Orion Delivery Pricing

Consultation and discussion paper

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1. Introduction

This paper presents Orion's proposed structural changes to our electricity delivery pricing for next year and continues our development of wider pricing reforms for the future.

For next year we propose a range of incremental changes following on from last year's changes, these include:

- Introducing a flat 15c per day fixed charge for all general connections, offset by reductions in other prices
- Applying a second incremental increase to the fixed charge for major customer connections, offset by reductions in other prices
- Adjusting the qualifying criteria for our interruptibility rebate to require metering information to validate the load and load response
- Ending our generation credits arrangement
- Introducing a small charge for issuing failure to pay and default notices

Our 2017 pricing consultation paper sets the wider scene for our pricing reforms (available at http://www.oriongroup.co.nz/customers/our-prices). This 2018 paper builds on this consultation and the feedback we received, with a greater focus on specific aspects of the options that are emerging.

At the same time we take the opportunity to reflect on the work being carried out by other parties, such as the Electricity Networks Association (ENA) - in which we are heavily involved - the Electricity Authority, and the various reports published by others, in particular those by Concept Consulting on electric vehicles and energy efficiency. Concept Consulting also produced a more generic report on network pricing for Orion[1].

Due to the timing of this paper, we have not included any comments on the government's Electricity Pricing Review or the forthcoming Electricity Authority paper on pricing principles. We will consider the implications of these as we finalise any changes for next year and as we develop our longer term thinking.

This paper is primarily intended for electricity retailers, but it has also been distributed to others who work with or on behalf of customers.

This discussion and your response to it will help advance our progress toward pricing reform.

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[1] The EV report is: "Driving change - A study on the issues and opportunities of mass-EV uptake in New Zealand", March 2018 and can be found at http://www.concept.co.nz/uploads/2/5/5/4/25542442/ev_study_v1.0.pdf.
The energy efficiency report is: "What is the case for electricity efficiency initiatives?" and can be found at http://www.concept.co.nz/uploads/2/5/5/4/25542442/concept-electricity-efficiency-report.pdf.
The report to Orion is confidential, but relevant references are included below.

2. Matters raised by our 2017 consultation

Our 2017 consultation sought feedback on a range of pricing related matters. All of the relevant documents are on our website, including our response to them, so we do not cover this in any detail here. However, we believe a number of points made in or raised by submissions merit further discussion.

2.1 The value of load management

In response to our 2017 paper, one retailer noted that we had not presented any analysis of the value / relative cost of our service with and without our current approach to load management. We address that point in this section.

Load management has been central to Orion's operation and network planning for many years. In essence load management enables demand response to reliably substitute for capacity at coincident peak demand times that would otherwise need to be provided by building more network capacity. This lowers our costs and this feeds through into lower prices. But how much does it lower our costs?

Our Long Run Average Incremental cost (LRAIC) calculation is an estimate of what it costs to provide an extra kW of peak distribution network capacity on an annualised basis. This is currently around $98 per kW per year. [2]

To put this in perspective, we estimate that the average residential water heating load would contribute about 1 kW to our network peaks (allowing for normal levels of diversity with varying usage and thermostats cycling on and off, if it was left to operate without any control). Therefore, every customer that elects to shift water heating to a night-only option or a peak control option provides us with the opportunity to reduce peak load by 1 kW. In the context of the distribution part of delivery charges totalling about $600 per customer per year, this represents a 17% saving.

Combining the benefit of night heating and peak controlled water heating across our residential customer base, we estimate that we have moved about 135 MW away from our peak load, <u>so this equates to a savings for customers (which is passed on within our prices) of about $13 million per annum</u>. The response to our peak and control period pricing signals is additional to this.

Additional benefits flow from the deferral of transmission network investment.

2.2 Static TOU pricing

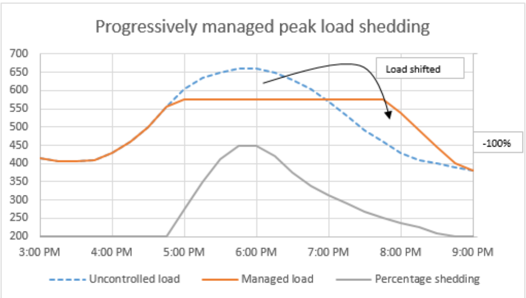
Our 2017 paper discussed the difficulty in designing static (pre-defined time period) TOU pricing in a number of areas. We received a range of comments supporting this option but we did not receive feedback on how we might address the challenges and difficulties that we identified with this pricing option. In the sections below we try to draw out these challenges and seek your feedback on how we might implement a solution.

[2] Refer to appendix E of our pricing methodology for the derivation of this value.

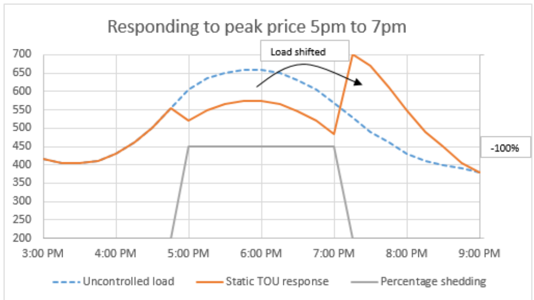
Existing storage heating loads

We currently operate both our peak control and night rate heating options during flat TOU price periods, during which we can manage loads and customers are indifferent to exactly when the heating occurs.

A specific concern for us, in the absence of a flat TOU price throughout the day, is that we think customers will respond to any peak price (within a static TOU structure) with an expectation their inclusive peak controlled water heating load will be turned off during the higher price periods. This will effectively remove our current ability to progressively manage this load and instead create dips in load every day, and create artificial peaks load from the point at which the price reduces and water heating is restored (and must catch up). This is illustrated alongside our current load management approach in the following graphs:



Current peak load management approach



Peak load management aligned with peak TOU price

It's clear that the response to pricing creates a peak when the undiversified water heating load is restored, but also note that the second graph shows almost twice as much load control (and therefore impact on water heating service levels) compared to the first graph. Two of the Concept Consulting papers reach the same conclusion.

It is important to highlight the fundamental point here: fixed time TOU pricing is not consistent with efficient management of energy storage, and the problem is greater the shorter are the 'peak' time periods. This is because all storage has the attribute that the longer it is off, the more the load will increase when it is turned back on.

A possible solution often mentioned within the industry is that controlled load could be separately metered, with a flat price. Unfortunately this option is not available to us because it would require changes to customer wiring, as well as the installation of new metering. Such changes would be prohibitively expensive, may not be acceptable to many customers, and most importantly, would not accommodate new storage loads.

Separately metered controlled load also constrains the off-peak price for the remaining load - the controlled load must be priced to be the same as or lower than the off-peak price to ensure customers continue to choose that option. This is a particular issue where the length of the peak price periods is the same or less than the length of time that the storage device can cope without supply. A structure with 4 hour peak price blocks morning and evening is an example of a situation where customers could inappropriately benefit from shifting traditional night time water heating off a controlled meter if the controlled price was higher than the off peak price.

Even if we solved this issue for water heating, we expect the adverse outcomes shown above would occur with an increase in electric vehicle charging load or wider use of batteries. Given that providing appropriate incentives to investment in new technologies is a key regulatory driver for pricing reform we think that this is a fundamental challenge that needs to be addressed.

Another possible solution sometimes discussed for "inclusive" situations (the most common arrangement on the Orion network) is that the peak price (in a two rate peak/off-peak structure) could be lowered to reflect the value of the controlled load that is part of the total load. We do not believe this works for two reasons:

- Customers would still be incentivised to avoid peak pricing times using their own resources (say a simple timer) – the value at stake is around a further $200 per year, which would easily fund that,[3]
- Customers could still reasonably ask us to ensure that their hot water was off during the defined peak periods to minimise their costs.

Either way, the peak shifting / peak increasing problem depicted above would occur.

We considered options that might allow us to progressively restore water heating loads after the end of the peak price period, but on top of the extended impact of load management during the high price period, this would require us to keep some water heaters off for significantly longer than our current service level targets (with a corresponding increase in no-hot-water complaints).

We would like your views on alternatives to address this issue as we haven't been able to identify any realistic options.

Discretionary load

Looking beyond storage heating load, we currently benefit significantly, and maintain prices lower than they would otherwise be, from the natural diversity in electricity usage. People are very good at doing things at different times, and in a recent study we observed that while individual household usage peaked at an average of 7.4 kW, the combined peak across households was just 2.3 kW. Any fixed-time pricing incentive will act to reduce this natural diversity and encourage customers to shift usage to the point where price reductions apply.

[3] Assuming two four-hour peak pricing blocks every day, a 10 cent per kWh peak/off-peak price differential and a 0.8kW average hot water heating load during those periods: 365 days * 8 hours * 0.8 kW * $0.10 = $ 230 per year.

This diversity is an important aspect of our supply and we would need to be sure that the benefits of any load shifting associated with static TOU pricing exceed the loss in diversity value. We'd like to get your views on how this problem might be addressed. The options we have considered are challenging, including:

- Establishing multiple price bands throughout the day (so that different customers respond at different price points), and changing prices regularly through the year to address peaks as they emerge, or

- Establishing multiple customer groups, with price changes applying at different times for each group, and shifting customers between groups to address any peaks that emerge, or

- Make price differentials sufficiently small that customers do not respond (we are not sure that this would achieve the cost reflective outcome sought).

In addition to any comments on the suggestions above, we would welcome any other suggestions you might have to address this concern. Essentially, for any load that consumers elect to shift in order to take advantage of lower price periods, we need to find a way to ensure that load is spread throughout that lower price period.

Solar

While our network peaks occur in winter, the majority of winter days are actually sunny, and on these mild days our loading levels remain well below (~20% below) peak loading levels. With static TOU pricing, customers with solar generation are rewarded with lower charges on these days when there is no corresponding reduction in network costs.

While winter solar generation is below the level that occurs in summer, electrical loads are higher, leading to lower export and a greater benefit from offset charges. Applying a higher TOU price or seasonal TOU price during fixed time peak periods will, at times, coincide with sunny periods, enhancing the savings for the customer but providing no corresponding benefit for the network.

The issue is that any savings that PV customers make, where there is no corresponding benefit or lowering of network costs, are ultimately funded by higher charges to non-PV customers.

We have not been able to find any solutions that align the reward for solar generation with the benefits to the network under a fixed time volume pricing approach. We would like your views or suggestions on this challenge.

Batteries

A static TOU price differential provides an incentive to shift load every day, yet all our peaks that drive costs occur on only a small handful of winter days. Customers responding by charging batteries overnight and reducing load during higher priced periods would be rewarded with lower charges on our ~330 per year non-peaking days, despite there being no benefit to the network.

Seasonal TOU pricing does not address this issue, because as noted above, the majority of our winter days are mild, with non-peaking loading levels. This is not cost-reflective pricing, and may inappropriately encourage investment in battery storage in situations where it is not economically efficient to do so. It also introduces an unnecessary burden on those that don't install batteries (who inevitably must meet the shortfall created by those who have batteries).

Charging and discharging batteries every day in response to an inaccurate network price signal has the additional feature that it reduces the extent to which batteries can be used to provide other, potentially more valuable services, such as continuity of supply during outages, frequency keeping, instantaneous reserve, voltage support or energy price response.[4]

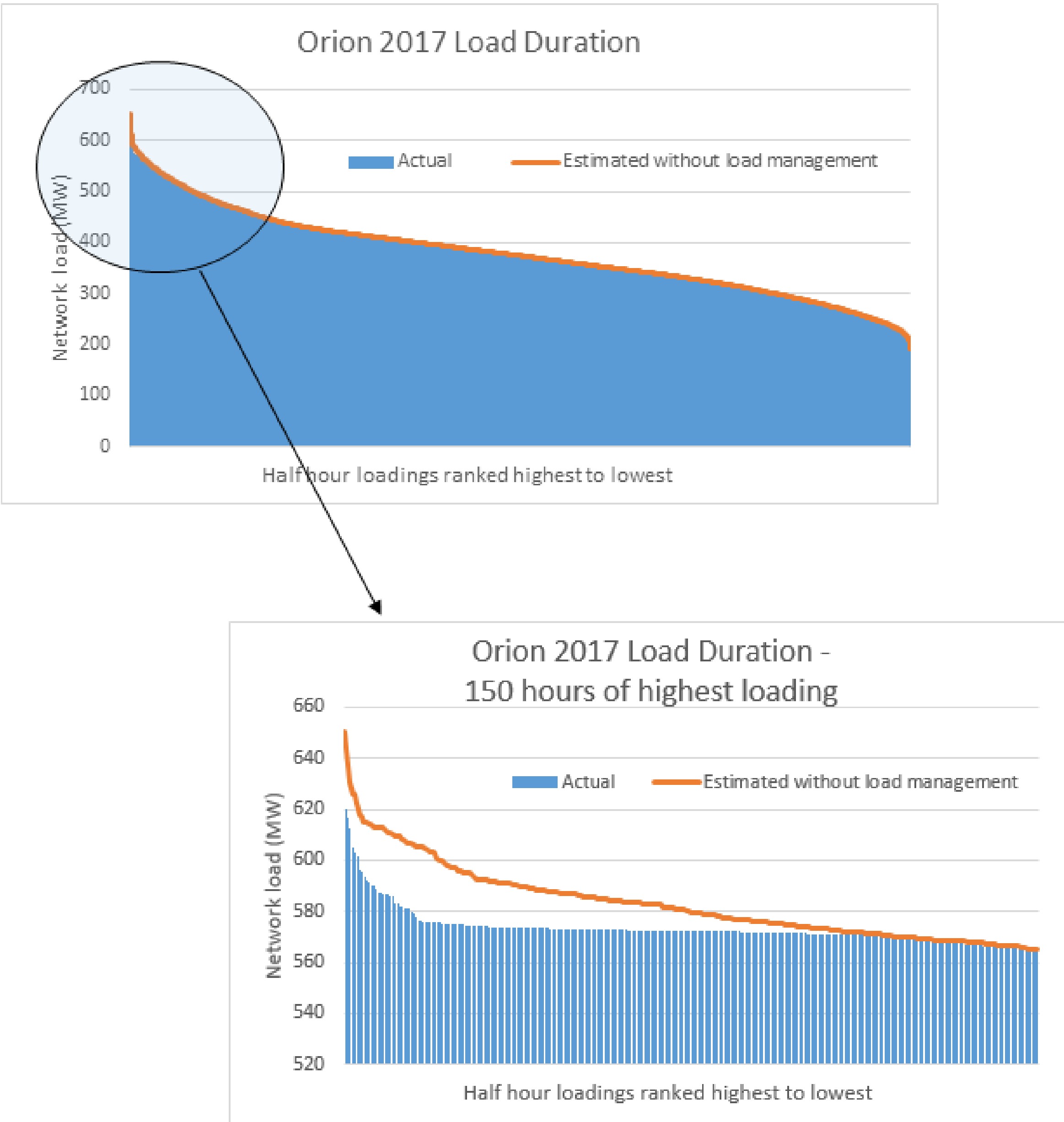
We would like your views on how these issues might be addressed as we have not been able to identify any realistic measures.

Load duration analysis

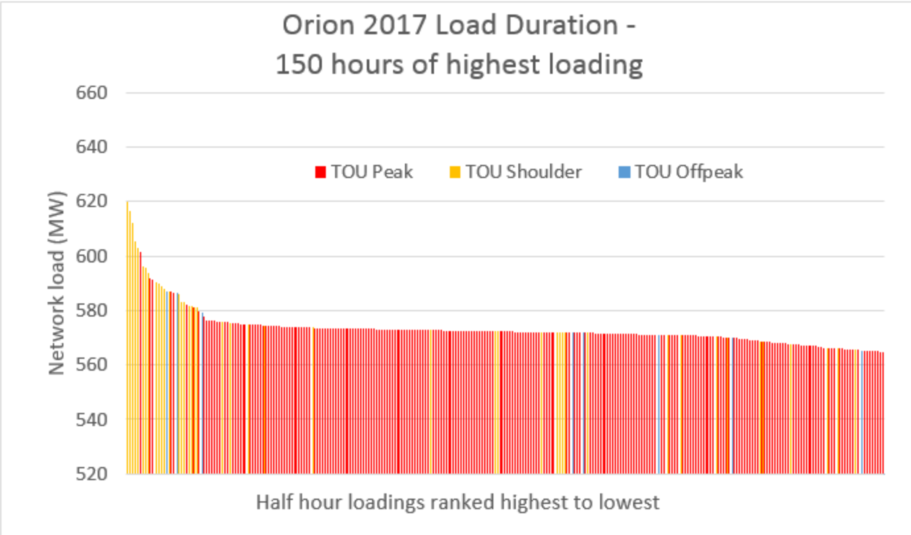
To illustrate the difficulty of capturing the peak loads that drive our network costs using a pre-set static TOU approach, we have set out our network loading results for 2017.

[4] Effectively, any form of storage is incompatible with fixed-time TOU. This is in part due to the fact that any form of TOU pricing is a form of 'price discrimination' (in the economic sense) which means it is only sustainable if it cannot be competed away. Storage, enables that competition. Having TOU price periods that are longer than the duty cycle of the storage helps mitigate this problem.

We use a “load duration curve”, where we sort and display our network loading levels from highest to lowest, to show our network utilisation. It is the highest loads to the left of this curve that drive the majority of our network capacity investments. The second chart focusses in on these peak loading levels and shows the result of our current load management approach – during the year we operated to a target of 575 MW, but demand for electricity pushed loading levels above this on a few days. The orange line shows our estimate of loading levels if we hadn’t managed load.

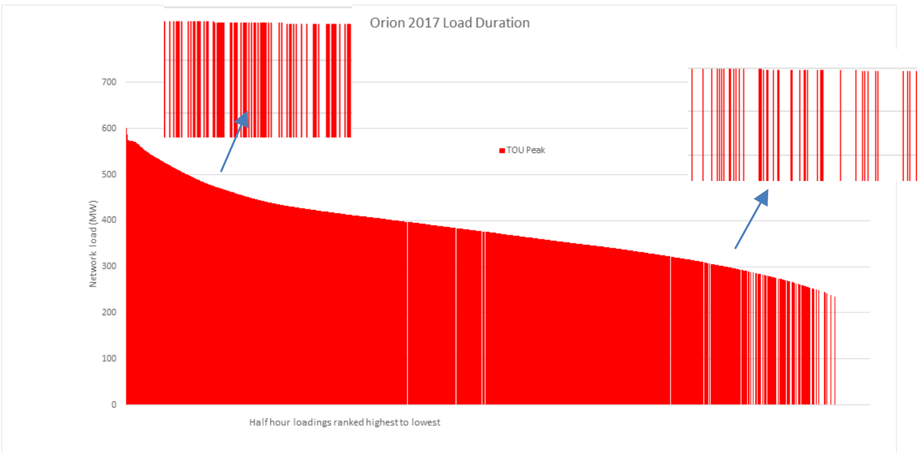


To consider how a pre-set static TOU might signal these high cost peak loads we have repeated the load duration curve, but colour-coded the periods that would fall within a typical peak, shoulder, off peak TOU structure[5]:



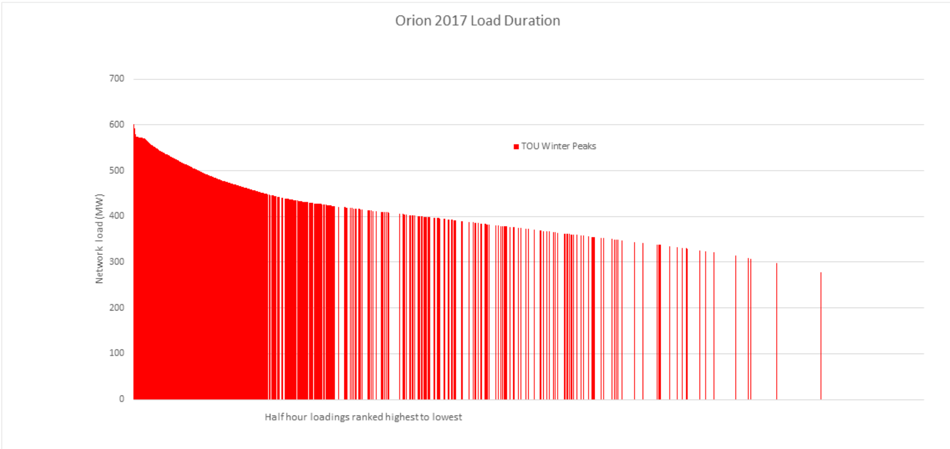
Perversely, this chart shows that most of the highest loads would have ended up being shoulder periods, and even a few off-peak periods are present. A TOU price structure would incentivise customers to move load to these times, so we expect our load, and therefore costs, would increase substantially.

At the same time, using this pre-set static TOU pricing structure would result in high prices at times when our network load is not peaking. This inefficiently encourages load response at times when there is no benefit – and any savings made by customers that respond must then be met by other customers! The following chart returns to the load duration for the whole year, and shows that the peak price under a TOU structure applies extensively through the load duration curve:



[5] Defining peak as 7am to 11am, and 5pm to 7:30pm, Shoulder between 11am and 5pm and from 7:30pm to 9pm, and off peak at all other times

Although retailers have submitted that seasonal pricing is not desirable, the inefficiency displayed above can be reduced somewhat by restricting the peak TOU periods to the winter months. The following chart shows the change that occurs if peak TOU prices are only applied from May to August. While an improvement, in our view the level of inefficiency is still unacceptably high, with 85% of peak TOU prices applying <u>when load is not peaking</u>:



We seek your feedback on how this discrepancy between pre-set static TOU periods and actual peak loads might be addressed, as we are not aware of any mechanism available that might provide a better alignment.

2.3 Booked capacity

One submitter on our 2017 paper suggested that we had disregarded or given insufficient attention to booked capacity as an option (where customers nominate a capacity (in kW or kVA) to operate within, and a higher price applies where this capacity is exceeded). This was not our intention. We believe booked capacity is a good candidate for at least part of a more cost reflective and service based pricing approach. We believe it has attributes that provide customer choice with appropriate incentives while being relatively easy to explain (particularly, for example, by analogy to broadband plans) and implement.

Unfortunately, booked capacity currently falls foul of the low fixed charge regulations, as any excess capacity charge that is at a higher rate (say per kW per day) than the rate that applies to the booked capacity makes this a stepped or tiered charge, which is not allowed under the regulations. With this restriction we could not put in place a structure that would encourage selection of an appropriate booked capacity. This is the position of the Electricity Authority as compliance agency for the regulations. Should the Authority change its position, or should the regulations be revoked or materially changed, then booked capacity could well be back on the table. See section 3 for more commentary on ENA's discussion with the Authority about LFC compliance.

2.4 Seasonal pricing and switching

Some submitters noted that an additional feature of peak pricing is that it potentially incentivises seasonal pricing and associated seasonal switching. While we consider this to be a feature of any form of seasonal pricing (and our peak pricing is definitely seasonal) rather than peak pricing itself, we agree with the general point and we do observe that at least some retailers have seasonal pricing, which creates an incentive for customers to switch seasonally.

We do not believe this is sufficient reason of itself to have pricing that is not seasonal. In our view it is for retailers to consider the various risks they face and price or contract accordingly. We also note that there are seasonal or even shorter term aspects of energy pricing that potentially raise similar issues. For example, customers would tend to switch from a spot price retailer when spot prices are high, and back to them when spot prices are low.

3. Low fixed charge regulations

The ENA has had a lengthy dialogue with the Electricity Authority since the Authority published its guidelines regarding the low fixed charge (LFC) regulations in August 2016.[6] This section summarises that dialogue.

The guidelines reflect the Authority's view that it "does not consider that the [LFC] Regulations are a barrier to distributors transitioning to pricing structures that are more service-based and cost-reflective."[7]

Despite this stated view, as ENA worked through the guidelines in terms of specific examples taken from previous ENA work, it became apparent that any option that is not consumption (kWh) based did in fact present a number of challenges under the regulations. These include:

- where a capacity (such as fuse size) is used, the fee to change the fuse size should not be more than the saving that the customer would make by changing,
- where a customer demand is used, this should be able to be changed "without undue delay" (what this means in effect is unclear), particularly "where [the consumer's] circumstances have materially changed",
- for booked (or nominated) capacity, the regulation's prohibition on stepped and tiered charges is deemed to prohibit an excess demand price (say $ per kW per year) that is higher than the price for the nominated capacity,
- estimation of demand or booked capacity - for example for new connections, new customers at a connection, or where the metering does not support the relevant measurement – should not use a previous customer's (at the same connection) quantity.

A feature of the dialogue has been the focus on LFC versus 'standard' pricing and demonstrating crossover compliance. To us it seems much more logical that the guidelines were encouraging distributors to use various non-kWh quantities as substitutes for higher fixed charges to avoid the complexity and compliance overhead.

On a more positive note, the Authority did propose what ENA took to be a novel approach to the regulations and the use of different "delivered electricity packages" as a way to have different prices for various levels of capacity. ENA worked this idea up and went back to the Authority seeking specific compliance endorsement as follows:

> **"Installed capacity**
>
> Distributors have been working on the basis that the prohibition on stepped or tiered charges would mean that the price per kW of capacity (or kVA or ampere) would have to be the same across the range of capacities.

[6] See: Variable charges under the low fixed charge Regulations – Guidelines, https://www.ea.govt.nz/dmsdocument/21123

[7] A view expressed in a number of places, with this particular quote from the Authority's letter of 17 August 2017 to ENA.

In discussion at the [previous] meeting, the suggestion arose that distributors could in fact treat the various capacities as different "delivered electricity package[s]", defined as "the bundle of components under the definition of delivered electricity that are supplied to a particular home" (Regulation 4 (1)).

The suggestion is very interesting, and so we have mocked up a price schedule showing how this could be implemented.

Delivered electricity package	**Price** ($ per kW per year)	**Price** (expressed as cents per day for top of band)	**Annual cost $** (based on kW at top of band)
0-1kW	$250.00	68.49	$250.00
1-2kW	$156.25	85.62	$312.50
2-3kW	$125.00	102.74	$375.00
3-4kW	$109.38	119.86	$437.50
4-5kW	$100.00	136.99	$500.00
5-6kW	$93.75	154.11	$562.50
6-7kW	$89.29	171.23	$625.00
7-8kW	$85.94	188.36	$687.50
8-9kW	$83.33	205.48	$750.00
9-10kW	$81.25	222.60	$812.50
10-11kW	$79.55	239.73	$875.00
11-12kW	$78.13	256.85	$937.50
12-13kW	$76.92	273.97	$1,000.00
13-14kW	$75.89	291.10	$1,062.50
14-15kW	$75.00	308.22	$1,125.00

Effectively it appears that the different package approach enables "stepped or tiered" pricing, which we previously thought was explicitly prohibited.

We thus seek confirmation in writing from the Authority that this approach, as set out above, is compliant with the Regulations."[8]

The Authority confirmed its view that this approach is compliant.

We remain sceptical that such an approach, even if compliant with respect to the current regulations, would be enduring in the face of the likely customer response. At this stage we await the approach that the government's electricity pricing review takes to the future of the regulations.

However, we would appreciate retailers' views on this approach, both whether you think it would be enduring, and what issues you see from a customer perspective.

[8] This is an extract from one of the ENAs letters. The pricing is purely indicative, but to avoid doubt these were the only delivery prices to apply to each package.

We also note that, LFC compliance aside, the idea of capacity bands with different daily prices does have some desirable features.

4. Changes proposed

While we continue to develop our approach for longer term pricing reform, we have identified areas where incremental improvements can be made to our current approaches, including steps that facilitate further future reforms.

For the next update we propose to:

- Introduce a flat 15c per day fixed charge for all general connections
- Broadening the major customer category (including apply a second incremental increase to the fixed charge)
- Adjust the qualifying criteria for our interruptibility rebate to require metering information to validate the load and load response
- End the generation credits arrangement
- Introduce a small charge for issuing failure to pay and default notices

These changes are discussed later in this section, but before that we provide an early indication of expected overall price movements for April 2019 as context.

April 2019 price movements

1 April 2019 marks the start of our first pricing year following our regulated customised price path (CPP). The Commission has determined a method for rolling over our current prices - less the claw-back component - for this 'gap' year before we return to the normal 5 year default price path (DPP) cycle from 1 April 2020. (Claw-back refers to the allowance included in our CCP to recover additional costs incurred between the 2010 and 2011 earthquakes and when our CPP came into effect on 1 April 2014.)

We expect this rollover to result in a 4% reduction in the distribution part of our prices. However this will be offset by increased costs that we are allowed to recover as part of our CPP IRIS [9] scheme as a result of our CPP operating expenditure being lower than forecast. This takes the expected overall distribution price movement to a reduction of around 2%.

Alongside this we are expecting a significant 10% reduction in transmission costs next year as a result of our lower load contribution to Transpower's regional coincident peak demand charges which were assessed in the year to 31 August 2018.

We estimate that the combined distribution and transmission price movements will lead to an overall *decrease* in delivery prices of around 5% from 1 April 2019.

[9] Incremental Rolling Incentive Scheme. IRIS amounts are recoverable costs, and as such form part of our allowable revenue.

These numbers are all subject to change over the next few months, but we doubt any changes will be material.

Fixed charge for general connections

Following our consultation last year we decided to introduce this charge and initially planned to do this from 1 April 2018. With other changes occurring at the same time, our analysis showed that the impacts on some customers would be too great, and we decided to defer the change.

As discussed above, this year there are a number of factors which provide a favourable overall price movement for customers and this facilitates the introduction of the structural change, mitigating the impact on customers that are charged a greater amount as a result of the fixed charge.

As noted last year, we can see the following benefits from this change:

- It signals a direction of travel to a world that is more based on the cost of providing the bundle of services that connection to a distribution network provides.
- It enhances our system capability to apply fixed charges across broad categories of customers, ready for a more significant application of ICP based charging in future, should this occur.
- Is a useful transition to applying higher fixed and lower variable pricing for larger (particularly non-residential) customers in future.
- Allows us to (slightly) reduce the price components that contribute to the high retail volume pricing, particularly the daytime price, which customers are exposed to. This helps (again slightly) reduce the cross-subsidy available for certain technologies.
- It is consistent with the approach already taken by a number of other distributors.
- It is likely to be consistent with any of the possible future options that we adopt.

The impact of this change on our charges to retailers with respect to our general connection category is reasonably straightforward to work out. For a *revenue neutral rebalancing*, the most our annual charges for an ICP can increase by is a year's worth of fixed charges (about $55 excl GST) where the volume is very low. A few unmetered supplies are in this category. Expressed as a percentage increase in delivery charges, these increases look very large simply because of the small (near zero) denominator.

At the other end of the scale, our charges for a very large general connections, using say 1GWh, will reduce by around $2,400 year, or 4%.

The breakeven point (no change in charges) is around 12,000 kWh per year, while our charges for a typical residential customer, which we assume uses around 9,000 kWh, would increase by around $16 or 2% (in the absence of any other price changes).

As noted last year, the impact of this change on most residential customers *at retail level* is limited by the low fixed charge regulations. Specifically, fixed daily retail prices for customers on a low user plan will not be able to be increased beyond 30 cents per day. Appendix A sets out our estimate of the retail impact for three different customer types, and various levels of consumption, although it does this in the context of the expected overall price reduction.

We propose to implement this fixed charge from 1 April 2019. Please let us know if you have any additional comments to those made last year.

Broadening the major customer category

Supported by the feedback from last year's consultation, we broadened the range where customers could elect to be in the major customer category, and adjusted the pricing (increasing the fixed component and reducing other components) to make it more cost-reflective at the smaller end of the loading range.

We implemented the first stage of this last year, lowering the minimum eligibility level from 250 kVA to 200 kVA, and increasing the fixed daily charge to $7.50.

We propose to implement the second stage of this change next year, further lowering the eligibility to 150 kVA and increasing the fixed daily charge to $10. As we did last year, we intend to assess and contact the customers within the elective range that will clearly benefit by a change in category, and also consider and look to mitigate any significant adverse impacts that might occur with this change. Overall we expect the number of connections in the category to increase by around 70.

We are aware that some retailer's systems do not support major customer pricing, and a widening of the eligibility may pose a problem for them, particularly if it applies to existing customers of those retailers. We would welcome any feedback on how we might deal with this.

Appendix B sets out the range of impacts of the proposed new pricing for existing major customers.

Metered measurement for interruptibility rebate

With the advances in metering we are taking the opportunity to enhance the use and value in our interruptibility rebate scheme. To do this we intend to incorporate the half hour data that is now available for the vast majority of our irrigation connections to:

- Assess the available emergency load, quantum and profile,
- Validate response in situations where the emergency shedding is called, and
- Depending on the results of our assessments and any other investigation (for example a site audit) update the creditable rebate quantity.

This change will enable us to better incorporate the facility in our asset planning and hopefully improve the credit going forward.

To implement this change, from 1 April 2019 we propose to make the rebate conditional on the monthly provision of half hour kWh interval metering information in EIEP3 format. For connections that do not have advanced metering or category 3+ metering and are already receiving the rebate, we propose to apply a grace period and implement the requirement from 1 April 2020.

For context, of the existing irrigation connections that participate in this scheme, 98.2% are recorded as having either an advanced meter or half hour meter, and just 11 connections would need to be upgraded. Where the metering is not upgraded we would cease applying the rebate from 1 October 2020.

We seek your feedback on this change, and in particular, your ability to provide half hour data in EIEP3 format for connections with advanced meters.

On a related matter, we were very pleased to see the letter from ERANZ data working group [10] that confirmed retailers see no issue with distributors contracting directly with meter equipment providers to source power quality information. We intend to progress this across a range of connections, but we see it as particularly useful for assessing the power factor of irrigation connections, both from a network monitoring perspective and an audit perspective, given that we apply power factor correction rebates to a number of irrigation connections.

Ending the generation credits arrangement

In 2017 we closed the generation credits scheme following extended issues with reliability of response, administration of credits and measurement of generation. At the time we opted to continue providing credits for the small number of customers already participating in the arrangement, subject to future review.

Part of the credit reflects the extent to which participating generation reduces our exposure to Transpower's interconnection charges. The Electricity Authority has now made changes to the rules which affect how these payments are funded which effectively means that the payments are only available for distributed generation that is both installed prior to December 2016 and approved by them. The Electricity Authority is now consulting on this approval and is proposing that no generation in Orion's network area is eligible for these "avoided cost" payments, see https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/acot-code-change-implementation/consultations-2/#c17580

If the Electricity Authority confirms its proposal then the available credit would approximately halve, and would fall substantially below the diesel cost of operating the participating generators. As a result, and subject to the outcome of the Electricity Authority's consultation, we intend to provide notice to those affected and end the arrangement effective 1 April 2019. At the same time, our prices for our separate export credits will also reduce to reflect the removal of this avoided cost of transmission component.

Please let us know if you have any concerns with the ending of our generation credits arrangement.

[10] Letter dated 16 August 2018 from Nick Wilson, Chair, ERANZ Data Working Group, to Rob Bernau of the Commerce Commission. ERANZ is the Electricity Retailers Association of New Zealand.

Late payment notices

A small number of retailers are not paying delivery service invoices by the due date. The issue has moved beyond occasional excursions and is occurring in many months. Following informal queries, our contractual credit process requires us to issue a formal “failure to pay notice” providing an additional period to pay, and then a “default and termination notice”, providing yet a further period to pay.

These notices are individually drafted to refer to the specific delivery service agreements and failure event, and must be executed by an appropriate delegated person, which usually means involving our CEO.

For larger retailers we have the additional ability to incentivise on-time payment by calculating and applying default interest. With respect to smaller retailers the amounts owing are usually quite small, so the default interest amount would be small both in absolute terms and relative to the cost of calculation. A fee for the notice would be a sharper incentive for small retailers to pay on time.

To better reflect the cost of this “reminder” service to the retailers using the service, we propose to introduce charges that will be applied when the formal notices are issued. We do not anticipate applying these charges more widely than the small number of retailers that will be familiar with these notices. We currently consider the charges will be in the range of $50 to $100 per event. The charge (or charges if there are multiple notices) would be added to the following month’s invoice.

The fee would of course be entirely avoidable.

5. What happens next?

We want to receive your feedback on this document by 5pm on Friday 12 October. This can be emailed to pricing@oriongroup.co.nz. We are happy to discuss this paper with you prior to your providing feedback: please email or call: bruce.rogers@oriongroup.co.nz, 03 363 9870 or 027 6789 744. Please let us know if any aspects of your response is confidential as we plan to publish feedback on our website.

If you are particularly constrained for time you might wish to focus your responses on the five specific proposals for 1 April 2019 set out in section 4 above. The more general discussion involves issues that will be revisited over the next few years, so this will not be your last opportunity to comment.

Following consideration of your feedback we will confirm the changes we intend to proceed with by the end of December, and we will also aim to issue our pricing revisions at the same time.

6. List of consultation questions

All of the questions in the paper above are included in the following table for convenience.

Please provide views on how existing controlled storage heating loads can be accommodated under a static TOU pricing plan
For any discretionary load that customers might elect to shift in response to a static TOU pricing plan, please provide comments on the options we have provided to spread the load response, or any alternatives you might identify.
For customers with PV, please provide your views or suggestions on how we might mitigate the inappropriate reward these customers receive under a static TOU pricing plan.
For customers with battery storage, please provide your views or suggestions on how we might mitigate the inappropriate reward these customers receive under a static TOU pricing plan.
For static TOU pricing plans, please provide your views or suggestions on how we might align the fixed peak price times with our weather dependent peak loadings, avoiding off-peak and shoulder prices applying at times of high load, and avoiding peak prices applying at times of low load.
The Electricity Authority has confirmed that a daily capacity charge ranging from 70 cents per day up to $3 per day for different size connections would comply with the LFC regulations. In your view, would this be accepted by your customers while the LFC regulations remain in place?
Please provide your views on our proposed implementation of a universal 15c/day fixed charge for ICPs in our general connection category.
Please provide your views on our proposal to further broaden the range where customers can elect to switch between our general and major customer category
Please provide feedback on our proposal to integrate half hour metering within the management and application of our irrigation interruptibility rebate. We also seek your feedback on your ability to provide this information in EIEP3 format in situations where it originates from advanced meters.
Please let us know if you have any concerns with ending our generation credits arrangement.
Please let us know if you have any concerns with the proposed addition of charges for notices when charges are not paid.
We are aware that some retailer's systems do not support major customer pricing, and a widening of the eligibility may pose a problem for them, particularly if it applies to existing customers of those retailers. We would welcome any feedback on how we might deal with this.

Appendix A – Estimated impacts of a 15 cents per day fixed charge on a typical retail bill in the context of an overall delivery price reduction of around 5%.

At retail level the low fixed charge regulations constrain how retailers can pass through a 15 cents per day distribution fixed charge for most residential customers, effectively shielding LFC customers from the increase in our charges to retailers for this group (annual consumption less than 9,000 kWh). This shield applies to nearly 100,000 residential customers on the Orion network. The residential customers for whom the shield does not apply are what we believe are not primary places of residence. We have estimated this based on the property name held by us[11], or the retailer's customer number being the same across multiple ICPs.

The following table show the estimated results for three customer groups:

1. residential, low fixed charge regulations apply
2. residential, low fixed charge regulations do not apply
3. SME.

	Residential (LFC applies)				**Residential (no LFC) & SME**			
Annual kWh	(1) Res #	%	$/year		(2) Res #	(3) SME #	%	$/year
0 to 1000	1,873	-0.8%	-3		1,094	2,810	10.5%	53
1001 to 2000	2,413	-1.0%	-6		580	1,169	5.6%	43
2001 to 3000	5,214	-1.0%	-10		519	1,415	3.2%	32
3001 to 4000	9,901	-1.1%	-13		464	887	1.7%	22
4001 to 5000	14,387	-1.1%	-16		452	865	0.8%	12
5001 to 6000	16,840	-1.1%	-19		386	704	0.1%	2
6001 to 7000	17,446	-1.1%	-22		315	646	-0.4%	-8
7001 to 8000	16,366	-1.1%	-26		256	545	-0.8%	-19
8001 to 9000	14,537	-1.1%	-29		233	515	-1.1%	-29
9001 to 10000	12,582	-1.4%	-39		180	547	-1.4%	-39
10001 to 11000	10,249	-1.6%	-49		147	406	-1.6%	-49
11001 to 12000	8,183	-1.8%	-59		110	390	-1.8%	-59
12001 to 13000	6,349	-1.9%	-70		92	420	-1.9%	-70
13001 to 14000	4,705	-2.1%	-80		73	333	-2.1%	-80
14001 to 15000	3,624	-2.2%	-90		73	355	-2.2%	-90
15001 to 16000	2,692	-2.3%	-100		48	319	-2.3%	-100
16001 to 17000	2,004	-2.4%	-110		49	317	-2.4%	-110
17001 to 18000	1,523	-2.5%	-121		34	291	-2.5%	-121
18001 to 19000	1,077	-2.5%	-131		29	251	-2.5%	-131
19001 to 20000	864	-2.6%	-141		20	239	-2.6%	-141
>20000						6,820	-3.8%	-2018

So in summary there is no increase in total annual cost at retail level for any residential (LFC) customer. Around 11,000 non-LFC residential and SME customers would see an increase, with a maximum of around 10% / $50 / year.

[11] To identify keywords such as "holiday home", "shed", "garage", "builder's temp", etc.

Appendix B – Estimated impact of major customer delivery price changes assuming a revenue neutral rebalancing of existing charges.

The following graph shows the impact of our proposed major customer pricing changes on the existing group of major customers and with a *revenue neutral rebalancing* of current prices.