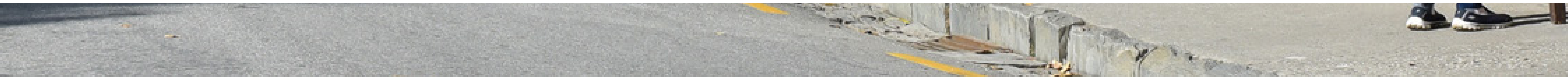
HAVE YOUR SAY
ON FUTURE PRICING

A CONSULTATION DOCUMENT ON PROPOSED DISTRIBUTION PRICING CHANGES

NOVEMBER 2021

Aurora
ENERGY



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SETTING THE SCENE
AN INTRODUCTION

Aurora Energy is New Zealand's seventh largest electricity distribution network, supplying power to over 92,000 homes, farms and businesses in Dunedin, Central Otago and Queenstown Lakes. We operate a major and essential part of the region's infrastructure, delivering around 1,300 gigawatt hours of electricity each year through a local network of poles, power lines, underground cables, substations and other equipment. The prices you pay reflect this service – to ensure you have electricity when and where you need it.

Along with other electricity distribution providers in New Zealand, we are looking to reform how we price the service we provide, and through it, the prices you pay. The current structure of distribution pricing across our country needs to change so that the charges customers pay for using electricity are simpler, more cost-reflective, more transparent, and more efficient in the long-term, whilst also giving customers greater control over their energy choices.

As Aotearoa drives decarbonisation efforts, customers are increasingly considering investment in technologies such as solar panels, batteries, electric vehicles (EVs) and home energy management systems.
With the emergence of these new technologies there is now more choice and control around how customers use energy, but with it too, increasing and changing demand needs on the network. These changes have demonstrated the limitations of the current distribution pricing approach, as how prices are structured will potentially affect how customers respond to, and make choices around, sustainable energy opportunities and new technologies.

The Electricity Authority is encouraging a move towards cost-reflective pricing structures to help send customers better pricing signals to support the choices they make and how they use electricity.

Aurora Energy has taken the time to consider the impacts of any future pricing changes to find a balance between what is efficient and fair for the majority of our customers. We are seeking feedback on proposed changes to our pricing approach so that it supports New Zealand's drive toward electrification and decarbonisation, as well as improves transparency and fairness of cost allocations.

This Consultation marks the first step in our journey towards more cost-reflective pricing. We want to share our strategy for making improvements to our pricing structures as well as changes we propose to improve the equitable sharing of network costs between our different regional pricing areas.

WE HAVE STRUCTURED THIS DOCUMENT IN TWO PARTS. WE WANT YOUR FEEDBACK ON...

1.

OUR PRICING STRATEGY
PART A

THIS OUTLINES OUR LONG-TERM APPROACH TO PRICING, AND THE STEPS WE THINK ARE NEEDED TO MAKE OUR PRICING MORE COST-REFLECTIVE.

2.

OUR PRICING METHODOLOGY
PART B

THIS OUTLINES THE STEPS WE ARE PROPOSING TO SIMPLIFY AND IMPROVE HOW WE ALLOCATE COSTS TO EACH OF OUR PRICING AREAS.

CONSULTATION TIMELINE AND PROVIDING FEEDBACK

We recognise that pricing change is complex and has the potential to impact both retailers and customers. Your views are essential to helping us improve our strategy and to implementing change effectively.

We want our pricing information to be accessible, clear, and understandable, and we are committed to an open and transparent Consultation* process. We welcome your views on the topics presented in this document.

*For clarification, this Consultation does not seek views on the total level of revenue that Aurora Energy can recover from its customers. In March 2021, the Commerce Commission set limits of the total revenue that we can earn for the period through to 31 March 2026 in its final Customised Price-Quality Path (CPP) determination, which followed a period of extensive customer consultation by both ourselves and the Commerce Commission.

THE TIMELINE

- CONSULTATION COMMENCES — 15 November 2021
- CUSTOMERS REVIEW & PROVIDE FEEDBACK — 15 November - 3 December 2021
- CONSULTATION CLOSES — 3 December 2021
- AURORA ENERGY FINALISES 2022/23 PRICING BASED ON FEEDBACK — January – March 2022
- AURORA ENERGY PUBLISHES 2022/23 PRICES AND ITS RESPONSE TO CONSULTATION FEEDBACK — 31 March 2022

GUIDE TO MAKING A SUBMISSION

We have included a series of feedback questions online to help you develop your submission, and to help us understand your feedback.
Our Consultation closes on 3 December 2021.
To provide feedback on our proposal go to:

YOURSAY.AURORAENERGY.CO.NZ

Alternatively, if you would like to send a hardcopy submission, you can download the form at yoursay.auroraenergy.co.nz or call us on **0800 220 005** to request a copy.
You can post or email your submission to:
Aurora Energy Pricing Consultation
PO Box 5140
Dunedin, 9054
Email: yoursay@auroraenergy.nz

PART A

OUR PRICING STRATEGY EXPLAINED

WHY WE THINK PRICING NEEDS TO CHANGE, HOW WE'RE PROPOSING TO CHANGE IT, AND WHO THE CHANGES WILL IMPACT

BEFORE WE GET STARTED
POINTS TO CLARIFY

BEFORE WE EXPLAIN OUR PRICING STRATEGY, WE THINK IT'S IMPORTANT TO CLARIFY AND PROVIDE SOME BACKGROUND ON TWO KEY ASPECTS OF WHAT IS BEING PROPOSED.

OUR PROPOSAL PRESUMES THAT OUR FUTURE DISTRIBUTION CHARGES WILL BE TRANSPARENTLY PASSED THROUGH TO YOU BY YOUR ELECTRICITY RETAILER.

THE TRANSPARENCY OF OUR DISTRIBUTION CHARGES

As part of our Pricing Strategy, we outline how customers can benefit from future distribution pricing if they are able to see and react to new price signals. We are mindful, however, that Aurora Energy has no control over the price signals customers actually see, as our charges are billed to Electricity Retailers who can choose how those charges are passed on.

Because Electricity Retailers combine several costs, including wholesale energy costs and distribution costs, there is no guarantee that our new distribution prices will pass transparently through to your electricity bill. We know that some Electricity Retailers transparently pass through our charges, while others repackage our charges in different ways.

Our proposal presumes that our future charges will be transparently passed through to you by Electricity Retailers, and that you will receive a price signal that allows you to understand the cost implications of using electricity at different times and react accordingly, if you choose to do so.

In our Consultation feedback questions online at **yoursay.auroraenergy.co.nz**, we ask for your views on how important you think it is for Electricity Retailers to transparently identify Aurora Energy's charges on your electricity bill. We welcome your feedback on this.

THE PROPOSED WAY OF PRICING OUR SERVICES WILL NOT REVERSE THE PRICE INCREASES THAT ARE TO COME OVER THE NEXT FEW YEARS AS PART OF OUR CPP WORK PROGRAMME.

THE FINANCIAL BENEFITS OF OUR PRICING STRATEGY

Our Pricing Strategy explains that by providing price signals which give customers incentives to change the way they consume electricity, we may be able to defer or even avoid some growth-related network investments. If we can avoid investment, then we can hold prices lower than they otherwise would have been because the cost of our investments are recovered through our charges to customers.

We need to be very clear, however, that our prices are on an upward path, as a result of the significant investments we need to make in asset renewals - which were approved by the Commerce Commission earlier this year (as part of our Customised Price-Quality Path application and consultation process).

The proposed way of pricing our services as part of this Consultation will not reverse the price increases that are to come over the next few years as part of our CPP work programme.

We are confident that our Pricing Strategy can offer customers savings over the long term, but those savings are relative to what charges would otherwise be if our pricing remained unchanged and did not offer incentives to change the way electricity is consumed.

OUR PRICING STRATEGY AT A GLANCE

OUR FIVE-POINT PLAN

OUR 5-POINT PLAN EXPLAINED
PRICING STRATEGY '101'

On 1 April 2021 we published our pricing strategy and roadmap on our website **auroraenergy.co.nz/disclosures/pricing/pricing-strategy-and-roadmap/**

REFINE HOW WE ALLOCATE COSTS TO PRICING AREAS

This has been an early priority for our strategy implementation and addresses an area of heightened community interest after our Customised Price-Quality Path (CPP) consultation. Improving our approach to how network investment costs are allocated to pricing areas is a key part of our pricing strategy. Our proposal for this is outlined in Part B of this Consultation document.

REFORM PRICING STRUCTURES

The cornerstone of our strategy is to transition to cost-reflective pricing. For residential customers, we think Time-of-Use (ToU) pricing is the best structure to do this. ToU targets times of investment pressure, and better signals the cost of using energy at different times of the day to help customers have more control over their choices, and what they pay.

ENHANCE CONTROLLABILITY DISCOUNTS

We already provide discounted prices for managed hot water and space heating. We will need to align the design of these discounts with our new pricing strategy and, as part of that, explore how we can make them available for managed electric vehicles (and possibly other technologies) in the future.

SIMPLIFY COST ALLOCATION WITHIN PRICING AREAS

Much of the complexity in our current pricing arrangements comes from the way we allocate costs to load groups. As we move to full implementation, we want to explore a simpler approach while maintaining cost-reflectivity. This aspect of our pricing strategy is more relevant to our non-residential (general) pricing.

DEVELOP ECONOMIC COST ESTIMATES

To implement cost-reflective pricing, we need sound estimates of the long-run marginal cost of supply (LRMC) in each of our pricing areas. This is a new input to our pricing approach and is based on engineering and economic methodologies. It will also move slowly over time, so will need updating every 5-10 years.

IMPLEMENT GRADUALLY AND CAREFULLY

We want to avoid unnecessarily exacerbating the bill pressure our customers already face as we implement our CPP work programme. Implementing pricing reform gradually and carefully, together with consultation like this, is a big part of our commitment to pricing reform.

THE ROADMAP

FROM 1 APRIL 2022
- Confirm pricing strategy based on Consultation feedback
- Implement revised cost allocators to pricing areas for overhead and capital investment-related costs
- Phase out the Low-User Fixed Charge in line with regulation changes
- Publish a single delivery price in our annual pricing schedules
- Improve the clarity of our Pricing Methodology document

FROM 1 APRIL 2023
- Phase in mild ToU pricing so customers have time to understand and adjust
- Move to a greater proportion of revenue being recovered through fixed charges so cost subsidies are removed and charges become more uniform for all
- Introduce any enhancements needed to controllability discounts
- Consider changes to our non-residential (general) pricing structures

FROM 1 APRIL 2024-26
- Continue to refine and rebalance pricing structures
- Ongoing impact analysis and adjustments

FROM 1 APRIL 2027
- Complete pricing structure transition
- Future pricing confirmed

THE CONTEXT
TRANSITIONING TO COST-REFLECTIVE PRICING

FOR OVER A CENTURY MOST RESIDENTIAL DISTRIBUTION PRICES HAVE BEEN BASED ON ELECTRICITY CONSUMPTION, REGARDLESS OF THE TIME OF DAY IT IS USED.

YET, OUR COSTS ARE BASED ON MANAGING THE NETWORK AROUND PEAK AND OFF-PEAK DEMAND NEEDS.

- We have an early morning peak on our network as people wake up, turn on heating, have showers and cook breakfast
- We have an early evening peak on our network when people return from work, heat their homes, cook meals, and watch television.

IF THE GROWTH IN PEAK DEMAND CAN BE EFFECTIVELY MANAGED WE MAY BE ABLE TO MINIMISE COSTLY INFRASTRUCTURE UPGRADES, AND THEREFORE, THE PRICES YOU PAY.

Managing the morning and evening peaks is important for distribution providers like Aurora Energy, as we have to build our networks with enough capacity to cope with these peak periods.

It is now also important in the context of changes facing our industry as consumers adopt new technologies such as electric vehicles (EVs), micro-generation (solar PV, micro-wind and micro-hydro), home energy storage systems (batteries) and smart appliances. These technologies can have an impact on the demand needs of the electricity network – either negatively by increasing network demand, or positively by using smart programming to avoid network peaks or by injecting energy into the network to offset the peak.

Further change is being driven by decarbonisation, including the electrification of process heat and transport. The Climate Change Response (Zero Carbon) Amendment Act 2019 seeks to reduce net emissions of all greenhouse gases (except biogenic methane) to zero by 2050. Further affecting the electricity industry is the Government's aspirational goal of reaching 100 percent renewable electricity generation by 2030.

Electricity distributors have an important part to play in this changing environment by ensuring that our networks can adapt to the increasing demands of electrification and meet the changing needs of consumers.

Improvements in pricing structures are necessary to encourage electricity consumption behaviour that minimises peak demand and ultimately supports efficient investment in the electricity network. Across New Zealand electricity distributors are moving toward pricing structures that reflect the underlying costs of providing electricity. Historically, our pricing was simply designed to recover the cost of investments we had made in the network, with some discounted pricing to reflect our ability to control, or turn off, some appliances at specific times (e.g. hot water cylinders and night-store heaters).

In the future, we intend that our pricing will signal the future cost of electricity distribution and provide customers with an incentive to modify their electricity consumption so that costly network upgrades are avoided or deferred, resulting in lower costs for all customers.

COST-REFLECTIVE PRICING SENDS BETTER SIGNALS TO CUSTOMERS FOR THE COST OF USING ELECTRICITY AND REMOVES CROSS-SUBSIDIES WHERE SOME PAY MORE THAN THEIR FAIR SHARE OF NETWORK PRICES, AND SOME PAY LESS.

OUR PRICING STRATEGY FOR RESIDENTIAL CUSTOMERS WE’RE PROPOSING SOME CHANGES

Our first priority for transitioning to more cost-reflective pricing over the next five years is to make changes to residential pricing structures.

Residential customers are defined as those customers with an electricity connection that is their primary place of residence.

The key changes we are proposing to make to residential prices are outlined in this section of the Consultation Document.

The changes we are proposing do not increase the total revenue we receive from customers or the relative proportion of revenue recovered from each pricing area.

WE PROPOSE
NEW TIME-BASED CHARGES TO SIGNAL PEAK PERIODS

WE INTEND PHASING IN TIME-OF-USE CHARGES OVER A FIVE-YEAR PERIOD FROM 1 APRIL 2023.

TIME-OF-USE IS THE 'SWEET SPOT' FOR RESIDENTIAL CUSTOMERS FOR NOW. OTHER PRICING OPTIONS ARE TOO SOPHISTICATED FOR RETAILERS TO IMPLEMENT OR FOR CUSTOMERS TO OPERATIONALISE.

We think it's important that residential customers have more control over the prices they pay. Cost-reflective pricing is an important tool that allows us to signal the relative cost of peak demand on the network and encourage customers to shift their electricity usage to lower priced, off-peak periods, where feasible.

To encourage the time-shifting of electricity consumption, we propose to implement Time-of-Use (ToU) pricing that sets higher prices during costly periods of peak demand, and lower prices during off-peak periods.

This is a change to existing residential line charges, where revenue is recovered based on the amount of electricity that is used without any consideration of when the electricity is consumed. This inconsistent charging approach has been in place for over a century and has largely been dictated by the available metering technology - put simply, the limitations of legacy metering equipment meant there just wasn't a better way available. With the wide-spread deployment of advanced (smart) meters in the past decade, options now exist to develop line charge pricing that better matches distributors' cost structures.

ToU pricing can send signals that help customers make efficient decisions about electricity usage and appliance purchases. ToU pricing can be implemented by most retailers now, and is relatively easy for customers to understand.

To design appropriate ToU pricing, we need to set peak periods that correspond to times of elevated network demand which, if ignored, could lead to significant investment in the network to increase capacity and, consequently, price increases. Peak demand periods may be different in each of our pricing areas - for example, weekends may be off-peak in Dunedin but not Queenstown, and summer may be off-peak in Queenstown, but not Central Otago. Confirming appropriate peak periods will be an early priority.

We intend to implement introductory ToU charges from 1 April 2023, for customers that have smart meters installed, and gradually fine-tune the price signals over a five-year period. Customers without smart meters installed will not be able to be placed on ToU pricing, and we are likely to develop pricing strategies to incentivise those customers to request installation of a smart meter.

WE PROPOSE
TO RECOVER A GREATER PROPORTION OF REVENUE USING FIXED CHARGES

MOVING TOWARDS FIXED CHARGES FROM 1 APRIL 2023 MEANS THE AMOUNT PAID WILL BECOME MORE UNIFORM.

CURRENTLY, HIGH USE CUSTOMERS PAY DISPROPORTIONATELY MORE THAN LOW USE CUSTOMERS DESPITE THE COSTS OF SUPPLY BEING RELATIVELY SIMILAR.

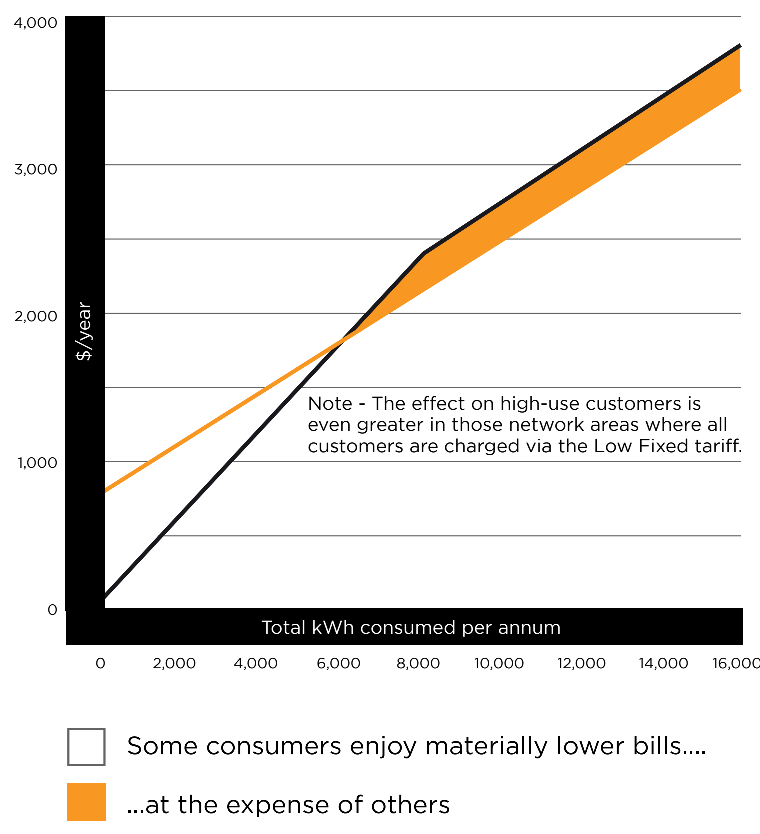
After first calculating the proportion of revenue that should be recovered from ToU charges in each pricing region (derived from the long-run marginal cost of forecast network growth investments), we will then recover the residual revenue through fixed charges. This approach reflects that distribution companies like Aurora Energy have costs that are largely fixed in the short-to-medium term and are independent of the amount of electricity that is transported through the network.

Moving towards more fixed charges means that the revenue recovered from each connection within a customer group is likely to become more uniform. Currently, network costs are being over-recovered from high users, and under-recovered from low users, leading to a degree of cross-subsidisation within customer groups, which creates the risk of uneconomic bypass.

With this proposed change, customers will see their variable prices drop, and their fixed prices rise. While some will pay more for their electricity use, and some will pay less, most customers will have similar bills overall and everyone will be paying their fair share for use of the network.

Increasing fixed charges will occur gradually over a five-year period, as the Government has set limits on how fast fixed charges can grow. It is important to note that, because the total amount of revenue Aurora Energy can charge in any year is fixed by Commerce Commission regulations, increases in fixed charges will be offset by corresponding reductions in variable prices.

The proportion of fixed charges to ToU charges may vary between pricing regions. A region that is starting to experience network congestion will see a greater proportion of ToU charges, whereas in uncongested regions, a greater proportion of charges will be fixed.



WE PROPOSE
TO PHASE OUT LOW-USER FIXED CHARGES

PHASING-OUT THE LOW-USER FIXED CHARGE FROM 2022 SUPPORTS OUR MOVE TOWARDS MORE COST-REFLECTIVE PRICING.

In September 2021 the Government announced the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (LFC Regulations) are to be phased-out over the next five-years. The LFC Regulations require that retailers must offer qualifying residential consumers (those consuming 9,000kWh or less per annum) a low fixed charge tariff that has a fixed charge component of no more than $0.30/day. The $0.30/day fixed charge is shared equally between retailers and distributors, meaning that the fixed charge component of line charges cannot be more than $0.15/day.

From 2022, the maximum fixed charge for distribution will increase by $0.15/day on 1 April annually, until 2027. At this point, the regulations will be removed and there will be no maximum fixed charge for low electricity users.

All of Aurora Energy's residential pricing is LFC regulation compliant. This reflects a decision made, when the regulations were introduced in 2004, to avoid the heavy administrative burden of identifying which residential customers were high users (using more than 9,000kWh per annum), which were low users, and tracking when customers moved in or out of the low user category.

Phasing out the LFC regulations supports our move towards more cost-reflective pricing and we will reflect the $0.15/day annual increase in our pricing for the next five years. While our proposed change to more cost-reflective pricing will not occur until 1 April 2023, we intend to increase our residential daily fixed charge from 1 April 2022 in accordance with the change in the LFC Regulations ($0.15 per day to $0.30 per day).

WE PROPOSE
TO RETAIN AND REFINE OUR CONTROLLED PRICES

WE WILL CONTINUE TO PROVIDE DISCOUNTED PRICES FOR CONTROLLED SUPPLY.

THIS WILL HELP US TO CONSIDER CONTROLLED PRICES FOR NEW TECHNOLOGIES IN THE FUTURE.

Our current pricing structure allows customers to choose to have some of their supply subject to control by Aurora Energy. A typical example of this arrangement is when customers opt to allow their hot water cylinders to be turned off during peak periods via Aurora Energy's ripple control system. Other appliances, like night store heaters, are controlled so that they only receive an electricity supply during off-peak periods. Customers who choose to have some of their electricity supply controlled in this way receive the benefit of discounted prices for that part of their supply.

We think it is still valuable to continue to offer customers the option of having a controlled supply, as it allows us more flexibility to manage network peaks, and ultimately reduces the amount of investment required in the network. Accordingly, we will continue to provide discounted prices for controlled supply. The discounted prices will be reviewed to make sure they complement the new ToU charges.

OUR PROPOSAL FOR COST-REFLECTIVE DISTRIBUTION PRICING AND THE IMPACT FOR THOSE WITH NEW TECHNOLOGIES

As electrification progresses, cost-reflective pricing will be increasingly important to provide customers with incentives to invest in new technologies that support more efficient use of electricity networks.

In this section of the Consultation Document we discuss the impact of various technologies on distribution networks, and how pricing will encourage their adoption.

FOR CUSTOMERS WITH SOLAR INSTALLATIONS WITHOUT BATTERY CAPABILITY

Customers with solar installations generate electricity during daylight hours, with more electricity typically generated in the middle of the day when the sun is strongest, and demand for electricity is relatively low. When a customer's generation exceeds their household demand, they may choose to export the excess electricity into the network. If there are clusters of customers all exporting energy into the same network circuit, this can create voltage issues which may lead to Aurora Energy requiring those customers to reduce their injection of electricity into the network at certain times; or investing in circuit upgrades so that larger volumes of generated electricity can be accommodated.

Network demand peaks tend to be at the beginning and end the day when there is less solar generation. If solar customers are unable to store the electricity they have generated during the day, they will still rely on supply from the distribution network during peak times and are not helping to reduce the required investment in network infrastructure.

In addition to receiving payment from their retailer for the electricity they export, these customers will continue to benefit from their solar investment by avoiding ToU charges to when they are consuming their own electricity during the day; however, their benefit may not be as great as those customers that invest in solar and a battery, as explained below.

FOR CUSTOMERS THAT USE SOLAR WITH BATTERY CAPABILITY

The challenge to the network of managing excess solar generation during the middle of the day, described above, can be avoided if customers also invest in a battery. Excess electricity generation is stored in the battery, instead of being exported into the network, and the battery can then be discharged to power a customer's household later in the day, when the solar panels are not generating.

Customers that use solar and batteries together can reduce their demand on the distribution network during peak times which helps reduce our future network investment.

Customers that pair a battery with their solar panels are likely to receive greater benefits than if they only had solar panels on their own. This is because the value of self-consumption is generally higher than the payments that would be received from exporting the excess energy into the network.

Cost-reflective pricing will encourage investment in battery storage by allowing customers to reduce their overall consumption from the network and avoid the higher consumption charges during peak network times.

FOR CUSTOMERS WITH STAND-ALONE BATTERY STORAGE

Customers can benefit from the installation of battery storage even if they do not have solar generation. Customers can use batteries to shift most of their electricity demand into off-peak periods. This is achieved by charging the battery from the network during off-peak times when prices are lower and then discharging to power their households during peak times, avoiding the higher peak prices.

Obviously, the benefit is greater if the battery is paired with solar panels, because customers generate a large proportion of their own electricity instead of buying it; however, a stand-alone battery can provide significant value when charges are based on Time-of-Use.

FOR CUSTOMERS WITH ELECTRIC VEHICLES

The increasing uptake of Electric Vehicles (EVs) will place a greater demand on distribution networks and it is important that pricing provides an incentive for customers to charge their EVs during off-peak periods, in order to minimise the level of network investment required to support electrification of transport. Future, cost-reflective pricing structures will provide stronger price signals at times of peak demand on the network. This means that customers who choose to charge their electric vehicles during peak times will pay more than those who are able to charge their vehicle at an off-peak time, such as the middle of the night.

As technology evolves, it may be possible for customers to use their EV's battery to supply their household during peak times, and then recharge overnight when electricity prices are lower, and therefore receive many of the benefits of a stand-alone battery owner described above.

A FUTURE OF DISTRIBUTED ENERGY RESOURCES (DER) AND FLEXIBILITY TRADERS

Customers are increasingly adopting new technologies to supply, or manage, their electricity needs. These can include generation assets such as solar panels, storage assets such as batteries, or automated load management devices. Collectively the industry refers to these assets as Distributed Energy Resources (DER).

Improving the cost-reflectivity of pricing will help manage periods of peak network demand by providing pricing incentives for customers to shift demand to off-peak periods. This will help defer investment in network upgrades and reduce costs for customers. However, pricing will only be able to achieve so much and, eventually, increased demand arising from electrification will start to exceed the capacity of the network. When demand reaches this point, Aurora Energy can further defer network investment by calling on DER to respond at very specific times within peak demand periods.

In practice, it is difficult for distribution companies like Aurora Energy to manage multiple DER assets across our network, so we will call on DER response via an intermediary known as a Flexibility Trader. The role of a Flexibility Trader is to manage a portfolio of customer-owned DER and provide additional supply to the network when required.

We will engage Flexibility Traders through commercial contracts when the cost of a DER solution is less than the cost of a physical infrastructure upgrade, which would result in lower costs to customers. Payments to Flexibility Traders and DER owners covered by the flexibility services contract are effectively made in lieu of upgrading the physical infrastructure, and as such will sit outside our standard pricing structure.

We have started using this approach in the Upper Clutha region and will keep an active watch on this. We will keep you updated as the future of emerging technologies continues to unfold.

OUR PRICING FOR GENERAL CONNECTIONS IS CURRENTLY MORE COST-REFLECTIVE THAN RESIDENTIAL PRICING. WE ARE KEEN TO CONSULT IN FUTURE ON SIMPLIFYING THE PRICING STRUCTURE FOR GENERAL CONNECTIONS.

OUR STRATEGY FOR PRICING GENERAL CONNECTIONS WE'RE PROPOSING NO CHANGES FOR NOW

General connections are defined as all those connections that are not residential – like businesses.

Overall, we consider that our pricing for general connections is more cost-reflective than residential pricing, with variable Control Period Demand (CPD) charges that reflect customer usage during periods of high network demand, and fixed charges that vary with the size and location of the customer's connection.

Our immediate priority is to improve residential pricing and look at adjustments to general pricing at a future date. While we have not considered general pricing in any detail, we think there may be opportunities to improve pricing structures so that they are simpler and easier to understand.

Much of the complexity of our general connection pricing comes from the relatively large number of customer load groups included in our pricing schedules. We think there is an opportunity to reduce the number of customer load groups, as well as the number of price components applying to each customer group.

While we are not proposing to make changes to general pricing at this time, we do intend to consult on changes that will simplify our general pricing structure in the future.

PART B

OUR PRICING METHODOLOGY EXPLAINED

HOW WE ALLOCATE COSTS, WHAT WE ARE PROPOSING TO CHANGE, AND WHAT IT WILL MEAN FOR CUSTOMERS

WE WANT YOUR VIEWS ON ASPECTS OF OUR PRICING METHODOLOGY

Our pricing methodology sets out the approach and key assumptions used to determine prices for each customer group in each pricing area of our network.

Each year, a new version of the pricing methodology is published on our website and includes the detailed inputs used to calculate prices for the year. The latest version of Aurora Energy's pricing methodology can be found at **auroraenergy.co.nz/disclosures/pricing/pricing-methodologies/**

In this part of the Consultation Document, we will address specific areas of our pricing methodology that we would like to either clarify or refine. We are keen to hear your views on:

- **OUR PRICING AREAS AND RATIONALE**
- **HOW WE ALLOCATE COSTS**
- **THE WAY PRICES ARE PUBLISHED**

To ensure that any changes made to our pricing methodology (as a result of this Consultation) are enduring, we have assessed our proposed options against the principles we consider to be fundamental to good pricing design, rather than focussing on the short-term impact that may arise from changes.

Any changes resulting from this Consultation will be reflected in the pricing methodology used to set prices from 1 April 2022.

OUR PRICING AREAS

Aurora Energy's network is served from five Grid Exit Points (GXPs); three in Central Otago and two in Dunedin. Feedback during our CCP Consultation in 2020 stimulated interest in pricing areas.

Currently the South Dunedin and Halfway Bush GXPs in Dunedin form a single pricing area, as do the Clyde and Cromwell GXPs in Central Otago. The Frankton GXP forms a standalone pricing area servicing Queenstown. We also operate a small, embedded network (residential subdivision) at Te Anau, which takes supply from The Power Company network.

DUNEDIN PRICING AREA

CENTRAL OTAGO PRICING AREA

QUEENSTOWN PRICING AREA

OUR RATIONALE
FOR DETERMINING PRICING AREAS

OUR CURRENT PRICING PHILOSOPHY IS THAT COSTS OF PROVIDING NETWORK ASSETS TO A PRICING AREA SHOULD LIE WHERE THEY FALL.

WE CONSIDER THAT OVERHEAD COSTS HOWEVER SHOULD BE SPREAD ACROSS THE ENTIRE CUSTOMER BASE, WHERE SCALE BENEFITS CAN BE REALISED.

Our pricing areas are defined by whether logical boundaries exist based on network layout (rather than arbitrary geographical or political boundaries), whether network areas are connected and able to offer load-sharing capability, or whether there are adjacent areas that could be consolidated because they have similar network characteristics.

Our CPP application process stimulated community (and regulator) engagement on the question of allocation to pricing areas, and as a result of customer feedback, we made improvements to the way we allocate operational costs to regional pricing areas before we set prices for the current year. We think the costs of providing network assets to a pricing area should lie where they fall (network capital and direct operating expenditure), and not be subsidised by customers that do not use those assets or benefit from them. We consider that overhead costs however should be spread across the entire customer base, where scale benefits can be realised.

Because regional pricing areas have different physical characteristics, there will be variations in pricing between pricing areas; however, because the overhead costs of operating the entire business are shared across all pricing areas, prices in each individual pricing area will be lower than if that pricing area was a stand-alone business operating in comparable circumstances.

Our strategy is to implement cost-reflective pricing across our network to ensure that prices provide clear economic signals about how customers' consumption choices impact the cost of providing the network, allowing us to design a more efficient network to meet the needs of customers. To achieve this strategy, it is important that our pricing areas reflect whether:

- The network layout is clearly defined and identified, with a clear link between costs and the services provided
- The areas are interconnected and able to support each other by transferring electrical demand
- Adjoining areas have similar network characteristics
- The benefits of separating out pricing areas offsets the costs of administering the additional pricing areas.

WE PROPOSE TO KEEP OUR REGIONAL PRICING AREAS AND REFINE HOW WE ALLOCATE COSTS TO THEM

We are not proposing to change our regional pricing areas. Overall, our current pricing area construct is broadly cost-reflective and consistent with the Electricity Authority's pricing principles. This view is supported by a review of Aurora Energy's regional pricing that was commissioned by the Electricity Authority in February 2021.

We are proposing that direct network costs lie where they fall, but the overhead costs for running our business be shared across pricing areas. In very simple terms, for example, that means if an area has 40% of network assets, those customers pay 40% towards maintaining and operating that investment. For overhead costs, if an area has 15% of Aurora Energy's total connections for example, then those customers would pay 15% of Aurora Energy's overhead expenses.

We consider that, as distributors use technology to gain greater visibility of their low voltage networks, a more granular view of network constraints will emerge. This is likely to shape the future of distribution pricing and we expect that greater differentiation of pricing across more pricing regions is likely to emerge over time.

HOW WE ALLOCATE OUR COSTS

In this section of the Consultation Document, we outline proposed refinements to our processes for determining the proportion of revenue that is recovered from each regional pricing area.

In response to customer feedback received during our CPP application process, we made improvements to the way we allocate operational costs to regional pricing areas earlier this year (before we set prices for the current year). We are now proposing to make further refinements, by changing the way that capital investment-related costs are recovered from each regional pricing area. Capital investment costs are those costs that are related to our direct investment in assets and generally comprise a return-on-investment, depreciation, revaluations, and tax.

Historically, we have used an estimate of asset 'Replacement Cost (RC)' to allocate our capital investment-related costs to regional pricing areas for recovery in prices. We have also used asset Replacement Cost (RC) to allocate other costs that are related to the value of Aurora Energy's assets. For example, Fire and Emergency New Zealand levies are imposed on Aurora Energy through insurance charges, which are based on Aurora Energy's asset value.

We consider that there may be a fairer and more objective option for allocating capital investment-related costs to regional pricing areas going forward. We want to get your views on the options available.

OUR RATIONALE FOR COST ALLOCATORS

We currently use proxy cost allocators for each component of forecast allowable revenue, to align the revenue we collect from each pricing area with the underlying costs of supplying services to that area.

We balance these considerations when choosing the proxy cost allocator for each cost category:

- How well the allocator reflects the drivers of costs
- How reliable and straightforward the allocator is
- Whether the allocator is transparent
- Whether the allocator is predictable and stable.

HOW WE CURRENTLY ALLOCATE COSTS

We currently use an estimate of asset Replacement Cost (RC) to determine the proportion of target revenue (recovery of costs) that is recovered in each pricing area. The table below shows the components of target revenue that are currently allocated to pricing areas by asset Replacement Cost (RC).

COMPONENT	% OF TOTAL COSTS	RATIONALE
CAPITAL RELATED COSTS:		
• Return on capital • Depreciation • Tax • Asset revaluations and other regulatory revenue	47.5%	All capital related costs are allocated to pricing areas in proportion to that pricing area's share of the total estimated network asset replacement cost. This approach reflects the level of network investment required by Aurora Energy to provide services.
PASS THROUGH AND RECOVERABLE COSTS:		
Local authority rates	0.9%	Rates are levied by councils based on Regulated Asset Base (RAB) value. Some rates are directly attributable to pricing areas; however, where allocation is required, we have maintained our allocation to pricing areas based on estimated asset replacement cost.
Commerce Act levies	0.3%	Commerce Act levies are allocated to distributors based on Regulated Asset Base (RAB) value. We have maintained our allocation to pricing areas based on estimated replacement cost.
Fire Emergency New Zealand (FENZ) levies	0.0%	FENZ levies are broadly based on asset values, via insurance premia. We have allocated FENZ levies to pricing areas based on the estimated asset replacement value of each pricing area.
IRIS – Capex	(1.2%)	The capex IRIS incentive in Regulatory Year 2022 (RY22) is a penalty for overspending capital expenditure allowances in the previous regulatory period. We have allocated the capex IRIS incentive (refund) amount based on the estimated asset replacement cost of each pricing area.

IMPROVING CAPITAL INVESTMENT-RELATED COST ALLOCATION OPTIONS AVAILABLE

We currently use estimated Replacement Cost (RC) as the basis for allocating capital investment-related costs (return on capital, depreciation, tax, and asset revaluations), as well as costs that Aurora Energy incurs based on the value of its assets.

RC is an adequate proxy for capital investment-related costs, as it is reasonably cost-reflective and is consistent with the Electricity Authority's pricing principles. However, it does have a weakness in that actual expenditure or depreciation costs for each region may not arise in proportion to regional replacement costs. As we continue our period of increased network investment, including our five-year CPP, it is appropriate that we revisit this method of cost allocation.

THERE ARE TWO ALLOCATORS THAT WOULD BE SUITABLE FOR DETERMINING THE RECOVERY OF INVESTMENT-RELATED COSTS IN EACH REGIONAL PRICING AREA.

It is important to keep in mind that the asset valuation methods described in this section of the Consultation Document are being used to determine the proportion of cost allocated to each regional pricing area for recovery in prices, therefore it is the relative differences between pricing areas that is relevant to price setting, rather than the absolute valuation amount.

We consider that there are two allocators that would be suitable for determining the recovery of capital investment-related costs in each regional pricing area - the current RC allocator and allocation using Regulated Asset Base (RAB) values - see below descriptions for each.

OPTION 1

REPLACEMENT COST (RC)

Defined as the present-day cost of building an equivalent network that would provide a broadly equivalent level of service. Our calculation of RC is based on standard replacement cost values published in the Commerce Commission's 2004 Optimised Deprival Valuation (ODV) Handbook. The values in the ODV handbook are adjusted for inflationary effects from the date of publication to present day, and then multiplied by the corresponding quantity of assets to determine the total RC in each pricing area. RC delivers a relatively stable network valuation, with annual changes limited to inflation and addition of new assets.

OPTION 2

REGULATED ASSET BASE (RAB)

RAB is the regulatory construct defined in the Commerce Commission's Input Methodologies that is used to value distributors' networks, and upon which they may earn a 'normal' return. Aurora Energy publicly reports its audited RAB as part of its annual regulated information disclosure. The RAB valuation changes each year to reflect asset additions and disposals, depreciation of existing assets, and asset revaluations. This means the RAB valuation is likely to fluctuate more than RC.

ANALYSIS OF COST ALLOCATION OPTIONS AND WHAT WE ARE PROPOSING

THE REGULATED ASSET BASE (RAB) METHOD IS A MORE ACCURATE REFLECTION OF THE ACTUAL NETWORK INVESTMENT IN EACH PRICING AREA.

THE ADVANTAGE OF RAB-BASED ALLOCATION IS IT LEVERAGES VALUES ALREADY USED IN REVENUE SETTING PROCESSES.

The options for allocating capital investment-related costs have been assessed against our cost allocator rationale in the table below.

		ASSESSMENT CRITERIA			
		REFLECTS UNDERLYING COST DRIVERS	RELIABLE AND STRAIGHTFORWARD CALCULATION	ALLOCATOR IS TRANSPARENT	ALLOCATOR IS PREDICTABLE AND STABLE
ALLOCATOR OPTIONS	**REPLACEMENT COST (RC)**	✔	✖	✖	✔
	REGULATED ASSET BASE (RAB)	✔	✔	✔	✖

Overall, we favour RAB as an allocator of capital investment-related costs as it is a regulated valuation methodology, audited, and publicly disclosed annually. While the RAB valuation method can be theoretically less stable than RC, it is a more accurate reflection of the actual network investment in each pricing area.

To enable RAB value to be used as an allocator, we engaged PricewaterhouseCoopers (PwC) to disaggregate our RAB (as published in our 2021 Information Disclosures) by regional pricing area, including reviewing the historic additions and disposals that occurred in each regional pricing area. From 1 April 2021, all asset additions and disposals are being recorded by regional pricing area, which allows us to update regional RAB values as part of the annual price-setting process.

The below table shows the relative proportions of RC and RAB value in each of our regional pricing areas.

It demonstrates that if Aurora Energy was to move from RC to RAB values as an allocator for capital investment-related costs, then:

- the Central Otago pricing area's share of capital investment-related costs would reduce by two percent; and
- the Dunedin and Queenstown pricing areas' share of capital investment-related costs would increase by one percent each.

ALLOCATION BASIS	PRICING AREA		
	DUNEDIN	CENTRAL OTAGO	QUEENSTOWN
ASSET REPLACEMENT COST (RC)	46%	35%	19%
REGULATED ASSET BASE (RAB)	47%	33%	20%

To demonstrate the impact of moving to RAB values as the allocator for capital investment-related costs, we have calculated the current year's revenue allocation using both the RC and RAB value methods and summarised these in the table below.

ALLOCATION BASIS	REGIONAL PRICING AREA		
	DUNEDIN	CENTRAL OTAGO	QUEENSTOWN
TOTAL REVENUE ALLOCATION USING RC	$56.6m	$31.0m	$19.4m
TOTAL REVENUE ALLOCATION USING RAB VALUES	$57.0m	$30.0m	$20.0m
CHANGE IN REVENUE ALLOCATION	+ $0.4m	- $1.0m	+$0.6m

In the table below, we have calculated the indicative impact on the monthly line charges paid by a standard residential customer resulting from the change in revenue allocation (refer to * below for the definition of a standard consumer). The indicative prices have been calculated using current year pricing and assumes no re-balancing of revenue allocation between residential and general connections.

		AVERAGE MONTHLY CHARGE FOR A STANDARD CONSUMER*		
		DUNEDIN	CENTRAL OTAGO	QUEENSTOWN
ALLOCATION BASIS	**INDICATIVE MONTHLY LINE CHARGE (RC)**	$69.80	$124.10	$97.00
	INDICATIVE MONTHLY LINE CHARGE (RAB)	$70.30	$120.10	$99.80
	ESTIMATED CHANGE IN MONTHLY LINE CHARGE	+$0.50	-$4.00	+$2.80

*A standard consumer consumes 9,000 kWh of electricity annually and has 20% of their total consumption controlled, with the price reflecting the most common/popular controlled pricing option in their pricing region:

+ in Dunedin, this is the 'all inclusive' option;
+ in Central Otago and Queenstown, this is the controlled 16 hour service.

WE PROPOSE TO DISCONTINUE USING AN ESTIMATE OF REPLACEMENT COST (RC) AS THE BASIS FOR ALLOCATING CAPITAL INVESTMENT-RELATED COSTS AND, FROM 1 APRIL 2022, MOVE TO REGIONAL REGULATED ASSET BASE (RAB) VALUES.

THE WAY PRICES ARE PUBLISHED

In this section, we are asking for your feedback on one change to the way prices are published, and invite you to comment generally on the clarity of our pricing methodology document.

WE PROPOSE
PUBLISHING A SINGLE DELIVERY PRICE

We propose to simplify our price schedules by publishing a single delivery price, instead of separately disclosing distribution and passthrough prices.

Aurora Energy's annual target revenue is made up of distribution costs (the direct costs that Aurora Energy incurs in owning, maintaining and operating its distribution network), and passthrough/recoverable costs (collectively referred to as passthrough costs) from third party providers such as Transpower and local rating authorities. Currently, our pricing schedules set out how much of each price relates to passthrough costs, and how much relates to distribution costs.

It is our view that the information presented in our pricing methodology provides full transparency of the value of various passthrough and recoverable costs, as well as the allocation of those costs to regional pricing areas and consumer groups. Therefore, there is an opportunity to simplify the pricing schedules by combining the distribution and passthrough/recoverable prices into one single delivery price.

TELL US WHAT YOU THINK

YOURSAY.AURORAENERGY.CO.NZ

HAVE YOUR SAY

WE WANT YOUR FEEDBACK

We're keen to hear your thoughts on the proposals outlined in this Consultation Document.

To help you form your submission, we have posed some questions online for each section of this document to help us understand your feedback.

To make a submission, please provide your feedback online by 3 December 2021. Go to yoursay.auroraenergy.co.nz

Alternatively, if you would like to send a hardcopy submission, you can download the form at yoursay.auroraenergy.co.nz or call us on 0800 220 005 to request a copy.

You can post or email your submission to:

Aurora Energy Pricing Consultation
PO Box 5140
Dunedin, 9054

Email: yoursay@auroraenergy.nz

Aurora Energy's Pricing Consultation document, along with a Summary, is also available online at **yoursay.auroraenergy.co.nz** or can be issued on request.

AURORA ENERGY

PO Box 5140
Dunedin 9054

0800 220 005

@auroraenergynz

auroraenergynz

www.auroraenergy.co.nz