Powerco Limited

CORPORATE OFFICE
84 Liardet Street
Private Bag 2061
New Plymouth
T 0800 769 372
F +64 6 758 6818
www.powerco.co.nz

1 March 2013

Submissions
Electricity Authority
PO Box 10041
WELLINGTON 6143

POWERCO

Dear Sir/Madam

Re: Transmission Pricing Methodology: issues and proposal

This is Powerco Limited's submission on the Electricity Authority's (EA's) consultation paper *Transmission Pricing Methodology: issues and proposal* (TPM proposal). Thank you for the opportunity to comment on this proposal.

Powerco has reviewed and supports the submission made by the Electricity Networks Association (ENA).

We appreciate that designing a transmission pricing methodology is a complex task with no single "correct" solution, as evidenced by New Zealand's recent experience. The TPM has been under almost review since 2004. There were two iterations prior to the introduction of the current methodology in 2008 and, subsequent to this, there have been reviews by the former Electricity Commission's Transmission Pricing Technical Group (TPTG) and the EA's Transmission Pricing Advisory Group (TPAG). There was also a separate independent review sponsored by the CEOs' Group. The EA has now developed an original reform proposal of a type not considered anywhere else in the world.

The EA has proposed fundamental changes to the current transmission pricing methodology (TPM), the most substantial of which involves incorporating the HVDC revenue into the interconnection (IC) revenue and recovering part of this combined revenue pool by undertaking "but for" solves of the schedule-price-dispatch (SPD) algorithm used to determine prices in the wholesale electricity market, but only for transmission assets of more than $2million that have been commissioned and added to Transpower's regulated asset base (RAB) since 28 May 2004, plus Pole 2 of the HVDC link. The differences between the SPD prices with and without each individual asset are intended to represent the benefits of each asset to offtake and generation customers during each half hour trading period. If this "SPD method" were adopted, these differences would be used as an allocator of part of the combined IC and HVDC revenue pool. The Authority has indicated that the SPD-based charges would be determined monthly[1].

[1] Verbal advice from John Rampton at the Authority's 7 February 2013 TPM Question and Answer session.

Other proposed changes include:

- the methodology used to rebate loss and constraint excess (and, in future, FTR revenue) to transmission customers would be incorporated into the TPM and reduce the net transmission revenue to be recovered accordingly;
- the balance of the IC and HVDC revenue not recovered by the SPD method would be split 50:50 and recovered from offtake and generators by way of regional coincident peak demand (RCPD) and regional coincident peak injection (RCPI) charges;
- the introduction of a new kVar charge to recover the cost of grid-located static reactive support assets;
- some modifications to the prudent discount arrangements;
- some changes that affect connection charges.

Consistent with the ENA submission, we support those elements of the TPM proposal that we believe have been clearly justified, specifically the kVar charge and the extension of the permitted term of a prudent discount agreement. However, we do not support, in its current proposed form, the introduction of the major element of the proposal, the SPD method, because we do not believe it has been adequately justified.

Cost benefit analysis of the SPD method

The Authority's cost benefit analysis of the SPD method is driven by two purported benefits:

- an improvement in dynamic efficiency (mid-point PV $171.8m);
- a reduction in the cost of disputes related to the TPM (mid-point PV $36.5m).

The following is the assumed mechanism that would achieve improvements in dynamic efficiency:

- the SPD method will identify the beneficiaries of grid investments more accurately and this will encourage the deemed beneficiaries to collect more information relating to grid investment proposals and engage to a greater degree with the grid capital expenditure decision-making processes;
- because of this increased information and engagement, the Commission's capital expenditure approval decisions will be 3 per cent more efficient. (The 3 per cent figure appears to be arbitrarily assumed.)

In our view, this is a rather tenuous mechanism. The TPM proposal, if implemented, would not change the administrative processes that apply to transmission capital expenditure. In particular, the Investment Test would not be modified in any way. We also note that, for most offtake customers, total energy costs are no more than a few per cent of their total costs and transmission is less than 10 per cent of total energy costs, so a change in transmission charges would not provide a sufficiently material incentive for them to engage more directly with the grid investment decision-making processes. This may not be the case for some very large offtake customers and generators, but, even if some larger transmission customers did engage to a greater degree than currently, we do not believe that such activity would be very likely to result in different capital expenditure approval outcomes, because the administrative requirements that must be applied, particularly the Investment Test, would not have changed. Hence, in our view, the most likely effect on dynamic efficiency of the mechanism described above is zero.

Further, the Authority's analysis appears to be flawed insofar as it fails to account for the negative effect of creating a variable IC charge that bears no relation to the cost of transmission. The SPD method will purposely create a highly variable and unpredictable IC charge for assets of more than $2million that have already been commissioned (since

May 2004) and which are therefore sunk. The cost of using these assets is effectively zero and, in any event, does not vary from trading period to trading period, so, if there is a consumption response to this charge, the economic impact will be negative. The Authority's cost-benefit analysis has not considered the effect of this distortion, but it should, as the present value of the cost could easily be tens of millions of dollars.

The SPD-based IC charge also does not pretend to reflect the long run marginal cost of new investment in the grid, so there will be no price signal promoting dynamic efficiency. The only way in which dynamic efficiency might be promoted is the administrative mechanism that the Authority has suggested, which we do not consider to be particularly credible.

Finally, we do not believe the SPD method, as defined by the Authority, would be likely to achieve a reduction in the cost of disputes relating to the TPM. In fact, the TPM proposal expands the scope for possible disputes. For example, by creating a distinction between assets commissioned before and after 28 May 2004, and treating these asset classes differently, the Authority will incentivise some customers to oppose the replacement and refurbishment of particular assets and others to support such action. Also, as the solution of "but for asset A" plus "but for asset B" plus "but for asset C" will not necessarily equal the solution of "but for A+B+C" we would expect to see many disputes about the definitions of assets and their treatment by the SPD method. Another example of where the scope for disputes would be increased is when a $2million+ asset that forms part of a group of assets that work together, and were commissioned before 28 May 2004, is replaced or upgraded. It is not clear whether such an investment would change the status of the whole group of assets to SPD method assets or if only the replaced or upgraded asset would become subject to the SPD method.

Degree to which the SPD method is consistent with "beneficiary pays"

The Authority has presented the SPD method as a "beneficiary pays" allocation method, but this is only partly true. Solving SPD with and without a particular asset will reveal the "spot benefit" of a particular asset during a given trading period. However, if the asset concerned were not actually present, the behaviour of generators and, to some degree, load would be different because of that fact and, consequently, the prices produced by SPD would also be different. Also, an asset that does not provide a benefit according to the SPD method, because solutions of SPD with and without the asset do not show a change in price, may still provide a benefit in the form of an insurance or option value if the asset would be used (and hence unserved load avoided) if demand were to increase by a small amount during a given trading period. This insurance value derives from the fact that transmission assets cannot be conjured up at short notice to meet changes in demand; as John Milton said: "They also serve who only stand and wait".

Durability of the SPD method

The Authority claims that the SPD method will be more durable than the current TPM or other alternative allocation methods. We are unconvinced by this claim. By changing the allocation of transmission costs, the SPD method would change the industry participants that have a reason to lobby for change, but not their incentive to do so. The fact of the proposal itself conveys a strong signal that the Authority will reward sustained lobbying on this topic, and thus undermines the very durability claimed for the proposal.

Summary of our view of the SPD method

In summary, our view is that the SPD method would be likely to create a net national economic cost if applied to the IC charge and we therefore do not support its use as an allocator of the IC charge. The most economic IC charge would be one that achieves non distortionary recovery of sunk costs and also signals the long run marginal cost (LRMC) of new investment where demand is increasing. A postage stamp IC charge of the sort currently applied comes as close as possible to achieving the non distortionary sunk cost recovery objective and the regional coincident peak demand (RCPD) allocation method moves some way towards signalling the LRMC of new investment in the Upper North and Upper South regions, albeit imperfectly. There is clearly potential scope to improve the signalling of LRMC, but the SPD method does not achieve this. We also note that the SPD method is not fully consistent with "beneficiary pays" and there is no good reason to believe it would be more durable than any other allocation method.

Proposal to allow distributors to opt out of the residual charge

The proposal to allow distributors to opt out of the residual charge is an important issue for Powerco and other distribution businesses. However, we consider that the Authority needs to provide more detail about the legal arrangements that would apply and the precise rationale for the proposal before we could agree or otherwise with the concept. If retailers were the counterparty for the residual charge, this would have major implications for the legal agreements that relate to the physical and notional embedding of generation assets. There is also the question of load control, given that the RCPD charge aims to flatten usage during regional peaks, at least in the Upper North and Upper South regions. At present, distributors carry out this function very well using conventional load control. It is not clear how well retailers would respond to the RCPD signal to manage GXP peaks, as there are multiple retailers at each node and they are constantly changing and any benefit from transmission cost savings would flow to all retailers.

The former Electricity Commission undertook a detailed review before deciding that distributors and direct connects should be Transpower's legal counterparties at GXPs and the offtake parties subject to transmission charges. Lower administrative costs and greater stability were factors that were considered at the time. We suggest that the Authority review the Commission's original decision and identify why the conclusions reached then no longer apply.

Relationship between the default price-quality path and the proposed residual charge

A critical issue for distributors, that is related to the opt out proposal discussed above, is how the residual charge would be able to be recovered, given the requirements of the default price-quality path (DPP). The residual charge will be volatile by design and the DPP currently requires the transmission charge for the following pricing year to be certain. As the DPP does not tolerate volatility in the transmission charge to be recovered by a distributor, if there were no change to the regulatory arrangements, all distributors would be forced to "opt out", so the option would exist in name only.

Possible solutions to the incompatibility of the residual charge with the DPP would be to:

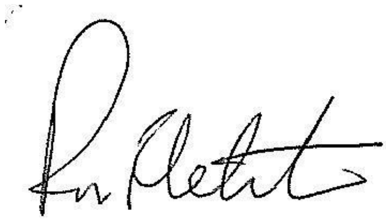
- include any volatility in the residual IC charge in a per MWh component of this charge, and levy this on retailers, thereby providing for the RCPD component of the charge to be stable within the financial year; or
- have the Commission re-design the DPP so that any volatility in the RCPD component of this charge was accommodated.

The problem with the second option is that it could complicate the DPP in ways that might lead to unintended breaches by distributors.

There is no indication that the Authority has investigated the relationship between the residual charge and the DPP and how they could be made compatible with each other. We strongly recommend that it do so before progressing this option any further.

Our detailed responses to the consultation questions are appended below.

Yours sincerely



Richard Fletcher
General Manager Regulation and Government Relations

Appendix: Consultation questions

Question	Powerco Response
1. What are your views about the materiality of changes in circumstances since the current TPM came into force in 2008?	We do not believe there has been a material change in circumstances since the current TPM came into force on 1 April 2008. The major investments referred to in paragraph 2.39(a) of the discussion document were already well in train when the current TPM was approved by the former Electricity Commission. The Electricity Authority has replaced the Electricity Commission and grid investments are now approved by the Commerce Commission, but this has not materially changed the way in which grid investments are approved – they are still subject to an Investment Test in the Capital Expenditure Input Methodologies that is comparable with the Grid Investment Test contained in the former Electricity Governance Rules 2003 (EGRs) and the provisions of the Electricity Industry Participation Code 2010 (the Code) that relate to transmission are largely unchanged from those that applied under the EGRs. It is true that the computational power of computers has increased, but we do not believe that this, of itself, represents a material change that would justify a review of the TPM.
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.	The TPM proposal appears to envisage that retailers would become designated transmission customers, which would require either extensive amendments to the Benchmark Agreement or the development of a new retailer-specific Benchmark Agreement, if the current regulatory arrangement, with a Code-defined contractual framework, is to be retained. The proposed changes to the treatment of the loss and constraint excess would also require amendments to the Benchmark Agreement. The Benchmark Agreement can only be amended by way of the review process set out in clauses 12.28 to 12.34 of Part 12 of the Code. Similarly, the TPM proposal includes amendments to the power factor requirements in the Connection Code and the Connection Code can only be amended in accordance with the process specified in clauses 12.18 to 12.26 of Part 12 of the Code. Also, the proposal to introduce a variable SPD-based charge, which would in turn also greatly increase the variability of the residual RCPD and RCPI-based charges, would have significant implications for the default price-quality path (DPP) regulation applied to non-exempt electricity distribution businesses (EDBs) if they do not opt out of this charge. The Authority will need to work with the Commerce Commission to resolve this problem as part of the development of a new TPM. It is possible that amendments to the Code could achieve the new relationships envisaged between Transpower and retailers, but the Code amendments required would be substantial and consequential amendments would still be required to the Benchmark Agreement. As the proposed TPM will not be able to be implemented until these other processes are completed, it would be

Question	Powerco Response
	appropriate for the Authority to outline how it intends to complete these other essential exercises as part of its process for developing and approving a new TPM.
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.	Yes, we believe the arrangements relating to the recovery of connection costs are generally efficient. However, we note that the discussion in the consultation document does not explain that the requirement in the Benchmark Agreement that the Grid Reliability Standards be applied means that most connection asset investments are subject to the economic limb of the Investment Test (as connection assets are mostly outside the Core Grid). We do not believe this causes any practical difficulties, but it does mean that the ability of offtake customers and Transpower to negotiate price-quality trade-offs is constrained.
4. What comments do you have about the potential for inefficient outcomes to arise from incentives to shift connection costs into the interconnection charge?	As noted in the discussion document, there are a few instances where a new connection asset investment could potentially create a continuous loop of nodes and links, and thereby convert some pre-existing connection assets to interconnection assets. However, as the discussion paper also notes, in practice this potential problem has been able to be resolved within the current framework. Consequently, we do not believe any amendments to the TPM are needed to resolve this issue.
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.	No. First, the advice we have received from Transpower is that, contrary to the statement in paragraph 4.2.22 of the discussion document, the "backstop" provision in clause 40.2(f)(2) of the Benchmark Agreement, which enables Transpower to request that the Commerce Commission request that Transpower include a connection asset investment in a capital expenditure investment proposal to the Commission, if agreement has not been reached with the customer within six months, has never actually been used. Two probable reasons for the backstop provision not to be used are that: • it is more uncertain for customers, as it requires both the Commission and Transpower to agree to include the asset concerned in a capital expenditure proposal; and • it also removes the customer from any input to the detail of the investment. Further, recovering connection asset costs under the TPM does not result in any under-recovery or inefficiency relative to recovery under a customer investment contract (CIC). The amounts recovered by both methods should be NPV neutral over the full lives of the assets. The difference relates to cash flow solely, as a return on and of capital is recovered more quickly under a CIC. The discussion in the consultation document seems to misunderstand how the asset return is recovered on

Question	Powerco Response
	assets in the TPM connection pool. Paragraph 4.2.21 states: “Under an investment proposal the asset investment costs are recovered through a connection charge, but this charge may fail to allocate the full investment costs to the connection party that derives a private benefit from the investment. This is because connection assets are valued with reference to a standard building block asset valuation register (in which the asset values have not been reviewed for some time).” The focus on the fact that the replacement cost valuation register is not current is inappropriate. Assets go into the connection pool at book value and a full WACC return is recovered on that (depreciated) book value. The charges for individual assets are then allocated according to replacement cost. Hence, because replacement cost is purely an allocator, updating the replacement cost schedule would not change the connection charges (unless the replacement costs of some assets have moved relative to one another, in which case some customers would gain and others lose, with the net effect across the pool being neutral). The connection cost allocation method used by the TPM in effect “under-recovers” the asset return on newer assets and “over-recovers” the asset return on older assets, with the net effect being NPV neutral over the full lives of the assets. The original justification for this approach was to remove the “saw tooth” effect on charges that would otherwise occur when assets were replaced like-for-like and discourage customers from opposing the replacement of assets. In summary, we do not believe the current arrangements create the potential for an inefficient outcome or that there are any meaningful incentives to “hold out” in order to get connection assets included in a capital expenditure proposal from Transpower to the Commerce Commission. We also note that no such instances have occurred to date.
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.	No.
7. What comments do you have about the Authority’s analysis of the private benefits deriving from the HDVC link?	We accept (as originally identified by TPAG) that the current HVDC charge is likely to result in some net inefficiency in generation investment by, at the margin, discouraging some efficient investment in the South Island and encouraging some inefficient investment in the North Island. We also accept that the HAMI allocation method may discourage some peaking generation in the South Island and this creates a small net cost.

Question	Powerco Response
	We agree with the Authority's findings that the South Island generators are not the sole beneficiaries of the link and that North Island load benefits substantially.
8. What comments do you have about the consequences of the material differences between private benefits from the HVDC link and HVDC charges?	The fact that the South Island generators are not the sole beneficiaries of the link and that North Island load benefits substantially is the main reason that the HVDC charge has been contentious for many years and may justify a different allocation of HVDC costs on equity grounds. However, we do not agree with the Authority's view that changes to the incentive to lobby will result in different HVDC investment outcomes in the future as there is no proposed change to the administrative basis of investment decision making, in particular the Investment Test. This view is supported by the fact that the current HVDC charge provides a strong incentive for the South Island generators to engage in lobbying related to HVDC investment, but this does not seem to have had any noticeable effect on the decisions by the regulators to approve investments in the HVDC.
9. What comments do you have about the Authority's analysis of the costs of inefficient generation investment resulting from the HVDC charge?	See the response to question 7 above.
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?	We agree (see the response to question 7 above).
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.	See the response to questions 7 and 8 above.
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?	We do not place much store by the dollar values estimated. With respect to the suggested inefficiency of transmission investment relative to a beneficiaries pay charge, we suggest this figure should be zero, as the administrative arrangements governing grid investment (in particular, the Investment Test) will not change and we doubt that the incentive to provide additional information to the Commission and to lobby it (which is the mechanism the Authority believes would achieve the greater efficiency) is likely to result in different investment approval outcomes. The costs related to generation investment, demand-side investment and demand response could be ameliorated by small modifications to the current pricing

Question	Powerco Response
	methodology.
13. What comments do you have about the Authority's analysis of the problems with interconnection charges?	We do not agree with the suggestion in paragraph 4.4.6(c) of the consultation paper that the interconnection charge is the subject of ongoing debate and lobbying because of a mismatch between the charge and the private benefits derived from interconnection. In fact, our understanding is that there have been very few complaints or disputes about the interconnection charge since the current TPM came into force and that the interconnection charge is generally well understood and accepted by industry participants. Hence, we would suggest that the Authority's problem analysis is deficient in relation to the charge.
14. Do you consider that there are any other problems with the interconnection charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the problem.	No.
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?	We agree. However, we note that the statement in paragraph 4.6.4 that two new prudent discount agreements have been entered into since the current TPM was introduced in 2008 is incorrect. In fact, only one new prudent discount agreement has been entered into, between Transpower, Vector and Mighty River Power with respect to generation at Southdown – this replaced a notional embedding agreement that had expired. With respect to the Authority's comment that it might have expected some uneconomic bypass to have occurred if the bar is set high for prudent discount agreements, we note that there are few commercially attractive opportunities to bypass the grid apart from those that are already subject to pre-existing notional embedding agreements.
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?	We do not oppose the concept, but we think the Authority should be made aware that achieving this change with be more difficult than it seems to anticipate, because the methodology used to rebate the loss and constraint excess does not exactly mirror the TPM.
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.	No to both questions 17 and 18. The discussion below explains why and highlights, in particular, the Authority's apparent misunderstanding of the role of the replacement cost schedule. The schedule is purely an allocator, so updating it will have no effect on the

Question	Powerco Response
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.	connection revenue recovered. The advice we have received from Transpower is that, contrary to the statement in paragraph 4.2.22 of the discussion document, the "backstop" provision in clause 40.2(f)(2) of the Benchmark Agreement, which enables Transpower to request that the Commerce Commission request that Transpower include a connection asset investment in a capital expenditure investment proposal (grid upgrade plan) to the Commission, if agreement has not been reached with the customer within six months, has never actually been used. Two probable reasons for the backstop provision not to be used is that it is more uncertain for customers, as it requires both the Commission and Transpower to agree to include the asset concerned in a capital expenditure proposal, and it also removes the customer from any input to the detail of the investment. Recovering connection asset costs under the TPM does not result in any under-recovery or inefficiency relative to recovery under a customer investment contract (CIC). The amounts recovered by both methods should be NPV neutral over the full lives of the assets. The difference relates to cash flow solely, as a return on and of capital is recovered more quickly under a CIC. The discussion in the consultation document seems to misunderstand how the asset return is recovered on assets in the TPM connection pool. Paragraph 4.2.21 states: "Under an investment proposal the asset investment costs are recovered through a connection charge, but this charge may fail to allocate the full investment costs to the connection party that derives a private benefit from the investment. This is because connection assets are valued with reference to a standard building block asset valuation register (in which the asset values have not been reviewed for some time)." The focus on the fact that the replacement cost valuation register is not current is inappropriate. Assets go into the connection pool at book value and a full WACC return is recovered on that (depreciated) book value. The charges for individual assets are then allocated according to replacement cost. Hence, because replacement cost is purely an allocator, updating the replacement cost schedule would not change the connection charges (unless the replacement costs of some assets have moved relative to one another, in which case some customers would gain and others lose, with the net effect across the pool being neutral). The connection cost allocation method used by the TPM in effect "under-recovers" the asset return on newer assets and "over-recovers" the asset return on older assets, with the net effect being NPV neutral over the full lives of the assets. The original justification for this approach was to remove the "saw tooth" effect on charges that would otherwise occur when assets were replaced like-for-like and discourage customers from

Question	Powerco Response
	opposing the replacement of assets. The method used recovers a full WACC return on the TPM connection assets in total, so there is no unrecovered balance transferred to the interconnection pool and recovered via the IC charge. We also note that the Authority seems to be under the misapprehension that all connection asset replacements are done pursuant to customer investment contracts (CICs). In fact, many "like for like" connection asset replacements are not done under CICs and the replaced assets consequently remain in the connection asset pool. We understand that Transpower considers that this approach to replacing assets does not contravene the requirement in clause 36.1(a)(2) of the Benchmark Agreement that it "not change the connection assets" (other than in accordance with the Agreement), as it believes that "like for like" replacement does not change the assets. In summary, we do not believe the current arrangements create the potential for an inefficient outcome or that there are any meaningful incentives to "hold out" in order to get connection assets included in a capital expenditure proposal from Transpower to the Commerce Commission. We also note that no such instances have occurred to date. Hence, we recommend that the proposed changes not be made, as they are unnecessary.
19. What comments do you have about the Authority's assessment and conclusions about a kVar charge to recover static reactive support costs?	We agree with the Authority's assessment and conclusion regarding a kVar charge to recover static reactive support costs.
20. Do you support: 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?	Yes.
b. setting a minimum power factor of 0.95 lagging in the Connection Code for all regions?	Yes. We note that this amending the Connection Code can only be done by way of a review carried out in accordance with clauses 12.18 to 12.26 of Part 12 if the Electricity Industry Participation Code (Code).
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.	No.

Question	Powerco Response
22. What comments do you have about the Authority's assessment and conclusion about charging options for dynamic reactive support?	Paragraph 4.5.8 of the discussion document notes that the cost of procuring dynamic reactive support is currently recovered under Part 8 of the Code. However, somewhat confusingly, paragraph 4.5.9 then cites a static var compensator (SVC) as an example of dynamic reactive support capability and refers to its cost being recovered under the interconnection charge. We would have thought that a SVC provides static reactive support. We support the Authority's kVar charge for static reactive support assets but recommend that the current Part 8 arrangements remain in place to enable the System Operator to procure dynamic voltage support when necessary and recover part of the cost using the mechanisms in clause 8.67 of the Code..
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?	As an initial observation, we do not accept the Authority's suggestion that the current interconnection charge is contentious. The charge is generally well understood and accepted by the industry and there have been very few disputes about the charge. We also think the Authority's claim that the SPD method is a "beneficiary pays" allocation method is only partly true. Solving SPD with and without a particular asset will reveal the "spot benefit" of a particular asset during a given trading period. However, if the asset concerned were not actually present, the behaviour of generators and, to some degree, load would be different because of that fact and, consequently, the prices produced by SPD would also be different. Also, an asset that does not provide a benefit according to the SPD method, because solutions of SPD with and without the asset do not show a change in price, may still provide a benefit in the form of an insurance or option value if the asset would be used (and hence unserved load avoided) if demand were to increase by a small amount during a given trading period. This insurance value derives from the fact that transmission assets cannot be conjured up at short notice to meet changes in demand; as John Milton said: "They also serve who only stand and wait". The Authority's cost benefit analysis of the SPD method is driven by two purported benefits: • an improvement in dynamic efficiency (PV $171.8m); • a reduction in the cost of disputes related to the TPM (PV $36.5m). The following is the assumed mechanism that would achieve improvements in dynamic efficiency: • the SPD method will identify the beneficiaries of grid investments more accurately and this will encourage greater lobbying of the Commerce Commission by the deemed beneficiaries; • as a result of this increased lobbying, the Commission's capital expenditure approval decisions will be 3 per cent more efficient. (The 3 per cent figure appears to be arbitrarily assumed.) In our view, this is a rather tenuous mechanism. As we

Question	Powerco Response
	do not consider the Commission to be susceptible to lobbying, and the proposal does not alter the administrative arrangements that apply to the approval of transmission capital expenditures, we believe the most likely effect on dynamic efficiency from this mechanism is zero. We also note that, for most offtake customers, total energy costs are no more than a few per cent of their total costs and transmission is less than 10 per cent of total energy costs, so a change in transmission charges provides very little incentive to engage in lobbying activity. This may not be the case for some very large offtake customers and generators, but, again, we do not believe the Commerce Commission is susceptible to lobbying. Further, the Authority's analysis appears to be fatally flawed insofar as it fails to account for the negative effect of creating a variable IC charge that bears no relation to the cost of transmission. The SPD method will purposely create a highly variable and unpredictable IC charge for assets of more than $2million that have already been commissioned (since May 2004) and which are therefore sunk. The cost of using these assets is effectively zero and, in any event, does not vary from trading period to trading period, so, if there is a consumption response to this charge, the economic impact will be negative. The Authority's cost-benefit analysis has not considered the effect of this distortion, but it should, as the present value of the cost could easily be tens of millions of dollars. The SPD-based IC charge also does not pretend to reflect the long run marginal cost of new investment in the grid, so there will be no price signal promoting dynamic efficiency. The only way in which dynamic efficiency might be promoted is the administrative mechanism that the Authority has suggested, which we do not consider credible. Further, we do not believe the SPD method, as defined by the Authority, would be likely to achieve a reduction in the cost of disputes relating to the TPM. In fact, the TPM proposal expands the scope for possible disputes. For example, by creating a distinction between assets commissioned before and after 28 May 2004, and treating these asset classes differently, the Authority will incentivise some customers to oppose the replacement and refurbishment of particular assets and others to support such action. Also, as the solution of "but for asset A" plus "but for asset B" plus "but for asset C" will not necessarily equal the solution of "but for A+B+C" we would expect to see many disputes about the definitions of assets and their treatment by the SPD method. Another example of where the scope for disputes would be increased is when a $2million+ asset that forms part of a group of assets that work together, and were commissioned before 28 may 2004, is replaced or upgraded. It is not clear whether such an investment would change the status of the whole group of assets to SPD method assets or only the replaced or upgraded asset would become an SPD method.

Question	Powerco Response
	With respect to the suggestion that productive efficiency would be promoted because calculation of the charge can be made contestable, we would observe that a simpler charging regime would not need a complex calculation arrangement in the first place. The amounts involved would also be trivial compared to the wider costs imposed by the TPM Proposal. We also do not accept the claimed durability of the SPD method. By changing the allocation of transmission costs, the SPD method would change the industry participants that have a reason to lobby for change, but not their incentive to do so. The fact of the proposal itself conveys a strong signal that the Authority will reward sustained lobbying on this topic, and thus undermines the very durability claimed for 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.	No, for the reasons set out in response to question 23 above.
25. Do you consider that there are beneficiaries-pay options that the Authority has not identified that are practicable, would deliver greater net benefits and would recover HVDC and interconnection costs? Explain your proposal.	Yes. We consider that the current allocation method would produce a higher net national benefit with respect to the interconnection charge, for the reasons set out in response to question 23 above. With respect to the HVDC charge, we accept the TPAG's conclusion that the current charge produces a small net national cost due to the discouragement of future economic generation investment in the South Island. We also accept that the Authority's estimates of the value of the HVDC link to the various market participants, set out in paragraph 4.3.9 of the discussion document, are very broadly correct. Consequently, if the Authority's prime objective is efficiency, it should roll the HVDC charge into the interconnection charge and recover the total costs using the current allocation method, as recommended by the TPAG. This would be superior to applying the half hourly SPD method every half hour because it would not produce any welfare reducing distortions to wholesale prices. As previously noted, the SPD method would also be an unreliable identifier of benefit as generators would have managed their hydro resources if HVDC assets had not actually existed this would significantly affect the price differential between the two islands. However, if the Authority wished to apply a beneficiary pays allocation for equity reasons it could split the allocation of the current HVDC revenue approximately 2:1 between the interconnection revenue pool and the HVDC revenue pool (based on the benefit estimates in paragraph 4.3.9 of the consultation paper) and continue to recover the reduced HVDC revenue from South Island generators as at present. This one-off beneficiary pays

Question	Powerco Response
	allocation would be superior to the half hourly SPD method for the reasons already noted above.
26. Do you agree with the proposal to apply the residual charge to: a. Generators;	We agree that, consistent with efficient tax theory, there is an argument for extending the interconnection charge (whether this be a residual charge or the whole interconnection charge) to include generators. However, we do not favour an RCPI-based charge for generators, because all generators would face the risk of being "caught" by an RCPI period during the winter and would factor this risk into their wholesale market offers. Given the low price elasticity of demand for electricity, the net result would be that the bulk of the RCPI charge would become, in effect, a per MWh charge borne by all load. Hence, if generators are to be charged, the charge should be per MWh. A per MWh charge would still affect generator offers and hence the wholesale energy price and ultimately be borne mostly by offtake customers. It is because the charge is ultimately borne by load that generators have not been charged interconnection charges in the past. The Authority may wish to review earlier work on this issue before making a final decision.
b. direct-connect major users;	Yes.
c. distributors, except where they opt out from the charge; and d. retailers, were distributors to elect to opt out from the charge?	See our response to question 27 below. We will need further information from the Authority, particularly about the legal arrangements and the relationship with the default price-quality path before we will be able to provide an informed response to these questions.
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?	This is an important question for Powerco and other distributors. However, we consider that the Authority needs to provide more detail about the legal arrangements that would apply and the precise rationale for the proposal before we could agree or otherwise. If retailers were the counterparty for the residual charge, this would have major implications for the legal agreements that relate to the physical and notional embedding of generation assets. There is also the question of load control, given that RCPD charge aims to flatten usage during regional peaks, at least in the Upper North and Upper South regions. At present, distributors carry out this function very well using conventional load control. It is not clear how well retailers would respond to the RCPD signal to manage GXP peaks, as there are multiple retailers at each node and they are constantly changing and any benefit from transmission cost savings would flow to all retailers. Another critical issue for distributors is how the residual charge would be able to be recovered, given the requirements of the default price-quality path (DPP). The residual charge will be volatile by design and the DPP currently requires the transmission charge for the

Question	Powerco Response
	following pricing year to be certain. As the DPP does not tolerate volatility in the transmission charge to be recovered by a distributor, if there were no change to the regulatory arrangements, all distributors would be forced to “opt out” so the option would exist in name only. Possible solutions to the incompatibility of the residual charge with the DPP would be to: • include any volatility in the residual IC charge in a MWh component of this charge, and levy this on retailers, and thereby provide for the RCPD component of the charge to be stable within the financial year; or • have the Commission re-design the DPP so that any volatility in the RCPD component of this charge is accommodated. The problem with the second option is that it could complicate the DPP in ways that might lead to unintended breaches by distributors. There is no indication that the Authority has investigated the relationship between the residual charge and the DPP and how they could be made compatible with each other. We strongly recommend that it do so before progressing this option any further. The former Electricity Commission undertook a detailed review before deciding that distributors and direct connects should be Transpower’s legal counterparties at GXPs and the offtake parties subject to transmission charges. Lower administrative costs and greater stability were factors that were considered at the time. We suggest that the Authority review the Commission’s original decision and identify why the conclusions reached then no longer apply. In summary, we recommend that the Authority: • investigate the relationship between the DPP and the proposed residual charge and how they could be made compatible with each other; • further develop the legal arrangements that would apply, particularly with respect to the physical and notional embedding of generation assets and load control arrangements; • review the former Electricity Commission’s decision that distributors and direct connects should be Transpower’s legal counterparties at GXPs and subject to transmission charges and identify why the Commission’s conclusions no longer apply; • consult again once this work has been completed.

Question	Powerco Response
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 half from generators, would best complement a beneficiaries-pay charge that calculates charges every trading period using the SPD model? Explain your response.	The RCPD charge is appropriate for offtake. The RCPD charge is now well understood by offtake customers and it does encourage some efficient demand response. However, it would seem to be almost inept to implement an RCPI charge with intention of discouraging peaking generators form injecting during regional peaks, as they must necessarily do so (albeit at a price that is attractive to them). As noted in response to question 26a, an RCPI charge would also inevitably mostly convert into a per MWh charge on all offtake customers consuming at the time. This is because all generators would face the risk of being "caught" by an RCPI period during the winter and would factor this risk into their wholesale market offers. Given the low price elasticity of demand for electricity, the net result would be that the bulk of the RCPI charge would become, in effect, a per MWh charge borne by all load. Hence, if generators are to be charged, we would favour a per MWh charge rather than an RCPI-based charge, although we recognise that the per MWh charge would also affect generator offer behaviour and hence wholesale prices, and mostly end up being borne by load. As we do not favour the SPD method we would see these allocators as applying to the whole interconnection revenue, not just the residual left after applying the SPD method.
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	Yes for the RCPD method applied to offtake customers. We do not favour the RCPI method for generators for the reasons set out in response to questions 26a and 28 above. The RCPD charge has the advantage of moving some way towards signalling the long run marginal cost of grid investment (albeit imprecisely) while retaining the main benefit of a postage stamp charge, which is the non-distortionary recovery of sunk costs (which comprise c\most of the grid costs).
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.	Yes. The RCPD method has been shown to be able to recover the balance of the full costs of providing the transmission grid not recovered by other charges.
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.	Yes, but, as noted above, we do not favour the use of the RCPI method. See the responses to questions 26a, 28 and 29 above for the rationale supporting our position.

Question	Powerco Response
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	On balance, we think this is inadvisable, as it would be very difficult to prove that a generation investment and consequent disconnection of load would be commercially viable due to the avoidance of transmission charges, but not otherwise. We would suggest that if any customers that wish to disconnect from the grid and generate to meet their own needs they should be allowed to do so, but prudent discount agreements based on the avoidance of such investment should not be permitted.
b. may apply for the expected life of the asset to which the prudent discount applies? Explain your response.	Yes, this is reasonable. The current limit of 15 years to the term of a prudent discount agreement does not accurately reflect the actual useful lives of the notional assets that support such agreements.
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.	No. The Authority's cost benefit analysis of the SPD method is driven by two purported benefits: • an improvement in dynamic efficiency (mid-point PV $171.8m); • a reduction in the cost of disputes related to the TPM (mid-point PV $36.5m). The following is the assumed mechanism that would achieve improvements in dynamic efficiency: • the SPD method will identify the beneficiaries of grid investments more accurately and this will encourage greater lobbying of the Commerce Commission by the deemed beneficiaries; • as a result of this increased lobbying, the Commission's capital expenditure approval decisions will be 3 per cent more efficient. (The 3 per cent figure appears to be arbitrarily assumed.) In our view, this is a rather tenuous mechanism. The TPM proposal, if implemented, would not change the administrative processes that apply to transmission capital expenditure. In particular, the Investment Test would not be modified in any way. We also note that, for most offtake customers, total energy costs are no more than a few per cent of their total costs and transmission is less than 10 per cent of total energy costs, so a change in transmission charges would not provide a sufficiently material incentive for them to engage more directly with the grid investment decision-making processes. This may not be the case for some very large offtake customers and generators, but, even if some larger transmission customers did engage to a greater degree than currently, we do not believe that such activity would be very likely to result in different capital expenditure approval outcomes, because the administrative requirements that must be applied, particularly the Investment Test, would not have changed. Hence, in our view, the most likely effect on dynamic efficiency of the mechanism described above is zero. Further, the Authority's analysis appears to be fatally

Question	Powerco Response
	flawed insofar as it fails to account for the negative effect of creating a variable IC charge that bears no relation to the cost of transmission. The SPD method will purposely create a highly variable and unpredictable IC charge for assets of more than $2million that have already been commissioned (since May 2004) and which are therefore sunk. The cost of using these assets is effectively zero and, in any event, does not vary from trading period to trading period, so, if there is a consumption response to this charge, the economic impact will be negative. The Authority's cost-benefit analysis has not considered the effect of this distortion, but it should, as the present value of the cost could easily be tens of millions of dollars. The SPD-based IC charge also does not pretend to reflect the long run marginal cost of new investment in the grid, so there will be no price signal promoting dynamic efficiency. The only way in which dynamic efficiency might be promoted is the administrative mechanism that the Authority has suggested, which we do not consider credible. Finally, we do not believe the SPD method, as defined by the Authority, would be likely to achieve a reduction in the cost of disputes relating to the TPM. In fact, the TPM proposal expands the scope for possible disputes. For example, by creating a distinction between assets commissioned before and after 28 May 2004, and treating these asset classes differently, the Authority will incentivise some customers to oppose the replacement and refurbishment of particular assets and others to support such action. Also, as the solution of "but for asset A" plus "but for asset B" plus "but for asset C" will not necessarily equal the solution of "but for A+B+C" we would expect to see many disputes about the definitions of assets and their treatment by the SPD method. Another example of where the scope for disputes would be increased is when a $2million+ asset that forms part of a group of assets that work together, and were commissioned before 28 may 2004, is replaced or upgraded. It is not clear whether such an investment would change the status of the whole group of assets to SPD method assets or only the replaced or upgraded asset would become an SPD method.
33. Do you agree with the assessment of the costs and benefits of the TPAG majority proposal against the counterfactual? Explain your answer.	We agree with the assessment of the costs and benefits of the TPAG majority proposal against the status quo, as the figures seem consistent with the TPAG's own analysis which we broadly support. As we consider that the net economic benefit of the Authority's SPD-based proposal would be negative if all costs were included, for the reasons set out in response to question 32 above, this would make the TPAG majority proposal the preferred approach.

Question	Powerco Response
34. Do you agree that the Authority's TPM proposal meets the Authority's objective for the TPM? Explain your answer.	No. For the reasons set out in response to question 32 above, we believe that the net national benefit of the Authority's TPM proposal would be negative if all costs were included. A net negative economic impact would be inconsistent with the Authority's objective of facilitating efficient investment in the electricity industry and efficient operation of the transmission grid, generation (including distributed generation), distribution grids and demand-side management.
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?	Long-term contracts (market option 1) are not a practicable method of recovering the costs of interconnection assets. This was demonstrated practically in New Zealand in the 1990s and early 2000s. However, they could be feasible in some limited circumstances for the HVDC link. In our view merchant investment in interconnection assets (market option 3) is not practicable because constraint rentals inevitably collapse once the asset is commissioned. Investment in HVDC links could theoretically be funded in this way but, in practice, most such ventures have ultimately proved to be not commercially viable.
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 network reactive support costs?	We agree.
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.	We do not have enough information to provide an informed view of the economic models approach. Based on the information we have previously seen, we would not agree that flow tracing is superior to the status quo. Otherwise we generally agree with Authority's comments on this method. The zonal postage stamp approach (sometimes call "licence plate") may have merit. We would need to see more detail to reach an informed conclusion.
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.	The guidelines appear adequate for the Authority's purpose, but note that Powerco disagrees with some major elements of the TPM Proposal and so would recommend that these guidelines not be adopted.
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?	See the response to question 38 above.

Question	Powerco Response
40. Do you agree with the Authority's proposed process that Transpower should follow in developing the TPM? Explain your answer.	At the very least the process needs to allow for the concurrent reviews of the Benchmark Agreement and the Connection Code, which will be required to enable retailers to have the status of designated transmission customers, the proposed method for rebating loss and constraint excess to be implemented and the proposed changes to the power factor provisions in the Connection Code to be amended, among other things. These reviews must be undertaken in accordance with clauses 12.28 to 12.34 of Part 12 the Code (for the Benchmark Agreement) and clauses 12.18 to 12.26 of Part 12 of the Code (for the Connection Code). It is possible that it may prove necessary to develop a new separate Benchmark Agreement for retailers to enable them to be counterparties to Transpower. Alternatively, amendments to the Code could achieve the new relationships envisaged between Transpower and retailers, but the Code amendments required would be substantial and consequential amendments would still be required to the Benchmark Agreement. The updated Benchmark Agreement (or Agreements), the revised Connection Code and any required amendments to the Electricity Industry Participation Code must come into force on the same date as the new TPM if all the regulatory arrangements relating to transmission pricing are to work effectively as a whole. As stated elsewhere in this submission, Powerco would prefer that the Authority undertake further work and consult again before promulgating new transmission pricing guidelines, specifically: • investigate the relationship between the DPP and the proposed residual charge and how they could be made compatible with each other; • further develop the legal arrangements that would apply, particularly with respect to the physical and notional embedding of generation assets and load control arrangements; • review the former Electricity Commission's decision that distributors and direct connects should be Transpower's legal counterparties at GXPs and subject to transmission charges and identify why the Commission's conclusions no longer apply; • consult again once this work has been completed.
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.	Yes, because investment approval is now the responsibility of the Commerce Commission and Transpower is subject to individual price-quality path regulation under Part 4 of the Commerce Act 1986.
42. Do you have any suggestions for amendments to the Authority's proposed process that Transpower should follow in its development of the TPM?	Yes, see the response to question 40 above.

Question	Powerco Response
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?	We suggest that the objective of having an amended TPM in place in time for it to be used to calculate prices for the 2015/16 pricing year is no longer feasible. It is already March 2013, the reviews of the Benchmark Agreement and Connection Code that need to be completed in tandem with the development of the new TPM have not year commenced, a great deal of further practical and legal work needs to be done, and past experience has shown that the processes in the Code that need to be completed require considerable time. For Transpower to apply a new TPM to calculate charges for the 2015/16 year, the new methodology would need to be approved by August 2014 at the latest. We would suggest that, from this starting point, this goal is not feasible. Consequently, if the Authority were to decide to proceed with the TPM Proposal in its current form (which we do not recommend) we would recommend that the Authority request that Transpower propose a timeframe and project plan that would enable a new TPM to be approved in time for it to be applied to the calculation of transmission charges for the 2016/17 pricing year.
44. Do you agree with the Authority's proposal to decide on the consultation period after the proposed TPM has been received from Transpower?	Yes, although we would suggest that, given the complexity of the proposals under consideration, a consultation period of more than six weeks will be required.