Orion

3 November 2021

Submissions
Electricity Authority
PO Box 10041
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by email: distribution.pricing@ea.govt.nz
(subject line "Consultation paper – Distribution Pricing Practice Note")

Response to consultation paper –
Supporting reform to efficient distribution pricing: a refreshed Distribution Pricing Practice Note

1. Orion New Zealand Limited (Orion) welcomes the opportunity to provide a submission on the consultation proposing a revised distribution pricing practice note issued by the Electricity Authority (the Authority) dated 21 September 2021.

2. We provide responses to the Authority's questions in the submission template attached to this submission. We also set out our key concerns, including areas that are not covered by the Authority's questions, in this letter.

3. Overall, we welcome the Authority's recognition of the constraints that we face, recognition of the impact on vulnerable customers and the acknowledgment that solutions will not be a "one size fits all". We further commend the Authority for its more recent support for the removal of the low fixed charge regulations. We are pleased that some of the messages and themes that we have provided through the Authority's engagement with industry are being reflected in this update.

4. We are facing rapid change in the options and services available to customers and we recognise the need for us to adapt and support this transition. The way we structure our prices influences our customers decisions and can support beneficial outcomes for our community.

5. Orion's purpose is to **power a cleaner and brighter future for our community**. Against this purpose we have developed a framework of sustainability goals and strategic themes, and within this framework we have identified that the key initiatives that our pricing can support are:

    a. sustainability, through the decarbonisation of our economy, and

    b. addressing inequity, by recognising and mitigating the impact on vulnerable customers.

6. To capture these initiatives, we have recently adopted a refreshed pricing strategy:

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

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7. Building on the two initiatives above, our sustainable development goals (which support our purpose) include:

   a. Sustainable cities and communities – the structure of our pricing influences customer behaviour relating to the adoption and sharing of renewable energy resources, the electrification of transport and process heat, and the level of non-renewable generation that is needed at times of peak consumption.

   b. Reduced inequities – in particular, for our pricing transition we are actively assessing the impact on vulnerable customers who do not have the resources to cope with change or adapt their behaviour. Alongside our pricing transition, we are seeking alternative approaches that might provide targeted assistance for vulnerable customers.

Sustainability

8. The Climate Change Commission, Ministry for Environment and others have identified that electrification of our transport fleet provides the greatest opportunity and least cost means for our community to decarbonise. We believe our industry can encourage this transition by providing strong messaging around supply resilience, signalling a stable price path for electricity delivery costs, and providing options for lower cost (off peak) charging. A further opportunity is process heat conversion with customers in our major customer category most likely to pursue this.

9. Looking further forward, we need to help customers share their local renewable energy resources and utilise the energy stored in their batteries (be they standalone or EV batteries via V2G) to stabilise the grid. Our current pricing structure actively discourages customers from utilising our network to trade excess distributed energy and to instead seek inefficient alternatives. We plan to reform our prices to address this barrier, providing service-based options that reflect localised use of our network.

10. Our current pricing structures with volume-based components are inappropriately incentivising inefficient investment in behind-the-meter bespoke rooftop PV, which is by far the most expensive form of renewable generation available and an inefficient path to decarbonisation. This issue will compound as customers adopt the technology and contribute less to the system. The cost burden then falls to others through higher prices (and this, in turn, encourages more customers to invest in PV).

11. On the other hand, volume-based pricing incentivises energy efficiency measures such as efficient appliances, heat pumps, LED lighting and insulation.

Vulnerable customers

12. Any change in pricing structure creates winners and losers. There is “collateral damage” when changes affect customers that are not contributing to an area of concern and/or are not in a position to respond. For context, while price restructuring might seek to achieve an underlying cost saving through behavioural change of 5% to 10% in the long term (an economic benefit), for individual customers, the structural change itself can easily have a 30% impact on the charges they pay (effectively, a wealth transfer).

13. Of particular concern, we have identified that a greater proportion of our vulnerable customers sit within the lower consumption bands. While a shift away from volume-based pricing will provide lower cost outcomes in the long term, it also shifts more of the cost burden onto these customers. By definition, vulnerable customers do not have the resources to accommodate the additional cost, nor to adapt their usage to mitigate the additional cost.

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

15. We also intend to look for ways we can provide targeted relief to customers in need, and we are supporting the industry initiative to set up a support fund that operates alongside the removal of the low fixed charge regulations.

Draft Distribution Pricing Practice Note

16. Our goals are much broader than the narrow economic focus taken by the Authority. We aim to go further than correctly signalling the most efficient use of the network. Our aim is to facilitate decarbonisation and to address energy equity.

17. Against the backdrop above, we have identified a number of areas where the draft practice note does not support our strategy, and does not align with our real-world experience with pricing and interaction with customers. Our key areas of concern include:

    a. Adopting cost reflective and efficient prices is not simple

    b. Misalignment with the reasonable expectations of customers

    c. Lack of recognition of customers' existing response and related investments

    d. Disconnect with the real-world attributes of distribution networks

    e. Challenges with non-distortionary pricing

    f. Conflict between cost reflective pricing and open access for network alternatives

    g. Retailer rebundling (confidential)

    h. Unresolved issues with TOU pricing

    i. Convoluted approach to price setting methodology

18. We elaborate on each of these concerns below.

19. In our view there is a lot of work to do on the draft practice note before it will provide coherent guidance for pricing reform. The sentiment given by the Authority is that it is seeking help to fine tune the practice note, but our view is that the approach and focus needs to shift substantially.

Adopting cost reflective and efficient prices is not simple

20. The consultation paper (paragraph 26) states that "cost-reflective and efficient prices is a *simple* way to support a prudent energy future". We submit our strong disagreement to the indication that it is "simple". If cost-reflective pricing was simple, then it would have been adopted ubiquitously on a global scale. It has not.

21. There is a significant trade-off between the practicality of pricing approaches and cost reflectivity, and this balance has challenged electricity pricing practitioners for more than a century. Technology has (or will) address some of the challenges, but the underlying issues remain.

22. For example, it is very easy to conclude that "peak pricing" is appropriate in certain circumstances. But the actual application of peak pricing is very difficult. Peak pricing is based on a customer's contribution to periods of congestion (the rate of consumption). As the congestion is seasonal (rather than monthly), it is not possible to calculate that contribution until the season is complete, and this gives only two options – peak charges must either:

    a. be based on an estimate and include a wash-up once the actual contribution is known, or

    b. lag behind the peak season, so that the contribution made in one season sets charges for the following year.

23. We know from experience that neither of these approaches is palatable in a residential context. Residential customers do not respond well to wash-ups, and they do not accept charges based on historical usage which might not reflect their current situation, or even the current customer.

24. We also know that peak charging approaches yield different results depending on when the weather driven periods of congestion occur. A family can make a very limited contribution one year but a much greater contribution the next year <u>through no change in their own behaviour</u>. We know that customers do not respond well to increases in costs when it cannot be linked to an increase in their own consumption.

25. Further, retailers have told us that peak charging exposes them to risk, as they can't concisely quantify charges in line with their monthly billing cycle and they may not retain customers for the period needed for a wash-up or delayed charging approach. Retailers tell us that this is dealt with through the addition of a risk premium in their price setting, which adds costs for customers.

26. We cannot ignore these practical challenges when developing pricing. Many commentators approach these challenges with a sense that a reasonable solution is just in front of us, it just needs to be found, and if we do enough research, customer consultation and trials we will find the holy grail of pricing. We submit that there is not such a solution.

27. Almost every pricing metric suffers real and difficult practical implementation challenges. Some examples are:

    a. Customer peak demand charges ($/kW/day) don't work with mid-month retailer switching, or retailer billing cycles that are not aligned with calendar months. Separately, distributors will often create or contribute to the peak demand at a particular premise through their management of controllable water heating load, and this would make the peak inappropriate to use for charging.

b. Dynamically signalled peak event pricing (c/kWh) creates an unacceptable seasonal impact on customers' charges. For distributors it creates unacceptable revenue volatility during extreme or mild winters. Peaks are driven by cold weather, caused by unstable weather events. A weather front arriving at 5pm will create a peak, but an hour earlier or later may not create a peak. This means that signalling a peak by reliably "communicating a reasonable period in advance" as suggested in the consultation paper is not a realistically achievable ambition.

c. Time of use pricing (c/kWh) encourages step changes in load at the point where prices increase or decrease which could only be addressed with complex ramping up and down of the price or segmenting customers and applying different prices and timings for each group[1]. Time of use pricing is not compatible with peak control of water heating because customers will want their water heaters turned off during all high-priced peak price periods.

d. Fixed prices ($/day), other than at a nominal level, need to reflect the size of the connection (because residential households expect to pay less than factories). This requires some complex reference to fuse size or connection capacity (together with associated monitoring and enforcement).

e. Booked capacity approaches must be accompanied by some form of extra charge when the booked capacity is exceeded which requires monitoring and enforcement. This approach is also affected by network management of controllable load where the distributor is likely to create or contribute to a peak that exceeds the "booked capacity".

f. Peak rebate pricing requires an estimate of the load that would have otherwise occurred. Measuring something that didn't happen (and using that to calculate a charge or reward) is challenging. A customer might arrive home to a signalled peak event and respond by not turning on the heater, but the load profile will show an increase in load as they cook their meal.

28. Describing cost-reflective and efficient prices as "simple" is not helpful. We would like to see the challenges directly addressed, and where the issues cannot be overcome, the constraints should be accepted.

29. The practice note would be more useful if it provided practical guidance on how the more cost reflective options might reasonably be structured, including defining the responsibilities and obligations on retailers in the implementation of those options.

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[1] Orion has attempted both of these approaches. Its predecessor used a choice of "Day 'n Night 6", "Day 'n Night 7", or "Day 'n Night 8" to spread the load spike when night controlled loads were turned on, and Orion initially used a complex ramping up and down of volume prices in the early 2000s.

Misalignment with the reasonable expectations of customers

30. The draft practice note appears to ignore some basic expectations of customers. It sets a scene of "delivering satisfactory outcomes to … customers", but disregards what we view as obvious and reasonable customer expectations.

31. Our customers expect:

    a. to pay less when our network is being utilised efficiently (approaching a constraint),

    b. to be rewarded when they adjust their behaviour to help us reduce or defer reinforcement costs,

    c. to not pay more if they haven't changed their behaviour, and

    d. a reasonable degree of stability and predictability in the prices they face.

32. However, the draft practice note suggests customers in congested areas should pay more[2]. Our view is that customers will not respond positively if we advise them that due to the uptake of electric vehicles by their neighbours (increased demand), and to help *us* avoid spending money (to invest in upgrades), their localised prices will increase and they will be charged more.

33. Our experience with customers is that they will see the higher prices as a penalty for their behaviour, rather than an incentive (or reward) for changing behaviour.

34. In situations where an upgrade is required, feedback from customers shows they do not expect to pay more if they haven't contributed to that need. Our customers do not expect to pay more if they haven't changed their behaviour. Those that can't afford an EV do not want to pay for an upgrade to support those that can[3]. Finally, customers do not want to pay more in order for us to avoid expenditure.

35. The locational approach suggested in the draft practice note would also lead to instability in pricing as the price signals are implemented and then removed. We find that customers disengage when faced with successive changes, and when their investment decisions are undermined. Orion supports more predictable and less volatile pricing and prefers socialisation of costs to avoid these issues, when appropriate.

Lack of recognition of customers' existing response and related investments

36. The draft practice note usefully summarises customers' response to price signalling, and paragraph 10 correctly indicates that customers' decisions can be invisible to the distributor.

37. However, the draft practice note takes a simplistic approach of defining appropriate pricing approaches for different situations. For example, for an unconstrained network where design matches or exceeds demand, it suggests that there is no rationale for a variable charge.

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[2] Draft practice note, figure 1 shows congested area 3 making a revenue contribution that reduces the remaining revenue requirement. Paragraph 60 indicates that prices should be lifted in areas and periods of congestion.

[3] Draft practice note paragraph 143: "costs should be allocated to the feeder through an increase in fixed daily charges"

38. We are not starting with a network where there is no customer response. Our load shape is considerably influenced by our current pricing approaches. We know it occurs, but we do not have visibility of the individual decisions made by customers to adjust their discretionary load. Observing that there is no congestion should not be taken as a basis to move to fixed daily charges.

39. We are also aware that our customers have made investment decisions that have helped them respond to our pricing and shift load. This includes things like large water cylinders that only need to heat overnight, night store heaters, appliances with delay start features, and alternative fuels for heating.

40. The draft practice note does provide an acknowledgement that existing controlled load might manage congestion and may need to be maintained. However, it suggests that zero-rating this with a nil price is an appropriate approach and will aid customer uptake. However, the suggested fixed charging approach means that all consumption will have a nil price, and zero-rating a specific part of that consumption will therefore have no influence on customer decisions to move load to controlled!

Disconnect with the real-world attributes of distribution networks

41. The draft practice note includes a strong steer toward locational pricing. It includes the suggestion in paragraph 53 that “a segmented economic cost view of energy use and utilisation on their network is expected to be a foundational piece of progress that distributors should be demonstrating”.

42. Distribution networks are usually much more complex than the Authority’s approach could accommodate. Both urban and rural networks are highly interconnected. The path of supply (and therefore the assets that belong to a particular segment) is changed and reconfigured over time.

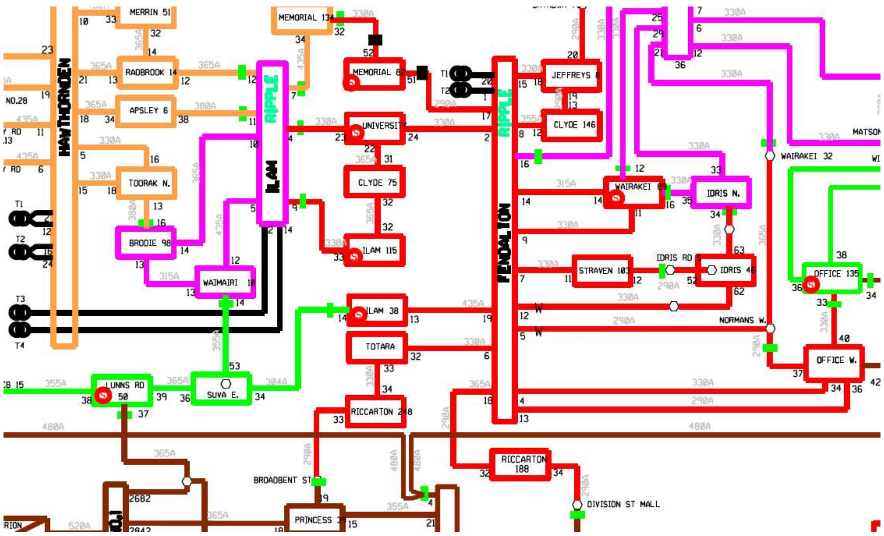
43. In particular, this reconfiguration occurs when an area of a network faces a constraint. Before upgrading the network for a constraint our planning team look for ways to reconfigure the network to alleviate the congestion. This involves changing open points to shift load both in[4] and out of the constrained area.

44. While this represents efficient use of the network, it would create unacceptable volatility to any locational pricing, as customers are shifted in and out of a constrained area (which might also occur on a seasonal basis).

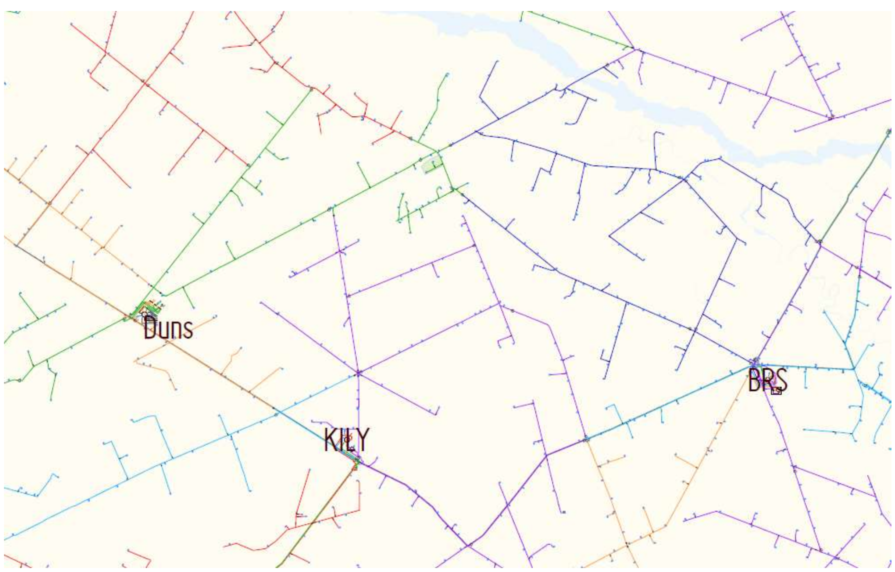
45. The Authority’s approach also ignores the fact that each electrical area is configured in such a way that it provides back up for neighbouring areas. In the situation where a power transformer at a zone substation fails, our contingency plans have the affected feeders shifted to adjacent zone substations while the fault is repaired. This interconnected dependency extends right across our network and there are very few isolated pockets where supply assets can be uniquely allocated to a single group of customers.

[4] A feeder might be shifted on to a constrained feeder in situations where that allows other feeders to be shifted off, or where the load profile of the new load is better suited to the constrained feeder.

46. The diagrams below show how we carefully ensure a high level of interconnection between adjacent zone substations, and the open points (marked with green lines) are the current settings for configuration. While this approach and architecture is efficient from a network planning and operating perspective, the location and reconfiguration of the open points is arbitrary from the perspective of an individual customer but would have a significant impact on the pricing they face under a locational pricing approach.



Interconnected urban network



Interconnected rural network

47. The Authority has indicated that locational pricing can extend right down to the low voltage network. There is a much greater degree of interconnection in the low voltage network, and the issues noted above (in relation to the high voltage network) would be compounded significantly if we attempted to reflect specific use of low voltage assets.

48. Distributors select the configuration of open points to make the most efficient use of the network. This selection will inevitably mean that some customers close to one distribution transformer might actually be fed through a long chain of conductors from another distribution transformer. This interconnection extends across the city, and it would not be reasonable for us to single out unlucky customers that happen to have a longer or constrained supply route at a particular point in time.

49. Locational pricing also carries an element of luck for customers. This is because *we* elect where to locate our network and network reinforcements, and these decisions will put assets close to some customers and further away from others. A significant example of this is the new grid exit that we are planning to reinforce supply to our rural network. There are a range of suitable locations that will allow us to redistribute rural load. However, for the location that we select, we will create a group of customers that were previously relatively remote (in terms of circuit length) but will become very close to our supply point (with very few interconnecting assets). Locational pricing would recognise this limited set of assets and charge less. While this might be economically efficient, if fails every test of equitable treatment between customers.

Challenges with non-distortionary pricing

50. The draft practice note includes a section on “recovering the residual” (page 14) and usefully develops the approach that this residual should be recovered in a non-distorting way.

51. The draft practice note then suggests that there are many ways that distributors can allocate costs to achieve this. Unfortunately, it does not address the very real challenges with each of the approaches.

52. Fixed charges create an equity issue between different size users. Customer feedback tells us that it is not acceptable for a 7 bedroom 10 acre estate to pay the same amount as a 1 bedroom social housing unit. Fixed charges carry the distorting effect of encouraging grid defection and inefficient amalgamation of supplies (for example, a farm house can be reconfigured to be supplied from the dairy shed).

53. Demand based categorisation has a number of issues: it encourages inefficient load smoothing using batteries, some customers’ peaks will be created by the distributor’s load management, historical demands may not reflect current usage (as a family evolves, or customers change homes), and recent demands suffer problems with differing billing periods between retailers and distributors and mid-period switching.

54. Volume based fixed charge banding simply recreates the distortionary influences of volume based pricing, but brings with it a raft of other challenges (for example, when customers change homes).

55. The draft practice note references the 2020 TPM guidelines which references historical anytime demand as being less distortionary. On the contrary, the TPM approach bakes-in the benefit of previous responses to the RCPD charge (which applied at the time of the historical anytime demand) and the volume based updating of the cost allocation under the TPM will be interpreted as an incentive to reduce volumes (albeit for a delayed benefit). Regardless, the notion that we might consider charging a residential customer based on usage at the premise 7 years prior shows a significant disconnect with reality.

56. Non-distortionary pricing is challenging. Our view is that the best approach might be to spread the recovery over a range of charges, so that each charge of itself is small enough that it does not elicit much response. This means teaming up fixed charges with capacity charges and flat volume prices for the recovery of the residual.

Conflict between cost reflective pricing and paying for network alternatives

57. The draft practice note is built around a conflicting premise that we can apply cost reflective pricing *and* engage with load aggregators/flexibility traders to resolve constraints[5].

58. We support the development of markets for flexibility traders because they will provide a good way for us to apply targeted responses to constraints without many of the issues associated with wider pricing adjustments.

59. However, there is a conflict between funding flexibility services and network alternatives and applying cost-reflective prices. The conflict occurs because truly cost-reflective prices inherently give a reward for a change in behaviour through lower charges, and the reward matches the underlying cost savings. Paying a flexibility trader to arrange the same response would be an alternative way to achieve the outcome, but would require non-cost reflective pricing to collect the revenue needed to pay the flexibility trader.

60. Another way of looking at the issue is that a customer will be rewarded for a change in behaviour through cost-reflective prices. If that customer also receives an incentive payment for the same change in behaviour via a flexibility trader, then the overall reward to the customer will exceed the cost savings, and the behavioural change is inefficiently over-incentivised.

61. We note that the Authority has effectively acknowledged this issue in the footnote on page 9 of the consultation paper, where it describes a retailer keeping customers on a “flat rate” rather than reflecting a peak price, and instead contracting with the customer via a flexibility trader to control load.

62. We would like to see some allowance for alternative distribution pricing approaches where a response (or a portion of any response) is being sought through alternative approaches.

[5] Draft practice note paragraph 32, 73 (for example)

Retailer rebundling

[redacted]

Unresolved issues with TOU pricing

63. The draft Practice Note promotes time-of-use pricing in a number of situations. We have identified a range of issues with time-of-use pricing that we have been unable to resolve. We have reached out widely in the search for solutions, but we have been unable to find practical resolutions. The main issues can be summarised as:

    a. There is a conflict between static TOU pricing and progressive (dynamic) load management.

    b. Many of our weather dependent peaks occur during times identified as shoulder or off-peak TOU times, and traditional peak times often have relatively low loading levels during mild weather.

    c. TOU pricing has an adverse impact on load diversity for discretionary load.

    d. TOU pricing provides an artificial reward for customers with solar PV and/or batteries (and this is not addressed with seasonal TOU pricing).

64. The following sections elaborate on each of these issues

Conflict with dynamic water heating control

65. Our current peak load management system uses a complex algorithm that measures changes in underlying load and makes decisions to shed or restore "channels", taking account of prior decisions it has made (but are not yet reflected in metering), focusing shedding in localised areas where there is a constraint, rotating through channels to balance the impact and meet reheating service level targets (with both regular and preferential channels), and estimating the magnitude of the load change for each channel shed or restored.

66. With around 30 separate signal injectors and 20 separate channels, the system manages more than 600 separate groupings of controllable load. Focusing in on just one of the groups, on our coldest day last winter, channel 65 controlled from our Papanui zone substation ripple injector was turned off 6 separate times as the system responded to load changes and service levels. The chart below shows the periods that this channel was off during the day, as well as two further channels controlled from the same injector:

67. In contrast to this refined management of load, time of use pricing signals are very blunt. We have experience of this from the past, and we adapted our approach in light of this experience.

68. In the 1980s, Southpower (Orion's predecessor) promoted a "Day n' Night" pricing plan, where electricity between 11pm and 7am was at a lower price, and water heating load was turned on at 11pm to reheat during the low price period. The plan was so popular that the water heating load being turned on at 11pm soon became the dominant peak in residential areas of the network.

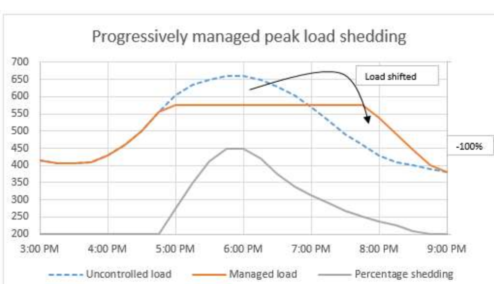
69. To address this peak, Southpower split the plan into three: "Day n' Night 6", "Day n' Night 7" and "Day n' Night 8". Each plan had the corresponding number of night hours, and the shorter night periods were provided at a lower price. The approach allowed customers with different water heating storage and hot water needs to select the option that best suited them, and Southpower engaged in a campaign to get customers to elect the option that suited them and to spread the load change.

70. The scheme was very successful. Unfortunately, Day n' Night 7 became the most popular plan and was still driving localised load peaks.

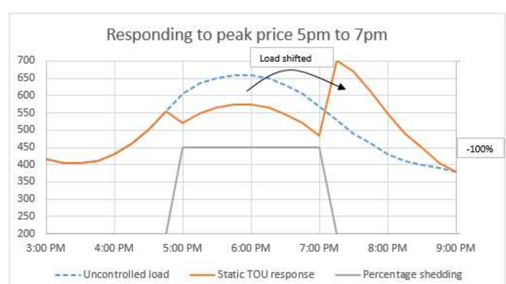
71. By 2003, Southpower had become Orion, and it moved to address the issue. The solution was to de-link price with management of load. It decided to provide a 10 hour period at the low night price (9pm through 7am) and within that 10 hour period, provide 7 ½ hours of heating. This approach allowed Orion to manage and coordinate the introduction of night load over a period of several hours and customers are largely indifferent to the exact timing as the heating still occurs within the low price period.

72. We currently operate both our peak control and night rate heating options during static TOU price periods (where the price remains the same for a set period of the day), during which we can manage loads and customers are indifferent to exactly when the heating occurs.

73. 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 that their 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 in 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

74. 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.

75. In our situation, before we implement a peak TOU price of any actionable magnitude, we will first need to invest in additional network capacity to meet the increased load as customers (perhaps facilitated by their retailers or other aggregators) adapt their water heating load in response to the signal.

76. Our experience shows that fixed time TOU pricing is not consistent with efficient management of energy storage. A Concept Consulting[6] report reached a similar conclusion in relation to EV charging.

77. 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 (like batteries and EVs, which would then also require separate wiring and metering).

78. 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 pricing 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 away from a controlled meter if the controlled price was higher than the off peak price.

79. 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.

80. Another possible solution sometimes discussed for "inclusive" situations (the most common metering 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:

    a. 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[7] per year, which would easily fund that, and

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[6] Concept Consulting EV report: "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

[7] 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.

b. Customers could still reasonably ask us to ensure that their hot water was off during the defined peak periods to minimise their costs.

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

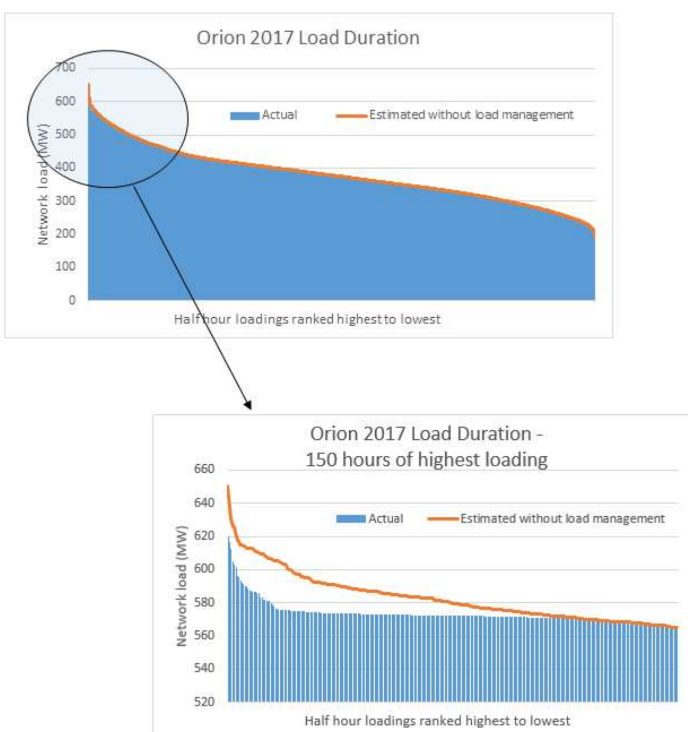
82. We considered options that might allow us to progressively restore water heating loads after the end of the peak price period, but on top of the extended impact of load management during the high price period, this would require us to keep some water heaters off for significantly longer than our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

83. A further issue with a shift to fixed time management of water heating load to align with TOU pricing is that the controllable load will not be available to respond to events like grid emergencies (load that is already off cannot be turned off again, and load that has recently been restored cannot be turned off without breaching service levels). It also means that controllable load is utilised all year (rather than just the peak winter season), and not available to respond to other uses in the value stack. This would mean that we could no longer facilitate Transpower's grid maintenance (as we have been doing during October).

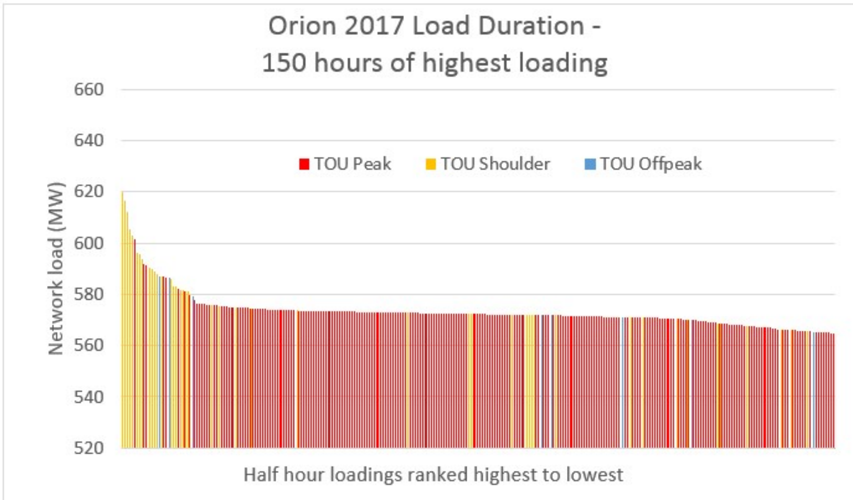
Load duration analysis

84. 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.

85. 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.

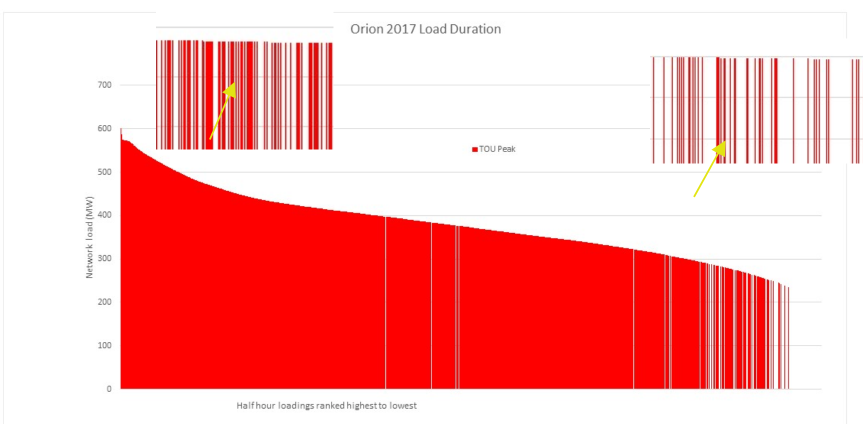


86. To consider how a pre-set static TOU might signal these high cost peak loads we have repeated the load duration curve, but colour-coded the periods that would fall within a typical peak, shoulder, off peak TOU structure[8]:



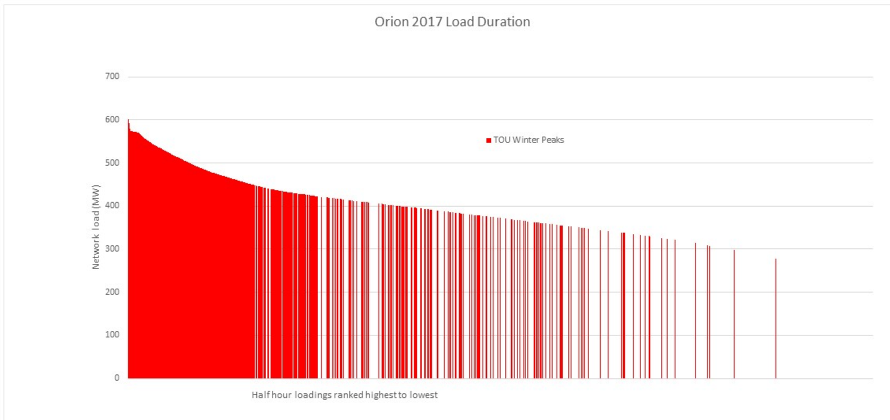
87. Perversely, this chart shows that most of the highest loads would have ended up being shoulder periods, and even a few off-peak periods are present. A TOU price structure would incentivise customers to move load *to* these times (rather than away from these times), so we expect our peaks, and therefore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

88. 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:



[8] 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

89. 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 when load is not peaking:



The impact of TOU pricing on discretionary load

90. 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.

91. 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. The options we have considered are challenging, including:

    a. 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

    b. 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

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

92. We consulted with retailers on these options and did not receive any support for them, nor did we receive any alternative suggestions for solutions.

Interaction between TOU pricing and solar

93. 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.

94. 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 (i.e. self consumption). Applying a higher winter season TOU price will, on most winter days, coincide with sunny periods, enhancing the savings for the customer but providing no corresponding benefit for the network. We are also concerned that it will provide an incentive for customers to oversize their PV system in an attempt to match lower winter generation with higher winter load.

95. 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.

96. We have not been able to find any solutions that align the reward for solar generation with the benefits to the network under a TOU volume pricing approach.

Interaction between TOU pricing and batteries

97. 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.

98. 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 incentive 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).

99. 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.[9]

100. Finally, charging and discharging batteries on a daily basis wastes energy as the charge/discharge cycle is typically only 80% to 85% efficient[10] – this represents an economic loss to our community and an adverse impact on our environment.

[9] 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.

[10] Tesla claims a round-trip efficiency for its Powerwall battery as 92.5%, but this only applies to a new product at optimal operating temperature and with a 2kW charge and discharge rate.

Convoluted approach to price setting

101. Part 2 of the draft Practice Note indicates that cost-reflective pricing requires a different approach to price setting. It then sets out a process of establishing cost reflective pricing components (where needed) before turning to establishing target revenue, deducting revenue received from cost reflective pricing, applying cost allocations, then returning to price setting for the remaining revenue requirement.

102. Firstly, this approach conflicts with our regulated disclosure requirements, which sets out an approach that requires us to show how target revenue is allocated to each consumer group.

103. Secondly, the suggestion that the "traditional price-setting" approach cannot achieve a cost-reflective outcome is incorrect.

104. The traditional approach is much more straight forward:

    a. Target revenue is established

    b. Target revenue is allocated to appropriately identified customer groups

    c. Pricing is established to collect the target revenue

105. Within these steps, in order for the resulting pricing to be cost-reflective, the allocation in step (b) must first look to allocate costs on a cost-reflective basis (for example, using contribution to coincident peak demand to allocate costs associated with meeting that peak demand). This is then mirrored in step (c), where a cost reflective pricing structure, consistent with the allocation approach, is established.

106. Pricing methodology documents have grown to become relatively long and technical documents. For them to remain relevant to the intended range of stakeholders, we need to be mindful of adding further complexity.

Concluding remarks

107. We submit that the practice note would be more useful if it was to be redrafted to address the challenges that we face implementing cost reflective pricing.

108. Thank you for the opportunity to provide this submission. Please note that the section titled "retailer rebundling" is provided on a confidential basis. We have included a version of this submission with the section redacted for publication on your website. If you have any questions please contact Alex Nisbet, Pricing Manager, on 03 363 9737 or by email alex.nisbet@oriongroup.co.nz.

Yours sincerely

Alex Nisbet
Pricing Manager

Supporting reform to efficient distribution pricing: a refreshed Distribution Pricing Practice Note
Q1. Do expectations laid out in the updated Practice Note on what 'good looks like' for efficient pricing provide a useful guide?
No. Making simple impractical statements like "no signal, fixed daily charge" is not helpful when it is not realistically feasible for us to transition to this approach. Likewise, simply stating that a price structure should be "peak", without any recognition of the practicality and implications of imposing a peak charge is not useful. Paragraph 27 in our cover letter summarises the main challenges with the challenges with the more common pricing metrics. It would be useful if the practice note acknowledged the specific issues and addressed them where possible.
Q2. Do you consider any of the material to be incorrect, subjective or superfluous?
We question the link made between pricing and reliability. The draft practice note suggests pricing can be used to improve reliability and resilience to mostly weather and asset lifecycle issues. We are not aware that pricing can prevent outages caused by weather events. The reference to energy losses is not appropriate in the context of distribution pricing (it is instead taken into account within energy pricing). The draft practice note indicates that price changes could occur more frequently than the current annual cycle. The Authority has effectively prevented this by locking us in to default distributor agreements where the Authority provided a default recorded term that only provides for one change every 12 months. The Authority indicated that the default recorded terms represented a balance between the needs of distributors and retailers, and we were unsuccessful in negotiating greater flexibility. There is now no process for us to adjust recorded terms without retailer agreement.
Q3. Are there edits or further explanation that you'd suggest to improve clarity?
Rather than edits to improve clarity, we suggest that the draft practice note needs a more substantive change to address issues (see paragraph 17 to 19 in our cover letter).
Q4. Is there material missing that would also be useful?

Note: Where you are asking us to include more material in the Practice Note, we would appreciate you explaining what you are seeking in as much detail as possible, to ensure that any further changes we make meet the need identified. *Please also consider whether any additional material is best developed and agreed with industry, or if the Authority is best placed to provide the directive solely.*
As noted above, addressing the practical implementation issues for the cost reflective pricing options and recognising the limitations of each would be useful.
Q5. Are the expectations laid out in the updated Practice Note on timing for reform achievable?
No. The draft practice note does not address the very real challenges we face in moving to cost reflective pricing. Once those challenges are addressed (or recognised) we will be in a better position to set out a realistic timeframe for pricing reform.
Q6. Do you believe it is useful for the Practice Note to become a 'living document' that is refreshed regularly to update for the Authority and industry's understanding? *Note: Considerations include, the frequency of updates and the associated consultation with stakeholders being most useful; the level of detail that provides useful guidance, and what focus future iterations could have.*
Yes, if it seeks EDB's views and takes out learnings from EDB trials.
Q7. Where questions of data access or use do not fall into the Updating regulatory settings for distribution networks consultation, is there any specific pricing-relating data concerns that the Authority should know, or be involved in?
Clause 3 of the default data agreement allows for 6 monthly access to detailed consumption data which provides a suitable basis for using the information to develop pricing structures and to assess responses to pricing structures. However, it is likely that our pricing reform will evolve to a point where the detailed consumption data is used in the billing process. For this to work, the detailed consumption information would need to be available on (at least) a monthly basis. The default data agreement only provides access on a more frequent basis under clause 4. Unfortunately, clause 4 does not include any obligation on the retailer to agree to provision of the information, or even to engage with distributors on any request. The clause does not provide any mechanism for access that was not available prior to the publication of the default data agreement template. This issue is not addressed by the changes that ERANZ/ENA requested.

We attempted to negotiate an alternative agreement with included monthly access to information under clause 3. Unfortunately, one of our main retailers indicated that it would only consider a data agreement that was aligned to the Authority's default. In this respect, the move by the Authority to issue a default has actually made access to information harder.

Q8. Where questions of customer contact data access or use do not fall into the Updating regulatory settings for distribution networks consultation, is there any specific pricing relating data concerns that the Authority should know, or be involved in?

The consultation paper usefully indicates the Authority's expectations around the use of customer contact information for the purpose of pricing reform and future price signalling. While the Authority expects retailers to work in good faith with distributors for this purpose, the reality we face is somewhat different.

We observe that retailers do not want distributors to engage with customers and they are not willing to tell us how our changes might be translated into retail prices.

As a recent example of this, in response to advice that we would be contacting customers to consult on changes to services (for example, pricing changes, security level changes), a large retailer responded with:

> *"it is not necessary to use [customer] information to do pricing analysis … as per our interposed arrangements, Orion should just engage with [the retailers] on pricing changes etc and it is for [the retailers] to hold the Customer relationship."*

Q9. Engaged customers are more likely to respond and in a more predictable manner than disengaged customers. What role do you see the Authority has in supporting consumer engagement on pricing?

We agree that engaged customers can help us achieve efficient outcomes and support decarbonisation. We consider that the Authority has a role to play in building customer understanding of:

(a) how the electricity system works and who the players are,

(b) the ways in which the electricity system will change and preparing customers for the options and choices they may have, and

(c) what drives costs for an electricity system.

However, we must also provide support for customers that do not want to engage (which we understand to be the majority of customers). For these customers, simple and consistent pricing incentives are important. The Authority should include acknowledgment of this approach in its practice note.

Q10. Ensuring that targeted pricing signals impact decision makers is important in distribution pricing reform. What role do you see the Authority has in supporting an industry Consultation paper: a

refreshed Distribution Pricing Practice Note Page | 15 discussion on ensuring price signals reach consumers, taking into account the need to comply with the Commerce Act 1986?

This is a very present issue for us. The argument that competition should drive efficient outcomes, and that retailers will accumulate and package the various cost drivers they face is not bearing out in practice. Efficient pricing has no value if it is ignored by retailers. Please refer to the information in paragraphs 63 through 81 of our cover letter.

We are not sure what the solution might look like, but we do think the issue should be addressed and could include knowledge sharing workshops.

Q11. Complexity in pricing structures could slow reform efforts. How do you see the Authority working with the sector to strike the correct balance?

We consider that maintaining an acceptable degree of complexity in pricing as a legitimate limitation in pricing reform, rather than something that might simply "slow" pricing reform.

The acceptable degree of complexity might evolve over time as technology develops, but this is more of a long-term evolution, rather than something that might change in the next few years.

We are recommending that the Authority address the implementation issues with the various alternative pricing approaches, and we think that this work will expose the limitations of each approach.

Q12. Can you provide feedback on how bill shock can be managed by industry and the Authority, to support ongoing reform of prices and not unduly impact on groups of customers?

We are conscious of the impact our pricing has on our customers, and in particular on our vulnerable customers (including those in energy hardship) who do not have the resources to respond or adapt. The acknowledgement of bill shock in consultation paper and the expectation that changes should be smoothed over progressive years (paragraphs 66 to 73) is useful.

Part 5 of the draft practice note sets out expectations on the timing of reform, and the issue of addressing bill shock and smoothing changes over years is notable by omission. We submit that this section should be amended to include the consideration of impacts on customers, bill shock, and mitigating measures.

Separately, and despite mitigating measures, we must accept that changes will have adverse impacts on some customers. Optimistically, the draft practice note indicates the target is to provide customers with the ability to respond to pricing signals, rather than to remove cross subsidisation[11]. In reality, it is not possible to separate the two. Changing a price structure to a form where customers can respond and receive a cost-reflective benefit will result in some customers facing higher charges. As usage and chargeable attributes vary across customers, any pricing change will create winners and losers.

[11] Draft practice note, paragraph 24

Q13. Are there aspects of LFC and its announced phase out that you see as an ongoing impediment to pricing reform?

We expect the LFC phase out to be applied through a simple adjustment to the daily cap. This will leave the following issues:

- Customers (and new customers) that are not in an LFC option will still be able to elect to shift to an LFC plan, and then face the prospect and impact of transitioning back to higher fixed charges. We would like to see the option for retailers to close LFC plans, provide a one way exit option for those whose energy consumption increases, and remove the obligation for retailers to write to customers advising if an LFC option is cheaper.

- The LFC requirements require an equivalent LFC option to be created for all standard plans. We would like to see this requirement removed in relation to new pricing plans in order to facilitate trials and development of new pricing plans.

- The LFC requirements prevent multiple fixed charges or stepped variable charges. With the exception of existing LFC options, we would like to see this requirement removed to allow more innovation in cost-reflective pricing.

Q14. We are interested to better understand what ongoing limitations LV visibility issues might have that could constrain future pricing reform, how industry can respond to them and what, if any, role you see for the Authority in addressing this area?

We currently construct and operate our network using a standard sizing approach for the low voltage network, and optimising the options for customer load response against the much greater value high voltage network. If we shift our focus to the low voltage network we will have to accept a suboptimal result for our high voltage network. This is because, within the limits of demand response, a response cannot be optimised against two separate drivers – for example, if a battery has enough storage to last for 2 hours, then that storage can either be deployed against congestion on the high voltage network *or* congestion on the low voltage network that might occur at a different time, not both.

This trade-off will need to be considered, together with the additional costs of LV visibility and actively managing loads, before we shift our approach.

Q15. Currently, installation of energy intensive devices such as EV fast chargers are not required to be notified to distributors. Do you see this this as an impediment to advancing pricing reform, and what role do you see the Authority having in this area, and how this could be done?

As the Authority is aware, distributors need data to support our understanding and development of our low voltage systems. Currently:

- distributors have some information on network congestion/constraints,
- retailers have access to smart meter data which distributors are seeking access to, and
- customers, or in practise it’s often their electricians, notify us of the installation of solar and battery devices.

In the future, notification of "vehicle to grid" devices will also be necessary to ensure safety.

Heading forward, the real power will come from the integration of all this information into digital distributor systems and maps. Integration will allow constraints that exist, or will exist, to be matched to possible solutions – be they traditional network solutions or innovative non-network solutions. The implementation of the lowest long-term cost solution being the goal.

The one missing significant piece of information is the identification of the location of what will be the largest contributor to growth on the low voltage network over the next decade and more. Namely electric vehicles.

We consider that it would be an advantage to know where EV fast chargers (7 kW and above) are installed. Establishing a requirement to notify distributors, and for distributors to load details to the registry would allow distributors and other service providers (such as flexibility traders) to access the information. Distributors and other service providers could then use this information to provide options for customers to participate in demand response programs.

But more importantly, it is the location of EVs that will drive the growth on the low voltage network, rather than the location of in-home dedicated EV fast chargers. Current trends, including trends that we observe overseas, show that the majority of EV drivers are likely to use standard three-pin plugs for charging (in Norway for instance 60% to 80% of EV drivers charge this way). We would miss out on a significant opportunity if we do not extend our focus beyond fast chargers.

If distributors had EV registration addresses, we could combine such information in our systems with half hour metering information and V2G information, and:

- be able to identify the kW size of charger being used in the house,
- be better able to identify where constraints are likely to occur in the future,
- be better able to identify opportunities for demand management of EVs, including the potential for V2G use and/or tendering for flexibility options.

Presently Waka Kotahi NZ Transport Agency (and the Ministry of Transport), collects registration information on EVs but only publicises the location of these EVs down to suburb level. We believe that greater detail of location could be shared with distributors.

We note that currently in the UK, distributors receive information down to a postcode level on where EVs are registered. In the UK postcodes are more granular than NZ postcodes and often identify the street, or even part of a street, that a house is located on. In New Zealand we have the opportunity to go one step further in the desire to efficiently decarbonise and provide the best possible solutions and tools to households to enable them to be part of the energy future.

We believe, with the objective of New Zealand decarbonising as efficiently as possible, the Authority should be working with Waka Kotahi NZ Transport Agency / Ministry of Transport to achieve EV registration address dissemination and this is precisely the sort of 'whole of government' approach to decarbonisation the Government has called for.

Q16. As we develop our thinking on further initiatives, tools or regulation, we will engage appropriately with the sector. We welcome any immediate suggestions you have regarding how we could better promote faster pricing reform.

Q17. Do you consider that the Authority has not properly understood any of the constraints listed in this paper, or has missed other issues that constrain efficient pricing reform progress and how they could be addressed? *Note: Where you provide further issues, please provide as much detail as possible. Please also consider whether any additional issues are best addressed by industry, or if the Authority is best placed to address the issue solely.*
Please see our cover letter with this submission (issues listed in paragraph 17).
Q18. Please do not limit your feedback to the above questions - we also welcome feedback on any other ways the Authority could work constructively with industry and consumers to support and drive accelerated pricing reform.
Q19. Please consider the role that you see appropriate for the Authority to be proactively involved in pricing evolution.
Q20. How the Authority could engage more with industry, either individually or through structured channels, and in formal and informal ways.
We seek more genuine engagement. We have conveyed the messages in this submission on many occasions, but the challenges we face have largely not been acknowledged, and the Authority continues to push pricing reform without addressing the legitimate barriers we face.