations							42,458,072	1,956,530
	Distribution and LV lines							38,100,988	1,441,071
	Distribution and LV cables							107,884,041	3,617,116
	Distribution substations and transformers							38,634,685	1,112,558
	Distribution switchgear							45,787,496	1,748,957
	Other network assets							10,345,444	529,138
Non-network	Non-network Assets							13,259,069	1,045,683
Total								**340,032,392**	**12,867,806**

Table 44: Quantities allocated to the Required Revenue at the Castle Hill GXP for the pricing year

Consumer Group		ICPs / Supplies (Number)	Consumption (kWh)	Installed Capacity (kVA)	Asset utilisation (kW)	Line length (meters)	Assessed Demand (kW)	RAB ($)	RAB Depreciation ($)
Streetlighting		2	12,917	2	1	31	1		
Residential Low User		184	633,686	2,840	1,988	51,045	161		
Residential Standard User		23	131,493	338	237	6,074	35		
Small General Connection up to 15 kVA		34	384,923	408	285	7,329	96		
Medium General Connection 16 kVA to 69 kVA		21	419,535	1,023	716	18,383	60		
Large General Connection >70 kVA		5	880,605	689	483	12,388	44		
Irrigation Connections		-	-	-	-	-	-		
Major Customer and Embedded Network Connections		-	-	-	-	-	-		
Total		**269**	**2,463,159**	**5,300**	**3,710**	**95,250**	**396**		
Network	Subtransmission lines							99,032	3,482
	Subtransmission cables							116,668	3,533
	Zone substations							210,230	9,688
	Distribution and LV lines							188,656	7,135
	Distribution and LV cables							534,186	17,910
	Distribution substations and transformers							191,299	5,509
	Distribution switchgear							226,716	8,660
	Other network assets							51,225	2,620
Non-network	Non-network Assets							65,652	5,178
Total								**1,683,665**	**63,715**

Orion

Table 45: Quantities allocated to the Required Revenue at the Coleridge GXP for the pricing year

Consumer Group		ICPs / Supplies (Number)	Consumption (kWh)	Installed Capacity (kVA)	Asset utilisation (kW)	Line length (meters)	Assessed Demand (kW)	RAB ($)	RAB Depreciation ($)
Streetlighting		1	4,248	1	1	36	0		
Residential Low User		83	301,007	1,310	917	46,866	76		
Residential Standard User		9	88,256	259	182	9,278	2		
Small General Connection up to 15 kVA		17	122,273	215	150	7,675	-		
Medium General Connection 16 kVA to 69 kVA		21	276,660	841	588	30,074	32		
Large General Connection >70 kVA		1	97,941	110	77	3,950	38		
Irrigation Connections		-	-	-	-	-	-		
Major Customer and Embedded Network Connections		1	306,771	15	11	537	51		
	Total	**133**	**1,197,157**	**2,751**	**1,925**	**98,417**	**199**		
Network	Subtransmission lines							51,394	1,807
	Subtransmission cables							60,546	1,833
	Zone substations							109,102	5,028
	Distribution and LV lines							97,906	3,703
	Distribution and LV cables							277,223	9,295
	Distribution substations and transformers							99,277	2,859
	Distribution switchgear							117,658	4,494
	Other network assets							26,584	1,360
Non-network	Non-network Assets							34,071	2,687
	Total							**873,762**	**33,066**

Table 46: Quantities allocated to the Required Revenue at the Hororata GXP for the pricing year

Consumer Group		ICPs / Supplies (Number)	Consumption (kWh)	Installed Capacity (kVA)	Asset utilisation (kW)	Line length (meters)	Assessed Demand (kW)	RAB ($)	RAB Depreciation ($)
Streetlighting		3	172,186	36	25	280	12		
Residential Low User		2,515	18,374,873	46,570	32,599	361,572	3,347		
Residential Standard User		674	7,426,382	13,023	9,116	101,110	1,404		
Small General Connection up to 15 kVA		511	3,143,653	6,155	4,308	47,786	520		
Medium General Connection 16 kVA to 69 kVA		493	10,529,147	21,118	14,783	163,962	1,395		
Large General Connection >70 kVA		116	17,062,104	16,565	11,595	128,608	2,212		
Irrigation Connections		266	41,592,709	45,766	32,036	355,335	18,809		
Major Customer and Embedded Network Connections		6	5,977,959	2,684	1,878	20,835	838		
	Total	**4,584**	**104,279,014**	**151,916**	**106,341**	**1,179,490**	**28,536**		
Network	Subtransmission lines							2,838,580	99,813
	Subtransmission cables							3,344,085	101,261
	Zone substations							6,025,905	277,683
	Distribution and LV lines							5,407,521	204,525
	Distribution and LV cables							15,311,551	513,363
	Distribution substations and transformers							5,483,267	157,901
	Distribution switchgear							6,498,437	248,222
	Other network assets							1,468,288	75,098
Non-network	Non-network Assets							1,881,807	148,410
	Total							**48,259,440**	**1,826,276**

Orion

Table 47: Quantities allocated to the Required Revenue at the Islington GXP for the pricing year

Consumer Group		ICPs / Supplies (Number)	Consumption (kWh)	Installed Capacity (kVA)	Asset utilisation (kW)	Line length (meters)	Assessed Demand (kW)	RAB ($)	RAB Depreciation ($)
Streetlighting		321	5,803,763	2,755	1,929	6,057	882		
Residential Low User		112,429	789,347,617	1,742,615	1,219,831	3,830,670	168,901		
Residential Standard User		33,283	389,805,712	560,464	392,325	1,232,029	83,305		
Small General Connection up to 15 kVA		6,626	56,596,653	89,919	62,943	197,663	14,334		
Medium General Connection 16 kVa to 69 kVA		8,937	202,778,559	439,028	307,320	965,085	47,254		
Large General Connection >70 kVA		2,142	323,198,476	445,452	311,816	979,206	62,405		
Irrigation Connections		428	27,777,981	30,768	21,537	67,634	11,599		
Major Customer and Embedded Network Connections		454	702,842,293	286,582	200,607	629,972	97,708		
Total		**164,620**	**2,498,151,055**	**3,597,583**	**2,518,308**	**7,908,317**	**486,387**		
Network	Subtransmission lines							67,221,581	2,363,709
	Subtransmission cables							79,192,648	2,398,008
	Zone substations							142,701,914	6,575,913
	Distribution and LV lines							128,057,718	4,843,451
	Distribution and LV cables							362,599,109	12,157,157
	Distribution substations and transformers							129,851,481	3,739,316
	Distribution switchgear							153,892,132	5,878,258
	Other network assets							34,771,117	1,778,438
Non-network	Non-network Assets							44,563,835	3,514,549
Total								**1,142,851,536**	**43,248,798**

Table 48: Quantities allocated to the Required Revenue at the Kimberly GXP for the pricing year

Consumer Group		No. of ICP / supplies	Consumption (kWh)	Installed Capacity (kVA)	Asset utilisation (kW)	Line length (meters)	Assessed Demand (kW)	RAB ($)	RAB Depreciation ($)
Streetlighting		2	72,759	15	11	140	5		
Residential Low User		617	4,210,273	10,719	7,503	98,691	735		
Residential Standard User		146	1,810,338	2,781	1,947	25,606	353		
Small General Connection up to 15 kVA		96	414,950	1,046	732	9,633	59		
Medium General Connection 16 kVa to 69 kVA		82	1,030,917	3,191	2,233	29,376	169		
Large General Connection >70 kVA		20	2,950,888	3,108	2,176	28,619	159		
Irrigation Connections		19	1,486,809	2,501	1,751	23,028	895		
Major Customer and Embedded Network Connections		-	-	-	-	-	-		
Total		**982**	**11,976,935**	**23,361**	**16,353**	**215,093**	**2,375**		
Network	Subtransmission lines							436,503	15,349
	Subtransmission cables							514,237	15,571
	Zone substations							926,634	42,701
	Distribution and LV lines							831,542	31,451
	Distribution and LV cables							2,354,536	78,942
	Distribution substations and transformers							843,190	24,281
	Distribution switchgear							999,298	38,170
	Other network assets							225,786	11,548
Non-network	Non-network Assets							289,375	22,822
Total								**7,421,102**	**280,836**

Table 49: Quantities allocated to the Required Revenue at the Norwood GXP for the pricing year

Consumer Group		No. of ICP / supplies	Consumption (kWh)	Installed Capacity (kVA)	Asset utilisation (kW)	Line length (meters)	Assessed Demand (kW)	RAB ($)	RAB Depreciation ($)
Streetlighting		-	-	-	-	-	5		
Residential Low User		1,047	8,172,052	20,056	14,039	172,788	1,500		
Residential Standard User		247	3,174,003	5,109	3,576	44,013	571		
Small General Connection up to 15 kVA		220	1,301,832	2,785	1,949	23,991	186		
Medium General Connection 16 kVA to 69 kVA		297	5,885,851	12,481	8,736	107,524	631		
Large General Connection >70 kVA		57	7,770,238	7,638	5,347	65,807	867		
Irrigation Connections		341	32,458,961	25,813	18,069	222,388	11,730		
Major Customer and Embedded Network Connections		3	3,686,392	1,814	1,270	15,626	455		
	Total	**2,212**	**62,449,328**	**75,695**	**52,987**	**652,138**	**15,944**		
Network	Subtransmission lines							1,414,382	49,734
	Subtransmission cables							1,666,261	50,456
	Zone substations							3,002,534	138,361
	Distribution and LV lines							2,694,411	101,909
	Distribution and LV cables							7,629,303	255,794
	Distribution substations and transformers							2,732,153	78,677
	Distribution switchgear							3,237,983	123,682
	Other network assets							731,605	37,419
Non-network	Non-network Assets							937,650	73,948
	Total							**24,046,282**	**909,981**

Appendix J - Directors' certification of pricing methodology

In accordance with clause 2.9.1 of section 2.9 of the Commerce Commission's information disclosure determination for electricity distribution businesses the certification of our pricing methodology document is included below.

We, Paul Jason Munro and Michael Earl Sang, being directors of Orion New Zealand Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The attached information of Orion New Zealand Limited, prepared for the purposes of clauses 2.4.1 of the Electricity Distribution Information Disclosure Determination 2012, in all material respects complies with that determination.

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

Paul Jason Munro	**Michael Earl Sang**

19 February 2026