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Submissions
c/- Electricity Authority
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SUBMISSION ON DISTRIBUTED GENERATION PRICING PRINCIPLES

Introduction

1 Orion New Zealand Limited (**Orion**) welcomes the opportunity to comment on the "Review of distributed generation pricing principles" consultation paper (the **paper**) released by the Electricity Authority (Authority) in May 2016.

2 In summary:

- we agree with the essence of the problem identified in the paper – that ACOT payments made under Part 6 may not reflect transmission system benefits,
- we think that the proposed solution is likely to work, in a narrow sense,
- we are, however, concerned that the proposal has not fully considered the rationale for the pricing principles being in Part 6 in the first place,
- we do not see that the proposed timing of the changes, and in particular the 1 April 2017 date, are reasonable or well-reasoned, and
- in our view it would be much better to take a more measured approach to a review of the pricing, commercial and economic aspects of Part 6.

3 The remainder of our submission is in two parts:

- comments on specific aspects of the paper
- answers to the specific questions in the paper, as an appendix.

4 The Electricity Networks Association (ENA) has also submitted on the paper. Orion endorses the ENA submission.

5 Some of the issues raised by the paper are similar to those raised in the associated TPM consultation. Our two submissions should be read in conjunction with each other.

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Orion's approach to distributed generation

6 Orion has a pricing approach which focusses on signalling the long term cost of adding new network capacity at times of coincident peak demand. This is a price signal against which consumers can invest in demand side alternatives. Most of the distributed generation (DG) on the network is 'behind' load in the sense that its main purpose is to reduce a connection's load at peak times. Sometimes the generator output exceeds the connection's load leading to export. But, whether or not there is export, our pricing is intended to recognise that DG *can* provide a substitute for network investment. To support the operation of DG for this purpose, we signal times of peak demand on the network using ripple signals, text messages and emails.

7 DG that can or may export must apply for export credits in order to get them, and in considering whether to grant these we consider whether the export will in fact provide network benefits. However, even when we do not assess any network benefits (for example we would not normally consider a wind farm to be a reliable substitute for traditional network assets), we believe that Part 6 as currently written obliges us to *at least* pass on the value of any export that occurs during RCPD periods, as this does reduce *charges* in the following year. We agree with the position in the paper that such payments are not always related to a reduction in the economic cost of the transmission service. However, it does not follow that DG does not or cannot provide any transmission benefit.

Part 6 of the Code

8 Perhaps our main concern with the proposal in the paper is one of process – the paper does not seem to engage with why we currently have the Part 6 principles, and Part 6 more generally. There is, in our view, a real risk that important aspects of the regulatory regime are changed without due consideration.

9 As we see it, the key reason why we have Part 6, and the associated pricing principles, is because there is, or was, a perception that in dealing with DG owners, natural monopolies such as distributors and Transpower may have a bias towards traditional network alternatives when set against DG as a non-network substitute. The principles also clarify that distributors may charge DG at least the incremental cost of connection, and this potentially reduces disputes.

10 While it may be that the existing, and wider, distribution pricing principles are sufficient to deal with specific potential issues associated with DG, we do not think the case has been fully made.

11 Having said that, the economic and market context moves on, with some forms of DG in particular being much lower cost than they were when Part 6 (and its ancestors) first emerged, and also much more likely to be located at a large number of points on the network. So this may indeed be a good time to consider changing the rules.

Timing of the proposed changes

12 The proposal is that the Part 6 pricing principles be removed from the Code effective 1 April 2017 for the lower North Island and the lower South Island, and 1 April 2018

in the two other transmission regions. We consider that these timings are too short, for the following reasons:

- They do not leave sufficient time for Transpower to develop a robust methodology for determining the actual transmission benefits of DG or to negotiate with the relevant parties.

- Transpower may need to agree an adjustment to its allowable revenue with the Commerce Commission to fund any payments that it makes to DG. This could take some time, and may not even be possible within a regulatory control period.

- We doubt that anyone who might have been expecting material ACOT payments is likely to invest in DG in the interim whether or not Part 6 is changed in the next year or two, and we likewise doubt whether any distributor would enter into a long term contract to incur costs (payments to DG) that it would likely soon be unable to recover.

- It seems more reasonable to align any changes to Part 6 with the changes to the TPM itself, and in fact the proposed changes to the TPM could conceivably end ACOT payments by distributors in any case as there may no longer be any transmission *charge* reductions associated with DG.

- The four current transmission pricing regions are just one way of dicing up the transmission system, and they are therefore somewhat arbitrary. We doubt they are anything like a good basis for establishing appropriate timings for, potentially, removing ACOT payments. Whatever method Transpower comes up with for valuing DG as a transmission alternative, it may or may not be based on benefits to a traditional region as the benefits could conceivably be much more localised, but still material.

- We understand the potential negative value impact of the proposal for DG owners to be in the billions of dollars. This sort of impact alone should be sufficient to induce considerable regulatory caution.

13 The paper acknowledges some of these concerns but does not in our view adequately address them or explain the need for haste. In fact the negative inference from para 4.3.8 (which explains why a later date of 1 April 2018 is appropriate for USI and UNI) is that the Authority has already decided that no transmission benefits accrue to DG in the other regions. Such a conclusion might be correct, but it should not be simply assumed.

14 We urge the Authority to take a more measured approach to a review of the pricing, commercial and economic aspects of Part 6 with a view to having such a review complete by, say, 1 April 2019. By “more measured” we mean taking the time to consider the wider rationale for Part 6 and the role that DG plays in the New Zealand electricity system. Failing that, and very much as a second best, the proposed changes could apply to new DG only from the proposed dates, leaving significantly longer (say until April 2019 at the earliest) to sort out the arrangements with existing DG.

Consistency with the TPM paper

15 Para 4.3.8 referred to above appears to be somewhat inconsistent with the position in the companion TPM paper that argues that RCPD demand response is inherently inefficient[1] and that in fact DG output should be added back when determining physical capacity. It is hard to reconcile this with the observation that it is more "likely that Transpower will want to contract for transmission support arrangements in [UNI and USI]".

Wider Part 6 changes

16 Most industry participants are considering the impact of new technologies on the way the electricity system is planned, operated and regulated. Accommodation of DG is one key aspect of this.

17 We consider that other aspects of Part 6 could usefully be reviewed as part of a more considered approach. We are particularly interested in the challenges posed by the concept of a congestion management policy. Over the last 3 years, academia and industry representatives including the EA have considered this challenge and developed a draft 'Guideline for the Connection of Small-Scale Inverter Based Distributed Generation'. This guideline is currently out for consultation which closes 30 July 2016.[2]

18 The guideline proposes a method for distributors to determine the export hosting capacity of their different low voltage networks and proposes a solution to how this hosting capacity could be made available in a sensible way to DG customers. That is, it addresses the challenges associated with a first in first served basis versus equal availability to all.

19 While the guideline proposes a method to meet the congestion management policy requirements in Part 6, it does rely on a particular interpretation of the meaning or intent of the requirements.

20 Furthermore, to avoid any conflict with the Part 6 pricing principles the guideline stops short of addressing how the commercial arrangements should be handled. While removing the pricing principles from Part 6 would create flexibility it may be more appropriate that the pricing principles address how distributors can use export pricing to enable customers to make the right price versus export capacity trade-off when they are designing their DG system.

21 In our view this is further reason to have a more measured review of part 6 to ensure that DG's role in the overall electricity system 'portfolio' is appropriately allowed for. We would be happy to discuss this with Authority at any time.

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[1] From para 66 of the TPM paper: "For interconnection assets, the RCPD signal is poorly correlated with times when the grid is congested, which means the price can be high at times during the day when the marginal cost of using interconnection circuits is very low. Hence, the RCPD signal in the interconnection charge is not cost-reflective, encouraging load customers to forgo consumption or to operate expensive distributed generation (DG) plant to smooth peak demand in circumstances when lower peaks provide no economic benefit at all."

[2] The guideline is on the EEA website at: http://www.eea.co.nz/Site/publications/drafts-for-comment/amg-guideline-connection-of-small-scale-.aspx.

Concluding remarks

22 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: Response to specific questions

Question No.	Question	Response
Q1.	Do you consider that the proposed Code amendment described in section 4.1 is preferable to the status quo and the alternatives described in section 4.6? If not, please explain your preferred option(s) in terms consistent with the Authority's statutory objective.	Partly. See comments in the body of our submission.
Q2.	Do you consider that the proposed Code amendment described in section 4.1 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed?	Compliance is not in itself sufficient reason for the Code amendment to proceed.
Q3.	Do you have any comments on the drafting of the proposed Code amendment described in section 4.1? (The drafting is included in Appendix B.)	We do not support the timings inherent in the proposed Code. See the body of our submission and below.
Q4.	Do you consider that the proposed Code amendment should come into force at a single date, or should it be phased in?	Given the wider changes being proposed to the TPM it is not clear to us why the dates are not aligned (that is, on 1 April 2019). It seems to us that the proposed TPM changes are likely to lessen or remove ACOT payments by distributors even under the current Part 6. We also believe that a 1 April 2017 date for the first two regions is a very short amount of time for the various DG parties and Transpower to develop the analytical approaches, support systems and contractual framework that would be needed to work out whether any ACOT payments are in fact appropriate. There may also be changes required to the price control of Transpower (and indeed distributors) under Part 4 of the Commerce Act.
Q5.	Is the proposed phasing for the Code amendment appropriate? (The phasing is discussed in section 4.3.) If not, what alternative phasing or dates would you propose and why	No. See comments above.
Q6.	If the proposal were to proceed, do you consider that there would be barriers that might prevent agreements being reached between Transpower and	Potentially, yes. Part 6, including the pricing principles, exists, at least in part, because of previous concerns about the balance of power between network providers and

	distributed generation owners to efficiently reduce or defer transmission network costs? If so, what are these barriers? Please consider both existing and proposed new distributed generation.	DG, and the possible bias network providers have to network solutions. We also note that there is a very wide range of DG owners in terms of capability to negotiate with Transpower. Transpower needs to develop analytical tools, processes and systems to deal with these concerns. (And we note that some of these concerns might be alleviated by the activities of intermediaries that might emerge.) This reinforces our concerns about timing above.
Q7.	If the proposal were to proceed, do you consider that there would be barriers that might prevent agreements being reached between distributors and distributed generation owners to efficiently reduce or defer distribution network costs? If so, what are these barriers? Please consider both existing and proposed new distributed generation.	Potentially, yes. This is why we have suggested that further thought be given to the proposal to remove the Part 6 pricing principles *in toto*, including those that relate to the avoided cost of distribution.
Q8.	If the proposal were to proceed, do you consider that those distributors that were no longer able to recover the cost of making ACOT payments would cease making such payments?	While we have made no final decisions, this seems likely. We will however need to consider the potential impact on wider demand response.