

TRANSPower NEW ZEALAND LIMITED

Submission to the Electricity Commission on Transmission Pricing Review: High-level options

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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: High-level options*.

This submission should be read in conjunction with Transpower's *Submission to the Electricity Commission on the Market Development Programme: Overview, December 2009*.

1.1 Overview

Transmission pricing has proved to be a difficult issue, not just in New Zealand but also in other jurisdictions, because there are significant common costs involved and there is no one correct way of allocating these costs. How the costs of potential new investments in the grid might be distinguished from the costs of the existing grid and how the different categories of grid cost should be allocated are also controversial issues. Finally, the allocation of transmission costs is a zero sum game – consequently, changes to it can involve significant wealth transfers. These characteristics of transmission pricing are bound to create a certain amount of tension between those who are required to pay.

We believe that there is little inherently wrong with the current TPM – it is stable, well understood and contains clear definitions that provide little scope for disputes. However, in the current context, with significant generation investment planned and a need to upgrade the grid, especially in the regions, we welcome this TPM review. Just as the regional coincident peak demand (RCPD) based allocation of the interconnection charge in the current TPM provides a signal to moderate peak grid use¹, there is the potential for further locational price signalling in the TPM. Two examples where a review could be of benefit are as follows:

Signalling the long run cost of transmission to generators

Currently, generators see the cost of using the grid (the cost of losses and constraints, as reflected in nodal prices), but the only

¹ The RCPD provides a signal to moderate peak grid use in the Upper North Island and Upper South Island regions, where significant future investment is likely. It should be noted though, that any actual response to the RCPD-based charge may be limited by the fact that the price-quality path regulation applied to distribution companies under the Commerce Act 1986 permits distribution companies to treat transmission charges as pass through costs. Although outside the scope of this review, the rationale for this decision may need to be reconsidered if locational signals to offtake customers are to have any commercial impact.

locational signals they see with respect to the cost of building the grid are connection charges and the HVDC charge. If a generator erects a wind farm in the Waikato or Southland, they pay only their connection costs and the HVDC charge in the case of the Southland connection, despite the fact that building in Southland may have significant cost consequences for the core grid. These cost consequences (and an assessment of comparative net benefits) are currently evaluated using the Grid Investment Test (GIT), but this has proved to be an imperfect instrument when it comes to replicating new generation investment decisions. Given the move towards the development of more (potentially remote) wind generation, it is timely to consider signalling long run transmission costs directly to generators, in order to encourage appropriate generation investment decisions.

Regional grid investment

The large core grid upgrades required in the near term have been approved by the Electricity Commission and, from a grid planning perspective, the focus is moving to the regional parts of the grid in the medium term.

Refurbishment of older grid assets creates opportunities to rationalise the existing grid for overall net benefit, but the current interconnection/connection definition may significantly increase transmission charges to smaller communities. The existing definitions also appear to create incentives for transmission customers to investigate investment options that are not economically sensible from a national perspective. This creates tension between Transpower and our transmission customers and also absorbs scarce resources in both organisations as we strive to arrive at appropriate outcomes.

It is timely to review the interconnection/connection definitions to identify whether or not outcomes that do not penalise regional development and better align national economic and commercial incentives could be achieved.

The Commission has developed a range of options that are designed to signal more accurately the future costs of investment in interconnection assets or to inject a greater element of the beneficiary pays concept to interconnection and connection charges: augmented nodal prices, a tilted postage stamp, load flow based and “but for” approaches to allocating charges. We outline our view on each of these below.

The pricing methodology review currently being undertaken by the CEOs’ Forum should also be used to inform the Commission’s review. Our understanding is that the emerging view from the CEOs’ review is that there is some value to sending an investment signal to generators in the form of a “tilted postage stamp”. This would send a better locational signal than the existing HVDC charge, although there is some uncertainty about whether the expected net benefits of such an

approach would warrant its introduction. Even if the tilted postage stamp method is not found to be justified, the HVDC charge should be abandoned and the costs concerned absorbed into the interconnection charge. We agree with these conclusions.

We do not agree with the Commission's contention that the pricing principles should not be reviewed. At present, there are too many pricing principles, they conflict with one another and they target outcomes that transmission pricing alone cannot achieve. If changes to the TPM are considered, the principles will be referred to; consequently, they should be reviewed.

Finally, the proposal to incorporate an unconditional service guarantee (USG) or a (compulsory) voluntary insurance scheme into the TPM is inappropriate in a policy sense and open to challenge legally. Transpower supports the concept of performance incentives in principle, but any performance incentives developed and agreed should form part of revenue setting under the individual price-quality path regulation to be developed pursuant to Part 4 of the Commerce Act 1986 – they should not be part of the TPM. The TPM is the method used to allocate Transpower's revenue to its customers – it should not be used to modify the revenue or allocate part of it to Transpower itself. These concerns are explained more fully in Appendix 1 of this submission. Such concerns highlight the importance of ensuring a consistent approach to market design, as highlighted in our companion overview submission.

These comments are expanded upon in the following sections.

2. Review of the pricing principles

We believe the pricing principles should be reviewed with a view to simplifying them, making them more consistent with one another and more realistic in terms of the outcomes that transmission pricing can achieve in practice. The principles should also require the methodology to be designed with the aim of producing reasonably consistent prices from year to year using clear definitions that minimise the scope for the application of the methodology to be disputed. A strength of the methodology which came into force on 1 April 2008 is the clarity of its definitions – this has resulted in a low incidence of disputes over the application of the methodology, which represents a marked change from previous methodologies.

At present, rule 2.2 of section IV of Part F requires the pricing of new and replacement investments in the grid to provide beneficiaries with “strong” incentives to identify least cost investment options, including energy efficiency and demand management options. In reality, particularly for offtake customers, transmission charges form only a small proportion of customers' total costs, so it will never be possible for transmission charges to provide strong incentives to modify customers' investment behaviour.

Similarly, while transmission charges can provide locational signals, to some extent, it is difficult for these signals to be “clear”, as required by rule 2.3, particularly in relation to the interconnected grid.

With respect to rule 2.1 (“user pays”) and rule 2.4 (“non distortionary sunk cost recovery”) our view is that these principles were meant to apply to different categories of assets on the grid, i.e. where it was possible to allocate costs on a user pays basis (e.g. for the connection assets) this should be done, but where this was not possible (e.g. for the interconnection assets) costs should be allocated in a way that minimises distortions to the production/consumption and investment decisions of grid users.

During the 2004-07 review of transmission pricing, the Commission took a different approach. It required, by way of the February 2005 *Statement of Reasons in relation to the Proposed Guidelines for Transpower’s Pricing Methodology*, that the principles in rules 2.1, 2.2 and 2.4 should be applied to all grid assets, but that rule 2.1 (“user pays”) should be interpreted to mean “causer pays” and should be ranked ahead of rule 2.2 (“beneficiary pays”) and rule 2.2 should be ranked ahead of rule 2.4 (“non distortionary sunk cost recovery”). Meanwhile, the guidelines required the interconnection charge to be “postage stamp” in nature, which was clearly consistent with the principle in rule 2.4, but not the principles in rules 2.1 and 2.3, or for that matter, the principle in rule 2.3 (“clear locational signals”).

That this sort of intractable interpretation and application problem can arise is, in our view, sufficient reason for reviewing the pricing principles with a view to simplifying them and making them more realistic. A possible revised set of principles could be something like:

- 2.1 recover costs on a beneficiary pays basis to the extent that this is reasonably practicable;
- 2.2 where it is not reasonably practicable to recover costs on a beneficiary pays basis, recover costs in a way that minimises the distortions to the production/consumption and investment decisions made by grid users;
- 2.3 consider introducing locational signals if such signals could reasonably be expected to result in economically meaningful improvements to consumption or investment decisions made by grid users;
- 2.4 design the methodology to produce charges that will be reasonably consistent from year to year, using clear definitions that provide little scope for the application of the methodology to be disputed.

The principles in rule 2.5 (which is usually considered to refer to nodal pricing) and rule 2.6 (recognising the linkages with other elements of market pricing) could remain.

The historical experience cited above also supports the case for amending section IV of Part F to clarify that the only means by which the Commission or other regulator may direct Transpower on the application of the pricing principles is via the pricing guidelines. We recommend that the possibility of progressing such an amendment be investigated.

3. Augmented nodal pricing

We do not believe that augmented nodal pricing is a practicable way of allocating transmission revenue. It would involve a lot of subjective assessments and would be bound to be controversial. It would also be likely to increase pricing volatility and make prices less predictable over time.

The concept that it might be possible to identify the optimal time at which to augment transmission assets, this being the point at which the transmission rentals attributable to the asset concerned just equal an economic return on the needed investment, is not practically applicable in any meaningful sense.

The concept also fails to consider the fact that transmission investments take many years to plan and implement and there are many risks and uncertainties associated with practical implementation – if these risks were properly valued, it would often be difficult to justify an argument that investments had been progressed too early. There are also asymmetric risks associated with commissioning new investments too late rather than too early – the costs of being too late vastly exceed the costs of being too early.

In practice, transmission investment planning does not take account of changes in nodal prices, but rather is based on analyses of secular demand trends and expected generation patterns, and aims to implement investments in order to avoid unserved energy as those trends play out. In a sense, it could be argued that this is in some ways equivalent to forecasting future nodal prices, as nodal prices could reasonably be expected to rise downstream of constraints as spare transmission capacity is utilised and constraints increase in number and extent. However, the actual observation of this phenomenon would occur far too late to be of any practical use for planning purposes.

It is also the case that, where there is no meaningful generation downstream of constraints, the nodal price will not rise downstream of a constraint – instead load would be shed, which would likely result in a drop in nodal prices rather than an increase (although this outcome may be modified by the introduction of scarcity pricing, as proposed by one of the other papers currently being consulted on).

If nodal prices were increased downstream of constraints and reduced upstream, the intention would presumably be to encourage reduced

consumption and more generation investment downstream and increased consumption and less generation investment upstream. In practice, only a small (but increasing²) proportion of offtake customers have time of use metering, and for much consumption the short-term value of electricity far exceeds its cost, meaning that load responsiveness to nodal prices is muted. For generators, there may be some marginal impact if they were convinced that the charging method was a permanent feature of the energy and transmission pricing environment. However, we understand that the generators have expressed the view that, in most instances, apart from the HVDC charge, transmission charges are not sufficiently material to influence location decisions.

Finally, a methodology for recovering the balance of interconnection revenue not recovered by the augmented nodal pricing methodology would still be required. In the situation where it was determined that transmission investment was being optimally timed, this “backstop” methodology would need to recover the full amount of the interconnection revenue.

On balance, we recommend that the industry and regulators not undertake further work on the augmented nodal pricing method. It is not practicable, its economic rationale is flawed, it would require too many subjective assessments to be made (which would make it vulnerable to challenge) and it would be unlikely to modify grid user consumption and investment behaviour significantly.

4. Load flow based approaches

We do not favour load flow based approaches except possibly for relatively simple situations involving two or three grid users only. Load flow based allocation methods rely on assumptions and, in significantly interconnected parts of the grid, these assumptions may bear little relationship to the beneficiary pays principle in practice.

Load flow methods also produce variations in prices from year to year that are both large and not readily predictable. A load flow based method was used by Transpower in the 1990s and was widely criticised at the time. The most heavily criticised feature of the method was that it produced price changes that could not be easily explained to grid users in any way that they could understand. Issues of null points prevailed, and consumers with constant loads would see their charges fluctuate significantly and unpredictably as a result of the actions of others.

These methods are also resource intensive insofar as they require a great deal of modelling for interconnected parts of the grid. Despite the extra resources needed to produce the pricing outputs, it is not clear that

² Transpower hopes and expects that over time smart grid technology will allow more consumers to see and respond to the nodal prices, but, nevertheless, expects price responsiveness to be at best partial for residential, commercial and light industrial consumers.

the prices that result are any more “correct” in terms of the pricing principles than those produced by administratively simpler methods.

An exception may be where there are only two or three grid users and the process may be both more tractable and more meaningful. These situations may occur in regional parts of the grid and may have merit there, but, for the interconnected grid, we recommend that the industry and regulators not undertake any further work on load flow based methods.

5. Tilted postage stamp approach and the HVDC charge

A tilted postage stamp approach could potentially provide a more general locational signal for generation investment than the current HVDC charge. The main challenges associated with the concept relate to how the magnitude of the tilt would be calculated and how it might be varied over time.

The consultation document suggests that the tilted postage stamp should also be applied to loads (indeed primarily to loads). We do not believe a good case can be made for applying a tilted postage stamp charge to loads, because, for most loads, electricity forms only a small proportion of their total costs and transmission represents less than 10 per cent of the total cost of electricity. Hence, any location signal provided to loads by way of transmission charges is likely to have little effect on actual consumption and investment location decisions.

However, in some cases, locational signals applied to offtake customers can be effective, if the customers concerned choose to respond out of concern for the wider national interest. A relevant example is the fact that the RCPD-based interconnection charge has driven greater utilisation of the grid in the Upper South Island. Nevertheless, the fact that the price-quality path regulation applied to distribution companies under the Commerce Act 1986 allows them to treat transmission costs as “pass through” costs tends to limit the effectiveness of any locational signals applied to offtake customers. If the TPM is to include more locational signals aimed at offtake customers, it may be appropriate for the Commerce Commission to review the way in which it permits transmission charges to be treated by distribution companies. Obviously, this is outside the scope of the current review.

An argument against charging generators for interconnection assets is that the charge would affect their supply curves and consequently end up being incorporated into the energy price, with the result that part of the cost of transmission would be recovered by a flat \$/MWh charge across the country, which would undermine the efficiency gains associated with charging based on consumption peaks (albeit that many smaller final consumers have these charges “rolled up” into their total energy charges in any event). However, the tilted postage stamp concept would apply charges at different rates to different generators,

and none at all to some, so this “energy price pollution” effect should be limited if this approach were adopted.

We believe that the tilted postage stamp concept has merit as a possible pricing mechanism by which to send a general locational signal for generation investment to replace the HVDC charge. The CEOs’ forum is also investigating the efficacy of a tilted postage stamp approach and we recommend that their work be used to inform the Commission’s review.

Finally, we note that it seems counterproductive to be trying to improve locational signalling through the TPM while at the same time recommending damping locational signals by introducing LRAs (accepting that LRAs are not a strongly preferred option by the Commission). This sort of potential inconsistency is something that should be considered by the market development programme as a whole.

6. Other high-level issues: connection-interconnection and node-link definitions with respect to investment incentives and boundary consistency

Two issues that have arisen as part of the development of some regional grid investment proposals is that the current connection-interconnection and node-link definitions can sometimes provide outcomes that are both inconsistent with regional development and incentivise transmission customers to prefer investment alternatives that are economically sub-optimal from a national perspective because they would result in lower transmission charges for the customers concerned.

In some instances, the prudent discount policy could potentially deal with this situation, by aligning the commercial and economic drivers, but not in all cases. Consequently we believe that a high-level option worthy of consideration is a review of the connection-interconnection and node-link definitions in relation to investment incentives. In relation to this proposal, we note that charges for “deep connection” assets recovered from connected parties represent less than five per cent of total transmission revenue. This review could also extend to examining the possible impact of zonal interconnection charges on investment incentives and an ability to recover via zonal charges the enhancement of interconnection assets beyond the investment that is justified under the GIT where all affected parties are willing to pay for this. (We note that investment to achieve enhanced service levels is already possible via investment contracts or, for connection assets, via the provisions in rule 5 of section II of Part F of the Rules. Zonal charging for interconnection assets could potentially add an additional means by which to achieve this goal.)

In the consultation on managing locational price risk, forms of zonal and/or hub pricing are being considered for energy prices and locational

hedges, and any such hubs should ideally form a basis for "over-the-counter" energy hedges and futures markets.

There are other boundary definitions currently in use, in particular:

- the grid points at which prices are determined;
- the System Operator control boundary, which defines where security constrained dispatch is applied to manage contingent events; and
- the core grid definition in the grid reliability standards, which defines where N-1 security must be maintained by grid investment.

The opportunity exists, through co-ordination of the various market development initiatives, to consider the possible consolidation or alignment of some of these boundaries. There are likely to be benefits over time from doing so, through the greater alignment of commercial, operational and planning frameworks and investment incentives.

7. "But for" method for determining connection charges

"But for" is essentially a "causer pays" method that allocates costs to the final connecting party that appears to trigger the need for additional investment in the interconnected grid. In the United States, the PJM interconnection uses this method to allocate costs for generator connections only. The method is reasonably uncontroversial in PJM, but this is probably because the costs at stake there are generally small relative to total project costs and the overall value of the PJM grid. This would probably not be the case if the method were applied in New Zealand, because our grid investments tend to be relatively "lumpy".

The main downside of "but for" is that others that benefit from an interconnection investment, but are not deemed to have "caused" it, can free ride on an investment paid for by the "causer". Although a connecting generator can necessitate the construction of network upgrades to accommodate the connection, there are potentially significant spillover effects that benefit other users of the existing grid. A "but for" approach does not take into account the benefits that accrue to other users of the grid and so may overstate the costs attributable to the generation plant.

Upgrades may also be associated with a number of new power plants – in this situation, identifying the "causer" of the upgrade would be difficult and contentious. Thinking historically, it could be argued that, "but for" the Clyde power station, Pole 2 of the HVDC link would not have been needed. Does this mean that the transmission costs associated with Pole 2 should be allocated to Contact, or should some of the cost be shared by other South Island generators that also benefited from the upgrade?

In many cases, the need for transmission investment is driven principally by secular growth, but this fact may be masked by a final single

connection that appears to “cause” the need for grid augmentation. In this situation, allocating all the cost of the augmentation to the final “causer” but for whom the investment would not have been needed may be considered inequitable.

Relative investment lead times may also lead to additional complications. Transmission investment lead times are so long that Transpower may need to commit to grid augmentations before new generation plants are constructed and commissioned. Once the transmission investments are committed, there is no point (from an efficiency point of view) to allocating costs to the generators as they are subsequently commissioned.

We recommend that the industry and regulators undertake no further work on the “but for” method.

8. “Green field” spur lines treated as interconnection assets

We believe that it will often be possible for the parties that will benefit from new “green field” spur lines to determine the best size for these lines via normal commercial engagement and agreement. However, in some cases, it may be possible to demonstrate that the most economic investment from a national perspective would be something different from that chosen by the first mover in a new green field location (such as a region with a substantial wind resource). In this sort of situation it may be appropriate for there to be a “backstop” provision, which would enable the investment to be undertaken by Transpower, if it can be economically justified, and a return on some of the capacity created recovered as if the asset were an interconnection asset until the capacity is fully utilised.

Consequently, we believe that the concept of permitting such a “backstop” provision with respect to green field connection asset investment should be further investigated by the industry and regulators.

9. Unconditional service guarantee or (compulsory) voluntary insurance

The Commission has included the concept of an unconditional service guarantee (USG) as an item for discussion. Also floated is the idea of a voluntary insurance scheme (which, ironically, would be compulsory for Transpower to offer). We believe these concepts are flawed in a number of ways and unlikely to achieve their stated objectives in practice. The reasons for this view are discussed in Appendix 1. We recommend that the industry and regulators not undertake any further work on these proposals.

Transpower supports the concept of performance incentives in principle, but any performance incentives developed and agreed should form part of revenue setting under the individual price-quality path regulation to be

developed pursuant to Part 4 of the Commerce Act 1986 – they should not be part of the TPM.

10. Treatment of reactive compensation

At present, a return on static reactive power assets that form part of the grid is recovered by way of the TPM, but the cost of voltage support procured by the System Operator is recovered under Part C of the Rules. There would be merit in ultimately aligning Part F with all the other reactive power arrangements in the Rules.

Recently, Transpower, following industry consultation, has developed, and is currently implementing, grid support contracts for voltage support. Under this arrangement, the allocation of costs for voltage support service will change, viz.:

- Currently, costs of the System Operator's voltage support ancillary service contracts are allocated in accordance with rule 11.6 of section IV of Part C of the Rules. This allocates costs to distributors in the zone in which they occur.
- Under grid support contracts, costs will be allocated in accordance with the TPM, which currently allocates interconnection costs to offtake customers (distributors and major industrial customers) nationwide.

We believe that aligning the methods used to allocate the costs of medium to long term real and reactive grid support, from both transmission and non-transmission sources, is appropriate, as they are substitutes to some degree. The TPM review should therefore investigate the most appropriate means by which to allocate transmission and non-transmission voltage support costs.

Currently, the rules require, by way of the connection code in the benchmark agreement, minimum requirements for the offtake power factor. These have proved very contentious with the industry and their workability has been questioned. Alternative options to signal reactive charging through the TPM could provide incentives for appropriate investment.

However, the sort of arrangements used to incentivise investment in static reactive power assets need to be examined with care to ensure that they do not result in too much or too little investment in reactive power assets. A proper analysis of the costs and benefits should be carried out before changes are made.

11. Treatment of other transmission alternatives

This section discusses the treatment of transmission alternatives other than for reactive compensation, discussed in the previous section. These are likely to take the form of grid support contracts for capacity

services to manage the risks of late delivery, higher than forecast demand growth and asset failure, or to enable investment deferral.

Some have expressed a view that providers of approved transmission alternatives should be able to gain access to regulated funding independently of any agreement with Transpower. We disagree with this view, as only Transpower is in a position to certify that the provision of transmission alternative services is actually needed at any particular time.

Frontier has also asserted that transmission alternatives should face similar transmission pricing signals to grid-connected loads and generators and that this suggests that market interventions (such as grid support contracts) should not be necessary. This seems to imply that investments on the interconnected grid are market-driven rather than the reality that they are planned by Transpower and regulated. In fact, the latter is the case today because the market-driven approach proved not to be practicable for the common good parts of the network.

Given that investment in the interconnected part of the network is centrally determined by Transpower (in consultation with the industry and with regulatory approval), there may be instances where grid support contracts may be the most economic way of dealing with potential unserved energy for at least a short period. In some cases, there may also be a need for grid support contracts because of regulatory uncertainties (i.e. where the administration of industry or environmental regulation does not enable grid upgrades to be approved in time to avoid the risk of unserved energy).

As the Commission notes, transmission alternatives are routinely considered as part of the fleet of options examined as grid upgrade plans (GUPs) are developed, and other industry participants have the opportunity to propose alternatives as part of the GUP approval process.

On balance, we believe that the current treatment of transmission alternatives should be retained.

12. Recommendations

In summary, Transpower recommends that:

- a) the pricing principles in rule 2 of section IV of Part F of the Rules be reviewed, with a view to simplifying them, making them more consistent with one another and more realistic in terms of the outcomes that transmission pricing can actually achieve in practice;
- b) an investigation be undertaken into the possibility of amending section IV of Part F to clarify that the only means by which the Commission or other regulator may direct Transpower on the application of the pricing principles is via the pricing guidelines;

- c) further work be undertaken on the “tilted postage stamp” concept as a possible pricing mechanism by which to send a general locational signal for generation investment to replace the HVDC charge. We recommend that the work undertaken by the CEOs’ forum on a tilted postage stamp approach be used to inform the Commission’s review;
- d) if the “tilted postage stamp” concept is found not to be worthwhile, the separate HVDC charge should still be abandoned and the HVDC costs recovered via the interconnection charge;
- e) augmented nodal pricing, load flow based allocation methods and the “but for” method for determining connection charges not be progressed further;
- f) the connection-interconnection and node-link definitions be reviewed in relation to investment incentives and the equity of cost allocations in relation to increased regional grid investment;
- g) the possible impact of zonal interconnection charges on investment incentives be examined and linked with a possible enhanced ability to contract for transmission investment beyond that which could be justified by the GIT (noting that such investment is already possible via investment contracts or, for connection assets, via the provisions in rule 5 of section II of Part F of the Rules);
- h) the proposal to incorporate into the TPM an unconditional service guarantee not be progressed further, as performance incentives should be part of revenue setting under Part 4 of the Commerce Act 1986, not part of the TPM;
- i) the proposal to incorporate into the TPM a compulsory requirement for Transpower to make available to customers a regulated insurance arrangement not be progressed further;
- j) the possibility of treating some or all of the capacity of “green field” spur lines as interconnection assets, as a “backstop” provision, be investigated further;
- k) the most appropriate means by which to allocate transmission and non-transmission voltage support costs be investigated, noting that pricing incentives generally offer more flexibility than regulated requirements;
- l) the current treatment of transmission alternatives be retained.

APPENDIX 1 – ANALYSIS OF THE UNCONDITIONAL SERVICE GUARANTEE (USG) AND VOLUNTARY (BUT COMPUSLORY) INSURANCE PROPOSALS

UNCONDITIONAL SERVICE GUARANTEE

A.1 Does not address the problem identified by the TPTG

The consultation paper presents the USG concept as if it were put forward in response to a concern raised by the Transmission Pricing Technical Group (TPTG). This is a misrepresentation. The concern raised by the TPTG was that, in circumstances where a transmission customer wished to receive a different (typically higher) level of transmission service, and was willing to pay for this service, it might be possible to find better ways to tailor transmission charges more directly to the level of service desired.

The issue was not about how to compensate customers for non supply or incentivise Transpower to improve supply performance. This is an incorrect interpretation of the TPTG discussions by the Commission.

A.2 Including a USG in the TPM would be legally invalid

The proposal to incorporate the USG into the TPM would put it in entirely the wrong place – revenue allocation rather than revenue setting. The TPM is the methodology for allocating Transpower’s permitted regulated revenue to its customers – it should not be used to modify the revenue or to allocate part of it to Transpower itself rather than to its customers. The power to make regulations or rules dealing with the transmission pricing methodology is contained in section 172D(1)(7) of the Electricity Act 1992. It is clear from that section that the primary purpose of the TPM is to allocate Transpower’s revenue requirement to various classes of customer. There is no power to recover part of the revenue from Transpower itself and, while subclause (b) of section 172D(1)(7) does provide for the imposition of quality standards generally, it says nothing about imposing a penalty on Transpower for a breach of such standards.

A.3 Proposal cuts across existing contractual provisions

It would be inappropriate for a USG to be imposed as part of the TPM when clause 20.2 of the Benchmark Agreement expressly limits Transpower’s exposure to a customer’s direct loss and clause 20.3 caps Transpower’s total exposure. Similar provisions are found in the new investment contracts and the same concept (but different limits) are in the Comalco Agreements.

The contracts also cap customers’ liability to Transpower for contractual breaches. This balance of liabilities is also present in the penalty

provisions of the Electricity Governance Regulations 2003. If the USG proposal were to be implemented, this balance of liabilities would be upset. There may also be a perverse incentive for customers to favour regulated investment rather than contractual investment.

It may also be ultra vires of the Commission to recommend a change to the Rules that imposed, by way of a USG, such a large penal charge; this is particularly the case given that the USG is inconsistent with existing provisions of contracts sanctioned by the Rules.

A.4 Moral hazard and perverse incentives

The concept is poor policy, regardless of its legality. The proposal is that compensation be paid at \$20,000/MWh for any loss of energy consumption caused by an unplanned loss of supply resulting from a failure of transmission assets. The compensation would be based on a comparison between actual consumption from the grid and historical consumption levels. In reality, for some customers, the compensation would represent more utility to them than the energy they would otherwise have received – this may encourage them to take a cavalier approach to the maintenance of assets that, if they failed, might contribute to a failure of grid supply. It is also possible that the use of an historical comparator may lead to an over-estimate of the actual loss suffered by the customer, e.g. consumption in the absence of the unplanned outage may have been lower than historically observed because of the economic recession.

Once an unplanned grid outage has occurred, actions by the distribution company or directly connected customer affected may either facilitate or delay the restoration of grid supply. For a customer that values the compensation more than the energy, there would be a temptation to act to delay restoration.

These perverse outcomes would be incentivised by the USG and are clearly contrary to the objective of improving grid performance.

A.5 Risk of multiple penalties for a single incident

At present, supply incidents that result in Transpower breaching the quality threshold specified in its administrative settlement with the Commerce Commission could lead to the imposition of pecuniary penalties, if the Commerce Commission chose to take action through the Courts. In addition, the same incidents may result in Transpower facing liability for direct damage to a customer's assets under the Benchmark Agreement, if the Outage Protocol procedures were not correctly followed, or liability for direct, indirect or consequential losses faced by a designated transmission customer if there was a breach of the interconnection rules. (These liabilities are capped.) In effect, this means that, in some circumstances, Transpower may face a potential

double jeopardy exposure to penalties for a given incident or set of incidents.

The proposed incorporation of a USG into the TPM would add a further potential layer of penalties, effectively creating a triple jeopardy exposure to a single incident or series of incidents in some circumstances. This would be an unacceptably onerous outcome if it occurred.

The precise form of the individual price-quality regulation to be applied to Transpower under Part 4 of the Commerce Act 1986 is not yet certain. However, it is expected to incorporate some form of quality incentive arrangement – this is the correct place for it.

A.6 Unconditional nature of the USG inappropriate

Failure of transmission assets can occur for a variety of reasons, including true force majeure events, such as earthquakes, actions by third persons over whom Transpower has no control (e.g. the forklift driver who caused the recent outage in Auckland and Northland), or inappropriate actions by industry participants. As noted above, the duration of supply interruptions may also be affected by the actions of distribution companies or directly connected customers.

The USG proposal would require Transpower to compensate customers even when the supply interruption in question was not Transpower's fault or occurred despite Transpower's efforts. This would be inequitable and, in our view, would not create the right incentives to encourage improved performance. It is one thing to impose an administrative penalty sufficient to be meaningful when the entity being charged is at fault and quite another to do so when there is no fault and the beneficiary of the charge may be able to influence the size of the charge.

A.7 USG costs borne either by other customers or taxpayers

It is not clear to what extent Transpower would be able to insure against the financial exposure represented by the USG. If it were able to do this, the costs of the USG exposure would be recoverable from its customers (i.e. on balance those not compensated) as part of its operating expenses. If Transpower were not permitted to insure against this risk, the net cost would ultimately be borne by the taxpayer. It is not clear that either of these outcomes would provide a meaningful performance incentive.

A.8 Most consumer supply interruptions not due to transmission equipment faults

Of the total electricity supply interruptions experienced by final consumers, only a small proportion of these, in terms of both number and energy supply lost, are due to transmission equipment faults. Consequently, the USG, even if it had some impact on Transpower's

performance, would be unlikely to produce a meaningful change to the reliability of electricity supply experienced by final customers.

A.9 No evidence that such schemes actually improve performance

The Commission has provided no empirical evidence that USG arrangements actually improve performance. We believe that they are unlikely to do so in practice. We also understand that the United States pest control company that was cited as an example of the application of a USG when the Commission originally proposed this concept, as part of the process that led to the development of the benchmark Agreement, has since gone bankrupt – this is despite this firm’s charges being ten times those of its competitors (or perhaps because of this fact).

“VOLUNTARY” INSURANCE SCHEME (COMPULSORY FOR TRANSPOWER TO OFFER)

Under this proposal, insurance against the negative effects of outages would be voluntary to the insured party, but it would be compulsory for Transpower to offer, and Transpower’s ability to price the insurance properly would be heavily constrained.

The consultation paper, at paragraph 3.4.23, describes the proposal as follows:

“3.4.23 Under a voluntary insurance option, Transpower would make insurance for loss of supply available to all customers (including parties, such as retailers, who are not designated counterparties). The requirement to offer insurance would be specified in the Rules. Parties could choose their level of insurance (in terms of \$/MWh taking into account potential for unserved energy valued at their own value of lost load and risk mitigation strategies). Transpower would base the premium on the customer’s load factor, the assessed reliability of the relevant grid exit point and the expected level of supply interruptions using a detailed regulated pricing methodology.”

We object to this proposal, because, first, it would be compulsory to offer, which is not the case for a conventional insurer. Commercial insurers are free to decline to take on risks at their own choosing, usually based on an actuarial assessment of the value of the risk. Second, the wording of the proposal seems to indicate that how Transpower could set the premiums for such insurance would be heavily constrained by a “detailed regulated pricing methodology”. The grid users most likely to take up the insurance would be those that are most vulnerable to outages, and it appears that the constraints that would apply to the setting of premiums may be such that Transpower may be restricted from setting actuarially correct premiums for these customers.

A commercial insurer would also reduce its overall risk exposure by maintaining a diversified portfolio of risks and by reinsurance. Transpower would not be permitted to diversify its exposure by insuring other risks and its ability to obtain reinsurance for an insurance product of this sort would probably be limited or, at best, costly.

Transpower is not in the business of providing insurance and should not be required to do so. Furthermore, the TPM is not the right place to include a requirement to provide insurance. The proposal also seems to contemplate that the requirement would apply to non transmission customers, such as retailers, which are not otherwise subject to the TPM. This would create a further complication.

As noted in section 8.6 above, in relation to the USG proposal, the TPM is the methodology for allocating Transpower's permitted regulated revenue to its customers and it should not be used to modify the revenue or to allocate part of it to Transpower itself rather than to its customers. There is nothing in section 172D(1)(7) of the Electricity Act 1992 (which creates the regulation making power that enables the TPM to be incorporated into the rules) that permits rules to be created to require Transpower to offer a financial instrument to customers, which is what a compulsory requirement to offer voluntary insurance to customers would amount to. The proposal would therefore be legally invalid, unless the Act were amended.

The compulsory voluntary insurance proposal would also have the effect of increasing or decreasing the revenue requirement, depending on how many transmission customers opted into or out of the scheme. This would create a further complication, by making the TPM part of the revenue setting process in addition to revenue allocation, and probably necessitating the re-introduction to the TPM of some form of economic value adjustment mechanism.

On balance, we believe the compulsory voluntary insurance concept should not be progressed further by the industry or regulators. Requiring Transpower to operate as an insurer, but restricting its ability to behave commercially as such, would be unduly onerous and inappropriate. Incorporating a requirement to offer a financial instrument into the TPM would unnecessarily complicate the revenue allocation methodology and make the TPM, in part, a mechanism affecting the size of the revenue. The apparent intention to require the financial instrument to be offered to non transmission customers, such as retailers, would represent a further complication of the TPM. The proposal would also be *ultra vires* given the current wording of the rule making power in the Electricity Act 1992. There is currently no legal power to impose on Transpower the obligation to offer a financial instrument against its wishes.

APPENDIX 2 – CONSULTATION QUESTIONS

Question	Transpower response
Q 1. To what extent do you agree that nodal prices can provide efficient signals for the use of the transmission network?	<p>In the sense that nodal prices provide the correct signals for efficient dispatch, they do provide the right signals to enable the transmission network to be used efficiently in the short run.</p> <p>However, nodal prices are not particularly effective at providing efficient consumption signals. This is because, first, only a small (but increasing³) proportion of offtake customers have time of use metering. Second, for most offtake customers, apart from some large industrials, electricity represents only a small proportion of their total costs.</p>

³ Transpower hopes and expects that over time smart grid technology will allow more consumers to see and respond to the nodal prices, but nevertheless expects price responsiveness to be at best partial for residential, commercial and light industrial users.

<p>Q 2. To what extent do you agree that nodal prices can provide efficient signals for investment in generation and load projects?</p>	<p>Again, most offtake customers with loads below 350kVA do not see the nodal prices directly, so any impact on investment decisions depends on how the nodal prices are passed onto these customers by retailers. For most offtake customers, electricity represents only a small proportion of total costs, so electricity costs are not likely to be instrumental in driving decisions either to invest or not to invest or to invest at one location rather than another.</p> <p>For some large loads, such as metal smelters and pulp mills, electricity costs may comprise a large enough proportion of total costs to influence decisions whether or not to invest or the location of investment. Whether or not the impact of constraints on nodal prices downstream and upstream of constrains is sufficient to affect investment decisions depends very much on the extent to which the potential investors perceive the constraints to be likely to be a permanent fixture or likely to be relieved at some stage by transmission investment.</p> <p>For those few potential investors for whom electricity costs are important enough potentially to affect investment decisions the impact of losses on nodal prices would be expected to be taken into account, because the price differentials due to losses are a permanent feature of nodal pricing (albeit that the losses can be affected by generator location decisions).</p> <p>For generators, the impact of losses on nodal prices would be expected to be taken into account, since this would be expected to be a more or less permanent feature of the nodal prices. However, generators are probably unlikely to locate downstream of a regular constraint solely in order to benefit from higher nodal prices, because of the risk that this advantage might be extinguished in the future by transmission investment.</p> <p>Information provided by generators also suggests that generation location decisions tend to be driven more by factors such as resource consents, capital costs, expected operating costs and fuel availability than by forecasts of nodal price differentials.</p>
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<p>Q 3. Do you consider that the nodal prices in New Zealand may be inappropriately suppressed due to the transmission system being augmented ahead of demand?</p>	<p>No. If the risks associated with project delivery and commissioning are properly valued, the asymmetric nature of the costs of investing too late rather than too early are properly considered⁴, and the significant economies of scale in transmission investment, we do not believe that any of the grid upgrades proposed by Transpower and approved by the Electricity Commission can be shown to have been too early. The Commission expressly noted that it took these factors into account when making its decisions, even if these risks were not expressly quantified in monetary terms.</p> <p>The only recently approved grid investment that may have been timed incorrectly is the replacement of Pole 1 of the HVDC link. The commissioning of the replacement will probably be about four years later than the ideal date. This deferred investment approval decision will have inappropriately inflated the average nodal price differential between Benmore and Haywards.</p>
<p>Q 4. Can you provide examples where a transmission alternative could have been undertaken instead of an investment in the grid?</p>	<p>No. Various alternatives can always be imagined, but none has eventuated with sufficient certainty to enable grid investment to be deferred.</p> <p>Transpower is currently evaluating responses to a request for proposals for voltage support grid support contracts in its Upper North Island Reactive Support Investigation. Transpower will seek approval from the Commission for selected transmission alternatives early in 2010.</p>
<p>Q 5. Do you agree that if locational transmission pricing signals are required to promote efficient participant investment decisions, both generators and loads ought to face these signals?</p>	<p>No, the case for loads to face locational signals is weak, because, for most loads electricity is only a small proportion of their total costs and transmission represents less than 10 per cent of the electricity cost, so, for most loads their locational decisions are not going to be affected by differential transmission charges. There is also the problem currently that the price-quality path regulation applied pursuant to Part 4 of the Commerce Act 1986 permits distribution companies to treat transmission costs as "pass through" costs. This obviously reduces the commercial incentive for distribution companies to respond to locational signals, although some do in practice.</p> <p>There is a stronger case for generators to face a locational signal, though the extent to which actual decisions to invest in particular locations will be affected by such a signal is a moot question.</p>
<p>Q 6. Are there any other jurisdictions whose electricity market arrangements should be examined to assist in the development of high-level transmission pricing options for New Zealand?</p>	<p>The international jurisdictions that have been surveyed by Frontier are sufficient to provide a fair picture of international practice with respect to transmission pricing.</p>

⁴ The costs associated with the unserved energy that would result from investing too late, if the investment were a reliability investment, would greatly exceed the lost return on alternative investments that would constitute the cost of investing too early.

<p>Q 7. Do you agree that the summarised issues Frontier identified from the Strata report are correct and relevant?</p>	<p>Not entirely. The observation:</p> <p>“The TPM does not link transmission prices paid by particular customers to the service levels they request or receive.”</p> <p>fails to recognise that, because of the common good nature of network assets, it is not possible, on the interconnected grid at least, to tailor the services provided or the prices charged to the service levels preferred by each individual customer, unless the customer concerned dominates a part of the network, in which case they will be able to pay for and receive the service they prefer and other customers connected to that part of the network will be able to free ride on the services the large customer has paid for.</p> <p>It is also inevitable that the level of service provided at the core of the network will be higher than that available at the periphery, unless <u>all</u> those connected to particular peripheral parts of the network are willing to pay more.</p> <p>For connection assets, the situation is different. Connection charges can be tailored to the level of service preferred by connected customers, and a mechanism for achieving this is already provided by rule 5 of section II of Part F of the Rules. For such a change to be made, the parties to the relevant transmission agreement must certify that they have consulted with all affected end use customers in relation to the proposed service levels or the proposed increase in reliability, and any resulting price implications, and there are no material unresolved issues affecting the interests of those end use customers.</p> <p>With respect to the statement:</p> <p>“Potential providers of transmission alternatives must contract with Transpower rather than being directly eligible for a regulated revenue source.”</p> <p>we believe this is entirely appropriate, as only Transpower is in a position to certify that the provision of transmission alternative services is actually needed at any particular time. In the absence of an agreement with Transpower, there is a risk that providers of transmission alternative services may be paid for their services at a time when the services are not actually needed as an alternative to transmission.</p> <p>If providers of transmission alternatives were to be able to gain access to regulated funding independently of any agreement with Transpower, it would require the regulator to take the role of operational central planner of the industry. This would not be good regulatory practice.</p>
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<p>Q 8. Are there other issues with the current transmission pricing that you think should be considered at this high-level options stage?</p>	<p>Yes, the current connection-interconnection and node-link definitions should be examined, because there appear to be some instances where the current definitions may be encouraging transmission customers to advocate investment proposals that would limit their own grid charges but not be economically efficient from the point of view of the nation as a whole. This review could be extended to examining the possible relationship between zonal interconnection charges and regional service quality preferences.</p> <p>The potential for aligning boundary definitions should also be investigated. There are likely to be benefits over time from doing so, through the greater alignment of commercial, operating and planning frameworks and investment incentives.</p>
<p>Q 9. Do you think it is appropriate to focus on locational cost allocation issues – as opposed to pricing structure issues – at this high-level stage of the review?</p>	<p>No. What could be termed pricing structure issues, such as the connection-interconnection definition, could be as economically significant as the locational cost allocation issues.</p>
<p>Q 10. Are there any particular Pricing Principles that ought to be given precedence over others?</p>	<p>As noted in the general discussion in this submission, Transpower believes that the pricing principles should be reviewed with a view to simplifying them and making them more realistic in terms of the objectives that transmission pricing can actually achieve in practice.</p> <p>If the current pricing principles are retained, none of the principles should be ranked higher than any of the others. This is because we believe that the original intention was that different principles should apply to different elements of the methodology. We believe the intention of the original rule drafters was that where it was possible to identify clearly the users of particular assets (e.g. connection assets) the principle in rule 2.1 should apply, but where this was not possible (e.g. for interconnection assets) the principle in rule 2.4 should apply. During the 2004-07 pricing review, the attempt to impose a blanket ranking of the pricing principles, by ranking the principle in rule 2.1 ahead of the principle in rule 2.2, and the principle in rule 2.2 ahead of the principle in rule 2.4 caused many practical problems when Transpower attempted to apply this directive. This was a particular problem insofar as the requirement to give precedence to the principle in rule 2.1 (“user pays” redefined by the Commission’s <i>Statement of Reasons</i> to mean “causer pays”) appeared to conflict with the requirement in the guidelines that the interconnection charge should be a “postage stamp” charge, which could not be “causer pays”.</p> <p>This problem is discussed in more detail in section 2 of the submission proper above.</p>

<p>Q 11. Do you agree that it is not appropriate to review the Pricing Principles at this time? If not, why not?</p>	<p>No, the pricing principles should be reviewed with a view to making them simpler, more consistent with one another and more realistic in terms of the objectives that transmission pricing can achieve in practice. The justification for a review is outlined in more detail in section 2 of the submission proper above.</p>
<p>Q 12. Do you think the existing TPM, combined with the GIT and nodal pricing provide appropriate operational and investment signals to existing and prospective participants? Please give examples or reasons for your answer.</p>	<p>Under the existing TPM, the charges for grid assets with private good characteristics (the connection assets and, arguably, the HVDC) are recovered from the beneficiaries of those assets and the charges for grid assets with common good characteristics (i.e. the interconnection assets) are recovered in a reasonably non-distortionary manner. Hence, for the existing assets, the operational consumption incentives are essentially correct.</p> <p>The current TPM does not signal the long run marginal cost (LRMC) of grid investment and does not claim to. To a large extent, this is not a problem, because investment in the interconnected grid is not undertaken in response to commercial incentives, but is centrally evaluated in accordance with the GRS, GEIP and GIT⁵. For connection assets, the beneficiaries of those assets pay for them, so they have the right commercial incentives to determine whether or not investment should be undertaken, and how much (with the possible caveat that lines companies may not always accurately reflect the preferences of final consumers).</p> <p>However, because the TPM does not signal the LRMCs of future grid investment, it might be argued that the consumption and investment decisions of offtake and generation customers may be distorted. This is probably not a material consideration for offtake customers, because, for most of them, electricity costs form a very small part of their total costs, and transmission charges comprise less than 10 per cent of their total electricity costs. However, the costs involved may be more material for generators, and may potentially affect their locational investment decisions in some instances, although transmission costs will be much less significant considerations than capital costs, other operating costs, the availability of fuel and resource consents. Nevertheless, the fact that transmission costs may sometimes be a significant consideration may warrant further examination of the possibility of introducing a tilted postage stamp interconnection charge for generators as a substitute for the HVDC charge.</p>
<p>Q 13. If not, are there relatively minor modifications that could be made to the existing regime to enable it to provide appropriate locational signals?</p>	<p>As noted in response to question 12 above, the introduction of a tilted postage stamp interconnection charge for generators, as a substitute for the HVDC charge, should be sufficient. If the tilted postage stamp approach does not prove to be worth introducing, the HVDC charge should still be abandoned and HVDC costs recovered via the interconnection charge.</p>

⁵ Grid reliability standards, good electricity industry practice, and the grid investment test.

<p>Q 14. Even if the existing approach does not provide efficient signals to participants, to what extent are participants' investment decisions likely to be distorted as a result?</p>	<p>For offtake customers, any distortion would be minimal, because, for most of them, electricity costs form a very small part of their total costs, and transmission charges comprise less than 10 per cent of their total electricity costs.</p> <p>For generators, transmission charges may be more significant in some case, though the instances in which transmission charges (other than the HVDC charge) would be critical to an investment decision would probably be few.</p>
<p>Q 15. Assuming there is a need for a locational element to transmission pricing, does the tilted postage stamp option provide a reasonable trade-off between signalling objectives and simplicity?</p>	<p>Yes – see discussion elsewhere in this submission, particularly section 5 above.</p>
<p>Q 16. What are submitters' initial views on the economic merits of the augmented nodal pricing approach and are these likely to be outweighed by practical implementation considerations?</p>	<p>The industry and regulators should not undertake any further work on the augmented nodal pricing method. It is not a practicable or economically efficient way of allocating transmission revenue. It would involve a lot of subjective assessments and would be bound to be controversial.</p> <p>See the discussion in section 3 of the main body of this submission.</p>
<p>Q 17. Assuming there is a need for a locational element to transmission pricing, is loadflow modelling a reasonable basis for cost allocation?</p>	<p>No. We do not favour load flow based approaches for allocating charges for interconnected grid assets. These methods apply arbitrary assumptions, which often bear little relationship to the beneficiary pays principle in practice.</p> <p>Load flow methods also produce variations in prices from year to year that are both large and not readily predictable. Transpower operated a method of this sort in the 1990as and it proved to be very unpopular with customers ta the time.</p> <p>We recommend that the industry and regulators not undertake any further work on load flow methods for allocating the costs of the interconnected grid. See section 4 of the body of this submission for further discussion.</p>
<p>Q 18. If so, do you have a view on whether the CRNP, ICRP or an alternative methodology is preferable?</p>	<p>N/A. The industry and regulators should not undertake any further work on load flow based methods for the interconnected grid.</p>
<p>Q 19. Are there any other high-level options that the Commission should consider?</p>	<p>A high-level option worthy of consideration is a review of the connection-interconnection and node-link definitions in relation to investment incentives. This issue has arisen as part of the development of some regional grid investment proposals. In some instances, the current connection-interconnection and node-link definitions can provide transmission customers with incentives to prefer investment alternatives that are economically sub-optimal from a national perspective, but which would result in lower transmission charges for the customers concerned. It may be worth reviewing the connection-interconnection and node-link definitions, as well as the effect of possible zonal interconnection charges to see if there might be a different approach that could ameliorate this problem. This work could also examine possible linkages between regional service preferences and zonal interconnection charges.</p>

<p>Q 20. Is there merit in pursuing a PJM-style 'deep' connection option in the New Zealand market?</p>	<p>No. The main downside of the "but for" method is that others that benefit from an interconnection investment, but are not deemed to have "caused" it, can free ride on an investment paid for by the "causer". Although a connecting generator can necessitate the construction of network upgrades to accommodate the connection, there are potentially significant spillover effects that benefit other users of the existing grid. A "but for" approach does not take into account the benefits that accrue to other users of the grid and so may overstate the costs attributable to the generation plant.</p> <p>In many cases, the need for transmission investment is driven principally by secular growth, but this fact may be masked by a final single connection that appears to "cause" the need for grid augmentation. In this situation, allocating all the cost of the augmentation to the final "causer" but for whom the investment would not have been needed may be considered inequitable.</p> <p>See section 7 of the body of this submission for further discussion of the "but for" method. We recommend that the industry and regulators not undertake any further work on this approach.</p>
<p>Q 21. Are there aspects of connection charging that should be reviewed? If so, please give arguments why.</p>	<p>The connection-interconnection and node-link definitions should be reviewed in relation to investment incentives. See the response to question 19 above for the rationale for this.</p> <p>With respect to "green field" spur lines, we believe that it will often be possible for the parties that will benefit from such lines to determine the best size for these lines via normal commercial engagement and agreement. However, in some cases, it may be possible to demonstrate that the most economic investment from a national perspective would be something different from that chosen by the first mover in a new green field location (such as a region with a substantial wind resource). In this sort of situation it may be appropriate for there to be a "backstop" provision, which would enable the investment to be undertaken by Transpower, if it can be economically justified, and a return on some of the capacity created recovered as if the asset were an interconnection asset, until the capacity is fully utilised.</p> <p>Consequently, we recommend that the concept of permitting such a "backstop" provision with respect to "green field" connection asset investment should be further investigated by the industry and regulators.</p>
<p>Q 22. Is it necessary or worthwhile to alter or clarify the existing treatment of transmission alternatives?</p>	<p>No. See section 10 of the body of this submission for the rationale supporting this view.</p>
<p>Q 23. Should either a USG or a voluntary insurance scheme be considered within the review?</p>	<p>No, we are strongly opposed to these proposals. They are not good policy and are not legally valid. Consequently, the industry and regulators should undertake no further work on them. See Appendix 1 of this submission for the reasoning in support of this view.</p> <p>Transpower supports the concept of performance incentives in principle, but any performance incentives developed and agreed should form part of revenue setting under the individual price-quality path regulation to be developed pursuant to Part 4 of the Commerce Act 1986 – they should not be part of the TPM.</p>

<p>Q 24. Are there other options for linking service quality and pricing that you think the Commission should consider? If so, please give details.</p>	<p>Not for individual customers. For connection assets, rule 5 of section II of Part F of the rules already makes it possible to link prices to different levels of preferred service quality.</p> <p>For interconnection assets, because of the common good nature of these assets, it is not possible to tailor the services provided or the prices charged to the service levels preferred by each individual customer. However, zonal interconnection charges could potentially reflect regional preferences, if customers could agree on these.</p>
<p>Q 25. Do you agree that the Commission should consider a methodology for allocating the costs of existing and new static reactive power assets as part of the review?</p>	<p>Yes, but with qualifications – see the discussion in section 9 of the body of this submission.</p>
<p>Q 26. If locational hedging instruments were introduced that had the effect of muting nodal price signals, do you consider that locational signals should be enhanced through transmission pricing?</p>	<p>Locational hedging instruments that have the effect of muting nodal price signals should not be introduced. If such instruments were to be introduced, this would represent a lack of coherency in the overall design of the market framework, revenue setting and revenue recovery.</p> <p>See our separate submission on managing locational price risk.</p>
<p>Q 27. Do you consider that the criteria outlined in this paper are appropriate criteria for filtering high-level options? Please outline your reasoning.</p>	<p>Criterion 1 – divergence from optimal transmission investment – is not a particularly useful criterion, as grid investments are not driven by nodal price differentials. Further, the Commission’s definition of “optimal” appears to assume away many of the risks and uncertainties that apply to transmission planning and investment. If uncertainties and the asymmetric risks attached to investing too late rather than too early were properly valued, it would be very difficult to demonstrate that any recent New Zealand transmission investments have been approved too early. See section 3 of the body of this submission for further discussion supporting this view.</p> <p>Criterion 2 – theoretical precision – is not a particularly useful or practicable criterion. A better criterion would be something like “likely effect on actual consumption and investment behaviour”. Some instruments may be theoretically correct, but would not have any actual economic effect in practice.</p> <p>Criterion 3 – locational hedging options – is really a bit bizarre, because it suggests that if a location hedge is developed that damps locational signals, then locational signals in the TPM should be reinforced. This would indicate that there is something wrong with the overall coherency of the market design framework. Simply, the possibility of ad hoc adjustments of this sort should not be considered seriously, and any locational hedge mechanism that would damp nodal pricing signals should not be introduced.</p> <p>The other filtering criteria seem reasonable.</p>

<p>Q 28. Are there other criteria that you consider might be appropriate?</p>	<p>As noted in response to question 27 above, a better criterion than theoretical precision would be something like “likely effect on actual consumption and investment behaviour”. It is only to the extent that there are actual changes to consumption and investment decisions that any real economic impact results.</p> <p>Criterion 5 – information requirements/ Implementation difficulty – should be extended to include consideration of and an attempt to quantify the actual compliance costs associated with implementing any changes.</p> <p>Another appropriate criterion would be:</p> <ul style="list-style-type: none">• The extent to which any changes to the TPM may increase the scope for disputes. <p>Historically, New Zealand electricity industry participants have demonstrated a high propensity to engage in litigation in relation to transmission charges and to refuse to pay charges for extended periods. Disputes over charges tend to consume resources and produce wealth transfers as opposed to actually generating wealth. Any changes to the TPM that increased the scope for uncertainty in its application or interpretation would be likely to increase the scope for disputes and their frequency.</p>
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