COMPETITION ECONOMISTS GROUP

Avoided Cost of Transmission Payments

A REPORT FOR VECTOR

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1 Introduction

1. This report has been prepared by CEG on behalf of Vector. Its subject is the pricing principle in Schedule 6.4 of the *Electricity Industry Participation Code 2010* (Code) that requires electricity distributors (distributors) to pay distributed generators (DG) for reductions in transmission and distribution costs that arise from connecting DG to their networks. These reductions are termed the avoided costs of transmission (ACOT).

2. It follows that, if the transmission charges that distributors are required to pay under the transmission pricing methodology (TPM) were to decrease for any reason, so too would the charges they would calculate as being avoided through the presence of DG. This would, in turn, reduce the revenues received by DG through ACOT payments, all other things being equal. The Electricity Authority (EA) signalled just such a reallocation of transmission charges – and consequential revenue reduction for DG – in its first TPM issues paper.[1]

3. Specifically, it proposed to commence charging transmission connected generators for use of the interconnected network – a service that is currently paid for exclusively by off-load customers, primarily distributors. If implemented, this approach would detrimentally affect DG in the manner described above. This aspect of the EA's proposal has drawn significant criticism from DG, and is put forth as yet another[2] reason why the "beneficiaries pay" methodology it has recommended should not be implemented.

4. The EA has responded to this criticism by questioning the appropriateness of the current arrangements for ACOT payments. In its latest working paper,[3] the EA concedes that its proposal may have a detrimental effect on DG given the current way in which ACOT payments are generally calculated. However, it concludes that this approach is not robust, and any detrimental effect on DG must be interpreted in that context. It preliminarily concludes, amongst other things, that:[4]

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1 Electricity Authority, *Transmission Pricing Methodology – issues and proposal, Consultation Paper*, 10 October 2012 (hereafter: EA Issues and Proposal Paper').

2 Many parties – including CEG – have highlighted many problems with the changes to the TPM that the EA has proposed. Submissions have focussed on the limited scope for the EA's proposed approach to deliver benefits and the potential for substantial inefficiencies to arise – particularly in the wholesale and retail markets. Those criticisms remain valid, and we do not repeat then in detail here. Instead, this report focuses on the *additional* claim that the proposal is also flawed because of the effect it will have on ACOT payments.

3 Electricity Authority, *Transmission Pricing Methodology: Avoided cost of transmission (ACOT) payments for distributed generation, Working Paper,* 19 November 2013 (hereafter: "EA ACOT Working Paper").

4 EA ACOT Working Paper, pp.iii-iv.

- there is little evidence to suggest that the location of DG has been determined by avoidance of a transmission investment, as opposed to other factors such as access to a suitable site or fuel source;
- ACOT payments, and the existence of DG, appear to have no effect on transmission investment and a prevalence of DG in some networks can, in fact, cause net costs to the distributor;
- with few exceptions, ACOT payments appear to have had little observed effect on distribution investments or costs and provide no other material benefits to distributors; and
- ACOT payments do not deliver any other material economic benefits and appear to have materially increased the overall cost of electricity for New Zealand consumers.

5. Vector dispersed over $10m in ACOT payments to DG in 2011. Although such payments are a "recoverable cost" under its default price path, it is nonetheless interested in the robustness of those charges, and the manner in which they are calculated. It has therefore asked us to provide an independent review the arrangements for payments to and from DG – including ACOT payments – and the material contained in the EA's working paper.

6. In our opinion, the EA is right to query the robustness of the current arrangements. The present framework results in DG being implicitly subsidised *vis-à-vis* transmission connected generators. This subsidy is funded within the industry and is likely to increase the prices paid by electricity consumers in the short term. It may also lead to inefficient generation investment decisions that may increase prices over the longer-term above what they would otherwise have been.

7. We elaborate in the remainder of this report, which is structured as follows:

   - **section two** explains why the current charging arrangements for DG provide an artificially strong incentive to embed generation;
   - **section three** sets out the potential short- and long-term implications of this implicit subsidy on electricity market outcomes;
   - **section four** identifies some potential ways to eliminate or at least mitigate the distortionary effects of the current arrangements; and
   - **section five** concludes.

8. Note that the opinions expressed in this report are those of the authors, and do not necessarily reflect the views of Vector.

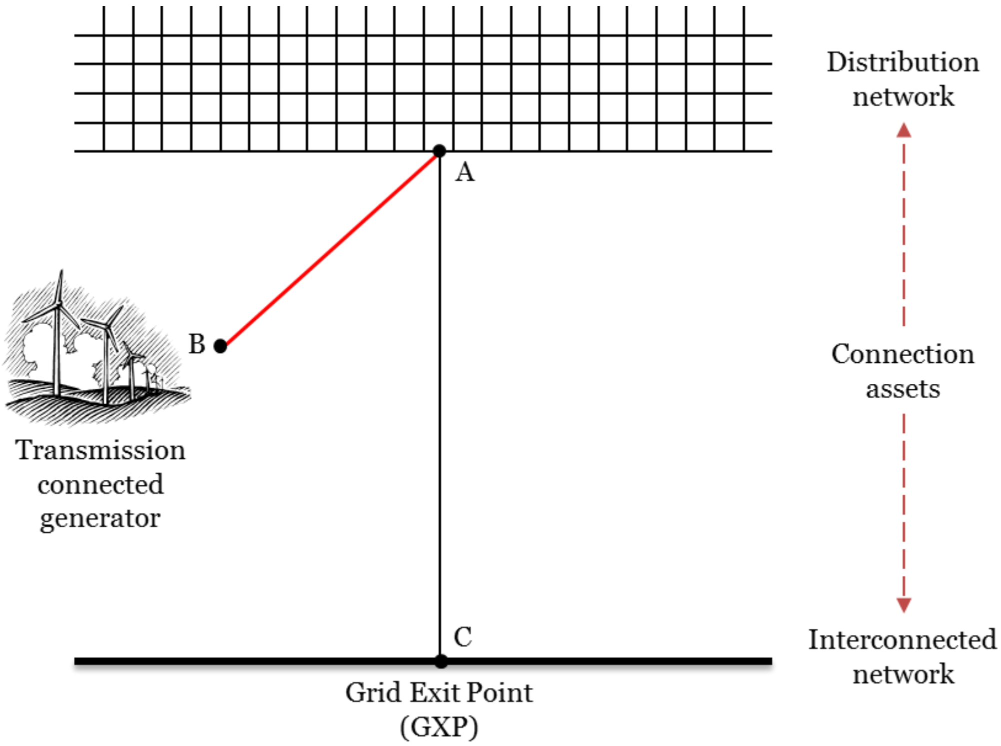
2 Different Charging Arrangements

9. There are significant differences between the charging frameworks for distribution versus transmission-connected generators. This has the potential to influence the types of generation investment that occur in the market. In particular, the arrangements provide artificially strong incentives to embed generation – including in circumstances in which it is not the most efficient option.

2.1 Transmission connected generation

10. Under the current version of the TPM, transmission connected generators do not pay interconnection charges (one of the most critical aspects of the arrangements that will change if the EA's proposal is introduced). They do, however, pay for the transmission connection assets that they are deemed to use. In the simplified grid displayed in Figure 1, suppose that a generator is considering building plant at location B, and connecting to the transmission grid at location A.

Figure 1 Charges paid by transmission-connected generator



11. If the generator proceeded with this investment and entered into a new investment contract with Transpower (rather than building the new dedicated connection assets itself[5]), it would be required to pay the following transmission charges:[6]

- new investment charges for capital recovery on the new link between A and B and any new switchyard equipment at the grid exit point (GXP);
- injection overheads related to the new switchyard assets; and
- a share of the connection charges associated with the link between A and C used by both the generator and the local load; namely:
  - the generator will pay for a share of the line based on its anytime maximum injection (AMI); and
  - the balance will be paid by the load (i.e., the distributor) based on its anytime maximum demand (AMD).

12. In other words, the generator would be required to pay for the incremental costs of connecting it to the transmission network (i.e., for the new "dedicated" connection assets) and for a share of the costs of the *existing* assets that it is deemed to be sharing with existing users. Finally, it would not receive any explicit compensation from either Transpower or the distributor for any reduction in forward-looking network investment requirements caused by its presence at location B.

2.2 Distributed generation

13. Distributed generators do not pay transmission charges in the same manner as transmission-connected generators. The only aspects of the TPM that continue to apply are injection overhead charges and, in the South Island, HVDC charges. However, these charges only apply if there is a net injection to the interconnected transmission grid. If all injections from the DG are accounted for by local load (i.e., if there is no injection at a GXP), then the TPM charges will be zero.

14. The payments to and from DG are specified in Schedule 6.4 of the Code. The relevant pricing principles require that:

- connection charges to DG must not exceed the incremental costs of providing connection services;

5 Namely, the new line from B to C and the necessary switchyard assets at the grid exit point.

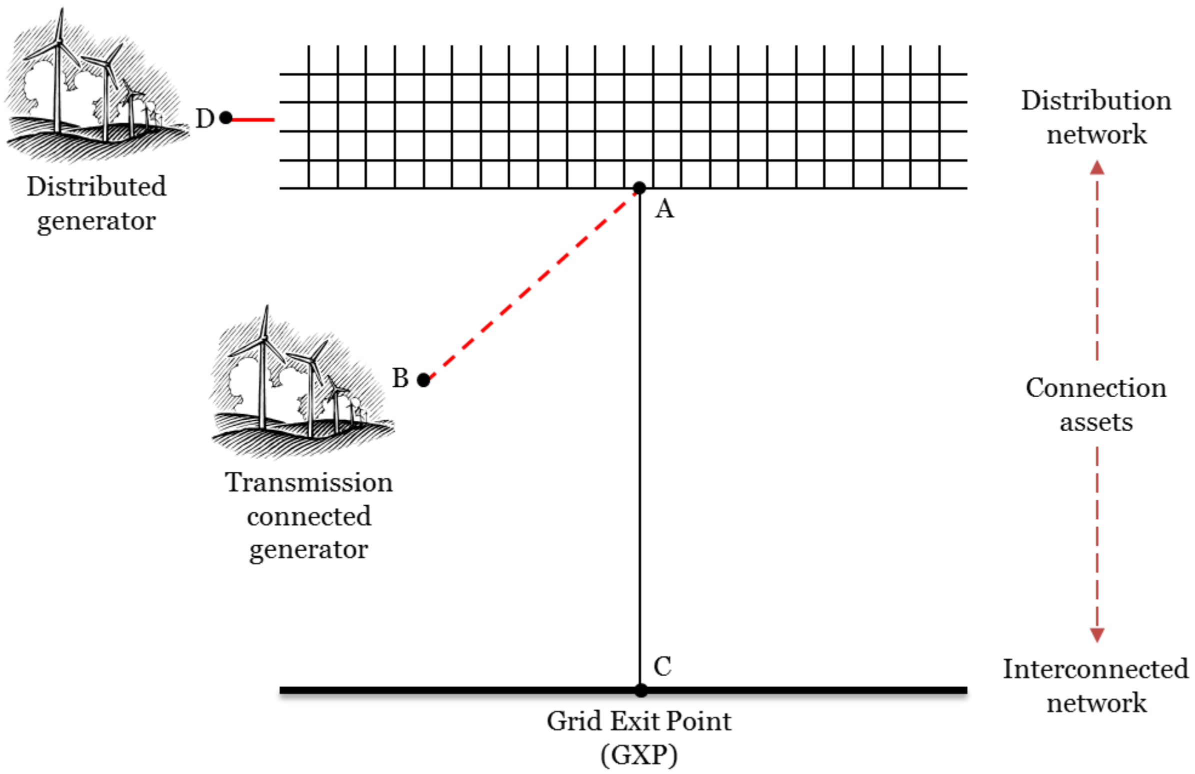
6 If the generator was based in the South Island, it would also pay HVDC charges, based on its historical anytime maximum injection (HAMI). However, for the sake of simplicity, we assume that the generator is based in the North Island and does not pay HVDC charges.

- the incremental cost is net of transmission and distribution costs that an efficient market operation service provider would be able to avoid as a result of the connection of the DG; and
- costs that cannot be calculated must be estimated by reference to how the distributor's capital investment and operating costs would differ, with and without the generation.

15. In other words, DG are required to compensate the distributor for the incremental capital, maintenance and operating costs associated with the new assets required to connect them to the distribution network. However, the distributor must also pay DG a sum reflecting the costs that they "avoid" as a result. As we noted earlier, the most common practice is to base this payment on an estimate of any consequential reduction in a distributor's average regional coincident peak demand (RCPD) brought about by the generator embedding in a location.

16. To illustrate, consider the simplified grid displayed in Figure 2, in which a generator is considering building plant at location D, and connecting to the distribution network. Assume that the grid is identical in every respect to that depicted in Figure 1. Suppose also that the generator is identical to that from the previous example, i.e., same capacity, same technology, etc. The only difference is the location of the connection point (point D instead of point B) and the fact it is embedded.

Figure 2 Charges paid by distributed generator



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17. If the generator proceeded with this investment and embedded its plant into the distribution network at location D ("behind the load"), then it would be required to compensate:

- the distributor for the incremental costs associated with its connection to the distribution network; and
- Transpower for a share of the connection costs associated with the link between A and C if it injects power into the transmission grid, i.e., if the local load does not account for all of its capacity and its AMI was positive.

18. Importantly, the latter category of costs could well be zero if the local load always took 100% of the power injected at point D. In addition, the DG would also receive an ACOT *payment* from the distributor reflecting the costs that it was estimated to avoid by the generator connecting at location When faced with the alternatives of investing at locations B or D, there may therefore be a strong incentive to choose the latter. Indeed, by connecting to the distribution grid, a generator can:

- reduce substantially (or potentially avoid altogether) the sum that it is required to pay for any existing transmission connection assets; and
- receive an additional stream of revenue in the form of ACOT payments that are not available to transmission connected generators.

19. This means that one form of generation is being subsidised compared with another. In our opinion, there does not appear to be a strong justification for this differential treatment and it has the potential to give rise to a number of undesirable distortions.

3 Potential Implications

20. The previous section described the incentive that generators may have under the existing charging framework to embed. This incentive would exist simply because DG must only pay the marginal costs of connection. However, it is then exacerbated by an addition stream of revenue – ACOT payments – that DG receive, but transmission connected generators do not.

21. This may cause generators to embed even when transmission connected generation would offer greater market benefits. If this occurs (as we can expect it will, on average, due to the artificial incentive) then customers will end up paying a higher price than is efficient. In this section we describe some of the potential implications of these differential charging arrangements in more detail.

3.1 Short term effects

22. The existing charging arrangements provide incentives to generators to avoid charges associated with existing connection assets by connecting directly to distribution networks. They may also provide generators with incentives to build smaller embedded plants with lower transfer capacity in order to calibrate their injections with the local load, and reduce (potentially eliminate) their charges for existing transmission connection assets, i.e., to "hide behind load", when larger transmission connected plants would offer greater benefits.

23. For this reason, it is conceivable that generation investments with significant net market benefits may be foregone in favour of less beneficial alternatives that entail lower connection costs (including embedded generation), or abandoned entirely. This will increase the prices paid by electricity consumers (sum of network and energy components) above the levels that would otherwise have prevailed – both in the short- and long-term.

24. That does not necessarily mean that a particular distributed generation investment cannot reduce distribution or transmission costs or deliver other market benefits relative to the status quo – it may (although, it often may not, as the EA observes in its working paper). It simply means that other options may have been available that would have entailed *even lower costs and/or offered greater benefits*, causing prices to be higher *relative to what they would have been* under those alternatives.

25. There is also an important distinction to be made between transmission *charges* and *costs*. In the short run, DG may reduce the former, but not the latter. It is likely to be relatively common for DG to cause a distributor's interconnection charges to fall, but for its presence to have no discernible short-term impact upon Transpower's total transmission costs. The only effect may be a reallocation of transmission charges amongst distributors and higher prices for consumers.

26. This can be seen using a simple example. Assume for the sake of illustration that Transpower has \$500m of interconnection assets[7] and is permitted by the Commerce Commission (Commission) to earn a 10% return under its individual price-quality path (IPP). Under the TPM, it will seek to recover \$50m (10% of \$500m) from its customers for those assets. It will do so based on off-take customers' contributions to the prior year's RCPD in the relevant locations.

27. Suppose that there are only two interconnection customers – distributors A and B, which each had 200MW of demand in the prior year. The interconnection charge would consequently be \$125,000/MW (\$50m ÷ 400MW). Each distributor would pay \$25m in interconnection charges (\$125,000/MW x 200MW). Now assume that distributor B had a DG that connected during the year and injected 25MW, reducing its contribution to RCPD by the same amount.

28. However, suppose that the presence of the DG does not affect Transpower's overall revenue requirement – it must still recover \$50m. Distributor A's contribution to RCPD is still 200MW, but distributor B's is now 175MW because of the presence of the DG. The interconnection rate must consequently increase in order to recover the \$50m from fewer chargeable units. The new rate is \$133,333/MW (\$50m ÷ 375MW), and the prices now differ for each distributor:

- distributor A pays \$26.67m (\$133,333/MW x 200MW); and
- distributor B pays \$23.33m (\$133,333/MW x 175MW).

29. Distributor B "avoids" \$1.67m in interconnection charges, but these are simply transferred to distributor A, which will then pass them on to its customers (since transmission charges are a pass-through cost). The net effect is that those consumers served by distributor A will pay higher electricity prices in the short term.[8] However, it does not follow that those customers served by distributor B will receive *lower* electricity prices in the short term. They may not.

30. This is because ACOT payments are deemed to be "recoverable" costs under the Commission's input methodologies. Distributor B is therefore permitted to pass-through the cost of any ACOT payments it must make to DG to its own customers. If it calculates that payment to be \$1.67m (\$25m *less* \$23.33m) the overall transmission costs it will seek to recover from customers remains \$25m (175MW x \$133,333/MW + \$1.67m).

31. In this simple example, the total transmission charges billed to end customers with the DG in situ are consequently \$1.67m higher in the short term than they would have been had the DG not connected, or if it had connected to the transmission

7 For the sake of illustration, we leave aside connection and HVDC assets.

8 *See:* EA ACOT Working Paper, §7.16.

network instead. In other words, the interplay between the TPM and Transpower's revenue requirement creates the clear potential for consumers to be made worse off in the short term by generators embedding.[9]

32. The EA makes precisely this point in its Working Paper. It estimates that ACOT payments have increased costs to electricity consumers by around $10 per household.[10] In other words, the existing charging arrangements in Schedule 6.4 are likely to be unambiguously disadvantageous to electricity consumers over the short term. The question is therefore whether the framework might deliver benefits over the longer-term that outweigh those near term costs.

3.2 Long term effects

33. The electricity industry is characterised by investments that have no alternative purpose and which exhibit decreasing costs over their useful lives.[11] In the long run, the costs of network utilities are therefore determined to a large extent by the efficiency of those investments, and its cumulative effect on the capital stock of the industry. Recognising and minimising inefficiencies in relation to these long-term investments is a key element of the design of sound regulatory frameworks.

34. The previous section explained why the existing compensation arrangements for DG appear to be disadvantageous to customers in the short term. A key question is whether such payments give rise to investment in DG that promotes savings in transmission costs over the long term that more than outweigh the short term costs. As the EA explains in its Working Paper, the two relevant enquiries are:[12]

- whether DG causes or contributes to a delay or cancellation of capacity enhancing expenditure; and
- whether this results in the regulated asset base being less than it would otherwise have been without the DG.

35. If the long term transmission and/or distribution cost savings precipitated by DG outweigh the short term costs to consumers described above, then there may be *some* justification for providing incentives for DG. Of course, it is important to remember that, in principle, *all forms of generation* can potentially reduce future network investment costs, including transmission connected generation.

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9 Vector provided a very similar example in its 11 November 2011 submission to the EA: *Submission on Distributed Generation Pre-Consultation, Public Version,* pp.4-5.

10 EA ACOT Working Paper, p.iv.

11 *See for example:* CEG, *Letter to Mr Carl Hansen, Chief Executive, Electricity Authority, Sunk Costs Working Paper*, 12 November 2013.

12 EA ACOT Working Paper, §7.8.

36. However, the analysis in the Working Paper suggests that:

- ACOT-funded DG appears to have had quite limited impact upon Transpower's peak demand forecasts, and so its ability to defer the assessed need for transmission investment;[13]
- historically, Transpower appears not to have considered DG to be a sufficient reliable alternative under the n-1 security standard to replace transmission assets – although, as the EA acknowledges, its view may have changed;[14] and
- evidence from a recent sample of distributors suggest that DG can create benefits for distribution networks – but only under a particular set of circumstances and not without attendant costs.[15]

37. This analysis suggests that the long term benefits from incentivising DG may not be material, particularly insofar as reducing or deferring long term transmission investment is concerned. However, these preliminary conclusions are difficult to reconcile with those contained in the EA's first TPM Issues Paper. In that earlier work, the EA concluded that the RCPD charge had been successful in deferring transmission investment in the upper north island (UNI) region through DG:[16]

> *"RCPD signals may also encourage parties to locate new peaking generation investment in the UNI (embedded into a local network, so that it can be used to reduce RCPD) in preference to the LNI. For instance, Transpower's recent investment in the Bream Bay peaker may help to defer the need for UNI transmission investment, and may have been supported in part by revenues stemming from its ability to reduce RCPD charges …*
>
> *… The conclusion is that the current RCPD charge is efficient in terms of reducing the need for interconnection investment serving the UNI, resulting in a net benefit in the millions of dollars (NPV) through deferring the next tranche of reactive investment, and potentially substantially more in the longer term."*

38. It is consequently imperative that the EA clarifies whether the views expressed in its ACOT Working Paper displace its earlier views and, if so, the basis for that difference of opinion. This is because they have a potentially important impact upon the best option for dealing with the distortions created by the TPM and Schedule 6.4. As we explain below, if the RCPD signal is not leading to any reduction in long-

13 EA ACOT Working Paper, §7.28.

14 EA ACOT Working Paper, §8.25.

15 EA ACOT Working Paper, §9.12.

16 Electricity Authority, *Transmission Pricing Methodology – issues and proposal, Consultation Paper*, 10 October 2012, Appendix D, §63-77.

term transmission costs in the UNI or USI (as intended) – including through DG – then the problem may extend beyond the treatment of DG.

39. On the other hand, even if the RCPD signal is having some effect on long-term transmission investment needs (as suggested in the EA's first Issues Paper), the pricing principles in Schedule 6.4 may still distort inefficiently the *type of generation* that is built. Specifically, regardless of whether a generator has chosen to build in a location to defer transmission spending or to simply be near a fuel source, Schedule 6.4 may incentivise it to embed, when it would be more beneficial for it to connect to the transmission network.

40. This incentive exists because distributed generators only pay the marginal costs of connection and they receive an addition revenue stream – ACOT payments – that transmission connected generators do not. As we noted above, this may cause generators to embed even when transmission connected generation would offer greater market benefits. This is likely to increase prices in the long run above what they might otherwise have been under alternative arrangements.

3.3 Summary

41. In our opinion, the current charging arrangements for DG set out in Schedule 6.4 of the Code:

- are likely to result in consumers paying higher electricity prices in the short term due to the interactions between the TPM, Schedule 6.4 and the Commission's input methodologies;
- are likely to distort the choice between *types* of generation, making firms more likely to invest in DG, including when transmission connected generation is equally feasible and may offer greater market benefits; and
- may not reduce transmission costs – although this aspect of the EA's analysis is unclear, given the inconsistency with its earlier Issues Paper.

42. The EA is therefore correct to query the robustness of the current framework and there is good reason to consider whether alternative arrangements might address some or all of the present shortcomings.

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4 Alternative Approaches

43. In this section we identify some options for potentially mitigating the distortionary effects described in the previous section. As a general principle, for there to be efficient incentives for investment in different forms of generation – including DG – alternatives that offer similar market costs and benefits should, all things being equal, pay the same overall transmission charge.[17]

44. The current arrangements do not reflect this principle, and this has the potential to lead to inefficient investment decisions that increase prices for electricity consumers in both the short and the long term. The alternatives described in this section are therefore targeted primarily at achieving (or at least improving) competitive neutrality between different types of generation.

4.1 Revise the TPM

45. Arguably the "first best" solution to the discrepancies described above would be to implement a TPM that better signalled to all generators – and other grid users – the long run costs that their actions impose on the transmission network. As we explained in an earlier report,[18] a generator weighing up where to invest would ideally face transmission price differentials that reflect the long run marginal cost (LRMC) differential that is not already reflected in nodal prices.

46. There would be no obvious reason for this transmission price signal to differ simply because a generator decided to embed, as opposed to connect to the transmission network. Two generators that are identical in every respect, but for the connection point, would pay the same LRMC-based charge. In *principle*, such a charging regime would:

- provide more efficient investment incentives by restoring competitive neutrality between the different forms of generation; and
- ensure that any change in transmission charges reflected a change in long-run transmission costs – which may not be the case under the current TPM.[19]

47. There would be some challenges associated with implementing a LRMC-based charge in *practice*, which we described in our earlier report.[20] Moreover, whether it

17 *See also:* Green et al, p.44.

18 CEG, *Economic Review of EA CBA Working Paper, A Report for Transpower,* October 2013, §57.

19 As noted above, this is currently unclear, given the inconsistency that exists between the analysis contained in the EA's first Issues Paper on the one hand, and the material contained in its more recent ACOT Working Paper on the other.

20 CEG, *Economic Review of EA CBA Working Paper, A Report for Transpower,* October 2013, §61-63.

is worthwhile contemplating such material changes to the interconnection charging framework to, in part, address the distortions described above depends upon the long-term effects of those arrangements and, in particular, whether the RCPD signal:

- provides efficient incentives to market participants – included DG – to make decisions that reduce long-term transmission costs; or
- has no material effect on long-term transmission costs, and therefore simply results in the same pool of costs being relocated differently.

48. In the case of the latter, this might imply that there is a *broader* potential problem with the signals being provided through the RCPD charge in the TPM that extends beyond the treatment of DG. If it *is* the case the RCPD signal has no effect on forward-looking investment needs, the question therefore becomes:[21]

- whether an alternative interconnection pricing approach *would* have the effect of reducing the NPV of forward-looking transmission investment; and
- whether the benefits from any such reduction in costs would be greater than cost increases elsewhere, e.g., through more expensive generation.

49. We offer no opinion in this report on whether a superior alternative may exist by reference to these criteria, or what the potential candidates might be.[22] Moreover, as we explained above, the contradictory conclusions contained in the EA's first Issues Paper on the one hand and in its ACOT Working Paper on the other means that it is unclear whether there is a material problem with the RCPD signal that is worth addressing in any event.

50. In other words, it is currently uncertain whether there is a material problem with the RCPD price signal that might warrant broader reform to the interconnection charging framework in the TPM. However, what does seem to be clear is that, irrespective of whether a broader problem exists, there is a more specific issue that arises from the differential treatment of generators, and the artificially strong incentive that there is to embed currently provided through Schedule 6.4.

51. Setting aside broader TPM reform, there a number of "pragmatic options" for reducing these differences between the charging arrangements for transmission connected generators under the TPM and those for DG under Schedule 6.4. They each have their respective advantages and disadvantages, as we explain in the

21 *See:* CEG, *Economic Review of EA CBA Working Paper, A Report for Transpower,* October 2013.

22 Other than to reiterate the opinion set out in our previous reports that the "beneficiaries pay" model proposed by the EA in its first Issues Paper would be unlikely to offer any material benefits and would entail significant additional costs.

following sections. Note that these options are not necessarily mutually exclusive – it may be possible to implement several simultaneously.

4.2 Base payments on avoided costs, not charges

52. The EA suggests that the majority of ACOT payment schemes could be improved through a greater focus on *economic costs* rather than the pass-through of avoided transmission *charges* to consumers. Although the motivation for this suggestion is understandable, there are some problems with it that might hinder its implementation, and it does not completely address the competitive neutrality issues that we described above.

53. Basing ACOT payments on the forward-looking economic costs that Transpower and, in turn, distribution companies are likely to avoid as a result of the existence of a DG would be likely to reduce short-term costs to consumers relative to the status quo. In particular, if the forward-looking costs avoided by DG are less than the reduction in interconnection charges, then the prices ultimately paid by consumers will fall in the near term.

54. For example, in the numerical example described in section 3.1 above, if the $1.67m reduction in distributor B's interconnection *charge* did not equal the reduction in forward-looking *economic costs* – if, say, there was *no reduction* in those costs – then the ACOT payment to the DG would be *zero*. The customers of distributor B would consequently receive the benefit of reduced transmission charges – which they would not under the present arrangements.

55. However, there would be significant *practical* complications associated with retaining the obligation upon distributors to make ACOT payments to DG, but basing those payments upon avoided economic *costs*, rather than *charges*. Estimating the latter is likely to be a manageable task for distributors, but calculating the present value of long-term investment costs that Transpower is likely to avoid by virtue of the presence of a DG is not.

56. If serious consideration is to be given to basing ACOT payments at least in part upon the economic transmission costs that are likely to be avoided by virtue of DG, then Transpower would presumably need to be involved in the calculation of those payments. It is ultimately going to be privy to the information necessary to make any such assessment – the distributor cannot realistically be expected to undertake an informed estimation.

57. However, even if Transpower's involvement was feasible, basing ACOT payments to DG based on avoided economic costs would still not address the competitive neutrality problem we described above. Schedule 6.4 does not allow *transmission connected* generators to be compensated for any transmission costs that they enable Transpower to avoid. If those costs were greater than zero (which is unclear, as we elaborated above), there would therefore still be an artificial incentive to embed.

58. Furthermore, as we explained above, if the costs that Transpower avoids from DG are currently over-signalled through the reduction in RCPD-based interconnection charges a distributor experiences, this may be symptomatic of a *broader problem* with the TPM. Namely, it may be that the RCPD charge is not sending the right signal to either DG *or load*. Basing ACOT payments on avoided economic costs would resolve that problem as it relates to DG, but not for the other parties paying RCPD charges, including distributors themselves.

59. The EA's preliminary solution would therefore address the immediate short-term consequences of higher prices, but would seem to entail potentially the same distortions to investment outcomes as under the existing arrangements (although perhaps on a significantly lesser scale). It also gives rise to a number of practical complications and would not address any broader problems associated with RCPD prices if they are, indeed, over-signalling economic costs.

4.3 Remove requirement to make ACOT payments

60. If the obligation to make ACOT payments was removed from Schedule 6.4, this would eliminate the short-term costs to consumers described in section 3.1 above. It would also ameliorate the incentive that generators might otherwise have to invest in DG when transmission-connected plant would be more efficient (although, as we explain below, the requirement to pay only the incremental cost of connection to the distribution network may mean that some incentive remains).

61. In these circumstances, new DG investments would need to be viable on their own merits relative to alternatives (including transmission connected generation), i.e., in the absence of a subsidy in the form of an ACOT payment. An argument might be made that the existing ACOT payments should be retained ("grandfathered") for existing DG that have invested under those arrangements; however:

- it may be very difficult in practice to distinguish between "old" and "new" DG, particularly if plant is partly or wholly replaced/refurbished over time; and
- to the extent a meaningful distinction could be made, this would create additional competitive neutrality problems as between "old and new" DG.

62. It is also potentially relevant that Part 12 of the Code allows Transpower to contract with generators (and other market participants who can offer, say demand-side management services) to provide services to reduce demand in a way that is prudent and efficient for Transpower.[23] In other words, the Code *already* allows Transpower

[23] Vector makes this point in its 11 November 2011 submission to the EA: *Submission on Distributed Generation Pre-Consultation, Public Version,* p.6.

to enter into arrangements with generators if doing so is likely to reduce forward-looking expenditure on transmission investment.[24]

63. As the EA has noted (and explained above), Transpower has commented in the past (in relation to grid support contracts) that it is "unrealistic to expect local generation or demand response to be able to achieve levels of reliability usually expected of the transmission system."[25] This suggests that such arrangements may be rare[26] and is consistent with the preliminary conclusion in the Working Paper that there are few long term benefits associated with ACOT payments.[27]

4.4 Contribution to fixed and common costs

64. In addition to the requirement in Schedule 6.4 for distributors to make ACOT payments, there is also the issue that distributed generators are required to pay only the incremental cost of connecting them to the distribution network. Consider for example the simple grid configuration depicted in Figure 3 (essentially a reproduction of Figure 2 from earlier). Assume that:

- the transmission connected generator's anytime maximum injection ("AMI" – as measured at point A) under the TPM is 60MW;
- the distributor's anytime maximum demand ("AMD" – as measured at point A) under the TPM is 40MW;
- that the distributed generator's AMI (as measured at point A) under the TPM is 20MW (i.e., 60MW *less* the maximum local load of 40MW); and
- this part of the grid is located in the North Island, so that the generators are not required to pay HVDC charges.

65. The transmission connected generator based at location B will therefore pay:

- for 100% of the link between location A and B (a "dedicated" connection asset that only it is using); and

24 As we understand it, these contracts for transmission alternatives can include payments to both distributed and transmission-connected generation, and so the arrangements do not exhibit the competitive neutrality problems contained in Schedule 6.4. It is also potentially relevant that the Australian Energy Market Commission has taken steps to ensure that transmission businesses take into account any avoided transmission use of service payments (the Australian equivalent of ACOT payments) to DG when negotiating a network support payment with an embedded generator to avoid double compensation. *See:* AEMC, Rule Determination, *National Electricity Amendment (Network Support Payments and Avoided TUoS for Embedded Generators) Rule 2011,* 22 December 2011.

25 Transpower, *Design Features of Grid Support Contracts*, July 2010, p.viii.

26 Although, as the EA also notes, it is possible that this historical reticence may have changed following the success of Transpower's recent demand side participation trial. *See* EA ACOT Working Paper, §8.21.

27 *See:* EA ACOT Working Paper, §12.4.

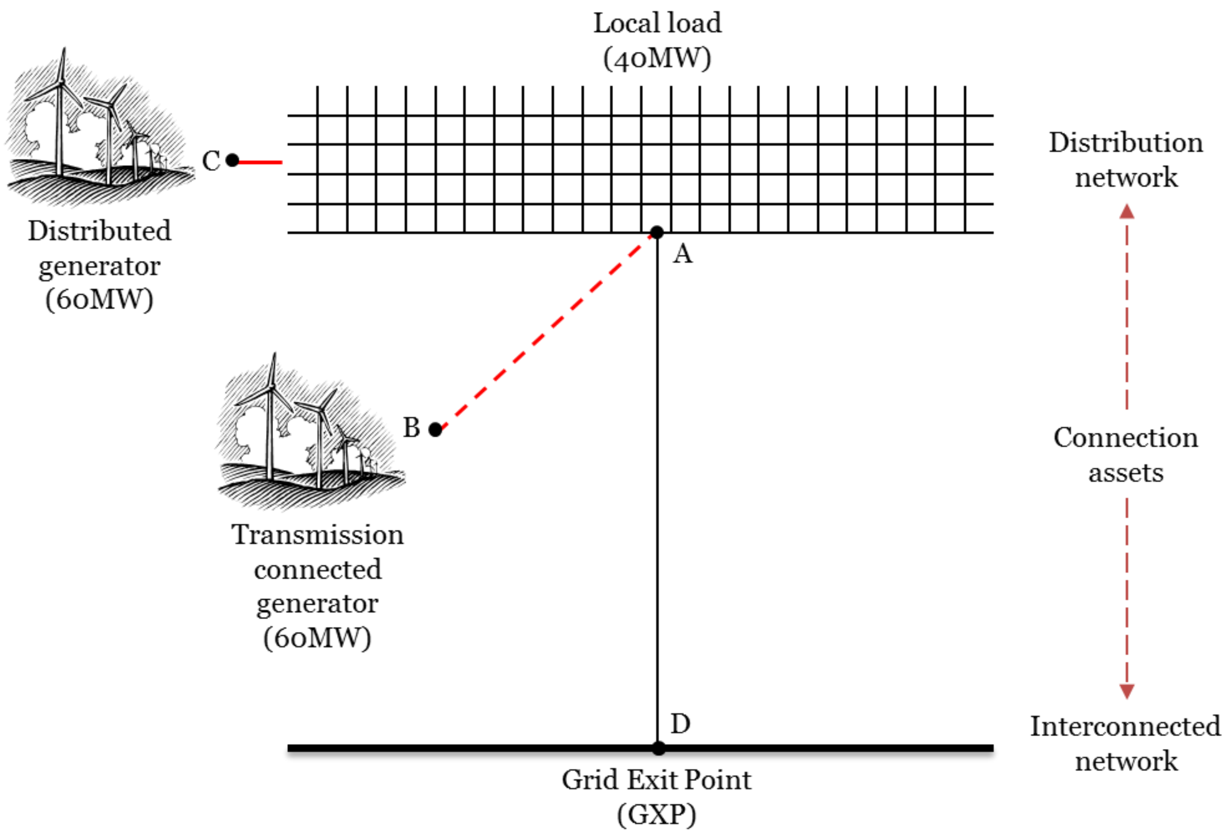
- for 50% of the cost of the "shared" link between A and D (based on its AMI of 60MW, i.e., 60MW ÷ [60MW + 40MW + 20MW]).

66. In contrast, the distributed generator will pay:

- for the incremental cost of connecting to the distribution network; and
- for 17% of the costs of the shared connection link between A and D (based on its AMI of 20MW, i.e., 20MW ÷ [60MW + 40MW + 20MW]).

67. This illustrates that transmission connected generators will often be expected to make a greater contribution to fixed and common network costs. There may therefore still be a distortionary effect on investment incentives even in the absence of ACOT payments. Specifically, there may still be an incentive to embed when transmission connected generation would offer greater market benefits.

Figure 3 Difference in contribution to fixed and common costs



68. There are at least two ways of addressing this potential problem. The first is to revise Schedule 6.4 so as to permit distributors to charge distributed generators for a share of the fixed and common costs in the *distribution network* it is deemed to be sharing. Ideally, any such charge would be levied in a manner that did not

compromise the efficiency of the use of the existing generation and network assets, i.e., through the use of a fixed charge.[28]

69. The second would be to calculate transmission-connected generators' shares of existing connection assets based on their injections at the relevant Grid Exit Point (GXP) rather than at the nodes between the connection assets and distribution networks. In Figure 3, this would mean measuring the transmission connected generator's AMI at point D, rather than at point A.

70. In the above example, the transmission connected generator's AMI at the GXP (at D) is likely to be significantly less than 60MW (the AMI at A) because, at any given time, a proportion of its output (up to 40MW) will be taken by the local load. Indeed, it is quite conceivable that it would pay for a similar – if not identical – share of the existing connection line between A and D as the distributed generator (at location C) under this alternative approach.

28 As we have noted in previous reports, a significant shortcoming with the EA's "beneficiaries pay" proposal is that it will distort the use of the existing grid by introducing a new variable charge that can be expected to distort grid participants' production and consumption decisions. In contrast, if distributed generators were required to contribute to distribution networks' fixed and common costs via a fixed charge levied based on, say, AMI, this is unlikely to entail any significant distortionary effects.

5 Conclusion

71. In our opinion, the current charging arrangements for distributed generators set out in Schedule 6.4 of the Code:

- are likely to result in consumers paying higher electricity prices in the short term due to the interactions between the TPM, Schedule 6.4 and the Commission's input methodologies;
- are likely to distort the choice between *types* of generation, making firms more likely to invest in DG, including when transmission connected generation is equally feasible and may offer greater market benefits; and
- may not reduce transmission costs – although this aspect of the EA's analysis is unclear, given the inconsistency with its earlier Issues Paper.

72. The EA is therefore correct to query the robustness of the current framework and there is good reason to consider whether alternative arrangements might address some or all of the present shortcomings. Potential options include:

- reforming the interconnection charges in the TPM that are applied to *all* parties – particularly if the RCPD prices currently over-signal the transmission investments that are avoided (which is unclear[29]);
- basing ACOT payments on the forward-looking economic costs that DG cause to be avoided as opposed to the transmission charges that they cause distributors to avoid (e.g., through a reduced RCPD), although:
  - it would be difficult to implement this option without significant involvement from Transpower;
  - it would not address the competitive neutrality issue pertaining to transmission connected generators; and
  - it would not address any broader issues with the RCPD prices applied to other parties – including to distributors – to the extent they exist;
- removing the requirement to make ACOT payments and relying on Transpower to enter into arrangements with generators under Schedule 12 when doing so is expected to reduce forward-looking expenditure on transmission; and/or
- changing the manner in which distributed and/or transmission connected generators contribute to fixed and common network costs to ensure more symmetric treatment, such as by:

29 As noted above, this opaqueness arises because of the inconsistency between the analysis and conclusions contained in the EA's ACOT Working Paper on the one hand, and those set out in its first TPM Issues Paper on the other.

- revising Schedule 6.4 to permit distributors to charge DG for a share of the fixed and common costs of the distribution network; and/or
- revising the TPM so that transmission-connected generators' shares of existing connection assets are based on their injections at the relevant GXP.

73. These options are not necessarily mutually exclusive. For example, ACOT payments could be removed and DG might also be required to contribute to fixed and common distribution network costs, and so on.