Aurora
ENERGY

PRICING STRATEGY

1 APRIL 2021

Content

Summary

This is driving similar reforms across NZ, Australia and the UK.

Technology change is making well-designed distribution pricing increasingly important, with the most important role being to **signal future investment costs**.

This is an early priority.

Our **pricing areas** make sense, but there is potential for minor improvement in how costs are **allocated to pricing areas**.

There is also scope to **simplify cost allocation within pricing areas** (to consumer groups) provided costs are within robustly determined subsidy-free bounds.

Developing more complete subsidy-free estimates is a precursor.

There is an opportunity to enhance access to a **discount for load control** across a wider range of storage technologies – including batteries and electric vehicles.

Uncontrolled EV charging could exert significant investment pressure longer term.

Seasonal, two-part structure is suitable for Queenstown and Dunedin. A year-round structure is better for Central Otago.

For smaller consumers, a **time-of-use (ToU)** structure is likely to be effective. For large users, a more dynamic form of peak pricing may be worthwhile.

As regulations allow, signalling can be improved by **rebalancing** from usage ($ per kWh and $ per kW) charges towards fixed ($ per day) charges.

High variable charges discourage low-cost usage.

Gradual transition will enable thorough consultation and analysis, keep prices in line with regulatory constraints, mitigate bill shock and enable careful implementation.

Context

- Pricing reform
- Our networks
    - Dunedin
    - Frankton
    - Central Otago
- Opportunities

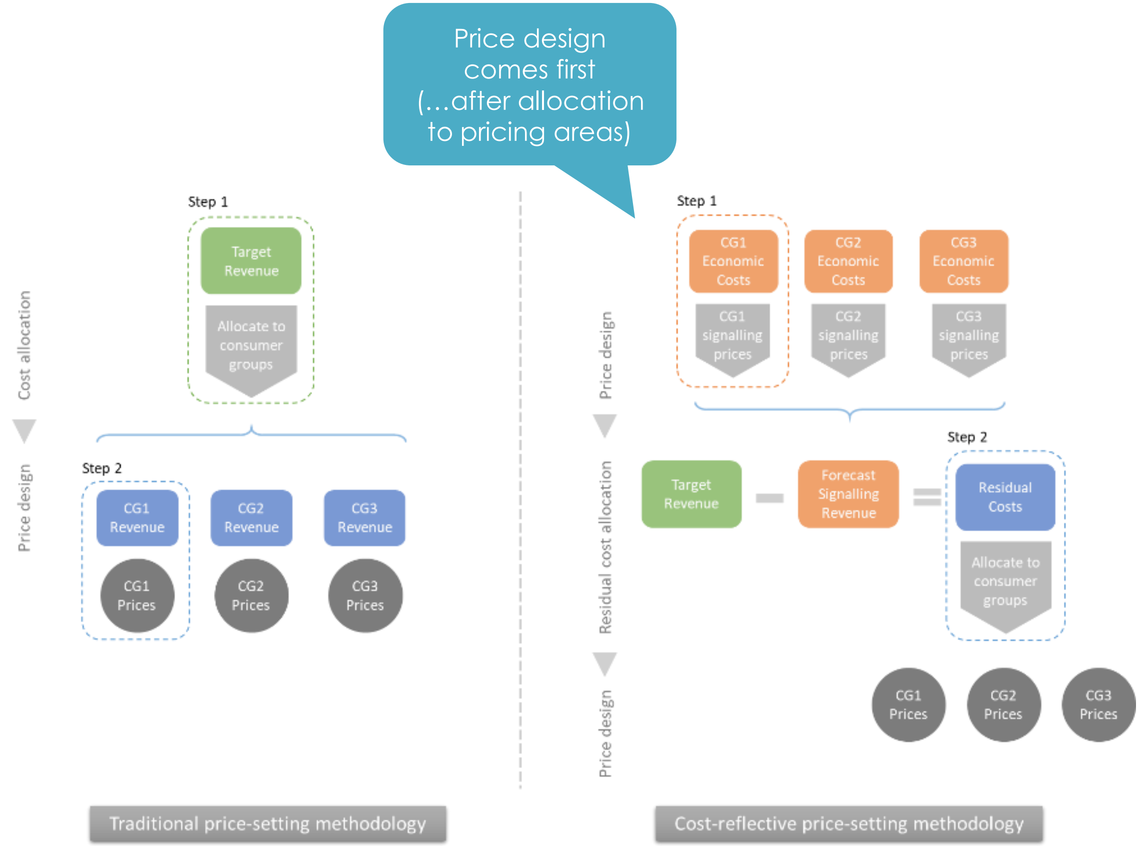
Context – pricing reform

New Zealand is following other countries in moving to a cost-reflective pricing (CRP) approach. This places less emphasis on allocating accounting costs, and more emphasis on signalling future economic costs.

Step One – design usage-based charge components that convey a useful signal about the network cost of adding to peak demand.

Step Two – top-up prices with off-peak or fixed charge components as needed to attain target revenue. Use simple allocators, but ensure result is subsidy-free.

If this is done well, it promotes a good balance between network investment and customer choices (e.g. about fuels, appliances and usage). This helps reduce long-term cost pressures, to everyone's benefit.



Context – pricing reform

Main implications for us:

1. Need for careful thought about when (within the year and day) and where (within the network) to signal economic costs. This informs pricing structures.
2. Signals need to be informed by network usage patterns and investment outlook. These differ between our pricing areas.
3. Need a more complete picture of standalone and avoidable cost (SAC and AC) for each customer group within each pricing area. This defines the 'subsidy-free' range.
4. There is scope to simplify the cost allocators we use within regions.

Most NZ distributors are similarly in the early stages of transitioning to CRP.

Our priority in recent years has been our CPP programme of work.

The Electricity Authority refreshed its pricing principles in 2019 and is actively encouraging and monitoring distribution pricing reform.

Context – rooftop solar

Observations:

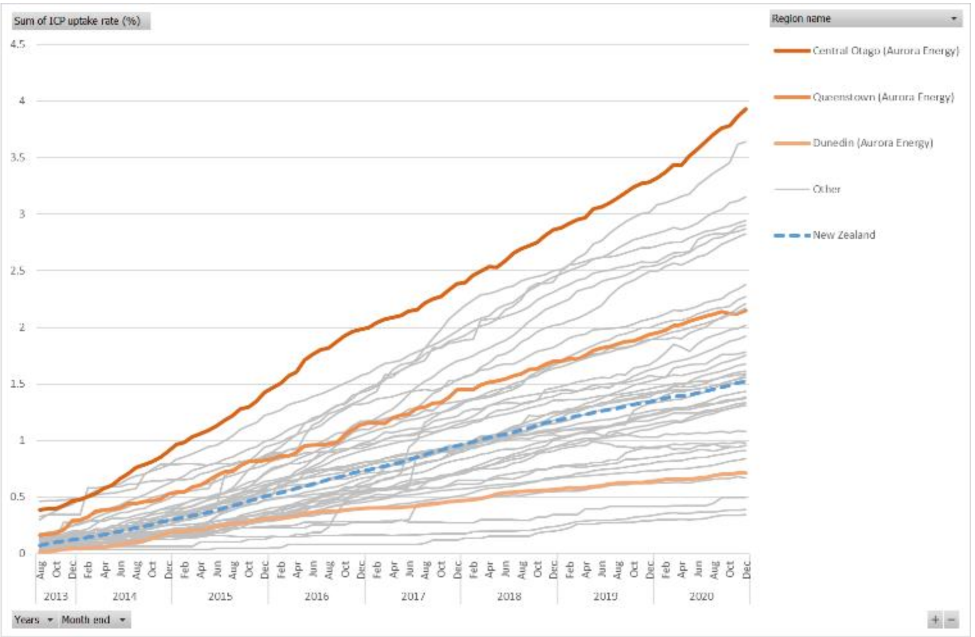
- falling prices mean solar has growing role to play, but there is a risk of over-signalling if variable charges outside peak times are too high – e.g. ~$90 per MWh prices in Queenstown and Dunedin during summer

- Central Otago has NZ’s highest solar uptake, which may be helpful given there is shrinking summer daytime capacity headroom on the network

- Dunedin has low uptake, even though the distribution price signal is similar to Queenstown. This may reflect comparatively poor solar resource and low house building activity.

Over-signalling the value of solar can contribute to costly over-investment *and* shift network cost recovery from solar ‘haves’ to ‘have-nots’

If solar penetration becomes very high, injection can become a network cost *driver* – a summer day injection charge could make sense as (or if) that point approaches.

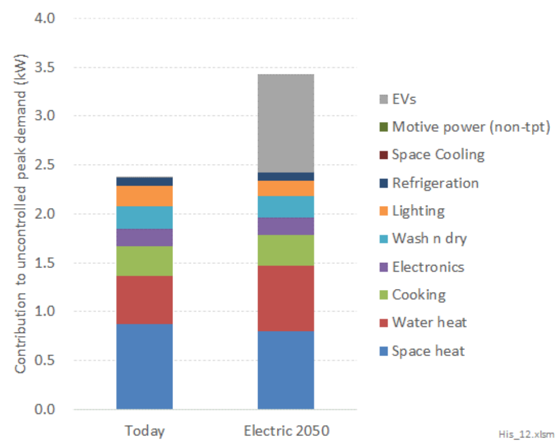


Context – electric vehicles

Observations:

- falling prices, improving technology, environmental benefits, and policy changes are likely to stimulate a generational changeover to electric vehicles (EVs) over the next two decades
- if large numbers of EVs are charged at peak, they could cause significant investment pressure – including in LV networks
- CCC-recommended fuel shifts from gas & LPG to electric heating could create additional peak demand
- time-of-use based charging can discourage peak charging, but can cause issues with very 'shiftable' load
- there may be significantly greater opportunity to optimise how EVs use the network if their charging is managed (much like hot water)
- distribution pricing could be used to signal the (distribution network component of the) value of interruptibility

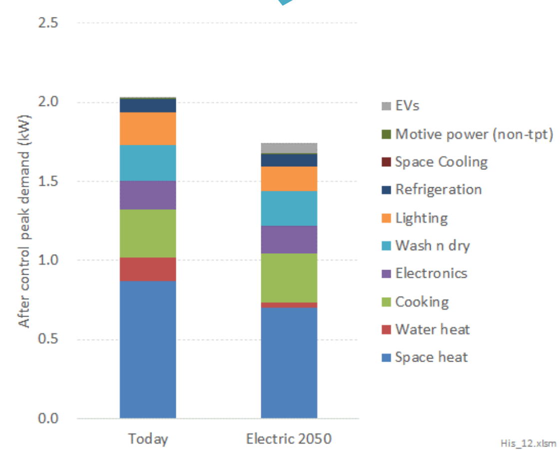
NZ average per household contribution to peak



Without control, EVs are likely to significantly increase peak-time demand…

…with control, household contribution to peak need not increase.

Orion encountered this issue with ToU pricing 15+ years ago.



This does not mean EV owners *have* to enable interruptibility.

Source: Concept Consulting

Context – CPP* & EPR

Observations:

- the CPP process stimulated community (and regulator) engagement on the question of allocation to (but not within) pricing areas
- the electricity price review (EPR) suggested distributors examine cost allocation between consumer groups, in particular whether it would be appropriate to re-balance between business and residential consumers
- our CPP program will focus on renewal and capability investment, with a near-term preference for more tactical solutions to growth pressures. This also suits uncertainty created by the pandemic
- longer-term, a return to growth pressures is inevitable – not least due to electrification
- in coming years, the CPP programme will reset revenue levels as we deliver catch-up investment and capability building

Refining how we allocate costs between regions is an early priority.

Pricing takes time to implement and flow through to customer choices, so it's appropriate for us to focus on investment pressures 7+ years from now.

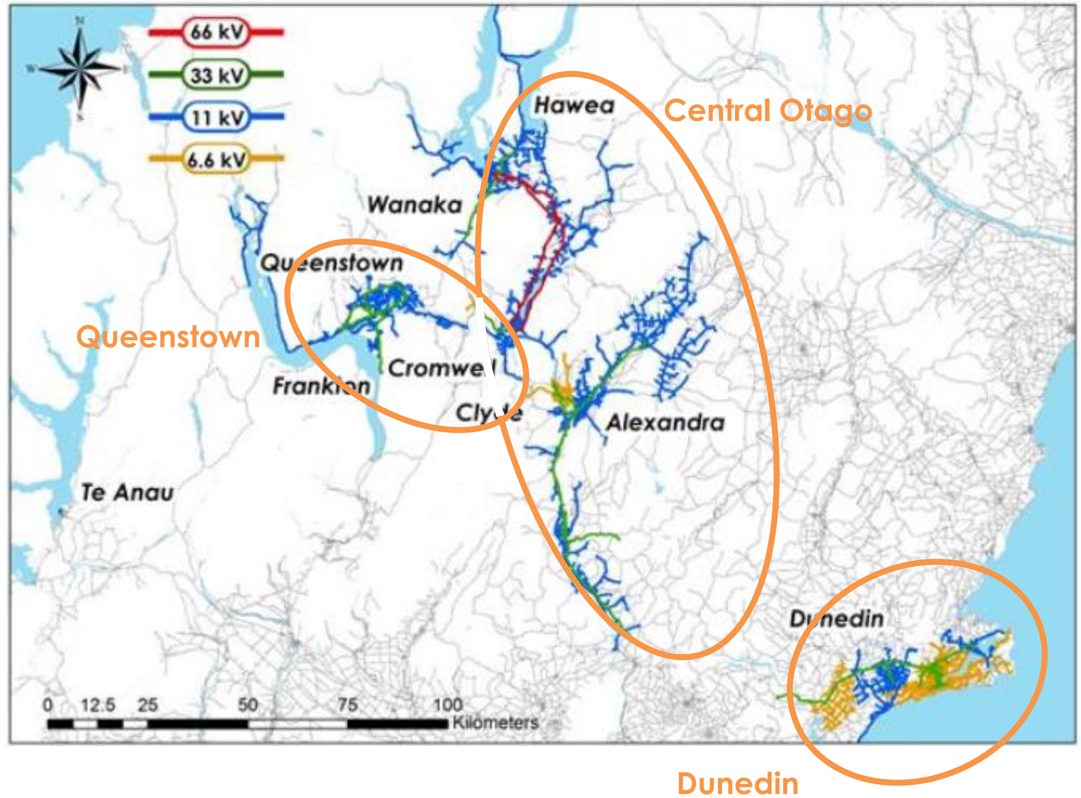
There is limited 'bill shock' headroom given the prevailing rate of change in total revenue. This will constrain how quickly we can reform our pricing.

*CPP = customised price-quality path. We applied to the Commerce Commission in 2019 for a CPP from April 2021 to March 2024 to enable catch up renewal investment and capability building.

Context – our networks

Our network context is unique, we:

- have a major programme of work underway to develop capability and improve network asset condition
- have four separate networks, with Clyde and Cromwell combined for pricing purposes*
- use load control to manage network peaks, which means we can't count on midday capacity headroom
- have much higher winter peaks than summer peaks Frankton and Dunedin, but a more balanced seasonal profile in Central Otago
- are servicing strong connection growth in Cromwell and Queenstown
- have limited connection growth but sizeable electrification potential in Dunedin.



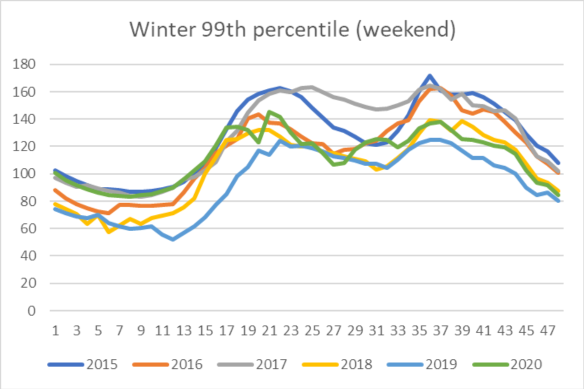
* We also have an embedded network at Te Anau. Embedded network pricing is influenced by pricing in the 'parent' network, so we do not directly address our Te Anau "Heritage" pricing in this strategy.

Context – Dunedin

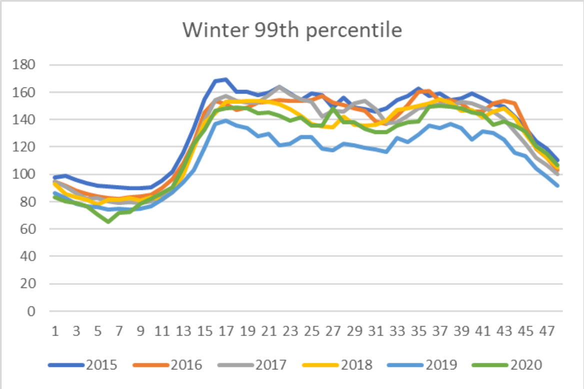
Key features:

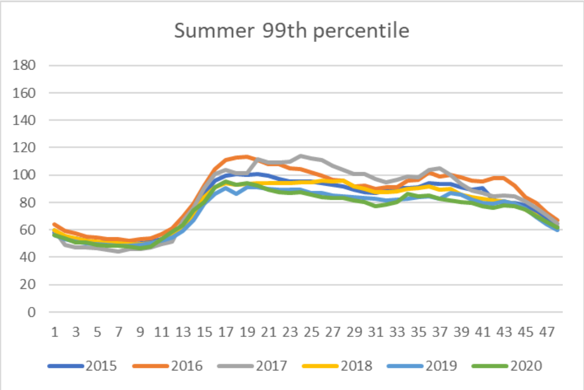
- winter peaks ca. 50% higher than summer – lots of capacity headroom in summer
- reliable and sizeable capacity headroom overnight
- ripple control playing significant role easing peaks, but means we cannot count on midday headroom
- predominantly dense* urban network with a long southern spur
- ‘inclusive’ metering configuration prevalent, meaning most controlled load not measured directly
- strong potential for EV and electrification-driven growth pressures

* 19 connections per route-km



Winter weekends don’t have significantly more headroom than weekdays.





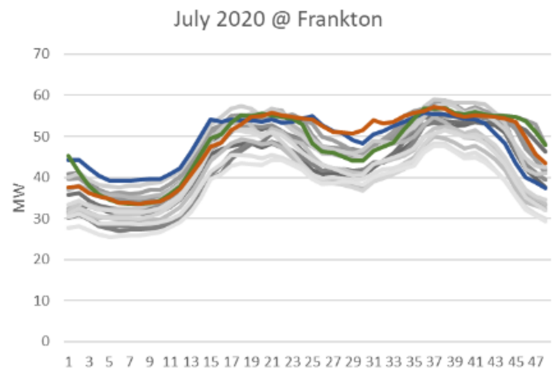
99[th] percentile by half hour for July (winter) and January (summer).

Context – Queenstown

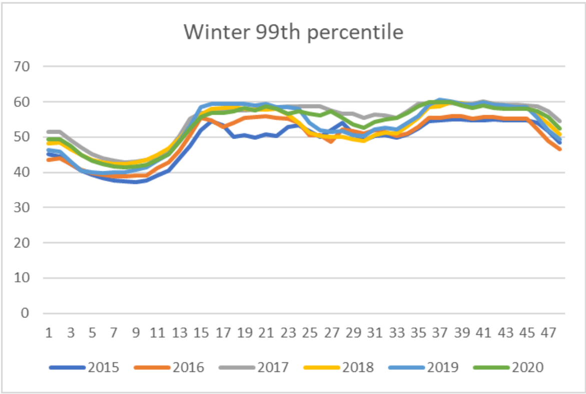
Key features:

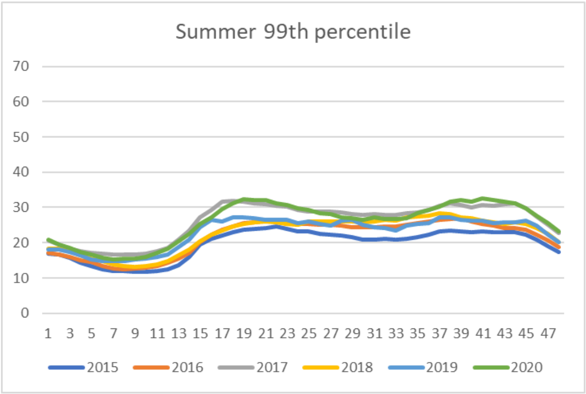
- winter peaks ca. 100% higher than summer – lots of capacity headroom in summer
- reliable night time off peak across most of the network*
- ripple control playing significant role easing peaks, but means we cannot count on midday headroom
- strong connection-driven growth, though economic disruption from 2020
- predominantly dense^ urban network, with spur to Glenorchy
- relatively high proportion (12% by number) of large (LG2) connections
- GXP reaching security limit, with tactical solutions planned

^ 12 connections per route-km



*Snow making consumes night-time headroom at GXP level, but not network wide.





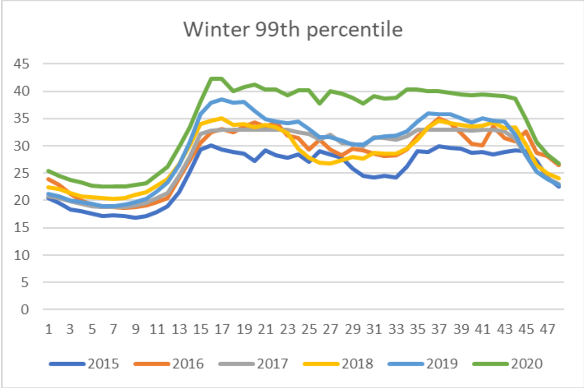
99^{th} percentile by half hour for July (winter) and January (summer).

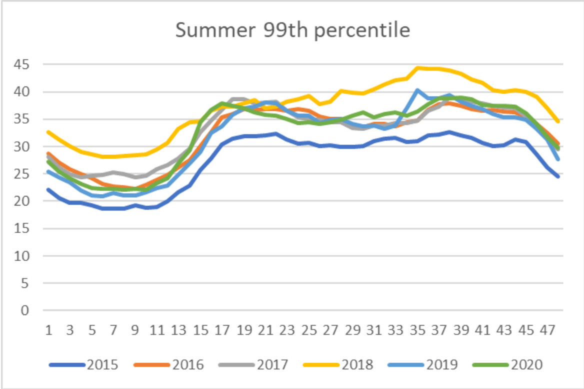
Context – Central Otago

Key features:

- Clyde and Cromwell are separate networks grouped into one pricing area
- both networks are relatively sparse*, with a mix of town and agricultural demand.
- the Cromwell network has relatively dense towns at either end, and the Clyde network has significant embedded hydro generation on its southern spur
- both networks have connection-driven growth and significant irrigation
- summer demand is growing to the point we cannot count on summer capacity headroom
- ripple control is playing a significant role easing winter peaks, but means there is no reliable midday headroom. We are planning to start summer ripple control.

Central Otago is a mid-size pricing area. On its own, Clyde would be NZ's third smallest retail market (by ICP count) and have a low ICP density.





99th percentile by half hour for July (winter) and January (summer).

* 7 connections per route-km

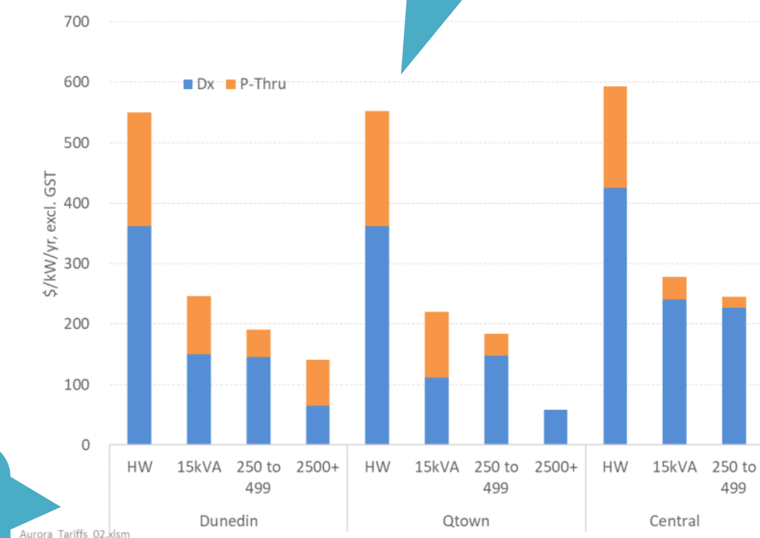
Context – price signals

- we have some targeted price-signalling built into our pricing – night rates (for space heating only), summer rates, discounts for hot water controllability, and capacity and coincident peak demand (CPD) charges for non-residential
- with a traditional pricing methodology that allocates cost within regions and then sets pricing levels, our pricing is understandably inconsistent in the signals it is sending
- similarly, the signal sent by our discount for ripple control is not consistent with other price signals
- our peak-time signals are probably high relative to the economic cost of network expansion.
- our off-peak signals are high relative to the (near zero) economic cost
- relatively high signalling strengths is consistent with having low fixed charges. Our ability to address this is constrained by regulations, which will also push future revenue increases into the variable charge components

Our hot water discount sends a stronger signal than our CPD pricing.

Engineering study is required to estimate the economic cost of expansion in each network (LRMC).

Differences in fixed costs across networks flow into signal strengths, which should instead align to LRMC differences.



Source: Concept Consulting

Estimates based on RY22 pricing, excluding incentive credits. Analysis relies on assumptions that could be refined in future.

Opportunities

Key features:

- small non-residential consumers (LG1) have a form of coincident peak demand (CPD) pricing that operates much like a winter daytime ToU, only on a lagging basis. Transforming to similarly designed ToU would shorten the cycle time between behaviour and bill.
- winter daytime ToU for residential (excl. Central Otago) would improve targeting of price signals. All-year daytime ToU is a better fit for Central Otago.
- as regulations allow, increasing fixed component would allow lower (or even zero-rated) off-peak charges
- robust LRMC analysis would allow peak components, and discount for ripple control, to be 'tuned' to appropriate levels
- more complete information about standalone and avoidable costs could help guide allocation to customer groups within a pricing area

ToU for the majority of LG1 can be used alongside 'proper' CPD for suitably equipped customers.

ToU is the 'sweet spot' for mass market consumers for now. Other pricing options are too sophisticated for retailers to implement or customers to operationalise.

Zero-rated off peak is the 'correct' price if there is no prospect of investment pressure at those times. Customers still pay for energy off peak.

Long-run marginal cost (LRMC) signals the economic cost of adding to peak demand. It requires engineering analysis to estimate accurately.

STRATEGY

A. Refine allocation to pricing areas
B. Develop economic cost estimates
C. Reform pricing structures
D. Enhance controllability discounts
E. Simplify allocation within pricing areas
F. Implement gradually

Strategy – refine allocation to pricing areas

1. Number

Retain existing pricing areas.

Smaller pricing areas can allow more targeted price signalling, while larger areas better support retail competition. Size also impacts how cost recovery is averaged across higher and lower-cost parts of the network. The current arrangement strikes a suitable balance.

To be tested through consultation.

2. Operating cost allocation

Implement refinements to allocation of operating costs between pricing areas from RY22.

Allocation to pricing areas can be refined ahead of other pricing reforms, as it is the first step in the pricing methodology.

This addresses an area of stakeholder interest from the CPP process. We can increase our use of causal allocators for some cost categories to refine cost allocation. This improves accuracy without introducing year-on-year volatility.

An example of a causal allocator is using circuit length to allocate vegetation management costs.

3. Capital cost allocation

Develop RAB-based approach to allocating capital costs from RY23 (subject to model assurance and consultation).

The advantage of RAB-based allocation is it leverages values already used in revenue setting processes.

This also addresses an area of stakeholder interest from the CPP process. Regulatory asset base (RAB) values are more robust than the replacement cost estimates we use currently, but will vary more over time.

RAB values decrease as assets age, and increase with network expansion, renewal and revaluation.

Strategy – develop economic cost estimates

1. System LRMC

Develop LRMC estimates for each pricing area.

LRMC is the economic cost most suitable for signalling through standing tariffs. To estimate LRMC, we need to model how future expenditure would change if there were a permanent step up in demand. This will differ for each network. It will also move slowly over time, so will need updating 5-10 yearly.

2. Low voltage LRMC

Develop a set of simple LV LRMC estimates.

This is a lower priority, but may become important if a need for widespread low voltage network reinforcement comes into prospect.

LV networks are sized to accommodate today's needs and upgrades are traditionally driven by connection growth (e.g. infill). New technologies could drive larger LV upgrade programmes in future – e.g. to host EV charging or rooftop solar. The cost of such programmes may become relevant to designing price signals, including discounts for controllability.

LRMC estimates are the bedrock for good price design.

We can start refining structures and harmonising signals with placeholder values, but will need better estimates as implementation progresses.

Strategy – reform pricing structures

1. Mass market

Migrate mass market customers to "mild" introductory ToU prices.

Our target pricing structure for mass market consumers will have lower off-peak rates and higher fixed rates than our current structures. Migrating customers to introductory ToU with minimal bill impact now *and then* gradually tuning the tariffs is less disruptive than trying to migrate later.

We can introduce ToU prices that mimic the outcome of current structures for residential and other small users. This puts the 'mechanics' of ToU in place early.

We will need to allow for some opt-out where retail or metering capability can't support ToU.

2. Larger customers and generators

Consult on tariff structures for larger customers and embedded generators.

Some larger customers are better able to engage with more sophisticated pricing arrangements, such as capacity charges and coincident peak demand.

There is an opportunity to simplify the number of charge components for larger customers, review the number of load groups, and modify the timescale over which prices operate. As with mass market, it is better to implement target structures ahead of tuning signals and simplifying cost allocation.

Transmission pricing is also changing, with the regional coincident peak demand (RCPD) signal due to become redundant.

Strategy – enhance controllability discounts

1. Existing

Refine existing discounts for controlled hot water and heating.

On first analysis, discounts for controlled hot water appear relatively high, and they're influenced by pass through costs. It would be useful to develop a clearer view of the basis for each discount and the best way of integrating discounts with new ToU structures.

> Introduction of summer ripple control in Central Otago is also a prompt for ensuring price signals are well structured.

2. New technology

Develop a plan for extending discounts to new technologies.

Encouraging controlled EV charging is likely to be a priority in future, and pricing is likely to play a role. This would be relatively straightforward if EVs were metered, but behind-the-meter is a more likely configuration.

> In theory, a directly metered EV with 100% effective load control could have zero-rated network usage charges (in conjunction with a fixed charge to recover control infrastructure costs).

It is timely to develop a view now of how EV control discounts can integrate into pricing.

> In principle, this work is also relevant to other new technologies such as stationary batteries and smart appliances.

Strategy – simplify allocation within pricing areas

1. Subsidy-free ranges

Enhance standalone and avoidable cost estimates.

We have partial information at present on avoidable and standalone costs. Developing a more complete estimate of these values is an important precursor to simplifying allocators and considering rebalancing.

Our current estimates include *short-run* avoidable costs and *non-network* standalone costs. Estimating full network-based values would improve our understanding of subsidy-free ranges.

2. Allocators

Select new allocators to use within pricing areas.

Our current methodology uses a cost-of-supply modelling approach that adds significant complexity without improving outcomes. CRP tends to use simpler allocators alongside robust subsidy free estimates to allocate residual costs.

Residual costs refers to the amount needed to bridge the gap between target revenue and revenue recovered through price-signalling components.

In theory, residual revenue should be recovered in a way that least distorts behaviour while remaining within subsidy-free ranges.

3. Rebalancing

Develop a rebalancing transition path.

Our target pricing structure should have well-calibrated peak signals, lower off-peak usage charges and higher fixed charges. The transition toward this structure has many constraints and considerations – including regulatory compliance, bill shock, and allocation.

The transition path for low-user low-fixed charge regulations will be a key factor.

Transition modelling should be refined each year as we firm up our target structure, observe how usage changes, and gather better information to inform impact assessment.

Updating allocators and transitioning to lower variable charges provide dual 'levers' for limiting bill shock.

Strategy – implement gradually

1. Consult

Consult at key steps of the process.

Pricing change is complex and directly impacts retailers and customers. It is important to consult well – both to build stakeholder awareness, and to support good design. Our stakeholders can help us improve our strategy and roadmap, and are key to successful implementation.

2. Structures first

Implement structures before rebalancing.

Putting new structures in place ahead of changing price levels has benefits of reducing 'adverse selection', allowing customers to learn in a safe way, and helping us to manage bill shock risks.

> If 'full-strength' ToU is offered immediately, then customers will be unsure of how it will impact them and only customers who already have a low system impact will transition.

3. Incremental change

Implement change in a series of small steps.

This enables us to get started sooner, while prudently managing risks. Pricing change can have unintended consequences that are best managed through careful and incremental change that supports continual learning.

Impact

Predicting the impact on customers

As we implement our strategy, it will alter our customers' bills – some will pay less, and some will pay more. Longer-term, the goal is that everyone pays less because prices are effective at softening investment pressures – reducing the costs we need to recover (compared to what they could have been).

Our strategy calls for gradual and incremental change, with more detailed design and impact analysis at each step of the process. As such, we cannot provide a full assessment of how customer bills will be impacted at this early stage.

As part of implementing our strategy, we plan to ask retailers for usage information that will help us assess bill impact. If we have a good sample of customer usage information, then we can develop a statistical view of how bills will change for different customer types.

For now, the best we can do is provide a qualitative description of impacts for most parts of our strategy. The following slides discuss impacts from key components of our strategy:

- Allocation to pricing areas
- Pricing Structures
- Allocation within pricing areas

Allocation to pricing areas

For RY22 we have refined the metrics we use to allocate **operating costs** (opex) to pricing areas. The tables to the right show the most material changes, and the overall impact.

From RY23 we anticipate implementing a change in allocation metric for **capital costs** – from replacement cost to current regulatory value. Previously, allocation changed over time with network growth. The new metric means allocation will also be impacted by relative depreciation and renewal rates.

We are proposing to retain our current **pricing areas**. If we were to instead split Central Otago into separate Clyde and Cromwell pricing areas, then:

- cost recovery per ICP would likely increase in Clyde, unless we also allocated more costs to embedded generation
- we expect retail competition could decline in Clyde, which could increase retail prices and reduce consumer choice.

Opex Type	RY22 Value ($m)	Prior Metric	RY22 Metric
System operations and network support	23.6	Asset replacement cost values	ICP count
Routine & corrective maintenance & inspection	10.4		Total circuit length
Vegetation maintenance	4.2		Overhead circuit length
Service interruptions and emergencies	4.8		50% ICP count & 50% total circuit length

Pricing Area	RY22 Opex Allocation ($m)		Opex Difference (%)
	Prior Metrics	New Metrics	
Dunedin	19.8	22.7	15
Frankton	8.0	6.5	(19)
Central Otago	15.2	13.8	(9)
TOTAL	43	43	-

Opex accounts for just under 40% of our forecast RY22 revenue.

Impact on total charges is much lower than these figures.

Pricing structures

Implementing our strategy is likely to result in changes for small consumers (including residential) due to:

- **peak** periods – much lower charges for off peak periods, and potentially higher (than otherwise) charges for peak periods. This will impact customers differently depending on how much of their usage is during peak times.
- **fixed** charges – most likely, higher fixed charges than today (at least for residential). This is beneficial for larger users and may increase bills for low users.

controllability discounts – potentially lower cost for hot water heating and EV charging for customers who opt for a managed service.

If we implement a coincident peak demand charge for large users, there may be more opportunity to manage bills by avoiding peak annual peaks.

Each pricing area will have tailored peak periods and pricing levels.

Factors that can contribute to low usage include:
- gas heating and/or hot water
- self-supply (e.g. solar)
- good insulation
- modern lighting and appliances
- small household
- nobody at home during the day

The net impact will *probably* be lower usage-based charges overall.

Solar production during off peak periods will provide less bill reduction than on-peak production.

Allocation within pricing areas

We aim to simplify allocation to customer groups within pricing areas, with guidance from robust subsidy-free estimates.

In parallel with this, we will aim to simplify tariff structures. This could involve:

- fewer charge components, especially for larger customers
- reorganised load groups.

The allocation changes could produce a shift in total allocation between, for example, residential vs. commercial customers.

The tariff structure changes could produce a range of impacts unique to each large customer.

Shifting some cost recovery from residential to commercial would be consistent with the government's electricity price review recommendations. We cannot say at this stage whether this is the most likely outcome.

Aurora
ENERGY