Methodology for deriving delivery prices

For prices applying from 1 April 2023

Issued 1 March 2023

We are pleased to present our Pricing Methodology Disclosure for prices effective 1 April 2023 to 31 March 2024 (the Pricing Methodology).

From 1 April 2023, we are moving to a pricing approach that better reflects the way consumers utilise our network. We are making changes to fixed charges because we believe that a capacity-based approach is more cost reflective and efficient than our current consumption-based approach. This includes a de-weighting of our peak based charge.

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 2023 and ending 31 March 2024 (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 (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 with 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 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 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.

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

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 219,000 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 pricing 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.[2]

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

Orion

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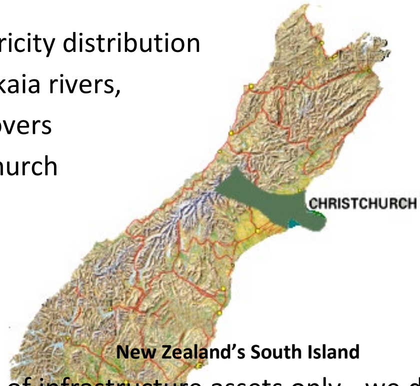
Who is Orion New Zealand Limited



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 7 different locations[3] and we distribute this electricity to more than 219,000 homes and businesses.

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 34% 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%).

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 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.

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,

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

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 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.

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 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.

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 5 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. [4]

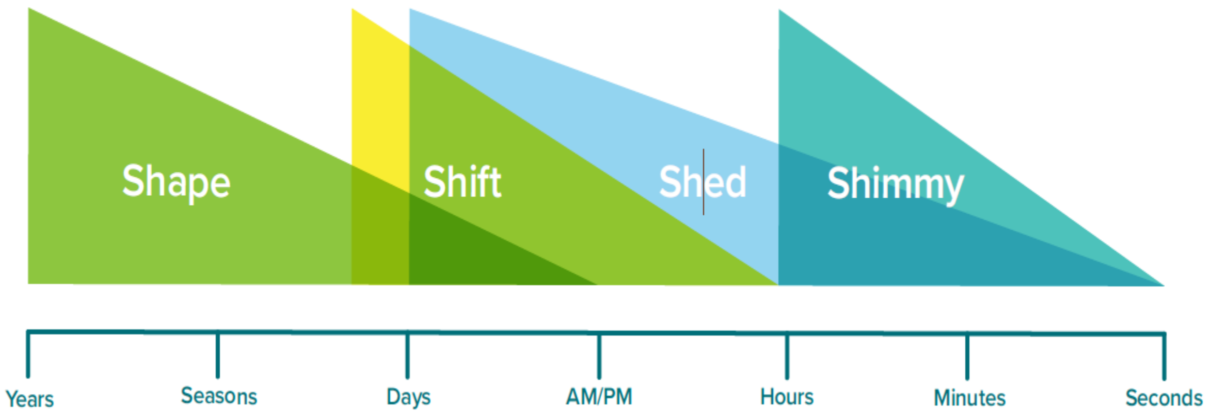
[4] Orion_AMP2023-web.pdf (oriongroup.co.nz)

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 would be very expensive. 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.

Methods of demand response – Source: Lawrence Berkeley National Laboratory (LBNL)



Shape – encourage energy efficiency and influence behaviour
Shift – store surplus energy and smooth peaks
Shed – reduce load to manage contingincy events
Shimmy – minimise load fluctuations to maintain system stability

Using flexibility

Our customers are looking for greater flexibility and choice in meeting their energy needs and, for Orion, this creates opportunities to better manage the security of supply to our community. For example, through pricing signals we may be able to stimulate changes in the demand or generation patterns of our customers, with the effect of reducing network constraints.

Customers can build flexibility into their energy management by using Distributed Energy Resources (DER), such as electric vehicles or battery storage systems. Enabling customers to connect DER to our network and creating opportunities for them to support the electricity system is a critical part of our role in powering a cleaner and brighter future with our community.

Flexibility can be stimulated by price-based mechanisms, such as distribution pricing, or agreed in advance through contractual arrangement as flexibility markets mature to use near real-time reward mechanisms. Mechanisms used to incentivise flexibility will depend on the type of constraint and desired response.

In November 2022, we issued a call for Expressions of Interest to emerging flexibility suppliers to seek cost effective, reliable alternative solutions to building additional network infrastructure in the Lincoln area. Our objective is to defer construction of a new zone substation and other upgrade works in the area, given load growth that is occurring in and around Lincoln.

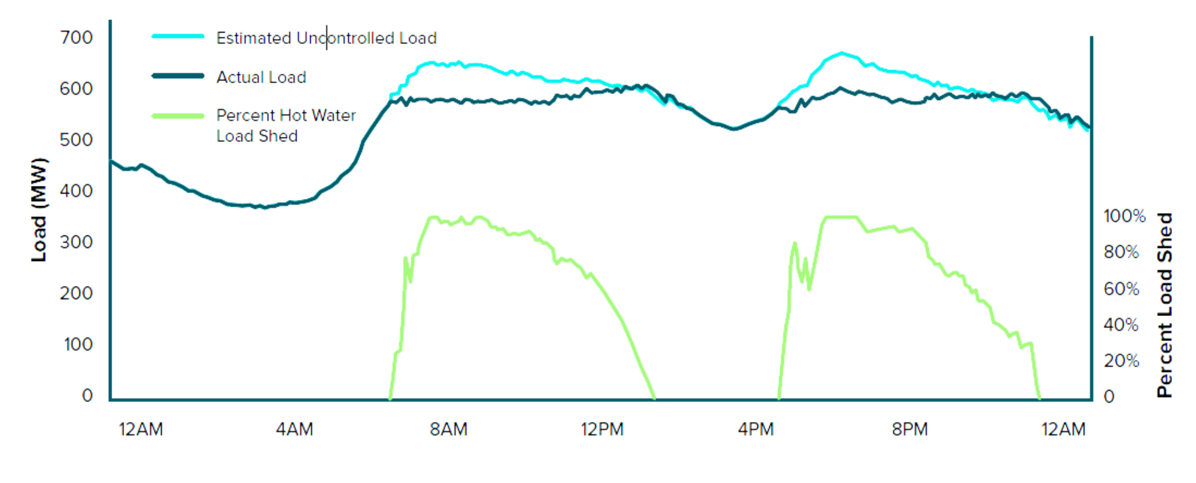
Load management

Orion has a long history of managing peak loading to promote efficient operation of the network and avoid or defer costly transmission and distribution network reinforcement. 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 during nights and weekends. 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 responding to signalling over cellular or fibre telecommunications infrastructure.

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.

To support this growth, we have planned significant projects. Some examples of these are:

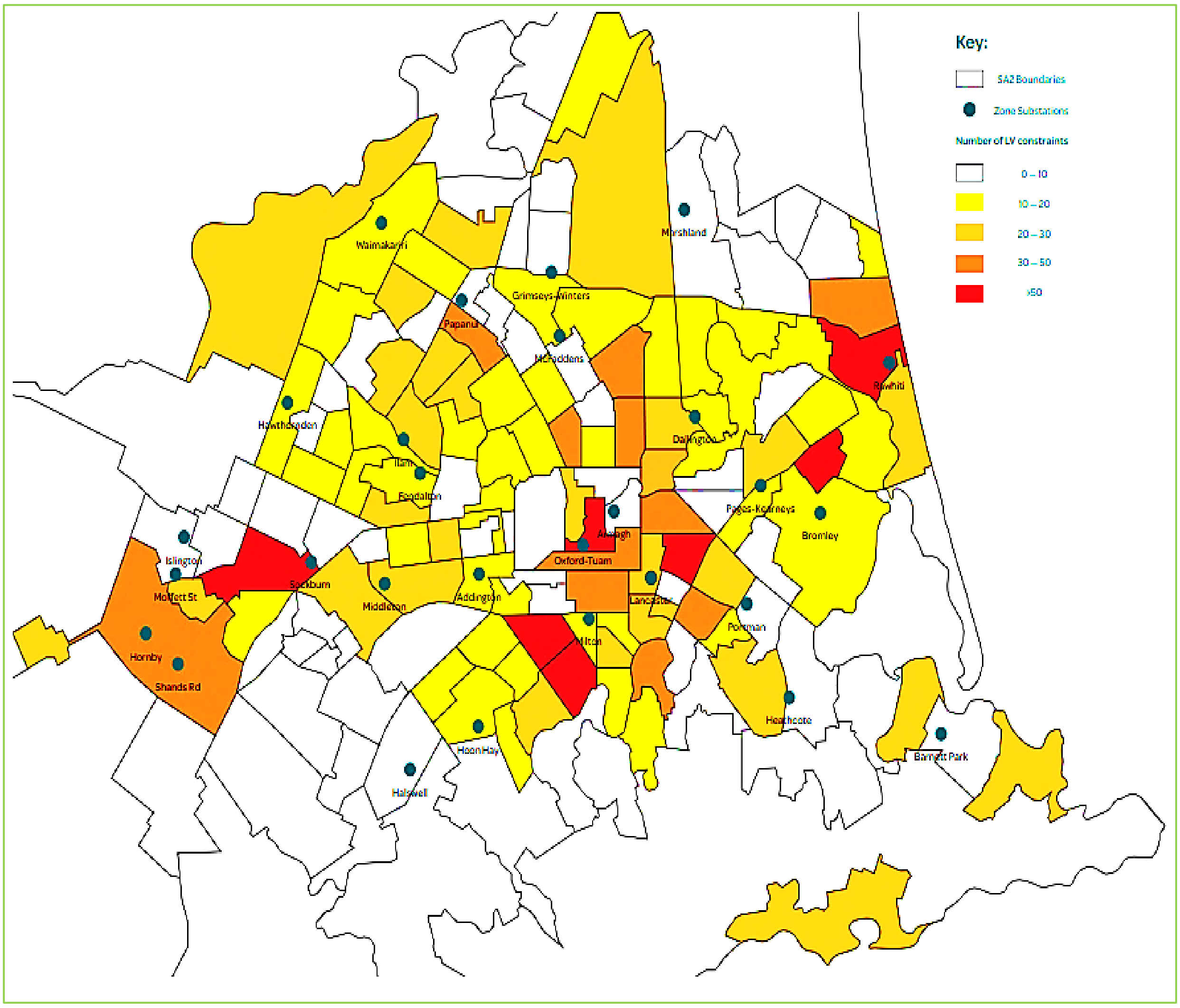
- a new Region B GXP at Norwood to support growth in Selwyn District and western Christchurch
- a new Region B zone substation near Rolleston to support load growth in Rolleston and shift load from Islington GXP to Norwood GXP

- an upgrade of the Haswell zone substation capacity to support residential load growth in the southwest of Christchurch a programme of LV network rein

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.

Growth drivers

Figure 2: Projected LV urban network constraints



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.

Changes in Technology and customer behaviour, the drive to decarbonise, and recent government rule changes regarding 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. This leading the industry towards 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.

This pattern reflects that; besides weather, other factors influence load growth:

Changes in Population

Stats NZ provides national level population forecasts. When the national forecast is broken down to a regional level, the accuracy is less reliable. At a regional level, we derive our load forecast from a combination of bottom-up inputs, such as household growth forecasts by Christchurch City Council and Selwyn District Council.

Historical population growth forecasts have underestimated actual growth particularly in the Rolleston and Lincoln area. For the past four years Orion's customer connections have grown by around 4,000 per year, and this level of growth is forecast to be sustained within this AMP. Adding to uncertainty around the amount and location of population growth in our region is the possible impact of recent housing intensification rules. In December 2021 the Resource Management Amendment Act was passed into law.

The impact of this law if applied to Christchurch would be that we would likely see an increased rate of infill housing and subdivision. This could significantly affect our network as instead of a low voltage feeder supplying 20 standalone homes, a number could be replaced by multiple apartment units, increasing electrical load and triggering network reinforcement. The cost to upgrade Infrastructure to service infill housing in older established areas is typically greater on a per-house basis than the cost to connect a new standalone house in a new subdivision.

Customer actions

How customers respond to national concerns about peak electricity usage and respond to calls for more efficient energy consumption is unknown. Also, government rules may change given carbon neutral targets. A focus on decarbonisation could lead to improved house insulation, greater appliance efficiency, and customers responding to reduce peak load. We have assumed up to 0.5% peak reduction in some of the range of forecasts.

Our network maximum demands

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 2022 winter period was 654MW during the peak that occurred on 11 July 2022, down 18MW 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.

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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 has introduced 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 maximum demand forecasting as shown in Figure 1.

Our total network forecast is higher than the linear history due to the forecast population increase in our region, industrial development in Rolleston, and ongoing regeneration in the central city. Winter peak demand on our network is anticipated to increase by approximately 114MW (18%) over the next 10 years. This is based on the mid scenario shown in Figure2. Significant volatility can be expected in annual actual maximum demands, with 10% variation depending on winter weather. Our maximum demand is linked with cold weather.

Low : the low scenario is based on continued energy efficiency at 0.5% per annum and battery storage, in either stationery or mobile form, being used to counter the impact of electric vehicle charging at peak, that is batteries inject power at peak to meet the charging needs of electric vehicles. The rate of coal boiler conversions to electricity is half that used in the mid scenario.

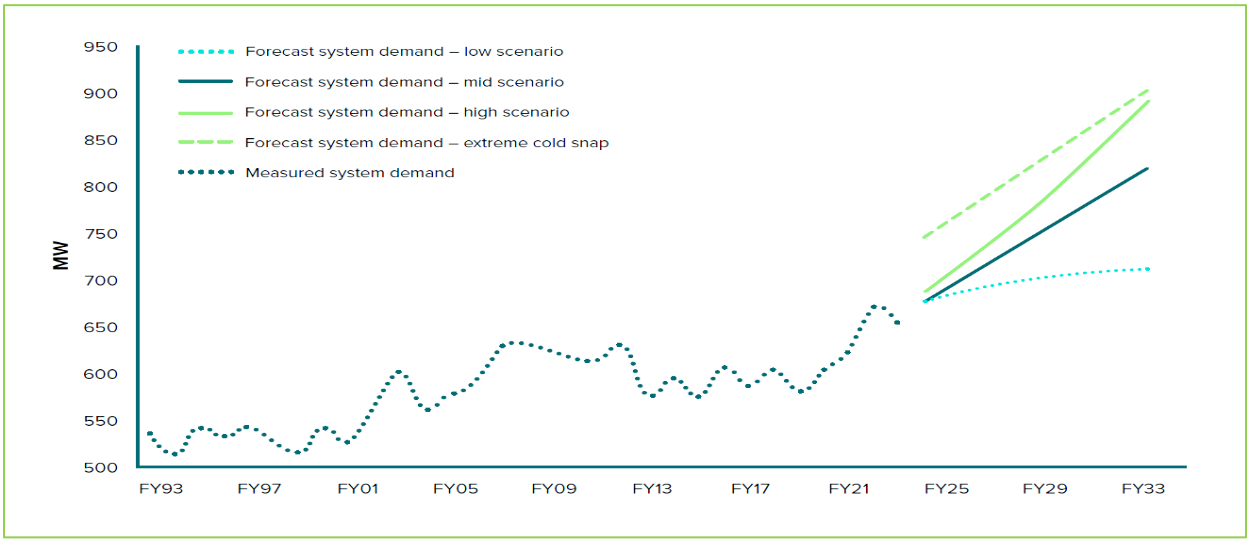
Mid: this indicates underlying growth from new residential households, industrial uptake and commercial rebuild. For EVs we have used Ministry of Transport potential uptake figures as a baseline. This assumes ~16% of the region's vehicle fleet will be electric in 10 years and we have assumed 20% charging at peak times. Energy efficiency continues to reduce peak demand by 0.5% per annum. We expect new business and residential buildings will be more energy efficient than the older buildings they replace. An allowance for coal boiler conversions has been included to align with Transpower's Te Mauri Hiko – Energy Futures vision.

This forecast does not include the effects of batteries which have more uncertain uptake and impact at peak winter times. The impact batteries have in reducing peak load is likely to be low compared to other uncertainties.

High: this high scenario shows the consequences of further energy efficiency gains becoming unattainable, coal boiler conversions matching the mid scenario and a trebling of the electric vehicle impact to match the highest scenario from the Climate Change Commission.

Potential extreme cold snap peak: this forecast is based on events, similar to those in 2002 and in 2011 when a substantial snowstorm changed customer behaviour. We experienced a loss of diversity between customer types. There was significant demand from residential customers due to some schools and businesses remaining closed. When planning our network, it is not appropriate to install infrastructure to maintain security of supply during a peak that may occur for two or three hours once every 10 years. This forecast is therefore used to determine nominal, all assets available to supply capacity requirements of our network only.

Figure 1: Overall maximum demand trends on the Orion network



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 networks, supply 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.

We have four LV initiatives currently ongoing:

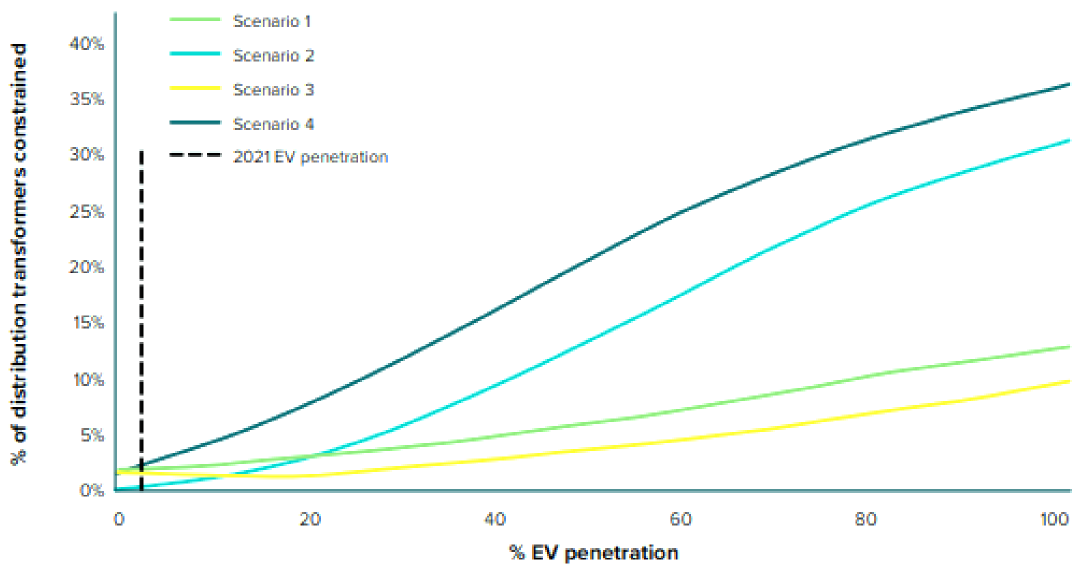
- LV feeder monitoring
- Smart meter information gathering
- LV network reinforcement, when identified as necessary
- LV research

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

Figure 2: Projected residential distribution transformer 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 costs of supply on our network; and
- where a revenue shortfall occurs, we recover the shortfall in a way that lest 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 types
- appropriately recover our pass-through costs (i.e., rates and levies) and recoverable costs (i.e., transmission charges).
- 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 to other electricity distributors
- 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 fixed charge regulations
- A lack of ability to control how prices are passed onto consumers by their respective electricity retailers.

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 for 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:

- decarbonisation of our economy, and
- addressing inequity, by recognising and mitigating the impact on vulnerable customers.

Building on these two initiatives, our sustainable development goals include:

- 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.

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 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 tool to mitigate this impact is to implement a staged transition, spreading the change over a number of years. This provides more opportunity for vulnerable customers to adapt and for support mechanisms to adjust.

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:

- 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.

The key economic input to our pricing is the long run average incremental cost (LRAIC) of investment in our network on the basis that, if customers are prepared to pay prices that reflect LRAIC, then further investment in network capacity is economically efficient. We apply this concept consistently in our pricing across the connection types, and in Respect of the pricing components we apply.

Our calculations and application of LRAIC is described in more detail in section 6 and Appendix H.

3.3.4 Even-handedness and practical considerations

Orion takes into account the need for even-handedness and practicality in determining customer groupings, cost allocations and the structure of our pricing.

Specifically, we:

- apply price averaging over connection types, 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 types 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:

- Work through the phase-out of the low fixed charge regulations and incrementally increase the proportion of fixed charge revenue recovered from general connections (residential).
- Introduce new price categories for small and medium enterprises (SME) in the general connection category and incrementally increase the proportion of fixed revenue recovered from them.
- Phasing out our fixed peak charge to variable TOU charges

Progressively rebalance how variable components are recovered:

- Introduce more targeted TOU variable pricing for general connections (residential and SME)

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3.4 Implement Gradually and Carefully

Unfortunately, we cannot move to capacity-based pricing for all consumers by 01 April 2023. 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, we have decided to apply 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 (general 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 to arrive at the chargeable GXP volumes
- Washing-up monthly kWh volumes in line with reconciled GXP data issued by the market reconciliatory (i.e., total billed kWh volume will equal reconciled GXP volumes)

We will continue to adjust consumption data by the appropriate loss factor to arrive at billable volumes for the foreseeable future. More information on the relevant loss factors for the 01 April 2023 pricing year can be found in section 4.4 of this Pricing Methodology.

To minimise the complexity and cost of our monthly billing process, we intend to continue using GXP pricing. The cost of changing our billing approach to be based on consumption at the individual ICP level (known as 'ICP billing') would be significantly higher than the cost of our current billing approach. We do not believe that consumers will be correspondingly better off if we were to change our billing approach at this time.

3.4.2 Changes made for 1 April 2023

We have made several fundamental but small changes to our prices effective 1 April 2023. 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 2023

Consumer Group	Description of the changes made effective 1 April 2023
General Connections	The general fixed daily supply charge will increase from 30 cents to 45 cents from the 1 April 2023. We intend to move to a fixed installed capacity charge over time. 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. 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. After 1 April 2027, we will increase the proportion of costs recovered through fixed charges to a fully cost reflective level. We will transition the fixed/ variable charge through de-weighting the daily fixed peak charge
General Connections **Group 1** **Group 2** **Group 3**	From 01 April 2023 we have created three new price categories codes. The change better reflects SME connections utilisation of the network. We are transitioning the fixed charge to a capacity-based charge over time. The categories are: General Group GC1: Small SME up to 15 kVA General Group GC2: Medium SME from 16 kVA – 69 kVA General Group GC3: Large SME 70 kVA and above
Peak charge	De-weight from the fixed daily peak charge into the variable charge

Delivery charges effective 1 April 2023 and a comparison with the delivery charges effective 1 April 2022 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 change 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 regulations have inherent limitations to our transition to cost-reflective pricing.

Phasing out of the LFC regulations will make pricing fairer for larger, often low-income, households which don't qualify for the low fixed charge. Residential consumers are cross subsidised by consumers in the commercial and industrial 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.[5]

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

“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.[6]

“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.”

4. Standard Connection Contract

We supply electricity distribution services to consumers via Retailers (e.g., Meridian, Contact, Mercury etc.) 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 nine 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 2023

Category	Breakdown of charges
Irrigation	Capacity charge (per kW, per day) Variable network charge (day units per kWh) Variable network charge (night/weekend units per kWh) Power Factor correction rebate Interruptability rebate
Street Lighting	Fixed network charge (per connection, per day) Peak charge Variable network charge (day units per kWh) Variable network charge (night/weekend units per kWh)
General Connections	Fixed network charge (per ICP, per day) Peak charge Variable network charge (day units per kWh) Variable network charge (night/weekend units per kWh)
General Group 1 (GC1)	Fixed capacity-based network charge (per ICP, per day) Peak charge Variable network charge (day units per kWh) Variable network charge (night/weekend units per kWh)
General Group 2(GC2)	Fixed capacity-based network charge (per ICP, per day) Peak charge Variable network charge (day units per kWh) Variable network charge (night/weekend per kWh)
General Group 3 (GC3)	Fixed capacity-based network charge (per ICP, per day) Peak charge Variable network charge (day units per kWh) Variable network charge (night/weekend per kWh)

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

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 connection contracts

We currently supply fifteen connections under non-standard contract terms or conditions.

In circumstances that a consumer approaches us with connection needs that are outside of the terms of our standard connection contract (i.e., unique), we would negotiate a non-standard connection contract with the consumer that meets their circumstances.

4.3 Customer consultation and Price-Quality Trade-Off

The information disclosure requirements include a requirement regarding the extent to which the views of customers in terms of price and quality have been sought and reflected in the price-setting process.[7]

For the refresh of our pricing strategy, we engaged with and consolidated feedback from a wide range of stakeholders. We:

- held briefing sessions with our directors;
- hosted a customer advisory panel discussion, where selected representatives of customer cohorts engaged on the problems we are tackling and provided views on our proposed approaches;
- consulted with other network operators and engaged with industry working groups;
- employed expert consultants to critique and peer review our work; and
- took account of the views expressed by electricity retailers in our 2022 consultation rounds.
- In addition, 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.

4.4 Loss Factors

Losses are the percentage of electricity entering the network lost during the delivery to consumers 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

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

- Variable component arising from the heating effect of resistance on the lines

The loss factors for the pricing year are provided in Table 3.

Table 3: Loss factors for the pricing year

Code	Loss Factor	Description
LVL	1.055	Low voltage metered connections (230v or 400v)
11L	1.025	11kV metered connections
SLL	1.029	Connection specific factors (HV)
FSL	1.004	Connection specific factors (HV)

4.5 Distributed Generation

Interest in utility-scale solar connections has significantly increased during 2022. Inquires indicate potential for 10MW to 600MW+ of solar PV generation to be added within Region B. 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. We have 185 small photovoltaic installations under 10kW.

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.

Solar and/ or Diesel – 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.

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. 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

Orion's network is constantly growing, with new connections, increased loads at existing connections, and alterations to accommodate development. To be fair to established consumers, we believe it is important that the resulting reinforcement and network extensions are priced appropriately.

Our economic aim is to apply efficient pricing policies which reflect the full economic costs of providing our delivery service. With this approach, consumers (particularly prospective consumers) make efficient decisions about which form of energy to use, and where to locate new load.

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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 consumers 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
- dedicated assets often become shared assets as the network expands. Existing consumers should share in the benefit of greater utilisation of shared assets (and other enhanced economies of scale)
- some spare capacity must be available before it is required to ensure that developments are not unduly delayed

In 2022, we have commenced a review of our capital contributions approach in light of our current context. We anticipate refreshing our approach by 1 April 2024.

Our Commercial terms for new connections and extensions can be found at: https://www.oriongroup.co.nz/ConnectionsAndExtensions5. 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 2023, we intend to recover the Required Revenue of $236,5m 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)
Administration and Corporate Costs	$52,958
Operations and Maintenance Costs	$36,012
Depreciation charges	$53,000
Network Rebates	$679
Transpower Charges	$56,096
Regulatory Costs / Levies	$37,816
Total required revenue	**$236,561**

5.1.1 Calculation of the Operations and Maintenance Costs

Our forecast Operations and Maintenance costs for the year are $36.0m. 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	$9,250
Vegetation Management	$6,000
Routine and Corrective Maintenance	$17,529
Asset Replacement and Renewal	$3,233
Total Operations and Maintenance Costs	**$36,012**

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5.1.2 Calculation of the Administration & Corporate Costs

Our forecast Administration and Corporate Costs for the pricing year are $52.9m. 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	$20,032
Business Support	$32,926
Total Administration and Corporate Costs	**$52,958**

5.1.3 Calculation of the Depreciation Charges

Our forecast Depreciation Charges for the pricing year are $53m. 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 2023 and 31 March 2024. 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	$4,000
System Fixed Assets	$49,000
Total Depreciation Charges	**$53,000**

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 2023 to 31 March 2024 are $55.709m.

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 $37.8m.

5.2 Change in Required Revenue

Our required revenue has increased by $3,912 or 2% for 01 April 2023 pricing year when compared against 01 April 2022 pricing year. Table 8 provides the movement in required revenue between the pricing years.

Table 8: Movement in Revenue Requirement between pricing years

Description	2023/24 $('000)	2022/23 $('000)	Movement $('000)	%
Operations and Maintenance Costs	$52,958	$50,100	$2,858	5%
Administration and Corporate Costs	$36,012	$23,900	$12,112	34%
Depreciation charges	$53,000	$48,000	$5,000	9%
Network discounts	$679	$1,100	($422)	(62%)
Transpower charges	$56,096	$63,400	($7,691	(14%)
Regulatory costs / Levies	$37,816	$46,239	($8,423)	(22%)
Total Required Revenue	**$236,651**	**$232,739**	**$3,822**	**2%**

5.2.1 Change in Operations & Maintenance Costs

The primary cause of the increase in target revenue is an increase in Operations and Maintenance costs expenditure of $7,1345m or 25% forecast for the 01 April 2023 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	2023/24 $('000)	2022/23 $('000)	Movement $('000)	 %
Service Interruptions and Emergencies	$9,250	$10,327	($1,077)	(10%)
Vegetation Management	$6,000	$4,825	$1,175	24%
Routine and Corrective Maintenance	$17,529	$12,558	$4,971	40%
Asset Replacement and Renewal	$3,233	$1,345	$1,8588	140%
Total Operations and Maintenance Costs	**$36,012**	**$29,055**	**$9,957**	**24%**

Operations and Maintenance costs are forecast to increase by 24%. 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 increase in Administration and Corporate costs has an increase of $16m (or 22%). Table 10 compares administration and corporate costs expenditure between pricing years.

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

Description	2023/24 $('000)	2022/23 $('000)	Movement $('000)	 %
System Operations and Network Support	$20,674	$21,045	($371)	(2%)
Business Support	$32,926	$23,900	$9,026	38%
Total Administration and Corporate Costs	**$53,600**	**44,945**	**$8,655**	**19%**

The 19% increase in Administration and Corporate Costs is attributable to general inflationary pressures.

The main driver of the 38% increase in Business Support has, the increase is largely driven by headcount and the sustainability of an expanding network. These roles will support the network business as technological changes impact the distribution sector, particularly in increasing data and digitisation and system control.

5.2.3 Changes in other costs

The increase in Depreciation Charges of $5m or 2.1% reflects the increasing value of our electricity network assets, which are subject to annual accounting revaluation.

The decrease in transmission costs of $7.6m is due to a decrease 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.[8]

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

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 consumer grouping for the pricing year

Consumer Group	**Required Revenue $('000)**	**Proportion (%)**
Irrigation	$10,254	4%
Street Lighting	$2,348	1%
General Connections	$184,991	78%
Major Customers	$35,105	15%
Large Capacity Connections	$3,845	2%
Total Required Revenue (excl. export credits)	**$236,543**	**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

The pricing design model sets our prices from which we recover our Target Revenue for each consumer group over the pricing year. The pricing design model first sets our distribution and transmission prices for each consumer group with a uniformed delivery charge.

6.1 Why do we apply a uniform delivery charge

Orion has decided to continue to apply 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 granulated 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…'

6.2 Connection categories

We have identified situations where groups of customers place significantly different demands on delivery assets, and situations where customers use different sets of those delivery assets. One of the aims with establishing these consumer groups is to support pricing that is subsidy free, allowing prices to more accurately reflect contribution to costs to avoid exceeding stand-alone costs or over-recovery. We have established connection categories that reflect these differences to provide a more equitable basis of assigning costs. Our categories are:

- Streetlighting connections (streets, parks and reserves)
- General connections
- Irrigation connections
- Major customer connections
- Large capacity connections

We determine which category applies to each ICP, and this is reviewed from time to time.

This section describes each of these categories, the rationale for maintaining the category, and the key statistics for the category. The key statistics inform the cost allocations set out in section 6.

6.2.1 Streetlighting connections

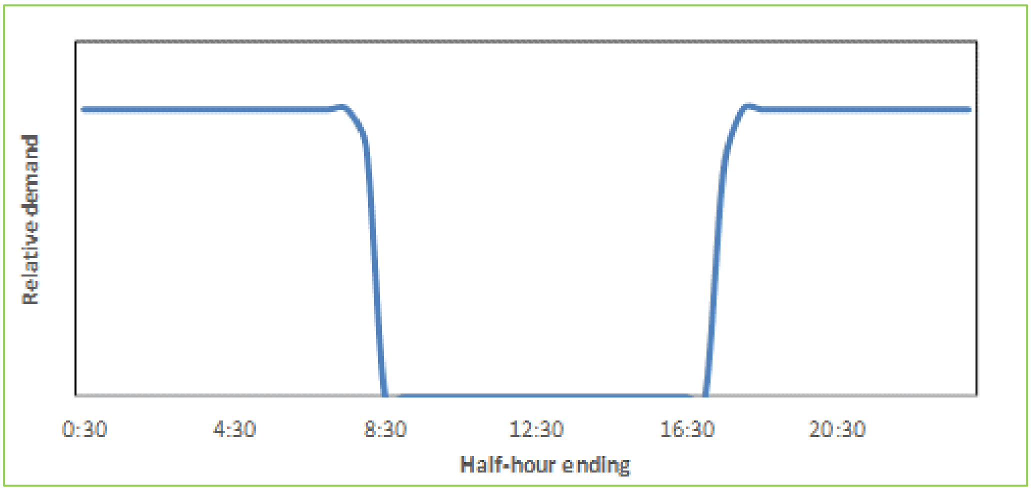
Orion owns and maintains a low voltage network of lines and cables dedicated to the provision of streetlighting (including lighting of some parks and reserves). To a large extent, this network runs alongside our regular low voltage network; it is the fifth wire on our overhead lines and the fifth core of our underground cables. These circuits are switched on at night and off in the mornings, using a combination of light sensors and timers and our ripple signalling system.

To reflect the dedicated use of our lighting network, we maintain a specific category for streetlighting connections. All private and publicly owned dedicated lighting connections supplied from our streetlighting circuit are included within this connection category.

Assessed key statistics for streetlighting connections (1 April 2023 to 31 March 2024)	**Forecast**
Number of chargeable connections	52,865 (average)
Energy volume	165,331 MWh
Peak demands	
- contribution to network-wide winter peak (ADMD)	1,140 kW
- contribution to network-wide summer peak (ADMD)	-
- contribution to local network peak (ADMD)	1,140 kW
- sum of individual connection anytime peaks (ΣAMD)	3,600 kW
Value of lost load (VOLL)	$17.60 /kWh

Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurement (i.e., with normal distribution losses added)

There is effectively no diversity of load within this category, and it contributes to both morning and evening load peaks during winter. The following depicts a typical winter day profile:



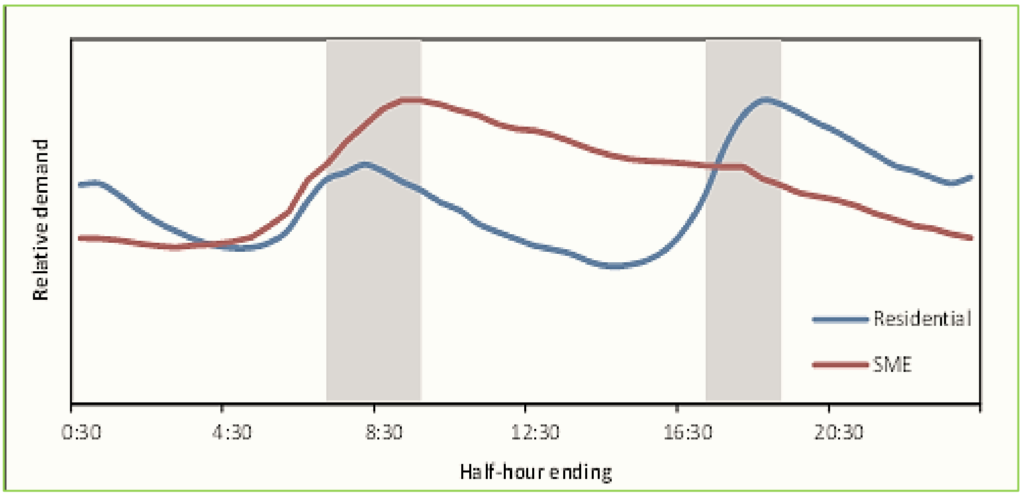
6.2.2 General connections

This category makes use of all network assets (except lighting circuits). It includes all residential connections and most business connections, including a number of sites with half-hour interval metering, but excludes connections that belong to the other connection categories (those in the streetlighting, irrigation, major customer and large capacity connection categories).

Assessed key statistics for General connections (1 April 2023 to 31 March 2024)	**Forecast**
Number of connections / ICPs	219,918 (average)
Energy volume	2,337,501 MWh
Peak demands	
- contribution to network-wide winter peak (ADMD)	502,532 kW
- contribution to network-wide summer peak (ADMD)	307,822 kW
- contribution to local network peak (ADMD)	537,295 kW
- sum of individual connection anytime peaks (ΣAMD)	2,149,178 kW
Value of lost load (VOLL)	$18.88 /kWh

Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurement (i.e., with normal distribution losses added)

The category includes a mix of customer types with different load profiles, and varying contribution to our winter weekday load peaks. The most dominant groups within the category are residential and small commercial, with the following typical winter weekday profiles:



6.2.3 Irrigation connections

We provide a specific irrigation connection category because electrical loads from irrigators are very different to those of other connection categories. In particular:

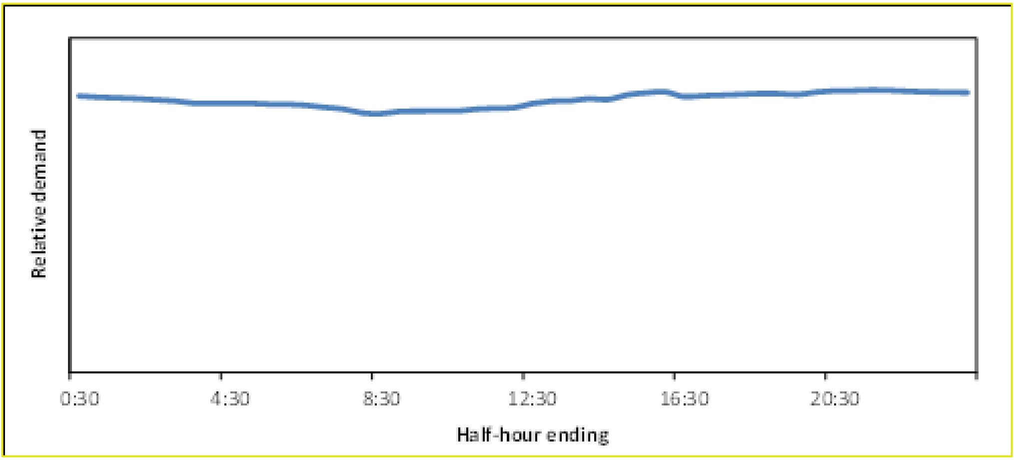
- they are all in lower density rural areas (using relatively long stretches of our overhead network),
- their load is highly correlated: when it's warm and dry they all switch on,
- their load and combined loading peaks are very flat (and any load management or demand response that aims to reduce these peaks must therefore operate for extended periods of time to be effective), and
- their peak demands occur in summer whereas the overall Orion network peak demands occur in winter.

This category generally applies to all connections with capacity greater than 20 kW where the primary purpose is to pump water to irrigate farmland. Orion determines the connections that are allocated to this category.

Assessed key statistics for irrigation connections (1 April 2023 to 31 March 2024)	**Forecast**
Number of connections / ICPs	1,029 (average)
Energy volume	137,625 MWh
Peak demands	
- contribution to network-wide winter peak (ADMD)	0 kW
- contribution to network-wide summer peak (ADMD)	33,959 kW
- contribution to local network peak (ADMD)	57,058 kW
- sum of individual connection anytime peaks (ΣAMD)	78,599 kW
Value of lost load (VOLL)	$1.20 /kWh

Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurement (i.e., with normal distribution losses added).

The dominant irrigation load in the rural network area alters the shape of peak loads that drive a significant portion of our costs, the peaks are summer based, with a long flat duration. The category has the following typical summer daily load profile:



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6.2.4 Major customer connections

We provide a specific category for our larger connections. These larger connections have enhanced metering that enables more specific and cost reflective pricing, and providing a separate category allows us to reflect specific factors for these customers, including:

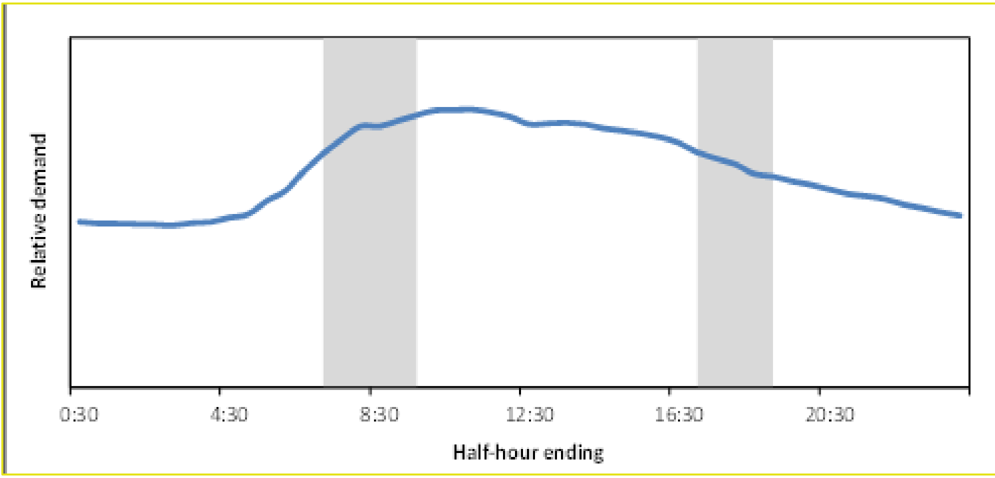
- most have a dedicated transformer and generally do not use our low voltage network,
- in some cases, we do not own or maintain the transformer,
- some have additional dedicated equipment, lines or cabling, and
- some customers have specific additional requirements in terms of their security of supply and back-up supply options.

We determine which connections are in this category based on maximum loading levels (and any contracted capacity for new or modified connections). Generally:

- customers (or their retailer) with a loading or export level between 150 kVA and 300 kVA may elect to be classified as a major customer connection, or
- customer connections with a loading or export level above 300 kVA are classified as a major customer connection.
- embedded networks are classified as major customer connections.

Assessed key statistics for Major connections (1 April 2023 to 31 March 2024)	**Forecast**
Number of connections / ICPs	532 (average)
Energy volume	864,091 MWh
Peak demands	
- contribution to network-wide winter peak (ADMD)	121,085 kW
- contribution to network-wide summer peak (ADMD)	131,698 kW
- contribution to local network peak (ADMD)	121,085 kW
- sum of individual connection anytime peaks (ΣAMD)	230,121 kW
Value of lost load (VOLL)	$26.36 /kWh

*Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurement (i.e., with normal distribution losses added)



6.2.5 Large capacity connections

We provide a specific pricing category to accommodate very large connections that require individual pricing consideration as a result of their size and impact on the local network. Such connections may also have:

- enhanced security of supply requirements, including back up supply and restoration obligations,
- very specific and dedicated assets, including transmission assets, and associated costs, with significant stranding risk should the connection cease operation,
- the ability to enter into long term contracts with us.

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 large capacity pricing.

Pricing and charge structures are individually negotiated and charged directly to the customer. Because of this ability to negotiate very connection-specific pricing, we are in an even better position to ensure consistency with the pricing principles. Our contracts with these customers include terms that require us to allocate assets and asset related costs in a manner consistent with the overall pricing methodology including establishing and disclosing:

- assets and asset groups that are used in providing delivery services to the customer including assets provided in order to meet specific security of supply requirements,
- an equitable method for assigning a proportion of the value of assets to the customer for assets that are also used by other customers,
- the current replacement value of the asset allocation above,
- capital costs (return on assets and depreciation) based on the asset allocation above,
- an equitable method for assigning operations, maintenance and administration costs, which may include separate consideration of customer specific costs, asset specific costs, and shared costs,
- an allocation of transmission costs consistent with the overall pricing methodology, and
- a pricing structure that aims to recover allocated costs.

Assessed key statistics for Large Capacity connections (1 April 2023 to 31 March 2024)	**Forecast**
Number of connections / ICPs	15 (at 2 locations)
Number of customers	2
Energy volume	144,376 MWh
Peak demands	
- contribution to network-wide winter peak (ADMD)	5,880 kW
- contribution to network-wide summer peak (ADMD)	24,070 kW
- contribution to local network peak (ADMD)	24,070 kW
- sum of individual connection anytime peaks (ΣAMD)	28,082 kW
Value of lost load (VOLL)	$70.60 /kWh

* Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurement (i.e., with normal distribution losses added)

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 in the large capacity connection category commercial sensitivity prevents us from providing any load profile for this category.

6.3 Allocating costs to connection categories

The cost allocation model varies for each pricing update. Each of the costs in the section above is individually considered and allocated to connection categories on a basis that reflects our pricing principles – in particular economic efficiency, equitability and practicality – and the key attributes of each category. We allocate many of our distribution costs based on each category's use of our delivery assets, and to do this it is necessary to first allocate the assets to each category.

6.3.1 Distribution asset allocation

Our distribution asset allocation method takes account of a number of factors:

- assets are allocated based on our assessment of the relative use of each asset category by each connection category,
- the allocation of assets that are largely shared (e.g., sub-transmission assets) is weighted more in favour of each category's contribution to local peak demands (After diversity maximum demand (ADMD)) on the basis that these assets are sized to meet the combined coincident loadings,
- the allocation of assets that are sized to meet the load of individual connections (for example low voltage assets), and those assets that tend to have a fixed size regardless of loading levels (for example land) is weighted more in favour of the sum of each individual connection's anytime peak demand (ΣAMD),
- the allocation of contingent assets (the assets that are provided to maintain supply after a fault - approximately 17% of our total asset value) is additionally weighted in proportion to each category's value of lost load (VOLL), as this measure reflects the relative need for the assets between the connection categories. We assess VOLL for each connection category as shown in section 6.2. The range of values we use is reasonably consistent with that from other

sources[9] and ranges between $1 and $68 per kilowatt hour (much higher than the normal retail cost of delivered electricity which ranges from 12¢ to 30¢ per kilowatt hour).

We initially allocate assets based on the replacement cost and the detailed asset assessment contained in our latest audited regulatory valuation prepared in accordance with the Commission's optimised deprival value (ODV) methodology, prepared as at 31 March 2004.

The resulting allocations by asset category are:

***Allocation of distribution assets** (based on 31 March 2004 ODV replacement costs)*

Asset category	Street lighting $ '000	General $ '000	Irrigation $'000	Major customer $'000	Large capacity* $'000
Subtransmission	$426	$191,727	$22,314	$51,433	$9,531
Power transformers	$69	$31,206	$2,360	$8,582	$3,232
11kV Distribution	$428	$197,705	$26,703	$57,621	$1,778
Land & property	$119	$71,253	$2,432	$7,84	$2,382
Distribution transformers	$151	$85,319	$4,083	$8,539	$72,490
Low voltage distribution	$41	$235,116	$1,129	$9,635	$0
Lighting	$14,577	$0	$0	$0	$0
Total	**$15,811**	**$810,326**	**$59,021**	**$135,810**	**$16,996**

* New assets constructed for this category after the date of our ODV valuation are added in at their ODV-equivalent cost.

Notable entries in this table include:

- major customers are allocated a relatively small share (4%) of the low voltage distribution network assets when compared with their share of subtransmission (19%) and 11kV distribution assets (20%). This reflects their very limited use of LV assets,
- large capacity connections are allocated no LV asset costs,
- all of the lighting network asset costs are allocated to the streetlighting connection category.

We then allocate our forecast average regulatory asset value (average RIV) to each category in proportion to the allocation of replacement costs. We use this method to allocate RIV because it:

- captures the change in asset value between our valuation date and the pricing year,
- ensures that the same proportion of depreciation is applied to the assets assigned to all connection categories, reflecting that we provide an ongoing service, rather than a service with diminishing value (in other words a delivery service provided with older assets is no less valuable than a service provided with new assets),
- captures and assigns assets that are used for our delivery service but are not included in our ODV (such as working capital, our faults vehicles and head office building).

The average RIV represents the indexed regulatory depreciated investment value of assets averaged over the year. The resulting allocation of average RIV for each connection category is:

[9] For example, the Authority in its 2013 paper "Investigation into the Value of Lost Load in New Zealand" estimated a range of $11 per kWh to $70 per kWh for a number of customer types in the Christchurch area. See: http://www.ea.govt.nz/dmsdocument/15385.

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	Street lighting $ '000	General $ '000	Irrigation $'000	Major customer $'000	Large capacity $'000	Total $'000
Average RIV allocation	$21	$1,069,431	$77,700	$189,122	$16,429	$1,373,500

The full detail of the asset allocation calculations is not shown in this methodology as it is a complicated process involving many interacting components. However, by way of one example, a diagram showing how the low voltage distribution assets are allocated to the general connection category is in Appendix D.

6.3.2 Other cost allocators

Costs that are not allocated on the basis of our asset allocation (above) are instead based on alternative allocators (i.e., in situations where the costs are not related to asset allocations). Summarising these allocators from section 6.2:

	Street lighting kW	General kW	Irrigation kW	Major customer kW	Large capacity kW	Total kW
After diversity maximum demand (ADMD)						
During winter	1,140	502,532	-	121,085	5,880	630,637
During summer	-	307,822	33,959	131,698	24,070	497,549
During local network peak	1,140	502,532	57,058	121,085	24,070	705,885
Anytime maximum demand (ΣAMD)	3,600	2,149,178	78,599	230,121	28,082	2,489,581

6.4 Transmission cost allocation

The investment in and capacity of the transmission system bringing electricity to our region is largely driven by the peak loadings within the greater upper South Island area. This is currently reflected in Transpower's residual charge (the main component of their charges to us) which is based on our contribution to Transpower's regional (in this case upper South Island) anytime maximum demand (AMD) and the smoothed maximum allowable revenue (SMAR) for the pricing year as determined in Transpower's IPP determination.

Our distribution network load is characterised by summer (rural) and winter (urban) seasonal peaks and, to the extent that all connection categories use the transmission service, and benefit from it, we have split the costs equally between the categories in proportion to their transmission demands (using network wide ADMD). We then allocate the additional cost of meeting the higher winter peak only to connection categories that contribute to the winter peak. This is not a 50:50 split. Based on current loading levels, the higher winter loadings mean that the winter peak attracts approximately a 45% greater share of the total interconnection charge.

This approach provides a smooth transition in the cost allocation as the observed summer peaks increase and approach the winter peaks. It also avoids the economic extremes of either:

- viewing the transmission grid as being built entirely for the winter peak (and allowing the lower summer peak to free ride), or
- viewing the transmission grid as being built for the summer peak, and only charging the winter peaking customers for the marginal additional cost of meeting the higher peak.

Either of these approaches can be argued as economically efficient (and the Authority supports the former), but neither provides an equitable or stable result.

We allocate a proportion of Transpower's other charges (for connection charges, benefit-based charges and new investment agreements) to the large capacity category based on actual use of assets and allocate the remainder of these charges to all other connection categories in proportion to each category's contribution to anytime maximum demand (ΣAMD).

Finally, we allocate the cost of transmission alternatives that we procure (currently just avoided transmission investments purchased from Transpower) according to ΣAMD as they are an alternative to connection assets.

The result of the allocation is:

	Street lighting $'000	General $'000	Irrigation $'000	Major customer $'000	Large capacity $'000
Residual Charge	$44	$29,258	$1,084	$8,886	$995,827
Connection charge	$6	$3,800	$139	$407	$102
Benefit based charge	$11	$7,368	$273	$2,238	$251
Transitional Cap	$.2	$141	$.5	$43	$5
New Investment charge	$1	$629	$23	$67	$10
Avoided Transmission Investment	$.5	$271	$10	$29	-
Total cost of allocation	**$64**	**$41,466**	**$1,534**	**$11,670**	**$1,363**

6.5 Pass – through cost allocation

The main component nearly 75% of pass-through costs is local authority rates, and these reflect the value of our assets. For simplicity we have allocated all pass-through costs in proportion to our allocation of assets. The resulting cost allocations are:

	Street lighting $'000	General $'000	Irrigation $'000	Major customer $'000	Large capacity $'000
Pass through cost allocation	$132	$6,779	$493	$1,199	$109

6.6 Quality incentive cost allocation

The quality incentive relates to the reliability of our assets, and we allocate these costs to connection categories in proportion to our allocation of assets. The resulting cost allocations are:

	Street lighting $'000	General $'000	Irrigation $'000	Major customer $'000	Large capacity $'000
Quality incentive cost allocation	$9	$481	$35	$85	-

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6.7 Distributed generation distribution cost allocation

The distribution components of our export credits reflect the savings in distribution costs gained from this generation contribution. The cost reduction provided by distributed generators relates to their ability to lower our peak loading, and we allocate the cost of providing these credits based on each connection category's contribution to peak loadings (ADMD), with the following result:

	Street lighting $'000	General $'000	Irrigation $'000	Major customer $'000	Large capacity $'000
Distributed generation cost allocation	$0	$5	$.6	$1	-

6.8 Capex wash-up adjustment cost allocation

The wash-up adjustment relates to capital expenditure, and we allocate these costs to connection categories in proportion to our allocation of assets. The resulting cost allocations are:

	Street lighting $'000	General $'000	Irrigation $'000	Major customer $'000	Large capacity $'000
Capex wash-up adjustment cost allocation	$12	$612	$44	$108	-

6.9 FENZ levy cost allocation

For simplicity we have allocated the FENZ levy in proportion to our allocation of assets. The resulting cost allocations are:

	Street lighting $'000	General $'000	Irrigation $'000	Major customer $'000	Large capacity $'000
FENZ levy cost allocation	$2	$89	$6	$16	$2

6.10 Payments for interruptible load and power factor correction

Our irrigation rebate schemes allow us to avoid investment in capacity upgrades and back up supply assets. These schemes lower our overall cost of service to all customers in the area (not just the irrigation category). That is, we view the schemes as a network alternative, and we allocate the cost of this network alternative in the same way that we would allocate the cost of the network they are funded by all categories. The power factor correction rebate works alongside the requirements in our network code and encourage customers to provide a level of correction that goes beyond the normal technical requirement in the network code, and in this respect, we believe it provides a more useful incentive to maintain power factor correction than alternative approaches[10]. This explains why we do not allocate the cost of our irrigation rebate schemes just to irrigators. The allocation is carried out in proportion to our allocation of assets:

[10] Alternatives include penalties for a low power factor, or charges for reactive load.

	Street lighting '000	General '000	Irrigation '000	Major customer '000	Large capacity '000	Total '000
Payments for rebates	$10	$530	$39	$94	$0	$737

6.11 Administration cost allocation

Costs associated with administration and overheads are largely independent of asset value, so we instead allocate these costs to each connection category in proportion to the sum of individual connection anytime peaks (ΣAMD), as this reflects the extent to which each connection utilises our service. The resulting allocation is:

	Street lighting '000	General '000	Irrigation '000	Major customer '000	Large capacity '000	Total '000
administration cost allocation	$47	$28,388	$1,038	$3,040	$413	$32,926

6.12 Cost of capital allocation (depreciation, return on capital and taxation)

Capital costs are all asset related, and we allocate these costs to connection categories in proportion to our allocation of assets. Offsetting these costs, we also provide a credit reflecting costs covered by avoided transmission charges, and a credit reflecting costs that are funded by sundry revenue (which is not collected via the prices in this methodology, e.g., rental income). The resulting cost allocations are:

	Street lighting '000	General '000	Irrigation '000	Major customer '000	Large capacity '000	Total '000
Depreciation	$805	$41,378	$3,006	$7,317	$494	$53,000
Return on capital (after tax)	$531	$27,253	$1,980	$4,819	$716	$35,299
Taxation	$156	$7,993	$581	$1,413	$148	$10,291
Costs funded by avoided transmission	($1)	($271)	($10)	($29)	$0	($310)
Total cost of capital allocation	**$1,491**	**$76,352**	**$5,557**	**$13,521**	**$1,359**	**$98280**

6.13 Revenue wash-up cost allocation

The revenue wash-up represents to the difference between actual allowable revenue and actual revenue in the assessment period two years prior. As it relates to total revenue, we have allocated the wash-up amount to connection categories in proportion to forecast allowable revenue for the current assessment period. Large capacity connections do not attract any of the wash-up as their delivery charges for the relevant assessment period have already been washed-up in accordance with their delivery services agreement. The resulting cost allocations are:

	Street lighting '000	General '000	Irrigation '000	Major customer '000	Large capacity '000	Total '000
Revenue wash-up cost allocation	$22	$1,658	$99	$312	$0	$2,093

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7. Revenue summary

The table below summarises the total projected revenue from the distribution and transmission parts of our pricing for each of the connection categories for 2023-24 compared to the projection for the previous (2022-23) year. Changes in revenue are a product of both changes in price and changes in chargeable quantities, and these are also set out in the table:

	Street lighting '000	General '000	Irrigation '000	Major customer '000	Large capacity '000	Total '000
Projected revenue 2023-24						
Distribution	2,283	143,529	9,393	23,444	2,598	181,243
Transmission	64	41,466	1,534	11,670	1,363	56,094
Delivery	**2,347**	**184,995**	**10,927**	**35,105**	**3,960**	**237,340**
Revenue change compared to previous year						
Distribution	(282)	16,243	21	1,136	240	17,358
Transmission	(106)	(5,874)	(520)	(1,733)	(1,130)	(9,363)
Delivery	(388)	10,370	(499)	(597)	(890)	7,995
Weighted average price change compared to previous year						
Distribution	(1.8%)	3.4%	3.7%	3.5%	19.7%	3.6%
Transmission	(4.1%)	(12.0%)	(14.1%)	(11.6%)	(11.9%)	(12.0%)
Delivery	(1.8%)	(0.6%)	0.7%	(2.1%)	5.9%	(0.7%)
Weighted average quantity change compared to previous year						
Distribution	0.7%	1.0%	(0.3%)	0.6%	(1.2%)	0.9%
Transmission	1.3%	0.5%	0.4%	(1.6%)	(4.7%)	(0.1%)
Delivery	**0.7%**	**0.9%**	**(0.3%)**	**(0.2%)**	**(2.7%)**	**0.6%**

*Individual unit prices are set out against previous prices in a schedule in Appendix A, showing changes and percentage changes to each price. The factors driving these changes are set out in section 6 above.

8. 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 to 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 6.7 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.

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 $68 per kW per year (as noted in Appendix H).

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.

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Appendix A - Price schedules

Schedule of changes to electricity delivery prices

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(applicable from 1 April 2023)

This schedule lists changes to 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 the electricity itself.

Connection categories and price components	Units	Previous delivery price (1 April 2022 to 31 March 2023)	New delivery price (from 1 April 2023)	Change	Percentage change
Streetlighting connections					
Fixed charge	$/con/day	0.0978	0.0970	(0.0008)	(0.8%)
Peak charge (peak period demand)	$/kW/day	0.3660	0.0928	(0.2732)	(74.7%)
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)	$/kWh	0.05946	0.09414	0.03468	58.3%
Nights & weekends (Sat & Sun)	$/kWh	0.01844	0.01844	-	-
General connections					
Fixed charge	$/con/day	0.3000	0.4500	0.1500	50.0%
Fixed charge - General Group 1 (Small SME)	$/con/day	0.3000	0.6100	0.3100	103.3%
Fixed charge - General Group 2 (Medium SME)	$/con/day	0.3000	0.9832	0.6832	227.7%
Fixed charge - General Group 3 (Large SME)	$/con/day	0.3000	1.1835	0.8835	294.5%
Peak charge (peak period demand)	$/kW/day	0.3660	0.0928	(0.2732)	(74.7%)
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)	$/kWh	0.05946	0.09414	0.03468	58.3%
Nights & weekends (Sat & Sun)	$/kWh	0.01844	0.01844	-	-
Low power factor charge	$/kVAr/day	0.2000	0.2000	-	-
Irrigation connections					
Capacity charge*	$/kW/day	0.4308	0.2933	(0.1375)	(31.9%)
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)	$/kWh	0.05946	0.09414	0.03468	58.3%
Nights & weekends (Sat & Sun)	$/kWh	0.01844	0.01844	-	-
Rebates					
Power factor correction rebate*	$/kVAr/day	(0.1590)	(0.1083)	(0.0507)	(31.9%)
Interruptibility rebate*	$/kW/day	(0.0398)	(0.0271)	(0.0127)	(31.9%)
* applied from 1 October to 31 March only					
Major customer and embedded network connections					
Fixed charge	$/con/day	10.0000	15.0000	5.0000	50.0%
Fixed charge (additional connections)	$/con/day	5.0000	10.0000	5.0000	100.0%
Extra switches	$/switch/day	3.2000	3.6700	0.4700	14.7%
11kV Metering equipment	$/con/day	4.5000	5.0200	0.5200	11.6%
11kV Underground cabling	$/km/day	3.7100	4.4000	0.6900	18.6%
11kV Overhead lines	$/km/day	2.6000	3.1800	0.5800	22.3%
Transformer capacity	$/kVA/day	0.0106	0.0122	0.0016	15.1%
Peak charge (control period demand)	$/kVA/day	0.3547	0.2949	(0.0598)	(16.9%)
Nominated maximum demand	$/kVA/day	0.1061	0.1073	0.0012	1.1%
Metered maximum demand	$/kVA/day	0.0701	0.0748	0.0047	6.7%
Miscellaneous					
Monthly invoice and contract charge to retailers and directly contracted major customers	$/invoice	30.00	49.00	19.0000	63.3%
Failure to pay notice	$/notice	50.00	123.00	73.0000	146.0%
Default and termination notice	$/notice	100.00	100.00	-	-
Export credits					
0 - 30kW generation					
Anytime credits (without PV), *or*	$/kWh	(0.0028)	(0.0026)	(0.0002)	(7.1%)
Anytime credits (with PV), *or*	$/kWh	(0.0001)	(0.0001)	-	-
Peak period credits (with or without PV)	$/kWh	(0.1992)	(0.1830)	(0.0162)	(8.1%)
30 - 750kW Control period credits	$/kW/day	(0.0682)	(0.0625)	(0.0057)	(8.4%)
plus	$/kVAr/day	(0.0224)	(0.0205)	(0.0019)	(8.5%)

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Appendix B - Regulatory requirements: pricing principles and information disclosure

This appendix outlines and comments on the aspects of this methodology that relate to the regulatory requirements of the Electricity Authority's (the "Authority") pricing principles and the Commerce Commission's (the "Commission") information disclosure requirements.

In 2019 the Authority published the distribution pricing principles to set clear expectations for efficient distribution prices. The Authority considers that efficient distribution pricing is for the long-term benefit of consumers and that efficient distribution pricing will provide signals that help households and businesses to consume the right amount of electricity, at the right time, and in the right place.

Shortly after publishing the distribution pricing principles, the Authority published a "Practice Note" to help distributors interpret and apply the distribution pricing principles and has also introduced a "scorecard" to evaluate distributors' pricing plans against the Authority's Distribution Pricing Principles. The Authority published a refreshed Practice Note in December 2021 and an updated Note in February 2022 with an emphasis on expected timeframes for distribution pricing reform and what 'good looks like'.[11]

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[12] 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,

[11] https://www.ea.govt.nz/assets/dms-assets/29/Distribution-Pricing-Practice-Note-2021-2nd-edition.pdf

[12] 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.

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	795		Estimated cost per kWh*	$0.68
	Customer service, billing, and admin	497		Annual volume (MWh)	15,331
	Transpower residual charge,benefit based charge and transitional cap	233			
		1,525	**2,348**	Total cost	**10,425**
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	17,471			
	Customer service, billing, and admin	25,526		Estimated cost per kWh*	$0.48
	Transpower residual charge,benefit based charge and transitional cap	34,827		Annual volume (MWh)	2,337,501
		77,825	**184,991**	Total cost	**1,122,001**
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	284			
	Customer service, billing, and admin	1,855		Estimated cost per kWh*	$0.68
	Transpower residual charge,benefit based charge and transitional cap	3,698		Annual volume (MWh)	137,625
		5,837	**10,254**	Total cost	**93,585**
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	991			
	Customer service, billing, and admin	4,514		Estimated cost per kWh*	$0.48
	Transpower residual charge,benefit based charge and transitional cap	10,023		Annual volume (MWh)	864,091
		15,528	**35,105**	Total cost	**414,764**
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	244			
	Customer service, billing, and admin	534		Estimated cost per kWh*	$0.38
	Transpower residual charge,benefit based charge and transitional cap	1,820		Annual volume (MWh)	144,376
		2,598	**3,845**	Total cost	**54,863**

* 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).

The LRAIC that we estimate is both a long-run and a network-wide value. Using a long-run network-wide pricing approach avoids the price volatility that would occur if a short-run approach was taken to manage localised constraints and recognises the fact our network is highly interconnected and constrained areas change as network switching or upgrades occur to alleviate the constraint. By providing a long-term price signal against which customers (or retailers or third parties) can invest in demand-side alternatives wherever they are on the network we help ensure that the demand response will be consistent and so can be assumed in our network design and planning. In this way we believe we align with principle (a)(ii).

Peak pricing also ensures that customers that use more of our service contribute more to the cost of providing that service. The LRAIC based peak pricing approach provides a useful mechanism to share the cost of existing peak capacity driven investments, and inherently provides a basis to trade peak load contributions – that is, a reduction by one customer can be taken up by another, and the peak price provides a reward to the first customer funded by the second customer, which aligns with principle (a)(iii). This trading of network capacity between customers also inherently avoids capacity upgrades that would otherwise occur, and in this context the LRAIC based price aligns with principle (a)(ii), reflecting the impact on economic costs that would otherwise occur (including in areas where no capacity upgrades are planned).

Peak pricing reflects Orion's assessment of LRAIC and any customer who reduces demand at peak times (be it by generation and / or load reduction) effectively reduces their costs by LRAIC i.e., customers are effectively electing to employ a network alternative where it is economic to do so. Orion will build more network when customers have shown collectively that they are electing to use our service on the basis that it is available at a lower cost than the alternatives (aligning with principle (a)(iv)). This is further explained in section 6 of the pricing methodology above.

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 interconnection 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.

Orion

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.

The LRAIC-based component of our pricing does not recover allowed revenue. 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.

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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 3.2, 5, 6.15, 7, 7.8 and Appendix A.
2.4.1 (3)	See sections 4.5 and 7.7 for non-standard contracts. See section 8 for distributed generation.
2.4.1 (4)	See section 2.8.
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 7.
2.4.3 (2)	See the first part of this 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 3.2 and 7.8.
2.4.3 (7)	See section 6.
2.4.3 (8)	See section 7. This shows amounts rather than proportions.
2.4.4 (1) to (3)	See sections 2.9, 2.10, 3.3 and Appendix C.
2.4.5 (1) (a) to (c)	See sections 4.5 and 7.7.
2.4.5 (2) (a) & (b)	See section 4.5.
2.4.5 (3) (a) & (b)	See sections 6.6, 8 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	**Design and develop**	Implement	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 types	Model	Implement	Review and refine
Transmission pricing	**Implement**	Review	Review
De-weight peak pricing	**De-weight peak charge**	Remove peak charge	Review
TOU pricing	Consult	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.

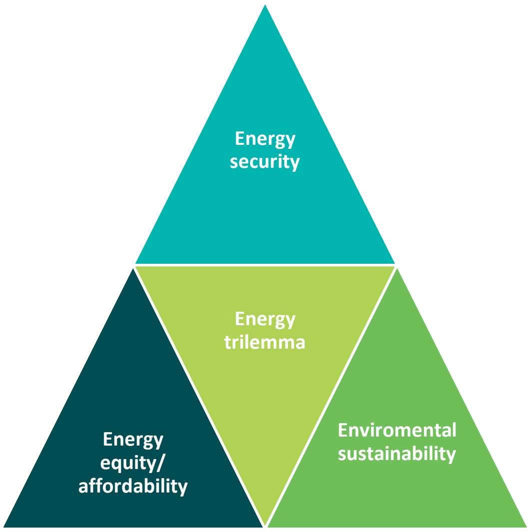
Our strategy for electricity delivery pricing

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[13] 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.

[13] 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

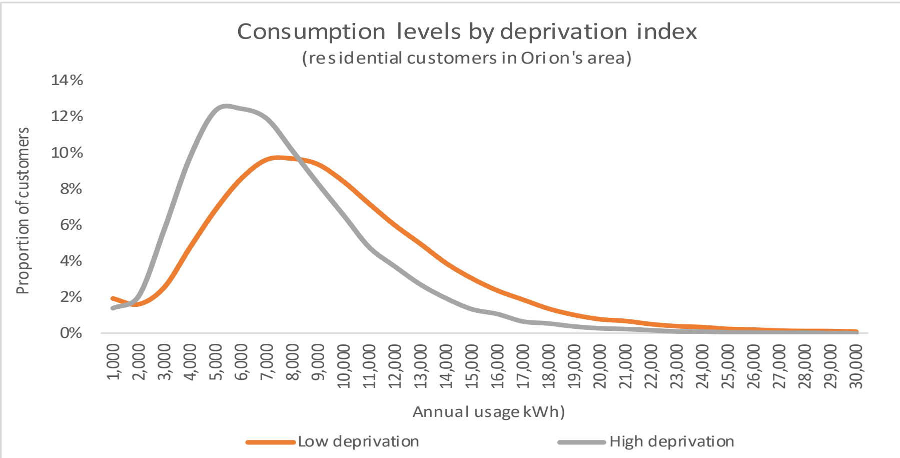
- instead use time-of-use volume pricing to provide clearer signals and rewards for residential customers that help ease congestion
- support overnight water heating and electric vehicle charging

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.



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.

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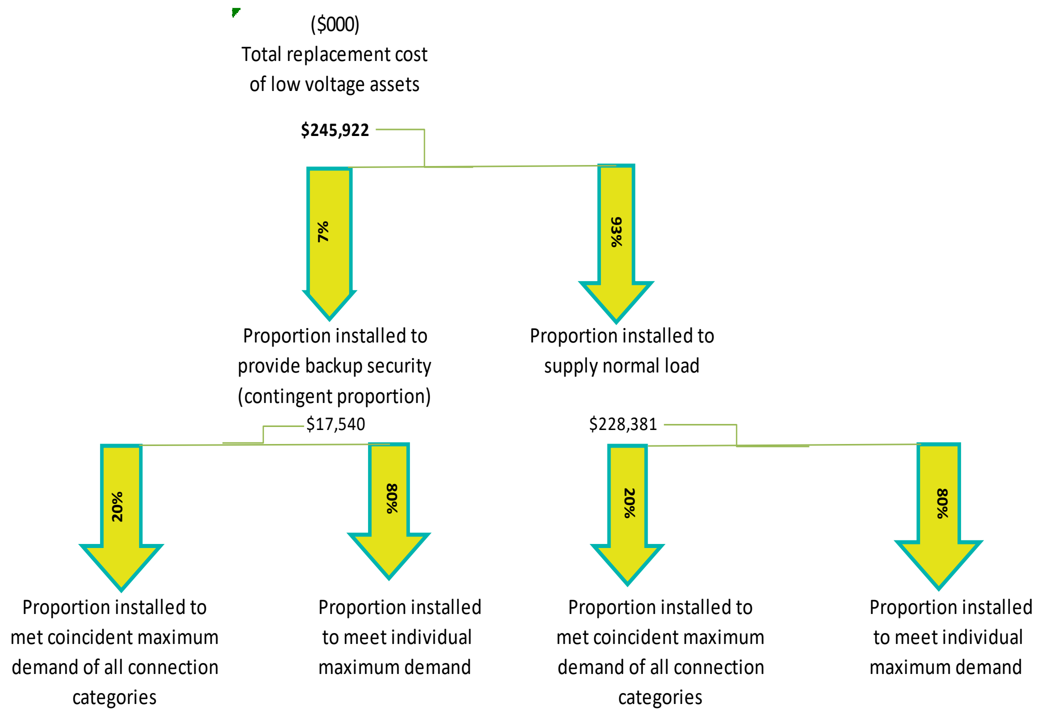
Appendix G – Asset allocation example

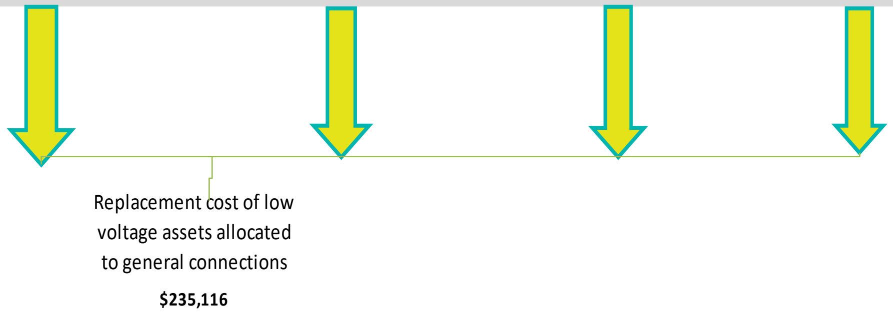
Example calculation

Asset allocation for low voltage assets to general connections

(based on replacement cost established in last regulatory ODV valuation)



	$3,508	$14,032	$45,676	$182,705
Asset allocators applied				
Relative use of assets factor	1.00	1.00	1.00	1.00
VOLL	$18.88/kWh	$18.88/kWh		
AMD Loading		2,149,178 kW		2,149,178 kW
ADMD Loading	502,532 kW		502,532 kW	
Product of allocators (N)	9,488,051	40,577,527	502,532	2,149,178
Product of allocators across all connection categories (D)	10,454,584	42,413,366	544,678	2,226,435
Allocation proportion (N / D)	90.8%	95.7%	92.3%	96.5%
Allocated asset value	$3,184	$13,425	$42,142	$176,365



Appendix H - Derivation of LRAIC

Appendix H

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	679.1 MVA
Lower LV network	557.5 MVA

Step 2

Estimate the replacement cost of the network	
Upper HV network	$1,399 m
Lower LV network	$579 m
Total replacement cost	$1,978 m

Step 3

Estimate the proportion of replacement cost that is load dependent	
Upper HV network	$798 m
Lower LV network	$270 m
Total replacement cost	$1,069 m

Step 4

Estimate the proportion of the load dependent replacement cost that is sized for loadings coincident with network peaks	
Upper HV network	$667 m
Lower LV network	$80 m
Total replacement cost	$747 m

Step 5

Calculate load dependent replacement cost per kVA	
Upper HV network	$982 /kVA
Lower LV network	$143 /kVA
Total replacement cost	$1,126 /kVA

Step 6

Annualise the replacement costs and add in network average operations and maintenance	
Upper HV network	$56 /kVA/year
Lower LV network	$9 /kVA/year
Total	$65 /kVA/year

Notes

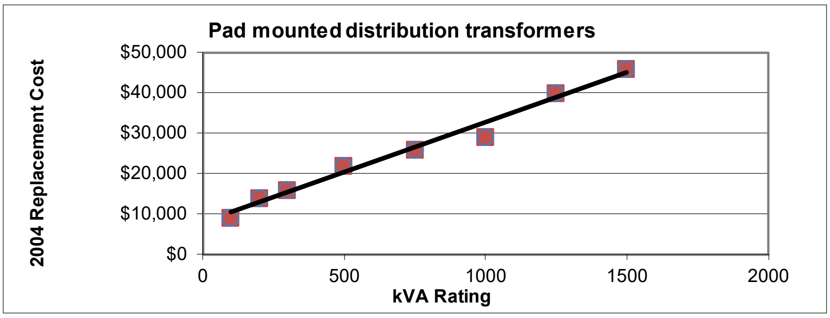
Step 1
This is the combined coincident peak demand of all loads

Step 2
Estimated as an average over the applicable pricing year

Upper network includes distribution transformers and above

Step 3

Individually assessed for each class of asset. For example, the cost of various size pad mounted distribution transformers shows that the fixed (load independent) cost is close to $8000 (the y-axis intercept in the graph below), and for our installed quantaties of these assets, this load independent cost equates to 48% of the total replacement cost



Step 4
This tends to be a considered engineering assessment. For example:

Asset	**Network peak load dependent proportion**	
Customer service fuses	Nil	While load dependent, these are sized to meet each customer's own peak load irrespective of the network peak load.
Low voltage conductors	35%	Based on the diversity between the sum of non-coincident peak demands of connections compared to that of distribution transformers.
11kV conductors	83%	Based on the diversity between the sum of non-coincident peak demands of distribution transformers compared to that of zone substations.
33kV and 66kV conductors	95%	Based on the diversity between the sum of non-coincident peak demands of zone substations compared to that of the total network.

Step 5
Simple division of load dependent replacement cost by the peak load delivered (both shown above)

Step 6
- Annualisation includes a levilised regulatory return, depreciation, taxation (including an allowance for the expected deprectaion tax shield), and asset based operation and maintenance costs.
- The upper HV network has an average total life of 52.3 years while the lower LV network has an average total life of 50.3 years.
- Budgeted operations and maintenance equates to 3.4% pa of RC for the upper HV network and 3.1% for the lower LV network.
- No allowance is made for administration cost on the basis that these are not asset or load dependent.

This annual cost is reflected in our peak pricing:
with adjustments for the basis of charging (ie loss factor and power factor adjustments),
smoothing the impact of changes (eg as a result of loading variablity) over a number of years, and
recognising the use of assets (in particular, major customers do not use the lower LV network)

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Appendix I - 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**

1 March 2023