Orion

Methodology for deriving delivery prices

For prices applying from 1 April 2024

Issued 29 February 2024

Orion

We are pleased to present our Pricing Methodology Disclosure for prices effective 1 April 2024 to 31 March 2025 (the Pricing Methodology).

We continue with the evolution of our pricing approach in line with our pricing roadmap to better reflect the way consumers utilise our network. We are making changes to the balance and form of fixed and variable charges because we believe that a capacity-based approach is more cost reflective and efficient than our current consumption-based approach. This includes removal of our control period peak based charge and using controlled and uncontrolled pricing in conjunction with targeted peak TOU based charges.

Over the next five (5) years, we intend to transition our pricing gradually and carefully so that the changes in prices are effective and appropriate in avoiding –

'.. overinvestment by the consumer in technologies to avoid network charges, shifting costs onto other consumers; and unnecessary network investment'.[1]

Consumers will be at the front of our minds as we take our transitional journey. We will not lose sight of our aims, objectives, or the impact of price changes on consumers.

Purpose Statement

The purpose of this Pricing Methodology is to outline the approach used by us in setting our prices for electricity distribution lines services effective 1 April 2024 and ending 31 March 2025 (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 Determination 2012[2] (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 will signal the efficient use of our existing network through our prices and reflect the costs of future investments to our network. Efficient pricing is particularly important as New Zealand embarks on its journey to be Net Zero by 2050.

Our pricing approach

Orion's objective is to balance price levels alongside providing our community with the reliability and resilience of electricity supply it requires for the specific conditions we face in Canterbury. Like roads, electricity networks have limited capacity and Orion's 'rush hour' typically occurs on very cold winter

[1] Electricity Authority, more efficient distribution network pricing – principles and practice, Decision paper, 4 June 2019 (the Decisions paper), Executive summary at page ii.

[2] The current version is consolidated to July 2023

mornings and evenings. Our priority is to ensure a network that can sustain these peaks in demand, even though they are typically only for short periods of time.

One option is to increase the network's capacity, much like making the roads bigger to handle an increased volume of traffic. This is, however, expensive and would require increases in our charges to cover the cost involved in expansion.

Another option is to actively promote mechanisms such as ripple control, through customers taking up controlled tariffs 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 use 'price signals', charging higher prices during periods of high electricity demand and lower prices during low demand periods, to support and reward customers managing their use in this way. Ways in which customers do this include:

- Having their hot water cylinders peak load controlled, which means it can be switched off and on by us
- Heating their 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 their consumption to a different time of day, or reducing the level of their consumption when signalled

Peak and off-peak pricing

Determining how much extra to charge customers during periods of high electricity demand is complicated. Some parts of our network cost more than others, and different parts are used to deliver electricity to each of our more than 224,000 individual customer connections. Individual customer pricing is simply not feasible for all of these connections.

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

- General (residential and small business) connections – where maximum electricity use is in winter.
- Major customer connections – businesses that are large electricity consumers.
- Irrigation connections – for farms with significant irrigation requirements.
- Street lighting connections – for private and publicly owned dedicated lighting connections supplied from Orion's separate lighting network.
- Large capacity connections – for very large businesses that consume a significant amount of electricity and for which Orion negotiates an individual price due to their size and impact on the local network.

More detail on how we apply our prices, and in particular how the chargeable quantities are calculated for each connection category, can be found in our Pricing Policy document, which is available on our website.[3]

[3] https://www.oriongroup.co.nz/assets/Company/Corporate-publications/PricingPolicy.pdf

Contents

Purpose Statement ... 2
Our pricing approach ... 2
Contents ... 4
1. Introduction ... 6
  1.1 Who is Orion New Zealand Limited ... 6
  1.2 Electricity distribution services are regulated ... 6
  1.3 Contributing to New Zealand's decarbonised future ... 7
  1.4 Our Network Characteristics ... 7
    1.4.1 Growth drivers ... 9
    1.4.2 Our network maximum demand ... 10
    1.4.3 Developing our LV capability ... 12
2. Our pricing aims and objectives ... 14
3. Implementing future prices ... 15
  3.1 Future pricing ... 15
  3.2 What is the problem the Authority wants to solve? ... 15
  3.3 Roadmap of our journey to cost-reflective pricing ... 15
    3.3.1. Decarbonisation ... 15
    3.3.2 Affordability ... 16
    3.3.3. Economic considerations ... 16
    3.3.4 Even-handedness and practical considerations ... 17
    3.3.5 Reviewing our Pricing Strategy in a fast-moving environment ... 18
  3.4 Implement Gradually and Carefully ... 19
    3.4.1 What aspects of our pricing have not changed ... 19
    3.4.2 Changes made for 1 April 2024 ... 19
  3.5 Changes to the low fixed charge (LFC) regulations have been an enabler ... 20
  3.6 Change in model ... 21
  3.7 Consumer Impact ... 22
4. Standard Connection Contract ... 23
  4.1 How we assign consumer to Price Categories ... 23
  4.2 Non – standard pricing ... 24
  4.3 Customer consultation and Price-Quality Trade-Off ... 26
  4.4 Loss Factors ... 27
  4.5 Distributed Generation ... 27
  4.6 Capital contribution ... 28
5. Calculation of our costs to serve ... 30

5.1 Calculation of the Required Revenue ... 30
5.1.1 Calculation of the Operations and Maintenance Costs ... 30
5.1.2 Calculation of the Administration & Corporate Costs ... 30
5.1.3 Calculation of the Depreciation Charges ... 30
5.1.4 Calculation of Transpower charges and Regulatory costs ... 31
5.2 Change in Required Revenue ... 31
5.2.1 Change in Operations & Maintenance Costs ... 31
5.2.2 Change in Administration and Corporate Costs ... 32
5.2.3 Changes in other costs ... 32
5.3 Recovery of Required Revenue from consumer groups ... 32
6. Our Approach to setting prices ... 33
6.1 Overview of our approach to allocating the Revenue Requirement ... 34
6.1.1 Allocate the Revenue Requirement to the GXP's ... 34
6.1.2 Allocate the Revenue Requirement at the GXP to consumer groups ... 35
6.1.3 Historical quantities to allocate the Required Revenue ... 39
6.2 Overview of our approach to setting Target Revenue ... 47
6.2.1 Why do we apply a uniform delivery charge ... 47
6.2.2 Determine the fixed / variable split ... 47
6.2.3 Calculate and set the fixed and variable charges ... 48
6.2.4 We smooth prices to avoid bill shock ... 49
6.2.5 We use forecast year-end quantities to set prices ... 49
6.2.6 Target Revenue is derived by multiplying prices by forecast quantities ... 50
6.3 Change in Target Revenue ... 50
6.4 Variance within consumer groups between required revenue and target revenue ... 50
6.4.1 Removing the cross-subsidisation of Residential connection ... 51
6.4.2 Removing the cross subsidisation of SME connection ... 51
7. Credits for export ... 51
7.1 Standard export credit prices ... 51
Appendix A - Price schedules ... 53
Appendix B - Regulatory requirements: pricing principles and information disclosure ... 56
Appendix C - Commerce Commission information disclosure requirements ... 60
Appendix D – Our pricing roadmap ... 62
Appendix E– Pricing Strategy ... 63
Appendix F– Previous Pricing Strategy ... 67
Appendix G– LRAIC ... 69
Appendix H - Directors' certification of pricing methodology ... 70

1. Introduction

1.1 Who is Orion New Zealand Limited

Orion New Zealand Limited (Orion) owns and operates the electricity distribution network in central Canterbury between the Waimakariri and Rakaia rivers, and from the Canterbury coast to Arthur's Pass. Our network covers 8,000 square kilometres of diverse geography, including Christchurch city, Banks Peninsula, farming communities and high country regions. We receive electricity from Transpower's national grid at 8 different locations[4] and we distribute this electricity to more than 224,000 homes and businesses.

New Zealand's South Island

Our service covers the delivery of electricity across our network of infrastructure assets only - we do not buy and sell electricity; we simply deliver it to the customers of electricity retailers that operate in our area. Electricity retailers, in turn, include this cost in their retail electricity prices. Our delivery charges amount to approximately 27% of an average household's electricity bill.

Our network is entirely within the boundaries of the two local councils that own Orion, Christchurch City Council (which owns 89.3%) and Selwyn District Council (which owns 10.7%).

1.2 Electricity distribution services are regulated

The approach we take to setting prices is influenced by various regulatory requirements administered by the Commerce Commission (the Commission) and the Electricity Authority (the Authority).

Electricity distribution is a regulated service under Part 4 of the Commerce Act 1986 (the Act) and is subject to economic regulation from the Commission.

As an electricity distributor under the Electricity Act 1992, we are a participant in the New Zealand electricity market and subject to market regulation by the Authority.

The Commission uses information disclosure regulation to measure our performance annually. This Pricing Methodology is written to meet the requirements of clause 2.4, Pricing and Related Information of the Information Disclosure (ID) Determination. Appendix C lists the requirements we must meet and describes how we have met those.

The Authority developed Pricing Principles to drive efficient pricing, with a view to:

- signal the economic costs of network use at a point in time or place; and
- recover any shortfall in target revenue in a way that least distorts network use.

In December 2021, the Authority released its Second Edition, Practice Note and in May and October 2022 updated its Practice Note, to assist distributors with applying the Pricing Principles. We will be adopting the Authority's guidance to the fullest extent practicable when setting prices. Appendix B lists the Pricing Principles and describes how we meet these.

[4] A small (but growing) amount of energy also enters the network from connections that have generation capability, such as solar panels.

Part 6 of the Code, administered by the Authority, sets out the framework that enables the connection of distributed generation to our network. Our approach to setting prices is an enabler, not a barrier, for distributed generation connections to our network. We discuss our approach to distributed generation in section 4.5 of this Pricing Methodology.

The low fixed charge regulations require us to offer qualifying primary residents a low fixed charge tariff option. We have set our prices to apply the low fixed charge regulations to all residential consumers including transitional provisions. More discussions about our approach to meeting the low fixed charge regulations can be found in section 3.5 of this Pricing Methodology.

1.3 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 correct, we could see an additional 114 megawatts of load added to our network. The 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., when installing 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.

1.4 Our Network Characteristics

Pricing and asset management investments are inextricably linked and somewhat symbiotic. Pricing can provide signals to inform customer behaviour that can influence utilisation and constraints on the network that may lead to additional infrastructure investment (a key cost driver). Infrastructure investment and operating expenditure will, over time, be reflected in changes in real prices that customers pay, and the quality of supply they receive.

In addition to our pricing consultation, and with a particular focus on price-quality trade-offs, we look to consultation and constraint information that is undertaken as part of our asset management plan (AMP) process. Section 6 of our asset management plan provides detailed information on the constraint and capacity status of our network from the Grid Exit Point (GXP) down to low voltage (LV) network level. [5]

To meet these challenges, we are implementing initiatives that increase our knowledge of the network, and systems that can fully utilise the data sources at our disposal, to optimise the decision making in the planning and operation of our network. Thus, enabling us to distribute clean, reliable, and affordable power to the benefit of our customers and our region through our open-access network.

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 some alternatives. To ensure our network investments represent good value for money, Orion explores other, more cost-effective alternatives to optimise utilisation before investing in traditional reinforcement. These may be to:

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

Load management

Orion's load management system allows us to control non-essential customer loads, such as hot water and irrigation. This enables 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 hardware and software platforms, including some legacy assets that are no longer supported. Nevertheless, the load management system remains an integral part of our distribution system. We are currently in the process of upgrading our load management software and are taking the opportunity to integrate it within our ADMS[6] system. Our investment plan for this asset class includes refurbishing the hardware and software of the USI load management master station due to its age and the unavailability of system support.

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. The objectives for our load management system are:

- Implement load shedding or demand response plans to lower peak demand during high-load periods, reducing network investment requirements.

[5] https://www.oriongroup.co.nz/assets/Company/Corporate-publications/Orion-AMP-March-2023.pdf

[6] Automated distribution management system

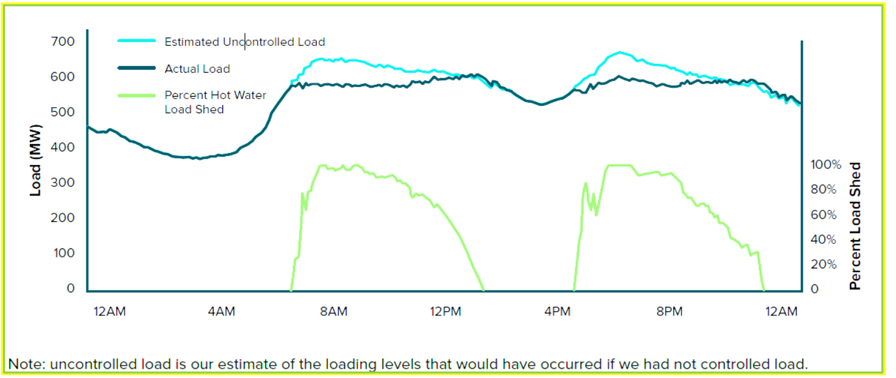
- Optimise network asset usage by effectively managing loads, prolonging the lifespan of equipment, and minimising the need for costly infrastructure upgrades.
- Contribute towards SAIDI and SAIFI targets through load reduction during critical load periods by reducing the likelihood of power outages.
- Provide 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. Orion uses ripple control to manage load in two ways:

- Peak hot water cylinder control: when network loading is high, usually on the colder winter weekday mornings and evenings, Orion has the ability to temporarily turn off hot water heating to reduce peak demand. This enables customers to take advantage of cheaper retail pricing plans and contributes approximately 50MW of peak load deferment.

- Fixed time control: Orion uses 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.

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.

1.4.1 Growth drivers

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. Peak electricity consumption growth on the Canterbury Plains has been driven by changes in land use rather than population growth.

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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. Some examples of these are:

- a new Region B zone substation near Rolleston to support load growth in Rolleston and shift load from Islington GXP to Norwood GXP
- an upgrade of the Haswell zone substation capacity to support residential load growth in the southwest of Christchurch a programme of LV network reinforcement

1.4.2 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 2023 winter period was 660MW during the peak that occurred on 11 August 2023, up 6MW from the previous year.

In the medium-term maximum network demand is influenced by 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. Many things influence changes in customer energy consumption which are hard to predict.

Some of the issues we need to consider are:

Electric vehicles: there are a number of uncertainties with EVs including uptake rates, what proportion of drivers will charge at home and when, the diversity of home charging and what size charger will be used.

Customer actions: how customers 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 customers responding to reduce peak load.

Coal boiler conversions: Government from time to time introduce initiatives for business to move away from coal for industrial processes and heating. We are engaging with larger boiler users to gain insight into their decarbonisation plans.

Solar photovoltaics: the future uptake rate, and size of solar installations is uncertain.

Batteries: battery uptake rates remain uncertain, as does knowledge of how our customers will use batteries. Customers 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 grid.

We have developed demand scenarios

Given the range of impacts these changes 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: medium growth in the Orion region and accelerating electrification closer to 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 years planning period. Network wide peak demand is an indicator of the load growth we expect to see on the network. 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 Scenario demand assumptions 2034-2050

	2034			2050		
	Maximum demand (MW)	Growth (MW)	% Change	Maximum demand (MW)	Growth (MW)	% Change
BAU	723	67	10%	839	183	28%
Progress	869	196	29%	1,196	523	78%
ST	959	285	42%	1,381	707	105%
CPBT	840	166	25%	1,056	383	57%
Central	863	192	29%	1,187	515	77%

1.4.3 Developing our LV capability

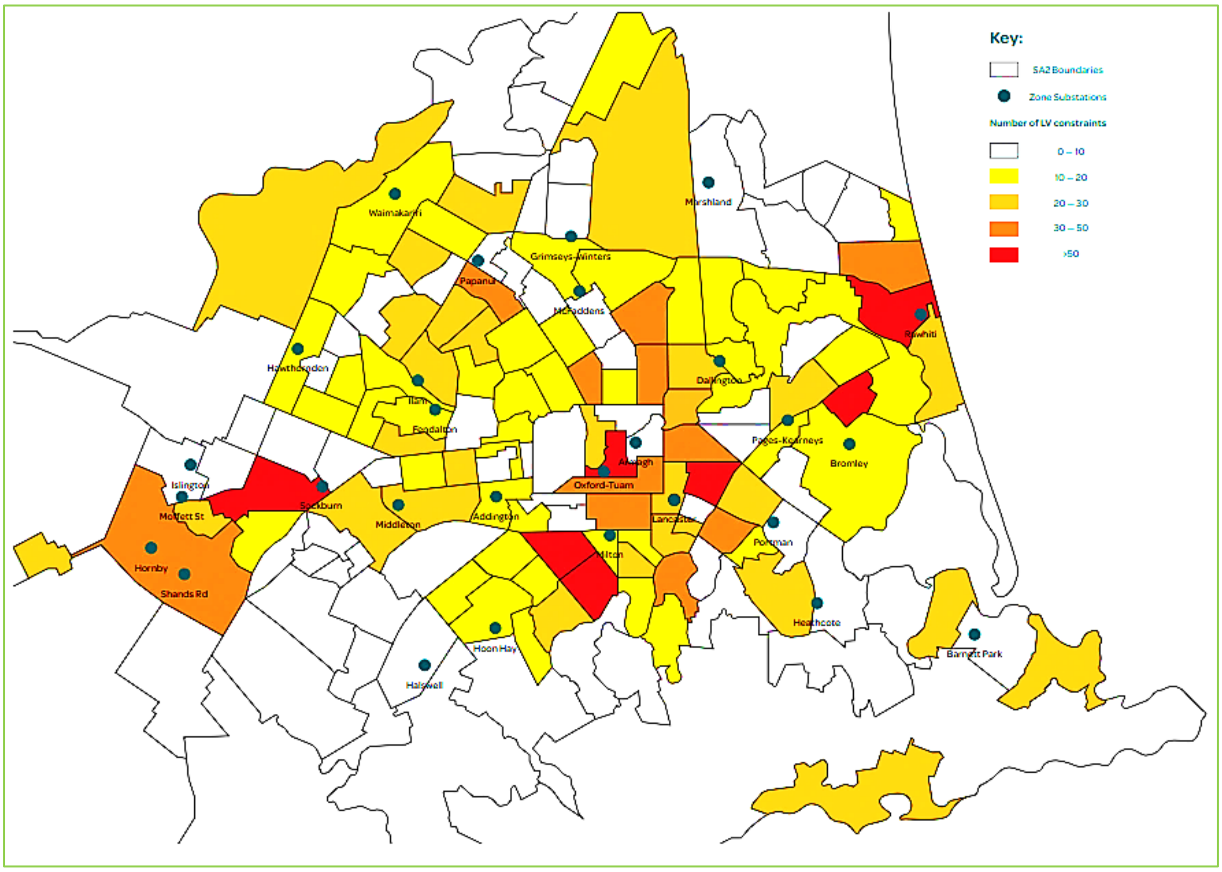
Historically, LV networks were planned for reasonably stable passive household loads with one-way power flow. However, more customers are adopting technologies such as electric vehicles (EVs) which can place significant additional demand on a street's LV system. Given Orion's LV network supplies most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

- Leverage access to smart meter and LV monitor data to create improved visibility of our assets and activity on our network, particularly Distributed Energy Resources (DER) and Low Carbon Technologies (LTC).
- Leverage data via advance analytics and enhanced capability to derive power system insights such as system constraints, network performance improvements and efficiency through optimal investment.
- 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.
- Unlock latent capacity in our network which becomes available using improved visibility, smart technology, and non-traditional solutions.
- Maximise the two-way throughput of energy across our network.

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

- provide information to guide our operational, planning and investment activities
- develop improved forecasting and modelling techniques for the future
- 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 other to participate in developing solutions.

Figure 3 Projected LV urban network constraints



2. Our pricing aims and objectives

We aim to set prices that are cost-reflective 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.

We measure appropriately against the need to provide sufficient revenue to recover our costs, including pass-through and recoverable costs, cost of capital, and the maintenance of and operation of our network.

With these aims in mind, we set prices so as 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[7]) 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.

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.

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

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3. Implementing future prices

3.1 Future pricing

Over recent years, we have evaluated our existing pricing approach against other pricing options. The stimulus for our review has been part of an industry-wide initiative led by the Authority, which wants electricity distributors to adopt cost- reflective and efficient distribution pricing structures quickly.

3.2 What is the problem the Authority wants to solve?

Electricity distribution is predominately a fixed-cost business. However, legacy pricing approaches mean most, including us, recover a high proportion of target revenue using variable charges, usually via a cents per kWh price. The problem with this historical approach is that prices do not generally reflect the economic costs of providing network services, which creates inefficiency and poor outcomes –

'… overinvestment by the consumer in technologies to avoid network charges, shifting costs onto other consumers, and unnecessary network investment.'

3.3 Roadmap of our journey to cost-reflective pricing

We develop and maintain our prices to support Orion's 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:

- Facilitating decarbonisation and hosting capacity at lowest cost, and
- 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 has 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. The following sections provide a summary of the main influences.

3.3.1. 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 customers 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 customers 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.

3.3.2 Affordability

We recognise the vulnerable customers within our community, customers that 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 customers 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 "collateral damage" when changes affect customers that are not contributing to an area of concern and/or are not in a position to respond.

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 customers.

The main tools to mitigate this impact is to implement a staged transition, spreading the change over a number of years and to provide pricing options throughout the day. This provides more opportunity for vulnerable customers to adapt and for support mechanisms to adjust[8], and for customers 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.

3.3.3. Economic considerations

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

[8] 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

- customers 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 customers.

In our 2023 Pricing Methodology, our 5-year Pricing Strategy outlined the problem definition and flagged our intention to transition fixed prices to an installed capacity basis. Fixed charges would be at an installation level based on installed capacity.

In this pricing year, the second year of our transitional journey, we have made further steps to transition consumers to a capacity-based pricing approach. Our long-term vision is to have our fixed daily charges based on installed capacity and variable charges to be the marginal price of electricity (i.e., the amount needed to recover the residual revenue not collected through fixed charges).

The five-year transition of the low fixed charge regulations means we cannot evolve our pricing approach in a single pricing year. We have updated our pricing strategy and roadmap in last year's Pricing Methodology.[9]

3.3.4 Even-handedness and practical considerations

Orion takes into account 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 customers 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 spread across new and existing customers that share in their use).
- recognise that customers 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,
- set prices that are the same for all retailers, providing a "level playing field" to promote retail competition.

By 1 April 2027, our pricing goals are to:

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

[9] https://oriongroup.co.nz/assets/Company/Corporate-publications/PricingMethodology.pdf

- Work through the phase-out of the low fixed charge regulations and incrementally increase the proportion of fixed charge revenue recovered from residential connections.
- Introduce new price categories for small and medium enterprises (SME)[10] and incrementally increase the proportion of fixed revenue recovered from them.
- Remove our fixed peak charge and convert to variable Peak TOU charges[11]
- Introduce controlled and uncontrolled charges[12]

Progressively rebalance how variable components are recovered:

- Introduce more targeted TOU variable pricing for residential and SME
- Introduce a demand charge
- Explore Distribution Energy Resources ("DER") and Customer Energy Resources ("CER") on our network around dynamic pricing and operating envelopes
- Move to full ICP pricing by 1 April 2025.

3.3.5 Reviewing our Pricing Strategy in a fast-moving environment

We initiated an evaluation of our pricing strategy in October 2023 to align to an agile milieu, to reset various objectives and to map the complexity of pricing reform. While not necessarily inconsistent, a review of some organising concepts will help us to navigate the various objectives and goals, and potentially help Orion's engagement to simplify and enhance future versions of its pricing strategy and methodology, for further stakeholder engagement on the roadmap with effect from the 01 April 2025.

Any reform will involve both desired outcomes and an implementation or transition approach. It is helpful for both reform design and from stakeholder engagement to:

- establish principles for the reform design that can lead to a collaborative vision for the tariff reform both internally and externally and ensure that tariff reform remains robust to its context and constraints and
- distinguish between principles that relate to desired end state outcomes versus those that relate to the process of transition.

Our overarching objectives are:

- recover total regulated revenue (outcome objective)
- support electrification that improves network utilisation (outcome objective)
- encourage efficient investment in and participation of Customer Energy Resources and Distributed Energy Resources (outcome objective)
- provide predictability for consumers to make investments with certainty (transition principle)
- robust two-way energy transference not just energy delivery (outcome objective)
- uses of the right levers for each consumer segment's required behaviour and controls, including simplicity where possible (transition principle)
- acknowledge the value stack and materiality when designing prices for cost recovery and behavioural response (transition principle)

[10] We completed this step in our 2023 pricing

[11] We transitioned this in our 2023 pricing and the fixed peak charge will be removed in our 2024 pricing

[12] We introduced controlled and uncontrolled pricing in our 2024 pricing

- align with Orion’s asset management strategy (including demand response controls) and investment plans (outcome objective and transition principle)

3.4 Implement Gradually and Carefully

Unfortunately, we cannot move to capacity-based pricing for all consumers by 01 April 2024. Practicalities necessitate that we transition the change in our pricing approach over time to execute the change effectively and appropriately.

3.4.1 What aspects of our pricing have not changed

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 customers. 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 6 of this Pricing Methodology.

We have decided to continue calculating the variable kWh charge for mass-market consumers (residential and SME connections) based on grid exit point (GXP) volumes (known as ‘GXP pricing’). We bill consumers by:

- Reconciling consumption (i.e., kWh) to the GXP volumes
- Adjusting metered loads by the appropriate loss factor[13] to arrive at the chargeable GXP volumes
- Washing-up monthly kWh volumes in line with reconciled GXP data issued by the market reconciliator (i.e., total billed kWh volume will equal reconciled GXP volumes)
- Charging variable charges not directly attributable to a consumer grouping. After doing a cost benefit analysis and bill impact modelling, we intend to transition to ICP pricing from the 01 April 2025 which is facilitated by a new billing platform that will be in place from 1 April 2024.

3.4.2 Changes made for 1 April 2024

We have made several fundamental but small changes to our prices effective 1 April 2024. The changes we have made to our pricing approach are listed in Table 1.

Table1: Summary of the changes made to our pricing approach effective 1 April 2024

Consumer Category	Description of the changes made effective 1 April 2024
General Connections	The general fixed daily supply charge will increase from 45 cents to 60 cents from the 1 April 2024. We intend to move to a fixed installed capacity charge over time.

[13] More information on the relevant loss factors for the 01 April 2024 pricing year can be found in section 4.4 of this Pricing Methodology.

Consumer Category	Description of the changes made effective 1 April 2024
	To support a smooth transition to a fixed installed capacity charge, we will conduct a staged process, including comprehensive communication and education program for residential consumers and an audit of all current connections in the SME category. 01 April 2024, we have transitioned the fixed/variable split from 22% fixed / 78% variable split to 37% fixed / 63% 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 Over the coming years, we will transition the fixed / variable split towards a higher proportion of our costs recovered through a fixed charge. We will do this to the extent permissible each year under the transitional arrangements of the low fixed charges regulations and will preserve some level of price signal through variable charges.
General Connections: **RES (Residential)** **GEN (GC1)** **GEN(GC2)** **GEN(GC3)**	From 01 April 2024 we have made some more gradual structure changes to better reflect both Residential and SME connection utilisation of the network. We are transitioning the fixed charge to a capacity-based charge over time. We have introduced TOU variable charging. Change the name of GEN price category to RES Controlled fixed network charge (per ICP, per day) Uncontrolled fixed network charge (per ICP, per day) Variable network charge (peak units per kWh) Variable network charge (shoulder units per kWh) Variable network charge (off peak units per kWh) Variable network charge (super off peak units per kWh) Variable network charge (weekend units per kWh)
Peak charge	Removal of the fixed daily peak charge.

Delivery charges effective 1 April 2024 and a comparison with the delivery charges effective 1 April 2023 is included in Appendix A.

3.5 Changes to the low fixed charge (LFC) regulations have been an enabler

In mid-September 2021, the Minister of Energy announced that the low fixed charge regulations would be phased out over five years. The announcement allowed us to begin changes to our pricing approach for network charges effective 1 April 2022.

On 29 November 2021, the Electricity (Low Fixed Tariff Option for Domestic Consumers) Amendment Regulations 2021 was enacted. The amendment regulations phase out the low fixed charges over five years and allow the regulated distributor tariff option to:

Year 1 replace 15 cents with 30 cents – 1 April 2022 to end of 31 March 2023

Year 2 replace 30 cents with 45 cents – 1 April 2023 to end of 31 March 2024

Year 3 replace 45 cents with 60 cents – 1 April 2024 to end of 31 March 2025

Year 4 replace 60 cents with 75 cents – 1 April 2025 to end of 31 March 2026

Year 5 replace 75 cents with 90 cents – 1 April 2026 to end of 31 March 2027

The regulations will be revoked on 1 April 2027

The low fixed charge (LFC) regulations place inherent limitations on our transition to cost-reflective pricing.

Phasing out of the LFC regulations will make pricing fairer for larger, often low-income, households which wouldn't qualify for the low fixed charge. Commercial and industrial consumers had been cross subsidised by residential and SME categories. Based on social-economic equity considerations, the historical cross-subsidisation was appropriate. However, decarbonisation is a disruptor. The increased demand from residential consumers as they electrify transport is likely to require a step-change in investment, making now the right time to unwind these historical cross-subsidisations and evolve our pricing approach to set more cost-reflective prices.[14]

"Average consumers, those consuming between 5,000 and 8,000kWh per year will see very little impact from the removal of the low fixed charge."

A 2019 study by Concept Consulting determined that not removing the LFC regulations would result in an economic cost of up to $1.5bn over 30 years and hurt the environment by adding 8 million tonnes of carbon dioxide emissions out to 2050 through disincentivising uptake of electric vehicles and heat pumps.[15]

"Doing away with the regulations will also smooth out power bills through the year – reducing large bills during the winter months - making it easier for families which struggle to budget."

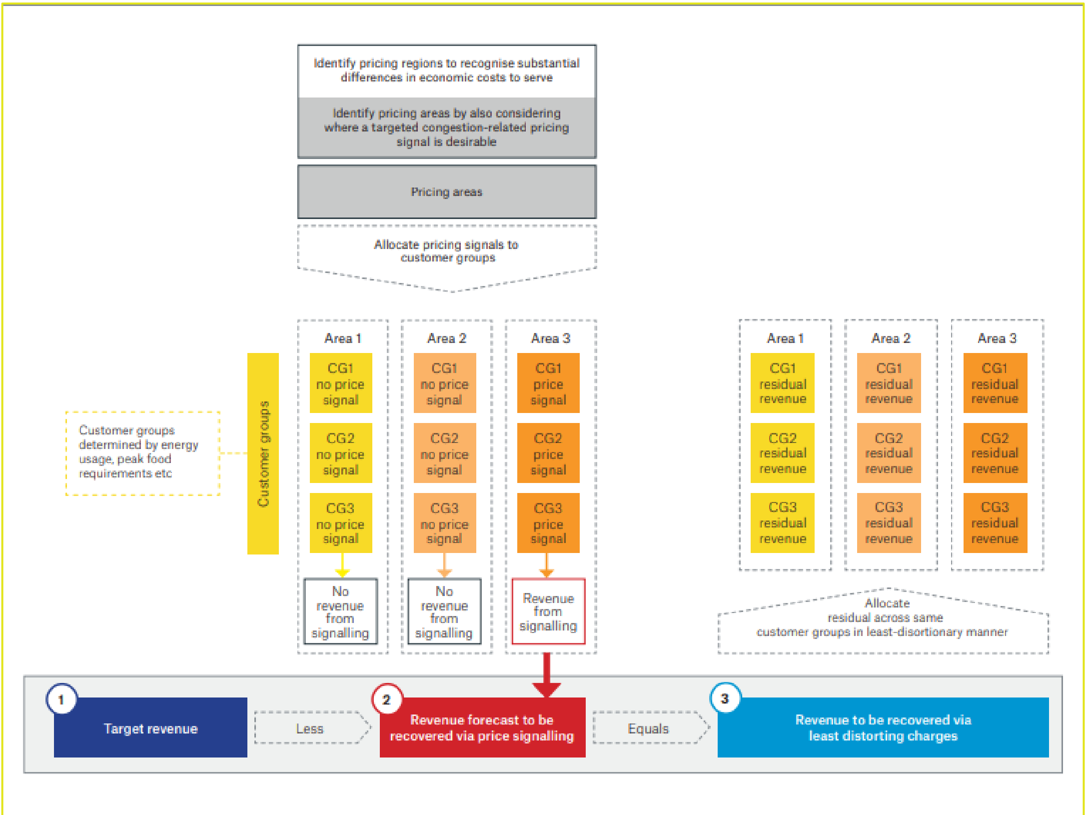
3.6 Change in model

We have this year changed our approach to cost allocation (see diagram below) to follow the approach proposed by the Electricity Authority in its 2022 practice note. Under this approach, we determine our target revenue, and then forecast the revenue to be recovered through price signalling. The residual revenue is recovered via the least distortionary charges.

However, we also continue to employ a phased implementation approach to mitigate the impact on consumers, as outlined in section 3.4. As such, final prices may not always perfectly reflect the cost allocation model.

[14] Transitioning out of the low fixed charge pricing option for electricity | ENA

[15] https://www.ena.org.nz/news-and-events/news/transitioning-out-of-the-low-fixed-charge-pricing-option-for-electricity/



3.7 Consumer Impact

We are mindful that a change in pricing approach can impact consumers differently. There is the potential that some consumers will be better off under capacity-based pricing in the short term, and some will be worse off. 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 mitigate perverse year-on-year outcomes to the fullest extent 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 6.2.4 of this Pricing Methodology.

The changes to this pricing year's low fixed charge regulations resulted in a 33% 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 +$9 or +3%.

The impact on the average SME connection was +$315 or +7% per annum, and +$4,168 or +4.9% 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.

SME consumers can affect their lines charges by right sizing their connection to meet their individual needs. We conducted a desktop audit of connected capacity on our network. It appears that several connections have installed capacity that is greater than their current needs. Oversized connections can be historical, i.e., due to connected load that had since been reduced when pumps, machinery, and other connected loads were replaced with newer, more energy-efficient equipment at the connection.

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 can be as simple as changing the fuses and performed on request.

Our network charges make up approximately 27% of consumers’ total electricity bills. The other 73% 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.

4. Standard Connection Contract

We supply electricity distribution services to consumers via Retailers[16] under the terms in our Default Distribution Agreement, our standard connection contract. We have 23 retailers trading on our network.

4.1 How we assign consumer to Price Categories

Consumers are assigned to one of eight price categories based on the consumer’s utilisation of our network. Revenue is recovered from consumers using a mix of fixed and variable prices.

Table 2 shows the consumer groups and network charge categories effective 1 April 2024

Category	Breakdown of charges
Irrigation	Capacity charge (per kW, per day) Variable network charge (peak units per kWh) Variable network charge (shoulder units per kWh) Variable network charge (off peak units per kWh) Variable network charge (super off peak units per kWh) Variable network charge (weekend units per kWh) Power Factor correction rebate Interruptibility rebate
Street Lighting	Fixed network charge (per lamp, per day) Variable network charge (peak units per kWh) Variable network charge (shoulder units per kWh) Variable network charge (off peak units per kWh) Variable network charge (super off peak units per kWh) Variable network charge (weekend units per kWh)

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

Residential Connections	Controlled fixed network charge (per ICP, per day) Uncontrolled fixed network charge (per ICP, per day) Variable network charge (peak units per kWh) Variable network charge (shoulder units per kWh) Variable network charge (off peak units per kWh) Variable network charge (super off peak units per kWh) Variable network charge (weekend units per kWh)
General Group 1 (GC1)	Controlled fixed capacity-based network charge (per ICP, per day) Uncontrolled fixed capacity-based network charge (per ICP, per day) Variable network charge (peak units per kWh) Variable network charge (shoulder units per kWh) Variable network charge (off peak units per kWh) Variable network charge (super off peak units per kWh) Variable network charge (weekend units per kWh)
General Group 2(GC2)	Controlled fixed capacity-based network charge (per ICP, per day) Uncontrolled fixed capacity-based network charge (per ICP, per day) Variable network charge (peak units per kWh) Variable network charge (shoulder units per kWh) Variable network charge (off peak units per kWh) Variable network charge (super off peak units per kWh) Variable network charge (weekend units per kWh)
General Group 3 (GC3)	Controlled fixed capacity-based network charge (per ICP, per day) Uncontrolled fixed capacity-based network charge (per ICP, per day) Variable network charge (peak units per kWh) Variable network charge (shoulder units per kWh) Variable network charge (off peak units per kWh) Variable network charge (super off peak units per kWh) Variable network charge (weekend units per kWh)
Major customer and embedded network connections	Fixed charge ($/connection/day) Fixed charge (additional connection) ($/connection/day) Peak charge (control demand period) ($/kVA /day) Nominated Maximum demand ($/kVA /day) Metered Maximum demand ($/kVA /day) Dedicated equipment charges ($/day or similar)
Large Capacity Connections	Individually assessed prices advised and charged directly to customers

4.2 Non – standard pricing

Non-standard pricing and individual account management is offered to industrial and large capacity connections to provide a tailored service. We offer this when the customer's needs are unique to their business need, e.g., timing and scale of investment. Our approach to non-standard pricing considers customers' individual capacity and demand to ensure, to the extent practicable, that the price is cost reflective.

Asset-based building block approach ("ABBA")

The asset-based building block approach is used to set prices for very large customers, customers that have a direct contractual relationship with Orion for a defined term, typically for:

- a step change upgrade or
- a new customer connection is required that involves significant investment.

Asset-based pricing comprises the following input components:

- return on capital investment, plus accounting depreciation in period or year

- sub-transmission cost allocation of direct and indirect costs for sub-transmission asset utilisation in period of year.
- operating and maintenance costs
- tax adjustment; and
- recovery of pass-through costs and recoverable costs (e.g. transmission charges and regulator levies).

As a general guide, and subject to the considerations above, connections requiring a capacity of greater than 10 MVA in the urban area, or greater than 4 MVA in the rural area would be considered for non-standard pricing.

Customer specific pricing applies to large capacity connections. Asset -based pricing may also apply to generation connections and special arrangement designed to mitigate the risk of uneconomic asset bypass. Each price is set individually set using a building block approach as further described in the table below:

Activity	**What's involved**
Measurement and forecasts of customer demand and connections	Measurement and/or estimation of customer's demand by historical AMD (Anytime Maximum Demand), CPD (Peak Coincident Demand) and ADL (Average Demand Level), is used to calculate asset-based prices.
Calculate value of assets	The assets used to supply the service are valued in association with the regulatory asset base (RAB) values to calculate the asset-based price. Assets are categorised as dedicated on-site assets or shared upstream assets. On-site assets are generally dedicated assets and wholly allocated to the relevant customer. Upstream assets are allocated using the site's maximum demand and the demand of the section of the network (e.g., zone substation) that the relevant upstream assets are a part of.
Calculate return of and on capital, and depreciation	An annual rate of return is recovered on the asset valuations attributed to each customer; this is based on Orion's prevailing weighted average cost of capital (WACC). Depreciation is allocated based on the asset's actual depreciation during the most recent financial year.
Allocate maintenance costs	Maintenance costs are allocated to the relevant load groups based on the load group's regulatory asset base (RAB) relative to the applicable GXP's total RAB. These costs allocated against the assets used by each customer, using an appropriate rate
Allocate indirect costs (fixed and variable)	Indirect costs are allocated to load groups based on its total usage as a proportion of the applicable GXP usage. Indirect costs are all costs of Orion's electricity business excluding transmission, asset-related costs, maintenance, interest, and tax.

Allocate transmission costs	Transpower's Connection, Benefit-based, and Residual Charges are allocated to Orion via various methods. We allocate and pass-through these charges to customers using mechanisms that reflect the Transmission Pricing Methodology (TPM) and the EA's Pricing Principles and TPM pass-through guidance. The Connection charge is based on the customer's demand, as measured by Anytime Maximum Demand "AMD" (load). The Benefit-based and Residual charges are allocated based on historical usage, measured by Average Demand Level "ADL".

Non-standard connection contracts

Large capacity connections have specific non-standard contractual terms including delivery obligations and responsibilities in the event of supply interruptions. These attributes are disclosed in our *Disclosure of prescribed contracts* document which is available on our website. In general, for these customers we:

- provide uninterrupted supply security against a range of faults by maintaining duplicate supply assets,
- prioritise restoration of supply following outages, and
- maintain a "last to shed" priority for grid emergencies, and to the extent reasonably practical, not include the connections for "automatic under frequency load shedding", nor "automatic under voltage load shedding".

This supply security is 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. The higher supply security is provided for these customers through the provision of additional back up supply assets, and this is reflected in the prices applied.

With only two customers presently in the large capacity connection category commercial sensitivity prevents us from providing any load profile for this category. These arrangements have no direct effect on the determination of ongoing prices of these customers.

4.3 Customer consultation and Price-Quality Trade-Off

The information disclosure requirements include a requirement around the extent to which the views of customers, in terms of price and quality, have been sought and reflected in the price-setting process.[17]

For the refresh of our pricing strategy and in setting annual prices, we engaged with and consolidated feedback from a wide range of stakeholders.

- held briefing sessions with our directors;

[17] Commerce Commission, Decision NZCC 22: Electricity Distribution Information Disclosure Determination 2012, 2.4.1 (4). The Determination uses the term consumer rather than customer.

- hosted two “powerful conversation” workshop around now and the future priorities;
- consulted with other network operators and engaged with industry working groups;
- employed expert consultants to critique and peer review our work.

Further for 2023 we:

- took account of the views expressed by electricity retailers in our consultation rounds, and
- we engaged with retailers and external consultant to undertake targeted research surveys of customer preferences related to price-quality trade-offs.

Both through ongoing engagement with the board and periodic surveys, the feedback we have received to date indicates that consumers are satisfied with the status quo in terms of the trade-off between network pricing and reliability.

We have commenced a review of our 2021 pricing strategy and roadmap. The results of this review will be reflected in the methodology for 1 April 2025 prices.

4.4 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.

In 2023, we undertook a review 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 3. The new loss factors will be effective 1 April 2024.

Table 3: Loss factors for the pricing year

Code	Loss Factor	Description
LVL	1.0636	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)

4.5 Distributed Generation

Interest in utility-scale solar connections has significantly increased since 2022. Inquires indicate potential for 10MW to 450MW+ of solar PV/wind generation to be added within Region B. We have 185 small photovoltaic installations under 10kW.

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.

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.

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 Orion's 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 www.oriongroup.co.nz/customers/connecting-your-solar-or-diesel-generation.

4.6 Capital contribution

Capital contribution applies to the generally up-front cost a customer will pay when connecting to the network. Primarily, we look to apply economic consideration to the balance between socialisation (shallow charging) and causer pays (deep charging) when setting our approach to connection charges.

Our approach to charges for connections and extensions forms part of our broader efficient pricing policies and our economic approach to recovery of costs for providing our delivery service. With this approach, customers (particularly prospective customers) make efficient decisions about which form of energy to use, and where to locate new load. We endeavour to provide new connections and enhanced capacity wherever it is economically viable, and our Connections and Extensions Methodology sets out our approach to establish this economic viability. However, there may be situations where it is imprudent, environmentally unsound or physically impracticable to provide supply or enhanced capacity.

Ideally, each new connection would pay for any necessary extension and reinforcement through its future delivery charges. However, a number of factors prevent this balance from occurring:

- we must apply price averaging over large groups of connections, because it is not practical to single out individual connections for cost-specific delivery pricing;
- the life and future utilisation of new connections are not known, so the present value of future delivery charges cannot be calculated with certainty;
- the assets involved have very long lives and it is not viable to lock some customers into a contract over a matching period;
- network reinforcement is incremental, it is often more efficient for us to add large amounts of capacity at a time (unlocking economies of scale);

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- dedicated assets often become shared assets as the network expands. Existing customers should share in the benefit of greater utilisation of shared assets (and other enhanced economies of scale).

Formula for calculating Capital contribution for non-standard connections

(CC) = ICCS + ICSN - IR (n = X)

Where:

Item	Description
ICCS	Incremental Cost Customer Specific (is the incremental costs incurred by Orion that are specific to the connection)
ICSN	Incremental Cost Shared Network (the network costs incurred by Orion as a result of the new or altered connection, but which are not specific to the connection, such as network augmentation. Where: ICSN = Unit Rate x Demand estimate Unit rate =Average cost of network augmentation (other than an extension beyond the standard service line) per unit of added capacity, expressed as $/kVA Demand Estimate = Estimated maximum demand at the connection point measured in kVA.
IR (n=X)	Incremental Revenue will be the NPV of all of the expected distribution line charges recoverable from the customer.

We apply the following principles in estimating the Incremental Revenue:

1. Forecast revenue will be based on the price path set out in the DPP determination for the period and the relevant network tariffs as set out in our Pricing Methodology and Schedules
2. A discount rate based on our approved regulatory WACC converted to pre-tax terms using the estimated average effective tax rate for the regulatory period
3. 30-year discount period will be applied for residential customers
4. 15-year discount period will be applied for business customers when calculating the expected line charges recoverable from the customer.
5. Where basic connection offer and the connection falls below the shared network augmentation charge threshold, we will exclude from the IR the portion of the charges attributable to augmentation of the shared network where it is estimated to be material
6. The operational and maintenance costs have no net impact on the capital contribution payable by the customer.

Our methodology for new connections and extensions can be found at:
https://www.oriongroup.co.nz/ConnectionsAndExtensions

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5. Calculation of our costs to serve

5.1 Calculation of the Required Revenue

The required revenue represents the forecasted costs incurred over the pricing year. Through our prices effective 01 April 2024, we intend to recover the Required Revenue of $257.8m during the pricing year. Table 4 provides a breakdown.

Table 4 provides a breakdown of our Required Revenue for the pricing year:

Description	Amount $('000)
Operations and Maintenance Costs	$33,307
Administration and Corporate Costs	$54,408
Depreciation charges	$56,000
Network Rebates	$879
Transpower Charges	$59,759
Regulatory Costs / Levies	$53,430
Total required revenue	**$257,783**

5.1.1 Calculation of the Operations and Maintenance Costs

Our forecast Operations and Maintenance costs for the year are $33.3m. Table 5 provides a breakdown of our forecast Operations & Maintenance Costs for the pricing year.

Table 5: Forecast Operations and Maintenance Costs for the pricing year:

Description	Amount $('000)
Service Interruptions and Emergencies	$9,390
Vegetation Management	$4,200
Routine and Corrective Maintenance	$16,778
Asset Replacement and Renewal	$2,939
Total Operations and Maintenance Costs	**$33,307**

5.1.2 Calculation of the Administration & Corporate Costs

Our forecast Administration and Corporate Costs for the pricing year are $54.4m. Table 6 provides a breakdown of our forecast administration and corporate costs for the pricing year.

Table 6: Forecast Administration & Corporate Costs for the pricing year

Description	Amount $('000)
System Operations and Network Support	$22,858
Business Support	$31,550
Total Administration and Corporate Costs	**$54,408**

5.1.3 Calculation of the Depreciation Charges

Our forecast Depreciation Charges for the pricing year are $56m. 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 01 April 2024 and 31 March 2025. Table 7 provides a breakdown of our budgeted Depreciated Charges for the pricing year.

Table 7: Forecast Depreciation Charges of the pricing year

Description	Amount $('000)
Non-System Fixed Assets	$5,000
System Fixed Assets	$51,000
Total Depreciation Charges	**$56,000**

5.1.4 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 01 April 2024 to 31 March 2025 are $59.8m.

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 $53.4m.

5.2 Change in Required Revenue

Our required revenue has increased by $21.2m or 8% for 01 April 2024 pricing year when compared against 01 April 2023 pricing year. Table 8 provides the movement in required revenue between the pricing years.

Table 8: Movement in Revenue Requirement between pricing years

Description	2024/25 $('000)	2023/24 $('000)	Movement $('000)	%
Administration and Corporate Costs	$54,408	$52,958	$1,450	3%
Operations and Maintenance Costs	$33,307	$36,012	($2,705)	-8%
Depreciation charges	$56,000	$53,000	$3,000	5%
Network discounts	$879	$679	$200	23%
Transpower charges	$59,759	$56,097	$3,663	6%
Regulatory costs / Levies	$53,430	$37,816	$15,614	29%
Total Required Revenue	**$257,783**	**236,562**	**$21,222**	**8%**

5.2.1 Change in Operations & Maintenance Costs

The primary cause of the decrease in target revenue is a decrease in Regulatory costs/ levies costs expenditure of ($2.7m) or (8%) forecast for the 01 April 2024 pricing year. Table 9 compares operations and maintenance costs expenditure between pricing years.

Table 9: Comparison of Operations and Maintenance costs between Pricing years

Description	2024/25 $('000)	2023/24 $('000)	Movement $('000)	%
Service Interruptions and Emergencies	$9,390	$9,250	$140	1%
Vegetation Management	$4,200	$6,000	($1,800)	(43%)
Routine and Corrective Maintenance	$16,778	$17,529	($751)	(4%)
Asset Replacement and Renewal	$2,939	$3,233	($294)	(10%)
Total Operations and Maintenance Costs	**$33,307**	**$36,012**	**($2,705)**	**(8%)**

Operations and Maintenance costs are forecast to decrease by 8%. The movement reflects the significant upward pressure on input costs experienced during the past year, primarily from:

- Wages and Salaries
- Service provider/Subcontractor rates
- Fuel
- Material / components
- Traffic management

5.2.2 Change in Administration and Corporate Costs

The Administration and Corporate costs have increased by $1.45m or 3%. Table 10 compares administration and corporate costs expenditure between pricing years.

Table 10: Comparison of Administration and Corporate Costs between pricing years.

Description	2024/25 $('000)	2023/24 $('000)	Movement $('000)	%
System Operations and Network Support	$22,858	$20,032	$2,826	12%
Business Support	$31,550	$32,926	(1,376)	(4%)
Total Administration and Corporate Costs	**$54,408**	**$52,958**	**$1,450**	**3%**

The 3% increase in Administration and Corporate Costs is attributable to general budget pressures. The main driver of the 12.4% increase in System Operations and Network Support, is largely the increase in data and digitalisation of an expanding network and the need to improve efficiency and decision making through data. This will support the network business as technological changes impact the distribution sector, particularly the need for greater cyber security and in support of greater LV network visibility and more sophisticated distribution network operation.

5.2.3 Changes in other costs

The increase in Depreciation Charges of $3m or 5% reflects the increasing value of our electricity network assets, which are subject to annual accounting revaluation.

The increase in transmission costs of $3.7m or 6% 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.[18]

5.3 Recovery of Required Revenue from consumer groups

We recover our Required Revenue from consumers through prices. Table 11 provides a breakdown of the Required Revenue by consumer grouping for the pricing year.

Table 11: Required Revenue by connection grouping for the pricing year

Consumer Group	Required Revenue $('000)	Proportion (%)
Street Lighting (LIG)	$484	0%
Residential Connections (RES)	$146,453	57%
General Connections (GEN GC1)	$6,957	3%
General Connections (GEN GC2)	$21,755	8%

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

Consumer Group	Required Revenue $('000)	Proportion (%)
General Connections (GEN GC3)	$33,856	13%
Irrigation Connections (IRR)	$5,723	2%
Major Customers	$38,673	15%
Large Capacity Connections	$3,883	2%
Total Required Revenue (excl. export credits)	**$257,783**	**100%**

As discussed, our pricing approach aims to set efficient and appropriate prices. When setting prices, we do so with the objectives of fairness, sending price signals to consumers, avoiding bill shock, and consistency with the Authority's Pricing Principles. We set prices to recover the total Required Revenue over the pricing year to meet our aims and objectives.

6. Our Approach to setting prices

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

Step 1 – the cost of supply model (CoSM) allocates the revenue requirement to the following:

- the eight grid exit points (GXP's) that Orion Network connects to: Arthurs Pass, Bromley, Castle Hill, Coleridge, Hororata, Islington, Kimberley, and Norwood
- eight consumer groups (LIG, RES, GEN (GC1), GEN (GC2), GEN(GC3), IRR, MCC, LCC)

Step 2 – the pricing design model sets the Target Revenue by:

- setting distribution and transmission prices, by GXP, within each consumer group based on a designated split between fixed /variable charges; and
- rolling the distribution and transmission prices up to set uniform delivery charges.

6.1 Overview of our approach to allocating the Revenue Requirement

6.1.1 Allocate the Revenue Requirement to the GXP's

The CoSM firstly allocates our Revenue Requirement across the eight GXPs that the Orion network connects to, based on the principal drivers of the cost components of the Required Revenue. We use eight drivers of cost at each GXP:

Table 12: The allocation to each GXP by cost driver

GXP	Arthurs Pass	Bromley	Castle Hill	Coleridge	Hororata	Islington	Kimberley	Norwood
No of ICP	0.1%	25.6%	0.1%	0.1%	2.0%	70.8%	0.4%	1.0%
Installed Capacity (kW)	0.1%	22.2%	0.1%	0.1%	3.5%	71.6%	0.5%	2.0%
Asset Utilisation	0.1%	22.2%	0.1%	0.1%	3.5%	71.6%	0.5%	2.0%
Consumption (kWh)	0.0%	20.2%	0.1%	0.0%	5.3%	71.6%	0.4%	2.2%
Anytime Maximum Demand (AMD) (kW)	0.0%	20.2%	0.1%	0.0%	5.3%	71.6%	0.4%	2.2%
Line Length (meters)	0.1%	24.0%	0.2%	0.1%	2.7%	71.5%	0.7%	0.7%
RAB ($)	0.1%	22.2%	0.1%	0.1%	3.5%	71.6%	0.5%	2.0%
RAB Depreciation ($)	0.1%	22.2%	0.1%	0.1%	3.5%	71.6%	0.5%	2.0%

1 April 2024 is the first pricing 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). This pricing year, we have moved to a more granular approach apportioning costs in support of cost reflective pricing. The six cost drivers above were chosen as we have readily available information for these drivers. Making the approach straightforward, appropriate, and fair. The allocation of our Revenue Requirement to each GXP by cost component and cost driver is shown in section 6.1.2 and 6.1.3 below.

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6.1.2 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 categories, again based on the driver of the cost to serve each consumer group. We use six drivers to allocate costs to the consumer groups:

- No of ICP
- Consumption
- Line length
- Installed Capacity
- Asset Utilisation
- Anytime Maximum demand

Table 13: Allocation to the consumer group by cost driver at the Arthurs Pass GXP for the pricing year

Description	LIG	RES	GEN(GC1)	GEN(GC2)	GEN(GC3)	IRR	MCC
No of ICP	1%	70%	17%	12%	1%	0%	0%
Line Length (meters)	3%	85%	5%	3%	5%	0%	0%
Installed Capacity (kW)	1%	57%	12%	28%	3%	0%	0%
Asset Utilisation	1%	57%	12%	28%	3%	0%	0%
Consumption (kWh)	1%	53%	16%	27%	2%	0%	0%
Anytime Maximum Demand (AMD) (kW)	1%	53%	16%	27%	2%	0%	0%

Table 14: Allocation to the consumer group by cost driver at the Bromley GXP for the pricing year

Description	LIG	RES	GEN(GC1)	GEN(GC2)	GEN(GC3)	IRR	MCC
No of ICP	0%	90%	4%	5%	1%	0%	0%
Line Length (meters)	3%	38%	9%	6%	3%	0%	42%
Installed Capacity (kW)	0%	70%	2%	10%	13%	0%	4%
Asset Utilisation	0%	70%	2%	10%	13%	0%	4%
Consumption (kWh)	0%	58%	3%	9%	10%	0%	19%
Anytime Maximum Demand (AMD) (kW)	0%	90%	4%	5%	1%	0%	0%

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Table 15: Allocation to the consumer group by cost driver at the Castle Hill GXP for the pricing year

Description	LIG	RES	GEN(GC1)	GEN(GC2)	GEN(GC3)	IRR	MCC
No of ICP	0%	77%	13%	7%	3%	0%	0%
Line Length (meters)	5%	65%	15%	10%	5%	0%	0%
Installed Capacity (kW)	0%	61%	7%	14%	18%	0%	0%
Asset Utilisation	0%	61%	7%	14%	18%	0%	0%
Consumption (kWh)	0%	59%	10%	14%	16%	0%	0%
Anytime Maximum Demand (AMD) (kW)	0%	77%	13%	7%	3%	0%	0%

Table 16: Allocation to the consumer group by cost driver at the Coleridge GXP for the pricing year

Description	LIG	RES	GEN(GC1)	GEN(GC2)	GEN(GC3)	IRR	MCC
No of ICP	1%	70%	12%	15%	2%	0%	0%
Line Length (meters)	5%	65%	15%	10%	5%	0%	0%
Installed Capacity (kW)	1%	58%	7%	28%	7%	0%	0%
Asset Utilisation	1%	58%	7%	28%	7%	0%	0%
Consumption (kWh)	1%	55%	9%	28%	6%	0%	0%
Anytime Maximum Demand (AMD) (kW)	1%	70%	12%	15%	2%	0%	0%

Table 17: Allocation to the consumer group by cost driver at the Hororata GXP for the pricing year

Description	LIG	RES	GEN(GC1)	GEN(GC2)	GEN(GC3)	IRR	MCC
No of ICP	0%	68%	11%	10%	4%	6%	0%
Line Length (meters)	3%	69%	6%	3%	6%	14%	0%
Installed Capacity (kW)	0%	34%	4%	10%	12%	27%	14%
Asset Utilisation	0%	34%	4%	10%	12%	27%	14%
Consumption (kWh)	0%	17%	3%	5%	6%	33%	36%
Anytime Maximum Demand (AMD) (kW)	0%	68%	11%	10%	4%	6%	0%

Table 18: Allocation to the consumer group by cost driver at the Islington GXP for the pricing year

Description	LIG	RES	GEN(GC1)	GEN(GC2)	GEN(GC3)	IRR	MCC
No of ICP	0%	88%	4%	5%	2%	0%	0%
Line Length (meters)	1%	38%	2%	1%	2%	0%	55%
Installed Capacity (kW)	0%	64%	2%	9%	16%	1%	7%
Asset Utilisation	0%	64%	2%	9%	16%	1%	7%
Consumption (kWh)	0%	49%	2%	8%	12%	2%	28%
Anytime Maximum Demand (AMD) (kW)	0%	88%	4%	5%	2%	0%	0%

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Table 19: Allocation to the consumer group by cost driver at the Kimberley GXP for the pricing year

Description	LIG	RES	GEN(GC1)	GEN(GC2)	GEN(GC3)	IRR	MCC
No of ICP	0%	77%	10%	8%	3%	2%	0%
Line Length (meters)	3%	60%	5%	3%	5%	25%	0%
Installed Capacity (kW)	0%	57%	5%	12%	15%	11%	0%
Asset Utilisation	0%	57%	5%	12%	15%	11%	0%
Consumption (kWh)	0%	49%	6%	11%	12%	23%	0%
Anytime Maximum Demand (AMD) (kW)	0%	77%	10%	8%	3%	2%	0%

Table 20: Allocation to the consumer group by cost driver at the Norwood GXP for the pricing year

Description	LIG	RES	GEN(GC1)	GEN(GC2)	GEN(GC3)	IRR	MCC
No of ICP	0%	58%	10%	13%	3%	15%	0%
Line Length (meters)	3%	60%	5%	3%	5%	25%	0%
Installed Capacity (kW)	0%	26%	12%	10%	27%	24%	2%
Asset Utilisation	0%	26%	12%	10%	27%	24%	2%
Consumption (kWh)	0%	18%	12%	7%	17%	40%	7%
Anytime Maximum Demand (AMD) (kW)	0%	58%	10%	13%	3%	15%	0%

6.1.3 Historical quantities to allocate the Required Revenue

We allocate costs based on our historical quantities using information from our billing system, EIEP files provided by traders, and our year-end information disclosure schedules.

Table 21: Quantities used to allocate the Required Revenue to the Arthurs Pass GXP for the pricing year.

Consumer Group	No of ICP / supplies	Consumption (kWh)	Installed capacity (kVA)	Asset utilisation (kW)	AMD (kW)	Line length (meters)	RAB	RAB Depreciation
LIG	1	13,348	15	11	3,004	108		
RES	114	857,003	1,591	1,114	192,894	3,689		
GEN(GC1)	27	258,898	324	227	58,272	217		
GEN(GC2)	20	437,521	779	545	98,477	108		
GEN(GC3)	1	38,350	75	53	8,632	217		
IRR	0	0	0	0	0	0		
MCC	0	0	0	0	0	0		
Total	**163**	**1,605,120**	**2,784**	**1,949**	**361,279**	**4,340**		
Network	Sub transmission Lines						$42,687	$1,548
Network	Sub transmission Cables						$52,380	$1,585
Network	Zone Substation						$93,366	$4,638
Network	Distribution LV Lines						$80,335	$3,345
Network	Distribution LV cables						$245,444	$8,226
Network	Distribution substations and transformers						$85,826	$2,466
Network	Distribution switchgear						$96,465	$3,794
Network	Other network assets						$22,335	$991
Non-Network	Non-Network assets						$33,802	$2,525
Total							**$752,640**	**$29,017**

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Table 22: Quantities allocated to the Required Revenue at the Bromley GXP for the pricing year.

Consumer Group	No of ICP / supplies	Consumption (kWh)	Installed capacity (kVA)	Asset utilisation (kW)	AMD (kW)	Line length (meters)	RAB	RAB Depreciation
LIG	7	511,681	575	403	115,169	53,453		
RES	51,395	402,636,473	747,482	523,237	90,625,059	694,895		
GEN(GC1)	2,349	20,778,146	26,003	18,202	4,676,727	160,360		
GEN(GC2)	2,711	62,237,435	110,813	77,569	14,008,346	106,907		
GEN(GC3)	824	71,524,661	139,878	97,915	16,098,707	53,453		
IRR	-	-	-	-	-	-		
MCC	90	134,964,993	48,256	33,779	30,377,800	767,749		
Total	**57,376**	**692,653,389**	**1,073,007**	**751,105**	**155,901,809**	**1,836,818**		
Network	Sub transmission Lines						$16,452,300	$596,810
Network	Sub transmission Cables						$20,188,405	$610,782
Network	Zone Substation						$35,985,124	$1,787,546
Network	Distribution LV Lines						$30,962,474	$1,250,617
Network	Distribution LV cables						$94,598,676	$3,170,344
Network	Distribution substations and transformers						$33,079,142	$950,327
Network	Distribution switchgear						$37,179,409	$1,462,195
Network	Other network assets						$8,608,388	$381,905
Non-Network	Non-Network assets						$13,028,018	$973,170
Total							**$290,081,936**	**$11,183,696**

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Table 23: Quantities allocated to the Required Revenue at the Castle Hill GXP for the pricing year.

Consumer Group	No of ICP / supplies	Consumption (kWh)	Installed capacity (kVA)	Asset utilisation (kW)	AMD (kW)	Line length (meters)	RAB	RAB Depreciation
LIG	1	13,348	15	11	3,004	435		
RES	198	1,653,677	3,070	2,149	372,208	5,651		
GEN(GC1)	32	283,669	355	249	63,848	1,304		
GEN(GC2)	17	397,644	708	496	89,501	869		
GEN(GC3)	8	463,270	906	634	104,272	435		
IRR	-	-	-	-	-	-		
MCC	-	-	-	-	-	-		
Total	**256**	**2,811,609**	**5,054**	**3,538**	**632,834**	**8,694**		
Network	Sub transmission Lines						$77,492	$2,811
Network	Sub transmission Cables						$95,090	$2,877
Network	Zone Substation						$169,495	$8,420
Network	Distribution LV Lines						$145,837	$5,891
Network	Distribution LV cables						$445,572	$14,933
Network	Distribution substations and transformers						$155,807	$4,476
Network	Distribution switchgear						$175,120	$6,887
Network	Other network assets						$40,547	$1,799
Non-Network	Non-Network assets						$61,364	$4,584
Total							**$1,366,323**	**$52,677**

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Table 24: Quantities allocated to the Required Revenue at the Coleridge GXP for the pricing year.

Consumer Group	No of ICP / supplies	Consumption (kWh)	Installed capacity (kVA)	Asset utilisation (kW)	AMD (kW)	Line length (meters)	RAB	RAB Depreciation
LIG	1	13,348	15	11	3,004	185		
RES	91	834,918	1,550	1,085	187,923	2,400		
GEN(GC1)	16	140,636	176	123	31,654	554		
GEN(GC2)	20	430,219	766	536	96,833	369		
GEN(GC3)	2	94,597	185	130	21,292	185		
IRR	-	-	-	-	-	-		
MCC	-	-	-	-	-	-		
Total	**130**	**1,513,719**	**2,692**	**1,884**	**340,706**	**3,692**		
Network	Sub transmission Lines						$41,276	$1,497
Network	Sub transmission Cables						$50,649	$1,532
Network	Zone Substation						$90,281	$4,485
Network	Distribution LV Lines						$77,680	$3,138
Network	Distribution LV cables						$237,333	$7,954
Network	Distribution substations and transformers						$82,990	$2,384
Network	Distribution switchgear						$93,277	$3,668
Network	Other network assets						$21,597	$958
Non-Network	Non-Network assets						$32,685	$2,442
Total							**$727,768**	**$28,058**

Table 25: Quantities allocated to the Required Revenue at the Hororata GXP for the pricing year.

Consumer Group	No of ICP / supplies	Consumption (kWh)	Installed capacity (kVA)	Asset utilisation (kW)	AMD (kW)	Line length (meters)	RAB	RAB Depreciation
LIG	5	26,696	30	21	6,009	3,054		
RES	3,057	30,861,819	57,294	40,106	6,946,351	73,290		
GEN(GC1)	511	4,881,502	6,109	4,276	1,098,724	6,107		
GEN(GC2)	465	9,679,931	17,235	12,065	2,178,750	3,054		
GEN(GC3)	161	10,530,966	20,595	14,417	2,370,300	6,107		
IRR	263	60,207,122	45,252	31,676	13,551,365	15,269		
MCC	6	66,240,693	23,684	16,579	14,909,396	-		
Total	**4,468**	**182,428,728**	**170,199**	**119,139**	**41,060,896**	**106,881**		
Network	Sub transmission Lines						$2,609,643	$94,665
Network	Sub transmission Cables						$3,202,259	$96,881
Network	Zone Substation						$5,707,914	$283,538
Network	Distribution LV Lines						$4,911,228	$198,371
Network	Distribution LV cables						$15,005,121	$502,876
Network	Distribution substations and transformers						$5,246,971	$150,740
Network	Distribution switchgear						$5,897,350	$231,932
Network	Other network assets						$1,365,451	$60,577
Non-Network	Non-Network assets						$2,066,488	$154,363
Total							**$46,012,426**	**$1,773,944**

Table 26: Quantities allocated to the Required Revenue at the Islington GXP for the pricing year.

Consumer Group	No of ICP / supplies	Consumption (kWh)	Installed capacity (kVA)	Asset utilisation (kW)	AMD (kW)	Line length (meters)	RAB	RAB Depreciation
LIG	12	1,087,433	1,222	855	244,759	79,501		
RES	140,320	1,199,812,327	2,227,414	1,559,190	270,052,691	2,703,048		
GEN(GC1)	6,458	59,982,783	75,066	52,546	13,500,871	159,003		
GEN(GC2)	7,993	184,156,825	327,889	229,522	41,449,854	79,501		
GEN(GC3)	3,143	286,948,484	561,174	392,822	64,586,110	159,003		
IRR	429	40,895,127	30,737	21,516	9,204,639	15,269		
MCC	392	679,218,821	242,851	169,996	152,877,968	3,947,537		
Total	**158,747**	**2,452,101,800**	**3,466,353**	**2,426,447**	**551,916,892**	**7,142,862**		
Network	Sub transmission Lines						$53,149,216	$1,927,996
Network	Sub transmission Cables						$65,218,716	$1,973,133
Network	Zone Substation						$116,250,074	$5,774,675
Network	Distribution LV Lines						$100,024,384	$4,040,123
Network	Distribution LV cables						$305,601,365	$10,241,808
Network	Distribution substations and transformers						$106,862,287	$3,070,035
Network	Distribution switchgear						$120,108,215	$4,723,626
Network	Other network assets						$27,809,428	$1,233,746
Non-Network	Non-Network assets						$42,087,060	$3,143,830
Total							**$937,110,746**	**$36,128,972**

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Table 27: 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)	AMD (kW)	Line length (meters)	RAB	RAB Depreciation
LIG	2	26,696	30	21	6,009	768		
RES	751	7,148,518	13,271	9,290	1,608,982	18,422		
GEN(GC1)	97	848,609	1,062	743	191,004	1,535		
GEN(GC2)	77	1,571,479	2,798	1,959	353,707	768		
GEN(GC3)	25	1,782,006	3,485	2,440	401,092	1,535		
IRR	21	3,348,832	2,517	1,762	753,752	7,676		
MCC	-	-	-	-	-	-		
Total	**973**	**14,726,141**	**23,163**	**16,214**	**3,314,547**	**30,703**		
Network	Sub transmission Lines						$355,156	$12,883
Network	Sub transmission Cables						$435,807	$13,185
Network	Zone Substation						$776,811	$38,588
Network	Distribution LV Lines						$668,387	$26,997
Network	Distribution LV cables						$2,042,101	$68,438
Network	Distribution substations and transformers						$714,079	$20,515
Network	Distribution switchgear						$802,592	$31,564
Network	Other network assets						$185,829	$8,244
Non-Network	Non-Network assets						$281,236	$21,008
Total							**$6,261,998**	**$241,422**

Table28: 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)	AMD (kW)	Line length (meters)	RAB	RAB Depreciation
LIG	1	13,348	15	11	3,004	768		
RES	1,281	13,379,703	24,839	17,387	3,011,492	18,422		
GEN(GC1)	217	8,894,418	11,131	7,792	2,001,948	1,535		
GEN(GC2)	297	5,277,767	9,397	6,578	1,187,915	768		
GEN(GC3)	75	12,892,315	25,213	17,649	2,901,791	1,535		
IRR	338	29,935,920	22,500	15,750	6,737,950.16	7,676		
MCC	3	5,073,493	1,814	1,270	1,141,937	-		
Total	**2,212**	**75,466,964**	**94,909**	**66,436**	**16,986,037**	**30,703**		
Network	Sub transmission Lines						$1,455,229	$52,789
Network	Sub transmission Cables						$1,785,693	$54,025
Network	Zone Substation						$3,182,936	$158,111
Network	Distribution LV Lines						$2,738,675	$110,619
Network	Distribution LV cables						$8,367,388	$280,421
Network	Distribution substations and transformers						$2,925,897	$84,058
Network	Distribution switchgear						$3,288,572	$129,333
Network	Other network assets						$761,424	$33,780
Non-Network	Non-Network assets						$1,152,347	$86,078
Total							**$25,658,161**	**$989,214**

6.2 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.

6.2.1 Why do we apply a uniform delivery charge

Orion has elected to continue applying a uniform delivery charge, that is indifferent of location and inclusive of both distribution 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 granulated prices.

6.2.2 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 29 compares the fixed and variable split applied in this pricing year to the prior pricing year.

Table 29: Comparison of the fixed / variable split between pricing years:

Consumer Group	*2024/25*		*2023/24*	
	Fixed	*Variable*	*Fixed*	*Variable*
LIG	28%	72%	26%	74%
RES	25%	75%	21%	79%
GEN(GC1)	36%	64%	33%	67%
GEN(GC2)	18%	82%	17%	83%
GEN(GC3)	24%	76%	6%	94%
IRR	19%	81%	29%	71%
MCC	100%	0%	100%	0%
LCC	100%	0%	100%	0%

More discussion on the evolution of our prices can be found in Chapter 3 of this Pricing Methodology.

Orion

6.2.3 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 29 above shows the proportion of the Target Revenue recovered through fixed charges for each consumer group.

Each connection category (excluding Major and LCC connections) have five variable prices- weekend, peak, shoulder, off-peak, super off-peak units per kWh. Accordingly, the costs are allocated to variable charges across each consumer group's variable price components. Table 30 shows the allocation to variable pricings for the pricing year.

Table 30: Allocation of variable prices (i.e. TOU) for the pricing year

Consumer Group	*Weekend*	*Peak*	*Shoulder*	*Off Peak*	*Super off peak*
LIG	24%	19%	10%	30%	17%
RES	22%	35%	31%	8%	4%
GEN(GC1)	20%	34%	35%	7%	4%
GEN(GC2)	17%	35%	38%	6%	4%
GEN(GC3)	27%	32%	30%	7%	4%
IRR	25%	27%	24%	15%	8%
MCC	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
LCC	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*

Table31 shows the breakdown of Target Revenue recovered through fixed and variable revenue.

Consumer Group	*Fixed Revenue ('000)*	*Variable Revenue (000)*	*Target Revenue ('000)*
LIG	$259,021	$650,297	$909,318
RES	$37,305,723	$110,197,358	$147,503,081
GEN(GC1)	$3,560,048	$6,204,404	$9,764,452
GEN(GC2)	$4,223,313	$18,622,080	$22,845,393
GEN(GC3)	$6,019,280	$18,621,582	$24,640,862
IRR	$1,887,679	$8,145,404	$10,033,083
MCC	$38,121,189	$-	$38,121,189
LCC	$3,882,270	$-	$3,882,270
TOTAL	**$95,258,523**	**$162,441,125**	**$257,699,648**

Orion

6.2.4 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 three-step process to smooth variable prices:

Step 1 — set the initial allocations based on the future pricing strategy.

Step 2 — adjust prices to comply with the transition arrangement of low fixed charge regulations.

Step 3 — spread the under-recovered revenue from applying step 2 across the SME consumers in a fair manner that avoids bill shock to the consumers in those consumer groups.

6.2.5 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)
- Consumption Peak (kWh)
- Consumption Shoulder (kWh)
- Consumption Off-Peak (kWh)
- Consumption Super off-peak (kWh)

Table 32: Forecast quantities for this pricing year

Consumer Group	LIG	RES	GEN(GC1)	GEN(GC2)	GEN(GC3)	IRR	MCC
Number of ICPs/ lamps controlled	*54,332*	*35,058*	*8,205*	*9,737*	*3,694*	*0*	*0*
Number of ICPs/ lamps uncontrolled	*0*	*160,851*	*3,210*	*2,095*	*569*	*0*	*554*
Consumption Weekend (kWh)	*4,092,000*	*446,937,072*	*25,179,553*	*75,538,660*	*75,538,660*	*35,764,944*	*0*
Consumption Peak (kWh)	*3,179,000*	*554,221,378*	*31,223,740*	*93,671,219*	*93,671,219*	*38,219,046*	*0*
Consumption Shoulder (kWh)	*1,658,000*	*411,643,296*	*23,191,172*	*69,573,515*	*69,573,515*	*33,675,131*	*0*
Consumption Off Peak (kWh)	*5,191,000*	*228,810,330*	*12,890,723*	*38,672,169*	*38,672,169*	*21,475,611*	*0*
Consumption Super Off Peak (kWh)	*2,923,000*	*95,154,892*	*5,360,839*	*16,082,517*	*16,082,517*	*11,272,353*	*0*
Installed capacity (kVA)	*0*	*0*	*0*	*0*	*0*	*76,484*	*385,340*
Demand (kVA)	*0*	*0*	*0*	*0*	*0*	*0*	*306,982*

6.2.6 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 33 provides the allocation and proportion of the target revenue between connection groups

Consumer Group	Description	Target Revenue	Proportion
LIG	Streetlights	$909,318	0%
RES	Residential	$147,503,081	57%
GEN(GC1)	SME (0 - 15kVA)	$9,764,452	4%
GEN(GC2)	SME (16kVA-69kVA)	$22,845,393	9%
GEN(GC3)	SME (>69kVA)	$24,640,862	10%
IRR	Irrigation	$10,033,083	4%
MCC	Major customers	$38,121,189	15%
LCC	Large capacity connections	$3,882,270	2%
Total Target Revenue		$257,699,648	100%

6.3 Change in Target Revenue

Target Revenue has increased by $ 21.2m (or+8%) for this pricing year. Table 34 shows Target Revenue's movements within consumer groups pricing years.

Table 34 Target Revenue's movements within connection groups pricing years.

Consumer Group	2024/25	2023/24	Movement
LIG	$909,318	$2,542,318	-60%
RES	$147,503,081	$130,169,820	13%
GEN(GC1)	$9,764,452	$6,207,533	57%
GEN(GC2)	$22,845,393	$20,635,978	11%
GEN(GC3)	$24,640,862	$25,486,118	-3%
IRR	$10,033,083	$13,079,086	-23%
MCC	$38,121,189	$34,595,921	10%
LCC	$3,882,270	$3,844,740	1%
Total Target Revenue	$257,699,648	$236,561,515	8%

6.4 Variance within consumer groups between required revenue and target revenue

As discussed in section 6.2.4 on page 48, we smooth our prices to meet the low fixed charge regulations, recover our required revenue and avoid bill shock to consumers as we evolve our prices to be more cost reflective. This pricing year, we chose to transition the cross-subsidisation between consumer groups. As a result, this pricing year has a variance between the Required Revenue and the Target Revenue.

Table 35 compares the Revenue Requirement and Target Revenue by connection grouping for the pricing year:

Consumer Group	Target revenue	Required Revenue	Variance
LIG	$909,318	$484,163	$425,155
RES	$147,503,081	$146,452,718	$1,050,364
GEN(GC1)	$9,764,452	$6,957,226	$2,807,226
GEN(GC2)	$22,845,393	$21,754,639	$1,090,753
GEN(GC3)	$24,640,862	$33,856,040	-$9,215,178
IRR	$10,033,083	$5,722,888	$4,310,194
MCC	$38,121,189	$38,673,189	-$552,000
LCC	$3,882,270	$3,882,270	$-
Total Target Revenue	$257,699,648	$257,783,133	-$83,486

6.4.1 Removing the cross-subsidisation of Residential connection

Last pricing year, we passed on the 100% increase in the fixed daily supply charge as permitted by the transition arrangements of the low fixed charge regulations. We moderated the overall increase in residential consumers' bills by keeping night and weekend consumption charges unchanged. We accepted our decision not to change consumption charges resulted in us over-recovering the true costs to serve residential consumers. We also signalled our intention to unwind the cross subsidisation of residential consumers over future pricing years and evolve our prices to be more cost reflective. In this pricing year, we have begun removal of the cross-subsidisation and have increased both the fixed and variable components of Residential consumers' prices. As discussed in section 3.7, this was not a decision made lightly, and it is a decision we believe is in the long-term best interests of consumers.

6.4.2 Removing the cross subsidisation of SME connection

Because we use GXP Pricing, consumption for the SME consumer group is included as part of determining the mass market variable rates. Accordingly, the consumption charges for the SME connection group must be the same as those for the Residential connection group. In this pricing year, we have chosen to take the step to decrease the cross-subsidisation of Residential and SME consumers and have increased both the fixed and variable components of small commercial connections' prices.

7. Credits for export

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. The credits do not represent the purchase of electricity, and exporting customers are able to separately negotiate to sell exported energy, 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 customers that use our delivery service. The cost allocations in section 6 above show the assignment of these costs to connection categories.

We do not specifically charge customers for exporting electricity to our network; however, customers 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 customer, is based on export demands where this is more than double the load demands, so excess peak export can increase delivery charges.

We do not maintain a separate category for customers with distributed generation. Customers in any category can install distributed generation, and our pricing approach is applied in addition to the pricing under the category.

7.1 Standard export credit prices

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 LRAIC which we calculate as $77 per kW per year (as noted in Appendix G).

Some of the costs represented in this LRAIC 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 at approximately a third of the full LRAIC.

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 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.

The export credit prices, and structure of pricing is shown in the "Export credit schedule" included in Appendix A.

Orion

Appendix A - Price schedules

Orion

Electricity delivery price schedule for Orion NZ Ltd

(applicable from 1 April 2024)

This schedule lists the wholesale 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 electrcity 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	Pass-through & Recoverable Price	Transmission Price	Delivery Price	Unit of measure
Fixed Daily Charges - Per Price Group							
Streetlighting							
Fixed charge	LIG	STFXD	$ 0.0123	$ 0.0002	$ 0.0005	$ 0.0131	$/con/day
Residential General Connections							
Residential Connection - Fixed Daily Charge - Uncontrolled	URES	URESFXD	$ 0.4236	$ 0.0287	$ 0.1475	$ 0.5998	$/con/day
Residential Connection - Fixed Daily Charge - Controlled	RES	RESFXD	$ 0.3567	$ 0.0149	$ 0.1320	$ 0.5036	$/con/day
Small General Connections							
Small Connection up to 15 kVA - Fixed Daily Charge - Uncontrolled	UGENGC1	UGC1FXD	$ 0.6897	$ 0.0330	$ 0.2181	$ 0.9408	$/con/day
Small Connection up to 15 kVA - Fixed Daily Charge - Controlled	GENGC1	GC1FXD	$ 0.5949	$ 0.0085	$ 0.1333	$ 0.7367	$/con/day
Medium General Connections							
Medium Connection 16 kVA up to 69 kVA - Fixed Daily Charge - Uncontrolled	UGENGC2	UGC2FXD	$ 0.7791	$ 0.0220	$ 0.2061	$ 1.0071	$/con/day
Medium Connection 16 kVA up to 69 kVA - Fixed Daily Charge - Controlled	GENGC2	GC2FXD	$ 0.3903	$ 0.0122	$ 0.4632	$ 0.8658	$/con/day
Large General Connections							
Large Connection >70 kVA - Fixed Daily Charge - Uncontrolled	UGENGC3	UGC3FXD	$ 1.9492	$ 0.3171	$ 1.7055	$ 3.9718	$/con/day
Large Connection >70 kVA - Fixed Daily Charge - Controlled	GENGC3	GC3FXD	$ 2.1808	$ 0.3272	$ 0.7305	$ 3.2386	$/con/day
Irrigation Connections							
Capacity Charge	IRR	ICCAP	$ 0.1321	$ 0.0128	$ 0.0447	$ 0.1897	$/kW/day*
Power factor correction rebate		ICPFC	$ (0.1197)	$ -	$ -	$ (0.1197)	$/kVAR/day*
Interruptibility rebate		ICIRR	$ (0.0296)	$ -	$ -	$ (0.0296)	$/kW/day*
* applied to 1 October to 31 March only							
Time-of-Use Charges - Irrigation, Streetlighting and General connections							
Weekend [3]		WKD	$ 0.0214	$ 0.0012	$ 0.0075	$ 0.03012	$/kWh
Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm)		P	$ 0.0854	$ 0.0048	$ 0.0299	$ 0.12020	$/kWh
Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm)		SH	$ 0.0492	$ 0.0028	$ 0.0181	$ 0.07007	$/kWh
Off Peak (Mon to Fri, 10:00pm to 3:00am)		OP	$ 0.0040	$ 0.0002	$ 0.0014	$ 0.00558	$/kWh
Super Off Peak (Anytime between 3:00am to 5:00am)		SOP	$ -	$ -	$ -	$ -	$/kWh
Major Connections and Embedded Networks	MCC						
Fixed charge		MCFXD	$ 20.0000	$ -	$ -	$ 20.0000	$/con/day
Fixed charge (additional connections)		MCFXDA	$ 15.0000	$ -	$ -	$ 15.0000	$/con/day
Extra switches		EQESW	$ 3.9000	$ -	$ -	$ 3.9000	$/switch/day
11kV Metering equipment		EQMET	$ 5.3000	$ -	$ -	$ 5.3000	$/con/day
11kV Underground cabling		EQUGC	$ 4.7000	$ -	$ -	$ 4.7000	$/km/day
11kV Overhead lines		EQOHL	$ 3.5000	$ -	$ -	$ 3.5000	$/km/day
Transformer capacity		EQTFC	$ 0.0118	$ -	$ -	$ 0.0118	$/kVA/day
Peak charge (control period demand)		MCCPD	$ 0.2074	$ 0.0408	$ 0.0492	$ 0.2974	$/kVA/day
Nominated maximum demand		MCNMD	$ 0.0974	$ 0.0008	$ 0.0010	$ 0.0992	$/kVA/day
Metered maximum demand		MCMMD	$ 0.0638	$ 0.0130	$ 0.0157	$ 0.0925	$/kVA/day
Large Capacity Connections	LCC						
Individually assessed prices advised and charged directly to the customers							

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. Weekend means all trading periods except for Super Off Peak between 3am -5am.

Export credit schedule for Orion NZ Ltd

(applicable from 1 April 2024)

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. Our prices for credits are:

(excluding GST)

Generator rated output	Period applied	Credit prices	Price Component Code[3]	Unit of measure
0 - 30kW generation[2]				
Anytime credits (without PV), or	Anytime	0.00280	EXPA	$/kWh
Anytime credits (with PV)	(24 hours, 7 days)	0.00000	EXPAPV	$/kWh
0 - 30kW generation[2]				
Peak period credits (with or without PV)	Chargeable peak period (Mon to Fri 7am to 11am and 5pm to 10pm)	0.00950	EXPPP	$/kWh
30 - 750kW Control period credits[4]				
- real power, plus	Chargeable control period	0.0676	EXPCP1	$/kW/day
- reactive power[5]		0.0222	EXPCP2	$/kVAr/day
above 750kW	*Individually assessed prices provided on application*			

Notes for export credit pricing

1. Full details, including metering requirements and how credit prices are applied, are available in our *Export Credits Policy* document available on our website.
2. Small 0 to 30kW generators may elect (in advance) to receive the alternative peak period based credits, subject to the installation of appropriate metering to record peak period export.
3. The price component code is used in our mandatory 'electricity information exchange protocol' files.
4. Control period credits are assessed during control periods and applied as an annual credit at 365/366 times the daily credit price.
5. The credit quantity for reactive power (kVAr) export is limited to 33% of the credit quantity for real power (kW) export in each half hour period, the equivalent of exporting with a 0.95 lagging power factor.
6. Approximately 11 connections are approved for export credits.

Orion

Schedule of Changes to electricity prices Connection categories and price components	Units	1 April 2023 to 31 March 2024 Delivery price (excl GST)	from 1 April 2024 Delivery price (excl GST)
Streetlighting connections (approx 54,332 connections)			
Fixed charge	$/con/day	0.0970	0.0131
Peak charge (peak period demand)[2]	$/kW/day	0.0928	n/a
Volume charges[2]			
Weekdays (Mon to Fri, 7am to 9pm)	$/kWh	0.09414	n/a
Nights & weekends (Sat & Sun)	$/kWh	0.01844	n/a
Time-of-Use Volume Charges[2]			
Weekend[3]	$/kWh	n/a	0.03012
Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm)	$/kWh	n/a	0.12020
Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm)	$/kWh	n/a	0.07007
Off Peak (Mon to Fri, 10:00pm to 3:00am)	$/kWh	n/a	0.00558
Super Off Peak (Anytime between 3:00am to 5:00am)	$/kWh	n/a	-
General connections (approx 223,418 connections)			
Fixed charge			
Residential General Connection			
Residential Connection - Fixed Daily Charge - Uncontrolled	$/con/day	0.4500	0.5998
Residential Connection - Fixed Daily Charge - Controlled	$/con/day	0.4500	0.5036
Small General Connection			
Small Connection up to 15 kVA - Fixed Daily Charge - Uncontrolled	$/con/day	0.6100	0.9408
Small Connection up to 15 kVA - Fixed Daily Charge - Controlled	$/con/day	0.6100	0.7367
Medium General Connection			
Medium Connection 16 kVA up to 69 kVA - Fixed Daily Charge - Uncontrolled	$/con/day	0.9832	1.0071
Medium Connection 16 kVA up to 69 kVA - Fixed Daily Charge - Controlled	$/con/day	0.9832	0.8658
Large General Connections			
Large Connection >70 kVA - Fixed Daily Charge - Uncontrolled	$/con/day	1.1835	3.9718
Large Connection >70 kVA - Fixed Daily Charge - Controlled	$/con/day	1.1835	3.2386
Peak charge (peak period demand)[2]	$/kW/day	0.0928	n/a
Volume charges[2]			
Weekdays (Mon to Fri, 7am to 9pm)	$/kWh	0.09414	n/a
Nights & weekends (Sat & Sun)	$/kWh	0.01844	n/a
Time-of-Use Volume Charges[2]			
Weekend[3]	$/kWh	n/a	0.03012
Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm)	$/kWh	n/a	0.12020
Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm)	$/kWh	n/a	0.07007
Off Peak (Mon to Fri, 10:00pm to 3:00am)	$/kWh	n/a	0.00558
Super Off Peak (Anytime between 3:00am to 5:00am)	$/kWh	n/a	-
Low power factor charge	$/kVAr/day	0.2000	
Irrigation connections (approx 1,036 connections)			
Capacity charge*	$/kW/day	0.2933	0.1897
Volume charges[2]			
Weekdays (Mon to Fri, 7am to 9pm)	$/kWh	0.09414	n/a
Nights & weekends (Sat & Sun)	$/kWh	0.01844	n/a
Time-of-Use Volume Charges[2]			
Weekend[3]	$/kWh	n/a	0.03012
Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm)	$/kWh	n/a	0.12020
Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm)	$/kWh	n/a	0.07007
Off Peak (Mon to Fri, 10:00pm to 3:00am)	$/kWh	n/a	0.00558
Super Off Peak (Anytime between 3:00am to 5:00am)	$/kWh	n/a	-
Rebates			
Power factor correction rebate*	$/kVAr/day	(0.1083)	(0.1197)
Interruptibility rebate*	$/kW/day	(0.0271)	(0.0296)
* applied from 1 October to 31 March only			
Major customer and embedded network connections (approx 554 connections)			
Fixed charge	$/con/day	15.0000	20.0000
Fixed charge (additional connections)	$/con/day	10.0000	15.0000
Extra switches	$/switch/day	3.6700	3.9000
11kV Metering equipment	$/con/day	5.0200	5.3000
11kV Underground cabling	$/km/day	4.4000	4.7000
11kV Overhead lines	$/km/day	3.1800	3.5000
Transformer capacity	$/kVA/day	0.0122	0.0118
Peak charge (control period demand)	$/kVA/day	0.2949	0.2974
Nominated maximum demand	$/kVA/day	0.1073	0.0992
Metered maximum demand	$/kVA/day	0.0748	0.0925
Export credits (approx 12 connections)			
0 - 30kW generation			
Anytime credits (without PV), *or*	$/kWh	(0.00260)	(0.00280)
Anytime credits (with PV), *or*	$/kWh	(0.00010)	-
Peak period credits (with or without PV)	$/kWh	(0.18300)	(0.00950)
30 - 750kW Control period credits	$/kW/day	(0.0625)	(0.0676)
plus	$/kVAr/day	(0.0205)	(0.0222)
Miscellaneous			
Monthly invoice and contract charge to retailers and directly contracted major customers	$/invoice	49.00	-
Failure to pay notice	$/notice	123.00	-
Default and termination notice	$/notice	100.00	-

Orion

Appendix B - Regulatory requirements: pricing principles and information disclosure

In May 2022, the Authority released its Edition 2.1, Practice Note updated to—

'Provide further guidance to assist distributors with applying the 2019 Distribution Pricing Principles.'

The Practice note provides context for the Authority's Pricing Principles, including that for each of the four principles, prices should:

- signal the economic costs of service provision
- recover residual costs in a manner that least distorts network use
- respond to end users' economic value of services and price/quality trade-offs
- develop in a transparent manner having regard for impacts on consumers.

We have reviewed our pricing for consistency with the Authority's 2019 Pricing Principles. In the following sections, we provide our interpretation of each principle, an assessment of how our current prices are consistent with the principle, and how we intend to improve as we implement and execute our five-year pricing strategy.

The information disclosure requirements require us to prepare and disclose a statement of the level of alignment with the Authority's pricing principles, and this is set out below.

Electricity Authority pricing principles

The following are the published Authority principles[19] and, below each, a comment on our alignment:

"(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 these principles, 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 Appendix H for more detail) 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 (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,

[19] As published in June 2019: https://www.ea.govt.nz/dmsdocument/25179-decision-paper-more-efficient-distribution-network-pricing-principles-and-practice-pdf

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.

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 have estimated the boundaries for each connection category as follows

Connection category	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	781			
	Customer service, billing, and admin	470		Estimated cost per kWh*	$0.68
	Transpower residual charge,benefit based charge and transitional cap	260		Annual volume (MWh)	17,043
		1,512	**909**	Total cost	**11,589**
General connections	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	17,086			
	Customer service, billing, and admin	22,959		Estimated cost per kWh*	$0.48
	Transpower residual charge,benefit based charge and transitional cap	35,801		Annual volume (MWh)	2,421,689
		75,846	**204,754**	Total cost	**1,162,411**
Irrigation connections	Assuming that distribution transformers and associated LV network assets can be abandoned			Reflecting geographic spread of load, an individual PV/Battery basis is assumed for each installation	
	Repair and maintenance costs	379			
	Customer service, billing, and admin	3,643		Estimated cost per kWh*	$0.68
	Transpower residual charge,benefit based charge and transitional cap	3,681		Annual volume (MWh)	140,407
		7,702	**10,003**	Total cost	**95,477**
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 supplimentary diesel generation	
	Repair and maintenance costs	956			
	Customer service, billing, and admin	3,953		Estimated cost per kWh*	$0.48
	Transpower residual charge,benefit based charge and transitional cap	10,040		Annual volume (MWh)	892,340
		14,949	**38,121**	Total cost	**428,323**
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	208			
	Customer service, billing, and admin	41		Estimated cost per kWh*	$0.38
	Transpower residual charge,benefit based charge and transitional cap	2,521		Annual volume (MWh)	178,232
		2,770	**3,882**	Total cost	**67,728**

* 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

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 6.8

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 customers 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 customers 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 customers to efficiently use our network to share their local renewable energy resources.

(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. For this update we have simply put through a universal 15 cents per day increase in the residential general connection fixed charge. 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 customer’s own peak, which is less subject to demand response than other measures.

(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.

Orion 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 customers. These connections have a significant impact on the network to which they connect such that significant additional investment by Orion is required. Customers that elect to go ahead with the supply will do so on the basis that the service provides economic value.

Customers in our major customer price category have the option to provide a range of their own connection equipment (transformers, switchgear, metering interfaces). Customers 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 customer 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 customer in light of the costs associated with the services. These options align with principle (c)(ii).

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

- General customers 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 peak price, weekday volume price, and our night and weekend volume price).
- Irrigation customers can choose to allow Orion to turn off their pumps during system emergencies, and the lower service level is reflected in credits that we pay.

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

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

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

Orion openly discloses its pricing methodology and actively works to promote a stable and long-term pricing basis, recognising the impact on customers 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 our general connection pricing structure is largely unchanged since its inception in 1999;

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 customers; and

iv. price changes are only enacted after stakeholder consultation.

In addition to this methodology document, we publish a plain English network pricing guide. Our asset management plan sets out our longer-term plans for the network and this includes indications of key cost drivers. We conduct twice-yearly major customer seminars at which pricing and other network related matters are discussed.

Orion applies 'GXP billing' for most connections where charges are based on electricity volumes injected into the Orion network (principally at Transpower grid exit points). The chargeable quantities for most connections therefore use the results of the wholesale market energy reconciliation process, which is governed by the Electricity Industry Participation Code. This provides administrative efficiencies and a very low transaction cost that is reflected in our charges. Orion has relatively few connection categories (and 99% of connections are "general" connections) and there are relatively few prices within each category.

In terms of uptake incentives, when prices reflect costs, customers 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 customers, 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 C - Commerce Commission information disclosure requirements

This section describes in a tabular format how this methodology document addresses key elements of the Commission's information disclosure requirements. Some of this information is included in the body of this methodology document above.

The relevant sections of the determination are 2.4.1 to 2.4.5.

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 3.3, 5, 6 and Appendix A.
2.4.1 (3)	See sections 4.2 for non-standard contracts. See section 4.5 and 7 for distributed generation.
2.4.1 (4)	See section 4.3.
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 4 through 6.
2.4.3 (2)	See Appendix B.
2.4.3 (3)	See section 5.
2.4.3 (4)	See section 5.
2.4.3 (5) (a) & (b)	See section 4.
2.4.3 (6)	See sections 3, 5.2 and 6.
2.4.3 (7)	See section 6.
2.4.3 (8)	See section 6. This shows amounts rather than proportions.
2.4.4 (1) to (3)	See sections 2, 3 and Appendix D, E and F.
2.4.5 (1) (a) to (c)	See sections 4.2.
2.4.5 (2) (a) & (b)	See section 4.
2.4.5 (3) (a) & (b)	See sections 4.5, 7 and Appendix A.

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Appendix D – Our pricing roadmap

WORK PLAN	SHORT TERM1-2 YEARS	MEDIUM TERM 2-5 YEARS	LONG TERM 5+ YEARS
Consultation	Ongoing	Ongoing	Ongoing
Cost of supply model	**Implement**	Refine	Review
More connection categories	Introduce three new SME price codes in the General Connection category (1 April 2023)	Introduce a Residential category and new price code(s)	Sharing of local renewable energy resources Flexibility
Shift to a form ICP pricing	Develop system and operating platform	Implement a hybrid pricing structure	Review and refine
Differentiate volumes for connection categories	Model	Implement	Review and refine
Transmission pricing	**Implement**	Review	Review
De-weight peak pricing	**Remove peak charge**	Remove peak charge	Review
TOU pricing	**Peak** **Off Peak** **Shoulder** **Super Off Peak:** **All-inclusive weekend pricing**	Implement	Review
Systems upgrade	Discovery and design	Implement	Review
Adapt to evolving pricing	LFC phase out EV Uptake Flexibility services discovery	LFC phase out Distributed generation Flexibility services seeded	Decarbonisation Flexibility services at scale
Impact analysis	Review	Review	Review

Appendix E– Pricing Strategy

Our refreshed pricing strategy was formally approved by the Orion board at its meeting on 29 September 2021. The strategy is set out below.

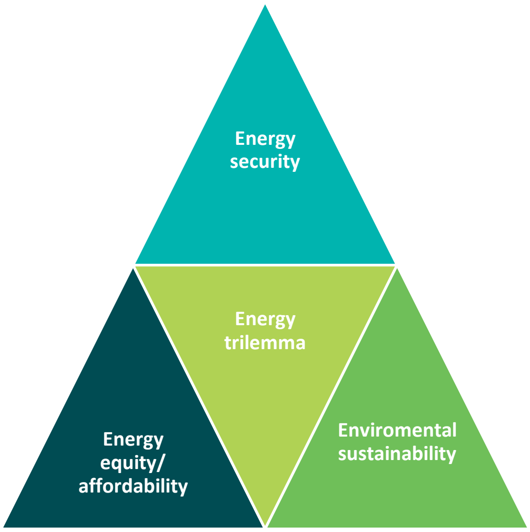
Our strategy for electricity delivery pricing

from 1 April 2022

We set and adjust our prices to support our group strategy and purpose:

powering a cleaner and brighter future for our community.

With a strong focus on sustainability, we recognise the role our pricing plays in supporting the decarbonisation transition within our community. Through this transition we seek to achieve an appropriate balance between the limbs of the energy trilemma, and in particular the trade-off between sustainability and affordability.



Our overall price path is set by the Commerce Commission to reflect our long-term economic costs ensuring that we have appropriate incentives to invest in and maintain our network in the long-term interests of customers. This pricing strategy and supporting road map set out how we structure prices within the overall cap.

We have established **primary strategic objectives** which guide our pricing development, these are:

- provide incentives for electrification (and decarbonisation) of our transport fleet and process heat,

- recognise customer expectations, technology choices and changing use of the network, and in particular, transition our pricing to enable customers to efficiently use our network to share their developing local renewable energy resources,

- balance this with consideration for the impact that our pricing and price changes have on vulnerable customers within our community (refer to residential customer impacts section below), and

- take account of the incentives for improved insulation, energy efficient appliances, LED lighting, and renewable generation.

Pricing Strategy

Reform prices to support the decarbonisation of our economy, help our community to develop and share local renewable energy resources, while recognising and mitigating the impact that changes have on vulnerable members of our community.

Alongside the trade-offs within these objectives, we also consider and recognise:

- the economic efficiency of our pricing, providing customers with appropriate incentives as to where and when they should utilise our service. We:
  - set prices to reflect costs associated with peak loads and congestion,
  - use capital contributions to reflect costs associated with different density areas (particularly urban vs rural) as these charges apply at the time customers are making decisions about where to connect.
- practical considerations, and apply prices to broad groups of customers with similar attributes,
- that all consumers should share in the benefits of greater utilisation of shared assets and economies of scale by ensuring that all customers contribute equitably when connecting, and all customers share in our fixed residual[20] costs,
- that consumers generally change their demand behaviour over relatively long periods of time, and it is important that we provide consistent pricing incentives, signal changes in advance and seek to mitigate impacts through staged transitions,
- the Government decision to phase out the low fixed charge regulations (which removes a significant restraint on how we structure our prices),
- the Electricity Authority's initiatives in relation to its pricing principles and associated practice note and scorecards,
- changes to the transmission pricing methodology for the national grid which we expect we will need to reflect in our pricing from April 2023,
- that retailers will re-bundle our pricing if they consider it too complex for customers.

[20] Fixed or dependent on the peak demand of individual customers or groups of customers

Key changes

The key areas of pricing reform that we are considering and developing in support of our strategy are:

Move away from volume pricing for recovery of residual costs

- encourage customers to share local renewable energy resources across the network
- reduce barriers to the uptake of electric vehicles
- avoid the burden of costs shifting to vulnerable customers over time (see below)

Simplify peak pricing

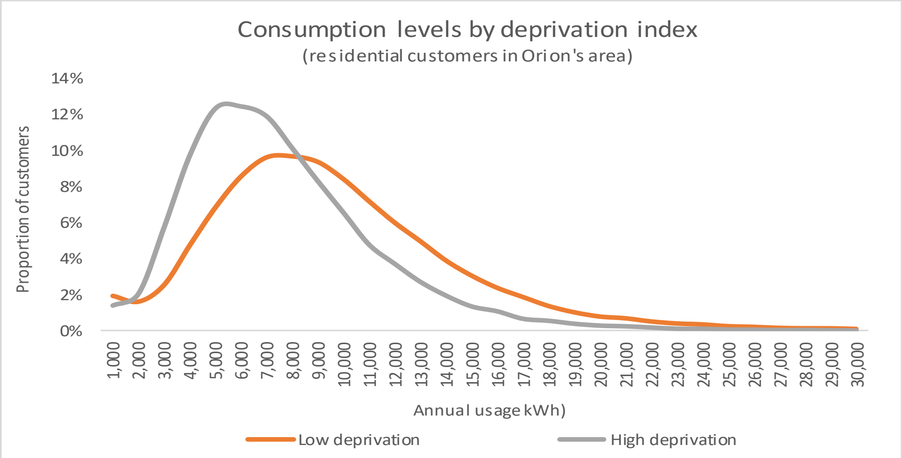
- instead use time-of-use volume pricing to provide clearer signals and rewards for residential customers that help ease congestion
- support overnight water heating and electric vehicle charging

Change the way we recover grid charges

- reflect Transpower's revised approach
- shifting the focus from peak pricing to a fixed approach
- supplemented with a volume component to reflect the lagged volume-based adjustments

Our pricing strategy specifically recognises the impact that our prices and changes to our prices has on ***vulnerable customers***. Through severe financial insecurity, these customers have a very limited ability to cope with increased costs and do not have the resources or flexibility to adjust their consumption to mitigate impacts.

Within our community we observe that our most deprived customers tend to be lower users than the less deprived categories.



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The dilemma this creates is that:

Reducing volume-based pricing and increasing fixed pricing means that our concentration of "low-use" vulnerable customers will pay more in the short term.	vs	Continuing with low fixed charges and high volume-based pricing will result in vulnerable customers paying more in the longer term, as other (less deprived) customer segments respond with energy efficient appliances, insulation and photovoltaic generation, and prices are adjusted to meet revenue requirements

We also recognise the need to provide consistent and stable price signals for customers (and the investment decisions that our customers have made against existing prices), and:

- that our volume-based pricing revenue is already among the lowest in New Zealand,
- that the inefficient investment outcomes caused by volume pricing are not occurring at the levels forecast by the Electricity Authority.

The primary mechanism to mitigate these impacts is to spread the changes over time.

A staged transition

- initial steps will be small
- volume price changes will be spread over a period of five years or more
- offsetting price changes will be applied where possible to mitigate impact

Impacts for customer categories

Our road map (refer to appendix C) provides more detail on our expected pricing reform. At a high level we expect the following impacts for our pricing categories over the next 5 years:

- for all categories, our regulated price path provides for a CPI linked revenue adjustment for the next 3 years, followed by a reset which will take account of underlying cost changes. We expect to reflect these adjustments, together with allowable wash-ups and incentives, in our annual price movements,

- for our streetlighting, general connection and irrigation price categories (including all residential connections), we expect to
  - progressively de-weight our volume-based pricing used to recover residual costs in favour of fixed and capacity-based components.
  - somewhat offsetting this reduction, we expect to reduce the peak price in favour of time-of-use volume prices to provide simpler signalling around peak and off-peak usage.
  - for recovery of transmission costs, we expect to phase out the transmission component in the peak charge to instead recover costs through a combination of fixed and volume-based charges.

- for our major customer connections, we expect to phase out the peak transmission component which makes up about 45% of the current peak charge to instead recover costs through a combination of fixed and volume-based charges.

Appendix F– Previous Pricing Strategy

The disclosure requirements require us to show changes to our pricing strategy. With the refreshed approach our changes were significant, and we show the changes by including our prior pricing strategy in full:

Previous pricing strategy

We aim to set our delivery prices to provide sufficient revenue to recover our prudent and efficient costs, including our cost of capital as determined under the price control regulations that apply to us.

We aim to reflect the long-term economic costs of providing consumers with the quality of delivery service that they require. Cost recovery is fundamental to retaining our incentives to invest in our network in the long-term interests of consumers. In structuring and setting our prices we take a medium to long term view, and we consider economic efficiency, equity, and practicality. We seek to ensure that our pricing is economically efficient, which means that customers who use our network face the appropriate cost of that use and are incentivised to weigh up the value of our delivery service and the alternatives. Cost reflective prices should help to ensure that our investments in our network over time will be at an appropriate level.

We recognise that customer 'capital' contributions are a component of the overall recovery of our costs - in simple terms the level of contributions determines how much is recovered up front as opposed to on an ongoing basis.

In determining customer groupings, cost allocation and the structure of our pricing we:

- apply price averaging over large numbers of connections, because it is generally not practicable to single out individual connections for cost-reflective delivery pricing. Where it is practicable to do so we allocate assets and costs to the specific connection categories that use them,
- recognise that all consumers should share in the benefits of greater utilisation of shared assets and economies of scale,
- recognise that consumers generally change their demand behaviour over relatively long periods of time, and it is important that we provide compelling and consistent pricing incentives aimed at maximising the efficient utilisation of our assets,
- use capital contributions to reflect costs associated with different density areas (particularly urban vs rural) as these charges apply at the time customers are making decisions about where to connect,
- seek to make our prices effective, by balancing strong price signals with simple application and measurement,
- set prices that are the same for all retailers, providing a "level playing field" to promote retail competition.

Key considerations relating to our pricing over the next five years include:

- our developing thinking on sustainability and the way we manage the trade-offs between the environmental and affordability aspects of the energy trilemma in New Zealand's transition to a low carbon economy,
- preserving incentives for managed water heating load,
- the impact of changing use of the network due to emerging technologies such as distributed generation, battery storage and electric vehicles,

- our expectation that the government will move to phase out the low fixed charge regulations (which will remove a significant restraint on how we structure our prices),
- the Electricity Authority's initiatives in relation to its pricing principles and associated practice note and scorecards,
- changes to the transmission pricing methodology which we expect we will need to reflect in our pricing from April 2023.

The way we implement our pricing strategy is updated and publicly disclosed in our pricing methodology document. We usually change our delivery prices on 1 April each year. We review and update this pricing strategy at least annually.

Appendix G– LRAIC

Derivation of Long Run Average Incremental Cost

Orion derives its long run average incremental cost (LRAIC) for delivery of coincident peak load described in section 7.1 as follows:

Derivation steps

Step 1

Establish expected peak demand during the year	
Upper HV network	680.2 MVA
Lower LV network	556.0 MVA

Step 2

Estimate the replacement cost of the network	
Upper HV network	$1,472 m
Lower LV network	$615 m
Total replacement cost	$2,087 m

Step 3

Estimate the proportion of replacement cost that is load dependent	
Upper HV network	$840 m
Lower LV network	$287 m
Total replacement cost	$1,127 m

Step 4

Estimate the proportion of the load dependent replacement cost that is sized for loadings coincident with network peaks	
Upper HV network	$702 m
Lower LV network	$85 m
Total replacement cost	$787 m

Step 5

Calculate load dependent replacement cost per kVA	
Upper HV network	$1,032 /kVA
Lower LV network	$153 /kVA
Total replacement cost	$1,185 /kVA

Step 6

Annualise the replacement costs and add in network average operations and maintenance	
Upper HV network	$69 /kVA/year
Lower LV network	$8 /kVA/year
Total	$77 /kVA/year

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Appendix H - 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 Orion’s 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**

29 February 2024