Orion

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Submissions
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SUBMISSION ON DISTRIBUTION PRICING

Introduction

1 Orion New Zealand Limited (**Orion**) welcomes the opportunity to comment on the "More efficient distribution prices" consultation paper (the **paper**) released by the Electricity Authority (Authority) in December 2018.

2 On the general topic of electricity pricing reform, of which distribution pricing is an important aspect, we consider that it is critical that this be strongly and clearly supported by government. In our view MBIE and the Authority should recommend that the government issues a government policy statement for electricity setting out clear expectations on distributors to introduce pricing that is less consumption (kWh) based. The GPS should acknowledge that this is likely to have significant adverse impacts on some consumers, and that it is putting in place mechanisms to help manage this, but that the change is necessary to ensure New Zealand maximises the benefits that new technologies can provide.

3 In the absence of such support, progress is likely to be slow.

4 Regarding the paper itself, in our view:

4.1 It does not adequately recognise the complexity of change or the impact of change particularly on our customers,

4.2 The proposed revised pricing principles unhelpfully shift the focus from longer term network investment to short term management of congestion, and nor do they help manage the trade-offs inherent in them,

4.3 The proposed star rating scheme is not well founded, and

4.4 The Authority's position on the low fixed charge regulation remains out of step with the industry.

5 The remainder of our submission is in four parts:

5.1 Comments on the paper,

5.2 Answers to the specific questions in the paper as Appendix 1,

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5.3 Detailed comments on the proposed new pricing principles as Appendix 2, and

5.4 A more detailed response on the low-fixed charge regulations, and the Authority's position on them, as Appendix 3.

Comments on the paper

6 Overall, we find the paper disappointing. It seems to be following the example of the TPM in that it repeats previous Authority views without adequately responding to the views of stakeholders. We do not believe this approach will lead to good outcomes, here or more broadly.

Issue the Authority would like to address

7 Section 2 of the paper sets out the issue the Authority would like to address. There is little new information or analysis in this paper compared with the Authority's 2015 paper, and because there appears to be no reflection of the submissions and other distributor inputs the Authority has received since, we repeat much of what we have previously said on this topic. We believe our views are valid and encourage the Authority, where it disagrees with them, to articulate why.

8 There is a slight twist on previous narratives, in that "benefit-based" has replaced "service-based" as a desirable co-attribute to "cost-reflective". This change is not explained. We presume it is intended to align with the Authority's approach to the TPM. In any case the change does not appear to influence the paper, although we do note that "use" and "benefit" are presented as equivalents in para 3.7.

9 Para 2.1 makes an unpromising start by defining efficient prices as "as low as possible". This looks like the paper is placing the emphasis on productive efficiency, which is not really about the structure of pricing at all. We submit that the concepts of allocative and, in particular, dynamic efficiency are the important ones here.

10 Para 2.2 states (as did the 2015 paper) that the status quo is "flat per kWh" pricing. This is not based on any empirical analysis or sound understanding of existing distribution pricing. As we noted in our submission to the electricity pricing review:[1]

[1] Our answer to question 26. The submission is available at: http://www.oriongroup.co.nz/assets/Company/Submissions/EPR-Submission-Orion-final-23Oct18.pdf

We believe it is important to start from an accurate description of the status quo. For most residential customers in NZ that is one of the following:

- A 'two meter' setup where one meter measures 'uncontrolled' consumption, while the other meters 'controlled' consumption that can be turned off and on at the discretion of the distributor. The distribution price for controlled consumption is typically materially less than that for uncontrolled consumption
- A 'single meter' or 'inclusive' arrangement, where part of the total load can be turned off and on by the distributor, with the single price being somewhat lower than the uncontrolled price, and
- Some form of TOU pricing, where there is a single meter with multiple registers, the most common being day/night.

While the first two of these can be characterised as flat rate, there are good reasons for this in the context of historical use of load management. Specifically, it is very hard to achieve a favourable outcome with respect to load management (one that supports lower investment and lower cost) unless the storage that underpins it is subject to central coordination, and that tends to require a flat rate so that the customer is indifferent to when that load management occurs. This admittedly leaves the "uncontrolled" portion over which a customer might exercise discretion, but:

- no matter how this is structured, if it is kWh based it is difficult to avoid an excessive reward to PV, and
- many TOU structures could incentivise investment in batteries (or charging of EVs) that simply shifts the peak, with no reduction in costs.

Overall, the key reason why consumption based charges are too high is that fixed (or other forms of non-consumption-based charges) are too low. This can only be addressed by the revocation, or significant amendment, of the low user fixed charge regulations together with a fundamental shift in the way consumers see the service being provided. Revocation, or significant amendment, of the low user fixed charge regulations is a necessary step to address pricing fairness issues.

11 We think the paper should have made it clearer that existing pricing (at least for most residential customers) is too consumption (kWh) based. We would agree with that formulation.

12 From para 2.4 of the paper, NZIER's 2015 estimates of the possible consequences of pricing that is too much consumption-based are restated: there could be significant over-investment by consumers in solar generation. This is indeed a concern and a risk. However, with the passage of three years we would have expected the paper to show how solar uptake is tracking compared with NZIER's assumptions. The data (from the Authority's EMI website) shows uptake is tracking nowhere near what NZIER assumed, at around 1% of ICPs compared with the assumed 8%, and in fact is almost exactly what would be expected, in NZIER's model, if consumption prices were not 'too high'. Whatever motivates investment in solar clearly has some factors that were not incorporated in NZIER's analysis. If the inefficient over-investment is not occurring, then neither is the wealth transfer effect.

13 Para 2.9 seems to suggest that existing networks have been overbuilt because of the structure of distribution pricing. The paper presents no evidence for this, and we do not agree with this assertion.

14 The electric vehicle (EV) case study that appears after para 2.9 (on page 3) indicates that, theoretically, all of the energy required to charge an electric vehicle can be delivered without

increasing a household's peak demand. That is arithmetically true. However, it begs the question of how the "smart charging" could be achieved by pricing. We note Concept Consulting's conclusions that:[2]

14.1 TOU pricing can be worse than flat rate pricing in this regard (because all of the EVs might start to charge around the start of the 'off-peak' period, making that a peak), and

14.2 as with the other – considerable - storage heating load connected to the network, coordination of the switching off and on of that load is essential to realise its value as a means of deferring or avoiding network investment.

15 It is essential that any analyses of possible new pricing approaches considers how they influence the incentives on customers to invest in the various technologies. This would provide a more robust basis for comparing different approaches.

16 The EV example also assumes that all EV owners are always indifferent to when their vehicle is charged so long as it is charged by the following morning. We doubt this is true and it certainly is not true with respect to the existing energy storage in the form of hot water. Consumers determine the value to them of the electricity they consume, and just as most consumers cook their dinner in the evening – including at times of peak electricity demand – at least some EV owners will want to charge their vehicles as soon as they get home. They will do this even if pricing is cost reflective. Moreover, even with cost reflective pricing we believe it will still be materially cheaper to run an EV than the petrol or diesel equivalent. Incentives to invest in EVs will still be strong.

EV case study

Neville buys an EV. He charges it when it suits him, usually when he gets home each evening. The EV charging load can be up to 7kW instantaneously, but due to normal network diversity it adds only 1kW to his contribution to coincident peak demand. This requires network investment that costs $150 per year to support. The EV uses 2,500kWh per year. Neville's home pricing plan is a flat rate of 6 cents per kWh (delivery only), which fully recovers the annual cost of the network investment required. Combining the 6 cents with 10 cents per kWh for energy, Neville is paying the equivalent of a petrol price of around 40 cents per litre for his EV. Neville is very happy.

17 To the extent that TOU pricing, despite its limitations, can be of benefit to those EV owners who are happy to charge their vehicles at off-peak times, we suspect an empirical analysis would show that in most parts of the country this option is already available.

[2] "Driving change" – Issues and options to maximise the opportunities from large-scale electric vehicle uptake in New Zealand, 7 March 2018, pp 4 and 5.

What needs to be done?

18 Section 3 of the paper discusses what needs to be done in response to the issues identified in section 2.

19 It begins (para 3.1) by listing two options that distributors have:

19.1 Introduce more efficient distribution prices, or

19.2 Restrict the use of new technologies.

20 These are presented as the only two options, and as mutually exclusive. We submit that this is a false dichotomy and is a limited and unhelpful view.

21 First of all there is the question of how much more efficient pricing has to be to address the issues. Structural pricing changes inevitably create material wealth transfer effects, so there must be some confidence that any new pricing will be sufficiently better – in terms of reducing inefficient investment - to justify those transfers. Pricing can be “more” efficient without being efficient enough. It depends on whether it materially changes investment incentives.

22 Moreover, if it is not possible to resolve all of the issues using pricing alone, and we do not believe that it is, then some form of “restriction” might play a useful and complementary role. For example the Authority is currently consulting on the idea of distributors specifying the “hosting capacity” of their networks with respect to Part 6 of the Code, the idea being that any potential DG investor would be able to determine how much DG could be installed at any ICP without triggering any additional network investment requirements.

23 More generally, in an interconnected system with strong common quality attributes, obliging parties to meet and maintain certain standards is standard practice. We note the wholesale market does not allow connected parties to simply do as they please, and a stable system requires a single party to coordinate the available resources. Distribution networks are not conceptually different in that regard.

24 Section 3 goes on (from 3.7) to describe efficient distribution prices. We note however that it does not acknowledge trade-offs, particularly between the first three attributes and the fourth.

25 Para 3.8 then sets out four different distribution services:

25.1 Connection

25.2 Access

25.3 Network use

25.4 Common costs.

26 This breakdown is not very clear about whether each of these should be seen as different services (with a possible implication that a consumer might use some but not others) or whether they are ways to think about costs. It looks like a mix. For us, *connection* gives *access*

to the network and allows *network use*, but it is difficult as a practical matter to separate these as distinct services – that is, provide one and not the others. Likewise the connected party has access and network use limited only by protection settings, constraints which activate in practice. Common cost cannot reasonably be seen as a service in itself, although common quality is an attribute of the service for most connections.

27 Moreover, we suspect that most consumers will not think about these as different services, nor will they consider that a pricing approach that might be 'good' for access could be less so for network use.

28 Paras 3.9 and 3.10 discuss signalling the marginal cost of network use.

29 Para 3.9 states that "Locational marginal prices could in future be the way to signal the dynamic cost of congestion and losses." but little more is said about this idea. A Sapere analysis of this idea (produced for the Authority) has been released by the Authority subsequent to the paper, but the Sapere analysis is not referenced in the paper.

30 It would be useful for the paper to have indicated:

30.1 why choosing to calculate energy prices at points along the supply chain closer to the customer has any particular relevance to distribution pricing

30.2 assuming it has relevance, when this future might arrive – if it is not too far away then it might be good to wait for it

30.3 how such pricing would align with (new) principles (c), (d) and (e).

31 But we disagree with the statement in para 3.10 that LRMC based prices are an "alternative" to locational marginal prices (a short run signal). They are simply a different thing. As we explained in our own paper on the subject [3] whatever the price needs to be, in real time, to manage demand when it approaches capacity is unrelated to a distributor's costs. In principle it is floored by the lowest price at which existing consumers would be prepared to reduce demand sufficiently to relieve the constraint, and capped by VoLL. Neither of these values is a distributor cost.

32 LRMC-based pricing by contrast is in support of longer term optimisation of network investment, by attempting to give consumers a price to invest against, say for example by investing in storage. A network can have zero growth or no current congestion and still benefit from this price signalling because the consumer investment means extra network investment is **never** required.

33 In our view this fundamental difference between the short run signals inherent in locational marginal prices and the signals that support efficient network investment is well established both in the general literature and in the more specific submissions to the TPM process, and indeed in the Authority's own TPM LRMC working paper[4]. This difference is just as fundamental

[3] See our 2017 consultation paper available at: http://www.oriongroup.co.nz/assets/Company/Corporate-publications/Retailer-Consultation-Paper-Final.pdf, section 7..

[4] Transmission Pricing Methodology Review: LRMC charges working paper, 29 July 2014. Paras 8.11 and 8.12, pp29-31.

and relevant in the context of distribution pricing. The Authority's view as expressed in the paper contradicts this earlier TPM work and is wrong.

The clarified distribution pricing principles

34 The apparent new preference for distribution pricing that tries to manage demand in real time is reflected in the proposed new pricing principles, and for that reason alone we consider the new principles are not as good as the existing principles.

35 Further, a key problem with the existing principles, and as identified by Castalia in their 2013 report [5] is that there are trade-offs between the various principles, yet little guidance on how those trade-offs are to be managed. Castalia suggested there should be more guidance. The new principles do not appear to provide this.

36 Our detailed comments on the proposed pricing principles are included in Appendix 2.

How can distributors do this?

37 Section 4 of the paper discusses three pricing structures. These structures are not described in any detail, although they are described (in para 4.4) as not "complex". Each has a "fixed" component and one or more "variable" components, although it is unclear whether "connection" in these examples is seen as an upfront cost charged to the connecting party (which is how it is described in para 3.8 (a)) or an ongoing cost recovered via the fixed charge from the retailer.

38 The paper does not say, at this point anyway, what the relative revenue proportions of the components is or should be, but it would appear that the fixed charge is intended to recover a significant proportion. The paper also does not say how this squares with the position expressed later in the paper that the low fixed charge regulations are not a barrier to more efficient pricing, since it would appear to be a barrier to these three approaches at least.

39 In terms of the three different approaches rated:

39.1 Seasonal TOU is seen as being a slight (one more star on "Use") improvement over the flat rate status quo. The paper notes that this approach should not be seen as an end-point.

39.2 Static critical peak demand (measured in kVA not kW) pricing, which also includes a contracted capacity component instead of a fixed charge, gets 2½ more stars than TOU (1½ for "use" and 1 for "access").

39.3 Dynamic critical peak gets one half star more for use compared with static peak.

40 The seasonal TOU example does not provide any detail on when the various TOU prices would apply, but we can surmise that TOU prices will be higher when network loadings are highest. Let us suppose then that high TOU prices apply on winter weekdays in the mornings (say 7am to 11am) and the evenings (5pm to 9pm). (This is certainly when Orion network peaks occur, at

[5] Castalia, Review of Electricity Distribution Businesses' 2013 Pricing Methodologies, Report to the Electricity Authority, November 2013, p38.

least in an average sense.) On the face of it this pricing looks to be an improvement over a flat rate from a solar perspective, but:

40.1 many winter mornings are sunny, and on such mornings the network load is often not very high compared to the coldest winter days (typically 20% less)

40.2 compared with summer, residential load is higher.

41 Together the structure of the pricing and these two factors make the value to the customer of winter morning solar generation higher as it is more likely to offset consumption. The exact impact of this depends on details of the relative prices and structure of the TOU periods, but without this detail we can only conclude that the superiority of seasonal TOU is ambiguous, at least with respect to incentives to invest in solar.

42 While the two demand approaches are described as not "complex", again no detail is provided on how these would work in a technical sense. The joint ENA/ERANZ technical implementation working group has highlighted that demand approaches tend to raise the most technical issues.

43 Regarding static demand, we note that a crucial decision will be what the static periods are, but there is also the question about how many demands in those periods count towards the chargeable quantity. For example is it the single maximum demand (for say the month)? Or is it some average of the top 'N' demands?

44 Static period critical peak shares many of the features of static period TOU, and indeed in the extreme, where the chargeable quantity is the average of all of the demands within the defined static period, it amounts to something very much the same.

45 Both static and dynamic critical peak present some complexities for retailers, particularly with respect to customers and switching. A retailer that has a customer for part of a measurement period will not be able to determine the correct chargeable quantity. The only way for this problem to be resolved is for the chargeable quantity to be measured during one whole period, and applied for the following whole period. This presents issues of its own. (For example, this is the approach the Lines Company took for a decade or so up until October 2018.)

46 Dynamic period critical peak pricing has the extra dimension that the dynamic period must be signalled to support response. This is certainly doable, and Orion has done it for many years, but it does not come without cost for both the distributor and other parties. If it is really only earns an extra half a star compared with the static approach, is it worth it?

Low fixed charge regulations

47 The paper contains a very short section on the low fixed charge (LFC) regulations. We devote Appendix 3 to a detailed discussion of the Authority's position on the regulations. Here we simply note that the paper does not acknowledge in any way the lengthy correspondence and engagement between the Authority and ENA on the 2016 guidance document.

48 We also note that the Authority has not yet released, after several years, the advice it received from the Retail Advisory Group on the LFC regs. This has been promised a number of times, including in Carl Hansen's letter of 8 May 2017 to ENA and ERANZ. That same letter stated the Authority's position that it is restricted by statute (section 113(2)(4)(b) of the Electricity

Industry Act 2010) from “commenting on or advocating changes to the LFC regulations”. We submit that is both an extreme view of that section, and a view that the Authority does not consistently apply, it having been happy to note on a number of occasions its view that the regulations are not a barrier to distribution pricing reform.

49 But at the end of the day if distributors say the regulations are a barrier, which we do, and the Authority thinks we can effectively render the regulations ineffective anyway, then there should be no problem in the Authority recommending the revocation of or significant change to the regulations.

50 More importantly, we believe that the sorts of price structure changes being contemplated need positive government and official advocacy and support as opposed to just permission. We believe the best way of doing this is via a government policy statement that clearly sets out expectations while accepting and acknowledging the implications for many consumers.

Steps distributors can take to set more efficient prices

51 From para 4.21 the paper describes a fairly standard looking process for allocating costs, defining consumer groups and setting prices. The paper says “efficient” prices, but the process described is generic and applicable irrespective of the efficiency of the prices that actually result. As such, this section is not very useful.

52 Moreover, the detail is also not helpful, and contains some errors. For example:

52.1 the “congestion period demand charge” is expressed (in Step 5 on page 16) as “$/kVa [sic]” when it must be expressed as “$/kVA/time period” to work,

52.2 the reference to “average power factor” looks like it should be a reference to **load** factor – a relationship between one kVA of peak demand and the annual peak TOU (or total annual) consumption associated with that 1kVA.

When should distributors do this?

53 Section 5 of the paper discusses the timing of the transition to move to more efficient pricing.

54 As pointed out above and in Appendix 1, solar uptake is not currently at anywhere near the levels that underpinned NZIER’s 2015 analysis. In addition, most EV owners have access (should they want it) to some form of off-peak pricing. The sense of urgency the paper tries to convey is at odds with these facts.

55 We agree that the more consumers invest in (some) emerging technologies the harder it will be to change pricing, but for those distributors that have already tried it has not been straightforward – for example Unison’s experience with the “solar tax”.

56 Para 5.5 states that “price reform is expected to lower the average price consumers will face”. This statement is not time-bound, but we note there is no reason to suspect that price reform will immediately reduce average prices at all, nor indeed materially in the medium term (say five years). By contrast, any bill shocks will be immediate - although they are likely to be phased in. There will definitely be a group of consumers that will pay more *now* on the basis that they *might have* paid even more *later on*. That is not an easy sell.

57 The paper presents no analysis on bill shocks. Our own and ENA's analysis suggest that bill shocks could easily exceed the impact of factors such as a lower WACC from 2020.

58 We support the Authority providing greater clarity in expectations as to the form and content of roadmaps (from para 5.9 in the paper).

The Authority will monitor distributors' progress

59 Section 6 of the paper discusses how the Authority will monitor progress. It also provides more information on the star ratings, and some further commentary on cost and revenue structures.

60 We have no problem with the concept of monitoring. However, if the Authority is to have useful conversations with monitored parties it needs to improve its understanding of the various possible pricing approaches and their attributes.

61 By way of example, we note that the star ratings given to different "charging methods" in Table 1 (page 19) is not supported by any commentary or analysis. We are surprised that "Anytime maximum demand" is rated the same as "Flat kWh". We are also surprised that "Installed capacity" is rated so much lower than a "Fixed Daily Charge" when the latter is usually defined with respect to a capacity band, so they are just different ways of expressing the same thing.[6] And why is an ongoing fixed charge seen as so much worse than a capital contribution, when the former could be set to simply recover the latter over time?

Transition

62 Section 7 of the paper discusses transition. Transition is important.

63 The section could be interpreted as implying that communication is all that is required to persuade communities of the need for change. We disagree. New Zealand must proceed on the basis that these reforms will be necessary but unpopular. A significant number of consumers will be worse off **now**, and this may or may not mean those consumers will pay less in future than they otherwise would have. That is why explicit government and regulatory support is necessary.

64 We also disagree that pricing reform will necessarily avoid inefficient network investment. It is not clear from the paper how this comes about, and the NZIER example is only about inefficient investment by some consumers in solar generation. That investment can be inefficient, and it can create wealth transfers from the worse off to the better off, but it does not necessarily involve any inefficient *network* investment.

[6] A point acknowledged by the Authority in its discussions with ENA over the low fixed charge regulations, see Appendix 3 below.

Concluding remarks

65 Thank you for the opportunity to make this submission. Orion does not consider that any part of this submission is confidential. If you have any questions please contact Bruce Rogers (Pricing Manager), DDI 03 363 9870, email bruce.rogers@oriongroup.co.nz.

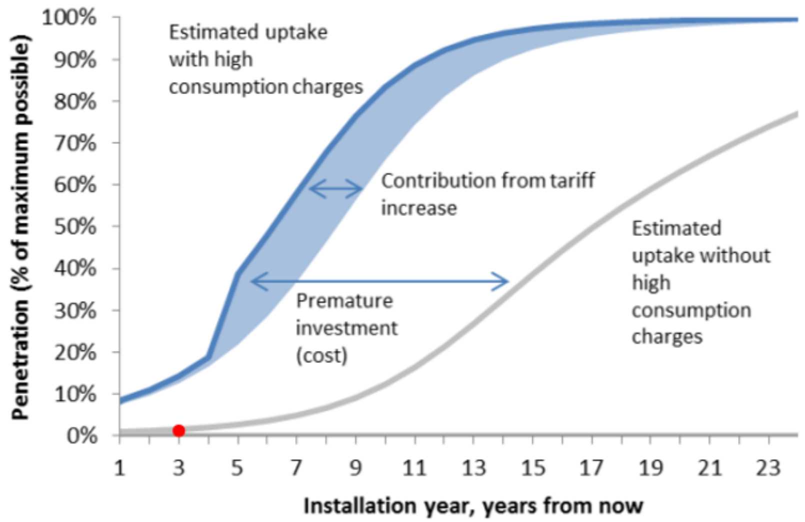
Yours sincerely

Rob Jamieson
Chief Executive

Appendix 1: Responses to specific questions

Submitter: Orion New Zealand

Number	Question	Response
Q1	Do you agree that distributors need to reform their prices? What is the reason for your answer?	We certainly agree that distributors need to review their pricing approaches from time to time, and that the changes being wrought by new and emerging technologies is a good reason to review current approaches. Whether “reform” is required, and what the nature of that reform should be is an open question. The right answer to that question depends on what pricing can achieve and what regulation allows.
Q2	How important and urgent are the issues identified by the Authority?	While the nature of new technologies is that the rate of uptake can change quickly, there is little sign that pricing is currently leading to poor investments by consumers. We note in particular that the uptake rates for solar that NZIER assumed in its cited 2015 report are far in excess of what has actually happened. In fact uptake is much more in line with the uptake that ‘should’ be occurring. This is shown below, which is NZIER’s 2015 chart with actual uptake added - shown as a red dot.

		Figure 1 Impact of high consumption tariffs on investment in solar Scenario with high cost solar and high cost grid-supplied electricity  Thus, while we agree there are important risks here, for the moment they remain risks rather than manifest problems. In relation to possible EV clustering, again this is a theoretical problem. In addition we note that: • It is unclear whether any pricing approach alone could deal with this problem, and • In any case, and unlike with DG, an EDB does not, at least currently, have accurate information on the whereabouts of EVs.
Q3	Do you agree with the proposed Distribution Pricing Principles?	No.

		The apparent new preference for short run / locational marginal price signals over long run incentives in support of dynamic efficiency is not, in our view, an improvement. In fact it represents a fundamental misunderstanding. We also do not consider the proposed principles are a material improvement more generally, and they do not provide the guidance around management of trade-offs that was suggested by Castalia back in 2013. See Appendix 2 for our more detailed comments.
Q4	What if any changes would you recommend are made to the proposed Distribution Pricing Principles, and why?	Overall the existing principles are better than the proposed new ones. More guidance on how trade-offs are to be managed would be an improvement.
Q5	What if any changes would you propose to the star-ratings to better reflect the relative efficiency of distribution prices?	We do not believe that the star ratings are very helpful. The way they have been derived does not appear to be well founded.
Q6	How long do you think distributors would reasonably need to introduce the different price structures discussed above?	It depends on the magnitude of the changes, and on the size of the customer impacts that might result from those changes.
Q7	Can you illustrate how and to what extent the LFC regulation hinders price reform?	See Appendix 3. The Authority's position on the regulations, as repeated in the paper, continues to be unhelpful.
Q8	How accurately has the Authority categorised distributor revenues and costs? How could this be done more accurately?	This categorisation adds no value. All costs are fixed in the very short term and variable in the very long term. There seems to be some inconsistency between the paper's discussion of fixed costs and its position on how various quantities can be seen as variable under the LFC regulations.
Q9	What if any would be better indicators of the efficiency of distribution prices, or the ambition of and progress being made by distributors on their price reforms?	It would be better to monitor and measure outcomes. For example, how is solar uptake tracking, is EV clustering occurring?

Q10	What assistance could the Authority (or other stakeholders) offer distributors in order to speed up the reform process, or help to remove or reduce barriers to distribution price reform?	The LFC regulations should be revoked as soon as possible. As a second best alternative, or as the first step of an orderly transition, the regulations could be amended so that they do not apply to connections with DG in the first instance, and other connections over time. One way to do this first step is by changing the definition of the primary place of residence in the regulations to exclude connections with DG. If the Authority feels it cannot comment on the regulations then it should apply this principle consistently, and forward our suggestions to MBIE. MBIE and the Authority should recommend that the government issue a GPS setting out clear expectations on distributors to introduce pricing that is less consumption (kWh) based. The GPS should acknowledge that this is likely to have significant adverse impacts on some consumers, and that it is putting in place mechanisms to help manage this, but that the change is necessary to ensure New Zealand maximises the benefits that new technologies can provide. Regulation, in the general sense, requires parties to do things they would not otherwise do. It does this because the regulated outcome is judged, in an overall sense, to be better for society than the unregulated outcome. The LFC regulations very clearly seek to make distributors and retailers price on a basis that is more consumption based than they would choose themselves absent the regulations. It is not for the regulated parties to decide that government policy as reflected in the regulations is wrong. If there is no political appetite for addressing the constraints that the regulations impose then any apparent mis-investment that results must be taken as what New Zealand wants.

Appendix 2: Detailed comments on the proposed amendments to the pricing principles

Appendix A of the paper sets out the proposed new principles, compares them with the old ones and provides a brief description of the changes. This appendix comments on Appendix A. We have not commented on every proposed change.

Principle (a)(i): It is proposed that the phrase “and/or other regulations” be deleted as redundant. In our view regulations are materially different to legislation, and we see no good reason to delete these words.

Existing principle (a)(ii) has been deleted on the basis that it is captured in existing principle (a)(iii) but that principle has been rewritten.

New principle (a)(ii) is said to clarify existing principle (a)(iii), but it crucially removes “to the extent practicable” and “future investment costs” appearing instead to have a much more short term focus.

New principle (a)(iii) could be interpreted as being anywhere in the wide range of very time and location specific (say at a particular ICP this afternoon) or quite general (applying to this network area for the next twelve months). The lack of clarity makes application of the principle difficult. We note that most distributors maintain prices for most connection groups that apply across quite wide regions, reflecting consistency of the service (or benefit derived from the service) across those regions, even though the actual assets used to provide the service to each consumer will differ somewhat.

New principle (b) includes a reference to “the requirements and circumstances of … potential users” where those users are neither retailers nor customers. It could be difficult to determine those requirements and circumstances and weight them against the requirements and circumstances of the parties that, directly and indirectly, pay for the service.

Existing principle (b) was a reasonably clear reference to Ramsey pricing. New principle (b)(i) says this in another way - “least distort network use” - but also includes “reflect the value that users derive from the network” which seems like an unnecessary addition. We are not sure if it intended to say the same thing in a different way or to be a new consideration.

New principle (c) is said to clarify principle (d), but we think it is a very different principle.

New principle (d) introduces the entity “other consumer agents” into existing principle (e). Since we do not know who these parties are, and have no contractual obligations to them, it seems unreasonable to propose that they be treated in an “economically equivalent” way to retailers.

New principle (e) states consumers should be able to “know or predict” the prices they will face. We note that consumers, in general, face retail prices, not distributors’ prices. Moreover, prediction is not straightforward for any party – including the distributor. This principle may act against necessary changes, which by definition may not have been predicted by the consumer. In any case, to work out the impact of a price a consumer would need to also know a quantity and the impact a choice they make might have on that quantity. To the extent we are talking about investments that might be in place for a number of years we submit that this calculation is unlikely to be being done in real time.

Appendix 3: Comments on the low fixed charge regulations and the Authority's position on them

This appendix sets out in more detail our views on the Authority's position on the low fixed charge (LFC) regulations.

The Authority's position on the regulations, first stated in its October 2015 paper and reiterated several times since, including in the current paper (page 13), is:

> "the regulations do not prevent distributors from progressing price reforms. For example by adopting charges based on capacity, peak demand or time of use".

There is some truth to this statement, but as we have discovered, the devil is in the detail.

To assist distributors, the Authority published the *Variable charges under the low-fixed charge regulations – Guidelines* in 2016. The guidelines formed the basis of a lengthy engagement (correspondence and meetings) between the ENA and the Authority.

ENA focused during this process on forms of charging that are not kWh based, as it is not in dispute that time of use (TOU) pricing is variable and compliant under the regulations. We note, however, that TOU pricing that is structured so as to comply with the regulations, will almost inevitably be at variable price levels that are 'too high' – because the fixed charge is limited to 15 cents per day and the kWh rates are correspondingly higher. Thus, while the regulations "do not prevent" distributors implementing TOU pricing, that is not the same as saying that they permit pricing that solves the problems. In this respect some of the Authority's comments are disingenuous.

ENA began its engagement by writing to the Authority with a number of comments on the guidelines in October 2016, pointing out, amongst other things:

- A price expressed as "$ per kW" is incomplete – a time period is required for it be applied,
- The guidelines stated that "average consumer" is a "convenient label" when in fact it is a defined term under the regulations. [7]

ENA suggested that the guidelines could be usefully amended to reflect its comments. The Authority replied noting that some of ENA's suggestions were useful, and that it would republish the guidelines at a later date to reflect some of the comments. The guidelines have not been republished.

As ENA developed possible new pricing approaches in early 2017, it reconsidered the guidelines. We put more specific questions (22 of them) to the Authority in June 2017 with respect to three approaches under consideration by ENA: installed capacity, booked capacity and customer peak demand. The Authority responded in August 2017.

The key points included:

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[7] As follows in regulation 4 (1): "average consumer means,—

(a) in relation to a consumer whose home is in the Lower South region, a person who purchases or uses 9 000 kWh of electricity per year in respect of that home; or

(b)in relation to a consumer whose home is elsewhere in New Zealand, a person who purchases or uses 8 000 kWh of electricity per year in respect of that home"

- Installed capacity (based on fuse size) implies that the capacity could be changed. A change (for example to a fuse) would involve a site visit, with associated cost. The guidelines said that compliance required that capacity must be able to be changed “in a reasonable time frame and at a reasonable cost”. Neither concept of reasonableness is covered in the regulations. The Authority advised that in its view if the fee to change the fuse size (even if the fee reasonably reflected costs) was more than the value available to the consumer, then the capacity charge would be interpreted as fixed. This means consumers must always be able to financially benefit from a change in fuse size.
- As a follow up to this point, we asked whether a capacity, once set, could be maintained for a year. The Authority responded that it must be able to be changed if the consumer is willing to pay, which they will be based on the previous requirement, and the fee to change must be less than the saving available.
- In relation to booked (or nominated) capacity, we asked whether the price for any kW in excess of the booked capacity could be at a higher rate than for the quantity booked. The Authority advised that this would not comply with the regulations because it would be seen as “tiered or stepped”, and this is specifically prohibited by the regulations. If the excess demand price cannot be higher than the booked price, then the consumer incentive is to book as low a value as possible, undermining the effectiveness of the approach.
- In the context of consumer demand we again asked the question about how long a demand, once set, can be used for charging. The Authority’s response was interesting:

  > “*Industry experience shows that consumers need to be able to respond to prices, alter their electricity consumption, and receive the benefits of altering their electricity consumption* ***without undue delay***.” [Emphasis added.]

  The prices, or price components that are relevant here are ones where the efficiency dimension is that consumers **not** be able to respond and receive the benefits, because in economic terms there are none.
- More generally we asked about whether prices that are per unit of capacity or demand (however measured) could be expressed as $ per day for various capacity / demand bands. This was to see if an approach where prices that are conceptually $ per kW per day can be expressed as $ per day for a band and still be seen as variable. The answer was “Yes”.

In November 2017, Authority and ENA reps met to discuss some aspects of the earlier correspondence further.

At that meeting it was confirmed that “excess demand” prices (per kW per day) could not be greater than nominated demand prices (because they would be “tiered or stepped”).

Much more interestingly though, the suggestion was made that, were capacity or demand pricing to be structured as different “delivered electricity packages” (a defined term under the regulations) the prices per kW (say) could differ for different “packages” of capacity (or demand) bands. This seemed to be pretty clearly at odds with the “tiered or stepped” limitation, so ENA explicitly asked, in a letter of 12 March 2018, for the Authority’s confirmation, which was received in the Authority’s letter of 28 March 2018. To be specific, the following tabular approach to capacity pricing, if expressed in this way, is compliant:

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

We note that this approach is not obviously dealt with in the guidelines (and is certainly not apparent in the regulations themselves) so ENA was surprised at this endpoint. While we do not doubt the Authority's intent in providing this confirmation, we cannot help but reflect back on the guidelines (page 10):

Prohibition on tiered or stepped variable charges

3.10 Under regulations 10(2)(a) and 16(1)(a), an LFC tariff must not contain a variable charge that is tiered or stepped according to the amount of electricity consumed.[7]

3.11 For consumption charges, this means that the c/kWh rate must not differ depending on the volume of electricity consumed. For example, charging 20c/kWh for the first 2,000 kWh of consumption and 10c/kWh thereafter is not allowed.

3.12 For demand or capacity charges, this means that the $/kW rate must not differ depending on the level of demand or capacity. For example, charging $300/kW for the first 2 kW of the peak demand level (or capacity required) and $200/kW thereafter is not allowed.

In our view the approach that the Authority has confirmed is acceptable is very clearly at odds with this section of the guidelines, in particular para 3.12. We do not believe it is plausible that the regulations contemplated a situation where they could be rendered ineffective simply by using the device of different "delivered electricity packages" for different levels of usage.

To make the point even more clearly, given that capacity here is variable, the values in the first column of the table could be expressed as kWh (in say bands of 1,000kWh) and with a different price per kWh in each band. This would apparently be compliant.

Our overall conclusion on the Authority's guidelines is that they are unhelpful. The Authority's compliance advice, as expressed in the correspondence discussed above, is inconsistent and not robust. No distributor or retailer could reasonably be expected to rely on it.