26 July 2016

Submissions
c/- Electricity Authority
PO Box 10041
Wellington 6143
by email: submissions@ea.govt.nz

SUBMISSION ON TRANSMISSION PRICING METHODOLOGY

Introduction

1 Orion New Zealand Limited (**Orion**) welcomes the opportunity to comment on the "Transmission Pricing Methodology: Issues and proposal - Second issues paper" (the **paper**) released by the Electricity Authority (Authority) in May 2016.

2 In summary:

- Overall we do not believe that the conceptual basis of a new TPM is sufficiently well developed to determine that the proposed new guidelines would lead to better outcomes.

- We strongly disagree with the paper's position on the value of load management and believe we can and have demonstrated its value over many years.

- We are concerned that the amount of detail being left to Transpower, and the amount of discretion it will need to exercise, makes it very difficult to know what the actual efficiency and equity implications of the proposal will be. Certainty is an important attribute of good regulatory practice, and it appears to be lacking in this case.

- We are particularly concerned about the proposed extensions to the prudent discount policy. We believe it will be very difficult for Transpower or the Authority to resist calls for discounts based on a business' financial circumstances.

- We are pleased that the Authority has devised a somewhat simpler proposal without the deeper connection component and which acknowledges the inherent unfairness of its previous proposed approach to capacity measurement for allocation of the residual.

- We are also pleased to see the Authority has taken on board a number of submitters views that connection charges represent a service the price of which does not need to be tied to the specific assets providing it. We believe this thinking can be extended to interconnection assets.

ORION NEW ZEALAND LIMITED
565 Wairakei Road, PO Box 13896, Christchurch 8141, New Zealand
PHONE +64 3 363 9898 | oriongroup.co.nz

3 The remainder of our submission is in two parts:

- comments on selected aspects of the paper, and
- 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 distributed generation pricing principles consultation. Our two submissions should be read in conjunction with each other.

The nature of the transmission service

6 In elaborating on the decision-making and economic framework for transmission pricing, the paper spells out in more detail the concepts of "service-based" and cost-reflective" pricing. This is useful and we support the concepts. However, the definition of "service-based" seems unnecessarily limiting in focusing on who pays, rather than what is being paid for. Combined with the emphasis on discrete investments and assets rather than how the transmission system as a whole supports and enables competitive markets leads, in our view, to a failure to see the bigger picture.

7 To some extent at least, everyone benefits from the transmission system. Without it a modern economy and society would be impossible, or at least it would be much more expensive if electricity was reliably supplied from distributed generation only.[1] In addition, the benefits can be subtle and indirect. For example Pole 3 of the HVDC has facilitated improvements in the way frequency keeping and reserves are procured.

8 In addition to everyone benefitting, the system has the feature that it is difficult to exclude parties from using it, or stop them changing their use of it.

9 Inevitably these two factors create a wedge between what parties are willing to pay (which might be quite considerable) and what they actually have to pay (which they might reasonably seek to minimise when they will get the benefits in any case).

10 On the other hand, the transmission service is not the same everywhere - for example it might not provide the same level of 'N-X' security everywhere. This would seem to be a key element to recognise in service-based pricing, but it does not appear to be in the paper.

11 To some extent the proposal in the paper, and the previous incarnations of it through the Authority's process since 2012, have been grappling with various forms of beneficiaries-pay, and this is an attempt to address the inherent problems. But of the methods we have seen so far for assessing benefits, all seem to be asset /

[1] For example the difference between individually self-sufficient consumers producing electricity at around $500 per MWh (approximate marginal cost of fossil fuel based small scale generation) and the delivered cost of around $250 per MWh gives an annual benefit of the entire electricity system of around $9 billion per year. ($500/MWh - $250/MWh * 35,000,000MWh/year)

investment specific and all seem to be quite sensitive to modelling assumptions such as the counterfactual grid and the historical period used for analysis. As a result they fail, in our view, to establish the value of the transmission system to various parties in a meaningful way.

12 We are pleased that the proposal seems to agree[2] with the submissions of a number of parties that connection charges can be seen as payment for a service that can, without compromising the service, be provided by assets of varying ages and types and without having a different price in different areas for the same unit of service. We think this logic can be extended to the interconnected system as well, and in fact it has even more force given the way the addition of a new asset can change power flows (and associated benefits) across many existing assets and parties. So if we are going to try and work out who the beneficiaries of the transmission system are, and what service they actually get, it would be better to focus on the system as a whole rather than its investment components.

13 Relatedly, the notion that investments are *in* regions rather puts the cart before the horse. Regions can be a convenient way to think about some aspects of the transmission service, but we should not allow this to cloud our thinking either by seeing the regions as being the same as beneficiaries, or by thinking that existing regions (such as 'UNI', 'LNI', 'USI' and 'LSI') are somehow either uniform or set in stone.

14 At least some of the concerns about one part of the country paying for investment that arguably benefits others is the accounting reality that New Zealand did not make a lot of major transmission investments for quite some time, and so the recent very substantial investments are being added effectively at replacement cost to an asset register which has book values reflecting significant depreciation. On this basis the investments have led to an unavoidable material and quite rapid increase in the average cost of the transmission service.

15 None of this means that New Zealand should necessarily stick with postage stamp pricing (where that means the same dollars per unit of service across the country). If there are indeed material differences in the service provided to and from various parts of the country, or in the cost of providing the service, then these might be appropriately reflected in different prices per unit of service. This will be particularly appropriate where (and if) there are areas where the averaged cost approaches or exceeds standalone cost. The changes to the guidelines that would be necessary to allow these sorts of approaches are, we suspect, quite minor, or if not minor, quite different to the changes being proposed.

Distributors are not consumers

16 Given that distributors are the counterparties for connection services there are good practical reasons for them also being the counterparties in relation to other aspects of the transmission service. However, care needs to be taken in seeing distributors as actually being "load" or "consumers". Distributors may manage and coordinate load, but they are not the actual load or consumers in at least three key respects:

[2] For example in paras 7.21 to 7.23 on page 87.

- They do not have exposure to nodal prices,

- They do not actually make decisions about where to locate load, whether or not to use electricity and whether to invest in complements or substitutes for electricity, although they have some influence over these things, and

- They might have input to but they do not make the decisions about interconnected grid investment, which can, by definition, have effects that extend well beyond the areas that they distribute to.

17 As with the transmission service, distributors provide the critical managed infrastructure that supports the interaction of buyers and sellers, but the outcome of that interaction is primarily the result of those other party's decisions.

18 Why is this important?

- Firstly, because to the extent that nodal prices are an important transmission price signal, distributors are largely indifferent to them.

- Secondly, distributors' involvement in transmission investment decision-making is usually in the same context as their consideration of distribution investment: they want to ensure that sufficient network capacity is available at an appropriate reliability standard before (but not too much before) it is actually required. Distributors are unlikely to wait until transmission constraints are evident in spot prices (caused by reduced security, increased constraints or non-supply) before looking to see investment, and, we suspect, neither is Transpower. It is the job of both Transpower and distributors to plan, as best they can, to ensure an ongoing reliable supply to meet consumers' needs.

- Finally the proposal, particularly with respect to the residual charge, attempts to minimise the incentives on parties to avoid using the transmission system. Yet, since distributors don't in fact use the delivered product, it is what consumers do that matters. So even if a theoretically incentive free (from a distributor perspective) method of residual charging can be created, it is how this is priced to consumers that will determine whether behaviour changes. Not only do distributors face regulatory constraints on how much of their charges can be fixed (subject to forthcoming Authority guidance), we, and retailers, are limited by practicality, measurement and reasonableness constraints around charging in the future on the basis of demands that happened over some historical period even when that is how we ourselves are charged.

Prudent discounts

19 We agree that there should be a prudent discount component of the TPM as any form of pricing of natural monopoly services is likely to have potentially undesirable effects at the margins and therefore the flexibility to deal with those is necessary. However the existing approach taken by Transpower, which is similar to that taken by distributors, is that such discounts be reserved for situations where, absent the discount, there would be inefficient bypass of the network.

20 However, the proposed extension of such discounts to respond to the financial state of businesses and the possibility of exit is, in our view, concerning. While we understand the arithmetical logic, we believe any process around it will be fraught

with asymmetry of information, incentives and resources such that any party will find it very hard to resist such proposals. If the prudent discount policy is to be extended along the lines proposed in the paper we strongly encourage the Authority to consider the following:

- Should the assessment consider wider economic impacts rather than just transmission costs? For example electricity consumers, and New Zealand overall, might be better off even if their transmission costs increase as a result of a customer's exit. Determining the appropriate breadth of the assessment might also influence the thinking on which party is best placed to carry out the analysis, and which party is best placed to make the decision.

- The process and decision needs to be subject to very firm transparency rules. For example the applicant could be required to produce documented and audited information supporting its claim. Such documentation could be required to be published, making the process open book.

- Any such discounts should be time bound, and with regular reviews within the period. To the extent that the financial position of the applicant fluctuates, there is no obvious reason why the discount could not sometimes be negative.

- That a party other than Transpower should give final approval to such proposals. This should at least be the board of the Authority, say on Transpower's recommendation, but it should perhaps be an even higher level decision – say a Minister.[3]

21 More generally, the proposed prudent discount policy and the related notion of possible optimisation of assets subject to the area of benefit (AoB) charge do not support the position that the proposed TPM is more durable. A small number of very large well-resourced participants could understandably be happy with it, but the perception, however accurate, of a potentially very large number of smaller consumers that the TPM is unfairly tilted against them may lead to durability problems from another direction.

Evaluation of the proposal

22 The proposal in the paper is notably less prescriptive than some of the previous options put forward. This may reflect a number of submissions that the Code limits the Authority's role with respect to the TPM to issuing guidelines. However there is some collateral damage in that it becomes very difficult to assess the actual TPM that might result as to both efficiency and fairness aspects. What we are actually needing to determine is whether this set of guidelines is better than the current guidelines, or some other conceivable sets of guidelines. We also need to assess the range of possible TPM's that might be consistent with the guidelines, and from the proposal this seems like it could be quite wide. Together these two requirements make it very difficult to judge whether the proposal is indeed an improvement on the status quo, and in particular whether the CBA is well-founded.

[3] It is well outside our area of knowledge, but such discounts look to us like they might potentially run counter, or be seen to run counter, to some of New Zealand's obligations under various international trade treaties?

23 However, we note that the process described in the paper involves Transpower developing the detail of a new TPM that reflects the new guidelines, and that that itself must be subject to consultation and justification. While we remain unconvinced that a change to the TPM is justified, we cannot judge that based on the draft guidelines alone as the indicative impacts are simply too indicative. Nor can we tell at this stage how the new TPM that results from the new guidelines would actually work in practice.

Grid investment decision-making

24 Since the beginning of the Authority's TPM work a major concern expressed in its papers has been that grid investment decision-making is currently poor and can be improved via changes to the TPM. In the latest paper this argument is developed to the point where it is claimed that: "The Commerce Commission's impartiality, analytical rigour and professionalism cannot save it from approving grid investments that overall are inefficient. Indeed, the more accurate are their forecasts of any inefficient grid use, the more certain the investment will be inefficient (in an overall sense)." (Para 80 of the paper.)

25 We have consistently questioned the rationale for the concern about investment decision-making, for three reasons:

- the Authority's own analysis has consistently shown that most of the recent major investments have actually had significant net benefits,[4]
- we believe it pays to detail specific evidence of past bad decisions before making changes to the TPM to ensure such changes are fit for purpose,
- to the extent that the quality of investment decision-making is a consequence of the major capex input methodology and associated process, it seems logical to at least consider what role changes to the IM might play in improving decision-making before proposing TPM changes. As a simple example, taken at face value the quote above implies that decision-making can be improved by the Commission using *worse* forecasts. But there may be more positive changes that can be made.

26 The paper suggests to us that the Authority is still over-reaching in this area. We note that the only example given of poor investment decision-making is a decision that was not required in relation to an investment 'proposal' that got no further than a parliamentary petition (referred to in para 86 of the paper). We do not believe this example has any bearing on whether actual grid investment decision-making is good or bad, or how it might be improved. The example is not relevant to the argument being made.

[4] For example, Figure 38 (on page 255 of the paper) shows that the Authority estimates that the six largest recent investments have, together, net benefits many multiples of the cost. As we noted in our last submission, these results cannot tell us that the investments made were better than some that were not, but they are hardly a damning indictment of current decision-making.

The relative size of the indicative components

27 It is important that the comments that follow are not misconstrued. We do not believe that the retrospective application of benefits in relation to transmission investments that have been made can improve the quality of those investments, nor can it affect the efficiency of their ongoing and future use much. We are merely seeking to ensure that the Authority applies its own framework consistently.

28 In the various proposals and options discussed in the last few years, there has always been a very sizeable "residual" component. A number of submitters have expressed concern about this, and the related point that if only a relatively small proportion of transmission cost can be allocated as anything other than residual, we have not moved very far in terms of our methods.

29 In the latest proposal, the size of the residual seems to be driven by two things:

- The limitation of the investment/assets to be subjected to an area of benefit (AoB) charge,
- The limitation of AoB charges to an estimate of the cost of the assets.

30 We are not sure if either limitation is necessary or desirable:

- The AoB charge, no matter how calculated, is higher up the Authority's framework than the residual. Given that the overall revenue requirement is unchanged, then, other things equal, it would seem logical to maximise the amount recovered from AoB. If there is a good method of allocating the cost of the interconnected transmission service based on benefit, then why not apply it to the whole transmission system? (And we note that improved computation power is one of the planks in the "material change in circumstances" argument.)
- When an assessment of the benefit exceeds the associated cost, why not charge based on the former rather than the latter (so long as it is less than standalone cost)? By definition the parties are willing to pay more than the cost, and in any case it avoids the cost being allocated less efficiently and to less appropriate parties via the residual.
- There is a risk, and perhaps a near certainty, that the physical capacity measure used for the residual includes capacity that is provided by assets covered by the AoB, thus leading to a double-dip in some areas.[5] This could mean the proposal actually leads to situations where charges exceed standalone cost, but even if it doesn't do that it merely flips unfairness in one direction to unfairness in the opposite direction.

31 Regarding the allocation of the residual 100% to load, we believe there is still no good rationale for this. The paper states (para 7.198) that residual charges to generators will possibly distort investment and operation decisions, and in any case are likely to be variabilised via energy prices and so may as well be charged to load

[5] A double dip would also likely occur if Transpower implemented an LRMC based charge in an area but left the other charges unchanged.

anyway. But any form of charging may, and probably will, distort such decisions, and the wholesale electricity price is the only way (in the New Zealand market) that a generator can recover its costs. Then there is the possibility that the way distributors recover the costs from the actual loads will create distortions of its own. In natural monopoly pricing we are usually looking to choose between the best of a set of distortionary approaches, not between distorting or not. If nothing else this is further reason for the residual to be minimised.

There are still measurement problems around "physical capacity"

32 The 2015 options paper proposed a basis for measuring physical capacity for distributors using ICP metering categories. We are very pleased that this has been abandoned. However, the proposed replacement approaches still have issues. This is particularly important given the very large size of the residual.

33 To us, the overriding principle is that distributors should pay for the service received, not the service *not* received. We think this principle is consistent with the Authority's conception of service based pricing.

34 We understand the rationale of not wanting to affect incentives, but it seems to us the proposal seeks to do this in two ways - by being both backward looking and based on values that are difficult to influence - when one way might suffice. Thus the approach is very keen to move away from RCPD because, according to the paper at least, this has led to inefficient demand response in the past. Whether or not that is true, it remains the case that cost allocation across shared assets is likely to be best done by some form of coincident peak demand measurement, as this automatically takes out some of the anomalies that can arise from other methods. One example of such an anomaly is that anytime maximum demands (AMD) will generally be greater when the number of points of measurement is greater even when all the downstream consumer demands are the same. For example a distributor with one GXP will almost certainly have a measured lower AMD than an otherwise identical distributor with two GXPs, and the difference between the two will be quite sensitive to the amount of load switching that the second distributor might do between GXPs.[6]

35 The fact that any approach is, or can be retrospective should be sufficient to allay the fears that behaviour might change to influence the charge – by definition it cannot. However, retrospectivity can lead to undesirable and arbitrary outcomes, so care needs to be taken in its use. We believe some form of coincident peak demand minimises the risk of arbitrary outcomes, and it is likely to also reduce rate shock as it is closest to historical practice.

36 We note in this regard the use of shares of coincident maximum demand is also a reasonable and indeed a "market-like" way that parties that jointly fund an asset might choose to share the cost of it over time. This is because the asset will need to be big enough to support that coincident demand, so each party's use of it at that time will be a very good proxy for their appropriate share of the cost. It also helps offset the incentive that they might otherwise, and inefficiently, build separate assets

[6] And we note Schedule 6.4, 2, (l) (ii) of Part 6 of the Code envisages the use of shares of coincident maximum demand for sharing costs between multiple DG owners that share use of assets.

to support their own individual maximum demands, the sum of which cannot be less than but will likely be higher than the coincident maximum demand.

37 The proposed approach to physical capacity measurement also includes the idea that existing DG and demand response be added back. This idea is subject to a "where practical" clause, and we believe there are indeed practical issues. But there are also conceptual ones:

- Both DG (some) and demand response (most) would require significant estimation. This means that the most accurate electricity metering used in New Zealand will have added to it some potentially very inaccurate estimates for transmission charging purposes.

- The boundary for demand response is not clear cut. For example it might include some or all of the following:

  (a) The estimated difference between controlled and uncontrolled load due to direct distribution load management actions,

  (b) The contribution of DG which is "behind" load (so the actual DG output is unknown),

  (c) Consumer price response, for example those 50,000 or so consumers on the Orion network that have chosen to have their hot water heated only at night,

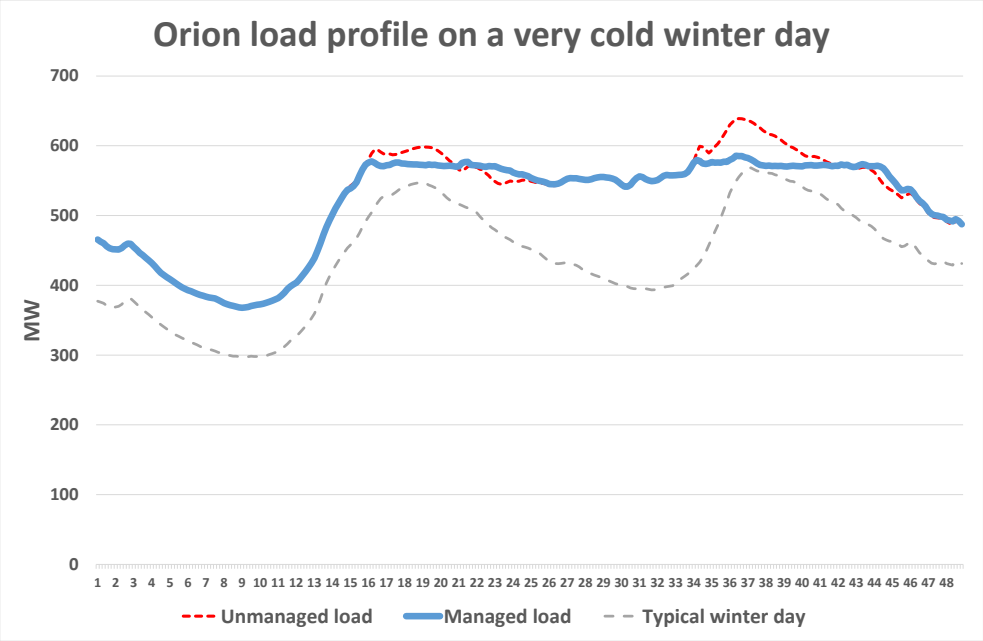
  (d) The demand response inherent in such actions as consumers building better homes, insulating existing homes, installing heat pumps, replacing incandescent light bulbs with LEDs and generally buying more efficient appliances.

38 The idea of adding back these components does however raise a related significant concern. If all of these forms of demand response are indeed inefficient, then Transpower should plan as if the response is not there, and this could well bring forward or cause transmission investment that would otherwise be deferred or avoided entirely. We presume this is the Authority's expectation and that by definition such investment, even though it is currently not necessary, would be efficient.

Load management

39 The discussion of physical capacity leads into our concerns about the paper's apparent stance on load management.

40 Orion has carried out successful load management for many years. We intend to carry on doing it and investing in it. Our distribution network peak demands coincide with periods of peak demand on the transmission system, and both are materially lower than they would otherwise be as a result of load management. The following graph shows this.



41 By way of explanation, the blue line is what the load actually was, the red line is an estimate of what the load would have been without load management, and the dotted grey line is a typical winter's day. It is important to note the material load profile difference between a typical winter day and the severe winter days where peak demand management matters the most[7]. The flat line is achieved by the coordinated management of tens of thousands of hot water cylinders within a service level constraint.

42 Para 66 of the paper states:

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.[8]

43 We submit this is at best a narrow view.

44 This is partly because the sheer quantum of peak load reduction achieved by coordinated load management can mean a region is on a lower growth path forever,

[7] Peak demand on severe winter days is a significant cause of transmission and distribution network costs. We note that the timing of high generation costs in the wholesale electricity market does not always align with the timing of peak demand, however, we are still seeing generation peaking plant investment in New Zealand. Also note that the uncontrolled (red line) load excludes the load shifted to the night by customers that have chosen to have their hot water heated only at night.

[8] As a technical matter, most load management of hot water is designed so that the electricity service is not *forgone*, but rather moved to a different time. It is also done within a context of service levels so that the output (hot water) is maintained even when the input (electrical energy) is varied.

so it is effectively built into the grid investment planning forecasts and indeed the forecasts distributors use to design new network.

45 But it is also the case that successful load management requires investments by multiple parties: distributors in control systems, retailers/MEPs in control equipment at customers' premises and customers in the means to manage their load (for example by having an appropriately sized hot water cylinder). All of these investments are medium to long term, and in our view they are better for being regularly used. They are also the sorts of investments that can be difficult and expensive to retrofit.

46 Load management also offers both the ability to help manage lower grid security limits as required by the system operator from time to time, and the possibility of supporting some ancillary services.

47 There is finally the observation that there may well be at least some wider benefits from load management via lower marginal losses and the avoidance of peak generation due to the inherently flatter load profile that results.

LRMC

48 The paper proposes that the guidelines permit Transpower to develop an LRMC based component in any new TPM. We believe LRMC is key to efficient transmission and distribution pricing, and as such it should be a required component. We acknowledge that implementation of LRMC based pricing presents challenges, but we consider that these are surmountable.

Cost benefit analysis

49 As noted above, we are unsure whether a robust CBA can be prepared given the lack of certainty about the actual form of the TPM that will emerge from the proposed guidelines. As a result we have not reviewed the CBA in much detail. However, we do have some observations:

- The $93 million of benefit that results from the ending of inefficient demand response associated with RCPD depends on the cost of the demand response: if the cost is low, then the benefit from stopping doing it will likewise be low. This cost is likely to be low if either the incremental cost of the response is quite low (which it is with a service level based peak load control of hot water cylinders) or the response would have occurred in whole or in part even with RCPD (which it might well in response to distribution network pricing signals). As it happens, both of these possibilities are in fact the case, at least in the USI.

- The published spreadsheet for the CBA has "historical" values for RCPD in the various regions that are manifestly wrong, ranging from 55% too low in the USI to 89% too high in the LSI. These errors, which have been pointed out to the Authority, have not, as far as we are aware, been explained or corrected.[9]

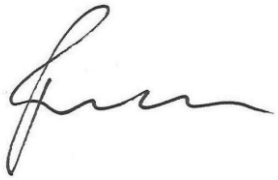
[9] The Authority has responded to a question on these values raised by Pioneer Energy. However the response does not, in our view, acknowledge or explain the error. See the Authority's 19 July 2016 document: "TPM second issues paper - Questions and responses", response to Pioneer's question 15. Either the numbers are

They may or may not propagate through the calculations, but they do compromise our confidence in the quality of the analysis.

Concluding remarks

50 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

not historical RCPDs, or the numbers provided in the analysis have been added up incorrectly from the source.

Appendix: Response to specific questions

Question No.	Question	Response
Q1.	What threshold value should be used to determine which new investments should be subject to the standard area-of-benefit charge versus the simplified area-of-benefit charge? Please provide your reasoning and evidence in regard to the trade-offs mentioned above and any other factors you believe are material to this decision.	If there is a reliable and robust way of calculating the benefits that the various transmission assets provide to the various transmission customers, then it is unclear why it would not be applied to all assets: that is, the entire interconnected transmission system. We note that AoB is higher in the Authority's hierarchy than the residual, and is obviously more service based. It thus seems logical to us, within the proposed structure, to *maximise* the AoB proportion.
Q2.	Bearing in mind that it is proposed that Transpower develop a method of determining the areas of benefit, which of the above methods do you think should be used to determine the areas of benefit from high value investments in the interconnected grid?	Whatever method is used must be reliable and robust. It is not clear why high value investments need to be singled out. While the grid has been built as a string of reasonably discrete investments, it nevertheless operates as a single system. Is the proposed approach more an ad hoc smoothing mechanism?
Q3.	Bearing in mind that it is proposed that Transpower develop a method for determining the areas of benefit, which of the above methods do you think should be used to determine the areas of benefit from low value investments in the interconnected grid?	See response to question 2. Whatever method is used must be reliable and robust. It is not clear why low value investments need to be treated differently.
Q4.	Do you prefer the residual-based approach or the surcharge-based approach or some variant of the two and why?	We are not sure the distinction is useful.