Carter Holt Harvey
Pulp&Paper

SH1
Private Bag 6
Tokoroa
New Zealand
Telephone
64 7 885 5952
Facsimile
64 7 885 5933

www.chh.com

28 February 2013

Submissions
Electricity Authority
Level 7, ASB Tower
2 Hunter Street
PO Box 10041
WELLINGTON

By email to submissions@ea.govt.nz

Consultation Paper – Transmission Pricing Methodology: issues and proposal

1. This is a submission by Carter Holt Harvey Pulp & Paper Ltd on the Electricity Authority (EA) consultation paper "Transmission Pricing Methodology: issues and proposal" published 10th October 2012.

2. This letter summarises the key issues as we see them that we have addressed more fully in the Appendix using the questionnaire from the consultation paper. We have referred in some parts of our submission to:

   - A separate independent report by the New Zealand Institute for Economic Research (NZIER) "Transmission Pricing Methodlogy2012: Evaluation of EA consultation paper" which was commissioned by MEUG.

   - A spreadsheet dated 3rd February with various charging scenarios prepared by Brian Kirtlan (Electricity Authority)

High level summary response

3. Our high level summary response to this proposal is

   - The financial benefits assessed by the Authority are small and uncertain relative to the overall annual electricity charges and when balanced against the proposal's complexity and risk of unintended consequences, it is clear to us that this proposal should not proceed.

   - We do however, support the concept of beneficiary pays and so have attempted to highlight issues as we see them with both the general concept and implementation process along with some recommendations.

Key issues

4. Cost Benefit analysis

   - While of course the Authority looks at the cost/benefit equation from a New Zealand Inc point of view, we at CHH have attempted to understand the materiality of the proposal by putting the cost benefit in our own context using the Authority's chosen efficiency improvement parameter and hence unit price reduction of $0.12/MWh [1]. This indicates a possible annual saving of around $60K on our present annual cost of transmission services of around $6.5M i.e. less than 1% saving.

   - The CBA includes as a significant part of the savings[2], improvements in future investment. It seems to us that taking into account the recent major transmission

[1] EA Cost benefit analysis of TPM proposal Appendix F section 3.15
[2] EA cost benefit analysis of TPM proposal Appendix F Table 6 and TPM proposal sections 4.4.9 to 4.4.11

investments and the emerging future demand, that any potential savings in that area are likely to be many years into the future.

- With the very significant increase in the share of transmission charges going to generators, it is very unclear how much more of this will be passed on to consumers in the form of increased spot prices or avoidance of SPD benefit charges. Since effectively all generators will have transmission charges rather than just the South Island generators as at present, there is a risk that a greater percentage of the generator charges that are presently passed on (i.e. HVDC charges) will be passed on immediately.
- The proposed SPD and RCPI methodology appears to provide opportunities for generators to structure their bids to minimise their exposure to both of these charges. Of course at least some consumers have the ability to structure their demand to minimise RCPD charges, but it seems to us that generators have far more scope in general than consumers under the proposal to avoid charges.
- Introduction of volatility into transmission charges on an ex post basis could well lead to some form of risk premium being factored in to generator bids and retailer margins.
- The points above can only lead in our view to downside to the estimated savings which are already minimal. We have not identified any immediate or near term bankable upside aspects of significance.
- We believe therefore that any successful and generally acceptable change to transmission pricing methodology must be accompanied with an analysis of benefit to consumers that is much more robust than the present proposal.

5. Treatment of embedded generators in the proposal

- **Summary recommendation:** Any calculation of transmission benefits using the SPD part of the proposal should use net load or generation at location points as the case may be, as is done now for RCPD calculations and we understand is proposed to be done for the RCPD/RCPI part of the proposal.
  - We have had difficulty in understanding fully the Authority's reasoning and the potential impact of the proposal on embedded and cogeneration plants. As we have cogeneration plants at both of our pulpmills at Kinleith and Tasman, this aspect of the proposal could have a very material impact on our transmission costs as well as future investment plans at our pulpmills.
  - We are appreciative of the engagement we have had with the Authority staff on this matter and the additional information that has been provided.
  - Kraft pulpmills and electricity generation.

    i) Both of our Kraft pulpmills have cogeneration plants which at present supply a little under 50% of our mill electricity needs as well as process steam and they are fully integrated with the overall operation. These cogeneration plants are fully embedded in the pulpmills themselves. We therefore consider that our pulpmills present themselves to the transmission system as a net load.

    ii) In the future it is quite possible that a significant investment in pulping and generation equipment at our mills could be made that would lead to a large increase in electricity generation at least equalling the mills' electricity loads and could even result in net export of electricity. All new Kraft pulpmills built around the world in the last few years have at least own generation capability and to remain competitive, many older mills similar to ours have made investments to achieve this.

CarterHoltHarvey
Pulp&Paper

- We have examined carefully the potential efficiency issues involving embedded generators identified in the proposal in the problem definition sections 4.4.13 to 4.4.17 and it is clear to us that none of those issues applies to our present generation or indeed any future investment in cogeneration at our pulpmills.
- The spreadsheet provided by the Authority using data at the Kinleith substation connection location indicated to us that in a worst case scenario, direct charges would be significantly higher than at present, and even at a scenario of RCPD calculated as at present (i.e. net load at the connection location) and with SPD based on both generator and load benefits, our direct charges would have a significantly smaller reduction than the average consumer.
- We see no valid reason to single out in particular embedded cogeneration such as ours or indeed other embedded generators for such a major change in transmission charges via the proposed SPD charge.
- We endorse the comments concerning fairness and reasonableness in paragraphs 86 to 91 of the NZIER report and urge the Authority to take note.
- We also endorse the comments on embedded generation in Paragraphs 147 to 150 of the same report.
- Our recommendation as above is a result of this analysis.

We thank you for the opportunity to make a submission on an issue that is of great importance to us as a manufacturer, exporter and electricity generator using renewable resources.

We would be happy to discuss or clarify any aspects of this submission.

Yours sincerely

Dr David Jon Ryder
Chief executive Officer
Carter Holt Harvey Pulp, Paper and Packaging

Appendix: CHH responses to questions in the October 2012 TPM consultation paper

Question		response
		Chapter 2 Context to transmission pricing
1	What are your views about the materiality of changes in circumstances since the current TPM came into force in 2008? (Refer Para 2.3.12, p34)	We agree that • Recent investments of $2 billion have increased significantly the sunk costs of the transmission system. • The change in regulatory governance from the EC to EA and in particular the change to the Commerce Commission for approving grid investment leads to a need for reviewing how investment approval decisions are now made. o However, we consider that changes to the TPM only will not necessarily lead to an improvement in new investment decisions and that any changes to enhance decisions in this area will need to be coordinated with the Commerce Commission

Question		response
		decision making process. o In addition, it appears that the future grid investment plan is very small for the next decade at least and this should be a factor in considering the timing and scale of any near term changes to TPM. • Technology and reduced computational costs is an enabler to allow TPM methodologies such as the SPD allocation approach to be considered. • However, it would seem likely to us that the impact of technology will have an even more important role in the future demand for grid connection services. The innovation and cost of demand side response technologies, improvements in electricity usage efficiency and distributed generation (and this includes electric vehicles as generators under some scenarios) may well lead to declining demand for peak grid connection services and a significant reduction in use of grid assets. • The TPM and other components of the regulatory regime need to address the question of who should bear the necessary asset value write down of existing assets under such scenarios and how it should be done. It is not a viable solution to this potential issue to require users of the grid to continue funding assets that are not used.
2	What comments do you have on the process that the Authority has outlined for developing and approving a new TPM? Describe and explain any variations to the process that you consider desirable. (Refer Para 2.3.19, p36)	We believe that the EA needs to consider any complementary changes to regulations under Part 4 of the Commerce Act or any other regulation as an integral part of any TPM changes to ensure that any proposed amendments fit with the overall Electricity industry framework.
		<u>Chapter 4 Problem definition: does the current TPM promote overall efficiency?</u>
3	Do you agree with the Authority's view that the arrangements under the TPM for recovering connection costs are generally efficient? Explain your answer. (Refer Para 4.2.12, p49)	Yes.
4	What comments do you have about the potential for inefficient outcomes to arise from incentives to shift connection costs into the interconnection charge? (Refer Para 4.2.19, p51)	We observe that while this has been raised as an issue to be resolved, and two potential examples have been noted, there appears to have been no attempt to quantify the problem from an overall NZ inc viewpoint in order to determine its materiality. I.e. Is there an estimate of the value of assets built in the last 10 years that should more properly have been connection rather than interconnection assets?

Question		response
5	Do you agree that there is the potential for inefficient outcomes to arise from incentives for connected parties to hold out for connection asset replacement to occur as a grid upgrade rather than under an investment contract? Explain your answer. (Refer Para 4.2.23, p52)	While the proposal focuses on customers holding out on agreeing to an investment contract in order to reduce their specific costs, there could equally be situations where the customer is holding out because they do not agree to major capital expenditure on the connection assets because for example their future needs are not clear and so may have an alternative proposal that may include enhanced maintenance, monitoring and refurbishment of the existing equipment to extend its life. Asset replacement at the perceived end of life of assets is the easy solution but is often not the most efficient solution in terms of overall cost effectiveness, reliability and future needs.
6	Do you consider that there are any other problems with the connection charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the problem. (Refer Para 4.2.23, p52)	No.
7	What comments do you have about the Authority's analysis of the private benefits deriving from the HDVC link? (Refer Para 4.3.11, p55)	The expectations and asset values of South Island generators when they were first established and or listed needs to be considered. This particularly applies to Pole 2.
8	What comments do you have about the consequences of the material differences between private benefits from the HVDC link and HVDC charges? (Refer Para 4.3.11, p55)	The EA gives no evidence of the claim of "significant economic cost" noted in paragraph 4.3.11. In addition, with expected cost of $30M NPV "but with considerable uncertainty" as per Appendix C Para 15, we are not convinced that issues with the current TPM in relation to the HVDC are significant or certain enough to warrant a major change from the present regime. We believe that the benefits to South Island generators are materially above present HVDC charges.
9	What comments do you have about the Authority's analysis of the costs of inefficient generation investment resulting from the HVDC charge? (Refer Para 4.3.13, p56)	CHH notes that NZIER in their overall view (p iv) regarding the inclusion of HVDC Pole 2 in the SPD approach include the comment: "*The inclusion of HVDC pole 2 troubles us. We say this because of the likelihood that the HVDC HAMI charge has already been factored into SI generators asset values. If this is the case, then the current HVDC charge has no (or no material) impact on generation investment and consumer prices and there is no real resource cost , meaning that a benefit based charge would simply result in a wealth transfer and no useful additional price signals and no gains in*

Question		response
		dynamic efficiency." In addition a more convincing analysis would include data and analysis on investments in SI generation over the past few years and evidence of investments that have not (or even claimed to have not) taken place due to HVDC link charges.
10	What comments do you have about the Authority's analysis of the costs of inefficient operation of South Island generation resulting from the HVDC charge? (Refer Para 4.3.15, p56)	Minor effect at best. More likely immaterial or nil effect.
11	Do you consider that there are any other inefficiencies arising from the HVDC charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the inefficiencies. (Refer Para 4.3.15, p56)	No comment
12	What comments do you have about a) the differences (including their materiality) between private benefits from interconnection assets and interconnection charges; and b) the consequences of those material differences? (Refer Para 4.4.17, p61)	A comparison of the $12 to $170M NPV of problems identified with interconnection charges with the annual interconnection forecast charge of $719m pa, leads one to believe that the overall materiality of the issues raised is not great. However, with a flat charge there must be some inequitable charging. The most identifiable and possibly more material impact is the disconnect between charges and benefits when load growth in specific areas and generation growth in specific areas results in the need for investment in interconnection assets. However, since any significant future investment seems to be many years away, the present materiality of this problem must be low. While the present interconnection charge is effectively a flat rate, once the lack of investment signal impact is discounted, the remaining identified issues do not seem to be material enough to warrant any major change that would inevitably have significant risk in assessing benefits.
13	What comments do you have about the Authority's analysis of the problems with interconnection charges? (Refer Para 4.4.17, p61)	See above.
14	Do you consider that there are any other problems with the interconnection charging arrangements under the current	No.

CarterHoltHarvey
Pulp&Paper

Question		response
	TPM? Provide a detailed explanation of the nature and materiality of the problem. (Refer Para 4.4.17, p62)	
15	What comments do you have about the Authority's view that a prudent discount policy may be necessary after taking into account the incentives provided by the price components of any revised TPM? (Refer Para 4.6.8, p66)	We agree in general with the views in the paper. The bar is indeed high to develop a PDP agreement and since there have only been two PDPs agreed in the last 5 years; it does not seem to be a major issue. Nevertheless, if there is any change to the price components of any revised TPM, a PDP will probably be necessary. The 15 year life of present PDPs is quite arbitrary and a more appropriate solution would be to have the length of a PDP to coincide with an agreed asset life.
		<u>Chapter 5 Proposed amendments to the TPM</u>
16	What is your position on the Authority's proposal to codify that LCE or residual LCE received by Transpower from the clearing manager is to be used to offset the components of Transpower's transmission charges that correspond to the origination of the rentals? (Refer Para 5.3.14, p77)	No comment
17	Do you agree there would be efficiency gains from each of the components of the proposal for the connection charge, as outlined in paragraph 5.4.9? Please provide an explanation for your answer. (Refer Para 5.4.15, p80)	Generally yes. However, we consider that the provision in Para 5.4.9 (c) should also include an ability for the customer to dispute decisions to replace assets prior to any actual replacement as well as charges arising from asset replacement.
18	Do you agree that the proposal will address the problem identified in chapter 4 in relation to the connection charge? Please give reasons for your views. (Refer Para 5.4.15, p80)	Yes
19	What comments do you have about the Authority's assessment and conclusions about a kvar charge to recover static reactive support costs? (Refer Para 5.5.23, p85)	Proposal is reasonable.
20	Do you support:	The proposal for introducing a kvar charge where there is a

Question		response
	a) Introducing a kvar charge based on off-take transmission customers' average aggregate kvar draw from the grid in areas where investment in static reactive support is likely to be required, at times of RCPD, at the long run marginal costs of grid-connected static reactive support investments? b) Setting a minimum power factor of 0.95 lagging in the Connection Code for all regions? (Refer Para 5.5.23, p85)	likely need to invest in static reactive support is reasonable. However, we can see no compelling reason advanced in the proposal to introduce a minimum power factor of 0.95. We do not support this aspect of the proposal and consider that any issues with reactive power should be solved on a case by case basis as per the proposed charge above.
21	Do you consider that there are alternatives to a kvar charge for recovering the static reactive support costs that the Authority has not identified that are practicable, would deliver a net benefit and would recover static reactive support costs? Explain your proposal. (Refer Para 5.5.23, p85)	We have not identified a better alternative.
22	What comments do you have about the Authority's assessment and conclusion about charging options for dynamic reactive support? (Refer Para 5.5.26, p86)	No comment
23	What is your view of the Authority's assessment and conclusions about using the SPD or vSPD model to establish a beneficiaries-pay charge for recovering some or all HVDC and interconnection costs? (Refer Para 5.6.60, p99)	CHH agrees with NZIER's overall view (p iv) that "... *if applied as is, the SPD approach will be unable to avoid precipitating material unintended outcomes that would likely result in a transmission pricing environment that is worse than the status quo. We suggest that the EA reconsider the SPD methodology as a whole and give attention to the issues that we describe in our assessment*." Applying the SPD allocation approach to sunk transmission costs (NZIER p iii) is very problematic and NZIER detail "shortcomings" of no provision for demand side response, the residual will be large for many years and that has issues including difficulty of avoiding generators being able to pass residual charges through to customers, the effect on embedded generation and a number of "structural flaws" or design elements where possible unintended outcomes have not be adequately considered. We do agree with NZIER's (p ii) supportive stance to the approach in relation to future grid investments but have

Question		response
		important caveats around synchronisation with the whole regulatory regime (i.e. Commerce Commission) and risk of unintended consequences particularly with demand uncertainty. **EMBEDDED GENERATION** As we stated in our cover letter, we are particularly concerned about the SPD aspect of the proposal with respect to the treatment of embedded generators. Our recommendation and analysis of the issue follows: • **Summary recommendation:** Any calculation of transmission benefits using the SPD part of the proposal should use net load or generation at location points as the case may be, as is done now for RCPD calculations and we understand is proposed to be done for the RCPD/RCPI part of the proposal. • We have had difficulty in understanding fully the Authority's reasoning and the potential impact of the proposal on embedded and cogeneration plants. As we have cogeneration plants at both of our pulpmills at Kinleith and Tasman, this aspect of the proposal could have a very material impact on our transmission costs as well as future investment plans at our pulpmills. • We are appreciative of the engagement we have had with the Authority staff on this matter and the additional information that has been provided. • Kraft pulpmills and electricity generation. i) Both of our Kraft pulpmills have cogeneration plants which at present supply a little under 50% of our mill electricity needs as well as process steam and they are fully integrated with the overall operation. These cogeneration plants are fully embedded in the pulpmills themselves. We therefore consider that our pulpmills present themselves to the transmission system as a net load. ii) In the future it is quite possible that a significant investment in pulping and generation equipment at our mills could be made that would lead to a large increase in electricity generation at least equalling the mills' electricity loads and could even result in net export of electricity. All new Kraft pulpmills built around the world in the last few years have at least own generation capability and to remain competitive, many older mills similar to ours have made investments to achieve this.

Question	response
	• We have examined carefully the potential efficiency issues involving embedded generators identified in the proposal in the problem definition sections 4.4.13 to 4.4.17 and it is clear to us that none of those issues applies to our present generation or indeed any future investment in cogeneration at our pulpmills. • The spreadsheet provided by the Authority using data at the Kinleith substation connection location indicated to us that in a worst case scenario, direct charges would be significantly higher than at present, and even at a scenario of RCPD calculated as at present (i.e. net load at the connection location) and with SPD based on both generator and load benefits, our direct charges would have a significantly smaller reduction than the average consumer. • We see no valid reason to single out in particular embedded cogeneration such as ours or indeed other embedded generators for such a major change in transmission charges via the proposed SPD charge. • We endorse the comments concerning fairness and reasonableness in paragraphs 86 to 91 of the NZIER report and urge the Authority to take note. *i)* *MEUG members asked NZIER for clarification on whether the CBA appropriately reflects all of the various costs to consumers, and whether issues of 'fairness and reasonableness' are addressed, if at all. There is a question of whether any premium of sorts may be afforded in a CBA to impacts that fall disproportionately to certain types of stakeholders. For instance, if owners of embedded generation were to pay more, relative to others, to the extent that some consider unfair, then what scope is there for that to be considered appropriately by decision makers?* *ii)* *The first observation is that the EA's Code Amendment Principles centre squarely on 'economic efficiency' (Principle 2), and so there is no straightforward avenue to engage in notions of fairness and reasonableness. We note this is in contrast to the FERC Order 1000 which requires that non-discrimination and equity requirements be considered when developing cost allocation methodologies for transmission services.* *iii)* *Nevertheless, even if the focus is solely on economic efficiency, there is scope for considering equity in efficiency appraisals. It would entail placing different weights on the*

CarterHoltHarvey Pulp&Paper

Question		response
		impacts of stakeholder groups — rather than the conventional assumption of assuming equal weights for all stakeholders regardless of context.[3] *iv) The area is difficult because it necessarily involves subjective value judgements. However, these judgements clearly matter given that participants are more likely to lobby for change or engage in legal action, or simply avoid transmission charges, if they feel aggrieved over the reasonableness of the transmission charges they face. Furthermore, the EA opens the door to considerations of equity in so far as they see gains from reduced lobbying and greater regulatory stability which, if achieved, will partly reflect the perceived fairness of benefit-based charging.* *v) Indeed, the reallocation of sunk costs under the EA's proposal through the introduction of RCPI charges and an SPD charge for HVDC pole 2 will doubtless leave some feeling aggrieved. Some will lose money on past investments made in the expectation that the regulatory environment would not change significantly. Others will gain. This kind of transfer matters little for a simple cost benefit analysis. However the fact that some are aggrieved could contribute to a sustained mistrust in the regulatory regime and a consequent sense of uncertainty that will not assist in the efficient long term development of the industry to the benefit of consumers.* *vi) The EA has suggested that their proposal will improve regulatory certainty and stability. Although it is hard to see that the EA's proposal would worsen uncertainty to any great degree, we are not convinced that stability and certainty will improve. Only time will tell.* • We also endorse the comments on embedded generation in Paragraphs 147 to 150 of the same report. *i) It is not clear what is envisioned for embedded generation. The EA must carefully consider and clarify the treatment of embedded generation in the proposed TPM. This includes clarifying how a node which is the site of injection and off take will be classified for the purposes of regional coincident peak ('residual') charges.* *ii) To support consideration of embedded generation we suggest that any and all charges must relate to net injection or off take at the point of connection to the grid. This is*

3 Weighting everyone equally follows from the *Kaldor-Hicks criterion*, where a policy should be adopted if and only if those who will gain *could* fully compensate those who will lose and still be better off (even if they do not actually compensate losers).

CarterHoltHarvey
Pulp&Paper

Question		response
		the best basis upon which to measure the benefits of interconnection. *iii) The EA appears to suggest, in places, that embedded generation could be charged on the basis of gross output. This would be a strange state of affairs that would not be consistent with the beneficiary pays principle or dynamic efficiency. When generators choose to embed this demonstrates that they do not (or cannot) derive sufficient benefit from the interconnected grid to make it worthwhile connecting - even in the absence (currently) of interconnection charges. The same can also be said for the load which some embedded generators are entirely dependent upon (as in the case of some cogeneration). The only benefit embedded generation derives is in relation to the net exchange that occurs at the point of connection to the grid.* *iv) The EA has correctly identified that problems could arise for embedded generation from inefficient pass through of charges by distributors (e.g. if benefit based charges are being passed to generators whose generation has been displaced). However this should be dealt with in the context of the regulation of distribution charges and not in the setting of the transmission pricing methodology.* • Our recommendation as above is a result of this analysis. **To summarise,** 1. We see little if any benefit and significant risk of unintended consequences in using the SPD model for sunk costs but see potential benefit for future investment assessment. 2. Any calculation of transmission benefits using the SPD part of the proposal should use net load or generation at location points as the case may be, as is done now for RCPD calculations and we understand is proposed to be done for the RCPD/RCPI part of the proposal.
24	Do you agree with the Authority's conclusion that the most efficient beneficiaries-pay charging option for applying to HVDC and interconnection costs is likely to be the SPD method? Please provide an explanation for your answer. (Refer Para 5.6.65, p101)	No. See the answer to Question 23 above.
25	Do you consider that there are beneficiaries-pay options that the Authority has not identified that	We recommend that further consideration is given to separating the charge regime that would apply to already sunk assets and the charge regime that would be applied to

CarterHoltHarvey
Pulp&Paper

	Question	response
	are practicable, would deliver greater net benefits and would recover HVDC and interconnection costs? Explain your proposal. (Refer Para 5.6.65, p101)	possible future investment in assets. In our view this is likely to simplify any future overall regime, make it less susceptible to unintended outcomes and would have a better chance of being acceptable to the wide range of participants in the electricity market. A proportion of the issues identified revolve around the effectiveness of signals for investment in transmission, demand management and generation of various types. Given the apparent current trends, it seems to us that any emphasis on future investment signals should be discounted somewhat and more emphasis placed on signals that encourage or at least don't discourage more efficient use of existing assets, be they transmission, generation or demand . Any view of encouraging efficiency (in a technical sense) in making use of the existing grid might well include signals to encourage all users to reduce and flatten their load profile and so make best use of existing transmission and generation capability and reducing the need for further grid investment..
26	Do you agree with the proposal to apply the residual charge to: a) generators and direct-connect major users; b) distributors, except where they opt out from the charge; and c) retailers, were distributors elect to opt out from the charge? (Refer Para 5.6.78, p104)	We are in particular concerned about the potential reaction of generators to RCPI charges in their market offers and note the view of NZIER (paragraph 120, p 33) that "*The proposal to raise the residual revenue on the basis of RCPD and RCPI needs further consideration. The potential for dynamic efficiency gains in investment decision making hinge to a large extent on the ultimate incidence of these residual charges*."
27	Do you agree with the proposal that distributors may opt out from the residual charge: a) to the extent that they do not benefit from offering interruptible load on the wholesale electricity market; and b) provided they consult with retailers that may be affected before they opt out? (Refer Para 5.6.78, p104)	This proposal may have some unintended consequences where connection locations and/or GXPs are presently shared between distributors and large wholesale customers. For example, If distributors opt out, it may introduce significant complexity in the sharing the costs with retailers of connection assets at a location.
28	Do you consider that the proposed RCPD/RCPI charge, designed to encourage efficient avoidance of peak regional use of the grid, with half of the residual revenue recovered from load and	The current RCPD charge we believe does encourage efficient avoidance of peak regional use of the grid. There may well be issues with the RCPD signal being inadequately seen by many retail and small business customers, but that is a separate issue. It should be remembered that there are power losses

Question		response
	half from generators, would best complement a beneficiaries-pay charge that calculates charges every trading period using the SPD model? Explain your response. (Refer Para 5.6.92, p107)	through use of the grid that are significantly more in cost than the claimed benefits of the proposed TPM, and signals that encourage greater use of the grid will have an economic cost in terms of power loss that should be taken into account. Our comments in question 23 make it clear that we do not consider that SPD charging has a place in recovering the cost of sunk assets.
29	Do you agree that the RCPD/RCPI charge would best meet the principles for an alternative charging option of: a) minimising the distortion in use of the transmission grid resulting from the imposition of charges; and b) Ensuring the costs of providing the transmission grid, as approved by the Commerce Commission, are fully recovered so future investment is not stifled by concerns by investors that they will not receive a return on their approved investment? Explain your response. (Refer Para 5.6.92, p107)	We are not persuaded by the proposal that the proposed RCPD/RCPI charge is materially better than the present RCPD charge. The recent major investments (particularly NIGUP) and the SPD analysis that incorporated them seem to demonstrate that with hindsight some may well not be needed for some time in the future if ever. The previous/current paradigm of ever increasing demand on the grid and hence the ongoing need for expansion looks more uncertain now and consideration of asset write-down we believe should be part of Regulators' future thinking.
30	Do you agree that the Authority's preferred option for the residual charge should be an RCPD/RCPI charge designed to encourage efficient avoidance of peak regional use of the grid? Explain your response. (Refer Para 5.6.92, p107)	See our comments in questions above.
31	What are your views about amending the existing prudent discount policy to provide that it: a) applies to disconnection of load as a result of investment in generation where this would not be privately beneficial in the absence of transmission charges; and b) May apply for the expected life of the asset to which the prudent discount applies? Explain your response.	These proposals seem reasonable. In particular, it seems arbitrary to have the life of a PDP at 15 years as at present, and a more appropriate solution as proposed would be to have the length of a PDP to coincide with an agreed asset life.

	Question	response
	(Refer Para 5.6.105, p110)	
32	Do you agree with the assessment of the economic costs and benefits of the Authority's TPM proposal versus the counterfactual? Explain your answer. (Refer Para 5.7.26, p114)	No. CHH agrees with NZIER's overall view (p iv) that "*We have difficulty accepting that the scale and scope of the intended outcomes, the net benefits, can be realised and we regard the EA cost benefit analysis as illustrative rather than predictive*." • While of course the Authority looks at the cost/benefit equation from a New Zealand Inc point of view, we at CHH have attempted to understand the materiality of the proposal by putting the cost benefit in our own context using the Authority's chosen efficiency improvement parameter and hence unit price reduction of $0.12/MWh. This indicates a possible annual saving of around $60K on our present annual cost of transmission services of around $6.5M i.e. less than 1% saving. • The CBA includes as a significant part of the savings[4], improvements in future investment. It seems to us that taking into account the recent major transmission investments and the emerging future demand, that any potential savings in that area are likely to be many years into the future. • With the very significant increase in the share of transmission charges going to generators, it is very unclear how much more of this will be passed on to consumers in the form of increased spot prices or avoidance of SPD benefit charges. Since effectively all generators will have transmission charges rather than just the South Island generators as at present, there is a risk that a greater percentage of the generator charges that are presently passed on (i.e. HVDC charges) will be passed on immediately. • The proposed SPD and RCPI methodology appears to provide opportunities for generators to structure their bids to minimise their exposure to both of these charges. Of course at least some consumers have the ability to structure their demand to minimise RCPD charges, but it seems to us that generators have far more scope in general than consumers under the proposal to avoid charges. • Introduction of volatility into transmission charges on an ex post basis could well lead to some form of risk premium being factored in to generator bids and retailer margins. • The points above can only lead in our view to downside to the estimated savings which are already

[4] EA cost benefit analysis of TPM proposal Appendix F Table 6 and TPM proposal sections 4.4.9 to 4.4.11

Question		response
		minimal. We have not identified any immediate or near term bankable upside aspects of significance. • We believe therefore that any successful and generally acceptable change to transmission pricing methodology must be accompanied with an analysis of benefit to consumers that is much more robust than the present proposal. We have reviewed the CBA and can only see downside to the assessment as elaborated on in the above comments and so consider that this proposal is not justified by the likely savings.
33	Do you agree with the assessment of the costs and benefits of the TPAG majority proposal against the counterfactual? Explain your answer. (Refer Para 5.7.26, p114)	No comment.
34	Do you agree that the Authority's TPM proposal meets the Authority's objective? Explain your answer. (Refer Para 5.8.6, p117)	No. CHH agrees in general with the NZIER's overall view Page iv • *"The EA's empirical analysis of costs and benefits is at best illustrative and leaves us unconvinced that the scale and scope of the purported net benefits will be realised.* • *We also have concern that, if applied as is, the SPD approach will be unable to avoid precipitating material unintended outcomes that would likely result in a transmission pricing environment that is worse than the status quo. We suggest that the EA reconsider the SPD methodology as a whole and give attention to the issues that we describe in our assessment. "*
		<u>Chapter 6 Evaluation of alternative means of achieving the objectives</u>
35	What comments do you have about the Authority's evaluation of alternative market-based and market-like approaches for the recovery of transmission costs? (Refer Para 6.3.61, p133)	No comment
36	What comments do you have about the Authority's acceptance of the TPAG's evaluation of alternative exacerbators pay approaches for the recovery of	No comment

	Question	response
	network reactive support costs? (Refer Para 6.4.3, p134)	
37	Do you agree with the Authority's assessment and conclusions about alternative beneficiaries pay options for establishing transmission charges to recover HVDC and interconnection costs? Please give reasons for your views. (Refer Para 6.5.44, p143)	No comment
		<u>Chapter 7 Proposed guidelines for Transpower</u>
38	Do you consider that the draft guidelines provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option? Explain your answer. (Refer Para 7.8.2, p154)	No because the proposed guidelines we don't think will give effect to the benefits the EA have assumed in the proposal. Any new guidelines developed will need sufficient detail that will leave no room for misunderstanding by market participants or Transpower as to how they should be developed as a methodology.
39	Do you have any suggestions for amendments to the draft guidelines to ensure that they provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option? (Refer Para 7.8.2, p154)	No views because the regime needs re-assessing before guidelines can be drafted.
		<u>Chapter 8 Draft process for development and approval of TPM</u>
40	Do you agree with the Authority's proposed process that Transpower should follow in developing the TPM? Explain your answer. (Refer Para 8.2.7, p156)	Seems reasonable.
41	Do you agree that the Authority does not need to require Transpower to propose how costs related to revenue not subject to regulatory review by the Authority or the Commerce Commission would be determined and allocated? Explain your answer. (Refer Para 8.2.7, p156-157)	Agree.
42	Do you have any suggestions for amendments to the Authority's proposed process that	No.

Question		response
	Transpowershould follow in its development of the TPM? (Refer Para 8.2.7, p156-157)	
43	Do you have any comments about the Authority's proposal that Transpower should propose a timeframe to the Authority that would achieve the Authority's objective of having the amended TPM in place in time for the April 2015 pricing year? (Refer Para 8.2.7, p156-157)	As well as proposing a plan to have invoices from 1st April 2015 based on a new TPM, we suggest Transpower advises the EA of: • The cost to achieve a 1st April 2015 deadline; and • The alternative cost if implementation were delayed to 1st April 2016 or later... If there was a material decrease in implementation costs with a delay, then the EA could weigh the savings in implementation costs against forgoing benefits in deciding optimal timing. With flat forecast demand there will be minimal new large investments proposed for approval by Transpower over the next few years, hence the benefits of the proposal in terms of improved investment decision making will be small and a delay may be optimal.
44	Do you agree with the Authority's proposal to decide on the consultation period after the proposed TPM has been received from Transpower? (Refer Para 8.3.3, p158)	Yes.