

TRANSPower NEW ZEALAND LIMITED

Submission to the Electricity Authority on the
Transmission Pricing Advisory Group's
Transmission Pricing Discussion Paper

July 2011

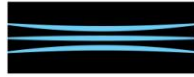


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1. Introduction

This is Transpower New Zealand Limited's submission on the Transmission Pricing Advisory Group's (TPAG's) 7 June 2011 *Transmission pricing discussion paper*.

We understand that, following this consultation, TPAG will make a final recommendation to the Electricity Authority Board and that, if this recommendation proposes an alternative transmission pricing methodology (TPM), and the recommendation is accepted, the Authority will publish and consult on an Issue Paper, including draft transmission pricing guidelines and a proposed process for the development and approval of a new TPM, as required by clauses 12.81 to 12.83 of Part 12 of the Electricity Industry Participation Code 2010 (the Code).

We note that the Authority intends to finalise a new TPM in time for it to be used to calculate prices for the transmission pricing year commencing 1 April 2013. Delays to the originally published TPAG process may make this objective difficult to achieve. As clause 12.94 of the Code requires the Authority to consult with Transpower when determining a date on which the TPM must take effect, we look forward to this consultation later in the process.

1.1 TPAG approach and principles

We commend TPAG for its clear approach to the review task. TPAG has focused the review on those elements of the methodology which may be suboptimal and hence where there may be a credible justification for change, and has restricted work to possible changes that are likely to be enduring. The analytical approach adopted to applying the Code amendment principles, with its emphasis on efficiency, is also laudable.

In particular, we agree with TPAG's observation that, on the interconnected grid, modelling usage of particular assets is not the same as identifying benefit. TPAG notes that the value associated with usage can be subjective and depend on a range of assumptions. We would go further and note that, if modelling showed that a customer was "using" a particular interconnected asset, but, on most occasions, the customer would observe little change to its service, including price, if the asset were not there, the customer could not be said to be benefiting from the asset to any meaningful extent. We also agree with TPAG's assessment that the benefits of any particular asset or set of assets can be different for different parties, and the value to those parties can vary over time.

In our view, TPAG has correctly identified that:

- when grid investment decisions are taken by a regulator, and hence those decisions do not rely substantially on private information, charging beneficiaries is much less likely to improve decision making;
- there is little value to be gained from allocating sunk (or fixed) costs to beneficiaries; and
- there is potential for any practical form of fixed and sunk cost recovery to create unintended price signals with negative economic effects.

We would add the observation that more complex cost allocation methods, particularly if they create an additional asset boundary, can provide greater opportunities and incentives not just to shift charges, but also to dispute charges, and this can add substantially to compliance costs.

1.2 Closing the review

We strongly recommend that part of TPAG's proposal to the Authority's Board should be a recommendation that any new set of transmission pricing guidelines should bring the transmission pricing review to a final close. Transmission pricing has now been under almost constant review since 2004. The time has come to provide some certainty and stability to the industry going forward and to focus on the higher priority parts of the Authority's work programme, which present much greater potential opportunities for meaningful economic benefits.

2. HVDC charge

TPAG's HVDC recommendation is split, but the analysis supported by the majority of the group concludes that there would be a net benefit from changing from the current allocation of HVDC charges to South Island generators. Their preferred approach is a ten year transition to a full postage stamp charge, starting with a \$30/kW charge to South Island generators (cf. \$36.58/kW for 2011/12).

This conclusion inevitably follows from the treatment of the HVDC assets, including Pole 3, as a sunk cost. The principal rationale for the current allocation method is beneficiary pays, but:

"The TPAG notes that the HVDC Pole 3 upgrade is now committed. Any investment efficiency benefits from applying a beneficiary pays approach will relate to any further HVDC investments. Future investments in the HVDC link, apart from a possible second cable for Pole 3, are probably 20-30 years in the future. In the short term the investment efficiency benefits from applying a beneficiary pays approach to HVDC allocation are likely to be relatively small."¹

¹ *Transmission pricing discussion paper*, Transmission Pricing Advisory Group, 7 June 2011, para. 6.4.24, p.57.

The main benefit of a shift to postage stamping the HVDC charge would be correct merit order investment in future new South Island generation capacity versus North Island capacity. We do not have a strong view ourselves, and are thus prepared to support the majority view, although the incremental benefit in its favour is small. This support is subject to a workable transition arrangement being able to be developed. If the choice were between a simple shift to postage stamping and per MWh allocation, we would favour per MWh allocation, because of the wealth transfer effect, but this problem appears to be dealt with adequately by the ten year transition concept.

TPAG's analysis shows that the generation investment merit order benefit only emerges to any significant degree after about 2021. However, we accept that this analysis is based on conservative assumptions. It is possible that South Island generation investment may occur earlier, as there are firm West Coast hydro and South Island wind proposals, but whether or not the decisions to proceed with these investments would be materially affected by the HVDC charge is unclear. We note that if West Coast hydro were to proceed early enough there could be transmission cost savings.

Overall, per MWh allocation would secure the most certain benefits and would be simple to implement. However, this approach may not be durable, as it would still be an allocation to South Island generators, which would increase the risk of future challenge. Postage stamping would achieve the benefits of the per MWh approach, and it may possibly achieve some further benefits due to its beneficial effect on generation investment merit order. The main downside is the substantial wealth transfer from end consumers to South Island generators, but the multi-year transition proposal should ameliorate this problem.

At some stage in the future the beneficiary pays argument may arise again if new investment in the link is required. We accept that the link has multiple beneficiaries and provides multiple benefits and that these may change over time. However, we would query the statement in 6.4.9(a) that South Island generators and/or North Island customers are the primary beneficiaries only in very wet periods. In our view, this can also be the case during normal weather periods. Nevertheless, at this stage in the investment cycle, with Pole 3 committed, this is a largely academic point, as substantial further investment will not be required for many years. TPAG's point that charges for the other parts of the interconnected grid are not levied on a beneficiary pays basis is also valid, and whether or not it is easier to identify the beneficiaries of the HVDC link than the beneficiaries of parts of the interconnected grid seems to be an increasingly moot question.

3. Options for deeper or shallower connection

In our view, the Authority should agree now that the work that TPAG has undertaken provides sufficient justification for concluding that no further

analysis of connection options or a deeper allocation of costs to specific customers should be undertaken.

The RCPD method already provides a locational signal which, while not LRMC-based, cannot be shown to be inappropriate. The other methods investigated, which would provide locational signals, have undesirable features, which could easily result in net negative economic outcomes. (See the responses to consultation questions 13 to 16 for further discussion of this point.)

The transmission alternatives regime is the most effective way of ensuring that economic alternatives to reliability investments are actually implemented, as it incentivises the right stakeholders to get involved, captures the widest range of potential options and ensures that only options that would genuinely defer the need for transmission are implemented. The suggestion that a price incentive is adequate to shift the location of a peaking generation plant and convert it into a transmission alternative is not correct. A price incentive alone will not create the degree of reliability needed to make a peaking station an effective transmission alternative. Only the detailed transmission alternatives regime can do this.

Transpower is committed to making the transmission alternatives process work, as demonstrated by the current Auckland example. As long as the transmission alternatives arrangements continue to function effectively, this work area should remain closed.

4. Options for static reactive compensation

We welcome the TPAG analysis of this issue and the recommended addition of a new “amended kvar charge” to the TPM. The current approach, which relies on inclusion of a unity power factor requirement in the Connection Code, for the Upper North and Upper South regions is undoubtedly unworkable and represents a regulatory failure. This is exemplified by the fact that the principal remedy in the benchmark agreement for non-compliance with the unity power factor requirement (which is a technical compliance obligation) is immediate de-energisation². This is not an option that Transpower would ever consider in practice for a breach of this nature.

We support the concept of the TPAG proposal for an amended kvar charge, which is based on the approach Transpower originally recommended in response to the previous round of consultation. This original approach proposed calculating a WACC return on the book value of reactive support assets in each region, plus depreciation of these assets, and allocating these amounts based on customers’ kvar draw during the RCPD periods in each region. This approach would ensure that the actual cost to Transpower of providing those assets in each region (exclusive of maintenance, which would be minimal) would

² Benchmark agreement, clause 15.2.

be recovered from the users of the assets, consistent with the objectives of the TPM.

TPAG has modified the original proposal, with the aim of putting new investment in static reactive assets in local distribution networks on a “level playing field” with the cost of reactive power from the grid. The original Transpower proposal would not have done this, because the proposed reactive power charge was based on the average cost of old and new static reactive assets on the grid and consequently would always be lower than the cost of investment in new static reactive assets in local networks. We accept this point.

TPAG has proposed basing the reactive power charge on the LRMC of grid connected static reactive equipment. It proposes that this should be determined by dividing the estimated annual capital and operating costs of new static reactive assets by the capacity they would provide (i.e. \$/kvar, assuming the assets were used at full capacity). This quantity would then be applied to the actual kvar draw at each connection location during the regional peak demand periods.

However, the TPAG approach also does not level the playing field between the cost of reactive power provided by grid located versus local network located static reactive assets. This is because the TPAG proposed charge rate assumes that the equipment will be used at full capacity, which it never will be in practice. A distribution company investing in new reactive support assets on its own network would recover a WACC return on these assets and spread this cost (plus the cost of depreciation of the assets) over kvar produced at less than the capacity of the assets. Assuming all other things were equal, this cost would be greater per kvar than the cost of consuming the same kvar from the grid, with this cost calculated using TPAG's proposed method.

Our suggested refinement to solve this problem is to calculate the TPM kvar charge using the WACC return method originally proposed by Transpower but basing the return on the replacement cost of new static reactive assets, rather than on the book value of the assets actually in place. An objection to this approach is that it would over-recover a return on the static reactive assets actually being used (and hence would represent a small cross subsidy from the users of static reactive assets to the users of all other interconnection assets). However, on balance, this should not be a significant problem, as most customers would consume the output of both classes of assets, and the actual dollar amounts involved would be small. There would also be the problem that the estimated current replacement costs of static reactive assets could be challenged. This could be resolved by specifying in the TPM that the estimates used are to be values determined by Transpower in its sole discretion.

Once a kvar charge is in place, there would seem to be little point in also retaining a minimum point of service power factor in the UNI and USI

regions. Provided the charge is set appropriately, there should be no incentive for customers to draw excessive amounts of reactive support from the grid.

With respect to the LNI and LSI regions, to maintain consistency we would recommend also applying the kvar charging approach to these regions, without any penalty rate. The current inclusion of a minimum power factor in the Connection Code will not incentivise appropriate investment in static reactive support assets in these regions for the same reason that it fails to do so in the UNI and USI regions.

5. Draft pricing guidelines

5.1 Requirement to update “Pricing for Grid Connection Services”

Draft pricing guideline 2, included in the discussion paper, requires Transpower:

“to provide an explanatory document updating ‘Pricing for Grid Connection Services’, at a similar level of detail, and suitable for Transpower’s customers to understand the basis on which it levies charges.”

“Pricing for Grid Connection Services” is an historical document that has now been superseded by the methodology set out in Schedule 12.4 to Part 12 of the Electricity Industry Participation Code 2010.

We recommend that the draft pricing guidelines be amended to remove reference to updating “Pricing for Grid Connection Services” and substitute reference to updating the transmission pricing methodology contained in Schedule 12.4 to Part 12 of the Electricity Industry Participation Code 2010. The proposed updated document could be supported by an explanatory “supplementary information” document should Transpower consider this appropriate.

Possible new wording could be:

“Transpower is to provide an update to Schedule 12.4 to Part 12 of the of the Electricity Industry Participation Code 2010, which may be accompanied by an explanatory “supplementary information” document if Transpower considers this appropriate.”

5.2 Requirement for Transpower to review the basis for the interconnection charge

TPAG’s draft pricing guideline 12 states:

Transpower is to review the existing basis on which it calculates the interconnection charge at a grid exit point. Specifically Transpower must review whether the allocation of interconnection charges for the UNI and USI regions being based on the average of the highest 12 coincident peak half-hourly demands in the relevant capacity measurement period remains the most appropriate approach given the Electricity Authority’s objective contained in section 15 of the Electricity Industry Act 2010 and proposed changes set out in these Guidelines.”

We understand that the reasons for this proposed review are that:

- the recommended change to a postage stamp allocation for the HVDC charge would slightly increase the strength of the signal that the RCPD method provides to encourage load flattening, given the larger proportion of Transpower's revenue that would be allocated to interconnection, and this may or may not be appropriate;
- the use of n=12 in the UNI and USI regions, which was intended to provide a slightly stronger load control signal because of the forecast need for substantial new investment in those regions, may no longer be required, because the major investments needed to meet forecast regional load growth are now already committed and in train.

We accept the rationale for the proposed review, but note that such a review will consume additional time and resources and may not be consistent the achievement of the Authority's objective of amending the TPM in time for the changes to be applied to the calculation of charges for the 2013/14 pricing year (see Implementation section below). We suggest that, if the Authority decides to include this guideline, Transpower and the Authority should agree to a limited scope for the review.

6. Implementation

Because of delays to TPAG's originally published work programme, the timeline for developing and implementing a new TPM is now very tight, if the Authority's objective of applying the new methodology to the calculation of 2013/14 prices is to be achieved (see summary below).

Indicative timeline for development of new TPM	
TPAG makes recommendation to Authority Board	Mid August 2011
EA publishes Issues Paper with draft transmission pricing guidelines and invites submissions	Mid September 2011
EA receives submissions on draft transmission pricing guidelines	November 2011
EA considers submissions, publishes final decision on new transmission pricing guidelines	November – December 2011
EA publishes process for development of the new proposed TPM and provides Transpower with written request to develop new proposed TPM	End December 2011
Transpower develops new proposed TPM, reviews use of n=12 in UNI and USI regions, calculates indicative prices, and submits to EA	January – April 2012
EA considers proposed TPM (which may be referred back to Transpower)	May 2012
EA approves new TPM (assuming no reference back to Transpower), publishes and invites submissions	June 2012
EA receives and considers submissions, makes decision on inclusion of new TPM as a schedule to Part 12	July – August 2012
New TPM gazetted	September 2012

Transpower will begin the process required to calculate 2012/13 prices in August 2012. Changes to the pricing software and other administrative procedures need to commence at least three months before August (i.e. May) if they are to be in place, tested and auditable in time to be applied during the "pricing round". Hence, on the face of it, the timeline above would make it impossible to meet the Authority's objective of a 1 April 2013 implementation date.

However, it may be possible for Transpower to commence work to implement the TPM changes in tandem with developing the proposed amendments to the methodology if agreement can be reached between Transpower and the Authority that the Authority will not make any substantial amendments to the draft methodology proposed by Transpower (provided the draft methodology gives effect to the pricing guidelines).

Agreement will also need to be reached on the scope of the proposed review of the use of $n=12$ in the UNI and USI regions. This will need to be quite a limited desktop study if the Authority's implementation objective is to be achieved.

Another option that could be considered would be to stagger the dates on which different elements of the amended TPM come into force. This might be appropriate if the new static reactive power charge requires more time to implement than the changes to the HVDC charging method.

A further complication is that the power factor requirements in the Connection Code can only be amended via a review following the process set out in clauses 12.19 to 12.25 of the Electricity Industry Participation Code 2010 (see clause 12.18 of the Code). As this review should be completed ahead of the implementation of the proposed static reactive power charge, this process requirement is another factor that could delay the implementation of this charge.

We note that clause 12.94 of the Code requires the Authority to consult with Transpower when determining a date on which the TPM must take effect. We look forward to discussing the above issues with the Authority when it undertakes this consultation.

APPENDIX – RESPONSES TO CONSULTATION QUESTIONS

Question	Transpower response
Q1. Do you agree with the TPAG's assessment that there does not appear to be a demonstrable economic benefit from enhanced locational signalling to grid users through transmission charges to defer economic transmission investments decision? If not, please provide your reasons.	Yes.
Q2. Do you agree with the TPAG's assessment that the changes to the statutory framework during the course of the transmission pricing review project do not require the Commission's analysis and development of alternative TPMs to be reworked?	Yes.
Q3. Do you agree with the TPAG's assessment that the options developed through stages 1 and 2 of the Review were developed in a manner consistent with the Authority's statutory objective?	Yes.
Q4. The TPAG efficiency considerations: Has the TPAG identified appropriate efficiency considerations to assess the costs and benefits of different options? If not what other efficiency considerations would be appropriate?	Yes. It is encouraging, in particular, to see unintended efficiency impacts and good regulatory practice recognised prominently as efficiency considerations. Increasing complexity of itself can increase the scope for unintended negative efficiency effects, such as customer actions aimed at shifting costs for no net economic benefit and additional disputes over the interpretation of particular definitions.
Q5. Do you agree there was sufficient evidence of a clearly identified opportunity for an efficiency gain to warrant analysis of alternative options for the allocation of HVDC costs? In particular do you agree with the assumptions and analysis contained in section 6.2 and further elaborated in Appendix D? If you do not agree please set out your reasons for reaching an alternative conclusion.	Yes.
Q6. Do you agree with the range of HVDC options identified for assessment? If not, why not?	Yes.
Q7. The TPAG has assessed the HVDC options against the efficiency considerations 1 - 6. Are there aspects of this assessment that you disagree with and/or could you provide further information on? Please provide details.	We generally agree with the assessment. The conclusion in favour of some form of postage stamping follows inevitably if the HVDC link is treated as a sunk or fixed cost. At some stage in the future the beneficiary pays argument may arise again if new investment in the link is required. We accept that the link has multiple beneficiaries and provides multiple benefits and that these may change over time. However, we would query the statement in 6.4.9(a) that South Island generators and/or North Island customers are the primary

Question	Transpower response
	<p>beneficiaries only in very wet periods. In our view, this is also the case during normal weather periods. Nevertheless, at this stage in the investment cycle, with Pole 3 committed, this is a largely academic point, as substantial further investment will not be required for many years. TPAG's point that charges for the other parts of the interconnected grid are not levied on a beneficiary pays basis is also valid, and whether or not it is easier to identify the beneficiaries of the HVDC link than the beneficiaries of parts of the interconnected grid seems to be an increasingly moot question.</p> <p>The main incremental benefit of a shift to postage stamping the HVDC charge vis-à-vis per MWh charging would be correct merit order investment in future new South Island generation capacity versus North Island capacity. TPAG's analysis shows that this benefit only emerges to any significant degree after about 2021. However, we accept that TPAG's analysis is based on conservative assumptions. It is possible that South Island generation investment may occur earlier, as there are firm West Coast hydro and South Island wind proposals, but whether or not the decisions to proceed with these investments would be materially affected by the HVDC charge is unclear. We note that if West Coast hydro were to proceed early enough there could be transmission cost savings.</p> <p>Overall, per MWh allocation would secure the most certain benefits and would be simple to implement. However, this approach may not be durable, as it would still be an allocation to South island generators, which would increase the risk of future challenge. Postage stamping would achieve the benefits of the per MWh approach, and it may possibly achieve some further benefits due to its beneficial effect on generation investment merit order. The main downside of the approach is the substantial wealth transfer from end consumers to South Island generators. However, TPAG has developed a multi-year transition proposal that should ameliorate this problem.</p>
<p>Q8. What is your position on the two views? Do you have further evidence to support either the majority or minority view?</p>	<p>We support the majority view, although the incremental benefit in its favour is small. If the choice were between a simple shift to postage stamping and per MWh allocation, we would favour per MWh allocation, because of the wealth transfer effect, but this problem appears to be dealt with adequately by the ten year transition proposal.</p> <p>Transpower has a concern about the effect that the HAMI allocation method has on the incentive to withhold peaking generation capacity at Manapouri, Roxburgh and Clyde. However, we note the argument in D.9 that this issue may largely be resolved by the commissioning of Pole 3. We also note that the indicative draft guidelines would require the transition period to be managed by a declining "incentive free" charge to existing grid connected South Island generation stations. Presumably this would mean using some sort of fixed allocator, such as the last HAMI value not updated. This sort of approach should eliminate any remaining incentive to withhold capacity.</p>
<p>Q9. Do you agree with the summary of the comparison of alternative options and the majority conclusion that leads to the identification of the postage stamp transition option as the preferred option? If not, please give reasons why.</p>	<p>We would qualify the majority conclusion by noting that the incremental generation investment efficiency gain is less certain to be secured than the other efficiency gains, but, on balance, we support the majority conclusion in support of the postage stamp transition option as marginally superior to the per MWh allocation option (see the discussion in response to Q7 and Q8 above).</p>

Question	Transpower response
<p>Q10. The TPAG's analysis assesses postage stamping the HVDC costs to offtake customers. In Table 17, the impact on the analysis of different postage stamp variants was considered. Do you think there are other variants of the postage stamp options that should be explored further? Please give reasons.</p>	<p>No, the range of options considered was adequate.</p>
<p>Q11. If a transition to postage stamp option were recommended to the Authority and progressed further, do you agree with the majority view that the \$30/kW initial charge to existing grid-connected SI generators and 10 year transition period is appropriate? If not, please give reasons. Are there other issues with the transition to postage stamp options that should be considered? Please provide details.</p>	<p>Yes. There are no other issues beyond those discussed in response to Q7 – Q9 above.</p>
<p>Q12. Do you agree with the TPAG's conclusion that any further analysis of deeper connection options requires close coordination with the Commerce Commission?</p>	<p>Yes.</p>
<p>Q13. The TPAG has made a broad estimate of the possible efficiency gains from deeper allocation of costs to specific participants of \$15 to \$40m NPV. What do you think is the likelihood that such efficiency gains might be possible? Please give reasons.</p>	<p>This analysis is very superficial. The suggestion that a price incentive is adequate to shift the location of a peaking generation plant and convert it into a transmission alternative is not correct. A price incentive alone will not create the degree of reliability needed to make a peaking station an effective transmission alternative. Only the detailed transmission alternatives regime, supported by contractual requirements, can do this.</p> <p>The price signal from flow tracing would be meaningful only for distribution companies and direct connects. It is not clear to what extent, if any, such an incentive would translate into greater investment in peaking generation plant or demand side management. By contrast, the transmission alternatives process engages a much wider range of stakeholders. Once passed through to end consumers the price signal from flow tracing would be very weak (e.g. a 20 per cent increase in Vector's transmission charges would translate to a roughly 2 per cent increase in end use consumers' total electricity charges – insufficient to have any meaningful effect on consumption or investment decision making).</p> <p>No evidence has been provided to show that a flow tracing based charge would accurately reflect the long run marginal cost of new grid investment, so it cannot be claimed to be an economically correct allocation of costs.</p> <p>The high level analysis of possible efficiency gains takes no account of the additional costs associated with the increased disputes over the interpretation of the TPM and the prices calculated pursuant to it that would be bound to occur if flow tracing or "but for" allocation methods were introduced. Flow tracing would add an additional asset category ("allocated interconnection") and hence an additional asset boundary between allocated interconnection and general interconnection. This boundary would also be variable depending on modelled energy flows. The additional asset boundary and the</p>

Question	Transpower response
	<p>need for definitions of the asset allocations at the boundary nodes would increase the scope for disputes. "But for" allocation rules would also be bound to be complex and open to dispute.</p> <p>The cost of increased disputes could easily amount to \$2m p.a. for the industry as a whole, an NPV of c.\$28m at a 7 per cent discount rate.</p> <p>For flow tracing, there are also significant set up and operating costs. TPAG has estimated the set up costs at \$2-4m and the ongoing operating costs at c.\$1m p.a., an NPV of c.10-12m. We agree with the set up and operating cost estimates but, if the operating costs are intended to include the cost of disputes, we would contend that the cost of disputes for the industry as a whole is likely to be greater, as noted above.</p> <p>Increased complexity would also increase the scope for customers to find ways to shift costs onto others. Such activity, while commercially advantageous to individual customers, represents a net cost to the nation as a whole.</p> <p>On balance, there is no evidence that flow tracing or a "but for" allocation method would produce any net national benefit. Indeed, it is quite likely that the overall effect would be a net national cost.</p>
<p>Q14. Do you agree with the range of options for deeper or shallower connection, or for deeper allocation of interconnection costs, that have been identified? If not, why not?</p>	<p>The range of options identified is satisfactory.</p>
<p>Q15. The TPAG has assessed the 'but-for', flow trace and shallow connection options against the efficiency considerations 1 - 6. Are there aspects of this assessment that you disagree with or could provide more information on? Please provide details.</p>	<p>The analysis covers the right issues, but we would give some matters more weight, as described under the various headings below:</p> <p>Beneficiary pays</p> <p>The following observation by TPAG is encouraging:</p> <p>"...flow tracing assumes that benefit is proportional to allocated flow shares, which may not be reasonable in all cases."</p> <p>However, we would go further and note that, objectively, if, on most occasions, a customer would observe little change to its service, including price, if an interconnected asset that it was modelled as "using" were not there, the asset could not be said to be benefiting the customer to any meaningful extent. Different customers may also obtain different benefits, or different rates of benefit from the same assets.</p> <p>With respect to the "but for" approach, the lumpiness of efficient grid investment is always going to present a problem in relation to the application of the beneficiary pays principle. This is particularly true for a small scale grid, such as New Zealand's. The "but for" principle may be able to identify one or more large beneficiaries of an investment at the time it is made, or the investment proposal is considered. However, other users are likely to appear later to take advantage of excess capacity produced by the investment. Are these customers to be permitted to use the now sunk assets at no additional cost, or are the charges to be shared? If the latter approach is applied, the interpretation of the sharing rules can easily lead to costly disputes. Also, as noted above, on the interconnected grid, it can be difficult to identify to what degree an individual customer actually benefits from particular assets.</p> <p>The following quotation from the 2007 Castalia paper on the "but for" method prepared for Transpower is relevant here:</p>

Question	Transpower response
	<p>“Based on evidence in PJM, adopting an approach that assigns costs to those who benefit can be fraught with problems. PJM has spent years and tens of millions of dollars litigating the method used to calculate benefits for reliability and system network upgrades. There can be little doubt the many conflicts will arise using this type of pricing approach since different methodologies to determine benefits can cause wide swings in the allocation of costs.”³</p> <p>Locational signalling</p> <p>TPAG correctly notes that the locational signal goes to parties other than those most likely to offer transmission alternatives. This problem is resolved by the transmission alternatives regime itself.</p> <p>Once passed through to end consumers, the locational signal becomes a very small part of total energy costs and an even smaller proportion of total costs. Hence, it becomes meaningless as an incentive for these parties.</p> <p>There is no evidence that the signal provided by flow tracing, in particular, in any way reflects the long run marginal cost (LRMC) of grid investment. Hence, it cannot be said to be an economically correct signal.</p> <p>As noted above, we do not believe the \$15m to \$40m of benefits quoted by TPAG are likely to result from such a signal. In particular, this is because a price signal to shift the location of peaking generation built to provide energy is not sufficient, of itself, to give such generation the reliability needed to make it a transmission alternative, and hence avoid the need for grid investment. For further discussion of this point, see the response to Q13 above.</p> <p>Unintended efficiency impacts</p> <p>As noted in response to Q13, we believe the scope for flow tracing to create unintended negative efficiency effects is greater than TPAG seems to allow. Simply by creating an additional asset category and asset boundary, the scope for disputes over interpretation is increased substantially. The classification of individual assets at the boundary nodes would be bound to cause problems, particularly as these could vary over time with the output from the flow tracing model. Exactly where the asset concentration index (ACI) dropped below the threshold would be certain to be subject to dispute, and customers would be incentivised to expend effort to try to get their allocated interconnection asset below these thresholds.</p> <p>If the methodology allocated particular interconnection assets to one customer, if their ACI exceeded a given threshold, other customers that shared these assets would presumably receive a “free ride”.</p> <p>With respect to the “but for” method, we agree that there would be incentives to time investments strategically to avoid being “caught” by “but for” charges, and also to dispute the allocation of charges. These incentives create unintended economic costs.</p> <p>Implementation and operating costs</p> <p>As noted above, we believe the costs of disputes related to the flow tracing method would be greater than that estimated by TPAG. Something like \$2m p.a. or NPV \$14m would be more likely. Transpower is probably more aware of this risk than other industry participants because of past experience of disputes over pricing. One of the big advantages of the current TPM is that its clear definitions and relative simplicity have greatly reduced the incidence of disputes.</p>

³ *The “but for” Method for Identifying User Specific Assets for Transmission Pricing Purposes*, Castalia Strategic Advisors, 17 April 2007, p. 12.

Question	Transpower response
	<p>With respect to the “but for” method, TPAG’s estimate of the costs of administering the allocations and resolving disputes is closer to being correct, but is probably still understated.</p> <p>The quote above from the 2007 Castalia paper is also relevant here.</p> <p>Good regulatory practice</p> <p>As noted above, the flow tracing and “but for” methods would substantially increase the scope for disputes and this would be likely to undermine the durability of both methods. The scope for gaming these methods is also inimical to the achievement of consistency over time.</p>
<p>Q16. Do you think there is justification for the Authority to progress further analysis of connection options or a deeper allocation of costs to specific customers? If so, please give reasons.</p>	<p>No. The Authority should agree now that the work that TPAG has undertaken provides sufficient justification for concluding that no further analysis of connection options or a deeper allocation of costs to specific customers should be undertaken.</p> <p>The RCPD method already provides a locational signal which, while not LRMC-based, cannot be shown to be inappropriate. The other methods investigated, which would provide locational signals, have undesirable features, which could easily result in net negative economic outcomes.</p> <p>The transmission alternatives regime is the most effective way of ensuring that economic alternatives to reliability investments are actually implemented. Price signals are very unlikely to achieve this outcome, given that they do not incentivise all the relevant stakeholders. Transpower is committed to making the transmission alternatives process work, as demonstrated by the current Auckland example.</p>
<p>Q17. Do you agree with the TPAG’s overview of the background on SRC and the identification of the regulatory failure described in this section? If not, why not?</p>	<p>Yes. The current approach represents a clear regulatory failure.</p>
<p>Q18. Do you agree with the selection of SRC options selected for assessment? If not, why not?</p>	<p>Yes.</p>
<p>Q19. For option 4, the amended kvar charge, do you support the approach of retaining a minimum point of service power factor for the UNI and USI regions as a backstop measure? If so, do you support the recommended approach of providing a penalty rate for demand in excess of the minimum?</p>	<p>No, there should be no minimum power factor or penalty rate. These should not be necessary if the kvar charge is set at an appropriate level.</p>
<p>Q20. The TPAG has assessed the amended status quo and the amended kvar charge options against the efficiency considerations 1 - 6. Are there aspects of this assessment that you disagree with or could provide more information on? Please provide details.</p>	<p>No, the assessment is comprehensive and appropriate.</p>
<p>Q21. Do you agree with the TPAG’s summary of the costs and benefits of the options assessed and its observations? If not, why not?</p>	<p>Yes.</p>

Question	Transpower response
<p>Q22. Do you think it appropriate that minimum power factor requirements are retained in the Connection Code for points of service in the LSI and LNI regions, when a view has been taken that such arrangements are unenforceable in the UNI and USI regions and thereby amount to a regulatory failure?</p>	<p>No, the kvar charging approach should also be applied to the LNI and LSI regions.</p>
<p>Q23. In your experience are there any other issues that arise from the current prescription within the Connection Code of minimum power factor for points of service in the LSI or LNI regions? Please provide background relevant to any issues you identify.</p>	<p>Although particular problems have not yet emerged, it is unlikely that specifying a minimum power factor for the LNI and LSI regions will incentivise appropriate investment in static reactive assets in those regions for the same reasons that it has failed to do so for the UNI and USI regions.</p>
<p>Q24. If you have identified issues in the previous question, do you think an approach similar to the amended kvar charge option, possibly incorporating a penalty charge for reactive power demand in excess of a set minimum power factor, would provide a better approach to address the issues you have identified? Are there other options that should be considered?</p>	<p>Yes, the same approach should be applied consistently, without a penalty charge.</p>
<p>Q25. Do you support the recommended introduction of an amended kvar charge (option 4) into the TPM? Please provide reasons.</p>	<p>Yes, but slightly modified. TPAG's proposed approach is good in principle but does not level the playing field between the cost of reactive power provided by grid located versus local network located static reactive assets, although it is intended to this. This is because the TPAG proposed charge rate assumes that the equipment will be used at full capacity, which it never will be in practice. A distribution company investing in new reactive support assets on its own network would recover a WACC return on these assets and spread this cost (plus the cost of depreciation of the assets) over kvar produced at less than the capacity of the assets. Assuming all other things were equal, this cost would be greater per kvar than the cost of consuming the same kvar from the grid, with this cost calculated using TPAG's proposed method.</p> <p>Our suggested refinement to solve this problem is to calculate the TPM kvar charge using the WACC return method originally proposed by Transpower, but basing the return on the current replacement costs of new static reactive assets, rather than on the book value of the assets actually in place, i.e. the "SRC revenue" would be a WACC return on the current replacement costs of static reactive assets in place allocated in accordance the reactive draw by each customer at each connection location during the regional coincident peak demand periods. An objection to this approach might be that it would over-recover a return on the static reactive assets actually being used (and hence would represent a small cross subsidy from the users of static reactive assets to the users of all other interconnection assets). However, on balance, this should not be a significant problem, as most customers would consume the output of both classes of assets, and the actual dollar amounts involved would be small. There would also be the problem that the estimated current replacement costs of static reactive assets could be challenged. This could be resolved by specifying in the TPM that the estimates used are to be values determined by Transpower in its sole discretion.</p>

Question	Transpower response
<p>Q26. Bearing in mind the indicative Draft Guidelines are intended to reflect the TPAG conclusions set out in this Discussion Paper, do you have any alternative drafting suggestions?</p>	<p>Yes. Draft pricing guideline 2, included in the discussion paper, requires Transpower:</p> <p style="padding-left: 40px;">“to provide an explanatory document updating ‘Pricing for Grid Connection Services’, at a similar level of detail, and suitable for Transpower’s customers to understand the basis on which it levies charges.”</p> <p>“Pricing for Grid Connection Services” is an historical document that has now been superseded by the methodology set out in Schedule 12.4 to Part 12 of the Electricity Industry Participation Code 2010.</p> <p>We recommend that the draft pricing guidelines be amended to remove reference to updating “Pricing for Grid Connection Services” and substitute reference to updating the transmission pricing methodology contained in Schedule 12.4 to Part 12 of the Electricity Industry Participation Code 2010. The proposed updated document could be supported by an explanatory “supplementary information” document should Transpower consider this appropriate.</p> <p>Possible new wording could be:</p> <p style="padding-left: 40px;">“Transpower is to provide an update to Schedule 12.4 to Part 12 of the of the Electricity Industry participation Code 2010, which may be accompanied by an explanatory “supplementary information” document if Transpower considers this appropriate.”</p>