Transmission pricing review: high-level options

Summary of Submissions

Prepared by Electricity Commission

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Executive summary

This report provides a summary of submissions for the *Transmission pricing review: high-level options* consultation paper (**consultation paper**).

The consultation paper set out the following issues for consultation:

- the framework for deriving high level options;
- the high level options;
- further issues; and
- filtering criteria.

Nineteen parties provided submissions in response to the consultation paper.

Most submitters welcomed the Review, although two (Genesis and Business New Zealand) stated that the Review was not necessary at this time and introduced regulatory uncertainty. A number of submitters gave detailed comments about the interrelationships with other market development work.

Framework for high-level options

There is general agreement that nodal pricing – reflecting congestion and loss costs – provides appropriate signals for efficient use of the transmission system.

In general terms, most submitters agreed that nodal pricing provides some locational signals to generation and load. However, the signals are unlikely to be fully efficient as they are either muted or weak compared to other considerations (e.g. proximity to fuel source).

Some submitters stated that nodal prices were suppressed by early augmentation of the transmission system and other factors, although most submitters considered that the suppression of nodal prices was appropriate, as it is economically appropriate to invest in transmission assets ahead of time.

Four submitters provided examples of where a transmission alternative could have taken place, has taken place, or may yet take place. Other submitters set out reasons why it was appropriate that there had been no alternatives - they did not provide the same level of reliability.

Those submitters who commented on which participants should face locational signals considered that generation should face locational signals – either wholly or as well as load, although one stated that if generators are to face locational transmission pricing signals, the generator should receive access to the reliability and security of supply value benefits that are delivered through its locational decision.

All submitters who commented considered that Frontier had investigated appropriate international jurisdictions, although some noted that they would like more information on certain overseas examples.

Around half of submitters who commented agreed that Frontier had summarised the issues with transmission pricing appropriately. Four submitters listed issues they thought were not summarised appropriately. These issues were repeated in other parts of submissions and are dealt with in more detail in the relevant parts of this report.

Five submitters listed other issues that they submitted should be considered at this high-level options stage. These issues were repeated in other parts of submissions and are set out in more detail in the relevant sections of this report.

Most submitters strongly agreed that it is appropriate for the Review to consider locational signalling. For some submitters the focus on locational signalling should be extended to all dynamic efficiency considerations such as operational signalling for load, and seeking definitions of connection and interconnection that better encourage appropriate investment decisions. Several submitters commented on the importance of analysis to assess whether locational signals would have an overall benefit on system efficiency.

Nine submitters would like to see the Pricing Principles reviewed. These submitters stated that the Pricing Principles conflict with each other and need clarification to avoid frustrating the review process. Of the two submitters that stated that the Pricing Principles should not be reviewed (MRP and Meridian), Meridian stated that they should be reviewed when a preferred option is selected.

High-level options

Seven submitters – a majority of those who gave a view – considered that the status quo does not provide appropriate operational and investment signals for existing and prospective generation and load. These submitters generally agreed that the status quo falls short particularly in providing investment signals for new generation.

Some submitters favoured maintaining the status quo – Powerco, Meridian, Norsk Skog, and Counties Power - although these submitters also supported investigation of other options or developments.

A majority of submitters giving an opinion on the Tilted Postage Stamp (TPS) approaches options either supported the view that the TPS provided a reasonable trade off between simplicity and meeting signalling objectives, or thought that it was worthwhile investigating this option further. Four submitters did not believe a TPS model was appropriate – Northpower, ENA, MEUG and Rio Tinto - although MEUG stated it recognised that the TPS may need to be worked on further to provide a counterfactual. Some submitters specifically saw the TPS as a mechanism for replacing the HVDC charge, not necessarily using it for charging for interconnection assets.

Some submitters noted that, in developing a TPS, the potential problem of establishing a mechanism for setting the tilt that is acceptable and that can adapt over time to changing conditions.

A number of submitters referenced the CEO Forum work on the TPS. Some of this work has subsequently been made available to the Commission.

Most submitters that gave a view on the augmented nodal pricing option considered that it appears too complex and is unlikely to be understood by participants. Of these submitters, some stated that they agreed with the theory, while others disagreed with the economic arguments that this approach would address deficiencies in nodal energy prices. Two submitters stated that the approach may be useful in assessing how to improve the status quo.

Submitters were split on load-flow based options. The largest group of submitters were strongly against further investigation of these approaches based partly on previous New Zealand experience with such models. Submitters noted concerns over instability, complexity and controversy, and possibly the disconnect between use of the grid and value derived from using it (not charging beneficiaries). However, five submitters supported further work on the basis that load-flow analysis could be part of developing a means to incorporate LRMC into grid charges, or agreeing an appropriate tilt for tilted postage stamp.

All submitters who gave a preference for the type of load-flow analysis (ICRP or CRNP) supported ICRP (forward-looking).

Four submitters made the following suggestions for alternative high level options:

(a) Product (tariff) rates similar to Lineco's approach to distribution pricing.

(b) A requirement on grid-connected generators to face the bulk of all transmission costs.

(c) The gas transport model.

(d) A review of connection-interconnection and node-link definitions in relation to investment incentives.

A series of other suggestions – prompted by work commissioned for MEUG – were made by submitters in relation to this or other parts of the consultation paper. MEUG would like to see further investigation of a 'but-for' test for new investment, and a more market-based approach to HVDC pricing (a capacity rights or arbitrageur approach.)

Further issues

Several large users and lines companies submitted in favour of further investigation of the PJM-style 'but-for' approach, as a way of allocating new investment costs to beneficiaries. Some submitters noted potential concerns with this approach including: problems of free-riding, of identifying costs attributable to particular new plant, and the difference in relative investment lead-times for transmission and generation.

Submitters noted connection charging issues including the current designation of connection and interconnection assets creating inappropriate investment incentives.

Submitters were split on the current transmission alternatives regime. Generators (with the exception of Todd Energy) and Transpower generally supported the current arrangements. Large users, lines companies and Todd Energy advocated change to the existing regjme, in some cases strongly. Possible changes included providing pricing signals for transmission alternatives and the ability for transmission alternative providers to access funding directly, rather than by contracting with Transpower.

Submitters generally supported performance incentives for transmission services, but a significant number considered such incentives should not be considered as part of this Review either because they are not a priority, or are better considered by the Commerce Commission. MEUG. Powerco, WPI and Todd Energy considered that a USG or voluntary insurance scheme was worthy of further consideration. Transpower was particularly opposed to the USG and voluntary insurance scheme proposals, and included an appendix setting out its objections.

Submitters were generally supportive of changes to the way static reactive power costs are allocated but were split on whether it is appropriate for this to be considered as part of the Review.

Filtering criteria

Submitters had varying views on the proposed filtering criteria, although a number had common concerns on criterion 1 – divergence from optimal investment. These submitters questioned whether this should be a criterion and stated that a cost-benefit analysis of locational signals should be an over-arching criterion.

Submitters also had concerns about the consideration of the development of locational hedging mechanisms influencing transmission pricing.

Other submitter issues

Finally, submitters made a number of comments and recommendations about integration with other work and priorities, specific comments about HVDC charging, differentiation between treatment of sunk costs and new investment and boundary issues.

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1. Introduction and purpose of this report

1.1 Introduction

1.1.1 In April 2009, the Electricity Commission (**Commission**) announced that it would undertake a wide-ranging review of transmission pricing (**Review**). The Review would consider options for the allocation methodology for transmission costs, and involve three analysis stages each including public consultation. The final output of this process will inform the Commission's decisions on the preferred option and the guidelines to be used in setting the Transmission Pricing Methodology (**TPM**).

1.1.2 The first consultation paper, *Transmission pricing review: high-level options*, (**consultation paper**) to be published as part of the Review was released in October 2009, with a deadline of 7 December 2009 for submissions.

1.1.3 The consultation paper was released in parallel with two other consultation papers on related issues.

(a) *Scarcity pricing and compulsory contracting: options*.

(b) *Managing locational price risk: options*.

1.2 Purpose of this report

1.2.1 This report provides a summary of the submissions received on the consultation paper. Submitters provided general comments on the consultation paper or provided responses to the questions asked in the consultation paper. Some submitters provided both general comments and responses.

1.2.2 In this report, the Commission has summarised the submissions and highlighted the key issues raised by submitters. The summary includes a summary by issue (section 2), a summary by submitter (section 3) and a table of submitters' responses to questions (appendix 1). This report does not provide comments on submitters' views.

1.2.3 The submissions and this report will assist the Commission in progressing analysis and development of a short list of options for transmission pricing for further consultation.

1.3 Submissions received

1.3.1 Nineteen parties provided submissions. Copies of all submissions are available at: http://www.electricitycommission.govt.nz/submissions/mdp-subs/tpr . The organisations that made submissions are listed in Table 1 below.

Table 1: Submitters

Generator/retailer	Large user	Distributor	Other
Contact Genesis Meridian Mighty River Power (MRP) Todd Energy (late submission)	Business New Zealand Major Energy Users' Group (MEUG) Norske Skog Pan Pac Rio Tinto Winstone Pulp International (WPI)	Counties Power Northpower Orion Powerco Vector Electricity Networks Association (ENA)	Transpower Electricity Efficiency and Conservation Authority (EECA)

1.3.2 No submissions were made by organisations representing retail consumers.

2. Summary of submissions by issue

2.1 Structure and overview

2.1.1 Except for a brief initial overview of submitters' overall response to the Review, this section follows the structure of the consultation paper.

2.1.2 The consultation paper gave a background to the Review, and then set out the issues for consultation in the following sections.

(a) The framework for deriving high-level options.

(b) The high-level options.

(c) Further issues.

(d) Filtering criteria.

2.1.3 This report also includes a final section on other issues that were raised by submitters. These issues are as follows.

(a) HVDC-related issues.

(b) Integration with other market development work.

(c) Boundary issues.

2.1.4 At the start of each issue, a shaded box provides a summary of the key points.

Overview

Most submitters welcomed the Review, although two (Genesis and Business New Zealand) stated that the Review was not necessary at this time and introduced regulatory uncertainty. A number of submitters gave detailed comments about the interrelationships with other market development work.

2.1.5 Many submitters provided substantial submissions on the consultation paper.

2.1.6 The majority of submitters supported the Commission's wide-ranging review of transmission pricing. Some submitters – Counties Power, Powerco, WPI and Genesis, in particular – cautioned about making significant changes and saw much in favour with the status quo.

2.1.7 Two submitters – Genesis and Business New Zealand - explicitly stated that they believed the Review was not necessary at this time and introduced regulatory uncertainty.

2.1.8 Most submitters also provided submissions in response to the other consultation papers on the related issues, and some submitters specifically included comments on the interrelationships of the three issues – Vector, Transpower, Business New Zealand and Contact. The submissions on the interrelationships of the three issues are summarised in section 2.6 of this report.

2.2 Framework for high-level options

2.2.1 This section of the consultation paper considered the economic theory for efficient pricing for transmission – in particular the role of nodal pricing in providing efficient signals for use of the transmission system and for investment in generation and load, international experience, issues with the current transmission pricing in New Zealand and relevant policy and regulatory considerations. This section also set out a rationale for the locational focus for the initial stages of the Review.

Nodal pricing for efficient use of the transmission system

There is general agreement that nodal pricing – reflecting congestion and loss costs – provides appropriate signals for efficient use of the transmission system.

2.2.2 The majority of submitters that commented on this issue agreed that nodal pricing provides signals for efficient use of the transmission system, although some agreed only in part. The following reasons for partial agreement were given:

(a) The New Zealand electricity market does not have full nodal pricing. Full nodal pricing has three components: losses, congestion and no artificial price caps below the value of unserved energy. While the first two are built into the New Zealand electricity market, the rules governing the way that Whirinaki is bid into the market has distorted marginal prices by not reflecting the full short run operational costs of that plant (MEUG, WPI).

(b) Nodal prices provide the correct signals for efficient dispatch (primarily for generation), but they are not particularly effective at providing efficient consumption signals. This is because only a small proportion of offtake customers have time-of-use metering and for most offtake customers, apart from some large industrials, electricity represents only a small proportion of their total costs (Contact, Transpower).

Nodal pricing for efficient investment in generation and load

> In general terms, most submitters agreed that nodal pricing provides some locational signals to generation and load. However, the signals are unlikely to be fully efficient as they are either muted or weak compared to other considerations (e.g. proximity to fuel source).

2.2.3 Four submitters explicitly agreed that nodal pricing provides efficient investment signals for generation and load. One of these – Contact – noted that nodal pricing can, in some cases, create excessive and disproportionate signals (if a spring washer occurs).[1] Meridian, while agreeing that nodal pricing provides appropriate signalling for investment in generation and load, qualified the comment noting that this was true when combined with a comprehensive regulatory test for the approval of forward-looking transmission investment and deep connection charging.

2.2.4 Eleven submitters stated that nodal pricing did not provide efficient investment signals for generation and load location, or did so only weakly or up to a point. Submitters gave the following reasons.

(a) The conditions required for nodal pricing to send efficient long-run investment and locational signals (as set out in the Frontier Report)[2] are so strict they could not apply in practice. In the real world there are the following issues:

(i) that there are significant economies of scale in transmission and generation investments;

(ii) that network planners and regulators are politically conditioned to be risk-averse in terms of planning timeframes for new projects; and

(iii) that supply security is not priced (WPI).

Todd Energy set out an example of a large capacity single shaft CCGT that would deliver significant economy of scale benefits over the staged build of smaller, multi-shaft equivalent capacity generation station, though the latter would deliver significant reliability and security of supply benefits over the former. This submitter stated that the nodal pricing regime does not provide adequate signals for security of supply and reliability when considering design of generation plant as well as location.

(b) A high nodal price disappears once a new generator is commissioned because it is impractical to build incremental generation just sufficient to

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1 The spring washer effect can cause prices in a constrained region to be many multiples higher than the marginal generator price.

2 Frontier Economics, *Identification of high-level options and filtering criteria*, September 2009, available at: http://www.electricitycommission.govt.nz/consultation/tpr

supply the incremental load that causes the high price. Similarly, a load that reduces its off-take during times of high nodal prices (or an embedded generator that effectively reduces offtake at a GXP) cannot capture that drop in price; but other loads, which take no action, see the benefits (Northpower, ENA).

(c) Most offtake customers will not respond to nodal prices. This is because most do not see nodal prices directly, or electricity represents only a small proportion of total costs, so is unlikely to drive investment decisions (Northpower).

(d) For some large loads, electricity costs may influence investment decisions but whether or not the impact of constraints on nodal prices downstream and upstream of constraints is sufficient to affect investment decisions depends on whether investors perceive the constraints to be permanent fixtures or likely to be relieved. 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) (Transpower).

(e) For generators, the impact of losses on nodal prices would be expected to be taken into account, since they are more or less a permanent feature. However, generators are probably unlikely to locate downstream of a constraint in order to benefit from higher nodal prices, because of the risk that the constraint might be relieved in future. Generator locational decisions are driven more by other costs (Transpower).

(f) The existing TPM assists efficient selection of generation between the islands (due to the HVDC charge). Within each island nodal prices are weaker resulting in under-investment of generation close to demand, e.g. Transpower's North Auckland and Northland grid upgrade proposal (**NAaN**), Transpower's North Island Grid Upgrade proposal (**NIGU**), 2x100 MW Open Cycle Gas Turbine (**OCGT**) and upper South Island generation cases discussed in box 3 of the consultation paper (MEUG).

2.2.5 Two lines companies made comments on the role nodal pricing provides in signalling appropriate investment in *transmission*. Powerco commented that generation and load growth should dictate the required transmission and nodal price differentiation should signal to the transmission owner the need for transmission investment. Orion stated that nodal pricing does not send appropriate nor effective new investment signals for transmission, in particular in regard to the core grid.

2.2.6 Pan Pac suggested nodal pricing could be used as a way to charge for transmission services.

Suppression of nodal prices due to early augmentation of the transmission system

> Some submitters stated that nodal prices were suppressed by early augmentation of the transmission system and other factors, although most submitters considered that the suppression of nodal prices was appropriate, as it is economically appropriate to invest in transmission assets ahead of time.

2.2.7 The consultation paper asked:

> Do you consider that the nodal prices in NZ may be inappropriately suppressed due to the transmission system being augmented ahead of demand?

2.2.8 The Commission accepts that this question should have been worded to ask whether submitters considered that real world augmentation of the grid was leading to a softening of efficient investment signals for generation and load. The Commission did not intend to imply that the transmission system is being augmented ahead of need.

2.2.9 Of the eleven submitters that commented on this question, six considered that nodal prices were not *inappropriately* suppressed. Of the others, three users considered that nodal prices were inappropriately suppressed (but this did not mean they thought that transmission investment was occurring too early).

2.2.10 The question elicited a strong response from a number of submitters that the transmission system being augmented ahead of time is the prudent thing to do. Contact, MRP and Transpower noted that the asymmetric cost of the decisions i.e. the expected cost of being too late far outweighs the expected cost of building early. In the view of some submitters the transmission system is being augmented *later* than is necessary (Northpower, MRP).

2.2.11 Orion commented that the nodal price effects of transmission constraints depend on generator offer behaviour rather than the physical constraint saying that potentially a single generator ‘upstream’ of a constraint gets to set the price at any level they like. The resulting nodal price differences therefore potentially represent market power rents, and have nothing to do with efficiency.

2.2.12 Meridian stated that it is inaccurate to say that there is over-investment in transmission because nodal prices are too low, and it is incorrect to say this level of investment will be reduced with a stronger locational signal. Meridian asked that the Commission investigate this question with a proper empirical analysis.

Examples of transmission alternatives

Four submitters provided examples of where a transmission alternative could have taken place, has taken place, or may yet take place. Other submitters set out reasons why it was appropriate that there had been no alternatives - they did not provide the same level of reliability.

2.2.13 The consultation paper asked submitters to provide examples of where a transmission alternative could have been undertaken instead of an investment in the grid.

2.2.14 Four submitters - Todd Energy, Orion, WPI, MEUG - provided examples of where a transmission alternative could have taken place, has taken place or might take place instead of an investment. The examples were as follows.

(a) Significant generation located in Upper North Island (NI) and Upper South Island (SI) regions could have been advanced if there was a robust regime in place that provided investors with benefits from the avoided transmission costs.

(b) Upper SI hydro schemes have been put forward.

(c) CCGT stations are feasible at Rodney and Otahuhu. While gas contracts are currently scarce, gas can be transported more cheaply than electricity into Auckland.

(d) One lines company stated that it could provide an example of a live issue where a transmission alternative could be undertaken instead of an investment in the grid but this may not proceed.

(e) One lines company stated that it could provide examples of where transmission alternatives have been successfully undertaken to defer investment in the grid. The recent work on the co-ordination of load management in the Upper SI is of current interest.

(f) Some transmission investment decisions and the future allocation of those costs have been less than optimal. For example, allocating the $824 million cost of NIGU to all consumers was inferior to the alternative of charging the parties that benefit from that upgrade. Had the beneficiaries been aware they would bear the cost, other lower cost alternatives or later timing for new assets may have emerged.

(g) 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.

2.2.15 Other submitters argued that no viable transmission alternatives had been approved instead of recent transmission investments for a number of reasons.

(a) They did not provide the same degree of reliability (Contact).

(b) Recent augmentations – such as NAaN – were needed to provide a required level of reliability to existing customers. A submitter noted that the complete loss of supply to the NAaN region on 30 October 2009 would not have been prevented by a 200MW generator installed north of Auckland whereas the NAaN upgrade would have (Northpower).

(c) Contact stated that the Stratford Peakers generation would not have been located in Auckland for a number of reasons previously explained to the Commission and a TPM locational signal would have had little bearing on this decision.

(d) Recent investments and approvals have reflected pressures to catch-up with rising demand, so it is difficult to argue that alternatives would have been more efficient. However, continuing along that path, rather than building new generation and taking demand-side measures that do not require further augmentation, would be inefficient (ENA).

2.2.16 Although not directly commenting on the issue of transmission alternatives, Counties Power commented that it appears the industry and market have not delivered optimal located generation or demand side initiatives – for example limited new generation or energy efficiency efforts in and north of Auckland, the special treatment of Top Energy in respect of Ngawha and the timing of Transpower's new 400kV line into Auckland.

Locational signals for generation and/or load

Those submitters who commented on which participants should face locational signals considered that generation should face locational signals – either wholly or as well as load, although one stated that if generators are to face locational transmission pricing signals, the generator should receive access to the reliability and security of supply value benefits that are delivered through its locational decision.

2.2.17 The consultation paper asked the question:

> 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?

2.2.18 Submitters generally agreed that if locational transmission pricing signals are required then generators should face these signals as well as load. The case for load facing these signals was generally considered weaker by the majority of submitters.

2.2.19 Submitters gave the following reasons why generators should face locational signals.

(a) Locational signals need to be seen by generators so that these signals are factored into the decision-making process for investment in new generation (Vector).

(b) It is desirable, in theory, that generators face some form of transmission price signal to encourage improved location decisions which would lead to lower system expansion costs over time (Vector).

(c) The present exemption from interconnection charges for generators effectively encourages generators to pick the easiest location from their perspective and then everyone else pays the cost of transporting the energy to the load (Northpower).

2.2.20 Submitters gave the following reasons why it is less appropriate for load to face locational signals.

(a) Locational signals for loads would be somewhat less useful because most loads are unlikely to locate on the basis of electricity pricing (as opposed to reliability of supply) (Contact).

(b) Loads sufficiently large enough to respond to such transmission pricing signals are capable of bypassing the transmission system (by building their own dedicated transmission) and negotiating with generators to avoid paying the fixed transmission costs generators will pay (Northpower).

2.2.21 One lines company – Orion – stated that it has previously agreed with the Commission's position that all interconnection charges could be paid for by off-take customers. However, it recognises that there are reasonable arguments for generators to pay up to 20% of the interconnection charge.

2.2.22 For several submitters, the assumption that generators should face locational signals was tempered by the caveat that this was only if they could respond to the signals. These submitters questioned whether generators would be able to respond to signals given that they may face higher-order locational considerations such as availability of resources. One submitter – Vector – stated that while locational signalling may not necessarily ensure that plant is built in the right place, providing stronger locational signals will encourage generation investors to take into account transmission costs when making location decisions.

2.2.23 Contact stated that signals for load should be limited to operational signals such as Regional Coincident Peak Demand (**RCPD**) and seasonal signals, rather than signals for investment at a particular location.

2.2.24 MRP stated that it believed that if generators are charged, the Commission must consider seriously the form of charging i.e. the unit – peak kW output, nameplate rating or kWh per annum. RCPD is appropriate for demand, but would introduce undesirable distortions for generators (particularly discretionary hydro). MRP would prefer to see either nameplate capacity charging or per-kWh charging (equivalent for a given load factor).

2.2.25 EECA submitted that the impact of locational signals on geographic diversity of generation and hence security of supply should be considered. For example, it is well known that the costs of wind integration can be lowered if wind generation is located in geographically diverse locations.

2.2.26 Transpower stated that locational signals can be effective for load – citing the example of the RCPD-based interconnection charge has driven greater utilisation of the grid in the Upper SI. However, Transpower pointed out that, under the Commerce Act, distribution companies are allowed to pass through transmission costs which tends to limit the effectiveness of any locational signals aimed at offtake customers.

2.2.27 Transpower presented an argument against charging generators for interconnection as 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. (Although Transpower noted that a tilted postage stamp approach to charging generators could limit this problem.)

2.2.28 Todd Energy stated that if generators are to face locational transmission pricing signals, the generator should receive full access to the reliability and security of supply value benefits (of the same value that is used to justify transmission investment under the GIT) that are delivered through its locational decision.

International experience: other jurisdictions

All submitters who commented considered that Frontier had investigated appropriate international jurisdictions, although some noted that they would like more information on certain overseas examples.

2.2.29 Submitters were generally satisfied that the international jurisdictions that have been surveyed by Frontier were sufficient to provide a picture of international practice. No submitters suggested further jurisdictions for consideration.

2.2.30 Northpower commented that many of the countries studied were quite different to New Zealand in terms of population density and generation. New Zealand has a relatively small population spread out along a ‘long skinny’ grid and Norway would be the only country in the selected jurisdictions that comes close to that model. Northpower additionally noted the United Kingdom and Chilean systems may offer a way forward in how transmission costs can be signalled to generators. Pan Pac also wanted to explore the United Kingdom model further.

2.2.31 Contact stated that it is difficult to get a fair comparison to the background, political scene, geography, generation mix, line company mix and market conditions in New Zealand. The specific details and how these compared to the New Zealand situation were not clear but the tradeoffs between locational energy market signals and transmission location signals are consistent.

Issues summarised by Frontier

Around half of submitters who commented agreed that Frontier had summarised the issues with transmission pricing appropriately. Four submitters listed issues they thought were not summarised appropriately. These issues were repeated in other parts of submissions and are dealt with in more detail in the relevant parts of this report.

2.2.32 Six submitters were in general agreement that the issues summarised by Frontier were correct, although one of those submitters, Powerco, noted that the issues were from the Transmission Pricing Technical Group (**TPTG**) and did not necessarily reflect the views of all participants.

2.2.33 Six submitters stated that they did not consider that Frontier had summarised the issues correctly or they disagreed with the issues listed.

2.2.34 Some submitters considered there were other issues that should have been considered, or disagreed with individual issues. In many cases, these issues were also discussed in other parts of the submissions. To avoid duplication, these issues are dealt with detail in the relevant parts of this report.

2.2.35 However, for completeness, these issues are listed in Table 2 below.

Table 2: Submitter comments on issues identified by Frontier

Submitter	Issue
Orion	Pricing principles, emphasis on dynamic efficiency.
Meridian	Pricing principles, locational signals, HVDC pricing, transmission alternatives, link between price and service, connection issues, voltage support charges, RCPD, load shifting impacting on distributed generator availability, review of connection definition.
MRP	HVDC, capacity rights and transmission alternatives.
Transpower	Link between price and service, transmission alternatives.

Other Issues

> Five submitters listed other issues that they submitted should be considered at this high-level options stage. These issues were repeated in other parts of submissions and are set out in more detail in the relevant sections of this report.

2.2.36 Five submitters listed other issues that should be considered at this high-level options stage. These issues are listed in Table 3 below.

Table 3: Other issues suggested by submitters

Submitter	Other issues
Northpower	• Loads should not be subject to locational signals. • Historical sunk costs and costs which have been committed under the present approval regime should not be subject to new regimes.
Powerco	• Pricing principles should be reviewed.
Contact	• Product-based pricing – whereby Transpower sets its prices similar to line companies and has a stake in the risk-sharing and forecasting of demand (to manage its revenue requirement).
Meridian	• Focus of industry resources should be on improving the implementation of the GIT and connection charge.
Transpower	• Current connection-interconnection and node-link definitions should be examined. • This review should be extended to examine the possible relationship between zonal interconnection charges and regional service quality preferences. • Aligning boundary definitions.
Todd Energy	• Contribution of local/distributed generation and consideration of transmission alternatives. • The use of gross regional demand to define the system peaks for transmission pricing and associated RCPD assessment.

2.2.37 The remaining five submitters who answered the question believed that there are no further issues to consider at the high-level options stage.

Locational focus

> Most submitters strongly agreed that it is appropriate for the Review to consider locational signalling. For some submitters the focus on locational signalling should be extended to all dynamic efficiency considerations such as operational signalling for load, and seeking definitions of connection and interconnection that better encourage appropriate investment decisions. Several submitters commented on the importance of analysis to assess whether locational signals would have an overall benefit on system efficiency.

2.2.38 Most submitters strongly agreed that it is appropriate for the Review to consider locational signalling. However, Contact and Transpower submitted that the locational signal issues should be limited to an alternative to the current HVDC charges. Some submitters – Transpower, Pan Pac, Orion, and Rio Tinto – considered that the focus should not solely be on locational signalling but on dynamic efficiency as a whole, which incorporates pricing structure issues.

2.2.39 Some submitters considered that, although it was appropriate to focus on locational signalling at a high level, it was important to check whether increasing locational signals would materially impact on the expected combined cost of generation and transmission over a significant timeframe (i.e. overall benefit in improving system efficiency). Meridian and MRP particularly emphasised the need to see robust analysis addressing this issue.

2.2.40 MRP also stated that the focus should be exclusively on whether to introduce locational pricing, adding that the Commission has much higher priorities than dealing with other elements of transmission pricing.

2.2.41 Orion, Pan Pac, Transpower and Rio Tinto all commented that the focus of the Review should be wider to include all dynamic efficiency considerations such as pricing signals for load consumption, and efficient definition of connection and interconnection that better encourages appropriate investment decisions.

Pricing Principles

> Nine submitters would like to see the Pricing Principles reviewed. These submitters stated that the Pricing Principles conflict with each other and need clarification to avoid frustrating the review process. Of the two submitters that stated that the Pricing Principles should not be reviewed (MRP and Meridian), Meridian stated that they should be reviewed when a preferred option is selected.

2.2.42 The consultation paper asked submitters two questions concerning the Pricing Principles:

Are there any particular Pricing Principles that ought to be given precedence over others?

Do you agree that it is not appropriate to review the Pricing Principles at this time? If not, why not?

2.2.43 Table 4 below lists the comments made on which Pricing Principles should be given precedence (for completeness, all the Pricing Principles are listed).

Table 4: Submitters comments on which Pricing Principles should be given precedence

Pricing Principles	Comments	Submitter
2.1 the costs of connection and use of system should as far as possible be allocated on a user pays basis		
2.2 the pricing of new and replacement investments in the grid should provide beneficiaries with strong incentives to identify least cost investment options, including energy efficiency and demand management options	2.2 and 2.3 governing new investment should be given a higher precedence.	WPI
2.3 pricing for new generation and load should provide clear locational signals	This is the most relevant.	Contact
	Support provision of strong locational signals being given precedence.	Counties
	This is the most important Pricing Principle alongside ensuring that Transpower is able to recover the cost of an efficient service provider (principally a matter for the Commerce Commission, but implicit in 2.1 and 2.2.)	MRP
	Pricing for new **generation** should provide clear locational signals.	Northpower
	2.2 and 2.3 governing new investment should be given a higher precedence.	WPI

Pricing Principles	Comments	Submitter
2.4 sunk costs should be allocated in a way that minimises distortions to production/consumption and investment decisions made by grid users;	This is critical to maintain stability and consumer confidence.	Contact
2.5 the overall pricing structure should include a variable element that reflects the marginal costs of supply in order to provide an incentive to minimise network constraints; and	This one – and 2.6 should be taken out.	WPI
2.6 transmission pricing for investment in the grid should recognise the linkages with other elements of market pricing (including the design of the financial transmission rights regime under section V, and any revenues from financial transmission rights).	This one – and 2.5 – should be taken out.	WPI

2.2.44 Meridian stated that it felt the groundwork had already been done on the Pricing Principles and cited the Commission's previous work on the application of the Pricing Principles. Orion made a similar point referring to previous Commission work.[3]

2.2.45 MEUG stated that the Pricing Principles are superior to the Government Policy Statement (**GPS**) because the GPS requirements do not consider use of system agreements or linkages with Financial Transmission Rights (**FTR**s) (or other locational price risk mechanisms).

[3] The Commission Statement of Reasons in relation to the Proposed Guidelines for Transpower's Pricing Methodology, 18 Feb 2006.

2.2.46 Northpower suggested that another principle should be: take into account the desirability for consistency and certainty for both consumers and the industry.

2.2.47 Todd Energy suggested that there should be more emphasis on the Commission's specific outcome in section 172N(2)(g) of the Electricity Act 1992.[4]

2.2.48 Transpower stated that, if the current Pricing Principles are retained, none of them should be ranked higher than others. Transpower argued that the attempt to impose a ranking of the principles caused many practical problems when Transpower attempted to apply the principles. In Transpower's view, the original intention was that the principles should apply to different elements of the methodology.

2.2.49 The Commission accepts that the question whether submitters agreed that it is not appropriate to review the Pricing Principles was worded awkwardly. Nevertheless, the submitters were able to make clear comments in response.

2.2.50 Ten submitters would like to see the Pricing Principles reviewed. Those submitters who argued strongly for a review noted that the Pricing Principles conflict with each other and some need clarification to avoid frustrating the review process. Of the two that stated that the Pricing Principles should not be reviewed (MRP and Meridian), Meridian stated they should be reviewed when a preferred option is selected.

2.2.51 The following reasons were given by submitters for reviewing the Pricing Principles.

(a) Once a new TPM is rolled out it may be increasingly difficult to change if certain principles were to change (Contact).

(b) The Pricing Principles are clearly a misfit group and will cause difficulties in subsequent stages (WPI).

(c) Should make the principles should be simpler, more consistent and more realistic (Transpower).

(d) The principles need to state more clearly beneficiary-pays and could be formulated to include the objective that prices should be set in a manner comparable with how they would be set if they had been determined by market negotiations (in the absence of free rider and hold out problems) (MEUG).

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4 "(g) the electricity sector contributes to achieving the Government's climate change objectives by minimising hydro spill, efficiently managing transmission and distribution losses and constraints, promoting demand-side management and energy efficiency, and removing barriers to investment in new generation technologies, renewables, and distributed generation."

(e) A review of the principles should be done taking into account possible changes to statutory objectives and outcomes for the new Electricity Authority (Powerco).

2.2.52 Orion noted that it would be useful to have a review of the Commission's earlier decisions in relation to the Pricing Principles, guidelines for Transpower's pricing methodology and for TPMs generally. Such a review would summarise the history behind these decisions and outline the reasons why the Commission now considers that changes to these decisions may be required.

2.2.53 In addition to requesting that the Commission review the Pricing Principles, Transpower recommended that an investigation be undertaken into the possibility of amending section IV of part V of the Rules to clarify that the only means by which the Commission or other regulator may direct Transpower on the application of the Pricing Principles is through the Pricing Guidelines.

2.3 High-level options

2.3.1 This section of the consultation paper considered four high level options:

(a) the status quo;

(b) tilted postage stamp (TPS) approaches;

(c) augmented nodal pricing; and

(d) load-flow based approaches.

2.3.2 The consultation paper also asked submitters if there were other high level options that the Commission should consider.

Status quo

Seven submitters – a majority of those who gave a view – considered that the status quo does not provide appropriate operational and investment signals for existing and prospective generation and load. These submitters generally agreed that the status quo falls short particularly in providing investment signals for new generation.

Some submitters favoured maintaining the status quo – Powerco, Meridian, Norsk Skog, and Counties Power - although these submitters also supported investigation of other options or developments.

2.3.3 Submitters were split on whether the status quo provided appropriate operational and investment signals to existing and prospective participants. ENA, Northpower, Orion, MEUG, Pan Pac and Rio Tinto stated that they did not consider the signals provided by the status quo were appropriate. These submitters generally agreed that the status quo falls short particularly in providing investment signals for new generation, and in the case of Todd Energy specifically local generation. Six others – Counties Power, PowerCo, Meridian, Transpower, MRP, and WPI – were either comfortable that the status quo provided adequate signals or felt that it did so at least partly. Of these, Transpower, Counties Power and MRP also noted that the signals for generation may not be adequate. Meridian added that it does not consider the HVDC charge is appropriate.

2.3.4 Submitters who considered that the status quo provided appropriate operational and investment signals gave the following reasons.

(a) The basis for the HVDC charges appears to be working as the majority of new generation has been in the North Island (Powerco).

(b) High nodal prices in the upper South Island identify the need for generation there – the fact that there is very little may be more to do with availability of resources (Powerco).

(c) HVDC charges provide a strong signal to generation in the SI but does not address the regional upper SI need (Contact).

(d) RCPD signals have encouraged greater demand-side management (Contact).

(e) Nodal pricing, the Grid Investment Test (**GIT**) and deep connection changes establish a locational signal that is efficient in practice (Meridian);

(f) The TPM does not signal the LRMC of grid investment but to a large extent this is not a problem, because investment is centrally planned (Transpower).

(g) For connection assets the beneficiaries of those assets pay for them (Transpower).

2.3.5 MRP commented that the existing arrangements only provided locational signalling for NI versus SI locational decisions. (MRP estimated that the effect of HVDC charging is equivalent to $5 to $10/MWh on the long run marginal cost (**LRMC**) of generation investments). MRP stated that whether the HVDC charges provided the *right* locational signals was something that needs testing.

2.3.6 In support of the RCPD-pricing in the current arrangements, Orion noted that under the previous interconnection pricing, it did not control load at summer peaking GXPs in winter months, even though that would have reduced load on the core transmission links into Christchurch. With the new RCPD approach Orion is now controlling load more appropriately.

2.3.7 Submitters who questioned the level of signalling given by the status quo gave the following reasons.

(a) Signals do not work well for significant new load or generation (Counties Power).

(b) Generators see very weak signals (Northpower).

(c) Generators need to see the full costs of their decisions; a decision to locate generation in the SI, remote from the load, does not presently result in the consequential transmission upgrades in the NI being factored into the decision (Northpower).

(d) Nodal prices are not a material factor in investment signalling (Orion).

(e) The existing TPM is only concerned with recovery of sunk costs, so it is not really relevant to investment (Orion).

(f) Although the GIT conceptually leads to alternatives to grid investment, in practice these are seldom pursued (Orion).

(g) The HVDC charge is not appropriate and leads to internal inconsistency within the TPM and an on-going challenge to the maintenance of regulatory certainty (Meridian).

(h) Short comings of nodal pricing in signalling (MEUG and ENA). These concerns refer to the answers given in earlier sections on the effective signalling from nodal pricing.

(i) If signalling had been effective the back-log of jobs would have been dealt with earlier (Pan Pac referring to transmission investments).

(j) Generators face muted nodal price signals (WPI).

(k) The investment costs of new transmission are socialised. Inefficient use of capacity may be encouraged as regions compete to be the ones that receive transmission investment at a cost subsidised by others (WPI).

(l) Because the TPM does not reflect the LRMC of grid investments, the consumption and investment decisions of offtake and generation customers may be distorted – this may not be material for load, but may be for generators (Transpower).

(m) Local generation operational and investment signals could be much improved by providing generators with access to regulated revenue where generation provides transmission services when co-located in a load-intensive area. If this revenue stream was available a number of CCGTs may have been better located and designed to greatly improve flexibility and reliability over the peak transmission periods and Contact (with other investors) may have considered undertaking the significant investment required in gas pipeline infrastructure to locate its Stratford peaking plant in Auckland (Todd Energy).

2.3.8 Submitters considered possible minor modifications to the status quo might be:

(a) Sheeting the costs of grid augmentation to those who cause it (Counties Power).

(b) A TPM that reflects the LRMC of the grid to reflect costs to generators. (Northpower).

(c) Some form of peak pricing to encourage short to medium term alternatives to grid investment (Orion).

(d) Replacing the HVDC charge with a tilt signal (Contact and Transpower).

(e) Different treatment for new and existing assets – particularly the HVDC (Meridian).

(f) MEUG (supported by Rio Tinto and Norske Skog) suggested some modifications that are considered later in this report ("but-for' methodology, and more market-based HVDC options).

(g) The HVDC charge should be abandoned and recovered via interconnection charge if a tilt signal is not considered worthwhile (Transpower). This suggestion was considered inappropriate according to Genesis and WPI.

(h) The regional demand used for determining the RCPD-based charges might be better based on a system gross demand model instead of net GXP offtake (Todd Energy).

(i) Grid-connected generators co-located with demand could be recognised via the TPM as providing transmission services at that connection location and the generator could gain direct access to a regulated allocation of the transmission benefits delivered (Todd Energy).

2.3.9 The consultation paper asked submitters to consider, whether, 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.

2.3.10 Submitters gave the following reasons why investment decisions are distorted under current arrangements.

(a) Not seeing the costs of additional transmission upgrades can cause significant waste in terms of constructing new generation remote from load (Northpower).

(b) The HVDC charges create distortion (Powerco and Meridian). Meridian explained that alarms alert Meridian's market operations when a station is about to contribute to HAMI, and output is reduced from what would otherwise be bid in. Transpower has acknowledged this distortion, agreeing to waive the contribution to HAMI where output from the station is needed in order to respond to a grid emergency.

(c) The HVDC charge has the potential to distort new investment decisions. The incremental effect of the HVDC charge on an existing South Island generator installing a new generation unit is less than the impact on a new entrant into the SI (Meridian).

(d) There is likely to be continued generation investment in the North Island and hence the power-flows will increase further North to South over time. This will increase the need for generation build in the South Island and underscores the importance of having some sort of self correcting mechanism that can respond to power flow changes over time (Contact)

(e) There can be inefficiencies in transmission investment linking remote generation (ENA).

(f) If there is insufficient investment in transmission, wealth generating industries will be constrained (Pan Pac).

2.3.11 Transpower and Meridian suggested that the distortions to investment may not be material as transmission cost may not be a factor in most investment – particularly for load. Meridian stated that, expending time and resources in 2010 to develop a theoretically pure price signal may not materially impact on future investment decisions.

2.3.12 MRP stated that the issue of whether there is possible distortion to investment decisions required more analysis.

Tilted Postage Stamp (TPS) approaches

A majority of submitters giving an opinion on the Tilted Postage Stamp (TPS) approaches options either supported the view that the TPS provided a reasonable trade off between simplicity and meeting signalling objectives, or thought that it was worthwhile investigating this option further. Four submitters did not believe a TPS model was appropriate – Northpower, ENA, MEUG and Rio Tinto - although MEUG stated it recognised that the TPS may need to be worked on further to provide a counterfactual. Some submitters specifically saw the TPS as a mechanism for replacing the HVDC charge, not necessarily using it for charging for interconnection assets.

Some submitters noted that, in developing a TPS, the potential problem of establishing a mechanism for setting the tilt that is acceptable and that can adapt over time to changing conditions.

A number of submitters referenced the CEO Forum work on the TPS. Some of this work has subsequently been made available to the Commission.

2.3.13 Of the four high-level options outlined by the Commission, this option gained the widest support for further work (although there was significant support for further work on options put forward by MEUG).

2.3.14 Of those submitters that gave an opinion, seven supported the view that the TPS provided a reasonable trade off between simplicity and meeting signalling objectives. Several submitters referred to the work of the CEO Forum on TPS models and encouraged the Commission to consider this work. Some of this work has subsequently been made available to the Commission and is available on the Commission website at: http://www.electricitycommission.govt.nz/opdev/transmis/tpr .

2.3.15 In several cases, submitters commented that they needed more detail in order to give a clear view on the TPS approach (and on other options). However, the submitters who supported further work on the TPS did so as they believed this option would be the most practical alternative to the status quo. Submitters – both those supporting the TPS and otherwise - had the following concerns about the option.

(a) That its most likely success may be with very small zones, which would effectively merge this approach with load-flow analysis models (Counties Power).

(b) That simplicity was less important that reflecting the LRMC of the grid to generators making locational decisions (Northpower).

(c) It might be difficult to set the tilt (and gain consensus) (Contact).

(d) That the choice of the amount of tilt should be based on forward-looking considerations, rather than simply reflecting the current grid configuration. (Orion) and should not influence the operation of sunk assets (Meridian).

(e) There will need to be a mechanism to change the tilt overtime; TPS approaches may prove difficult to adapt should generation and load patterns change. The durability of such an approach would be in question (Meridian).

(f) Conceptually the creation of regional pricing loads (similar to the old South Island differentials) implies an undesirable rigidity that will lead to investment distortions.(ENA)

(g) TPS rates should not be applied to loads (MRP, Transpower).

(h) TPS approaches are unlikely to be theoretically precise and may prove difficult to adapt (MEUG).

2.3.16 Todd Energy suggested that an underlying gross GXP load model (i.e. devoid of location generation contribution) could be used to set the extent of the tilt in recognition of the transmission benefits provided by local/distributed generation. This suggestion is linked to Todd Energy’s suggestions for modifications to the status quo.

Augmented nodal pricing

Most submitters that gave a view on the augmented nodal pricing option considered that it appears too complex and is unlikely to be understood by participants. Of these submitters, some stated that they agreed with the theory, while others disagreed with the economic arguments that this approach would address deficiencies in nodal energy prices. Two submitters stated that the approach may be useful in assessing how to improve the status quo.

2.3.17 In general, those submitters that gave a view on the augmented nodal pricing option did not support further work on this, arguing that the approach was too complex and is unlikely to be understood and accepted by participants.

2.3.18 A number of submitters stated they could see advantages in the theory - Meridian, Vector, Counties Power - but others – e.g. MRP, Transpower – disputed the theoretical economic efficiency in the approach.

2.3.19 MEUG and Vector supported further consideration of this option in assessing how to improve the status quo although, at this stage, considered that augmented nodal pricing is the most likely option to yield benefits.

Load-flow based approaches (network analysis approaches)

Submitters were split on load-flow based options. The largest group of submitters were strongly against further investigation of these approaches based partly on previous New Zealand experience with such models. Submitters noted concerns over instability, complexity and controversy, and possibly the disconnect between use of the grid and value derived from using it (not charging beneficiaries). However, five submitters supported further work on the basis that load-flow analysis could be part of developing a means to incorporate LRMC into grid charges, or agreeing an appropriate tilt for tilted postage stamp.

All submitters who gave a preference for the type of load-flow analysis (ICRP or CRNP) supported ICRP (forward-looking).

2.3.20 Of the submitters that gave an opinion on the load-flow analysis options, nine submitters stated that load-flow modelling was not – or unlikely to be – an appropriate basis for cost allocation. Most held strong views against the use of these options – and several referenced previous experience of these methods in New Zealand. These submitters made the following comments.

(a) The option was complex, contentious and potentially unstable – both because of changes in load flows and because of arguments about the methodology (Counties Power, Genesis, MEUG, Rio Tinto, WPI, Transpower).

(b) These approaches have been tried previously and passed over (Orion).

(c) These approaches introduce complexities over what benchmark time and characteristics the load-flow should be based on (Powerco).

(d) It may be a technically accurate way of measuring ex-post use of the grid, but it is not a good way of signalling ex-ante future costs of generation and transmission decisions (Meridian).

2.3.21 The five submitters who considered that these options may be worth further investigation as an appropriate basis for cost allocation made the following comments.

(a) Load flow modelling could be part of developing an LRMC of the grid to reflect each point of injection (Northpower).

(b) Review of the forward-looking load flow methodology should help to ensure the locational pricing methodology the Commission decides to implement is the most robust one, and may inform work on a TPS approach (MRP).

(c) Cost-reflective load-flow analysis could be used to set the tilt for tilted postage stamp or forward looking load-flow analysis could be used as a basis for valuing the contribution from transmission alternatives (Todd Energy).

2.3.22 Transpower submitted that it did 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.

2.3.23 All but one of the submitters who gave a view – whether they supported the investigation of the load-flow analysis or not – favoured forward-looking ICRP methodology over the historic CRNP methodology because this should signal the LRMC of the grid rather than allocating sunk costs on a load-flow basis.

2.3.24 Todd Energy stated that the part F regime is used as a basis for assessment and approving future grid investment so it is arguable that there is no broad need for ICRP based charges.

Other options

Four submitters made the following suggestions for alternative high level options:

(a) Product (tariff) rates similar to Lineco's approach to distribution pricing.

(b) A requirement on grid-connected generators to face the bulk of all transmission costs.

(c) The gas transport model.

(d) A review of connection-interconnection and node-link definitions in relation to investment incentives.

A series of other suggestions – prompted by work commissioned for MEUG – were made by submitters in relation to this or other parts of the consultation paper. MEUG would like to see further investigation of a 'but-for' test[5] for new investment, and a more market-based approach to HVDC pricing (a capacity rights or arbitrageur approach.)

2.3.25 Four submitters suggested other high-level options in response to this part of the consultation paper.

(a) Tariff rates similar to the lines companies approach to distribution pricing (Contact).

(b) A requirement on grid-connected generations to face the bulk of all transmission costs (ENA).

(c) The gas transport model where shippers invest in the pipelines and the costs are paid for through wholesale gas rates (WPI).

(d) A review of the connection-interconnection and node-link definitions in relation to investment incentives. This may avoid the incentives on transmission customers to prefer investment alternatives that are economically sub-optimal from a national perspective, but which result in lower transmission charges for the customers concerned. This could also examine possible linkages between regional service preferences and zonal interconnection charges (Transpower).

2.3.26 A series of other suggestions were made by submitters, prompted by work commissioned for MEUG from NZIER. These suggestions were largely made in relation to connection issues (see section 2.4), but as these amount to significant potential changes to existing arrangements they are also considered briefly here.

[5] In simple terms, the "but for" pricing policy is where the generator must pay for network upgrades that would not be required "but for" that generator connecting to the grid.

2.3.27 MEUG has explored the possibility of a 'but-for' test for new investment and a more market-based approach to HVDC pricing (termed capacity rights or arbitrageur models).

2.3.28 The 'but-for' approach advocates a deeper connection charging method for new investment. A number of submitters stated that they would like to see more investigation of the 'but-for' approach. They were: Counties Power, ENA, MEUG, Pan Pac, Rio Tinto, Norske Skog, and WPI.

2.3.29 Submitters' views on the "but for" approach are considered in the section 2.4 of this report.

2.3.30 MEUG also submitted a report by NZIER[6] which set out a more market-based approach to HVDC pricing. Contact, Business NZ, Rio Tinto, and WPI also suggested that more work should be done on this.

2.3.31 Todd Energy commented that more work is required on encouraging transmission alternatives in the evaluation of the high-level options.

2.4 Further issues

2.4.1 Separate from the high-level options, the consultation paper considered four other key issues.

(a) Treatment of connection costs.

(b) The treatment of transmission alternatives.

(c) Linking transmission pricing with service and quality.

(d) Static reactive compensation.

Treatment of connection costs

2.4.2 This section considered first whether there was merit in a PJM[7]-style 'deep' connection option known as 'but-for', and then other aspects of connection charging.

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6 NZIER, *Alternative options for transmission pricing*, October 2009

7 The area encompasses 13 states and one district in the north east of the United States. PJM Interconnection is the regional transmission organisation responsible for reliability and the operation of the wholesale electricity market in the PJM area.

The ‘but-for’ approach

Several large users and lines companies submitted in favour of further investigation of the PJM-style ‘but-for’ approach, as a way of allocating new investment costs to beneficiaries. Some submitters noted potential concerns with this approach including: problems of free-riding, of identifying costs attributable to particular new plant, and the difference in relative investment lead-times for transmission and generation.

2.4.3 Seven submitters favoured further investigation of a PJM-style ‘but-for’ approach. These submitters – with the exception of Counties Power and ENA –were large users. MEUG provided a report by NZIER[8] that recommends the current connection charges should be supplemented with additional charges on new generators and new load over a *de minimus* level, based on the ‘but-for’ approach.

2.4.4 The main case for this option put by submitters is the potential for the approach to address the user/beneficiary pays problems for new investment.

2.4.5 WPI pointed out that it would work best for large discrete blocks of generation or load that required clearly identifiable grid investments.

2.4.6 Submitters had the following concerns about this approach.

(a) Complexities would probably result in stalling any action which is critical to get the appropriate signals for investment now (Northpower).

(b) The problem of free-riding; participants that benefit from an interconnection investment, but are not deemed to have caused it can free ride (Vector, Transpower).

(c) 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 (Transpower).

(d) It could deter new generation investment where it is most needed and encourage a higher-level of embedded generation – which may be of suboptimal size (Contact).

(e) Difficult to enforce fairly given the organic growth in types of generation and for combinations of load and generation (Contact).

(f) The deeper the connection pricing methodology goes the greyer and more contentious the analysis of causation becomes (Meridian).

[8] NZIER, *Alternative options for transmission pricing*, October 2009

(g) In many cases the need for transmission investment is driven principally by organic growth, but this fact may be masked by a final single connection that appears to cause the need for the augmentation (Transpower).

(h) Although the method is relatively uncontroversial in PJM, this may be because the costs at stake are generally small relative to total project costs and the overall value of the PJM grid. In NZ our investments are relatively lumpy (Transpower).

(i) Relative investment lead times may also be an issue. Transmission investment lead times are so long that Transpower may need to commit to grid augmentations before new generation plants are constructed. (Transpower)

Other aspects of connection charging

Submitters noted connection charging issues including the current designation of connection and interconnection assets creating inappropriate investment incentives.

2.4.7 The consultation paper asked submitters whether there are aspects of connection charging that should be reviewed. Some submitters noted the strengths of the current connection charging regime – in particular the aim to charge identifiable beneficiaries connection costs where possible, and to have an option for contestable connection construction and ownership – and cautioned against making changes unless there was clear evidence that inefficient investment decisions were being made. Table 5 below lists the issues noted by submitters:

Table 5: Connection charging issues

Issue	**Detail**
Definition of interconnection/connection assets *(This issue is linked to the other high-level option proposed by Transpower)*	Current designation of interconnection/connection assets can result in incentives to connect new load where upgrade costs will be shared (eg connecting at Islington (an interconnection node versus Bromley (a connection asset) or for load to persuade Transpower to upgrade interconnection assets instead of connection assets (Meridian, Orion, Transpower). A more shallow definition of load spurs would provide greater price stability. Contact cited examples where price shocks can occur – where connection assets may join (such as Te Awamutu to Hangatiki spurs), where interconnection becomes connection, or where spur connection costs are shared between AMI/AMD users) (Contact).

Issue	Detail
Looping spurs	Looping spurs from the core grid that are classed as connection assets in the TPM should be charged on the basis of the minimum build that would serve the load without the need to carry the full core grid load and meet the core grid requirements (Northpower).
Land and buildings cost allocation	At a shared interconnection node, the connection charge allocation of land and buildings to off-take is based on Transpower's connection asset value, not the land and buildings used. See 3.59.2 (c) of TPM. This creates an inappropriate incentive for parties to install and own connection assets on Transpower's land. Land and buildings could be allocated on an AMI or AMD basis (Orion).
Connection assets allocation factors	Distortion occurs in connection asset allocation pricing due to Transpower's allocation factors. For example, if a particular asset is optimised out of the regulatory asset base it is still included in the connection charges for that wider area but all the values in that area are scaled down by an allocation factor to reflect the optimisation. This creates distortions and also makes the annual auditing/price checking process impossible (Orion).
Replaced assets charge	When connection assets are due for replacement (not an upgrade which is handled by an new investment agreement) the ARR calculation leads to an artificially low cost to the connected party as the price for the replaced assets is linked to the age and replacement cost of all New Zealand connection assets. For contestability at the asset boundary, the connection charge for replaced assets needs to reflect actual replacement not historic replacement cost (Orion).
Contestable spur connections	Parties may build their own spur assets but this should be a consultative process to avoid the building of sub-optimal capacity lines (Contact).
Capacity rights	Could consider mechanisms for allocation of capacity rights for non-regulated investors in transmission assets (Genesis).

Issue	Detail
Possible inappropriate investment signals through different connection options	A generator's connection charges will depend on whether it connects its plant to the interconnected grid directly at a GXP, to the interconnected grid indirectly via dedicated or shared connection assets, or to the distribution network, bypassing the interconnected grid. Given the way connection charges for generators can vary based on their locational decisions and the type of generation, investment decisions can be distorted as a result. In particular, the existing arrangement creates incentives for generators to avoid charges associated with existing connection assets, to build smaller plants with lower transfer capacity and to avoid building near existing remote loads (Meridian).
Volatility in shared connection assets	Charging arrangements for shared connection assets may result in volatile charges as new customers connect and existing customers disconnect from the transmission network (Meridian).
'Greenfield' spur lines and connection assets serving remote regions with renewable energy resources	Potential issues may arise where a connection asset is required for a remote region with significant renewable energy resources such that it may be shared by multiple generators. These new connection asset issues were raised in the Commission's transmission to enable renewables project (EECA). In some cases, the most economic investment from a national perspective would be something different from that chosen by a first mover in a new green field location. In this situation it may be appropriate for there to be back stop provisions to enable the investment to be undertaken by Transpower and a return on some of the capacity created recovered as it the asset were an interconnection asset until the capacity is fully utilised (Transpower).
Incentives to co-locate with demand	Grid-connected generators co-located with demand could be attributed with providing transmission services at that connection location. This could provide some trade-off for the generator to connect to connection assets whereby the generator may otherwise look to connect to interconnection assets to reduce their transmission charges under the current regime (Todd Energy).

Treatment of transmission alternatives

Submitters were split on the current transmission alternatives regime. Generators (with the exception of Todd Energy) and Transpower generally supported the current arrangements. Large users, lines companies and Todd Energy advocated change to the existing regjme, in some cases strongly. Possible changes included providing pricing signals for transmission alternatives and the ability for transmission alternative providers to access funding directly, rather than by contracting with Transpower.

2.4.8 The consultation paper asked submitters if it is necessary or worthwhile to alter or clarify the arrangements for transmission alternatives.

2.4.9 Submitters were split on this issue, with the generators (except Todd Energy) and Transpower largely supporting existing arrangements, while the lines companies and large users set out reasons why the treatment of transmission alternatives should be changed.

2.4.10 WPI commented that a key question was whether there is a policy desire to tilt the playing field in a way that brings forward transmission alternatives and develop transmission alternative markets in advance of whether they might otherwise become established. In WPI's view this is a policy-level issue that could stand on its own as a market development initiative.

2.4.11 Submitters gave the following reasons in support of the existing arrangements.

(a) Generation transmission alternatives are not a complete substitute for transmission – they are not 99.9% reliable – nor do they offer the two way diversity of transmission (Meridian).

(b) The current approach ensures a level of rigour is applied to any transmission alternative proposal (Meridian).

(c) Regulation of transmission alternatives creates risks that generation projects that would have gone ahead anyway would end up being subsidised (MRP).

(d) Only Transpower is in a position to certify that the provision of transmission alternative services is actually needed at any particular time and hence providers of transmission alternatives should not be about to gain access to regulated funding independently of Transpower (Transpower).

2.4.12 Genesis commented that weaknesses in the treatment of transmission alternatives to date have more to do with Transpower and the Commission's application of the existing framework rather than the framework itself.

2.4.13 Large users and line companies made the following comments in support of altering existing arrangements.

(a) Timeframes are presently too short for parties to offer alternatives that are viable but not committed (Northpower).

(b) Some transmission alternatives (DSM strategies) require long term changes in behaviour and investment that cannot be contracted or guaranteed in the short timeframe required to be transmission alternatives. A long term marginal price signal will provide a better signal to encourage this type of DSM response (Orion).

(c) There should be a mechanism that provides funding directly to transmission alternatives. GSCs are a positive mechanism that should be developed further (Vector).

(d) Demand response and electricity efficiency can potentially be used as transmission alternatives but these do not receive the same transmission pricing signals as grid connected generation or load. Many consumers have minimal exposure to nodal prices and signals provided by transmission charges (EECA).

(e) Barriers include lack of consumer information or awareness of opportunities and free rider problems (EECA).

(f) Distributed generation and demand side management are treated very badly by the existing nodal pricing system and by the pricing counterparty arrangements that effectively give remote generators subsidised access to markets where they compete with those alternatives (ENA).

(g) The regime in place favours transmission investment over alternatives because of the regulated uncertainty for approved transmission investments (WPI).

(h) Transpower only seriously looks into alternatives when it has to and then only as a stop gap (WPI).

(i) Some transmission alternatives, such as demand side options and small-scale distributed generation, require aggregation in order to be viable (WPI).

2.4.14 Business New Zealand submitted that the issue should be about how it might be possible to take a commercial energy market project and make it a true transmission alternative. However, in Business New Zealand’s view, in the face of being unable to progress this issue, the Commission should abandon all consideration of transmission alternatives.

Service quality and pricing

Submitters generally supported performance incentives for transmission services, but a significant number considered such incentives should not be considered as part of this Review either because they are not a priority, or are better considered by the Commerce Commission. MEUG. Powerco, WPI and Todd Energy considered that a USG or voluntary insurance scheme was worthy of further consideration. Transpower was particularly opposed to the USG and voluntary insurance scheme proposals, and included an appendix setting out its objections.

2.4.15 The consultation paper asked submitters two questions:

> Should either a USG or a voluntary insurance scheme be considered within the Commission's Review?
>
> Are there other options for linking service quality and pricing that you think the Commission should consider?

2.4.16 Submitters gave views on issues wider than these two questions. All the submitters that commented on these issues, generally agreed that incentives are appropriate for a transmission provider. However, a significant number of the submitters submitted that such incentives should not be considered as part of this review. These submitters made the following comments.

(a) This is a complex issue that might be best considered slightly behind the review or is not a priority at this stage (MRP and ENA).

(b) 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 – they should not be part of the TPM (Transpower).

(c) Service level incentives are possibly best kept under the Commerce Act provided they can be expanded under that existing agreement (Powerco).

(d) The Commission should take no further action as price-quality trade-offs are properly the responsibility of the Commerce Commission, which has some experience in developing quality incentive mechanisms (Vector).

(e) Including issues of a stronger link between price and service risks bogging down the Review or not doing justice to existing issues (Meridian).

2.4.17 On the other hand, MEUG maintained that service and pricing should be considered simultaneously and other submitters argued that the existing arrangements – either through the TPM or the service measures through the Benchmark Agreement - were inadequate.

2.4.18 MEUG, Powerco, WPI and Todd Energy considered that the USG approach or voluntary insurance scheme was worthy of further consideration. MEUG particularly noted that it had not been satisfied that the initial Benchmark Agreement provided an incentive on Transpower to improve service delivery and the Commission had indicated that later reviews might consider a USG or insurance option. Todd Energy particularly commented that generator connections should be considered for a USG as generator outages can have a significant economic impact on parties. Other submitters had the following concerns about a USG or other possible mechanisms for linking price and service.

(a) Any liabilities would likely have to be recovered from users (ENA, Pan Pac and Powerco).

(b) The costs of administering schemes may not be warranted and self-insurance is likely to be more efficient (Orion).

(c) Given that the assets involved are very reliable with failure rate around 1 in 40 years, it does not seem appropriate to apply an annual assessment of reliability or even a 5 year average at each connection node (Orion).

(d) Service levels on the core grid are very good and likely to improve. Service can be addressed at the individual connection level and must be kept in context with the level of security provided by the distribution company (Contact).

(e) Transpower set out in an appendix to its submission an analysis of the USG and voluntary insurance proposals that outlined its arguments that the proposals should not be further progressed. Transpower's objections included:

   (i) that including a USG in the TPM would be legally invalid;

   (ii) that USG proposals cut across existing contractual provisions;

   (iii) that USG proposals may create perverse incentives for customers;

   (iv) Transpower may face exposure to multiple penalties from single events from provisions in the part 4 of the Commerce Act, transmission agreements and a USG; and

   (v) there is no evidence that the schemes would improve performance.

2.4.19 Orion suggested an option for consideration is to regulate reliability/plant availability on a national basis. This could be implemented by monitoring failure rates for assets and benchmark this against international results and penalties set, although such a scheme would need to be carefully thought through.

2.4.20 Meridian stated that improved information and transparency are more important than the correct link between price and quality. Better information ex-ante on connection risks, for example, is likely to drive more appropriate behaviour than an ex-post price penalty.

2.4.21 Pan Pac noted that conditions should be well known in advance and in writing as part of the relationship contract.

Static reactive compensation

Submitters were generally supportive of changes to the way static reactive power costs are allocated but were split on whether it is appropriate for this to be considered as part of the Review.

2.4.22 Submitters were asked if a methodology for allocating the costs of existing and new static reactive power assets should be considered as part of the Review.

2.4.23 Submitters were generally supportive of changes to the way static reactive power costs are allocated, but were split on whether it is appropriate for this to be considered as part of the Review.

2.4.24 For those submitters who considered that it was not appropriate to consider reactive power compensation as part of the Review, they submitted that it was not a priority at present, or it was worthy o separate consultation in order to undertake a proper analysis of the costs and benefits and to consider all options.

2.4.25 Some submitters made specific comments about how static reactive power costs should be treated.

(a) Lead times must be realistic to allow participants to design, cost and install new static power-factor correction assets. (Northpower)

(b) Price signals may be preferable to an allocation methodology; we do not allocate the costs of the interconnected core grid to specific parties based on their location, so why should core grid reactive support be allocated to specific parties. However we do want to change connected party power factor behaviour if it is economic to do so. A peak period (RCPD) kVAr price component could be introduced that matches the forward price of grid reactive support so connected parties could have the options to respond to that price (Orion).

(c) It may be better that reactive power costs are just treated as transmission assets (Powerco).

(d) A development of a pricing mechanism, supplemented by realistic minimum power factor requirements could encourage economically efficient investment in reactive compensation equipment (Vector).

(e) The most appropriate means by which to allocate transmission and non-transmission voltage support costs should be investigated, noting that pricing incentives generally offer more flexibility than regulated requirements (Transpower).

(f) Allocation of reactive power costs via the TPM will make costs more visible to participants. Costs should be regionalised to the extent possible (Todd Energy).

2.5 Filtering criteria

Submitters had varying views on the proposed filtering criteria, although a number had common concerns on criterion 1 – divergence from optimal investment. These submitters questioned whether this should be a criterion and stated that a cost-benefit analysis of locational signals should be an over-arching criterion.

Submitters also had concerns about the consideration of the development of locational hedging mechanisms influencing transmission pricing.

2.5.1 This section of the consultation paper set out the filtering criteria that Frontier Economics proposed for assessing high level options. Submitters were asked a specific question about the relationship with locational hedging options and two more general questions about the filtering criteria

General comments on filtering criteria

2.5.2 Whilst some submitters supported the criteria proposed by Frontier, others made the following general comments.

(a) The Commission needs to use cost benefit analysis to assess long term benefit to consumers (Meridian, MEUG, MRP, Pan Pac, WPI).

(b) The Commission should use the pricing principles as criteria (Orion).

2.5.3 Table 6 below lists the comments made about specific criteria.

Table 6: Comments on specific filtering criteria

Criterion	Comments
1. Divergence from optimal transmission investment	Submitters' comments on this criterion were related to comments on whether 'overbuild' is appropriate or not. (See section 2.2). Some submitters did not think this was an appropriate criterion, and one stated that this was because grid investments are not driven by nodal prices. The GRS plays an important rule and establishes a minimum level of transmission investment that matches society's risk tolerances. The GRS and its impact on transmission investment will be a constant across all TPM options, to this extent this will not act as a useful criterion (Meridian).
2. Theoretical precision	Will have practical caveats (Meridian). Not particularly useful – a better criterion would be likely effect on actual consumption and investment behaviour – some options may be correct but not have an economic effect in practice (Transpower).
3. Locational hedging options	Submitters were asked: 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? Submitters' responses were to some extent determined by their views on whether further locational signals are needed for generators. For example, a submitter that supported locational signals for generators stated that locational pricing signals for generators are required whether or not locational hedging is introduced. Some submitters noted that the locational hedging instruments should be considered as an instrument for purchasers, not generators and as such would have a minimal effect on generation locational signal. Vector said there was insufficient analysis to support the suggestion that reformed transmission prices will be able to compensate for the removal of nodal price signals under the LRA regime. The signals provided by the nodal price signal and transmission prices are quite different. It cannot be assumed that they will act as perfect or even reasonable substitutes for each other. Rather they are complements that best address different issues (short-term dispatch and long-term investments). Two submitters were cautious about potentially lowering locational signals in energy prices and consciously over-signalling in transmission pricing. Two submitters did not think this should be a criterion.

Criterion	Comments
4.Network topology	No comments received.
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 (Transpower).
6 Governance requirements	Scrutiny by a third party is implicit in the current arrangements, and any politically acceptable alternative (Meridian).
7. Good regulatory practice	No comments received.
8. Stakeholder acceptability	This is important. The industry needs stability in transmission pricing, which will only come if the TPM is broadly acceptable to all stakeholder groups (Meridian). The Commission should not be driven by what certain stakeholders of vested interests should prefer (MRP, MEUG).

2.5.4 MRP suggested an alternative set of criteria; the criteria should improve efficiency to the long-term benefit of users, and as a subset to this it should follow the following principles:

(a) promote the efficient day-to-day operation of the full power market;

(b) signal locational advantages for investment in generation and demand;

(c) signal the need for investment in the transmission system;

(d) compensate the owners of the existing transmission assets;

(e) be simple and transparent; and

(f) be politically implementable.

2.5.5 In addition to suggestions to extend or change some of the above criteria, Transpower suggested another criterion could be the extent to which any change to the TPM may increase the scope of disputes.

2.5.6 Todd Energy commented that it is not clear how the high-level options will be assessed against wider-government objectives. Todd particularly mentioned pending government policy objectives of incentivising petroleum exploration through the recognition of the key importance and necessity of gas to electricity generation in supporting security of supply with a greater uptake of renewable generation.

2.6 Other submitter issues

Finally, submitters made a number of comments and recommendations about integration with other work and priorities, specific comments about HVDC charging, differentiation between treatment of sunk costs and new investment and boundary issues.

Integration with other work and priorities

2.6.1 Vector, Transpower, Business New Zealand and Contact specifically included views on the interrelationships between transmission pricing and the other two consultation papers that were released concurrently. Other submitters made comments on links with other work throughout their submissions, and many of these have been noted in this report where appropriate. Some particular comments are given here as they are of an overarching nature.

2.6.2 Vector's submission stated that the proposals for the market developments need clear statements of outcomes sought, indicators for success, clear understanding of the linkages, relative costs and benefits of options compared to the status quo.

2.6.3 Business New Zealand considers that a clear pathway forward regarding either locational hedging or transmission pricing has not been revealed, and suggested that analysis on the value of locational signalling and implied improvement in retail competition from removing locational risks should be done before moving ahead.

2.6.4 Meridian suggested that there should be a regular forum where stakeholders can be briefed on progress and identify issues and assist with coordinating outcomes.

2.6.5 Genesis and Contact commented on the relative priorities of the market development projects. In Genesis' view scarcity pricing and locational price risk management are higher priorities, and in Contact's view changes to the Whirinaki offer strategy and reserve market could proceed ahead of the more complex scarcity pricing, locational hedging and transmission pricing developments.

2.6.6 MRP commented that the Commission is juggling too many substantive policy initiatives and if, at any time, locational signalling is found to be impractical or does not warrant further consideration, the Review should be disestablished.

2.6.7 MEUG commented that the Commission might need to consider a number of other areas in parallel with the TPM; the Benchmark Agreement, locational price risk, voluntary initiatives for improving price discovery in the energy market and ensuring energy prices reflect the value of lost load when a supply shortfall occurs.

2.6.8 Meridian considered that the focus of industry resources should be on improving the implementation of the GIT and connection charge.

HVDC comments

2.6.9 Contact, Vector and Meridian particularly commented that the consultation paper should have dealt with HVDC issues such as how the HVDC pricing is treated, and who gets the HVDC rentals.

2.6.10 On the other hand, some submitters specifically commented that the Commission should not consider changing current HVDC charging as this would result in a very significant wealth transfer.

2.6.11 Rio Tinto submitted a report by NZIER on the mechanics of how an alternative to the existing HVDC charging could operate. MEUG also provided a report on alternative options for transmission pricing that included considerations of alternatives for HVDC charging. These reports are available on the Commission's website alongside the relevant submissions.

2.6.12 Transpower considers that the costs of the HVDC link should be recovered via the interconnection charge whether this is via a TPS or the existing methodology.

Sunk costs v new investment

2.6.13 A number of submitters commented – in relation to different aspects of the consultation paper – that sunk costs (and costs already committed) should not be subject to new regimes. (For example, Northpower in relation to issues with the current transmission pricing).

Boundary consistency

2.6.14 Transpower submitted that the opportunity exists, through co-ordination of the various market development initiatives to consider the possible consolidation or alignment of some boundaries such as:

(a) the grid points at which prices are determined;

(b) the System Operator control boundary, which defines where security constrained dispatch is applied to manage contingent events; and

(c) the core grid definition in the grid reliability standards, which defines where N-1 security must be maintained by grid investment.

3. Summary by submitter

Submitter	High Level Views.	Preferred option
Distributors		
Northpower	Locational signals need to be seen by generators so that these signals get factored into the decision-making process for investment in new generation. Locational signals for loads would be somewhat pointless because most loads are unlikely to locate on the basis of electricity pricing (as opposed to reliability of supply).	Favours locational allocation that reflects LRMC – appears to favour load-flow.
Orion	Urges Commission to consider findings of CEOs Forum. Main consideration should be dynamic efficiency (not just locational signals.)	Possibly TPS, likes RCPD
Vector	Supports options put forward for investigation. Favours tilted postage stamp. Needs analysis to show locational signals would have benefits for generator location.	TPS (but supports investigation of others)
Powerco	Too much emphasis on price as the primary mechanism to promote efficient outcomes. Pricing principles should be reviewed first. There are sufficient locational signals in current arrangements (including the HVDC charge). Powerco questions whether a shift to a more complex TPM is warranted.	Status quo
Counties Power	Does not have a committed view, but considers that the TPM works reasonably well. But-for model may work for new generation. Recognises that the Tilted Postage Stamp has limitations and would merge into Load-flow option.	Status quo, recognizes TPS could merge into load-flow.

Submitter	High Level Views.	Preferred option
ENA	Review pricing principles. Want to see nodal pricing signals supported by, or replaced by, signals that lock in locational investment messages. Support analysis on but-for.	Replace nodal pricing? Supports analysis of But-for
Generator-retailers		
Mighty River power	Supports locational signalling. Need cost-benefit analysis. Tilted Postage Stamp likely to be best, but continue looking at forward-looking load-flow. May need to use load-flow to inform the tilt. No need to review pricing principles.	TPS, but look at forward-looking load-flow
Genesis	Is disappointed that there is a review at all. Supports leveraging CEO Forum work and tilted postage stamp. Weaknesses in transmission alternatives have more to do with how the Commission and TP apply the framework.	TPS
Meridian	Need to check overall focus on locational signaling through analysis. Considers nodal pricing, GIT and connection include sufficient locational signaling. Disputes HVDC charge.	Status quo, without HVDC charge.
Contact	Supports a thorough review of transmission pricing and any changes that result in a material improvement in overall efficient of transmission pricing arrangements. Would be concerned if any change put at risk grid upgrade programme. A locational price signal would only be effective if participants were able to respond to it. Choice of location may be possible for certain new generation if the signal is strong enough and sustained. Signals for demand are best left to more operational signals such as RCPD and seasonal signals (and improving load factors).	Consider TPS and Load-flow (in order to redistributed HVDC charge)

Submitter	High Level Views.	Preferred option
	Preferred option: Keep definition of existing local Connection assets, but use a more shallow definition of load spurs . No fundamental change to interconnection - these are best recovered from load on a postage stamp basis. Further consideration of HVDC charge through treating HVDC as interconnection and using a tilted postage stamp for generators or a capacity-based market.	
Todd Energy	Benefits of efficient pricing theory must be balanced with practical implementation concerns and ready comprehension by stakeholders. The tilted postages stamp offers advantages. The review needs a greater emphasis on transmission alternatives. Rectify distortionary pricing signals delivered by the TPM by moving to a regional peak demand assessment based on a gross demand model at the GXP for determining the applicable -based transmission charge component.	Tilted postage stamp or modifications to the status quo.
Users		
Business NZ	Business New Zealand does not consider that a clear pathway forward regarding either locational hedging or transmission pricing has been revealed. No clear objective - such as increasing retail competition - needs a clear framework for considering how to assess the trade-offs between improved competition and diminished locational price signals. This analysis on value of locational signaling should be done before we move ahead. This analysis may, or may not, reveal that a zonal-based solution will enhance regional retail competition enough to produce a net benefit. Either way, this analysis will be informative and lead to the development of a more robust and durable solution. In the absence of this analysis, a choice of preferred options is extremely problematic.	None as yet

Submitter	High Level Views.	Preferred option
Rio Tinto	Believes that an improvement on status quo is achievable, and thinks the methodology chosen should maximise the dynamic efficiency for the NZ economy - even if it compromises some static efficiency. All methodologies are likely to have some anomalies and boundary issues. Preferred option is: - a but-for test for new investments in the AC grid. - deep connection (direct) allocation for existing AC assets. - an indirect allocation across all nodes for the residual AC assets (with or without locational or demand signalling) and - a sale of capacity rights for the HVDC assets. Note Rio prefers 'directly' or 'indirectly allocated costs' terminology.	But-for plus capacity-rights for HVDC
Norske Skog	Mistake to make any significant change to the status quo for the HVDC. If there has to be a change then the capacity-rights approach has a lot of appeal. Definitions for connection and interconnection assets for the existing grid should remain. New investments should be subject to the 'but for' test.	Status quo.
Pan Pac	Pan Pac appears to confuse nodal energy pricing with the British model, and is interested in learning more about the British model. Supports RCPD. Makes a number of comments outside the scope of the review.	
MEUG	But for test for new AC investment. Deeper connection definition for sunk AC assets. Capacity rights or arbitrageur for HVDC. Review of transmission alternatives. Better align with contracted service obligations. (However, continue analysis on Tilted Postage Stamp as a counterfactual).	But-for, plus capacity rights or arbitrageur for HVDC

Submitter	High Level Views.	Preferred option
Winstone	Supports stability and predictability of current TPM. Drop further consideration of load-flow-based approach, Consider the capacity rights approach for HVDC cost recovery. Prefer continuation of the current TPM with some consideration given to tilted postage stamp. Review Pricing Principles.	Status quo, poss TPS, plus capacity rights for HVDC
Others		
Transpower	Review pricing principles. Consider tilted postage stamp concept as a way of replacing the HVDC charge by adding a more general locational element to the interconnection charge. If TPS is not preferred, abolish the separate HVDC charge. Do not progress other options. Review connection-interconnection and node-link definitions. Consistency across commercial, operational and planning boundaries.	TPS
EECA	Welcomes consideration of locational signals. Has concern over connection costs, particularly where assets serve remote regions with renewable energy resources. Welcomes consideration of how to improve efficient investment in transmission alternatives.	

Appendix 1 Submitter responses to questions

1.1.1 This table contains submitter responses to the questions posed in the consultation paper: Transmission pricing review: high-level options. Some longer responses have been summarised.

Submitter	Response	Comments
1. To what extent do you agree that nodal prices can provide efficient signals for the use of the transmission network?		
Northpower	To generators but not to load.	While nodal pricing may be an efficient way to dispatch generators, it gives no meaningful signals to most loads. It gives a very weak locational signal to generators. Ultimately, the nodal prices are passed-through to the end-use customers who do not have any influence over dispatch of generators.
Orion	Disagree	Orion is on record as disagreeing that nodal pricing provides efficient signals for the use of the transmission network. "We have for many years argued that nodal pricing does not send appropriate nor effective new investment signals for transmission, in particular in regard to the core grid" (Letter 2002 from Orion to Commission.)
Powerco	Nodal prices can provide signals but are unlikely to be effective.	See our comments earlier in this submission Too much emphasis on price to promote efficient outcomes; transmission system is a natural monopoly that requires significant time to plan and build. Generation and load growth should dictate the required transmission. Nodal price differentiation should signal to the Transmission owner the need for transmission investment - not dictate where new load or generation should be located.
Contact	Yes	Nodal prices do provide efficient signals for the use of the transmission network and can provide very sharp signals to certain industrial consumers and regional generators but have limited effect on the behaviour of the mass-market. Constraints initiatives are taken to manage high nodal prices and hence network "usage" is managed accordingly and efficiently.

Submitter	Response	Comments
Meridian	Yes	Meridian agrees that nodal prices can provide efficient signals for the use of the transmission network.
Mighty River Power	yes	Nodal prices provide efficient short-term pricing signals e.g. for which generation plant should be dispatched.
Todd Energy	Up to a point	Due to the lumpy nature of transmission augmentation, and economies of scale involved in transmission, generation and load, the transmission system will never be augmented perfectly efficiently, and thereby nodal prices alone will not provide the signals that would result in the most efficient use of the transmission network.
ENA	Yes	Agree nodal pricing is a useful tool for efficient transmission and grid-connected generation dispatch.
Transpower	Yes for generators and not so much for load	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. However, nodal prices are not particularly effective at providing efficient consumption signals. This is because, first, only a small 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.
MEUG	Nodal prices partly, rather than fully, provide efficient signals for transmission.	Agree with the discussion in paragraph 3.2.4 of the paper that economies of scale, over-caution by network planners and regulators, and lack of a price to reflect the value of lost load when demand exceeds supply lead to the conclusion that nodal prices can only partly provide efficient price signals for transmission.
Panpac	Agree	

Submitter	Response	Comments
WPI	"Full" nodal pricing should provide the appropriate short run signals for grid users' operational decisions. The issue is that NZ does not have a full nodal pricing regime in place.	Full nodal pricing has three components: losses, congestion and no artificial price caps below the value of unserved energy. While the first two are built into the NZ market, the way that Whirinaki has been bid into the market has distorted marginal prices by not reflecting the full short run operational costs of that plant. We note that this area overlaps with scarcity pricing which is discussed in a separate consultation paper.
2. To what extent do you agree that nodal prices can provide efficient signals for investment in generation and load projects?		
Northpower	Only to a small extent	Nodal signals are very muted in signaling the need for new generation investment. A high nodal price disappears once a new generator is commissioned because it is impractical to build incremental generation just sufficient to supply the incremental load that causes the high price. Similarly, a load that reduces its off-take during times of high nodal prices cannot capture that drop in price; but other loads, which take no action, see the benefits. It is important that generators see the true transmission cost that they cause by their location decisions. New Zealand is seeing a number of large wind generation projects being considered in Otago and Northland. It is critical that the proponents of these schemes see the additional transmission cost of (for example) choosing to construct a windfarm in Otago when the new load is based in Auckland. Generation can choose its location – Aucklanders are unlikely to relocate to Otago just for cheaper electricity. Loads are located on the basis of availability of resources and security of supply, rather than marginal energy prices.

Submitter	Response	Comments
Orion	Disagree	Nodal pricing is a potentially useful signal of investment requirements: however there are several reasons why, in itself, it is unlikely to be sufficient to provide complete information about the costs of transmission. We note that the Commission has addressed a very similar question to this (question 2) in its consultation paper on transmission pricing (Electricity Commission, Guidelines for Transpower's Transmission Pricing Methodology, 24 December 2004.) Response from the Commission noted some factors and said it agreed with generators that expectations about future nodal prices will influence generator choices most strongly when other factors balance out. In these cases even a 5 to 10% differential can be influential but these cases arise infrequently. The Commission noted that few consumers are likely to alter locational choices as a result of forecasts of future nodal prices. Orion considers that these arguments are as relevant today as they were in 2004.Orion has previously noted concerns with the current TPM not providing appropriate location signals.
Powerco	Yes	Nodal prices already appear to provide sufficient locational signals.
Contact	To a great extent	To a great extent. Nodal prices provide a relevant signal for generation investment. While nodal pricing (or augmented pricing signals) may change the sequencing of generation investment it is unlikely to change locations as these will be dictated by renewable resources. Equally they will have little bearing on load projects which may be dictated by many other factors. Energy charges will be largely the same and transmission charges (in proportion to their total energy bill) would be a minor economic consideration. Nodal pricing though can create excessive and disproportionate signals (if a spring washer occurs) that is not representative of an accurate signal reflecting physical flows over the long-run.
Meridian	Yes - if:	Yes, provided that nodal prices are combined with: - a comprehensive regulatory test for the approval of forward-looking transmission investment; and - deep connection charging. Meridian believes that the GIT has resulted in correct investment decisions so far (from a national perspective, if not individual), but at some point a review may be worthwhile. Current deep connection construct performs a useful role.
Mighty River Power	No	The conditions required for nodal pricing to send efficient long-run investment and locational signals are so strict they could not apply in practice.

Submitter	Response	Comments
Todd Energy	Up to a point	There are economies of scale involved in generation (and load) investment, and the value of security of supply and reliability is not currently adequately signalled via nodal prices. As such, nodal prices alone will not deliver the most efficient signals for investment in generation and load projects. Availability of fuel and raw materials are also a significant consideration for investors.
ENA	No-weak and in appropriate	Weak and in appropriate investment signals. Nodal pricing discriminates against distributed generation in networks, and against demand-side options that would otherwise be capable of delivering efficient outcomes.A very small reduction in load downstream of a GXP resulting from an embedded generator of a demand-side initiative causes a nodal price collapse. This eliminates the incentive to respond to high energy losses and constraints in the grid through local investments. No effective contractual mechanism for overcoming this outcome has emerged.Also, as grid-connected generators remote from markets can capture a nodal price loading at GXPs that compensates them for energy losses in the transmission system, there is a signal provided to invest at a considerable distance from markets. This is demonstrated by the drive to invest in remote SI wind resources rather than in options closer to the key Auckland market.
Transpower		Most offtake customers with loads below 350kVA do not see the nodal prices directly For most offtake customers electricity represents only a small proportion of total costs, so are not likely to drive investment decisions. For some large loads, electricity costs may influence investment decisions but whether or not the impact of constraints on nodal prices downstream and upstream of constraints is sufficient to affect investment decisions depends on if investors perceive the constraints to be permanent fixture or likely to be relieved. 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). For generators, the impact of losses on nodal prices would be expected to be taken into account, since they are more or less permanent feature. However, generators are probably unlikely to locate downstream of a constraint in order to benefit from higher nodal prices, because of the risk that the constraint might be relieved in future. Generator locational decisions are driven more by other costs.

Submitter	Response	Comments
MEUG	Nodal prices partly, rather than fully, provide efficient signals for demand and supply investment.	The status quo TPM assists efficient selection of generation between Islands. Within each Island nodal prices are weaker resulting in under-investment of generation close to demand, eg the NAaN, NIGU, 2x100 MW OCGT and upper South Island generation cases discussed in box 3 of the consultation paper.
Panpac	Agree	
WPI	Nodal prices cannot provide appropriate signals for generation and load due to the issues identified in the Frontier report.	The issues are (a) that there are significant economies of scale in transmission and generation investments, (b) that network planners and regulators are politically conditioned to be risk-averse in terms of planning timeframes for new projects and (c) that supply security is not priced. There appear to be no practical remedies for these issues in terms of enhancements to the nodal pricing regime alone.
Northpower	We disagree with the assumption in the question.	Nodal prices suffer from several real life issues outlined in the consultant's paper. In our opinion, the transmission grid is being augmented later than is necessary, rather than ahead of demand. The Commission has expressed a view that projects such as NIGU and NAaN are being provided ahead of the absolute latest date based on the Commission's economic assessment criteria, but Northpower considers that the more generally held view is that these projects are already overdue and that some regions in NZ have sunk to a "third world" status of electricity supply security.

Submitter	Response	Comments
Orion	To some extent	Nodal prices may have been inappropriately suppressed due to the transmission system being augmented ahead of time. However the alternative that the transmission system is augmented too late is of greater concern. The impact of even short outages due to inadequate transmission capacity are enormous, and while there is clearly a cost of investing too early the cost of not having transmission infrastructure available when required would far outweigh the gains. That said, we do not consider that it is appropriate to invest significantly ahead of need. The nodal price effects of transmission constraints depend on generator offer behaviour rather than the physical constraint. Potentially a single generator 'upstream' of a constraint gets to set the price at any level they like. The resulting nodal price differences therefore potentially represent market power rents, and have nothing to do with efficiency. Prudent investment needs inputs other than existing nodal prices.
3. Do you consider that the nodal prices in NZ may be inappropriately suppressed due to the transmission system being augmented ahead of demand?		
Contact	No	No, not necessarily. They may be suppressed but this may not be inappropriate. The transmission system being augmented ahead of time (within reason) can be the prudent thing to do. The asymmetric risk of the investment being too late can far outweighs the cost of it being too late – given the increasingly variable and dynamic nature of the power flow characteristics
Meridian	No	It is inaccurate to say that we have over-investment in transmission because nodal prices are too low, and it is incorrect to say this level of investment will be reduced with a stronger locational signal. Meridian asks that the Commission investigate this question with a proper empirical analysis.
Mighty River Power	No	We believe, given the uncertainty around demand growth and risks of transmission projects running overtime that it is efficient and prudent to make transmission investments ahead of projected demand. That this will result in a reduction in nodal prices earlier, than just-in-time transmission investment, is the correct economic signal reflecting the upgraded transmission capacity. There is nothing "inappropriate" about the resulting reduction in nodal prices. We believe a substantial proportion of transmission investment in New Zealand is being made later than it should.

Submitter	Response	Comments
Todd Energy	Yes	There will always be some suppression of nodal price due to the lumpy nature of transmission build which is generally augmented ahead of time for the larger projects and the economies of scale in future proofing by allowing for future load growth in the receiving region
ENA	No	No - we can see no economic reason why suppression of nodal prices would be inappropriate.
Transpower	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. 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.
MEUG	Yes.	
Panpac	Not convinced.	A correctly designed nodal price (transportation) system can correctly simulate before and after investment and can determine where and when investments should occur. The most difficult concept is the effect of transmission capacity on an efficient energy market.

Submitter	Response	Comments
WPI	Yes.	It will always be impractical to plan pinpoint commissioning dates for new investments with acceptable risk of delay. There will always be political pressure on regulators and planners to avoid the lights going out, even if that might be an “economically efficient” outcome. The highly complex and difficult environmental planning processes that confront transmission planners result in very long planning lead times. Within these timeframes, original assumptions about future needs and conditions may prove to be inaccurate or inadequate several times over. Hence, the pragmatic approach for planners will always be to build options value by establishing and protecting viable investment options. Options development and protection for significant public works is typically an expensive exercise but essential if the risk of being caught with no practical options for relieving a significant constraint is to be avoided.
4. Can you provide examples of where a transmission alternative could have been undertaken instead of an investment in the grid?		
Northpower	No, because growth is not the driver for present gird upgrades.	In “Box 3” the Commission has observed that building a 200MW OCGT plant north of Auckland could have deferred the NAaN project by several years. This appears to overlook the general theme of the presentations made to the NAaN conference in early 2009 which, in Northpower’s opinion, proposed that the NAaN augmentation is required to provide an appropriate level of reliability to 250,000 existing end-use consumers, rather than just meet an additional MW of demand in 2016. The complete loss-of-supply to the NAaN region at 07:59 on 30/10/2009 confirmed the vulnerability of the existing double-circuit 220kV tower-line through Auckland. A 200MW generator north of Auckland would not have prevented the outage because the 600MW of load would have tripped the 200MW generator, even if IL and AUFLS had operated.
Orion	Yes	We can provide an example of a live issue where a transmission alternative could be undertaken instead of an investment in the grid but this may not proceed. We can provide examples of where transmission alternatives have been successfully undertaken to defer investment in the grid. The recent work on the co-ordination of load management in the upper South Island is of current interest.

Submitter	Response	Comments
Contact	No	Not to the same degree of reliability that transmission grid investment provides. The Stratford Peakers generation has been used as an example - but this was not located in Auckland for a number of reasons that have been explained directly to the Electricity Commission. A TPM locational signal would have had little bearing on this decision. The type of generators used would not provide the same degree of base load reliability that the transmission upgrade does. Any transmission alternative must be considered in terms of equivalent reliability.
Meridian	No	The question should be not whether a particular transmission project could have been avoided, but whether a locational signal would have had that effect.
Mighty River Power	No	No. Mighty River Power does not agree with any of the transmission alternatives the Electricity Commission has suggested in various of its Grid Investment Test reviews e.g. the NAAN.
Todd Energy	Yes	Setting aside the considerable gas transmission capacity issues, construction of HLY e3p in Auckland rather than Huntly could have deferred the significant pending transmission upgrade into Auckland (Todd Energy submitted a similarly generation-based transmission alternative proposal at the time, though this proposal was ultimately unsuccessful), with further deferral perhaps achieved had Contact had pending SFD peakers in Auckland also. Delivery of these 'efficient' transmission alternatives would rely on the generator changing their locational decisions (and perhaps design of plant) through gaining accessibility to the resulting value benefits. See also response to Question 5 below.
ENA	No	No recent investments and approvals have reflected pressures to catch up with rising demand , so difficult to argue that alternatives would have been more efficient. However we consider that continuing along that path rather than building new generation and taking demand-side measures that do not require further augmentation would be inefficient.
Transpower	No	No. Various alternatives can always be imagined, but none has eventuated with sufficient certainty to enable grid investment to be deferred. 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.

Submitter	Response	Comments
MEUG	Difficult to quantitatively assess as would have to revise GIT assuming say the theoretically best option of Augmented nodal price signals.	For a subjective view of an example, refer comments on NIGU in paragraph 2 a) of this submission.
Panpac	No	
WPI	Yes	Significant generation located in UNI and USI regions could have been advanced if there was a robust regime in place that provided investors with benefits from the avoided transmission costs. USI hydro schemes have been put forward. CCGT stations are feasible at Rodney and Otahuhu. While gas contracts are currently scarce, gas can be transported more cheaply than electricity into Auckland. The regime in place favours transmission investment over alternatives because of the regulated certainty for approved transmission investments. Transpower is a transmission company – its core business is transmission assets. Transpower only seriously looks into alternatives when it has to and then only as a stop gap. The recent USI “controllable load” initiative is an example of this. Transmission alternatives will need to have equitable access to regulated revenue streams to be practically viable but this cannot happen under the current regime. Another issue is that some transmission alternatives, such as demand side options and small-scale distributed generation, require aggregation in order to be viable.

Submitter	Response	Comments
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?		
Northpower	Yes Only generators should face the signals.	Only generators are in a position to respond to the locational pricing signals. Giving location signals to load achieves little or nothing. Loads sufficiently large enough to respond to such a transmission pricing signals are capable of bypassing the transmission system (by building their own dedicated transmission) and negotiating with generators to avoid paying the fixed transmission costs generators will pay. The present exemption from Interconnection charges for generators effectively encourages generators to pick the easiest location from their perspective and then everyone else pays the cost of transporting the energy to the load.
Orion	To some extent	The Commission has previously articulated its views in relation to the party that should face transmission charges (Paragraph 193 "Proposed Guidelines for Transpower's Pricing Methodology", Electricity Commission in September 2004.) Orion agreed with the Commission's view that all interconnection charges could be paid for by off-take customers. This position was consistent with our earlier response to a Commission consultation in which we indicated that we believed that distributors are the appropriate party to face transmission charges. However we recognise that there are reasonable arguments for generators to pay up to 20% of the interconnection charge.
Powerco	Agree	
Contact		Signals should only be introduced if you can practically respond to them (such as RCPD, TOU or seasonal signals). The vast majority of existing load and generation cannot practically change locations. New load is unlikely to change location purely based on transmission charges as it would be governed by many other – more important factors (resources etc). The signals are unlikely to be strong enough and if they were they would have to be fixed long-term before load would take these into account.

Submitter	Response	Comments
Meridian		Question is circular. If locational signals are required, then the signals should go to participants. Empirical analysis is needed on whether locational signals are required.
Mighty River Power		Mighty River Power believes the impact of locational-based pricing should be quantifiably tested. This would help determine the extent to which locational price signals would affect generation and load investment decisions. But, principally, Mighty River Power believes the majority of benefit from locational signals would be in better generation plant location decisions. It may well be the case that it is best to provide a locational (tilted postage stamp) signal to generation but maintain postage stamp charges for load. If generators are charged, the Commission must consider seriously the form of charging i.e. the unit – peak kW output, nameplate rating or kWh per annum. RCPD is appropriate for demand, but would introduce undesirable distortions for generators (particularly discretionary hydro). MRP would prefer to see either nameplate capacity charging or per-kWh charging (equivalent for a given load factor).
Todd Energy	Would depend on final mechanism/ methodology	A framework that suitably recognised and rewarded local or distributed generation for the tangible transmission alternative services provided would provide significant additional system benefits (eg. reliability, security of supply, ancillary service procurement) that would not be delivered through some locational transmission pricing regime based on some arbitrary postage stamp charging mechanism applied to generators across the board. One of the historic arguments against DG or local generation as a viable transmission alternative has been that generation is not as reliable as transmission. This is because historically there has not been adequate incentive on local generators, by way of being suitably reimbursed for the transmission services that are actually provided, to trade-off the additional cost for increased reliability by design (eg. increasing number of generation units and/or shafts for the same station capacity, etc) against economies of scale. Nodal prices alone are not enough to have a bearing on these costly reliability investment/design decisions as generators are not equivalently compensated through the VOLL assigned to offtake and transmission. To improve generator locational decisions and incentivise improved plant design, the generator investor needs access to some of the same value benefits placed on security of supply and reliability that are used to justify transmission investment under the GIT. If generators are to face locational transmission pricing signals as does load, the generator should receive full access to the reliability and security of supply value benefits (of the same value that is used to justify transmission investment under the GIT) that are delivered through its locational

Submitter	Response	Comments
		decision.
ENA	Yes	Yes - provided the relative benefits that the transmission system provides to the parties involved are fairly reflected on costs.
Transpower		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. 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.
MEUG	Yes.	It is more critical to have locational transmission pricing signals for generators because differential transmission costs are unlikely to be a major factor in decisions of where load will locate, except for very energy intensive large industries. Changes to consider could include deeper connection charges for generators and loads (eg using the "but for" approach) for new investment.
Panpac	Yes	

Submitter	Response	Comments
WPI		This is an obvious conclusion that has been successfully repelled by generators since the separation of transmission from generation and from the establishment of the wholesale market. Once established, a transmission pricing regime inherits significant “institutional inertia”; regime changes are seen as wealth transfers amongst the players and are thus very difficult to impose outside of the rule of law (as was observed with the legal protections that were required to protect Transpower’s revenue stream by the late 1990s). Over the ensuing years, new generation investment options have remained largely immune to comprehensive locational signals with almost all (other than their direct connection costs and the HVDC Link costs) of the costs of providing the grid being passed directly downstream to end-consumers. More recently, politically motivated initiatives such as the “transmission to encourage renewables” investigation demonstrate that transmission costs are no impediment when higher level imperatives (such as climate change) are in play.
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?		
Northpower	Yes	Many of the countries studied were quite different to NZ in terms of population density and generation options. NZ has a relatively small population spread out along a “long skinny” grid and Norway would be the only country in the selected jurisdictions that comes close to that model. The British and Chilean systems offer a way forward in how transmission costs can be signaled to generators.
Orion	No comment	
Powerco	Powerco is not aware of any other jurisdictions	

Submitter	Response	Comments
Contact		It is interesting to assess implications of certain regimes and methodologies but it is difficult to get a fair comparison to the background, political scene, geography, generation mix, Lineco mix and market conditions in NZ. The specific details were not clear and how these compared to the NZ situation but the tradeoffs between locational energy market signals and transmission location signals are consistent. The issue of generators contracting for grid augmentation or maintaining of capacity is an interesting one and requires further consideration in the NZ context – and should not be limited to generation.
Meridian	No	Frontier's international review is useful and a number of observations reinforce Meridian's view that we should not assume the need for further locational signals. Meridian notes references with respect to Australia, Great Britain, Singapore and New Zealand.
ENA	?	Unsure. We do not feel that NZ has been particularly well-served by importing other arrangements.
Transpower	No	The international jurisdictions that have been surveyed by Frontier are sufficient to provide a fair picture of international practice with respect to transmission pricing.
MEUG	Not aware of any others.	
Panpac		I would like to know more about the British system using the transportation algorithm
WPI	No	
7. Do you agree that the summarised issues Frontier identified from the Strata report are correct and relevant?		
Northpower	Yes	

Submitter	Response	Comments
Orion	In part	We agree that the summarised issues Frontier identified are correct and to some extent relevant. We also consider that a useful point in the Strata report that Frontier has not included specifically is that: *Although the TPM is a cost allocation method there may be a role for dynamic signaling*. We also not that the Strata report noted that the pricing principles in rules 2.1 to 2.5 potentially conflict with one another. The TPTG suggests that the Commission considers a review of the pricing principles.'
Powerco	Agree that these appear to be correct , but not sure of relevance.	The summarised issues are from individual members of the TPTG and do not necessarily reflect the views of all participants.
Contact	Yes	Yes, but the emphasis of the Strata paper was a summary of a range of issues and was not looking at high-level options.
Meridian	No - not all	Meridian has listed the issues summarised and made comments against each, however these comments have been summarised in other areas of this table to enable them to be considered alongside other submitters'' views.
Mighty River Power	Not entirely	The HVDC charges mean generators have locational signals to invest in the North Island rather than the South Island. We believe issues around capacity rights and transmission alternatives should be dealt with in separate (lower priority) workstreams.
Todd Energy	In part	Generally agree in the context of the summary of issues, though a detailed review of the Strata report has not been undertaken.
ENA	No	In general no, we disagree that full nodal pricing provides efficient generation signals.

Submitter	Response	Comments
Transpower	Not entirely	1. The issue that the TPM does not link prices to service fails to recognise that, because of the common good nature of network assets, it is not possible on the interconnected grid to tailor the services provided or the prices charged to the service levels, unless a customer dominates a part of the grid. The situation for connection assets is different and a mechanism is already provided by rule 5 of section II of Part F. 2. The issue of potential providers of transmission alternatives having to contract with Transpower rather than being directly eligible for a regulated revenue source. Transpower thinks this is appropriate. In the absence of an agreement with Transpower, there is a risk that providers of transmission alternatives may be paid for their services at a time when the services are not actually needed as an alternative to transmission
MEUG	Agree.	
Panpac	Not sure	
WPI	Yes	
8. Are there other issues with the current transmission pricing that you think should be considered at this high-level options stage?		
Northpower	Yes	There is no point in reflecting locational signals to loads when loads can not react to them. Transmission charges should be used as a tool to drive generator location decisions. There is also the issue of fairness of allocation of costs for augmentation projects that have already been committed under the present regimes. Some parts of NZ (particularly the lower North Island) have enjoyed the benefits of a strong diverse grid for many years and this was funded by all electricity users throughout NZ. Now that other parts of NZ (particularly the Upper North Island) are about to get some very overdue grid investment, it would be unfair to change the cost allocation methodology for new investments already committed (as seems to be implied in some sections of the consultation paper). Historical sunk costs and costs which have been committed under the present approval regime should not be subject to new regimes.

Submitter	Response	Comments
Orion	Yes	Connection charging, however these are lower level issues.
Powerco	Yes	The Pricing Principles have been identified by the TPTG and Frontier as requiring review and clarification. This should be done before any further work into the cost allocation methodology.
Contact	Yes	Product based pricing – whereby Transpower sets its prices similar to Lineco's and has a stake in the risk sharing and forecasting of demand (to manage their revenue requirement). This would allow a greater degree of flexibility with the model and Transpower's revenue requirement would be relative to their performance of their forecasting, customer management and forward pricing year – as is the case with the Lineco's.
Meridian	Yes	The focus of the industry's resources in 2010 should be on improving the implementation of the GIT and connection charge.
Mighty River Power		No. The focus should be exclusively on whether to introduce locational pricing. If, at any stage during the TPM review process, the Electricity Commission decides that locational pricing is not practical or does not warrant further consideration then we believe the TPM review should be abandoned. The Electricity Commission has much higher priorities than dealing with cost allocation (wealth transfer) issues amongst Transpower's customers, relitigating its HVDC pricing decision for a third time or incrementalist tinkering of the existing TPM.
Todd Energy	Yes	Contribution of local / distributed generation and consideration as transmission alternatives should be considered, along with the use of gross regional demand to define the system peaks for transmission pricing and associated RCPD assessment. See also response to Q13 for further detail.

Submitter	Response	Comments
Transpower		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. 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.
MEUG	No.	
Panpac	Not at this time	
WPI	No	The report appears to summarise the key issues.
9. Do you consider it is appropriate to focus on locational issues – as opposed to pricing structure issues – at this early high-level stage of the review?		
Northpower	Yes	It has significant opportunities to incentivise the most appropriate investment in generation.
Orion		We believe the focus of the review should be forward-looking at driven by dynamic efficiency considerations. As such a focus on pricing is appropriate.
Powerco	No	We think there is too much focus on locational cost allocation issues when the first principles of the cost allocation methodology should be reviewed. Please see Q8.
Contact	Yes	Yes – the locational signals and costs allocation principles are the issues. We believe the locational signal issues should be limited to the alternative HVDC allocation.
Meridian	Yes	But Meridian is concerned that the question, 'would it be more efficient to change the TPM to produce a more accurate locational signal? Has not been rigorously addressed.

Submitter	Response	Comments
Mighty River Power		Yes
Todd Energy	Yes	Locational cost allocation issues are more symptomatic of the underlying perceived problems with the cost allocation methodology, while pricing structure issues are more the means for the delivery of the final regime.
ENA	Yes	Where transmission costs are simply treated as a cost pass-through to consumers there is little to be gained from refinements in the methodology for applying them.
Transpower		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.
MEUG	Appropriate for high level evaluation.	Once options for more detailed analysis are chosen, the details of each option including price structure and linkages with service quality will become important.
Panpac	It appears too early to not continue evaluation of both	
WPI	Yes.	The proposed approach is reasonable. It will not be possible to deal with detailed structure until a high-level architecture has been resolved.

Submitter	Response	Comments
10. Are there any particular Pricing Principles that ought to be given precedence over others?		
Northpower	Yes. 3.2.18 (6th dot point): "Take into account the desirability for consistency and certainty for both consumers and the industry." and 2.3: "Pricing for new generation should provide clear locational signals"	The latest TPM resulted in many significant changes and price-shocks. The emphasis over the next 10 years needs to be in completing and strengthening the grid to give sufficient capacity, reliability and confidence for NZ industry and commerce to move forward in the 21st century. Locational signals for generation only.
Orion	Yes	Orion notes the Commission has previously considered the precedence of the pricing principles and provided a view paras 49 to 51 Electricity Commission 'The Commission Statement of Reasons in relation to the Proposed Guidelines for Transpower's Pricing Methodology. 18 Feb 2006.
Powerco	Please see comments box	If the pricing principles are indeed conflicting as others report then there needs to be clarification. At the end of the day there needs to be some sort of balance to the whole cost allocation methodology.
Contact	Yes	Principle (3.2.20) 2.3 "pricing for new generation and load should provide clear locational signals" is most relevant. Principle 2.4 is critical to maintain stability and consumer confidence.
Meridian		Although this is a review, the groundwork on this question has already been done. Meridian cites EC work previously on the application of the pricing principles.

Submitter	Response	Comments
Mighty River Power		The most important pricing principles are to ensure Transpower is able to recover the cost of an efficient service provider (principally a matter for the Commerce Commission, but implicit in 2.1 and 2.2) and that pricing for new generation and load provides clear locational signals (2.3).
Todd Energy	Yes	Based on historic failure to recognise the valuable contribution from local and distributed generation, more emphasis needs to be placed on Pricing Principle (g) [*Assumed this refers to Specific Outcome (g)].*
ENA	Yes	We support the provision of strong locational signals being given precedence.
Transpower		If the current pricing principles are retained, none of them should be ranked higher than others. 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 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 review, the attempt to impose a blanket ranking of the principles, by ranking 2.1 ahead of 2.2, and 2.2 ahead of 2.4 caused many practical problems when Transpower attempted to apply this directive. This was a problem insofar as the requirement to give precedence to 2.1 ("user pays" redefined by the Commission's Statement of Reasons 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".
MEUG	The Pricing Principles need a review because they do not at present provide the best balance. Refer MEUG answer and response to question 11.	MEUG agrees with Frontier and the EC (paragraph 3.2.22 of the consultation paper) that the Pricing Principles are superior to the GPS requirements because the latter do not consider use of system agreements or linkages with FTR (or other locational price risk mechanism).

Submitter	Response	Comments
Panpac	No	
WPI	Yes	The first four principles sit together well and are linked to economic efficiency and fairness drivers and a desire to get appropriate incentives in place governing new investment in particular. The last two sit aside and seem to be afterthoughts, these should be taken out and relocated to some more suitable place. If this is done the remaining four concern cost recovery of existing assets (2.1 and 2.4) and new investments 2.2 and 2.3. The principles governing new investment should attain a greater precedence.
11. Do you agree that it is not appropriate to review the Pricing Principles at this time? If not, why not?		
Northpower	No	The question is written in the negative. So if it not clear whether “If not” refers to “agree” or the “appropriate”. The 6th dot point of 3.2.18 of the paper should become a Pricing Principle.
Orion	No	If the Commission now believes that these principles are no longer appropriate then it should review them. How can the Commission approve a scheme if it does not believe that the underlying principles have been set appropriately.
Powerco	No	The TPTG and Frontier identify the need for these pricing principles to be reviewed and clarified. This should be done taking into account possible changes to statutory objectives and outcomes for the potential new Electricity Market Authority.
Contact	Disagree	Disagree. It is an integral part of this review. Once a new TPM is rolled out then it may be increasingly difficult to change if certain principles were to change.
Meridian	Yes	Meridian considers that it is not necessary to review the Pricing Principles to complete this stage of the consultation. However, once a decision is made to develop a particular pricing approach further, a review of the Pricing Principles should be undertaken before further development.
Mighty River Power		Mighty River Power sees no need to review the Pricing Principles at this stage. The Pricing Principles in Part F are fundamentally sound.

Submitter	Response	Comments
Todd Energy	No	If, as part of the wider review, it becomes evident there are shortcomings with the existing Pricing Principles it would seem logical that they are reviewed at this time.
ENA	Yes	Long overdue
Transpower		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.
MEUG	Disagree.	The Pricing Principles need to be reviewed to make sure that they are much clearer that beneficiaries pay. For example the Pricing Principles could be formulated to include the objective that prices should be set in a manner comparable with how they would be set if they had been determined by market negotiations (in the absence of free rider and hold out problems)
Panpac	Not sure	
WPI	No	Pricing principles are clearly a misfit group and will cause difficulties in subsequent development stages.
12. Do you think 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.		
Northpower	No	Generators see very weak signals as to where to locate their new generation. They need to see the full costs of their decisions. A decision to locate generation in the South Island, remote from the load, does not presently result in the consequential transmission upgrades in the North Island being factored into the decision.
Orion	No	We do not believe that nodal prices are a material factor in investment signaling. The existing TPM is only concerned with recovery of sunk costs, so it too is not really relevant to investment. That leaves the GIT, While conceptually the independent nature of this test leads to consideration of alternatives to grid investment, in practice these are seldom pursued.

Submitter	Response	Comments
Powerco	Yes	The basis for the HVDC charges appears to be working as the Commission notes given that the majority of the new generation has been in the North Island. High nodal prices in the Upper South Island identify the need for generation there. The fact that there is very little may be more to do with the availability of raw energy resources suitable for electricity generation.
Contact		That may be the case. HVDC charges provide a strong signal to generation investment in the South Island (but does not address the regional upper South Island need for generation investment). This discourages investment in the South Island and as a consequence security challenges are emerging over time. Unfortunately the current TPM involved a cost on existing South Island generators that could not be passed onto to customers in the competitive market, despite the system wide security benefits and competition benefits of the HVDC. RCPD signals have encouraged greater demand-side management.
Meridian	Yes	Meridian thinks that nodal pricing, the GIT and deep connection charges establish a locational signal that is efficient in practice. BUT Meridian does not consider that the HVDC charge is appropriate and considers this further in Q14. The result is internal inconsistency within the TPM and an on-going challenge to regulatory certainty.
Mighty River Power		Only for North v South Island generation decisions.20 We estimate the effect of HVDC charging to be equivalent to $5-$10/MWh on the long-run marginal cost of generation investments in the South Island.
Todd Energy	Could be improvements for local/ distributed generation	See also answer to Question 5. Local generation operational and investment signals could be much improved by providing generators access to regulated revenue where generation provides transmission services when co-located in a load-intensive area. For example, if this revenue stream was available: • A number of the large CCGT's may have been better located and designed as multi-shaft units to greatly improve flexibility and reliability over the peak transmission pricing periods. • Contact (in partnership with other investors) may have considered undertaking the huge investment required in gas pipeline infrastructure to locate their pending Stratford peaking plant in Auckland

Submitter	Response	Comments
ENA	No	See comments Q2.
Transpower		Under the existing TPM, the charges for grid assets with private good characteristics (connection and, arguably, the HVDC) are recovered from beneficiaries and the charges for grid assets with common good characteristics (i.e. interconnection) are recovered in a reasonably non-distortionary manner. The TPM does not signal the long run marginal cost (LRMC) of grid investment. To a large extent, this is not a problem, because investment in the interconnected grid is centrally evaluated. 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). However, because the TPM does not signal the LRMCs of future grid investment, the consumption and investment decisions of offtake and generation customers may be distorted. This is probably not a material for offtake. However, it may be for generators, and may affect their locational investment decisions. This may warrant further examination of a tilted postage stamp.
MEUG	Current arrangements could have improved locational signals.	Refer shortcomings of existing nodal prices and TPM in answers to questions 1 and 2.
Panpac		No, if they had been efficient the current backlog of jobs would have been dealt with earlier.

Submitter	Response	Comments
WPI	Reasonably well	Generators face muted locational signals via nodal prices. The current TPM, in applying interconnection charges to loads only, conflicts with principle 2.3. Postage stamp rates applied on a national basis socialise the investment costs for new transmission. As transmission prices will increase in regions far removed from the region receiving the benefit of significant new transmission investment, price signals to encourage demand-side management will be reduced. Inefficient use of capacity may be encouraged as regions compete to be the ones that receive transmission investment at a cost subsidised by others. The obvious example is that under the current TPM, lower South Island grid offtake customers will see increased transmission prices once the large upper North Island projects (NIGU and NAaN) are commissioned. Conversely, the regional beneficiaries of these projects will see their transmission charges increase but not to the full extent that they would if all costs were recovered from local users. It is simply not possible to reconfigure cost allocation in respect of past investment decisions in pursuit of efficiency or perceived equity.
13. If not, are there relatively minor modifications that could be made to the existing regime to enable it to provide appropriate locational signals?		
Northpower	No	A TPM that reflects the Long-run Marginal Cost (LRMC) of the grid is required to reflect the costs of decisions to generators.
Orion	Perhaps	In our view some form of peak pricing is needed to encourage short to medium term alternatives to grid investment, We are not sure if this is a minor modification.
Powerco	No comment	
Contact		Replacing the HVDC charge with a more sophisticated tilt signal is one option to provide more appropriate locational signals (and allocation) A tilt based on power flows across the HVDC with appropriate gradients for the upper South Island and top of the North Island.
Meridian		Generally do not need modifications, but further consideration should be given to whether different treatment for existing and new assets is appropriate, in particular HVDC assets.

Submitter	Response	Comments
Mighty River Power		No
Todd Energy	Yes	The “regional demand” used for determining the RCPD-based charges would be better based on a system gross demand model (instead of net GXP offtake) as this is the underlying driver for transmission and generation capacity investment. The RCPD periods would then be directly aligned with peak system gross demand and more predictable for those parties with an interest and incentive in reducing peak demand and capacity required from the transmission system. This increase in predictability will improve dynamic efficiency as day-to-day operational decisions will be less distortionary (than a RCPD based on net GXP demand) and more accurate in setting the peaks used for transmission charging purposes. The aggregate gross load could be used to derive a postage stamp ‘generation interconnection rate’ ($/kW) for some appropriate regulated allocation of transmission alternative benefits to local / distributed generators. These transmission alternative benefits would be added to the revenue requirement to be recovered from offtake customers via interconnection charges based on net offtake. This would avoid providers of transmission alternatives having to contract directly with Transpower for a regulated revenue source and remove the current arbitrary, contrary, and generally stalling approach some line companies adopt in their assessment of avoided transmission cost, reducing transaction costs and delivering more efficient outcomes. A further improvement to locational signals that would deliver efficiency benefits is grid connected generators co-located with demand being duly recognised via the TPM as providing transmission services at that connection location and the generator gaining direct access to a regulated allocation of the transmission benefits delivered. Currently the generator has to forfeit a connection contract with Transpower and negotiate a (notional) connection through the local line company (or offtake party) to access these benefits, increasing transaction costs and reducing competition benefits as the monopoly line companies insist on a hefty share of the transmission cost avoided. These minor changes to the TPM will deliver improvements in the three key efficiency objectives outlined in section 2.2.6 of consultation paper. We would also view the titled postage stamp approach as a relatively minor modification to the existing regime, and could also incorporate the changes suggested above.
ENA	Possibly	But we are not aware of them.

Submitter	Response	Comments
Transpower		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.
MEUG	Yes.	Changes that could be considered include: § A "but for" approach. Refer also MEUG response to question 20. Note this may not be a "minor modification", but it should still be assessed; § Charging generators part or all interconnection charges (possibly disaggregated by Island); § Improving linkage with terms and conditions of transmission agreements and in particular service quality/liabilities.
Panpac		Appears a relatively easy problem that correctly designed transportation Linear programming soft ware could solve
WPI	Unlikely	Outside connection charges and HVDC it is purposely a non-signaling methodology.
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?		
Northpower		Not seeing the costs of additional transmission upgrades can cause significant waste in terms of constructing new generation remote from load.
Orion	Significant distortion may result	We provide the example of how, under the previous interconnection pricing, Orion did not control load at summer peaking GXPs in winter months, even though that would have reduced load on the core transmission links into Christchurch. With the new RCPD approach we are now controlling load more appropriately.
Powerco	Please see comments box	There is perhaps some distortion caused by the HVDC charges. At the end of the day, the Commission through the TPM has some influence on where and it generation is built.

Submitter	Response	Comments
Contact		There is likely to be continued generation investment in the North Island and hence the power-flows will increase further North to South over time. This will increase the need for generation build in the South Island and underscores the importance of having some sort of self correcting mechanism that can respond to power flow changes over time.
Meridian		Meridian considers that nodal prices, the GIT and deep connection currently provide a practically efficient price signal that appropriately influences the combined cost of generation and transmission. A more theoretically pure signal may not materially impact on future investment decisions. Meridian considers that the HVDC charge continues to distort use and investment decisions. For example, alarms alert Meridian's market operations when a station is about to contribute to HAMI, and output is reduced from what would otherwise be bid in. Transpower has acknowledged this distortion, agreeing to waive the contribution to HAMI where output from the station is needed in order to respond to a grid emergency. The HVDC charge has the potential to distort new investment decisions. The incremental effect of the HVDC charge on an existing South Island generator installing a new generation unit is less than the impact on a new entrant into the South Island.
Mighty River Power		This is a question that warrants further work and quantitative analysis.
Todd Energy	See comments on Q13 above.	
ENA		The wind farm investments referred to in our answer to Q4 are indicative of the scale of the inefficiencies occurring in investment signals. We consider that an orderly transition to a more efficient regime for signaling locational costs would be of very considerable economic benefit.
Transpower		For offtake customers, any distortion would be minimal. 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.

Submitter	Response	Comments
MEUG	See question 12.	
Panpac		If insufficient transmission capacity is not provided then investment in wealth generating industries will probably be constrained.
WPI	Depends on the investment	Costs of investments that are able to be ring fenced (i.e. they would not be necessary but-for the generator/load created need) ought to be able to be efficiently recovered from the direct beneficiary through a connection type charge.
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 signaling objectives and simplicity?		
Northpower	No	Simplicity is less important than reflecting the LRMC of the grid to generators when they make locational decisions on generation investments. The tilted postage stamp option makes no distinction between historical decisions (sunk costs and committed projects) and new investment decisions.
Orion	Yes	The tilted postage stamp option may provide a reasonable trade-off between signaling objectives and simplicity. We would need to see much more detail before we could endorse this approach. However, we note that the Commission is aware of the work been carried out in this area by NERA Economic Consulting on behalf of the industry. We recommend that the Commission take this work into consideration when preparing high level options. Clearly the choice of the amount of 'tilt' will be critical. In our view this should be forward looking rather than simply reflecting the current grid configuration.
Powerco	Yes	But note Powerco does not believe any further locational signals are required or warranted.
Contact		Perhaps – as it is a simple enough concept (applied to generation side only) but would be difficult to get consensus on the correct tilt – due to the evolving power-flow characteristics hence requires a mechanism for "self-correction".

Submitter	Response	Comments
Meridian		The TPS appears intuitively simple. However it would be a mistake to approach the TPS concept on the basis that the tilt is set once and never changed. Grid investment, demand and generation are all dynamic, and there will be a need to change the tilt over time. This tends to reduce the claims to simplicity. It is likely also that an overly simplistic application of a TPS approach would produce unacceptable distortions, leading to adjustments or exceptions. In particular, it would make no sense for a TPS charge to influence the operation of sunk generation assets, or at the extreme strand sunk generation assets. Exceptions may be necessary to avoid these perverse or inefficient outcomes, introducing complexity. For these reasons, the trade off between signaling objectives and simplicity at this high level are hard to determine.
Mighty River Power		Yes believe the tilted postage stamp methodology is likely to prove the most practical option to implement. (Although MRP suggests that this might only be for generation with postage stamp for load.
Todd Energy	Yes	If there is a greater need for signalling (or perhaps defending) the objectives underlying the locational element, the relatively simple to understand 'tilt' could be derived against some basic load-flow back-drop. An underlying gross GXP load model (ie. devoid of local generation contribution) could be used to set the extent of the tilt in recognition of the transmission benefits (ie. transmission alternative services) provided by local/distributed generation. See also comments provided for Question 13.
ENA		Conceptually the creation of regional pricing loads (similar to the old South Island differential) implies an undesirable rigidity that will lead to investment distortions.
Transpower		Yes

Submitter	Response	Comments
MEUG	No.	Tilted postage stamp could provide a useful counterfactual to the status quo or incremental improvements. MEUG agrees with the observation by Frontier Economics: 'Tilted postages stamp approaches are unlikely to be theoretically precise because a participant's distance from the main grid, or its longitude or latitude, do not bear a linear relationship to transmission costs and needs in NZ, given the extreme variations in geography and resource locations.' Tilted postage stamp approaches will also prove difficult to adapt (or at least require significant regulatory intervention) should generation and load patterns change. For example a major gas discovery on the east coast of the North Island could result in new users' and gas fired power stations on that coast, new grid investment and a change in the general direction of power flows.
Panpac		Do not know, but it probably is a small improvement.
WPI	Yes	A variation on this theme has been raised in previous consultations on TPM. Striking regional interconnection rates based on a regional asset pricing pool links future costs to local beneficiaries; a national postage stamp approach does not. To reflect that for some investments there are both national (or at least island) and regional benefits, it might be helpful to consider that a nationally (or island-wide) equal portion of the tilted postage stamp charge reflects national (island) benefits while a regionally determined portion reflects regional benefits. The selection of regions will be important under this option. Regions will need to be "right sized and located" to reflect an appropriate "common locality and issues" principle. There would probably be between 5 and 8 regions in each island. A key attraction to this approach is its relative simplicity.
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?		
Northpower		An overly complex approach would only be understood by a few people in NZ. This would be likely to lead to widespread mistrust and a lack of confidence which, in turn, would result in negative business outcomes for NZ.

Submitter	Response	Comments
Orion		Orion does not agree with the high priority implicitly given to non-distortion of nodal price signals by Transpower, and now by this paper. Orion submits that dynamic efficiency considerations should dominate over sunk cost allocation.
Powerco		Sounds complicated and unlikely to be justified.
Contact		Contact does not support this and is likely to be outweighed by practical considerations and confusion over timing on investment decisions.
Meridian		Conceptually Meridian can see the point being made in the augmented nodal pricing discussion. However it is not clear this approach would work in practice, and there is a risk it is simply responding to the trade-off that has been accepted in setting the GRS.
Mighty River Power		We do not support the augmented nodal price approach. We consider the premise this approach is based on – namely, addressing "the deficiencies in nodal energy prices created by excessive or premature network investment"21 – to be fundamentally flawed.
Todd Energy	Economic merits will be outweighed	While we agree the underlying concept has merit, the augmented nodal pricing methodology will be overly complex, less readily understood by investors and stakeholders on the receiving end, and likely costly to implement. The observed/perceived degree of network overbuilding (a fundamental underlying the methodology) will always be a contentious argument between the different stakeholders.
ENA		This approach appears to us to be too heavily weighted against supposedly 'premature' transmission investments. It creates incentives for Transpower to promote demand growth rather than encourage DSM and energy efficiency. It also looks rather like a 'patch on a patch' approach to avoid addressing the fundamental issue of providing effective locational signals.
Transpower		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.

Submitter	Response	Comments
MEUG	This is a useful theoretical benchmark though implementation appears to have practical limitations.	Agree with Frontier and the EC that difficult to assess precisely variance between the status quo or any of the other options and this theoretical "best" option, and also may have practical limitations in how to implement. This option though is useful when assessing how to incrementally improve the status quo.
Panpac	Not sure.	With the grid being funded on the basis of cost there should not be loss and constraint revenues.
WPI	Practical implementation limitations may outweigh economic merits (if any).	Highly theoretical and very complex to design a set of rules around. It would take a lot of development and testing work and a comprehensive industry education programme to implement.
17. Assuming there is a need for a locational element to transmission pricing, is load-flow modeling a reasonable basis for cost allocation?		
Northpower	Yes	Load flow modeling would be part of developing a LRMC of the grid to reflect to each point of injection. In saying "Yes", we are responding to the question, but not necessarily supporting the underlying assumption for all applications.
Orion	Unlikely	Orion notes that the Commission included a brief discussion on 'experience with Power Flow based locational transmission charges' (Appendix 2, Proposed Guidelines for Transpower's Pricing Methodology, Sept 2004.) Given that this approach has been tried previously and passed over we consider that it is unlikely that a load flow approach would be appropriate.
Powerco	No	We went down this path early. This produces its own set of complexities, the least of which is what the benchmark time and characteristics that the load-flow should be based on. The system is dynamic and no day is ever generally the same.

Submitter	Response	Comments
Contact		Yes.
Meridian		Meridian submits that in a hydrology dominated system like New Zealand's, load-flow analysis is not useful for the purpose of signaling future transmission investment. It may be a technically accurate way of measuring ex post use of the grid, but it is not a good way of signaling ex ante the future costs of generation and transmission decisions.
Mighty River Power		Mighty River Power believes the tilted postage stamp and load flow-based approaches both warrant further work. While we believe the tilted postage stamp methodology is likely to prove the most practical option to implement, review of the forward-looking load flow-based approach should help ensure the locational pricing methodology the Electricity Commission decides to implement, if any, is the most robust one possible. We also believe work on the load flow-based approach could help better inform the Electricity Commission, if it introduces a tilted postage stamp, on what the "tilt" should be. In particular, it should seek to evaluate the benefit of increasing complexity (the marginal returns of which, we believe, are small). the load-flow modeling needs to be forward looking, and not lead to increasing complexity for the sake of it.
Todd Energy	Perhaps, but at a very basic level	NZ system is long and skinny and more a radial rather than meshed network. There would seem little need to adopt a complex load-flow approach for cost allocation. Some partial application of a load-flow approach may have some merit but this will depend on application and whether this can be kept simple. Eg. In setting the 'tilt' (cost reflective / CRNP at most basic) or as basis for valuing contribution from 'transmission alternatives' (future investment cost / ICRP basis). See also response to Question 18 below.
ENA		This question would be best addressed after the locational mechanism has been defined.

Submitter	Response	Comments
Transpower		No. These methods apply arbitrary assumptions, which often 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. Transpower operated a method of this sort in the 1990's and it proved to be very unpopular with customers at the time.
MEUG	MEUG agrees improvements to the locational signal in transmission pricing is desirable; however there are better options than load flow based approaches.	Load flow approaches have several shortcomings, eg they require the transmission company supplying detailed information to the regulator that then has to be validated and approved (particularly for the forward looking cost models). Load flow approaches are very unstable year to year. Frontier Economics noted "… transmission charges – being unhedgeable – should be as predictable and stable as possible to enable investors to make robust decisions." Using load flow approaches would be a significant departure from the existing market design. The other approaches are likely to require less change and also have greater benefits.
Panpac		Appears has merit.
WPI	No	year-on-year instabilities and perceived inequities of the old load flow methodology led to its dumping. NZ grid frequently swings between quite extreme load flow patterns and that to the extent that the load flow data are updated periodically (typically annually) to reflect changing load flow patterns, creates significant price swings that are completely unrelated to an offtake customer's GXP demand. If the load flow patterns are fixed to try and mitigate this effect then they become "notional" very quickly and lose conceptual connection with actual grid operating patterns. New generators and large new loads or load shifts quickly undermine the integrity of the methodology. That the two overseas methodologies cited require "patches" to mitigate these effects is likely testament to an inherently unstable and eminently unsuitable methodology for NZ's "long thin" grid.

Submitter	Response	Comments
18. If so, do you have a view on whether the CRNP, ICRP or an alternative methodology is preferable?		
Northpower		The ICRP has the advantage of being forward looking and signaling the LRMC of the grid.
Orion	No	On balance a preference for ICRP.
Powerco	No	
Contact		A methodology that does not penalise sunk investment but provides suitable signals to future investment would be preferable.
Meridian		Given our reservations with this approach (see our response to Question 17), Meridian would be more likely to support an approach that was closer to the UK's Investment Cost Replacement Pricing (ICRP) methodology than the Australian CRNP, on the basis that the ICRP is more forward looking. However, our starting point is that load flow modeling is not an appropriate basis for transmission pricing in a hydrology dominated system, and we note the reservations in the Frontier International Review about the ICRP methodology resulting in over-signaling.
Mighty River Power		Not at this stage. This is a question that warrants further work and quantitative analysis.
Todd Energy	Part F regime used as basis for assessment and approving future grid investment, so arguable that there is no braod need for ICRP in TPM.	An alternative methodology based on ICRP may be warranted so far as assigning a 'transmission alternative' value on the transmission services provided by local/distributed generation. This would be achieved by using the gross GXP demand (ie. set all local/DG contribution to zero) in the load-flow model and assessing the extent or value of transmission augmentation required but for the local generation. The current RCPD-based pricing regime (but based on actual gross demand rather than net demand observed at the GXP) in a framework where local/distributed generators are allocated the benefits for providing transmission alternative services will be key component, as this will: • Provide strong locational price signals for generation investors • Will provide incentive for improved flexibility and reliability in design of local generation plant (eg. increasing the number of generation units for the same total station capacity), with significant flow-

Submitter	Response	Comments
		on benefits for reliability, security of supply, ancillary service procurement, etc • Will incentivise local generators to maximum output at times of peak demand on the transmission system
Transpower		N/A
MEUG	Not applicable.	Refer MEUG comment to question 17.
Panpac		Favour the British system using the transportation algorithm. Would like more investigation to become more advised.
19. Are there any other high-level options that the Commission should consider?		
Northpower	No	
Orion	Yes	We note that the industry is also involved in considerable work in this area. We recommend that the Commission take this work into consideration when preparing high level options.
Powerco	No comment	
Contact		Product (tariff) rates similar to Lineco's approach to distribution pricing.
Meridian	No	
Mighty River Power		No
Todd Energy	Yes, as per other comments	The review needs a greater emphasis in evaluation of the high-level options for greater recognition of transmission alternatives via the TPM

Submitter	Response	Comments
ENA		Possibly the simplest effective solution would be provided by a requirement for grid-connected generators to face the bulk of all transmission costs, with transitional contractual arrangements that avoid major price shocks to such generators.
Transpower		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.
MEUG	Not aware of any others.	
Panpac		Not aware of any
WPI	Potentially	In the gas industry, the transmission pipeline was put in place by shippers (i.e. suppliers, including Governments) to transport remote gas resources (e.g. Maui) to markets (e.g. Huntly power station). It is paid for through charges to shippers who build the cost of bulk transport into delivered wholesale gas rates, with relatively little controversy and significant regime stability. Can the electricity industry learn anything from this? In addition to seeking international electricity transmission comparisons we ought to consider energy industries more broadly in search of guidance. Considering gas transport as a model would highlight the option of charging all grid interconnection charges, HVDC and HVAC, to generator/retailers.

Submitter	Response	Comments
20. Is there merit in pursuing a Pennsylvania-New Jersey-Maryland (PJM) style 'deep' connection option in the New Zealand market?		
Northpower	No	While appealing, the complexities would probably result in stalling any action which is critical to get the appropriate signals for investment now.
Orion	No comment	
Powerco	No comment	
Contact		There is merit in a "but for" approach as it tries to address user/beneficiary pays problems that can exist. However it may be difficult to maintain given he nature of the grid in NZ. It would also be difficult to maintain (and agree on) "deep" zones as the grid becomes more interconnected – that would apply to the load-side. The outcome would simply provide unacceptable cost increases to areas such as the upper South Island. These additional deeper connection costs would deter new generation investment where it is most needed and encourage a higher level of embedded generation – which may be of a sub-optimal scale and distort the allocation of the HVDC charges. It could also increase the costs for customers relative to the status quo. Also difficult to enforce fairly given organic growth in types of generation and for combinations of load and generation.
Meridian		Meridian is cautious about the value of pushing deeper into the transmission network. The deeper the connection pricing methodology goes, the more grey and contentious the analysis of causation becomes. Further, there is a risk of confronting investment that is being driven by the GRS.
Mighty River Power		No
Todd Energy	No	This option would require a significant number of existing market and regulatory changes to be implemented, and add further complexity.

Submitter	Response	Comments
ENA		If no better approach is accepted by the commission then the PJM-style one would be more promising than the existing, generator-centric approach. We support the analysis of the strengths and problems of PJM-style deep connection provided by the Commission. Ideally, this would be used as a counterfactual or benchmark for evaluating other, more fundamental approaches to locational pricing.
Transpower		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. 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.
MEUG	Yes	The PJM market is different from New Zealand (eg PJM has a capacity market) and therefore adopting the PJM “but for” approach without changes might not be appropriate. Nevertheless still worth considering. Note NZIER recommended for the AC network “The current connection charges supplemented with additional charges on new generators and new load over a de minimus level, based on the ‘but for’ approach.”
Panpac		Potentially. Worth more investigation
WPI	Potentially	This methodology would be difficult to apply retrospectively in respect of the core grid, as it’s impossible to say what investment decisions would have been made under different rules and incentives. However, for future investment, this may be an option worth looking at. It would work best for large discrete blocks of generation or load that required clearly identifiable grid investments and would be generally in line with current causer-pays principles applied to direct connection assets. It would apply locational incentives that favour investing in regions with spare capacity. We agree that it raises a number of issues as identified by Frontier and these will require careful

Submitter	Response	Comments
		consideration.
21. Are there aspects of connection charging that should be reviewed? If so, please give arguments why.		
Northpower	Yes	Looping spurs from the core grid that are classed as connection assets in the TPM should be charged on the basis of the minimum build that would serve the load without the need to carry the full core grid load and meet the core grid requirements.
Orion	Yes	1. Current designation of interconnection/connection assets can result in incentives to connect new load where upgrade costs will be shared. (eg Bromley vs Islington.) 2. At a shared interconnection node, the connection charge allocation of land and buildings to off-take is based on TOs connection asset value, not the land and buildings used.See 3.59.2 (c) of TPM. This creates an inappropriate incentive for parties to install and own connection assets on Transpower's land. Land and buildings could be allocated on a AMI or AMD basis. 3. Distortion occurs in connection asset allocation pricing due to Transpower's allocation factors. For example, if a particular asset is optimised out of the RAV it is still included in the connection charges for that wider area but all the values in that area are scaled down by an allocation factor to reflect the optimisation. This creates distortions and also makes the annual auditing/price checking process impossible. 4. When connection assets are due for replacement (not an upgrade which is handled by an NIA) the ARR calculation leads to an artificially low cost to the connected party as the price for the replaced assets is linked to the age and replacement cost of all NZ connection assets. For contestability at the asset boundary, the connection charge for replaced assets needs to reflect actual replacement not historic replacement cost.
Powerco	No comment	

Submitter	Response	Comments
Contact		Some load spur lines such as the Bromley/Islington example and the Hangatiki/Te Awamutu spur. Because the TPM is an "allocation" (not a pricing) methodology and hence any change (in methodology – or operational behaviour) simply transfers costs – sometimes directly from one party to another – which can be unacceptable to both major users and generators. An example of this cost transfer is when connection assets may join (such as Te Awamutu to Hangatiki spurs) – or the opposite (if interconnection becomes connection), or if spur connection costs are shared between AMI/AMD users. This can create major price shocks to some consumers – yet have negligible effect of the majority of (interconnected) consumers – hence a shallower connected grid would provide more stable pricing in the long-run. The connection asset investment process works very well with Transpower and the TPM provides for an appropriate allocation of costs. It is a contestable market and parties may build their own spurs assets but this must be a consultative process to avoid the building of sub-optimal capacity lines.
Meridian		The current deep connection approach provides a valuable locational signal to connecting parties. However, the implementation of that approach is not perfect. In particular, because connection charges vary substantially depending upon the type of generation that is built and its location, regardless of the net market benefits, inappropriate investment incentives can be created in some circumstances. In addition, the arrangements for recovering the costs associated with existing shared connection assets may give rise to significant step-changes in connection charges as beneficiaries change over time. Meridian submits these issues would be a useful focus of the review, if only to confirm that this is the behaviour/outcome desired from the connection charge. Meridian's submission lists examples.
Mighty River Power		No
Todd Energy	Yes	See also response to Question 13. Grid connected generators co-located with demand should be attributed with providing transmission services at that connection location. This will provide some trade-off for the generator to connect to connection assets whereby the generator may otherwise look to connect to interconnection assets to reduce their transmission charges under the current regime.

Submitter	Response	Comments
ENA		We are fairly sure that there are. However, this is a question best answered by connected parties handling those charges.
Transpower		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. 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 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 recommend that the concept of such a "backstop" provision should be further investigated by the industry and regulators.
MEUG	Yes with respect to HVDC charges.	NZIER have suggested HVDC charges be based on either § A capacity rights basis; or § An arbitrageur approach. Both approaches facilitate market discovery by parties that benefit from the HVDC and a market value for the utility they derive. MEUG notes that NZIER have prepared a report on the mechanics of how a HVDC Capacity rights regime might work for Rio Tinto Alcan New Zealand Ltd to be appended to their submission on the Transmission Pricing Review. The NZIER work demonstrates that a capacity rights basis for charging existing and new HVDC assets is more than just a theoretical option. Implementation would be relatively straight forward and the resulting "prices" for use of the HVDC would be derived by market participants. This is likely to be a more durable longer term solution than most other proposals (except possibly the arbitrageur approach).
Panpac		May be.

Submitter	Response	Comments
WPI	No	To achieve efficient price signals and outcomes the principle that identifiable investments for a single (or a very few) beneficiary should be charged to that beneficiary and the option for contestable connection asset construction and ownership, seem to support the stated view that the current regime is satisfactory.
22. Is it necessary or worthwhile to alter or clarify the existing treatment of transmission alternatives?		
Northpower	Yes	Timeframes are presently too short for parties to offer alternatives that are viable but not committed.
Orion	Yes	Some transmission alternatives (DSM strategies) require long term changes in behaviour and investment which cannot be contracted or guaranteed in the short timeframe required to be transmission alternatives. To reiterate, a long term marginal price signal will provide a better signal to encourage this type of DSM response.
Powerco	Yes	This would be helpful. Clarification always helps.
Contact		Not really. As long as they are of equivalent reliability and have sufficient diversity.
Meridian		While Meridian supports the concept of transmission alternatives, Meridian prefers transmission investment rather than generation transmission alternatives. Generation transmission alternatives are not a complete substitute for transmission (i.e., they are not 99.9% reliable) nor do they offer the two way diversity of transmission. The current approach to transmission alternatives ensures a level of rigour is applied to any transmission alternative proposal, and that should continue. Transmission alternatives should not be approved without appropriate scrutiny.
Mighty River Power		No - not specifically as part of a review of TPM. Regulation of transmission alternatives creates risks that generation projects that would have gone ahead anyway would end up being subsidised. MRP notes Commission opinion from previous consultations that suggest postage stamp is a barrier to transmission alternatives.

Submitter	Response	Comments
Todd Energy	Yes	We agree with this aspect being identified as a 'key issue' for transmission pricing consideration, particularly in regard to local /distributed generation.
ENA		As noted in our answers above, alternatives such as DG and DSM are treated very badly by the existing nodal pricing system and by the pricing counterparty arrangements that effectively give remote generators subsidised access to markets where they compete with those alternatives. It seems to us to be very important to alter this, especially given the focus with Government policy, and in networks, on greater downstream and demand-side empowerment in delivering efficient electricity supply outcomes.
Transpower		No
MEUG	Yes.	It may be that having no transmission alternatives approved over the last few years has been the optimal outcome. But that is very unlikely and therefore this needs to be checked.
Panpac		Yes. Q12 highlights the deficiency with this approach
WPI	Yes	Transmission alternatives face a range of barriers to market entry that the building of transmission infrastructure does not. Transpower is only incentivised to pursue non-transmission asset related transmission alternatives as a shorter term risk management exercise. A key question here is whether there is a policy desire to tilt the playing field in a way that brings forward transmission alternatives and develop transmission alternative markets in advance of when they might otherwise become established. This is a policy-level issue that could stand on its own as a market development initiative, initially separated from transmission pricing considerations. The regime in place favours transmission investment over alternatives because of the regulated certainty for approved transmission investments. Transpower is a transmission company – its core business is transmission assets. Transpower only seriously looks into alternatives when it has to and then only as a stop gap. The recent USI "controllable load" initiative is an example of this. Transmission alternatives will need to have equitable access to regulated revenue streams to be practically viable but this cannot happen under the current regime. Another issue is that some transmission alternatives, such as demand side options and small-scale distributed generation, require aggregation in order to be viable.

Submitter	Response	Comments
23. Should either a USG or a voluntary insurance scheme be considered within the Commission's review?		
Northpower	No	
Orion	No	We are not convinced that the costs of administering schemes of this nature are warranted. Self insurance by consumers is likely to be more efficient.
Powerco	Maybe	An USG scheme may be helpful provided it does not just increased the allocated costs to all the other unaffected participants. Service level incentives are possibly better kept under the Commerce Act provided they can be expanded under that existing arrangement.
Contact		No. Contact believes this should be considered outside this review and can be addressed separately.
Meridian		See Q 24
Mighty River Power		No. Not a high priority at this stage.
Todd Energy	Yes	We agree there would be some merit in further investigating these options. Generator connections should be considered for an Unconditional Service Guarantee as generator outages can have a significant economic affect on parties depending on generator-retailer spot price risk exposure at the time. However we remain wary that these measures linking service quality and pricing may result in another non-transparent socialised cost (in addition to the retailer demand buy-back scheme currently be promulgated by policy makers) that would ultimately be passed on to consumers.
ENA		This is quite a complex issue that might best be considered slightly behind the review. While exposing Transpower to some level of risk or prudency test could lead to more efficient investment pressures, it could also imply a risk transfer to other parties. It could also prove ineffective if any additional costs to Transpower resulting from a USG were recovered anyway through other elements of transmission pricing.

Submitter	Response	Comments
Transpower		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. 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.
MEUG	Yes.	Service and price should be considered simultaneously.
Panpac	No	No. Such liability is not appropriate to a national infrastructure provider, as any liabilities would have to be recovered most likely from all users. That is an increase in costs overall.
WPI	Yes	WPI considers that performance based service measures are appropriate for monopoly services such as electricity transmission. The USG approach is worthy of further consideration.
24. Are there other options for linking service quality and pricing that you think the Commission should consider? If so, please give details.		
Northpower		We consider that the methodology used to set and reset the Service Measures in the Default Transmission Agreement (DTA) is fundamentally flawed.
Orion		There are two parts to service quality. The first part is the capital investment stage where the security of supply and price quality trade-off with connection assets occurs during negotiation of the NIA. This addresses the fundamental configuration and price options effectively. The second part is the availability and reliability of the plant once commissioned. Given that the assets involved are very reliable with probability of failure rates around the 1 in 40 years, it does not seem appropriate to apply an annual assessment of reliability or even a 5 year average at each connection node. One option perhaps worthy of consideration is to regulate reliability/plant availability on a national basis. This could be implemented by monitoring failure rates for assets; per transformer, bus, line km, cable km etc and benchmark this against international results. An outlier assessment (needs to be a long term assessment) could be applied to draw out extreme results in a particular area. The introduction of any penalty scheme needs to be carefully thought through.

Submitter	Response	Comments
Contact		This is not an important factor in this review as the services levels on the core grid are very good and likely to improve further. Service can be addressed at the individual connection level and must be kept in context with the level of security provided by the distribution company.
Meridian		Questions 23 and 24 raise some hard issues about whether a stronger link between price and quality should be made in the TPM. Meridian submits these questions should not form part of this review. These issues are substantial and complex in themselves, and were recently considered as part of the Benchmark Agreement process. Including them in the review risks bogging down the review or not doing justice to existing issues. As an indication of Meridian's preliminary views: - cautious about a tight link between price and quality and the incentives this would put on Transpower; - that said, there comes a point where good faith requires some relief if service levels drop (depending on the significance of the asset, the duration of the event, etc); - more important than a theoretically correct link between price and quality is improved information and transparency. Better information ex ante on connection risks, for example, is likely to drive more appropriate behaviour than an ex post price penalty.
Mighty River Power		Not a high priority at this stage.
Transpower		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. 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.
MEUG	Not aware of any others.	
Panpac		Conditions should be well known in advance and in writing as part of the relationship contract.

Submitter	Response	Comments
WPI		WPI has previously argued in submissions to the Commission that an outputs rather than inputs based approach should be taken to establish transmission service and performance. The current 'asset availability' measure is not meaningful to consumers as it does not reflect the availability of a usable supply of the service. Specific quality measures that relate to the availability of a 'live' connection within capacity and quality specifications would make more sense to consumers and create meaningful measures of transmission performance. Consumers should not be required to pay for transmission at times when it does not provide the ability to access electricity at the contracted quantity and quality.
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?		
Northpower	Yes	But lead-times must be realistic to allow participants to design, cost and install new static power-factor correction assets.
Orion	Yes	Yes, but we prefer a price signal rather than an allocation methodology. We do not currently cost allocate the use of the interconnected core grid to specific parties based on their location, so why should core grid reactive support be allocated to specific parties. However, we do want to change connected party power factor behaviour if it is economic to do so. If a peak period (RCPD) kVAr price component was introduced that matched the forward price of grid reactive support then connected parties have the option to respond to that price. Once again this facilitates long term changes in behaviour rather relying on impractical short term transmission alternatives when the next piece of reactive plant is proposed.
Powerco		Reactive power flows can be complicated but are very necessary for the stability of the system and voltage support. To simplify things, Powerco believes that it may be better that these components are just treated as transmission assets (owned by Transpower). Worthy of a separate consultation.
Contact		Reactive support assets on the core-grid are interconnection assets.

Submitter	Response	Comments
Meridian		Meridian submits that a review would be appropriate at some point. There are concerns that the current proposal could open up risks of hold out. However this raises again the issue of prioritising the various regulatory work streams and industry resources. Meridian more likely to support cost recovery under part F than part C.
Mighty River Power		Not a high priority at this stage.
Todd Energy	Yes	Allocation of reactive power costs via the TPM will make costs more visible to participants. Costs should be regionalised to the extent practicable.
ENA		We are very concerned at the Commission's approach to allocating the costs of achieving a power factor of 1 at GXPs to distributors via Transpower, and would like this aspect of cost allocation to be considered ahead of the review. It implies very large additional investment costs and the closing off of alternative DSM-focused investments by distributors, and is effectively a wealthy transfer from the grid-dependant generators, who were responsible for maintaining power factor, to end users via distributors.
Transpower		Yes, but with qualifications – see the discussion in section 9 of the body of this submission.
MEUG	No.	This work is needed but may be more efficient to consider reactive power pricing and incentives as a separate work stream. MEUG understands that the primary issue with a market approach to reactive power is the high losses in its transmission leading to acute market power issues. That is why the original market design excluded allocating costs for reactive power.
Panpac		Yes. Pan Pac has offered power factor correction capacity, but has been turned down. Such potential use of unused capability should have the advantages shared and compensated.
WPI	Yes	WPI supports consideration of a reactive power pricing mechanism in the TPM. To incentivise appropriate investment in reactive power plant, grid users should in principle see a pricing signal for the reactive power they import from or export to the grid.

Submitter	Response	Comments
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?		
Northpower	Yes	Locational pricing signals for generators are required whether or not locational hedging is introduced.
Orion	No	It is unclear why, if the industry decided that it is appropriate to introduce locational hedging instruments that had the effect of muting nodal price signals, it would then want to enhance, through transmission pricing, the very locational signals that it had just muted. As noted above we do not believe that nodal prices provide reliable or strong locational investment signals.
Powerco	Maybe	This depends on the extent of the effect of locational hedging.
Contact		Not necessarily as they are likely to have a minimal effect on changing a generation location decision.
Meridian		This is a difficult question to answer without a full analysis of the implications. As a starting point, Meridian is cautious about responding to a perceived lowering of the locational signal in energy prices by a conscious over-signaling in transmission prices. Pricing should be set on a more principled basis, and there are likely to be different sets of “winners” and “losers" in the energy pricing and transmission contexts. Meridian is also conscious that different forms of locational hedges are possible, with different potential impacts on nodal price signals.
Mighty River Power		Firstly, we believe purchasers do not, generally, respond to short-term nodal locational signals. Secondly, and as articulated in our locational price risk submission, locational hedging options should be considered as an instrument primarily for purchasers. Hence we do not see the muting of nodal signals for purchasers as requiring material alterations in the transmission price (which, like nodal pricing, is more to drive generation decisions).
Todd Energy	Yes	

Submitter	Response	Comments
ENA		We would prefer to see the nodal pricing signals supported by, or replaced by, signals that lock in locational investment messages.
Transpower		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.
MEUG	Yes.	
Panpac	Do not agree	Appears a strange option to introduce hedges, which reduce signals and then because of this raise differentials to counter.
WPI	No	WPI's understanding is that the current allocation of the sunk costs of the Grid has been adopted to avoid distortion of locational price signals. Basically the variable cost components of transmission are included in the nodal price. If a hedging methodology was adopted that removed the variable cost component from the nodal price then it is logical that the sunk cost allocation could be changed to include a variable cost signal. A disadvantage of this approach is that multiple price signals would be seen by consumers and these may at times be contradictory and/or confusing.
27. Do you consider that the criteria outlined in this paper are appropriate criteria for filtering high-level options? Please outline your reasoning.		
Northpower	Yes	
Orion		It is unclear why the Commission does not continue its previous approach and use the pricing principles (even if amended) and the guidelines as appropriate criteria for filtering high-level options.
Powerco	No comment	Please see question 8 - (need to review pricing principles)
Contact	Yes	

Submitter	Response	Comments
Meridian		Meridian agrees with all the filtering criteria, but makes specific points about some: Divergence from optimal transmission investment, Governance arrangements and Stakeholder acceptability.
Mighty River Power		Proposed criteria are not particularly helpful. Frontier hold the view that the greater the degree of overbuild the greater the benefit of locational pricing (criterion 1). We believe the opposite is the case. The benefit of locational pricing is it sends signals for new generation and load which would reduce the need for future transmission investment. The EC should not be driven by what certain stakeholders of vested interests should prefer (criterion 8). Ultimately, the criteria should be whether locational pricing will improve efficiency to the long-term benefit of end-users. As a subset to this, as advocated by Green22, the TPM should be designed to satisfy the following six principles: - promote the efficient day-to-day operation of the bull power market; - signal locational advantages for investment in generation and demand; - signal the need for investment in the transmission system; - compensate the owners of existing transmission assets; - be simple and transparent; and - be politically implementable.

Submitter	Response	Comments
Todd Energy	Yes	The proposed criteria would seem reasonable, though we note the application of the criteria may not be straight forward. For example, the assumptions behind Criterion 1 (divergence from optimal transmission investment) in considering the historic generation investment decisions that would likely have eventuated through a greater (regulated) recognition and promotion of the benefits that transmission alternatives would have produced in the deferral of non-optimal transmission build. There was a decade where New Zealand was taking the glide path with investment in the transmission grid as Transpower was forecasting the uptake of distributed generation would such that the need for incremental transmission capacity would largely be deferred over the long-term. Rather than looking to actively promote a beneficial change to future locational investment decisions of potential local/distributed generator investors by providing incentives through recognising the generation contribution as a transmission alternative, it would appear from the consultation document that the Commission's preference is instead to penalise generators for their perceived historic inefficient locational decisions that arguably resulted through the failed policies and pricing methodologies applicable at the time.
Transpower		Criterion 1 - is not useful. Grid investments are not driven by nodal price differentials. Criterion 2 - theoretical precision - not particularly useful. A better one would be likely effect on actual consumption and investment behaviour, some may be correct but not have any actual economic effect in practice. Criterion 3 is bizarre. It suggests that if a locational 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. Any locational hedge that would damp nodal pricing signals should not be introduced. Other criterion are reasonable.
MEUG	Unsure about criterion 8 – stakeholder acceptability. Assume the ultimate criterion is a cost-benefit-analysis (refer question 28).	If two options had identical net benefits and were equivalent for all other criterion, then criterion 8 – stakeholder acceptability could be a useful way to decide between the two. If one option had a higher net benefit than a second option, but the second one had higher stakeholder acceptability, the first option should be implemented.

Submitter	Response	Comments
Panpac		Probably
WPI	Partially	The new investment process can become a political issue. Recent responses to news-worthy regional outages, particularly in respect of supply to the Auckland region are examples of this. The question of whether there is a degree of overbuild present is not a criterion that ranks alongside the others; deciding whether better locational signals are needed is a precursor to filtering amongst the possible options. So Criterion 1 should stand on its own. Criterion 3 in respect of FTRs and LRAs is not a criterion but a subset of options. It should be removed from the list of option filters. The remainder appear to be a useful list of filtering criteria.
28. Are there other criteria that you consider might be appropriate?		
Northpower	No	
Orion	No Comment	
Powerco	No comment	
Contact	No	
Meridian	Yes	As emphasised in this submission, Meridian believes that it is important to check the degree to which a theoretically improved locational signal is expected to impact on location decisions in practice, and the expected combined cost of generation and transmission investment. This should be a filter or threshold criteria.
Mighty River Power		See Q 27
Todd Energy	Yes	It is not clear from the filtering criteria how the high-level options will be assessed against wider government objectives7. For example, producing a strong locational signal for generation investment by allocating an

Submitter	Response	Comments
		element of interconnection asset cost recovery to generators will likely provide a barrier to any significant short to medium term investment in gas-fired generation as the current gas transmission capacity constraints largely restrict any economically viable gas-fired generation prospects to the Taranaki region. This will go against pending government policy objectives of incentivising petroleum exploration through the recognition of the key importance and necessity of gas to electricity generation in supporting security of supply with a greater uptake of renewable generation.
Transpower		Note comment on criterion 2. Criterion 5 should be extended to include consideration of and an attempt to quantify the actual compliance costs associated with implementing any changes. Another criterion could be the extent to which any changes to the TPM may increase the scope for disputes. (Transpower has noted costs associated with litigation and disputes.)
MEUG	Standard cost-benefit-analysis.	
Panpac		Need a method to model and check options out on a proper mathematical basis, instead of talking the options through. Suggest using Linear Programming modeling to achieve effective method to compare options and come to mathematical evaluation conclusions.
WPI	No	The paper has done a good job of discussing potential filtering criteria.