

TRANSPower NEW ZEALAND LIMITED

# Submission to the Electricity Commission on Transmission Pricing Review: Stage 2 Options

*September 2010*



**TRANSPower**



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## **1. Introduction**

This is Transpower New Zealand Limited's submission on the Electricity Commission's consultation paper *Transmission Pricing Review: Stage 2 Options* and its appendices. This submission comprises:

- An overview, discussing high level issues
- Part 1 – a commentary on the Commission's options, including a key point summary
- Part 2 – a commentary on the process requirements and timeline for implementation of any changes
- Appendix – responses to the Commission's consultation questions.

The principal messages in this submission are:

- We strongly oppose the flow tracing method. It would be complex to administer and difficult to define legally and to audit. The 80 per cent usage threshold for defining assets as either ultra deep connection or allocated interconnection would provide strong perverse incentives for customers to find ways to get below the threshold. The interaction with the default transmission agreement (benchmark agreement) with respect to investment is likely to cause problems which have not yet been properly investigated. Some major assets would be likely to have their cost allocations changed radically. Prices would be bound to be unstable and this problem would not be fixed by averaging over time, because of cyclical trends in hydrology (e.g. El Niño and La Niña). The complexity would add to compliance costs and increase the scope for disputes over pricing, but it is not clear what the benefits would be, as the allocation would apply to offtake customers only and transmission comprises a very small part of most offtake customers' costs.
- We oppose the generator credit element of the bespoke tilted postage stamp concept as it is currently proposed. The Electricity Commission has not undertaken any analysis to demonstrate that there would be likely to be any economic response to such a signal. A simple market incentive may not incentivise generators to invest in the multiple peaking units needed to provide reliability equivalent to that provided by grid augmentation and a single plant would have market power at times of peak demand. An incentive based on long run marginal cost (LRMC) would also be difficult to calculate and apply in a way that was robust and durable over time.
- A bespoke incentive to encourage further demand-side management in appropriate regions could be investigated further, but much more work would be needed to demonstrate that this could be done in a way that was robust, transparent and durable over time.

- There is no point in further tweaking price signals for offtake customers if the treatment of transmission charges as a pass through cost for distribution customers is not addressed.
- We agree with allocating the HVDC charge based on MWh injected rather than HAMI, as the benefits from disincentivising South Island peaking capacity and intermittent generation should outweigh any costs.
- Postage stamping the HVDC charge would result in higher prices for end consumers and a wealth transfer from end consumers to South Island generators – this is a major issue that needs to be considered carefully against the Authority’s statutory objective.
- We would prefer a kVar-based allocation of a WACC return on the book value of static reactive power assets in each region.
- A shift to a shallow connection definition could avoid perverse incentives for some customers to expend resources promoting uneconomic investments –such a change would affect only 4 per cent of HVAC revenue.
- The process requirements in section IV of Part F of the Electricity Governance Rules mean that it is now not possible to gazette a new methodology in time for it to be applied to the calculation of prices for the 2012/13 pricing year – this is without allowing for the time required to make the software and other administrative changes required to implement one of the complex methodology changes being considered.
- With the exception of the allocation of the HVDC charge based on MWh, no changes are sufficiently developed for them to be implemented without significant further investigation and consultation.

## 2. Overview

The transfer of responsibility for the transmission pricing methodology (TPM) from the Electricity Commission (EC) to the Electricity Authority (EA) affords an opportunity for the EA to examine the progress that has been made by the current Transmission Pricing Review and evaluate possible changes that might be made against what can realistically be achieved by any modification of the method used to determine transmission charges.

Points that we believe should be considered carefully are:

### **There is no single “right” transmission pricing methodology**

A substantial proportion of transmission costs are common costs and theory suggests that there is no single “right” way to recover these costs.

### **Many features of the existing transmission pricing arrangements are fundamentally sound**

The first conclusion of the August 2009 report by NERA Economic Consulting to the New Zealand Electricity Industry Steering Group was

that many features of the existing transmission pricing arrangements are fundamentally sound. The methodology enables the costs of the transmission system to be recovered in a way that does not create perverse incentives. The connection charges allocate the costs of those parts of the grid that have many of the characteristics of private goods to the beneficiaries of the assets concerned. The interconnection charges recover the costs of the common good parts of the grid in a way that provides appropriate incentives for offtake customers to reduce consumption at times of peak demand in those regions that will soon require significant transmission investment.

### **There are benefits to stability and simplicity**

Major change creates uncertainty and, in a capital-intensive industry with long-lived assets, such as the electricity industry, uncertainty can discourage efficient investment and create unnecessary costs. The benefits of stability and simplicity should be weighed carefully before embarking on any fundamental change. The corollary to this is that, if there is to be a change, incremental change should be favoured over grand modelling experiments and fundamental change should be subject to a high net benefit hurdle.

### **Compliance costs, transaction costs and the costs of increasing the scope for disputes**

Adding complexity to the TPM would necessarily increase the costs of complying with it. These additional costs would be borne particularly by Transpower, but also by other industry members. Any substantial change would impose compliance costs and, possibly, also additional transaction costs, and these should be considered against the estimated net benefits that the change would be expected to produce.

Consideration should also be given to how any possible alternative revenue allocation methodology could be defined in a way that would be sufficiently clear and certain to minimise the scope for disputes. In the past, New Zealand electricity industry participants have demonstrated a high propensity to dispute charges whenever there is any ambiguity in the methodology. This has sometimes resulted in lengthy legal disputes, which have wasted resources. The zero sum nature of the allocation methodology creates an incentive for transmission customers to try to find ways to dispute charges and shift costs to other customers. Definitional clarity and simplicity help to limit such activity. Since the current TPM has been in force, there have been very few disputes over the charges – a considerable improvement on past experience and due in no small way to the clarity of the current definitions.

Adding complexity to the methodology would also make the annual pricing audit a more costly and time consuming process.

To date, the EC has not overtly taken account of the increased compliance costs, transaction costs and dispute resolution costs that might result from possible changes to the TPM.

**The economic impact of TPM pricing signals is generally limited**

For offtake customers, any pricing signals provided by the TPM are bound to have a limited economic effect, because, for most businesses and households, transmission costs are only a small part of total energy costs (no more than 10 per cent) and energy costs are, in turn, only a small part their total costs. Interconnection charges, in particular, are likely to have no meaningful effect on the vast majority of offtake customers no matter how they are structured. However, once locational decisions have been made, incentives to moderate consumption during peak demand periods may have some effect, especially if demand is being monitored on behalf of end users by distribution companies or other aggregate consumers.

Transmission charges are a more important cost for generators, so there is greater scope for changes to the charges to affect generators' economic behaviour.

## Part 1 – Commentary on Options

### 3. Key Point Summary

#### **Bespoke tilted postage stamp for interconnection**

- Further analysis is needed to demonstrate any net benefit from this approach;
- The bespoke generator credit sub-option suffers from:
  - difficulties associated with maintaining a durable, robust and transparent (and hence credible) pricing signal based on long run marginal costs (LRMCs) which vary significantly over time;
  - the risk that market power may be exercised by a single peaking generator during peak demand periods;
  - to achieve availability and reliability equivalent to grid investment multiple generating units would be required – it is not clear how a simple market incentive would achieve this;
- We recommend not progressing the bespoke generator credit sub-option;
- There may be scope for bespoke augmentation of the regional coincident peak demand (RCPD) signal for offtake based on LRMC estimates, in order to encourage more demand side management, but further work would be required to establish a robust, transparent and durable means by which to do this;
- The disincentive created by the classification of transmission charges as pass through costs for distribution companies would also need to be addressed.

#### **Flow tracing as basis for ultra deep connection or allocated interconnection**

- This is a complex approach that would create many practical problems and perverse incentives;
- It would be very difficult to define and audit;
- The 80 per cent usage threshold would create a strong incentive for customers to find ways to get their usage below the threshold and so shift charges to others, e.g. via asset swaps or encouraging some of their own major customers to connect directly;
- The relationship with the default transmission agreement (benchmark agreement) could cause problems for investment in major assets, if flow tracing defined these assets as connection;
- Some major lines would be likely to change their allocations completely, e.g. Manapouri- North Makarewa would likely shift from Meridian to Tiwai Point;
- Instability of prices is likely, which would not be overcome by averaging flows over several years as there can be cyclical trends in hydrology (e.g. El Niño and La Niña);
- There are no demonstrable economic benefits – the application would be to loads only and, for most loads, transmission represents a very small proportion of total costs;

- Complexity and definitional ambiguity would significantly increase the scope for disputes over prices;
- We recommend not progressing the flow tracing option.

### **HVDC charging**

- We agree that the lack of demonstrable benefits from locational signalling justifies re-examining the HVDC charge;
- Shifting from HAMI to MWh injected as the charge allocator is likely to produce a net benefit, eliminating current disincentives to invest in peaking capacity and intermittent generation or operate at full capacity during peak demand periods;
- Postage stamping the HVDC charge would result in higher prices for end consumers and a wealth transfer from end consumers to South Island generators – this is a major issue that needs to be considered carefully against the Authority’s statutory objective.

### **Charging for static reactive power assets**

- The current approach, which relies on a unity power factor requirement in the Connection Code and the enforcement of charges for mitigation measures via non compliance agreements is not legally practicable and provides no meaningful incentive for customers to comply with the Code;
- Option 1 – amending the Code requirement to “unity or leading power factor” – does not address the underlying problems with the status quo;
- Hence, we recommend that Option 1 not be progressed;
- Option 2 – extended connection asset definition – would be better, but gaining customer agreement to investment in new static reactive support assets under the default transmission agreement would be difficult;
- Hence, we recommend that Option 2 not be progressed;
- Our preferred option would be kVar-based allocation of a WACC return on the book value of static reactive power assets in each region – this would provide an incentive for distribution companies to consider the most cost effective way of providing static reactive power support and be consistent with the general scheme of the TPM;
- We note that, for the incentive provided to be fully effective, the classification of transmission charges as pass through costs for distribution companies would need to be addressed.

### **Transmission alternatives regime**

- We do not agree that Transpower has any systemic bias in favour of grid investment – in fact, the risks and the administrative and technical hurdles associated with grid investment mean that we only invest in the grid when it is essential to do so in the interests of reliability and security – cheaper alternatives will always be attractive;

- There is scope for incremental improvements in the development and evaluation of transmission alternatives, including greater transparency, but there is no need to split elements of grid planning between Transpower and third parties – this will only blur accountabilities and make it difficult to achieve effective, integrated grid planning;
- Hence, we do not support an independent RFP process or independent assessment of transmission alternative proposals.

### **Connection issues**

- We agree that, with respect to new participant investment in existing connection assets, a negotiated settlement beneficial to all parties should generally be possible, but there should be a backstop circuit breaker provision when negotiations are protracted (e.g. extend beyond one year);
- A broader issue relates to the incentive that the current “deep” connection definition provides, in some circumstances, for some customers to expend resources promoting uneconomic investments because they would result in assets being classified as interconnection rather than connection;
- We suggest that a solution to this problem could be a change to a “shallow” connection definition, which would result in only 4 per cent of HVAC revenue (\$21million p.a.) shifting from connection revenue to interconnection revenue.

### **Conclusions**

- The flow tracing method should not be progressed further;
- With the exception of a change from HAMI to MWh injected as the allocator for the HVDC charge, none of the other proposed options is sufficiently developed to be implemented;
- Hence, further investigation and consultation are required.

### **Detailed commentary on options**

#### **4. Bespoke tilted postage stamp for interconnection**

The bespoke tilted postage stamp (TPS) concept has been proposed by the EC because the general TPS approach did not demonstrate any meaningful economic benefits. The GEM model showed no significant benefits from the general TPS because the economic signal was not strong enough to change the merit order of generation investment in any meaningful way.

The rationale presented in support of the bespoke TPS has a number of deficiencies. The consultation paper’s Figure 3 shows that if forecast peak demand is reduced by peaking generation and demand side management then the need for transmission investment will be reduced, which is an unsurprising result. The text also quotes some numbers focusing on the benefit of deferring transmission investment without

considering the cost of the alternative. The document then proceeds to ask:

“In particular, do you agree with the conclusion that any incentive through the TPM which defers future reliability-driven transmission investment will likely provide some net benefit?”

The answer must be no, as there will only be a net benefit if the incentive leads to investment in peaking generation or demand side management that is more cost effective than the transmission investment it is displacing. An incentive set at more than the long run marginal cost (LRMC) of the transmission investment would incentivise a transmission alternative that would produce a net cost from the national perspective.

The consultation paper also seems to suggest that transmission reliability investments are an entirely separate class from economic investments and there is no relationship between the two. In reality, however, both types of investment are evaluated in the same way, by applying the grid investment test, but on the Core Grid, for reliability investments, the distinction is that, while the highest NPV option that meets the n-1 criterion is chosen, this option does not need to be NPV positive. Another way of looking at the difference between the two is that, on the Core Grid, externalities are factored into the standard that are not reflected in the value of lost load (VoLL) and hence, by implication, the VoLL on the Core Grid is effectively higher for reliability investments than it is for economic investments.

Hence, the GEM analysis that the EC used to test the possible net benefits of a general TPS could also be used to test the bespoke TPS concept, simply by increasing the cost of transmission to reflect the level of transmission investment justified by the deterministic reliability investment criteria. In fact, the Commission has already done this to some extent when it tested the sensitivity of the results of its 18 region version of GEM by doubling transmission investment costs. This test resulted in an increase in net benefits to just \$27.3million, which, relative to total costs of c.\$20billion, was still within the margin of error.

Given that the two regions where a bespoke TPS could possibly be justified based on the future need for reliability investment would be the Upper North Island and Upper South Island, it would seem reasonable to undertake some further sensitivity testing using either the 18 region version of GEM or a more granulated version to see if an interconnection charge tilt reflecting the LRMC of future transmission investment in those regions would provide a significant net benefit as a result of changing the economics of generation investment. However, the work done to date suggests that such analysis would be unlikely to conclude that there would be a significant net benefit.

The consultation paper identifies that investment in peaking generators as alternatives to transmission will often result in the owners of those plants possessing regional market power at times of peak demand. This

would be the case particularly in areas like the Upper South Island, where only one economically sized plant would be needed to defer transmission investment. This problem would be obviated to some degree by grid support contracts (GSCs) for generation as a transmission alternative as the design features of GSCs set the payment terms for power supplied as an alternative to transmission on the basis of past offer behaviour, in order to prevent the exercise of market power.

The availability and reliability of a single shaft peaking generator is such that it could not deliver a level of reliability equivalent to that provided by grid augmentation. It would take three generating units operating independently to deliver reliability equivalent to the 99.9 per cent availability provided by transmission, if each unit operated independently and had a 90 per cent availability rate. It is not clear how a simple market incentive in the form of the generator credit element of a bespoke tilted postage stamp charge could incentivise generators to invest in multiple peaking units, when this would be unlikely to be the most commercially attractive option for them.

Another issue, which is also alluded to by the consultation paper, is the problem associated with the variability of LRMC-based charges, when these are calculated correctly. LRMCs typically rise markedly ahead of the need for new investment, but drop once investment is made, whether this takes the form of actual grid investment or investment in a transmission alternative, such as generation close to load or demand-side management. This because, once investment is made, the need for a further tranche of investment will extend many years into the future. LRMC estimates can also vary markedly when demand forecasts and, consequently, the forecast need for new investment change.

A variable and uncertain charging path is likely to discourage investment, in the same way that high nodal prices do not incentivise generation investment “downstream” of constraints, because of the uncertainty attached to continuation of the high prices. A way around this problem would be to construct a charging formula that would aim to smooth the expected fluctuations in LRMCs over a long period of time in order to create a more durable and reliable charge. However, this approach would be difficult to defend because, for most of its life, the charge would not actually approximate the LRMC of transmission investment and so could easily be critiqued by customers disadvantaged by it as giving an incorrect economic signal. This problem would, in turn, undermine the perceived durability of the charge and, hence, its value as a long-term economic incentive.

On balance, we consider that the generator credit element of the bespoke tilted postage stamp concept is unlikely to prove a satisfactory means of incentivising economic investment in peaking generation plant close to load that would provide reliability equivalent to the alternative of grid augmentation.

There may, however, be some scope for providing a bespoke incentive to encourage further demand-side management in regions where substantial new transmission investment is forecast. The differential “n”s used by the current regional coincident peak demand (RCPD) allocation method already do this to some degree and some offtake customers respond to the signal provided. It may be possible to augment this incentive by adjusting the RCPD signal based on estimates of LRMCs in the Upper North Island and Upper South Island regions. However, considerable further work would be needed to establish that any such adjustments could be done in a way that was robust, transparent and reasonably durable and consistent over time. The disincentive to respond created by the ability of distribution companies to pass through transmission charges would also need to be addressed.

## **5. Flow tracing**

The flow tracing method of revenue allocation would apply an algebraic matrix equation to SPD final outputs and utilise a number of arbitrary parameters. The aim of the analysis would be to attribute the flow through specific transmission assets to particular loads during each trading period. The Commission’s concept would identify assets that the modelling finds to be used more than 80 per cent by particular loads and allocate the costs of those assets to those loads. This would effectively produce an ultra deep connection charge. The Commission has indicated that, rather than an ultra deep connection charge, the method could instead be used to allocate the interconnection revenue to particular loads, but in terms of the actual pricing effect, it is hard to see how this would be different from ultra deep connection. The Commission is not proposing to use this method to allocate network costs to generators.

The method proposed is complex and would create many practical problems and possibly perverse incentives. Exactly what is meant by “flow tracing” would need to be very carefully defined if assets were to be classified by applying it, and/or revenue allocated based on it. The definitions would need to be precise enough to enable an auditor to replicate the process and also limit the risk of alternative feasible interpretations leading to challenges to the pricing calculations. It would be important to define very carefully how assets are defined at the sub-node level. In some cases, an “80 per cent usage” definitional rule would result in major lines being defined as connection or “allocated interconnection”, but part or all of shared spur lines being defined as conventional interconnection with, i.e. the reverse of the current situation.

Some major lines would also have their allocations changed entirely, e.g. the Manapouri-North Makarewa line, which is currently a connection asset allocated to Meridian, would presumably be allocated to Tiwai Point by the flow tracing method, as more than 80 per cent of the flow on the line goes to Tiwai.

The interaction between the flow tracing method, the default transmission agreement (benchmark agreement)<sup>1</sup> and existing new investment agreements (or customer investment agreements (CICs) as they are now being styled) would need to be considered carefully. Important legal questions would be raised if the flow tracing method were to reverse the revenue allocated to assets that are currently subject to a CIC (e.g. the West Wind connection lines, which flow tracing might allocate to Wellington Electricity). This sort of outcome might also raise legitimate questions about whether or not the flow tracing method is actually consistent with the beneficiary pays pricing principle<sup>2</sup>.

If flow tracing were to define some major transmission lines as connection assets, investments in these lines would be governed by the benchmark agreement (or other pre-existing transmission agreement) and would generally need to be undertaken pursuant to a CIC. As these assets would still be shared by multiple parties (even if one were deemed to be the 80 per cent user of the asset) the negotiations relating to any capital investment would be likely to be complex and protracted, and would be likely to see the re-emergence of the free rider and hold out problems that existed in the pre Part F era. Dealing with major transmission investments in this way would also cut across the capital expenditure regulation regime being developed under Part F of the Commerce Act.

The consultation document suggests that the ultra deep connection investment problem could be obviated by moving to a shallow connection definition but dedicating some interconnection assets, and consequently a share of interconnection revenue, to particular customers based on the flow tracing analysis. The legal implications of this approach, which would create two sets of customer dedicated assets with different investment characteristics, would need to be considered carefully.

The flow tracing allocation method would create strong perverse incentives for customers to find ways to get their individual asset usages below the 80 per cent threshold in order to shift charges from themselves to other customers. This could possibly be achieved by undertaking asset swaps or encouraging particular major customers to connect directly to the grid. The current pricing methodology creates no incentive of this sort, because the node-link configuration defines what are connection and interconnection assets and changing asset ownership does not alter this. The complexity of the flow tracing method is bound to open up other opportunities for shifting charges that have not yet been thought of.

Instability of prices is a further concern. Away from the main load centres flows can vary significantly from year to year, often as a

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<sup>1</sup> or other transmission agreement, if a customer has a pre-existing agreement

<sup>2</sup> Rule 2.2 of section IV of Part F of the Electricity Governance Rules.

consequence of changes in the hydrological situation. As a result of changing flows, assets could be reclassified between connection and interconnection, or between conventional interconnection and allocated interconnection. The consultation paper suggests that this sort of instability could be overcome by averaging flows over a number of years. However, it is not clear that this would solve the problem, as there can be cyclical trends in hydrology that extend over a number of years (e.g. El Niño and La Niña cycles). Changing asset classifications each year based on flow tracing would add significantly to compliance costs during the pricing round and the time taken to complete annual pricing, including auditing the prices and the process followed.

The consultation paper suggests that the flow tracing method would provide incentives to loads to take action to defer or avoid new transmission investment that is likely to be required to serve their individual requirements. However, for most loads, transmission forms only a small proportion of total energy costs and energy, in turn, forms only a small proportion of their total costs, so the effect of flow tracing on the consumption behaviour and location of loads is likely to be limited. Consequently, there would be little or no economic benefit. As noted above, the major incentive would be for offtake customers to try to find innovative ways of shifting charges from themselves to others.

A further concern is that changing the identification of assets within the Zemindar pricing model, based on flow tracing, would be difficult and probably expensive. It is likely that entirely new software would need to be written, depending on the final form of the preferred allocation method – this could be time consuming (up to 12 months) and expensive (\$1million to \$5million)

We strongly recommend that the Authority not progress the flow tracing method. It would create significant additional compliance costs for Transpower, and substantially increase the scope for disputes over pricing. The additional cost of negotiating and settling such disputes would create extra costs for Transpower and transmission customers – these additional costs would be a net cost to the nation. Additional costs of \$1million to \$5million per annum could be expected. There would also be strong incentives for customers to arrange their affairs to avoid charges and shift costs onto others. From the national perspective, this activity would also be a waste of resources. Against these costs it is not clear that there would be any significant economic benefits.

If, despite our recommendation, the Authority were to decide to proceed with the flow tracing method, we strongly recommend that it undertake further work to define the detail of the method and discuss with Transpower how it could be implemented in practice. These actions should be undertaken ahead of the publication of an Issues Paper with draft pricing guidelines. To ensure a sound process, a further round of consultation would probably also be appropriate ahead of the publication of an Issues Paper and draft pricing guidelines.

## 6. Options for HVDC charging

We agree that the fact that analysis shows that there are unlikely to be benefits from locational signalling for economic transmission investment suggests that it may be worth re-examining the existing HVDC charging regime.

The Commission has proposed the following criteria to test the need for the HVDC charge and its form if it continues:

- the benefit of preventing or deferring the need for a new inter-island link;
- the benefit of preventing or deferring the need for AC transmission upgrades that support northward flow;
- the cost of incentivising new North Island generation options rather than more economic South Island options;
- the cost of disincentivising South Island generators from operating at their full capacity (because it would increase their HAMI);
- the cost of disincentivising South Island generators from taking opportunities to increase their peaking capacity (because it would increase their HAMI);
- the cost of reduced competition in generation development, because owners of South Island generation (notably Meridian) face a lower marginal signal on increased capacity than other generators.

We agree that these criteria are appropriate.

The Commission has identified the following options for the HVDC charge:

1. maintain the status quo;
2. maintain the separate HVDC charge, but calculate it based on annual MWh injected rather than HAMI;
3. maintain the separate HVDC charge, but use an “incentive free” allocation method (yet to be defined);
4. postage stamp the charge (i.e. incorporate it into the interconnection charge).

We agree that these are appropriate options and that further consideration of these options is appropriate, as proposed by the Commission.

At this stage, there appears to be a reasonable case for retaining the charge, but moving to MWh injected rather than HAMI as the allocator, since the inefficiency caused by variabilising the charge would seem to be minimal and less than the benefit that would be likely to result from removing the incentive that HAMI may currently create for South Island generators not to invest in increased peaking capacity or intermittent generation and not to operate their existing plant at full capacity during

peak demand periods. Charging on a per MWh injected basis would add an extra variable element to the cost of South Island generation which may disincentivise South Island generation at times of low prices, with a consequent increased risk of hydro spill, but the cost of this would seem to be small.

The main impediment to postage stamping the HVDC charge is that this would result in higher prices for end consumers and a wealth transfer from end consumers to South Island generators. This is a major issue that the Authority will need to consider carefully against its statutory objective.

## 7. Charging for static reactive power assets

### Status quo and Option 1 (slightly modified status quo)

We are concerned that the chain of reasoning used in the consultation paper to explain how the status quo or Option 1 arrangements could operate to incentivise investment in static reactive power assets and recover the cost of that investment is incorrect, because, in brief:

- Transpower has no practical way to enforce compliance, as it cannot take legal action for damages if it has suffered no loss itself;
- Transpower is legally unable to charge customers under non compliance agreements for mitigation measures<sup>3</sup> – Transpower may only charge for transmission services in accordance with rule 9.1 of Section IV of Part F of the EGRs and non compliance agreements are not included among the permitted charging instruments; and
- non-compliant parties can hold-out and refuse to enter customer investment contracts for static reactive power assets knowing that Transpower will not de-energise.

Another problem with the current Connection Code provisions is that it is physically impossible to achieve a power factor of exactly unity, but this deficiency would be remedied by the change of definition proposed by Option 1 to “unity or leading power factor”.

The following discussion is a detailed response to particular arguments made in *Appendix 5: Static Reactive Power Compensation*. The paragraph references are to paragraphs in Appendix 5.

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<sup>3</sup> Rule 9.1 of Section IV of Part F of the Electricity Governance Rules 2003 states:

**9.1 Charges to comply with approved transmission pricing methodology**

9.1.1 Except for the **input connection contracts, new investment agreement contracts, and notional embedding contracts**, and subject to rule 9.1.2, upon approval of the **transmission pricing methodology** by the **Board**, from the date that the **transmission pricing methodology** must take effect, **Transpower** must charge for those transmission serves affected only in accordance with the approved **transmission pricing methodology**.

9.1.2 **Transpower** is permitted to impose charges additional to those set out in the **transmission pricing methodology** if those charges are provided for in the **Comalco agreements**.

### **Para 2.2.6**

The starting point for Transpower, rather than “breach of contract”, would be to deal with the non-compliance under clause 15.2 of the default transmission agreement (dTA) – this deals specifically with technical non-compliances (which covers connection code breaches) and, whilst Transpower acknowledges that clause 15.2 is without prejudice to its other remedies (such as breach of contract/specific performance), the preferable starting point for addressing a non-compliance in respect of which Transpower would not grant a non-compliance agreement is clause 15.

### **Para 2.2.14**

The argument here is rather muddled. Transpower cannot just install a new connection asset without customer agreement (such as a customer investment contract). There are two aspects to providing new assets:

- the dTA implications: effectively clause 36(1) of the dTA prevents Transpower from changing the connection assets or changing the configuration diagram without customer agreement;
- the pricing aspect: Transpower cannot simply charge the relevant customer additional charges for connection assets which Transpower installs without customer agreement.

Transpower cannot “require the breaching party to enter into power factor non-compliance agreements to underwrite the costs of such connection assets” – as this paragraph states. Appendix A of the Connection Code specifically sets out what is required in terms of the application, and obligations on Transpower to consider the application. There is an ability for Transpower to charge the customer for the costs incurred in considering the application (see clause 4 of Appendix A) and Transpower must also provide an estimate of the costs to the customer before it proceeds to consider the application (clause 2). There is nothing specific which allows Transpower to charge the costs of undertaking an investment to address the non-compliance, and presumably this is because it is a customer non-compliance which needs to be remedied and it is up to the customer to propose a solution which Transpower finds acceptable, acting reasonably.

We note that clause 3(b) of Appendix A requires Transpower to act reasonably in deciding whether or not to enter into an agreement under Appendix A and also in determining the terms and conditions on which it is prepared to enter into an agreement. In our view, the imposition of costs of an investment (especially one which may be hundreds of thousands of dollars) under a non-compliance agreement is not a matter which could reasonably be imposed by Transpower on a customer, without express provision for this in the Benchmark Agreement or otherwise in the rules and, as noted above, rule 9.1 of section IV of Part F makes no such provision. Further, are the incentives on a customer to sign a non-compliance agreement effectively committing it to funding such an investment any different from the incentives to sign a new investment contract (or customer investment contract)? The only

“difference” is the threat of de-energisation because it is a technical non-compliance, but this is not a realistic option for Transpower to take.

**Para 4.2.8/ 4.2.11**

See above regarding managing the allocation of a cost involved in departing from the Connection Code.

**Para 4.2.13**

As stated above, Transpower will not be entitled, without customer agreement, to recover the costs of connection assets on the basis of the TPM.

**Para 4.2.14**

The ability, under the dTA, for Transpower to request the EC to request it to put in a GUP where agreement with a customer on connection asset investment cannot be reached only applies to investments which are “driven” through a failure to meet the grid reliability standards (GRS) (see clauses 40.1 and 40.2 of the dTA). It is not clear to us that connection asset investment to meet the power factor requirement will always (or usually) be driven by a failure of connection assets to meet the GRS.

**Para 4.2.17**

We acknowledge that the technical non-compliance provisions are expressed to be “without prejudice” to Transpower’s other remedies, such as breach of contract. However, it is not clear to us what loss Transpower would suffer. The consultation paper appears to consider the cost of Transpower undertaking the investment to be the “loss” Transpower would incur, but there are a number of difficulties associated with this, viz.:

- 1) normally one invests based on a contractual entitlement to recover a return of and on the cost of that investment – not on the basis that Transpower could recover by way of suing for breach of contract;
- 2) would Transpower actually proceed to undertake the investment? It seems highly unlikely that Transpower would do so – it has not done so to date – in which case any loss would be purely theoretical, rather than having actually been suffered by Transpower;
- 3) even if Transpower does have a theoretical right to sue a customer for breach of contract, what it might be entitled to in terms of damages is complex and far from clear;
- 4) from a customer relationship perspective, it is highly unlikely that Transpower would wish to go down the “breach of contract” route with its customers or ever contemplate threatening such action.

The proposed definitional change in Option 1: amended status quo would enable the power factor requirement to be complied with, which is not currently the case, but it would still not provide a practicable mechanism by which to promote efficient investment in static reactive support assets, if that is the intention (as it appears to be).

Consequently, given the many practical difficulties associated with the status quo and the many incorrect assumptions about how it might work in practice, our view is that the “amended status quo” option outlined in the paper is not desirable or practicable.

## **Option 2**

On the face of it, Option 2: extended connection asset definition is a reasonable approach to take. However, extending the definition of connection assets to include reactive support assets runs into the problem that investment in these assets would then be subject to the default transmission agreement (dTA), and clauses 40.1 and 40.2 of the dTA contemplate investment in connection assets being driven by expectations that the power system will not continue to meet the n-1 criterion or more generally comply with the grid reliability standards. It is not clear that this approach is applicable in most cases to investment in reactive support assets. It would also be difficult to obtain customer agreement to investment in new static reactive support assets when the future benefit of those assets to particular customers was unclear. Hence, we recommend that the Authority not progress Option 2.

## **Alternative approach**

KVar-based charging or allocation of some form would seem reasonable. An alternative approach that could provide an incentive for distribution companies to consider the most cost effective way of providing static reactive support, but avoid the problems associated with extending the connection asset definition as proposed by Option 2, would be to treat static reactive assets (other than those requested and contracted for directly by customers) as a subset of interconnection assets. A WACC return on the book value of these assets could be allocated using reactive draw during peak demand periods at each connection location as a proportion of total reactive draw in each region during peak demand periods. This would be consistent with the overall scheme of the TPM and the requirement in the Electricity Act for the TPM to be a revenue allocation methodology. We note that, for the incentive provided to be fully effective, the classification of transmission charges as pass through costs for distribution companies would need to be addressed.

Although this method may still overlap to some extent with the System Operator’s procurement of dynamic voltage support, the need for this is expected to be largely eliminated by the forthcoming capital expenditure on Upper North Island reactive support assets (as the consultation paper notes).

This approach (or any form of kVar based allocation or charging for static reactive support assets) would take at least six months to implement (and probably longer), as it would require substantial changes to the Zemindar pricing software and other administrative systems and testing of the changes.

## **8. Transmission alternatives regime**

The consultation paper states that some industry participants consider that a key shortcoming of the transmission alternatives regime is that Transpower has competing interests as the network owner and the entity responsible for conducting the RFP process and assessing proposed alternatives. The implication is that Transpower is biased in favour of grid investment. We do not accept this criticism.

In reality, the regulatory framework applied to transmission does not fully compensate Transpower for all the risks and costs it faces when it undertakes grid investment. Expanding the grid is a challenging and difficult exercise which presents many administrative and technical hurdles, as exemplified by the major projects currently in train (the North Island grid upgrade, Pole 3 of the HVDC link and the North Auckland and Northland upgrade). The demands in terms of capital and expertise are very considerable, but Transpower can only ever recover a return on its actual costs and bears the risk of any cost overruns. Hence, we have a strong commercial incentive not to invest unless it is essential to do so in the interests of reliability and security. If it is possible to find a cheaper alternative to grid investment that will deliver equivalent benefits, this will always be attractive to Transpower.

Based on the assumption of systemic bias, the consultation paper proposes as possible improvements:

- making an independent decision maker responsible for conducting the RFP process;
- making an independent decision maker responsible for assessing transmission alternative proposals.

We do not support these proposals. Transpower believes that there is scope for making incremental improvements to the evaluation of transmission alternatives and the development and application of grid support contracts, but there is no reason to split elements of grid planning between different parties. All this would do is blur accountabilities and make it more difficult to achieve effective, integrated grid planning. Both the Government and the Ministerial Review have strongly endorsed the policy of having a single grid planner. It would be inappropriate and unnecessary for the EA to diverge from this approach. The purported rationale for the proposed change, i.e. that Transpower is incentivised to favour grid investment over transmission alternatives, is not valid, because the regulatory framework established by Part 4 of the Commerce Act provides no such incentive.

## **9. Connection issues**

We agree that, with respect to the incentives relating to new participant investment in existing connection assets, a negotiated settlement beneficial to all parties should generally be possible. In practice,

however, negotiations can be protracted (e.g. ESL Ltd and Aurora at Frankton) so it may be reasonable to include a “game breaker” provision of some sort as a backstop, if no agreement is reached after, say, one year.

Another issue that we urge the Authority to consider seriously is the possibility of moving from the current “deep” connection definition to a shallower definition. The rationale for deep connection is that it is more consistent with the “user pays” and “beneficiary pays” pricing principles<sup>4</sup>. However, in practice we have found that, in some circumstances, the current deep definition can encourage some transmission customers to expend resources promoting investments that will result in assets possibly being reclassified as interconnection rather than connection, or assets being located at interconnection nodes rather than connection nodes, even though these investments are clearly sub-economic relative to alternatives<sup>5</sup>. Transpower must respond to its customers, which results in further resources being expended pointlessly.

An alternative would be to move to a “shallow” connection definition, with connection assets limited to individual connection locations. NERA Consulting Ltd has estimated that such a change would result in an annual reduction in connection revenue of about \$21million per annum and a corresponding increase in interconnection revenue. This would represent about 4 per cent of total HVAC revenue<sup>6</sup>. In our view, such a change would result in no significant reduction in allocative or dynamic efficiency, but would produce a meaningful saving in total administration costs for transmission customers and Transpower.

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<sup>4</sup> Rules 2.1 and 2.2 of Section IV of Part F of the Electricity Governance Rules 2003.

<sup>5</sup> The three instances where this has occurred are Waipa (Te Awamutu upgrade), Christchurch (Bromley or Islington transformer investment) and Lower Waitaki Valley.

<sup>6</sup> *New Zealand Transmission Pricing Project – A Report for the New Zealand Electricity Industry Steering Group*, NERA Consulting Ltd, 28 August 2009, p. 20.

## Part 2 – Commentary on Process and Implementation

We are concerned by two elements of the proposed process described by the consultation paper. First, the paper states that the Commission expects that any changes to the TPM arising from the review will be effective from the 2012/13 pricing year. In reality, even if the EA were to publish its preferred option and draft pricing guidelines in late December 2010/ January 2011, it would be impossible in practice to get a new TPM gazetted and implemented by July 2011 (in time for next year's pricing round). This is because of the process requirements contained in section IV of Part F of the Electricity Governance Rules (which are replicated by the new Industry Participation Code). An indicative timeline is set out below.

<b>Indicative timeline for development of new TPM (assuming no reference back to Transpower for further development or other delays)</b>	
EA publishes preferred option and draft transmission pricing guidelines and invites submissions	Late Dec/Jan 2011
EA receives submissions on draft transmission pricing guidelines	Feb 2011
EA considers submissions, publishes final decision on new transmission pricing guidelines	Feb-March 2011
EA publishes process for development of the new proposed TPM and provides Transpower with written request to develop new proposed TPM	Beginning April 2011
Transpower develops new proposed TPM, including indicative prices and submits to EA	April-June 2011
EA considers proposed TPM (which may be referred back to Transpower)	July 2011
EA approves new TPM (assuming no reference back to Transpower), publishes and invites submissions	August 2011
EA receives and considers submissions, makes decision on inclusion of new TPM as a schedule to Part 12, consults with Transpower on date new TPM will take effect	September-October 2011
New TPM gazetted	November 2011

This timeline does not take into account the time needed to make changes to the various software packages and any other administrative changes that may be required. Updating the Zemindar pricing software is not a straightforward process and consequential amendments may also be required to the Meter Data Repository (MDR), Maintenance Management System (MMS) and Financial Management Information System (FMIS). For anything other than a minor modification to the existing methodology, the changes required are likely to take several

months and possibly up to a year, depending on the complexity of the changes, and require significant expense (>\$1million, not including staff time and other internal resources). Consequently, Transpower would appreciate the opportunity to discuss with the Authority the likely content of the draft transmission pricing guidelines, and their practical implications if adopted, ahead of the publication of an Issues Paper.

Second, the consultation paper proposes a rapid progression to an Issues Paper setting out a preferred option and new draft pricing guidelines, probably to be published in late December 2010 or January 2011. The consultation paper states:

“The preferred option to be identified in the Issues Paper will be based on the Commission’s ongoing analysis, submitters’ views and the stage 2 options; the preferred option may be one of the stage 2 options or an amalgam of concepts.”

In our view, if the preferred option were the bespoke tilted postage stamp or flow tracing, or some combination of these two, proceeding directly to an Issues Paper with draft pricing guidelines to give effect to such an option would constitute an inadequate consultation process. This is because the bespoke tilted postage stamp is a new concept proposed by this consultation paper and not yet developed in any detail or adequately examined (albeit that something like it was alluded to by the August 2009 NERA paper) and the flow tracing approach would represent a fundamental change to the methodology that would require detailed examination of many aspects of its practicality before it could reasonably be considered for implementation.

If the EA were to decide that either the bespoke tilted postage stamp or the flow tracing method, or some combination of the two, was its preferred option, good process would require at least a further round of consultation and additional work to develop the preferred option into a practical form prior to the publication of an Issues Paper and draft pricing guidelines.

## APPENDIX – RESPONSES TO CONSULTATION QUESTIONS

Question	Transpower response
Q 1. What, if any, bearing do you consider the Authority's proposed objective has on the review's approach to analysis and evaluation to date?	The Authority's objective does not contain the fairness and environmentally sustainable elements of the Commission's principal objectives, but this change should have no practical implications for the analysis and evaluation of transmission pricing options.
Q 2. Do you agree that the Commission has identified the relevant factors in its assessment (paragraphs 3.2.6 to 3.2.13) of whether nodal pricing provides adequate signals for efficient generation and load investment? If not, please explain your reasons.	Yes, although another factor that is worth considering is the time it takes to implement a transmission investment. As this can be many years, the point at which nodal pricing will signal the need for transmission investment will typically be beyond the point at which efficient investment should have commenced. This is most obviously the case where there is no generation "downstream" of a line that may need augmentation as demand increases.
Q 3. Do you agree with the Commission's approach (outlined in paragraphs 3.2.21 and 3.2.22) to determining whether any form of additional locational signal through transmission pricing is necessary? If not, please provide reasons.	Yes.
Q 4. Do you agree that there appears to be limited value in providing an enhanced locational signal to generators to ensure co-optimisation of economic transmission investments and generation? If not, please explain your reasons.	Yes.
Q 5. Do you agree that it needs to be determined whether the current locational signal provided by the HVDC charge is causing or is likely to cause inefficient operational and investment decisions? If not, please explain your reasons.	Yes.
Q 6. Do you agree with the high-level analysis provided on the costs and benefits of the current HVDC charging regime? If not, please explain your reasons.	Yes.

Question	Transpower response
Q 7. Do you agree that the Commission has correctly identified the four possible options for the HVDC charge? If not, please explain your reasons and provide alternative options.	Yes.
Q 8. What are your views on the validity of each of the options?	<p>At this stage, there appears to be a reasonable case for retaining the charge, but moving to MWh injected rather than HAMI as the allocator, since the inefficiency caused by variabilising the charge would seem to be minimal and there would appear to be some benefit to be gained from removing the incentive that HAMI may currently create for South Island generators not to invest in increased peaking capacity and not to operate their existing plant at full capacity during peak demand periods. Charging on a per MWh injected basis would add an extra variable element to the cost of South Island generation which may disincentivise South Island generation at times of low prices, with a consequent increased risk of hydro spill, but the cost of this would seem to be small.</p> <p>The main impediment to postage stamping the HVDC charge is that this would result in higher prices for end consumers and a wealth transfer from end consumers to South Island generators. This is a major issue that the Authority will need to consider carefully against its statutory objective.</p>
Q 9. Do you have specific lower-level issues around the structure and details of HVDC charging that you would like considered in stage 3?	No.
Q 10. Do you agree with the analysis provided in the section headed “Analysis of benefits of signalling reliability-driven investment”? In particular do you agree with the conclusion that any incentive through the TPM which defers future reliability-driven transmission investment will likely provide some net benefit? If not, please explain your reasons.	<p>No, the analysis provided by in the section headed “Analysis of benefits of signalling reliability-driven investment” seems to be seriously deficient in that it appears to take no account of the additional cost of peaking generation plant relative to the cost of transmission, or the additional cost of demand side management, including the loss of utility contingent on reduced consumption relative to the cost of transmission investment.</p> <p>The answer to the question must be no, as there will only be a net benefit if the incentive leads to investment in peaking generation or demand side management that is more cost effective than the transmission investment it is displacing. An incentive set at more than the long run marginal cost (LRMC) of the transmission investment would be likely to incentivise a transmission alternative that would produce a net cost from the national perspective.</p> <p>The consultation paper seems to suggest that transmission reliability investments are an entirely separate class from economic investments and there is no relationship between the two. In reality, however, both types of investment are evaluated in the same way, by applying the grid investment test, but on the Core Grid, for reliability investments, the distinction is that, while the highest NPV option that meets the n-1 criterion is chosen, this option does not need to be NPV positive. Another way of looking at the difference between the two is that, on the Core Grid, the value of lost load (VoLL) may</p>

Question	Transpower response
	<p>effectively be higher for reliability investments than it is for economic investments and, consequently, the value of transmission investment that may be justified may be higher (although not necessarily so).</p> <p>Hence, the GEM analysis that the EC used to test the possible net benefits of a general TPS could also be used to test the bespoke TPS concept, simply by increasing the cost of transmission to reflect the increased transmission investment that may sometimes be justified by the deterministic reliability investment criteria. The Commission has already done this to some extent when it tested the sensitivity of the results of its 18 region version of GEM by doubling transmission investment costs. The result of this test was in an increase in net benefits to just \$27.3million, which, relative to total costs of c.\$20billion, was still within the margin of error.</p> <p>Given that the two regions where a bespoke TPS could possibly be justified based on the future need for reliability investment would be the Upper North Island and Upper South Island, it would seem reasonable to undertake some further sensitivity testing using the 18 region version of GEM to see or a more granulated version if an interconnection charge tilt reflecting the LRMC of future transmission investment in those regions would provide a significant net benefit as a result of changing the economics of generation investment. However, the work done to date suggests that such analysis would be unlikely to conclude that there would be a significant net benefit.</p> <p>The availability and reliability of a single shaft peaking generator is such that it could not deliver a level of reliability equivalent to that provided by grid augmentation. It would take three generating units operating independently to deliver reliability equivalent to the 99.9 per cent availability provided by transmission, if each unit operated independently and had a 90 per cent availability rate. It is not clear how a simple market incentive in the form of the generator credit element of a bespoke titled postage stamp charge could incentivise generators to invest in multiple peaking units, when this would be unlikely to be the most commercially attractive option for them.</p> <p>Other issues relate to the variability of LRMCs and market power concerns. For a full discussion see section 4 of the submission proper above.</p> <p>There may be some scope for providing a bespoke incentive to encourage further demand-side management in regions where substantial new transmission investment is forecast. The differential “n”s used by the current regional coincident peak demand (RCPD) allocation method already do this to some degree and some offtake customers respond to the signal provided. It may be possible to augment this incentive by adjusting the RCPD signal based on estimates of LRMCs in the Upper North Island and Upper South Island regions. However, considerable further work would be needed to establish that any such adjustments could be done in a way that was robust, transparent and reasonably durable and consistent over time. The disincentive to respond created by the ability of distribution companies to pass through transmission charges would also need to be addressed.</p>

Question	Transpower response
<p>Q 11. The Commission has decided not to pursue the options outlined in paragraph 4.1.8. Do you agree with the Commission's assessment (including the analysis contained in section 5 of Appendix 2) that these options are not worth pursuing? If not, please explain your reasons.</p>	<p>Yes.</p>
<p>Q 12. If the Commerce Commission proposal outlined in paragraph 4.2.16(c) is adopted for the final determination, do you think this will address the regulatory anomaly referred to above?</p>	<p>In principle yes. In practice it will depend on how the Commerce commission determines whether or not the avoided charge is a result of reducing the overall cost of the supply of electricity line services.</p>
<p>Q 13. The Commission has identified three options alongside the status quo to defer or avoid reliability transmission investments. Do you agree that these options are worth pursuing? Are there other options which deserve further consideration? Please provide reasons.</p>	<p>In fact, the Commission appears to have identified two options, viz:</p> <ul style="list-style-type: none"> <li>• making an independent decision maker responsible for conducting the RFP process;</li> <li>• making an independent decision maker responsible for assessing transmission alternative proposals.</li> </ul> <p>We do not agree that these options are worth pursuing. The options are predicated on the assumption that Transpower is biased in favour of grid investment. Transpower does not accept this criticism.</p> <p>In reality, the regulatory framework applied to transmission does not fully compensate Transpower for all the risks and costs it faces when it undertakes grid investment. Expanding the grid is a challenging and difficult exercise which presents many administrative and technical hurdles, as exemplified by the major projects currently in train (the North Island grid upgrade, Pole 3 of the HVDC link and the North Auckland and Northland upgrade). The demands in terms of capital and expertise are very considerable, but Transpower can only ever recover a return on its actual costs and bears the risk of any cost overruns. Hence, we have a strong commercial incentive not to invest unless it is essential to do so in the interests of reliability and security. If it is possible to find a cheaper alternative to grid investment that will deliver equivalent benefits, this will always be attractive to Transpower.</p> <p>Transpower believes that there is scope for making incremental improvements to the evaluation of transmission alternatives and the development and application of grid support contracts, but there is no reason to split elements of grid planning between different parties. All this would do is blur accountabilities and make it more difficult to achieve effective, integrated grid planning. Both the Government and the Ministerial Review have strongly endorsed the policy of having a single grid planner. It would be inappropriate and unnecessary for the EA to diverge from this approach. The purported rationale for the proposed change, i.e. that Transpower is incentivised to favour grid investment over</p>

Question	Transpower response
	transmission alternatives, is not valid, because the regulatory framework established by Part 4 of the Commerce act provides no such incentive.
Q 14. Can you suggest other matters to be included in the Commission's stage 3 deliberations on charging for HVDC costs?	No.
Q 15. Do you agree with these preliminary conclusions? If not, please provide reasons.	Yes. See also the response to Q.8 above.
Q 16. Do you agree that connecting parties should be able to negotiate mutually-beneficial access arrangements for independently provided new connection assets? If not, please explain your reasons, giving specific examples where possible.	In principle yes. However, in practice, negotiations can be protracted (e.g. ESL Ltd and Aurora at Frankton) so it may be reasonable to include a "game breaker" provision of some sort as a backstop, if no agreement is reached after, say, one year.
Q 17. The Commission has developed three options that it considers have potential to encourage efficient investment in static reactive power. Which of these options do you consider best encourages this objective? Please give reasons.	<p>We would prefer an alternative option. On the face of it, Option 2: extended connection asset definition could be a reasonable approach to take. However, extending the definition of connection assets to include reactive support assets runs into the problem that investment in these assets would then be subject to the default transmission agreement (dTA), and clauses 40.1 and 40.2 of the dTA contemplate investment in connection assets being driven by expectations that the power system will not continue to meet the n-1 criterion or more generally comply with the grid reliability standards. It is not clear that this approach is applicable in most cases to investment in reactive support assets. It would also be difficult to obtain customer agreement to investment in new static reactive support assets when the future benefit of those assets to particular customers was unclear. Hence, Transpower recommends that the Authority not progress Option 2.</p> <p>KVar-based charging or allocation of some form would seem sensible. An alternative approach that could provide an incentive for distribution companies to consider the most cost effective way of providing static reactive support, but avoid the problems associated with extending the connection asset definition as proposed by Option 2, would be to treat static reactive assets (other than those requested and contracted for directly by customers) as a subset of interconnection assets. A WACC return on the book value of these assets could be allocated using reactive draw during peak demand periods at each connection location as a proportion of total reactive draw in each region during peak periods. This would be consistent with the overall scheme of the TPM and the requirement in the Electricity Act for the TPM to be a revenue allocation methodology. We note that, for the incentive provided to be fully effective, the classification of transmission charges as pass through costs for distribution companies</p>

<b>Question</b>	<b>Transpower response</b>
	would need to be addressed. Although this method may still overlap to some extent with the System Operator's procurement of dynamic voltage support, the need for this is expected to be largely eliminated by the forthcoming capital expenditure on Upper North Island reactive support assets (as the consultation paper notes).
Q 18. Are there other options for the allocation of static reactive power costs that the Commission should pursue?	See the response to Q.17 above.