Transmission pricing review: stage 2 options

Summary of Submissions

Prepared by Electricity Commission

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Executive summary

This paper provides a summary of submissions for the *Transmission pricing review: stage 2 options* consultation paper (**consultation paper**). Eighteen parties provided submissions.

The paper first provides a summary by issue that generally follows the structure of the consultation paper. A summary of each submitter's submission follows and an appendix is attached with submitter's responses to the questions posed by the consultation paper.

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2.2 Background

A number of parties included in their submissions comments on the Review process, although the consultation paper had not included questions on this issue. The comments concerned: views on the integration of the Review with other initiatives and the relative priority of the Review; views on the timeframe for the stage 3; and requests for further consultation. The common tenet of these views is that transmission pricing should not be rushed and is of a lower priority than the 'new matters' set out in the Electricity Industry Bill. Transpower submitted that there is no longer time to develop a new TPM for the 2012/2013 pricing year. Four submitters suggested that the Commission should consider further consultation as part of the Review.

Submitters were split on whether the Authority's proposed objective has any bearing on the Review's approach to date. Some considered that the objective was consistent with the Commission's principal objectives with respect to transmission pricing and others set out specific reasons why the change in objective should impact on approach and analysis of the Review. Two submitters specifically requested that the Authority should clarify its interpretation of the objective and potentially consult on it.

2.3 Stage 2 analysis

Submitters generally concurred with the economic theory analysis that the Commission presented in the consultation paper, agreeing that the consultation paper had identified the relevant factors in its assessment of whether nodal pricing provides adequate signals for efficient generation and load investment.

A minority of submitters questioned the Commission's modelling for assessing the benefits of locational signalling for economic transmission investments on the basis that the modelling was highly dependent on the input assumptions and that the use of the Generation Expansion Model (**GEM**) may not have been appropriate. Despite these concerns most submitters agreed with the results: that there is limited value in signalling economic transmission investments.

Submitters challenged the analysis of the benefits of signalling reliability investments more strongly.

2.4 Stage 2 options

The Commission had set out its decision not to pursue some high level options described during stage 1 of the Review or previously suggested by submitters. Submitters generally supported the Commission decision not to further consider augmented nodal pricing and tilted postage stamp. Three large user representatives considered that the Commission should undertake further analysis on the ‘but-for’ approach and the capacity rights option suggested for the HVDC link.

Submitters were divided on the benefits of the incentives for deferring reliability investments, and gave arguments both for and against the three options suggested: bespoke pricing, flow tracing and improving the transmission alternatives regime. Summaries of the comments on each of the option are given.

2.5 The HVDC charge

The consultation paper set out costs and benefits of the existing HVDC charge and four possible options for the allocation of HVDC costs, this paper summarises submitters’ views on these and their suggestions of other costs and options to be considered.

The three largest South Island generators all favour postage stamping the HVDC costs. Large user representatives support further consideration of an alternative option – capacity rights, as an alternative means of allocating costs to beneficiaries. Transpower’s considers that there appears to be a reasonable case for retaining the charge, but allocating it based on MWh. Meridian and Todd Energy also suggest allocating the charge according to flows across the link.

Two submitters considered the existing charging is well-founded and inefficiencies are at worse, negligible, and there is no need to consider the efficiency implications of the charge any further.

2.6 Further issues

Submitters commented on arrangements for independently provided connection assets. Some have suggested that, although parties should in principle be able to mutually-negotiate shared arrangements for new connection assets, in practice there is a need for intervention as a backstop. Submitters have also raised other issues in relation to connection arrangements.

Of the three options presented in the consultation paper, submitters generally favoured either option 2 – connection asset definition and option 3 – kvar charging. Transpower presented an alternative variant of kvar charging for consideration. There were strong views against both the status quo and amended status quo which rely on the terms of the Connection Code.

2.7 Other submitter issues

3. Summary by submitter

The paper concludes with a summary of other submitter comments.

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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**)[1]. 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 second consultation paper, *Transmission pricing review: stage 2 options* (**consultation paper**) was published in July 2010, with a deadline for submissions of 24 September 2010[2].

1.2 Establishment of the Electricity Authority (Authority)

1.2.1 This paper has been written over a period covering both the Commission's and the Authority's jurisdiction over transmission pricing. The Commission was replaced by the Authority on 1 November 2010 and responsibility for the Review passed to the Authority on this date. References are made to both organisations in this paper.

1.3 Purpose of this paper

1.3.1 This paper summarises the submissions received on the consultation paper. 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 paper does not provide comments on submitters' views.

1.3.2 The submissions and this paper will assist the Commission in progressing analysis and development of a preferred option for transmission pricing for further consultation.

[1] Further information is available at: http://www.electricitycommission.govt.nz/opdev/transmis/tpr

[2] The stage 2 consultation had an original deadline of 31 August 2010 that was extended at the request of a number of submitters.

1.4 Submissions received

1.4.1 18 parties provided submissions. Copies of all submissions are available at: http://www.electricitycommission.govt.nz/submissions/substransmission/tprstage2options . The organisations that made submissions are listed in Table 1.

Table 1: Submitters

Generator/retailer	Users	Distributor	Other
Contact Genesis Meridian Mighty River Power (**MRP**) Todd Energy Trustpower	Business New Zealand Major Energy Users' Group (**MEUG**) Norske Skog RTANZ	WEL Networks Northpower Powerco Vector Electricity Networks Association (E**N**A)	Transpower Electricity Efficiency and Conservation Authority (**EECA**) Opuha Water

2. Summary of submissions by issue

2.1 Structure and overview

2.1.1 This summary of submissions by issue closely follows the structure of the consultation paper (outlined below), with the exception of the submitter views on the HVDC analysis and options which have been grouped together in section 2.5.

2.1.2 The consultation paper described the following.

(a) Background to the consultation paper including the Review process and relevant policy, regulatory and governance considerations.

(b) Stage 2 analysis. This analysis reconsidered the economic theory arguments for further locational signalling and considered the potential benefits of further locational signalling from two perspectives:

(i) for signalling economic transmission investments; and

(ii) for signalling reliability transmission investments.

(c) Stage 2 options. This section of the paper set out the options that the Commission had decided not to pursue and those that it proposed to consider further. Those options that the Commission proposed for further consideration focussed on two areas:

(i) options for providing incentives for participants to take action to defer or avoid reliability transmission investments where there are benefits in doing so; and

(ii) options for the treatment of HVDC costs.

(d) Further issues. This section considered four further issues that were considered in the stage 1 consultation paper:

(i) the link between price and service;

(ii) connection issues;

(iii) transmission alternatives; and

(iv) static reactive power compensation. The consultation paper outlined three possible options for allocating static reactive power costs.

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

(a) General considerations.

(b) Distribution company forecasting.

(c) The treatment of sunk costs.

(d) Competition benefits and options value of transmission investment.

2.1.4 At the start of each section, a shaded box provides a high level summary of the submitters' views.

2.2 Background

2.2.1 This section of the consultation paper covered background on:

(a) transmission pricing;

(b) the Review of transmission pricing; and

(c) the relevant policy, regulatory and governance considerations.

Review process

A number of parties included in their submissions comments on the Review process, although the consultation paper had not included questions on this issue. The comments concerned: views on the integration of the Review with other initiatives and the relative priority of the Review; views on the timeframe for the stage 3; and requests for further consultation. The common tenet of these views is that transmission pricing should not be rushed and is of a lower priority than the 'new matters' set out in the Electricity Industry Bill. Transpower submitted that there is no longer time to develop a new TPM for the 2012/2013 pricing year. Four submitters suggested that the Commission should consider further consultation as part of the Review.

2.2.2 Submitters made the following comments on the Review process. Some of these comments are directly related to views of submitters to the change in regulatory framework covered in the section starting at paragraph 2.2.14.

Integration and relative priority with other initiatives

2.2.3 **Genesis, Todd Energy and Business NZ** each submitted that 'new matters' in the Electricity industry Bill 2010 should remain far higher priorities than the Review. Their views were based on the fact that the current TPM is not fundamentally flawed or that there are unlikely to be alternatives that warrant wealth transfers and disruption (**Genesis** and **Todd Energy**) and that the market should be given a chance to 'reach a new equilibrium as the changes foreshadowed in the Electricity [Industry] Act are implemented' before making further significant changes to the market (**BusinessNZ**).

2.2.4 **BusinessNZ** submitted further that an early statement is needed from the Authority as to the extent to which it considers transmission pricing one of its priorities.

2.2.5 **BusinessNZ**, **Meridian**, **MRP** and **Genesis** each made comments on the integration between the Review and other market design initiatives.

- **MRP** stated that it is concerned with the Market Development Programme's (**MDP's**) ambitious timelines, the order in which policy initiatives are being developed and the high level of regulatory intervention. In MRP's view, scarcity pricing should be understood before locational price risk management and transmission pricing.
- **Genesis** submitted that implementing a locational price risk management tool may have implications for transmission pricing, but this is best addressed by progressing the locational price risk management work as a priority. As decisions are made, the Authority can review whether any unavoidable need to alter the transmission pricing arises.
- **Meridian** submitted that HVDC rental rebates are intrinsically linked with the payers of the HVDC charge. 'Until there is a change in charging for the HVDC, the HVDC rentals must remain with SI generators, and cannot be used to fund financial transmission rights between the North and South Islands.'
- **BusinessNZ** recognised the practical relationship between various priorities, such as the treatment of HVDC rentals, that drive others to pursue it as a higher priority.

The timeframe for stage 3

2.2.6 In addition to those submitters that commented that the Review should be seen as a lesser priority than other matters, two submitters gave comments on the stage 3 timeframe.

2.2.7 **Transpower** submitted that the process requirements in section IV of Part F of the Electricity Governance Rules mean that it is now not possible to gazette a new methodology in time for it to be applied to the calculation of prices for the 2012/13 pricing year – this is without allowing for the time required to make the software and other administrative changes required to implement one of the complex methodology changes being considered.

2.2.8 **MEUG** noted Transpower's observation that there is unlikely to be sufficient time to implement changes by April 2012, and if so, in MEUG's view there would seem to be no point in pursuing an intensive work programme to proceed to stage 3. A pause to allow other market changes to bed down would seem prudent.

Further consultation

2.2.9 Four submitters made specific requests for further consultation.

2.2.10 **Norske Skog** made a request for cross-submissions before the next phase.

2.2.11 **Meridian** submits that, given the change in regulatory framework and regulator, stage 3 needs to proceed in two parts. First, the Authority should lead a discussion on the new statutory purpose statement, the pricing principles carried over to the Code, other regulatory factors, and how the consideration of these factors is influenced by the efficiency analysis. The second step is to apply this analysis to the TPM options and select a preferred option.

2.2.12 In **Transpower's** view, if preferred options for transmission pricing were bespoke pricing or flow tracing, proceeding to an Issues paper with draft pricing guidelines would constitute an inadequate consultation process. With the exception of the allocation of the HVDC charge based on MWh, Transpower considers that no changes are sufficiently developed for them to be implemented without significant further investigation and consultation.

2.2.13 **Powerco** submitted that the Commission's timetable is very tight and it would prefer the Authority to take its time, and to include consultation on detailed examples of how any pricing changes would work, as this is where it is easier to understand the impact on its business and operations.

Framework to be established under the Electricity Industry Bill

Submitters were split on whether the Authority's proposed objective has any bearing on the Review's approach to date. Some considered that the objective was consistent with the Commission's principal objectives with respect to transmission pricing and others set out specific reasons why the change in objective should impact on approach and analysis of the Review. Two submitters specifically requested that the Authority should clarify its interpretation of the objective and potentially consult on it.

2.2.14 The consultation paper described the changes in the relevant policy, regulatory and governance considerations for the review and asked the question:

1. What, if any, bearing do you consider the Authority's proposed objective has on the Review's approach to analysis and evaluation to date?

2.2.15 The responses were split between those submitters that stated that the objective had little or no bearing on the review's approach to date (Contact, Trustpower, RTANZ, Transpower, Meridian, Todd Energy, Powerco) and those that saw a material bearing (Norske Skog, Northpower, Vector, BusinessNZ, MEUG, ENA, EECA). Some submitters considered wider impacts from other changes to the regulatory framework beyond the proposed objective. A number also gave specific comments about the pricing principles and two commented on the need to understand the Authority's interpretation of its objective.

2.2.16 Those who considered the proposed objective has little or no bearing on the approach to date gave the following reasons for their views.

Considering the objective only

(a) The Authority's objective is consistent with the Commission's statutory objectives for setting transmission pricing (**Contact**, **Trustpower**).

(b) The Review's approach has been largely consistent with the Authority's proposed objective (**RTANZ**, **Todd Energy**).

(c) The Authority's objective does not contain the fairness and environmentally sustainable elements of the Commission's principal objectives, but this change should have no practical implications for the analysis and evaluation of transmission pricing options (**Transpower**).

(d) The goal of transmission pricing generally fits with the Authority's objective of efficiency and security of supply (**Powerco**).

Considering wider changes

(e) 'No reason why the change from Electricity Commission to the Electricity Authority would necessarily alter the direction of this review and we would be disappointed it there was a delay to the review programme as a result.' (**Contact)**.

(f) The empirical analysis that has been undertaken should not be impacted by any change in the overarching regulatory framework (**Meridian**).

2.2.17 Those who saw a material bearing gave the following reasons.

Considering the objective only

(a) The focus is changed significantly in terms of the 'long term benefit of consumers'. This will require the Authority to revisit the previous analysis. For example, the TPM must incentivise generators to locate closer to load rather than expecting consumers to manage their load patterns to cope with constraints (**Northpower**).

(b) When legislation shifts responsibility for a task from one organisation to another and the new organisation has a different statutory objective, it would be very unusual (and, *prima facie*, contrary to the will of Parliament) for that change to have no impact on the analysis, evaluation and decisions that are

(c) The Authority objective would lead to a more rigorous examination of the options identified for controlling power factor (**ENA**).

Considering wider changes

(d) We expect that the Commerce Commission re-writing the Grid Investment Test (GIT) and the Authority concentrating on competition and efficiency will ensure that transmission investments will only be approved if they have a positive net benefit (**Norske Skog**, **MEUG**).

Considering pricing principles

(e) Although **Meridian** considered that the objective should have no material change on the analysis to date, it submitted that the narrower objective will need to be considered and the appropriateness of the pricing principles contained in Part 12 reviewed in light of the new objective. Meridian also notes that the interaction of the proposed Code Amendment Principles with the pricing principles will be important. Meridian included a set of draft guiding principles relating to the Authority objective that was prepared for the CEO Forum[3].

(f) **Contact** maintains its view that the pricing principles should have been reviewed as part of the Review, however, Contact is satisfied with the thoroughness of the Review as it stands.

(g) **Powerco** is not significantly opposed to the pricing principles, but, if the Commission now believes that the principles are no longer appropriate then it should review them.

(h) The biggest risk from the new regulatory framework is perhaps a change by the Authority to the transmission pricing principles in Part F (**Todd Energy**).

(i) A key question is the compatibility of the user pays principle to the Authority's objective, whether the user pays principle is underpinned by fairness and equity or efficiency considerations and the relative weighting that should be applied between fairness and equity and efficiency considerations (**EECA**). (EECA particularly references the application of the user pays principle to the allocation of HVDC costs).

[3] This is available at: http://www.electricitycommission.govt.nz/pdfs/submissions/pdfstransmission/tprstage2options/MeridianApp2.pdf

2.2.18 Two submitters stressed the importance of understanding how the objective will be interpreted.

(a) It will be important for the Authority to consult on how it will approach its new purpose statement and objectives, issues of regulatory certainty and wealth transfers, and the pricing principles carried over to the Code and the foreshadowed Code amendment principles (**Meridian**).

(b) **BusinessNZ** also commented that the Authority should provide certainty on its interpretation of its objective.

2.3 Stage 2 analysis

Submitters generally concurred with the economic theory analysis that the Commission presented in the consultation paper, agreeing that the consultation paper had identified the relevant factors in its assessment of whether nodal pricing provides adequate signals for efficient generation and load investment.

A minority of submitters questioned the Commission's modelling for assessing the benefits of locational signalling for economic transmission investments on the basis that the modelling was highly dependent on the input assumptions and that the use of the Generation Expansion Model (**GEM**) may not have been appropriate. Despite these concerns most submitters agreed with the results: that there is limited value in signalling economic transmission investments.

Submitters challenged the analysis of the benefits of signalling reliability investments more strongly.

2.3.1 This section of the consultation paper considered:

(a) economic theory;

(b) analysis of the benefits of locational signalling for economic transmission investments;

(c) analysis of the HVDC charge; and

(d) analysis of the benefits of signalling for reliability transmission investments.

2.3.2 This part of this paper considers submitters' views all these issues, except those views on the analysis of the HVDC charge which are summarised in section 2.5.

Economic theory considerations

2.3.3 The Commission asked submitters the following question:

2. Do you agree that the Commission has identified the relevant factors in its assessment (paragraphs 3.2.6 to 3.2.13) of whether nodal pricing provides adequate signals for efficient generation and load investment? If not, please explain your reasons.

2.3.4 The majority of submitters agreed that the Commission had identified the relevant factors (Contact, EECA, Meridian, MEUG, Todd Energy, MRP, Vector, RTANZ, Powerco, Transpower). One submitter, ENA, disagreed. Some submitters suggested other factors, or gave views on the significance of the factors.

2.3.5 Submitters suggested the following other factors.

(a) The positive impacts on competition that a less constrained electricity grid enables (**Trustpower**).

(b) The need for investors in generation to consider the overall risk position of locating a generation plant in a new location (**Trustpower**).

(c) The distortion created by generators not seeing the nodal transmission pricing, apart from the HVDC charge (**Northpower**).

(d) The extent to which location decisions are driven by factors other than electricity costs (**Vector**, **RTANZ**, and **Trustpower** (particularly decisions for load). In **Norske Skog's** view other factors such as proximity to raw materials and markets of fuel sources are much more important than nodal pricing.

(e) The time it takes to implement a transmission investment. As this can be many years, the point at which nodal pricing will signal the need for transmission investment will typically be beyond the point at which efficient investment should have commenced (**Transpower**).

(f) In times of above average or excess supply (eg. fuel abundance for renewable-based generation), nodal price incentives for users and investors to manage peak demand will be significantly muted (particularly for peaking generation), with a loss in long-term efficiency benefits. Enduring price signals are required to effect long-term behavioural change required for efficient use of (and thereby investment in) the transmission and distribution system (eg. peak demand management, energy efficiency investments) (**Todd Energy**).

(g) The practical extent to which consumers are able to respond to nodal pricing (**EECA**).

2.3.6 **BusinessNZ** was unclear about the distinction between economic and reliability investments for the purposes of transmission pricing, particularly in light of the transfer of responsibility for the approval of grid investments to the Commerce Commission. As 'only transmission investments that are in the long term benefits of consumers will be approved' there was no need for an additional signal. This view was mirrored by **Norske Skog** and **MEUG**.

2.3.7 **ENA** disagreed that the Commission had identified the relevant factors and said that the fundamental weakness of nodal pricing as a mechanism for signalling efficient generation or load investment is its fragility when loads change.

Analysis of the benefits of signalling economically-driven investment

2.3.8 Submitters were asked:

3. Do you agree with the Commission's approach (outlined in paragraphs 3.2.21 and 3.2.22) to determining whether any form of additional locational signal through transmission pricing is necessary? If not, please provide reasons.

2.3.9 A majority of submitters who answered this question agreed with the approach (Contact, EECA, Meridian, MRP, Vector, Trustpower, Powerco, Transpower). There were four submitters, including three large user representatives, who disagreed (MEUG, RTANZ, Norske Skog, Northpower).

2.3.10 Concerns that submitters noted (from submitters who both agreed and disagreed) were as follows.

(a) It is important to consider the possible dis-benefit from additional locational signals (**Trustpower**).

(b) Approach should be an incremental analysis where the cost and benefit of additional locational signalling (beyond nodal prices, connection and HVDC charges and the GIT) is evaluated (**RTANZ**).

(c) The approach is highly dependant on the input assumptions (**Todd Energy**, **MRP**). Although **BusinessNZ** considered that the modelling had on balance been net-positive to the decision-making landscape, it submitted that, because of the uncertainty in the input parameters, it is important that the results of the modelling is not seen as determinative.

(d) The counterfactual should be the status quo, not an abstract 'no locational signals' scenario (**MEUG**).

2.3.11 **Norske Skog** gave detailed comments on the use of the GEM model submitting that the Commission puts far too much faith in results from the GEM model. **MEUG** cited Norske Skog's concerns in its submission. Norske Skog recommends that the Commission engage with an independent party and publish a conclusion on the validity of the assumptions underlying GEM. In summary, Norske Skog's concerns were as follows.

- Because of the way GEM has been used (by specifying ‘bound gaps’ greater than zero) it is not possible to claim that an optimal solution has been found.
- Relaxing binary variables adds approximation and waters down the integrity of the modeling.
- GEM has some unnecessary constraints that should have been removed to leave GEM free to choose the most sensible solutions:
  - restrictions on volumes of generation plant technology;
  - restrictions on generation from each fuel type; and
  - minimum requirement for generation from renewable sources.
- In Norske Skog’s view it is unreasonable to use a deterministic version of GEM to make any conclusions whatsoever about investment over a time horizon of 31 years.

2.3.12 The consultation paper asked submitters:

4. Do you agree that there appears to be limited value in providing an enhanced locational signal to generators to ensure co-optimisation of economic transmission investments and generation? If not, please explain your reasons.

2.3.13 A majority of submitters who answered this question agreed that there appears to be limited value in providing an enhanced locational signal to generators to ensure co-optimisation of economic transmission investments and generation (Contact, EECA, Meridian, MEUG, Todd Energy, Vector, Norske Skog, Powerco and Transpower). Off these, a number qualified their responses. **Todd Energy** noted its concerns over the input assumptions for GEM. **Norske Skog** and **MEUG** noted their concerns with the use of GEM. Norske Skog and said its agreement was not due to Commission analysis – ‘It is a common sense conclusion.’ Powerco submitted that it supported the Commission’s approach ‘to look at less significant changes’. Trustpower disagreed with the Commission’s findings that there was ‘limited value’, stating that there ‘is no value or possibly negative value given that a signal may distort the merit order of new generation investment.’

2.3.14 **Meridian** questioned whether the analysis undertaken will sufficiently capture the impact of the increased HVDC charge (ie post Pole 3 commissioning) on efficient market operation.

2.3.15 **RTANZ**, **Northpower**, disagreed with the Commission’s finding.

2.3.16 In **Northpower’s** view, the fact that new generators are being constructed at locations far away from the main load in the Upper North Island (**UNI**) indicates that stronger locational signals are required for generators. In Northpower’s

2.3.17 **Todd Energy** submitted that it would be useful to see some sensitivity analysis around a scenario of significant increase in the uptake of distributed generation (**DG**), where the operation and maintenance costs of DG-capable projects were offset through receipt, under the provisions of the DG Regulations, of transmission costs avoided.

Analysis of the benefits of signalling reliability-driven investment

2.3.18 The consultation paper asked submitters:

10. Do you agree with the analysis provided in the section headed "Analysis of benefits of signalling reliability-driven investment"? In particular do you agree with the conclusion that any incentive through the TPM which defers future reliability-driven transmission investment will likely provide some net benefit? If not, please explain your reasons.

2.3.19 **Todd Energy**, **Contact** and **Powerco** agreed that there does seem to be opportunities to improve incentives to defer reliability-driven transmission investment. **Contact** also believes there would be greater benefit in optimising investment in the gas and electricity transmission network. Contact suggested this would highlight the efficiency gains that may have deferred or avoided the North Island Grid Upgrade (**NIGU**) and North Auckland and Northland (**NAaN**) projects.

2.3.20 Other submitters gave the following qualified responses.

(a) Analysis is insufficient to draw conclusions (**RTANZ**, **Vector**).

(b) Reliability investments are only deferrable by demand side management (**DSM**) or local generation if the cause of reduced reliability is growth-related, rather than being a consequence of vulnerable equipment (**Northpower**). Northpower cited NAaN as an example of an investment as a consequence of vulnerable equipment.

(c) High-level benefits may be overstated due to bullish Statement of Opportunities (**SOO**) peaking generation and DSM assumptions (**MRP**, **Norske Skog**). Norske Skog commented that building base load plant makes more sense, with hydro used to meet peak demand and provide firming capacity for wind generation.

(d) Delays in investing in transmission should not occur if the result is reduced competition in the energy market. Transmission alternatives, particularly generation options, could lessen competition (**Meridian**).

(e) This additional signalling will not be required under the new decision-making arrangements where the Commerce Commission will be responsible for transmission investment approvals. Requiring beneficiaries of an investment to pay for the investment would provide them with incentives to choose the options that provide the highest net benefits (**MEUG**, **RTANZ**).

(f) **Transpower** had the following comments.

- Analysis takes no account of the additional cost of peaking generation plant relative to the cost of transmission, or the additional cost of demand side management, including the loss of utility contingent on reduced consumption relative to the cost of transmission investment.
- There will only be a net benefit if the incentive leads to investment in peaking generation or demand side management that is more cost effective than the transmission investment it is displacing. An incentive set at more than the long run marginal cost (LRMC) of the transmission investment would be likely to incentivise a transmission alternative that would produce a net cost from the national perspective.
- The availability and reliability of a single shaft peaking generator is such that it could not deliver a level of reliability equivalent to that provided by grid augmentation. It would take three generating units operating independently to deliver reliability equivalent to the 99.9 per cent availability provided by transmission, if each unit operated independently and had a 90 per cent availability rate. It is not clear how a simple market incentive in the form of the generator credit element of a bespoke titled postage stamp charge could incentivise generators to invest in multiple peaking units, when this would be unlikely to be the most commercially attractive option for them (Transpower).
- Transpower suggests some further analysis using GEM could assess the level of potential benefits. The rationale and approach for the analysis is, in brief:
  - Reliability investments are not an entirely separate class from economic investments. Both types of investment are evaluated in the same way, but on the Core Grid, the value of lost load (VoLL) may effectively be higher for reliability investments than it is for economic investments.
  - The GEM analysis that the Commission used to test the possible net benefits of locational signalling could also be used to test the bespoke pricing concept, by increasing the cost of

transmission to reflect the increased transmission investment that may be justified by the reliability investment criteria.

– Given that the two regions where bespoke pricing could possibly be justified based on the future need for reliability investment would be the UNI and Upper South Island (**USI**), it would seem reasonable to undertake some further sensitivity testing using the 18 region version of GEM or a more granulated version to see if an interconnection charge tilt reflecting the LRMC of future transmission investment in those regions would provide a significant net benefit as a result of changing the economics of generation investment.

2.4 Stage 2 options

The Commission had set out its decision not to pursue some high level options described during stage 1 of the Review or previously suggested by submitters. Submitters generally supported the Commission decision not to further consider augmented nodal pricing and tilted postage stamp. Three large user representatives considered that the Commission should undertake further analysis on the ‘but-for’ approach and the capacity rights option suggested for the HVDC link.

Submitters were divided on the benefits of the incentives for deferring reliability investments, and gave arguments both for and against the three options suggested: bespoke pricing, flow tracing and improving the transmission alternatives regime. Summaries of the comments on each of the option are given.

Commission decision not to pursue some high-level options

2.4.1 The consultation paper and the attached appendix 2 described the Commission’s considerations and decision not to pursue some options previously considered in stage 1 of the Review, or suggested by submitters to the stage 1 consultation paper. These options were augmented nodal pricing, a nationwide tilted postage stamp, the ‘but-for’ approach and the HVDC options presented by NZIER for MEUG. The consultation paper asked submitters the following question:

11. The Commission has decided not to pursue the options outlined in paragraph 4.1.8. Do you agree with the Commission’s assessment (including the analysis contained in section 5 of Appendix 2) that these options are not worth pursuing? If not, please explain your reasons.

2.4.2 Eight submitters that responded to this question agreed the options should not be pursued: Contact, Meridian, Todd Energy, MRP (partially), Vector, Trustpower, Northpower, and Transpower.

2.4.3 Of these **MRP** appears to favour leaving open the option of the tilted postage stamp (along with the bespoke pricing and flow-tracing options considered as options to defer reliability transmission investment.) MRP submits that is worth further exploring these in the event the view on locational signalling changes (eg due to changes in generation technologies or decommissioning of Tiwai Point.)

2.4.4 Those that disagreed - **MEUG**, **RTANZ** and **Norske Skog** – disagreed with the Commission's decision not to pursue the 'but-for' approach and the NZIER HVDC options, in particular the 'capacity rights' option. Comments on these two approaches are given below.

But-for

2.4.5 **MEUG** submits the EC needs to consider the 'but-for' approach more 'innovatively' as applied to an energy-only market.

2.4.6 **RTANZ** strongly supports the 'but-for' approach with the following comments:

- Logic behind 'but-for' is similar to flow-tracing but involves only a one-time application looking at power flows driving the need for investment and thus identifying the beneficiaries of the investment. (Comments about the similarities between flow-tracing and 'but-for' were also made by **Norske Skog and MEUG**).
- In paragraph 5.7.2 on page 69 of the paper, the Commission expresses the view that the 'but-for' approach requires Transpower to seek long term contracts with new generators and new loads to underwrite the costs of significant new transmission investment. 'But-for' is a cost allocation approach and it is not necessary for new investment contracts to be entered into.
- All 'but-for' does is use the data underpinning the GIT for a new investment and allocates the cost of that investment to the grid injection and exit points that will benefit from the investment. As these must be reasonably well identified in order to calculate the benefits of the investment, the allocation is comparatively straightforward.
- There is information generated by Transpower such as Asset Management Plans and the Annual Planning Report that can also be used to support a 'but-for' approach.

Capacity rights

2.4.7 Whilst the capacity rights and arbitrageur options for the HVDC are more complicated than the status quo they would have advantages in addressing the South Island (**SI**) peaking plant investment disincentive and allowing flexibility to allocate charges to users if north to south flows become from frequent (**MEUG**).

2.4.8 Proposals for the use of capacity rights are much less relevant as the pending upgrades (**Contact**) will ease capacity constraints on the HVDC.

2.4.9 **RTANZ** provided an appendix on the capacity rights option[4]. RTANZ includes the following comments in its submission:

- Capacity rights is criticised in appendix 2 for the potential for generators not to have acquired sufficient rights to be fully dispatched and so a least cost dispatch is not achieved. A trader that repeatedly makes mistakes through not maximising their position by not ensuring they have sufficient capacity rights won't remain a trader for long.
- The arbitrageur approach is criticised for the potential for the same inefficiency through withholding of capacity. However, such strategic actions by the monopolist would doubtless draw the eye of the regulatory authorities who would amend the rules of operation if there was a detriment to consumers.
- Free-riding is only a concern, from the perspective of economic efficiency, if welfare enhancing investments do not occur because of the ability of hold-outs (free riders) to avoid contributing to that investment.
- The ability of some parties to free ride on an investment does not necessarily mean that the investment was wrong or that those who fund the investment have been overcharged. In this debate, the concerns put forward about free riders are generally not concerns about economic efficiency. They are more generally concerns about perceptions of equity. It is also instructive to note that an exactly analogous situation exists with the status quo in regard to embedded SI generators. They pay no HVDC charges either.
- If free riding was such an overwhelming concern then the solution to this would be the irreducible pricing outcome of postage stamp prices across all injection and off-take points. That is, smear the costs across everybody without regard to the efficiency of such an allocation.

[4] Available at: http://www.electricitycommission.govt.nz/pdfs/submissions/pdfstransmission/tprstage2options/RioTinto2.pdf

2.4.10 **Norske Skog** includes reference to research from the University of Auckland[5] that concludes that auctioning capacity rights for the HVDC are welfare-enhancing if generator market power is addressed.

Options for providing incentives to defer or avoid reliability transmission investments

2.4.11 The consultation paper suggested three options alongside the status quo to defer of avoid reliability transmission investments: bespoke pricing, flow tracing and improving the transmission alternatives regime. The consultation paper suggested a concern, for at least one of the options, was the lack of financial incentive for distributors to minimise transmission costs for their customers. It also noted the Commerce Commission's proposal to allow those distributors subject to the price quality regime to retain avoided transmission charges where it can be demonstrated that the avoided charge is a result of reducing the overall cost of supply of electricity line services (paragraph 4.2.16(c) of the consultation paper).

2.4.12 The consultation paper asked submitters:

12. If the Commerce Commission proposal outlined in paragraph 4.2.16(c) is adopted for the final determination, do you think this will address the regulatory anomaly referred to above?

2.4.13 Of those submitters that responded to this question, Contact, RTANZ, Trustpower, Norske Skog, Transpower, MRP agreed that the regulatory anomaly would be addressed. Some of these submitters had specific comments.

(a) It is important that there should be a requirement to pay the avoided cost of transmission to those businesses that are providing the benefit (**Trustpower**).

(b) This is only for the case of non-exempt Electricity Distribution Businesses (**EDBs**)(**MRP**).

(c) An environment should be encouraged where the consumer has the property right to their load and can therefore choose the highest value DSM project (**MRP**).

2.4.14 Some submitters that did not directly agree to the question recognised the concern over the lack of incentive for distribution companies to reduce transmission costs (**Meridian**, **MEUG**). **Meridian** asked whether the Commission had considered the relationship of this proposal with the requirement under the

[5] Allocating physical capacity rights on an electricity transmission line, AB Philpott and LN Huang, 2 Aug 2010, www.epoc.org.nz/papers/HVDCpaperv3.pdf

Electricity Governance (Connection of Distributed Generation) Regulations 2003 that lines businesses share avoided transmission costs with the relevant distributed generator.

2.4.15 Those submitters – including all three distribution companies that made detailed submissions – who disagreed or had concerns (Northpower, Powerco, Vector, ENA, EECA, Todd Energy) gave a number of comments. Vector's comments were supported by both ENA and Powerco.

(a) It is not clear what degree of evidence the Commerce Commission will require **(Powerco**).

(b) Demonstrating the reduced cost will be difficult as EDBs have limited information on the costs of future transmission investments (**Powerco**, **EECA**).

(c) The ex-post approval of investments made to avoid transmission charges means the lines companies face the risk that investments will not be approved (**EECA**, **Vector**).

(d) The efficiency test is unnecessary as Transpower and the distributor will only reach an agreement for avoided transmission investments where the cost is lower (**Vector**).

(e) The efficiency may stifle the willingness of distributors to make avoided transmission investments and adding costs and complexity (**Vector**, **EECA**).

(f) The Draft Input Methodologies Determination fails to provide for the pass through of avoided transmission costs paid by distributors to distributed generators where peak demands are reduced as a result of a distributed generator's supply (**Vector**).

(g) A better alternative would be the inclusion of avoided transmission charges as a Recoverable Cost. Avoided transmission cost payments to distributed generators should also be re-instated as a pass-through cost (**Vector**).

(h) The distributors will likely favour their own projects over those of other parties in the award of transmission cost savings benefits (**Todd Energy**).

(i) Distributors will only be able to retain avoided charges for five years although there may be on-going costs (**EECA**).

(j) The proposal may not be compatible, or reinforce enhanced transmission pricing signals provided by either bespoke pricing or flow tracing (**EECA**).

(k) Avoided transmission charges may be less that the underlying avoided cost of transmission as transmission charges only increase after a transmission investment is made (**EECA**).

2.4.16 Considering the three options for deferring or avoiding reliability transmission investments, the consultation paper asked following question:

13. The Commission has identified three options alongside the status quo to defer or avoid reliability transmission investments. Do you agree that these options are worth pursuing? Are there other options which deserve further consideration? Please provide reasons.

2.4.17 General responses to this question are summarised first, followed by specific comments on the three options.

General comments

2.4.18 Those submitters that were generally supportive of measures to defer or avoid reliability investments (Contact, Trustpower, Powerco, EECA) made the following comments or suggestions.

(a) It is important that Transpower is able to pursue additional investment in our regions and that the proposals support this aim (**Powerco**).

(b) There are some areas where signalling could have economic benefit, but this could be a targeted incentive, rather than part of the TPM (**Trustpower**).

(c) There are other issues that need to be addressed where distributed generation and DSM are treated poorly 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 (**Powerco**).

(d) The options that support the deepening of connection assets should be developed further (**Contact**).

(e) DSM faces barriers that may limit uptake resulting in an inherent bias to generation transmission alternatives (**EECA**).

2.4.19 MEUG, Genesis, Todd Energy, MRP, Vector, RTANZ, and Northpower disagree with the proposals. In **Northpower's** case, it disagrees with any proposal that sees load charged more. Reasons given for the objections are as follows.

(a) More administration costs – including a new adjudicator to second-guess Transpower (**Vector**).

(b) The problem of Transpower favouring transmission investment may be less applicable as the Commerce Commission's indicative draft Cost of Capital Input Methodology produces a lower WACC which is unlikely to facilitate large-scale investment by Transpower (**Vector**).

(c) These are not necessary if only reliability investments that have net positive benefits are invested in and beneficiaries pay for them (**MEUG**, **Norske Skog**, **RTANZ**).

(d) A robust grid has benefits for competition and option value, an over emphasis on alternatives may jeopardise this. (**Genesis**).

(e) The most significant grid upgrades to occur in decades, and likely required over many future decades, have already been approved (eg, HVDC upgrade, NAaN, NIGU) and are to become part of the sunk costs recovered via the TPM (**Todd Energy**).

(f) Introducing the mechanisms proposed by the Commission will hinder development of the regional augmentation options and solutions which already suffer under the status quo, (**Todd Energy**). (Although Todd Energy submits that the only practical ways to counter increasing average LRMC of transmission are to provide enduring signals to effect the behavioural changes required from the demand side and to influence the decisions investors in generation.)

2.4.20 **Todd Energy** included general comments on the allocation of AC costs to load and on what is, in its view, a disproportionate over-allocation of shared connection asset costs to generators. For reliability investments, Todd Energy submits, the demand customers mandate the levels of security of supply and reliability delivered by the transmission grid, not generation. VoLL (much greater than the value that generators place on lost generation) is used in the justification of reliability investments in the grid.

2.4.21 In **Todd Energy's** view it is reasonable that demand customer's face the bulk allocation of AC asset related cost recovery as it is the raw demand growth and demand-side security and reliability requirements predominantly driving the investment required in transmission and the supply side.

Bespoke pricing

Some submitters supported either the concept or further analysis of bespoke pricing (EECA, Contact, Meridian, Todd Energy). **Transpower** particularly opposes the generator-credit element of bespoke pricing but suggested that a bespoke incentive to encourage demand-side management in appropriate regions could be investigated further.

Table 2 Comments on bespoke pricing

Submitter views.	
Benefits of bespoke pricing	Distributors will be able to pass this signal through to customers without increased risk of breaching their price-quality paths (**EECA**).
General concerns,	Whether a 'carrot and a stick' type system is an appropriate long term,

bespoke pricing	sustainable investment signal (**Meridian**). Subjectivity and difficulty of determining the regional LRMC of transmission (**Meridian, Transpower**). Incentives for gaming – parties may be incentivised to withdraw capacity in order to encourage more incentives at an alternative site, or to receive a credit for refurbishing existing plant so it continues to operate (**Meridian**). The relationship of the proposals to mechanisms aimed at addressing demand side participation/ bidding in the wholesale market (**Meridian**). Potential distortions from generation transmission alternatives to the competitive generation market (**Meridian**). Bespoke signals will not be enduring (**Norske Skog** and **Transpower**). (**Norske Skog** gave an example: there was insufficient transmission capacity to meet demand in the Bay of Plenty but commissioning of a 100 MW geothermal power station at Kawerau reversed the problem. Now there is, at times, insufficient transmission capacity to get power out of the Bay of Plenty.) Credits to some generators and levying higher charges for loads in particular regions would be inappropriate and unfair. At a bare minimum, generators close to major load centres could continue to be exempt from interconnection charges and remote generators could start paying some interconnection charges. The net effect would be similar, but without off-take customers having to shoulder even more costs (**Northpower**). Implementation of this initiative should not fundamentally change the regional coincident peak demand (**RCPD**)-based AC interconnection revenue cost recovery mechanism under the existing TPM (**Todd Energy**)
Concerns over **generator** bespoke pricing	No demonstrated economic response to such a signal (**Transpower**). Generation is unlikely to locate in response to price signals rather continue to be located close to fuel sources (**Norske Skog**). Generators would not be incentivised to invest in the multiple peaking units needed to provide reliability (**Transpower**). A single plant would have market power at times of peak demand (**Transpower**). New Zealand needs more baseload, allowing hydro to meet peak demand and firm wind (**Norske Skog**). **Todd Energy** questioned the consultation paper, paragraph 4.2.5(c)

	"generation investors should be indifferent between connecting to the transmission network or embedding within a distribution network". Todd Energy submitted that assuming the generator is allocated the full benefit of avoided 'interconnection' transmission costs, as promulgated under the pricing principles of the DG Regulations, the generator would be in a better position by $60/kW through embedding in the distribution network, regardless of whether the generator was located in a bespoke region. **Todd Energy** submitted on two further issues regarding treatment for 'distributed generation'. The first is where a distributed generator is connected at the Grid Exit Point (**GXP**) but providing the same benefits as an embedded generator. The second is Todd Energy's view that distributors devalue the embedded generator contribution to reducing RCPD (para 13 and 14, Todd Energy). **Todd Energy** submits that as a direct result of this discriminatory treatment it has not progressed otherwise economic distributed generation opportunities in Auckland, instead choosing to invest in other networks where the distributor takes the appropriate position on the application of the DG Regulations and resulting transaction costs are less. An incorrect bespoke pricing signal may encourage multiple uneconomic gas peaking plant ahead of economic renewable generation. 'Soft' signals that gradually change over time should be encouraged (**MRP**).
Concerns over **load** bespoke pricing	The treatment of transmission charges as a pass-through for distribution customers should be addressed (**Transpower)**.

Flow tracing

2.4.22 Contact, EECA, and Meridian support either the concept or further analysis of flow tracing. Norske Skog, RTANZ and MEUG cited similarities between flow-tracing and the 'but-for' approach (see paragraph 2.4.5 following). Todd Energy, Northpower and Transpower did not support flow tracing.

Table 3 Comments on flow tracing

Submitter views.	
Possible benefits of flow-tracing	Could be used to improve the allocation of the monopoly loss and constraint excess (**Todd Energy**). Could be used to identify beneficiaries under the 'but-for' test. (**Norske Skog**, **MEUG**, **RTANZ**).

Concerns	Complex to administer, which would add to compliance costs and increase the scope for disputes (**Transpower**). Difficult to define legally and to audit (**Transpower**). A threshold would provide strong perverse incentives for customers to get below the threshold (**Transpower**). Interaction with the benchmark agreement with respect to investment is likely to cause problems (**Transpower**). Major assets would be likely to have their cost allocations changed radically (**Transpower**). Prices would be unstable and this problem would not be fixed by averaging over time, because of cyclical trends in hydrology (**Transpower**). **Meridian**, **RTANZ** and **Todd Energy** had similar concerns, although Todd recognised that flow tracing might have lower stability concerns than earlier load-flow models. Not clear what benefits would be as the allocation would apply to offtake only and transmission comprises a very small part of most offtake customers' costs (**Transpower**). Lines companies will be less able to signal via pricing the cost of future transmission investment to customers given that transmission charges will only increase after an investment (**EECA**).

Improving the transmission alternatives regime

General comments on the rationale for changes

2.4.23 Some parties submitted on their views on whether there is an underlying problem with the transmission alternatives regime and, if so, what it is.

2.4.24 The consultation paper noted that submitters to the stage 1 consultation paper had concerns over Transpower's perceived competing interests as network owner and the entity responsible for conducting the RFP process and assessing any proposed alternatives (para 4.2.19, consultation paper).

2.4.25 **Transpower** and **EECA** questioned whether this was justified.

2.4.26 According to **Transpower**, if it is possible to find a cheaper alternative to grid investment that will deliver equivalent benefits, this will always be attractive to Transpower. Transpower submits that, under the regulatory framework applied to transmission, it has a strong commercial incentive not to invest unless it is essential to do so in the interests of reliability and security.

2.4.27 **EECA** noted Transpower is in the process of developing its capability to develop transmission alternative projects and therefore questioned the extent to which it has a bias against transmission alternatives.

2.4.28 Both **MRP** and **BusinessNZ** considered that the issue was not Transpower's perceived conflicts and suggested there might be other problems.

(a) **BusinessNZ** submitted that there is only one grid owner and it is accountable for the development of its plans. It suggested that if there was a problem it might be one of incentivising Transpower to appropriately consider transmission alternatives.

(b) **MRP** suggested the issue is the availability of suitable technology and poorly defined transmission alternative criteria.

2.4.29 On suggestions for improving the transmission alternatives regime

2.4.30 Meridian, Contact, Todd Energy, Norske Skog and Powerco generally supported further investigation of improvements to the regime and further consideration of the idea of an independent decision maker.

2.4.31 **EECA** considered that regulatory costs may exceed the benefits of involving a third party in the transmission alternatives regime and **Transpower** submitted that effectively splitting responsibilities for grid planning would blur accountabilities and make it more difficult to achieve effective, integrated grid planning.

2.4.32 A number of submitters stated that other improvements could be made.

(a) **Transpower** believes that there is scope for making incremental improvements to the evaluation of transmission alternatives and the development and application of grid support contracts.

(b) The operation of the transmission alternatives framework could be improved without altering the framework itself (**Genesis**).

(c) Parties could have access to a stream-lined independent review process should they have valid concerns with Transpower's initial RFP or the following analysis used in support of Transpower's final decision (**Todd Energy**).

(d) The Commission (or the Commerce Commission) needs to clearly specify service and price thresholds prior to the RFP process (**MRP**).

(e) Better incentivise Transpower to appropriately incorporate consideration of transmission alternatives into its analysis. (**BusinessNZ**).

2.4.33 **MRP, BusinessNZ** and **Genesis** submitted that any transmission alternatives regime is a matter for the Commerce Commission to consider through its input methodology work.

2.4.34 **EECA** stated that the Authority should work with the Commerce Commission to ensure that Transpower’s price-quality path includes mechanisms to encourage investment in transmission alternatives noting that under Section 54Q of the Commerce Act, the Commerce Commission “… must promote incentives and avoid imposing disincentives for suppliers of electricity lines services to invest in energy efficiency and demand side management, and to reduce energy losses…”.

2.4.35 Meridian noted that the Authority needs to ensure that transmission alternatives do not inappropriately delay transmission investments.

2.4.36 **MRP** considered that generation:

(a) is not a transmission investment unless strict conditions are met; and

(b) that as a transmission alternative has the potential to distort the generation investment market and result in inefficient outcomes.

2.5 The HVDC charge

The consultation paper set out costs and benefits of the existing HVDC charge and four possible options for the allocation of HVDC costs, this paper summarises submitters’ views on these and their suggestions of other costs and options to be considered.

The three largest South Island generators all favour postage stamping the HVDC costs. Large user representatives support further consideration of an alternative option – capacity rights, as an alternative means of allocating costs to beneficiaries. Transpower’s considers that there appears to be a reasonable case for retaining the charge, but allocating it based on MWh. Meridian and Todd Energy also suggest allocating the charge according to flows across the link.

Two submitters considered the existing charging is well-founded and inefficiencies are at worse, negligible, and there is no need to consider the efficiency implications of the charge any further.

2.5.1 The consultation paper considered the following issues with regard to the treatment of HVDC costs:

(a) Whether the current locational signal provided by the HVDC charge is causing or likely to cause inefficient decisions.

(b) The costs and benefits of the current allocation of HVDC costs.

(c) Options for the allocation of HVDC costs.

(d) Preliminary conclusions of HVDC analysis.

2.5.2 The consultation paper asked submitters the following question, following its analysis of the benefits of locational signalling for economic investment:

5. Do you agree that it needs to be determined whether the current locational signal provided by the HVDC charge is causing or is likely to cause inefficient operational and investment decisions? If not, please explain your reasons.

2.5.3 Contact, EECA, MRP, Meridian, RTANZ and Transpower agreed with question 5. RTANZ and Todd Energy gave qualified agreement; **Todd Energy** qualified its response with its view that the 'beneficiary pays' arguments should factor.

2.5.4 MEUG and Northpower both disagreed. In **Northpower's** case, it argued that the existing methodology is well founded. **Genesis**, although not responding directly to this question, submitted that, as a soon-to-be South Island generator, it was comfortable with the beneficiary-pays model and considered that, in any plausible scenarios the beneficiary pays rationale remains valid and the locational signalling value of the HVDC charge is, at worst negligible.

2.5.5 **MEUG** submitted that locational signals are just one element to be considered, reviewing HVDC aggregate charges, pricing methodology and service levels to ensure they are fit-for-purpose compared to alternatives is more important.

2.5.6 Some submitters' made suggestions for approaches to the analysis of the efficiency of the HVDC charge

(a) It would be better to consider not only the status quo, but any candidate pricing methodology. If none of the candidates have any advantages in terms of operational efficiency and incentives for investment decisions then there is no justification to change from the status quo (**Norske Skog**).

(b) It is critical that the investigation clearly establishes what those inefficiencies are, determines their root cause and recommends remedies that provide a strictly more efficient outcome for the benefit of consumers (**RTANZ**).

(c) There may be merit in further quantifying the value of inefficiencies. It is an inefficient allocation to a subset of participants which is distortionary due to the cost of transmission not being fully reflected to consumers (**Contact**).

(d) **Meridian** considers the disbenefits of the charge could be assessed by:

- Modelling the NPV of future system costs that might arise if South Island generators are subject to a Historical Anytime Maximum Injection (**HAMI**) based HVDC charge;

- Then model the NPV of future system costs that might result if generation and transmission are perfectly co-optimised; and
- Then compare the two results to provide an indication of the dis-benefits of the current HAMI based HVDC charge.

(e) The Commission's decision framework for options for charging for the HVDC starts from the position of considering whether the benefits of incentivising North Island generation (through the HVDC charge to South Island generators) are outweighed by the costs. If the decision framework started from the question 'is an enhanced locational signal necessary' the conclusions that might be drawn may be different (**Meridian**).

(f) It would be useful for the Commission to clearly delineate costs and benefits that relate to the allocation to South Island generators and those that relate to the pricing structure (**RTANZ**).

6. Do you agree with the high-level analysis provided on the costs and benefits of the current HVDC charging regime? If not, please explain your reasons.

2.5.7 Most submitters gave comments on the different costs and benefits and these are included in Table 4. The following submitters generally agreed with the high-level analysis: Contact, EECA, Meridian, Todd, MRP, Transpower, and Vector.

2.5.8 **Northpower** did not agree stating: the Authority just needs to ensure the generators do not withhold peak generation simply to shift HVDC costs from themselves to other generators. The single test is now the "long term benefit of consumers", not the profitability of the generators.

2.5.9 **Meridian** questioned whether the analysis undertaken will sufficiently capture the impact of the increased HVDC charge (ie post Pole 3 commissioning) on efficient market operation.

Table 4 Comments on the costs and benefits of the HVDC charge

Item	Submitters comments
Benefits	Benefits (a) and (b) overlook the 'demonstration effect' caused by not charging for an investment once made. Not charging beneficiaries of investments will create an incentive to call for investments that beneficiaries do not value sufficiently to pay for (**MEUG**). Benefits (a) and (b) do not consider the dynamic efficiency effects from investment incentives to South Island users/consumers, who would otherwise invest in North Island, overseas or not at all (**MEUG**).
Benefit (a) Preventing or deferring need for new DC link Initial assessment: Not material	
(a)	Unlikely to be a new link in future (**Contact**). Agree that the benefits are not material (**Meridian**). The future is unknown (especially over 30 years) and it is not inconceivable that additional HVDC capacity will be required at some stage. If beneficiaries are not charged they will have an incentive to lobby for investment, whether it is needed or not (**Norske Skog**).
Benefit (b) Preventing or deferring need for new AC upgrades Initial assessment: Probably not material	
(b)	Agree (**Meridian**)
Cost (c) Incentivising NI generation investment rather than more economic SI investment Initial assessment: Material but small – initial estimate is $16 million NPV, although this falls to $8 million	
(c)	Likely to be understated as not only are uneconomic North Island (NI) projects potentially being built, but substantial AC upgrades to support north flow are also planned/underway (**Contact**). **EECA** provided analysis of wind projects that it considers *may* provide some *limited* indication of the impact of the HVDC charge on SI wind generation development and the degree of competition in SI wind generation development. **ECCA** noted that Trustpower has stated that its wind developments have been influenced by the HVDC charge. Likely to be material (**Meridian**). Given the inevitable uncertainty in costing various future generation options in different parts of the country, the estimated costs of (c) are so small that it is not certain whether the incentive of the HVDC charge in relation to NI generation is actually a cost. It could be a benefit if measurement errors were excluded (**MEUG**).

Item	Submitters comments
	If there is an inefficiency of $16 million this raises the question of whether or not generators are paying efficient levels of transmission charges (**RTANZ**). There is benefit in not discriminating against SI generators as this may defer the need for further SI transmission investment (**Trustpower**). Since the costs are based on GEM analysis and fall within the margin of error they are insignificant and no conclusions can be made (**Norske Skog**).
Cost (d) Disincentivising existing SI generation from operating at full capacity Initial assessment: not material	
(d)	This is conservative. The need for this capacity – particularly peaking capacity continues to grow and the costs of supply and non supply during those peaks is also increasing (and could further increase based on the proposed scarcity pricing initiatives). Some generators have made public statements about their intention to remove existing peaking capacity from the market increasing the size of the disincentive (**Contact**). **Meridian** submitted that it does take into account the HAMI methodology and its impact on Meridian's share of HVDC costs in its operational decisions. The ability of South Island generators to apply for a dispensation from increased HAMI charges as a consequence of a grid emergency underlines the arbitrary and non principled basis of the current charge. Further, it acts as a general distortion on the energy market (during non-emergency periods) as SI generators are not free to exercise operational decisions without penalty. The present HVDC charging regime causes generators to be reluctant to offer infrequently used peaking capability into the market. The marginal cost of the present HVDC charge is well over $100,000/MWh if only dispatched for one 30 minute period. If only dispatched for one five minute period the marginal cost is even higher (**Trustpower**). On the assumption SI generators are evaluating new generation opportunities in the SI, and these additional projects are likely to increase the functional operating and peaking capacity of these incumbents, it is perhaps hard to comprehend that costs (d) and (e) could be material (**Todd Energy**). The disincentive is not material (**MEUG**, **RTANZ**). **Norske Skog** questions the Commission's conclusions and notes that there are no calculations provided to support the Commission's assertion that the value of cost (d) is somewhere in the low end of the 0 to $100 million range. SI hydro generators may prefer to spill at times of high inflows rather than generate in order to manage their HVDC charges.

Item	Submitters comments
Cost (e) Disincentivising incremental SI peaking capacity Initial assessment: Material but small enough to be discounted - estimate $0-$25 million NPV	
(e)	**Meridian** submitted that it has taken into account the HAMI methodology and its impact on Meridian's share of HVDC costs when considering investments in incremental peaking capacity. Overall there is likely to be a net benefit rather than net cost. Builders of plant in the SI who are focused on meeting local demand and not interested in providing power to the NI still benefit from the link through higher prices in the SI than there would be without the link, but they also have to pay a share of the costs of the link, even though they are not major beneficiaries. The positive incentive would likely outweigh the negative. Builders of SI peaking plant pay a share of the cost of the link even if they never use it, although they also benefit from higher prices in the SI than there would be without the link. That peaking plant would generate only when prices were high anyway (**MEUG**). Any SI generator, including peaking plant, receives a higher spot price with the HVDC than they would have without it. Whether or not they use the link is irrelevant. The HVDC creates a national market, even if no power ever flows across it (**Norske Skog**). See **Todd Energy** comment for cost (d) above. A simple way to eliminate this disincentive would be to charge for power transported across the HVDC (See **RTANZ's** views on Capacity Rights). SI new investment is being progressed at a sub-optimal level to avoid the present HVDC charging, and new investment is very unlikely to proceed while there is a penalty applied to new SI renewable generation connected to the Transpower grid (**Trustpower**).
Cost (f) Competitive advantage to Meridian in constructing new SI generation Initial assessment: Not clear but likely to be smaller than cost (c)	
(f)	See **ECCA** comment for cost (c). **Meridian** submitted that the effect of the current charge is that its competitors have a greater incentive to embed generation options than it does; it has less of an impact on its incentive to invest than other parties given the size of its portfolio. The charge is likely to act as a significant barrier to entry for new investors wanting to connect plant directly to the transmission grid in the SI. However, Meridian agreed that this cost is unlikely to be material. We are doubtful if this is in practice an impediment to competition to build new generation in the South Island. The anecdotal evidence is that, apart from Meridian, there are several existing and new investors in generation that have been progressing possible projects

Item	Submitters comments
	(**MEUG**). **RTANZ** includes analysis in its submission to demonstrate its view that this is not an issue, that everyone investing in new generation in the SI faces exactly the same HVDC opportunity cost. **Norske Skog** includes in an appendix to its submission analysis that demonstrates its view that this is an issue, that the dominant generator does have a stronger incentive to invest than other parties. Norske Skog notes that it is not sure if this is a material problem. If it is, in Norske Skog's view, it can be easily resolved by charging only existing SI generators for the HVDC, These generators obtained their assets under the premise that they would always pay for the HVDC costs, including any repairs and replacements and thus have no reason to complain. The present charges effectively give Meridian a significant competitive advantage in the South Island generation development market. This cannot be good for the competitive electricity market (**Trustpower**).

2.5.10 Submitters identified further costs:

(a) The HVDC charge may contribute to a less geographical diverse wind generation portfolio. This may increase wind integration costs such as those associated with frequency keeping and wind forecast accuracy (**EECA**).

(b) The HVDC charging regime could create an uneven playing field in favour of those line companies looking to invest in generation for retailing in their own network (**Todd Energy**).

(c) Current charge provides an incentive to embed generation within a distribution network. This could lead to lost opportunities for achieving potential economies of scale and increased losses with a distribution network (**Meridian, Todd Energy, Opuha Water**).

2.5.11 The consultation paper described four different options for the HVDC charge and asked the question:

7. Do you agree that the Commission has correctly identified the four possible options for the HVDC charge? If not, please explain your reasons and provide alternative options.

2.5.12 Submitters that answered this question generally agreed that the Commission had identified four possible options. Some noted that there were a number of alternatives within these options, or that there were others that should be considered. Some submitters did not consider that all four of these options were valid. Where submitters commented on the validity of the options, their comments are summarised in the next section.

Alternatives within the four options

2.5.13 The postage stamp option could involve splitting the costs over load and generation or sharing the incidence based on capacity utililtsation to reflect changes in flows during wet/dry years (**Meridian**).

2.5.14 **Todd Energy** suggested a similar option to Meridian where HVDC costs could be pro-rated each year based on the total annual flows (MWh) in each direction. North-flow HVDC cost allocation would be shared equally between SI generation (MWh charge based on gross generation volumes reflecting that the embedded generator also receives the benefit of an increased average SI spot price than it would without the HVDC link) and NI demand (via postage stamp adjunct to Interconnection Rate to form a ‘NI Interconnection Rate’).South-flow HVDC cost allocation would be spread across all demand via a postage stamp adjunct to the Interconnection Rate. Todd Energy included more details of the benefits of this charging regime in its submission (response to Q7).

2.5.15 To slowly phase out the existing pricing regime and phase in the postage stamp option (**EECA**).

Other options

2.5.16 Capacity rights approach or variant thereof (**RTANZ**). See comments on capacity rights paragraph 2.4.7.

2.5.17 The consultation paper then asked:

8. What are your views on the validity of each of the options?

2.5.18 Submitters were divided on their opinions on the different options. A summary of the submitters preferences is given in Table 5.

Table 5 Summary of submitter preferences for HVDC options

Option	**Supporters**	**Rationale**
Maintain status quo	Genesis, Northpower	‘ The current regime is soundly based’ (**Northpower**). ‘Comfortable with the beneficiary pays rationale’ (**Genesis**).
Move to MWh	Transpower	There appears to be a reasonable case for retaining the charge, but moving to MWh injected rather than HAMI as the allocator, since the inefficiency caused by variabilising

		the charge would seem to be minimal and there would appear to be some benefit to be gained from removing the incentive that HAMI may currently create for SI generators not to invest in increased peaking capacity and not to operate their existing plant at full capacity during peak demand periods (**Transpower**).
'Incentive free'	None	
Postage Stamp	Contact, Meridian, Trustpower	The three largest existing SI generators all favour postage stamping. **Meridian** considers that, 'if there is no efficiency rationale for an otherwise arbitrary charge [current HVDC charge] it should be removed.' **Trustpower** considers that the status quo 'does not demonstrate any benefit within any reasonable margin of error'. **Contact** considers it is not a valid option for the reasons given in the consultation paper 3.2.22 - .25.
Other	MEUG, RTANZ, Norske Skog	The Authority should further consider the capacity rights approach (**MEUG**, **RTANZ**, **Norske Skog**).
Undecided, support further consideration of all options	MRP, Vector, Norske Skog, Business NZ, MEUG, EECA (preference is for non-distortionary charge)	Insufficient analysis.

2.5.19 Some submitters made general comments on the issue of whether to maintain the charge on SI generators (whether as the status quo, MWh charge or 'incentive free').

2.5.20 **Northpower** and **Genesis** supported maintaining the charge (see Table 5 above).

2.5.21 The comments made by current SI generators (noting that Genesis is a SI generator-to-be) are as follows.

(a) The current HVDC charge is not efficient because consumers are effectively facing a price for transmission services that is below the total opportunity cost of supply. This means that the level of transmission investment is unlikely to be efficient, as demand will be above a level that would be sought where price reflected the full opportunity cost of producing and transporting that electricity (**Contact**). Contact asserted that, the existing HVDC charge was not consistent with the objectives of other MDP initiatives such as scarcity pricing and dispatchable demand which are responding to concerns of a lack of visibility of costs.

(b) **Contact** gave an evaluation of the rationale behind the Commission's 2006 decision on the TPM Guidelines[6] (**Contact,** p 10, Redundancy of other traditional arguments).

(c) Postage stamping is the only option. All other options are based on economic analysis that does not demonstrate any benefit within any reasonable margin of error (**Trustpower**).

(d) **Meridian** (and likely other South Island generators) will suffer a private detriment from the HVDC Pole 3 upgrade with the current HVDC charge.

(e) That there are a range of beneficiaries. NI loads and, during dry periods, SI loads and NI generators are beneficiaries (**Meridian**).

(f) The HVDC link is part of maintaining a national wholesale electricity market (**Meridian**).

2.5.22 Submitters made the following comments for each of the options individually[7]:

Maintain status quo

2.5.23 Both **RTANZ** and **EECA** considered that the status quo, whilst it is a valid option, will not lead to regulatory certainty as the pressure for review and reform will remain.

Move to MWh charge

2.5.24 **Genesis** is not convinced that there are compelling reasons to move away from HAMI – the distortions do not appear to be materially detrimental.

2.5.25 Does not allocate costs in a consistent way without distortion (**Contact**).

2.5.26 If the Authority decides a signal to SI generators remains appropriate the per MWH charge is preferable to the HAMI charge (**Meridian**).

2.5.27 More efficient to use a capacity rights approach (**RTANZ**).

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[6] Section 3.3.22 of the consultation paper.

[7] Several of the issues, particularly concerning the status quo, have been captured in the costs and benefits Table 4 or earlier comments on HVDC issues. Where they are already summarised, they are not repeated here.

2.5.28 The inefficiency caused by variabilising the charge would seem to be minimal and there would appear to be some benefit to be gained from removing the incentive that HAMI may currently create for South Island generators not to invest in increased peaking capacity and not to operate their existing plant at full capacity during peak demand periods (**Transpower**).

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

Incentive-free allocation to SI generation plant

2.5.30 **Contact** and **Meridian** submitted that this allocation would be 'arbitrary' and would fuel regulatory uncertainty.

2.5.31 Incentive-free allocation would introduce further distortions (**Contact**).

2.5.32 A distortion-free approach would detract from the beneficiary-pays rationale and would eliminate any locational signalling benefits (**Genesis**).

2.5.33 The capacity rights approach achieves this (**RTANZ**).

2.5.34 **EECA** – whilst not directly commenting on this option – submitted that it would favour a distortion-free option.

Postage stamp

2.5.35 Part of the rationale for the NZ-wide 'postage stamp' option for spreading HVDC costs is on the basis that the existing arrangement provides dominant SI generators a (material) competitive advantage when it comes to constructing new SI generation. This advantage, if a valid argument against the existing charging regime, would theoretically transfer to the dominant generators should all generators incur a postage stamp allocation of HVDC charges and therefore detrimental to the smaller and new-entrant generators (**Todd Energy**).

2.5.36 This should be a refuge if all other alternatives offer no efficiency gains (**RTANZ**).

2.5.37 Three submitters had particular concerns about wealth transfer issues, although **Contact** considered that these might be managed via transitioning to the new allocation methodology over time. These concerns are:

(a) This would result in higher prices for end consumers and a wealth transfer from end consumers to SI generators. This is a major issue that the Authority will need to consider carefully against its statutory objective (**Transpower**);

(b) The burden on consumers will be significant would cause consumers to curtail demand to a certain extent and would have a negative effect on any future investment decisions made by the productive sector (**Norske Skog**);

(c) There are already pressures on retail prices from the rate of GST increasing and on going increases in the real cost of electricity driven by such factors as gas and carbon prices. Approaches to lessening the impact on consumers include slowly transitioning away from the existing pricing regime over a period of years or to allocate a portion of the HVDC charge to generators (**EECA**); and

(d) A wealth transfer from SI generators to consumers is likely to have only a small impact on consumers' consumption decisions. It can be assumed that a 10% increase in electricity prices will reduce demand by 2.4%. If residential electricity prices increase by around 0.8% as a result of the HVDC charge being applied to just consumers then this implies that residential electricity demand will decrease by only around 24 GWh. (**EECA**).

9. Do you have specific lower-level issues around the structure and details of HVDC charging that you would like considered in stage 3?

2.5.38 Submitters suggested the following issues.

2.5.39 If SI generators are withholding 100MW of peak generation simply to shift the allocation of costs by HAMI from themselves to other generators, then that would appear to indicate a failure of the electricity market that needs to be addressed, rather than a reason to alter the TPM (**Northpower**).

2.5.40 There needs to be some risk analysis of potential outcomes of going down the paths to the four possible outcomes. However some form of option value analysis should be undertaken to demonstrate conclusively why the HVDC is different to any other interconnection asset in how it should be treated (**Trustpower**).

2.5.41 **EECA** suggested that the TPM and the pricing principles provided for in the distributed generation regulations are reviewed as a whole to establish the extent to which there are inefficient incentives, or disincentives, for the connection of distributed generation.

2.5.42 The 'beneficiary pays' principle should factor in the cost recovery mechanism for such a capital intensive transmission investment, where the benefiting parties are readily identifiable. The main benefactors of the investment would be readily identified by modelling relevant LRMCs and the corresponding cost impacts resulting from the likely investment decisions in each island that would have occurred with and without the HVDC link. This analysis would show that SI generators and NI demand are the historic, current and likely future significant benefactors of the HVDC investment, these parties being the main recipients of the net benefits. A more even spread of net benefits across the total demand side would likely occur with an annual balancing in HVDC directional flows. Should this scenario eventuate, there would seem justification in spreading HVDC costs across all of the demand side (**Todd Energy**).

2.5.43 The consultation paper suggested key questions that need to be resolved in determining the preferred option for HVDC charging. The Commission asked submitters if they could suggest other matters and if they agreed with preliminary conclusions.

14. Can you suggest other matters to be included in the Commission's stage 3 deliberations on charging for HVDC costs?

2.5.44 No submitters suggested any further matters that had not been raised in other parts of their submissions.

15. Do you agree with these preliminary conclusions? If not, please provide reasons.

2.5.45 Submitter views on the preliminary conclusions are given in Table 6.

Table 6 Submitter views on preliminary conclusions

Preliminary conclusions	Submitter views.
(a) There is little or no economic benefit in encouraging NI generation through an HVDC charge on South Island generators (it will not result in a significant decrease in transmission costs).	Agree (**Contact**, **Meridian**, **Trustpower**) Disagree (**RTANZ**) as the conclusion drawn by the Commission comes from a static analysis of the economics, based on already sunk costs, and does not look at the dynamic effects associated with signalling investment costs to the beneficiaries of those investments. The Commission's analysis risks exacerbating the gross inefficiencies that already exist in the pricing methodology whereby significant beneficiaries of transmission investment have large incentives to lobby for these to proceed as they bear none of the costs or are heavily subsidised through the postage stamp approach to pricing that smears costs across consumers who clearly derive no benefit from the investment. Disagree (**Norske Skog**) Unless beneficiaries are charged for investments they will have incentives to lobby for inefficient investments.

(b) The HAMI allocation of HVDC charges is inefficient and should be changed.	Agree that HAMI allocation is inefficient, but does not believe the it should be changed to MWh or incentive-free (**Contact**) Agree (**Meridian**, **RTANZ**, **Trustpower**) Probably (**Norske Skog**)
(c) A per-MWh HVDC charge on SI generators would not cause significant inefficiency.	Disagree (**Contact**) Disagree (**Meridian**) – In Meridian's view a per MWH based HVDC charge is likely to result in a more productively efficient outcome than the current HAMI based HVDC charge but the Commission should investigate the potential dynamic efficiency impacts. Meridian makes suggestions of analysis the Commission should undertake to assess the disbenefits of per MWH based HVDC charge (Meridian, p7-8). Agree (**RTANZ**) A per MWH charge would fix the problem of different capacity generators, but does not fix the allocation problem between large and small generators in the SI, and provides an additional cost on SI generators (**Trustpower**). Probably (**Norske Skog**)
(d) It may be possible to implement a practical and sustainable incentive-free allocation of HVDC charges to SI generators, perhaps by allocating HVDC charges proportional to historical output over some period.	Disagree (**Contact**) Disagree (**Meridian**). It may be technically possible, but this is not the right question; see Meridian's comment 2.5.30. Agree (**RTANZ**) but note that a long time horizon is likely to be required to reduce the inefficiency of the existing HAMI approach. Disagree (**Trustpower**). It will cause subsequent problems with decommissioning of plant and sale of assets. Agree (**Norske Skog**) Making new SI generation exempt of the HVDC charge would remove the problem of uneven incentives for investment.

2.6 Further issues

Connections issues

Submitters commented on arrangements for independently provided connection assets. Some have suggested that, although parties should in principle be able to mutually-negotiate shared arrangements for new connection assets, in practice there is a need for intervention as a backstop. Submitters have also raised other issues in relation to connection arrangements.

2.6.1 The consultation paper asked submitters the following question:

16. Do you agree that connecting parties should be able to negotiate mutually-beneficial access arrangements for independently provided new connection assets? If not, please explain your reasons, giving specific examples where possible.

2.6.2 Contact, Meridian, MEUG, MRP, RTANZ, Norske Skog, Northpower agreed that parties should be able to negotiate mutually-beneficial arrangements for new connection assets. Of those in agreement, **RTANZ** submitted most strongly that: 'there is no way a regulatory system should be designed to facilitate commercially irrational behaviour.'

2.6.3 Todd Energy, Vector and Transpower agreed in principle but noted practical concerns:

- Parties assign different values to the reliability and security required of the assets (**Todd Energy**).
- Parties may not be willing to enter into agreements with their competitors (**Vector**).
- Negotiations can be protracted (eg ESL Ltd and Aurora at Frankton) so it may be reasonable to include a 'game breaker' provision (**Transpower**).

2.6.4 **EECA** did not agree and **MEUG's** agreement was subject to the Authority monitoring outcomes and being prepared to consider intervention if unintended barriers or anti-competitive behaviour emerge.

2.6.5 **EECA** submitted that in some situations potential beneficiaries of a proposed connection asset may not know with certainty the size or timing of the generation projects that they may wish to connect in the future. Such potential beneficiaries will not be in a position to indicate with certainty how much, and when, they will contribute towards a proposed connection asset.

2.6.6 **EECA** submits further that, if the GIT were to be applied to such an investment, Transpower would also have to make a similar evaluation but with potentially the following advantages:

- Potential beneficiaries may be in a better position to disclose potentially commercially sensitive information on project size and timing to a third party such as Transpower; and,
- The GIT process may implicitly accept greater uncertainty around the size and timing of potential generation projects.

2.6.7 Rather than relying on anecdotal evidence we suggest that the Authority progresses analysis recommended in the Phase 1 Transmission to Enable Renewables project to understand the potential generation resource that could be economically unlocked with further transmission investment. This would provide a more robust understanding of the extent to which connection issues could be a problem. (**EECA**)

2.6.8 Transpower, Trustpower and Todd Energy considered three other issues with connection arrangements.

2.6.9 A shift to shallow connection definition could avoid perverse incentives for some customers to expend resources promoting uneconomic investments – such a change would affect only 4% of HVAC revenue (**Transpower**)

2.6.10 **Trustpower** submitted that, in a number of connections to the transmission grid the technical configuration of the connection is different if Transpower is the owner of the connection asset or some other party is. Generally the configuration if Transpower is the owner results in a lower asset requirement, than if another party is. The difference in asset requirement is driven by reliability, technical, or safety issues, but that Transpower requires an additional demarcation at the point of ownership change.

2.6.11 **Todd Energy** noted an issue with existing connection assets. This is an issue present in the current TPM (which can skew a party's position when negotiating access to new connection assets) for allocation of connection costs for shared assets, where the generator is required to fully contribute to cost recovery on the total connection asset capacity required to meet the higher reliability (eg. N-1) required by the demand, and in excess of the reliability (eg. N) required by the generator. This provides a further incentive for the generator to look to embed within the local distribution network, where connection charges are required to be based on incremental costs only, or alternatively seek a connection to interconnection assets to avoid paying a premium for reliability and security not required. A possible solution to remove the distortionary price signals, without moving to a full incremental costs approach, would be for the generators allocation of shared connection asset costs to be based on the ratio of the generators peak asset usage to total capacity able to be serviced by the assets under an N security criteria (i.e. Generator AMI / N-capacity of connection assets).

Static reactive power compensation

Of the three options presented in the consultation paper, submitters generally favoured either option 2 – connection asset definition and option 3 – kvar charging. Transpower presented an alternative variant of kvar charging for consideration. There were strong views against both the status quo and amended status quo which rely on the terms of the Connection Code.

2.6.12 The consultation paper included an appendix 5, on static reactive power compensation which described three options for encouraging efficient investment in static reactive power. The consultation paper asked submitters the following questions:

17. The Commission has developed three options that it considers have potential to encourage efficient investment in static reactive power. Which of these options do you consider best encourages this objective? Please give reasons.

18. Are there other options for the allocation of static reactive power costs that the Commission should pursue?

2.6.13 This summary considers submitter views first on each of the three options, then considers alternatives suggested and other general comments made by submitters on static reactive compensation.

2.6.14 Powerco, Vector, ENA, Transpower submitted in detail on static reactive power compensation. WEL Networks submitted solely on this issue. ENA included a report by SKM as an appendix to its submission[8]. Some submitters gave no comment on this issue (**EECA**, **BusinessNZ**).

2.6.15 **Norske Skog** and **Northpower** gave general comments on the issue but did not comment on the different options. Norske Skog considered that 'causers should pay'; Northpower did not support any of the options.

2.6.16 **Genesis** submitted that work on reactive power is best pursued as a separate project that has a broader common quality, ancillary services and network regulation perspective and should be lower priority than the 'new matters' contained in the Electricity Industry Bill.

[8] Review of EGR Connection Code, SKM, September 2010 available at: http://www.electricitycommission.govt.nz/pdfs/submissions/pdfstransmission/tprstage2options/ENAApp1.pdf

2.6.17 **MEUG** had doubts about the options given that static reactive power is a local issue and so may be difficult to address through market solutions.

Option 1: Amended status quo

2.6.18 Those submitters who commented on this issue did not support this option.

2.6.19 **Transpower** noted that it is physically impossible to achieve a power factor of exactly unity but that the proposed change of definition in the Connection Code to 'unity or leading power factor' would remedy this.

2.6.20 Submitter concerns over this option are as follows.

(a) **Transpower** considered the reasoning used in the consultation paper to explain how the status quo or Option 1 arrangements could operate to incentivise investment in static reactive power assets and recover the cost of that investment is incorrect because:

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

Transpower included a detailed response to Appendix 5 in its submission.

(b) A unity/ leading power factor should not be required and that a power factor standard should not be applied all of the time. For example, EDBs have to accommodate the impact on power factor of distributed generation which can have a significant impact. A more targeted approach would be to require a certain power factor coincident with peak times, but this leads to complexities, such as managing to the GXP or the UNI/USI peak and the uncertainty of knowing when these peaks occur (**Powerco**).

(c) Power factor correction has diminishing returns. For example correcting from 0.90 power factor to 0.93 power factor takes 8.9 kVAR of correction per 100kW of load, and reduces kVA by 3.6 kVA. Whereas correcting from 0.97 to 1.00 takes 25.1 kVAR of correction per 100kW (almost 3 times as much) and reduces kVA demand by 3.1 kVA. Correcting beyond unity is not of nil benefit, it starts to increase kVA again which reduces the network efficiency.

A leading power factor in isolated pieces of network can lead to de-energisation resonance which can destroy connected plant (**Powerco**).

(d) Option 1 will take a long time to implement due to the lead time to renew contracts including a power factor requirement with major connected customers (**Powerco**).

(e) The status quo is not working efficiently because it requires active and ongoing enforcement of contract terms and does not provide a mechanism for discovery of the optimum investment and its location. However, while it does avoid charges being levied where reactive power demand does not require investments in compensation, it provides no signal to improve the energy efficiency of the system (**RTANZ**).

(f) In terms of any increase in line current and losses within an electricity system, there is no inherent difference between lagging and leading power factor (**Vector**).

Option 2: Connection Asset Definition

2.6.21 **Powerco**, **Vector**, and **MRP** preferred this option, and **ENA** considered this option, along with option 3 should be further considered. **RTANZ** considered that this option works best for grid and transmission compensation investment signalling but does not work well for ensuring optimal power factor is maintained at the point of consumption. According to RTANZ, distributors may favour investment in distribution compensation above end user locations because, as an efficiency investment, they are able to make a return on the investment.

2.6.22 Submitters made the following comments in favour of this option:

(a) More flexibility to respond to investment needs (**Powerco**).

(b) It provides an incentive to distributors to invest through the Commerce Commission avoided cost of transmission scheme (**Powerco**).

(c) It provides reactive power certainty at a transmission level, with a relatively simple method of charging customers for the service (**MRP**).

(d) It would be administratively less costly than option 3 (**Vector**).

(e) It will work because if Transpower does not invest then no cost will be faced. If Transpower does propose an investment, distributors will be able to determine whether they can make equivalent investments more cheaply. If distributors can invest more cheaply, they should benefit from the avoided transmission charges (**Vector**).

2.6.23 Submitters had the following concerns with option 2:

(a) The reference in the definition of static reactive support to an asset that is commissioned after a particular date should be removed. If an asset already exists that provides reactive support, there seems no logical reason to exclude it from this regime (**Vector**).

(b) Care will need to be taken in specifying the measurement point – only reactive power consumed on a distribution network should be counted, not reactive power consumed by the grid (**Vector**).

(c) There is no need for any actual minimum power factor requirement. Option 2 essentially creates a price signal for reactive power and as a result all efficient investments to reduce reactive power will be made. If there must be a minimum requirement, Vector recommends 0.95 lagging or leading as the minimum requirement consistent with the recent findings of SKM (**Vector**).

(d) Extending the definition of connection assets to include reactive support assets runs into the problem that investment in these assets would then be subject to the default transmission agreement (**dTA**), and clauses 40.1 and 40.2 of the dTA contemplate investment in connection assets being driven by expectations that the power system will not continue to meet the n-1 criterion or more generally comply with the grid reliability standards. It is not clear that this approach is applicable in most cases to investment in reactive support assets. It would also be difficult to obtain customer agreement to investment in new static reactive support assets when the future benefit of those assets to particular customers was unclear (**Transpower**).

Option 3: kvar charging

2.6.24 **Trustpower**, **RTNAZ**, **Meridian** and **Todd** Energy favoured the kvar charging option. **Transpower** considered that it would seem a sensible approach, but suggested an alternative variant of kvar charging.

2.6.25 Submitters made the following comments in favour of kvar charging.

(a) The market needs to provide the signals for least cost reactive support, co-optimised with the energy market. The present free supply of voltage support from generators is based on the traditional synchronous generator capable of providing reactive power over a standard range, which has now been cemented into the technical requirements. Technologies are changing, such that some technologies supply inferior and some superior reactive support to the transmission grid. Those that are inferior are presently considered for dispensations, while those superior are not rewarded (**Trustpower**).

(b) It appears to be the simplest (**RTANZ**).

(c) Whilst it could be levied only when investment requirement was becoming imminent, it could also be charged on an ongoing basis to consumers to provide an incentive for maintenance of good power factors by applying the cost for situations where a target power factor was not met at peak periods (**RTANZ**).

(d) It will encourage innovation and more cost effective solutions (**Todd Energy**, **Meridian**).

2.6.26 Submitters had the following concerns about kvar charging.

(a) It may be more expensive to implement than option 2 (**Vector**, **Powerco**).

(b) As kvar charging will be a new feature of the regulatory regime, accurately forecasting it is likely to be difficult and distributors face fines for breaching their price paths for inaccurate forecasting. Vector therefore recommends, if a kvar charging regime is introduced, the charges be delayed by one year to avoid forecasting risk for distributors (**Vector**). **Powerco** also had concerns that the kvar charging approach would be harder to forecast transmission costs.

(c) **Vector** disagrees with the Commission's view that the peak period should be the same as used for determining other transmission charges. The need for reactive support is potentially greatest in summer rather than winter. Anytime peaks should be used to identify peak kvar requirements.

(d) In **Vector's** view, the Commission is incorrect where it states that demand in excess of the predicted amount of peak kvars would need to be supplied by dynamic reactive sources in the region. It would be possible (and probably cheaper) to install oversized static equipment to meet this requirement, rather than consuming the capacity of dynamic compensation installed for a completely different purpose.

(e) **Vector** disagrees with the statement that a kvar charging regime could largely eliminate the need for the System Operator (**SO**) to contract separately for dynamic reactive reserves. The SO contracts for voltage support under Part C of the Rules for the same reason that it contracts for interruptible reserve – because in reality events occur that require short term back-up voltage support.

(f) Stranded assets could be a problem (What if hypothetically a region had Transpower static reactive support equipment installed, and then all the distributors in that region found a way to reduce their kvar usage to zero?)(**Meridian**).

Other options

2.6.27 Submitters suggested the following alternatives.

2.6.28 **Transpower**: Treat static reactive assets (other than those requested and contracted for directly by customers) as a subset of interconnection assets. A WACC return on the book value of these assets could be allocated using reactive draw during peak demand periods at each connection location as a proportion of total reactive draw in each region during peak demand periods. This would be consistent with the overall scheme of the TPM and the requirement in the Electricity Act for the TPM to be a revenue allocation methodology.

2.6.29 Mandating the minimum power factor for equipment connected to the electricity networks in NZ **(Northpower)**.

2.6.30 A full market for static reactive power (**Trustpower**).

2.6.31 The previous power factor requirement (of 0.95 lagging across New Zealand) should also be considered as an option for the following reasons (**Vector, supported by ENA**):

(a) The Commission has entirely failed to demonstrate that the old power factor requirement was creating a problem that justifies the expense of a new charging regime.

(b) Vector also draws the Commission's attention to the report by SKM. This report raises significant concerns with the Commission's analysis that led to the introduction of the unity power factor requirement and concludes that, if one only considers the benefits associated with network loss reduction, a sensible minimum power factor for New Zealand distributors would be in the region of 0.95.

2.6.32 Making the current interconnection kW charge a kVA charge, with a minimum acceptable level of power factor (measured at peak time) would be an effective improvement (**Contact**).

Other general comments on static reactive power compensation

2.6.33 Transmission pricing for reactive power should not be considered in isolation to distribution pricing as both need to be aligned to ensure optimum compensation is maintained along the supply chain (**RTANZ**).

2.6.34 Relaxing the power factor limit in the Connection Code to 0.98 is necessary to reduce the need for dynamic reactive support due to the periodic over and under compensation of large blocks of static reactive support in the system (**MRP**).

2.6.35 Induction machine generators (mainly wind turbines) have significant impacts on power factor, and any option must look to address growth areas of wind generation (**Powerco**).

2.6.36 A large number of capacitor banks can make a power system more unstable because their VAR export is proportional to the square of the voltage and proportional to frequency. Just when you need the reactive power to restore performance, their reactive power production is disappearing (**Powerco**).

2.6.37 Switching discrete chunks of capacitors in and out can make voltage prone to step changes that can disrupt power quality (**Powerco**).

2.6.38 Smart meters will have reactive power measurement features that will allow price incentives to flow through to consumers and it seems sensible to use these features (**RTANZ**).

2.6.39 **MRP** suggests investigation of how distributors provide incentives for consumers to ensure the most efficient electrical outcome.

2.6.40 Consideration should be given to whether substantially the same outcome could be achieved at lower cost by mandating a minimum power factor at regional level rather than at individual GXPs ie allowing aggregation across all the GXPs supplying a distribution company in the region (**ENA**). **WEL Networks** and **Vector** also suggested aggregation.

2.6.41 **Todd Energy** submitted that a current untapped potential exists in embedded generation plant that is not required to make its reactive power available for dispatch under Part C:

- Many of these embedded plants operate in a peaking capacity where a credit is received from the distributor for avoided transmission costs through RCPD reduction achieved. As the peaking operation is provided largely independent from nodal price incentives, the embedded generator could also provide reactive power support at peak demand times where adequate incentive exists.
- It would be preferable for the embedded generator to contract directly with Transpower.
- Large industrial plant with synchronous motors installed may also have the ability to produce significant kVAr for export into the network, though perhaps it is more likely that this is already consumed by site load.
- The distributor could also potentially receive a credit from Transpower (where Transpower then recovers the credit from the causers of the investment otherwise required) where net kVAr injection to the transmission network occurs over the relevant peak demand periods.

2.7 Other submitter issues

2.7.1 Finally, submitters made a comments about issues that are either wider than those under consultation, or were relevant to issues raised in the consultation paper.

General considerations that should be made in assessing changes

2.7.2 **Transpower** submitted on a number of points that it believe the Authority should consider:

- That many of the features of the existing arrangements are fundamentally sound.
- There are benefits to stability and simplicity, particularly in a capital intensive industry, and where possible incremental change should be favoured (Similar views were given by **BusinessNZ**, **Powerco** and **Genesis**).
- Compliance costs, transaction costs and the costs of increasing the scope for disputes should be considered (costs that will be born by Transpower and the industry). Definitional clarity and simplicity help to limit these costs.
- The economic impact of TPM pricing signals is generally limited as transmission makes up a small portion of most businesses and households.

Distribution company forecasting

2.7.3 **Powerco** and **Vector** (in relation to kvar charging, bespoke pricing and flow tracing) submitted that distributors face increased risk of breaching their price paths where they are required to forecast inputs. For this reason, distributors are likely to favour transmission pricing options that deliver certainty in transmission prices.

Treatment of Sunk costs

2.7.4 The costs of sunk cost investments and those new investments already committed under the existing regimes (such as the NAaN and NIGU projects) should not be subject to new regimes (**Northpower**).

Competition benefits and options value of transmission investment

2.7.5 Some submitters made comments about the benefits of transmission from a competition perspective. These comments were made in relation to benefits of signalling for economic transmission investments, incentives to defer reliability investments and in general comments by submitters.

2.7.6 **Genesis** commented that omitting consideration of the benefits of transmission capacity in supporting competitive outcomes and on the 'option value' of a robust grid, are likely to bias the Commission towards overrating the benefits of delaying and discouraging transmission investment or encouraging transmission alternatives.

2.7.7 Other related comments were made by Trustpower (2.3.5(a)), Meridian (2.3.20(d)), Genesis (2.4.19(d)).

3. Summary by submitter

3.1.1 This section gives a bullet point summary of each submission. It is not intended to give a summary of each submitter's view on each issue, but rather an assessment of the key messages in the submissions.

Submitter	
	Lines companies
WEL networks	- Submitted only on the static reactive power compensation issues. - Suggests: a minimum range of power factor would be a better compliance target; and aggregating GXPs – some data is included.
Northpower	- Considers change in objective requires Authority to revisit the previous analysis. - Submits that pricing should incentivise generators to locate closer to load rather than expecting consumers to manage their load patterns. - Considers existing regime for HVDC is sound. - Submits reliability investments are only deferrable if the cause of reduced reliability is growth related, not vulnerable equipment. - Strongly disagrees that the three options for deferring reliability investment should be pursued further. - Does not support any of the static reactive power options. - Expresses the view that the costs of committed and sunk investments (such as NAaN and NIGU) should not be subject to new regimes.
PowerCo	- More can be done to incentivise distributors to respond to price signals. - Advises that it is vital that transmission charges are fixed for any given year; the harder it is to forecast prices, the higher the risk of distributors breaching their price paths. - Would like consultation on detailed examples of how any pricing changes would work. - Submits that TPM should support reliable and robust transmission. - Supports development of incentives to use load control to reduce the total cost of delivering electricity. - Prefers option 2 for static reactive power compensation. - Supports exploring less radical changes to the regime. - Supports the option of an independent decision maker having responsibility for the transmission alternatives RFP process.

Submitter	
Vector	- Broadly supports Commission's current thinking. - Submits that the Commission should understand that the Commerce Commission's proposed solution to the 'regulatory anomaly' is unlikely to succeed. - Recommends analysis on benefits of deferring reliability investments be presented to the TPTG. - Submits that options to defer reliability investment will add costs and should face a high hurdle in demonstrating that they are necessary. - Has continued concerns with static reactive power analysis, but views options as a positive step – Vector submits in some detail on the options and is referenced by ENA. - Prefers option 2 for static reactive power compensation.
Generator/retailers	
Trustpower	- Seeks changes to HVDC charge – 'the only valid option is postage stamping'. - Supports some signalling to avoid reliability-driven investment, but as a targeted incentive, not as part of the TPM. - Supports work to improve the transmission alternatives regime.
Genesis	- No reason to prioritise work on transmission pricing; locational price risk work should be progressed as a greater priority and as this work progresses, decisions can be made on transmission pricing. - Favours status quo; no alternatives likely to present sufficient benefits to justify wealth transfers, transition costs and disruption to regulatory stability. - Comfortable with HVDC charge as it is; beneficiary pays rationale remains valid. - Doubts that there are benefits from deferring reliability investments. - Reactive power should be completed as a separate piece of work.

Submitter	
Contact Energy	- Supports finding that there is likely to be limited value in an enhanced locational signal. - Considers that where the options put forward by the Commission for deferring reliability investments have characteristics that support the deepening of connection assets they should be developed further. - Supports improving the transmission alternatives regime. - Supports the Commission's finding that the lack of benefit in a locational signal has repercussions for the HVDC cost methodology. - Submits that a postage stamp allocation of HVDC costs supports regulatory certainty. - Submits that concerns around the wealth transfer impacts of a change to postage stamp for HVDC costs can be managed. - Summaries detail on previous arguments for the HVDC cost allocation.

Submitter	
Mighty River Power	- Is concerned with MDP's ambitious timelines, illogical development approach and high level of regulatory intervention. - Considers there is no comprehensive plan for how to effectively integrate the MDP workstreams. - Considers scarcity pricing should be understood first. - Submits that bespoke pricing will impact directly on market outcomes and may undermine rather than support competition; if there are benefits from bespoke pricing, MRP believes these should be 'soft' signals that are gradually changed over time so generation investment is not distorted. - Has concerns about peaking generation as a viable transmission alternative as it considers the Commission has overstated how much is required (also see MRP SOO submission). - Considers that the fact that Transpower is a potentially conflicted party for transmission alternatives is not the issue; the issue is availability of technology and poorly defined transmission alternative criteria. - Submits DSM must be considered to create the highest benefits for consumers but that the ownership of this capability has to be clarified (Consumers should 'own' their own load). - Still sees some advantage in exploring the tilted postage stamp, bespoke tilted postage stamp and flow-tracing methods in the event that the view on locational signalling changes – eg due to changes in generation technologies or decommissioning Tiwai.

Submitter	
Meridian	- Considers that efficiency should be the prime consideration. - Agrees with analysis that there is limited value in providing for an enhanced (or additional) locational signal to generators. - Submits that the Authority should consult on how it will approach its new purpose statement and objectives, issues of regulatory certainty and wealth transfers, and the pricing principles carried over to the Code and the foreshadowed Code Amendment Principles.’ Meridian included a set of draft guiding principles that was prepared for the CEO Forum. - Has concerns over the transfer of rental rebates for the HVDC link from the SI generators to enable the finding of FTRs. - Recommends further analysis is undertaken on whether there is a disbenefit to a locational signal for generation (particularly the HVDC charge). Meridian suggests a method for this analysis. - Includes detail on the HVDC issues and options.(Questions 5 to 9). - Has concerns about the bespoke pricing proposal including possible distortions to the generation market and incentives for gaming. - Considers that the flow-tracing proposal is ‘interesting’ and more work should be undertaken. - Agrees that introducing an independent assessor to the transmission alternatives regime would be an incremental improvement but continues to have reservations regarding transmission alternatives as a reliable alternative to transmission investment. - Has an initial preference for kvar option for static reactive compensation.

Submitter	
Large Users	
MEUG	- Considers that given that Transpower suggests that there is insufficient time to change the TPM for 2012/13, there would seem to be no point in pursuing an intensive work programme for the TPM. - Submits that risk of imprudent investment being approved should be reduced (with approval handed to Commerce Commission and subsequent review of approval process) and hence additional signalling will not be required in the future - Believes the Commission needs to consider the 'but-for' 'more innovatively as it might be applied to an energy-only market' – MEUG notes that the 'but-for' looks very similar to a one-off load flow analysis that the Commission has considered worthy of investigation. - Questions costs and benefits of HVDC– has concerns and suggests additional analysis that is required on dynamic efficient effects on SI consumer/user investment incentives, the risk of creating incentives for beneficiaries to call for investments that they do not value sufficiently to be willing to pay for, and incentives for the HVDC operator to uncover and meet the service levels desired by those that pay for the HVDC and to lower costs for any given service level.
Norske Skog	- Requests an opportunity for cross submission before the next phase. - Includes some detailed comment on the use of GEM. - Includes detailed comment and an appendix on the HVDC charging analysis. - Submits that costs and benefits of HVDC charging need to be established, and that the wealth transfer will be significant. - Submits that assumptions about demand growth and need for peaking plant in the draft SOO and the consultation paper are dubious. - Considers that the NZIER 'but-for' approach should be seriously considered – flow tracing could be used as part of this. - Considers that the NZIER capacity rights proposal should be seriously considered (referencing research from University of Auckland.) - Considers that reliability investments should only progress if efficient. - **Bespoke pricing -** considers NZ needs more base load so hydro can meet peak demand and to provide firming capacity for wind generation. - **Flow tracing** – this could be used implement a 'but-for' approach. - **Transmission alternatives** – supports independent decision maker.

Submitter	
Rio Tinto	- Strong concerns about the Commission's 'refusal to consider the 'but-for' and capacity rights approaches'. - Includes an appendix on proposed design of Capacity Rights regime. - Considers current review's approach is largely consistent with the Authority's objective. - Does not agree with the Commission's approach to determining whether any form of additional locational signal is necessary. - Includes detailed comment and analysis on HVDC charging costs and benefits. (Including analysis of the same issue Norsk Skog submits on: whether the largest SI generator has a stronger incentive to invest than any other party. (But appears to reach the opposite conclusion.) - Submits that the new regulatory regime with the Commerce Commission assuming responsibility for investment approvals should mean a greater focus on the economics of an investment. - Considers that flow tracing could involve significant swings in charges and will be complex. - Prefers a kvar charging approach for static reactive compensation.
Others	
Opuha Water (embedded in Alpine Energy Network)	- Argues that its injection through Albury should be exempt from HVDC charges as if it was connected at Timaru, it would likely avoid the charges. - Further argues that HVDC charges for embedded generation should be amended to allow for embedded generation to be aggregated with the network demand and not just the immediate GXP as it is a disincentive for embedded generation to locate remotely.

Submitter	
Business NZ	- Has preference for the market to be given a chance to reach a new equilibrium following changes in Electricity Industry Act. - States that results of modelling should not be seen as determinative. - Believes it is important not to underrate impact of the change in the Authority's objective and the Authority needs to provide certainty urgently regarding its interpretation of the objective. - Considers that transmission pricing review modelling is disconnected from broader issues in the market design programme. - Considers that an early statement from the Authority is required on whether this project is a priority. - Is unclear about the importance of the distinction between economic and reliability investments for the purpose of transmission pricing (especially as the Commerce Commission will have responsibility for approval of grid investments and may change the approach). - Considers that improving transmission alternatives should be focussed on incentivising Transpower to appropriately incorporate consideration of transmission alternatives – Commerce Commission should work through this. - Believes all of the options relating to the HVDC should remain on the table – the requirements of the 'other regulatory settings' should be applied in an even-handed way across all options. - Considers business confidence is best promoted by stability.
ENA	- Submission is focused in static reactive power issues and supports a more rigorous examination of the options for 'controlling power factor'. - Includes a report by SKM on UNI and USI power factor requirements. - Supports Vector's more detailed analysis and submission on static reactive power. - Recommends that the Authority: reverts to requiring power factors at GXPs of 0.95 at times of peak demand, or perhaps 0.98; embarks on more detailed analysis on options 2 and 3; and considers whether it is worth mandating a minimum power factor at regional level rather than at GXP.

Submitter	
EECA	- Agrees with Commission analysis showing limited value in enhanced locational signalling for economic transmission investment and high-level analysis on the costs and benefits of HVDC charge. - Includes some analysis on the impact of current HVDC charge on wind generation development that provides some *limited* indication that the HVDC charge *may* be holding up wind development in the South Island. - Gives an initial preference for 'incentive-free' or postage stamp HVDC options. - Considers wealth transfer issues will be an important consideration for HVDC options and is less concerned about regulatory certainty. - Agrees that further consideration should be given to bespoke pricing and flow tracing. - Is less supportive of proposed amendments to transmission alternatives regime – not convinced a third party would add a great deal of value, although urges the Authority to work with the Commerce Commission on ensuring Transpower's regulation includes mechanisms to encourage investment in transmission alternatives. - Particularly comments on whether connecting parties should be able to negotiate access arrangements for new connection assets.
Todd Energy	- Stick with the current TPM, there are more important market-wide changes that will demand stakeholders full attention. - Horse has bolted with respect to deferring reliability investments; introducing mechanisms now might hinder development of the regional augmentation options. - Agree that there could be some localised signals but any approach should be based on the RCPD approach currently used. - Concerns about the treatment of distributed generators.

Submitter	
Transpower	- Strongly oppose flow-tracing. - Oppose the credits for generators component of bespoke pricing. - Bespoke incentive for load could be further investigated, but much more work needed. - No point in tweaking price signals for offtake if transmission charges without addressing pass-through of these charges by distributors. - Agree with MWh rather than HAMI for HVDC charge. - Has concerns of wealth transfer if HVDC is postage stamped (this may not be consistent with the Authority's objective). - Supports a shallow connection definition. - Prefers kvar charging for static reactive compensation. - It is now not possible to gazette a new methodology in time for it to be applied for 2012/2013 pricing year. - With the exception of the allocation of the HVDC charge based on MWh, no changes are sufficiently developed for them to be implemented with out significant further investigation and consultation. - Considers that a further consultation will be required if options such as bespoke pricing or flow-tracing were to be considered.

Appendix 1 Submitter responses to questions

This table contains submitter responses to the questions posed in the consultation paper: *Transmission pricing review: stage 2 options*.

Submitter	Answer	Notes
1. What, if any, bearing do you consider the Authority's proposed objective has on the review's approach to analysis and evaluation to date?		
Contact	Contact maintains its view (noted in q11 of the Stage 1 submission) that the pricing principles should have been reviewed as part of the TPM review, however Contact is satisfied with the thoroughness of the review as it stands. Contact believes the Authority's objective is consistent with the Commissions statutory objectives for setting transmission pricing and sees no reason why this change should materially impact on the reviews analysis to date. Contact also sees no reason why the change from the Electricity Commission to the Electricity Authority would necessarily alter the direction of this review and we would be disappointed if there was a delay to the review programme as a result.	
EECA	No general comments. We briefly discuss the implications of the Authority's proposed objective in relation to the HVDC charge in our response to Question 8.	
ENA	We would expect that the proposed objective "to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers" would lead to a more rigorous examination of the options identified for controlling power factor, which our submission mainly focuses on. The Commission will be aware of the many objections from distributors that resulted from its decision to incorporate unity power factor requirements in the Connection Code, and we would expect the Authority to apply a level of economic analysis to requirements for new investments (in this case in the order of $75 million) comparable to the exacting processes that the Commission has applied in using the Grid Investment Test.	
Meridian	Meridian notes that the regulatory framework, under Part 12, section 12.75 of the forthcoming Industry Participation Code requires that if a conflict arises when applying the pricing principles (section 12.74), that the Electricity Authority should resolve the conflict with the objective of best satisfying the Authority's statutory objective. As the consultation paper acknowledges the Electricity Authority will be an Independent Crown Entity rather than a Crown Agent. This means that the Authority is required to "have regard" to statements of government policy concerning the electricity industry issued by the Minister, rather than "give effect" as is required of the Electricity Commission. However, Meridian understands that MED is currently of the view that there will not be a government policy statement post 1 November 2010. With regards the question of what bearing the Electricity Authority's proposed statutory objective[9] should have on the analysis	Appendix 2 attached - draft guiding principle from CEO Forum

[9] At the time of preparing this submission the Electricity Industry Bill had not been enacted.

	undertaken to date, Meridian considers that the empirical analysis that has been undertaken should not be impacted by any change in the overarching regulatory framework. Good analytical work will always stand on its merits. Meridian does consider that the narrower objective will need to be considered, and the appropriateness of the pricing principles contained in Part 12 reviewed in light of the new objective. Meridian understands that the Electricity Authority intends to consult shortly after its establishment on a draft consultation charter, which contains Code amendment principles[10]. The interaction of these Code amendment principles with the Part 12 pricing principles will be important. A matter the Authority will need to consider is whether the Code amendment principles will have any statutory or regulatory standing, relative to pricing principles that will have been codified. Meridian looks forward to engaging with the Authority on this charter, the Code amendment principles and their relationship with the transmission pricing principles. Appendix Two contains a set of draft guiding principles that was prepared for the CEO Forum for the purposes of beginning engagement with the Authority on such matters. These are provided here as information.	
MEUG	There will be important differences in the governance environment after the Electricity Industry Bill is enacted compared to the status quo as follows: • The Commerce Commission will develop a new GIT that will need to be consistent with the purpose of Part 4 of the Commerce Act; and • The Electricity Authority will have more focus on competition and efficiency. Collectively these changes will lead to better regulatory frameworks to ensure only investments, either reliability or economic, that have a positive NPV and promote the long-term benefit of consumers will be approved.	
MRP	The objective is clear about promoting competition to meet the best long term outcome for consumers. This aligns with MRP's view that, where possible, competition should be the driver for price, not regulation.	
Norsk Skog	Once the Electricity Industry Bill is passed into law we look forward to the Commerce Commission re-writing the GIT and the Electricity Authority concentrating on competition and efficiency. We expect that these changes will ensure that transmission investments will only be approved if they have a positive net benefit and are paid for by beneficiaries.	
Northpower	In Northpower's opinion, the Authority's objective "to promote competition in, reliable supply by, and efficient operation of, the electricity industry <u>for the long-term benefit of consumers</u>" changes the focus significantly to now measure everything in terms of the "long term benefit of consumers".	

[10] Presentation to Regulatory Managers by the Electricity Commission and CEO Designate of the Electricity Authority, 16 September 2010.

	In Northpower's opinion, this will require the Commission to revisit the previous analysis. For instance, Northpower again emphasises that the Pricing Methodology must incentivise generators to locate closer to load centres, rather than expecting consumers to manage their own load patterns to cope with constraints which are due to generators locating in the most remote parts of NZ.	
Powerco	The Authority's aim is narrower than the Commission's, but the goal of transmission pricing generally fits with the Authority's objective of efficiency and security of supply. It is a relatively short time since the Commission established the transmission pricing principles and Powerco is not significantly opposed to them. However, if the Commission now believes that the principles are no longer appropriate then it should review them. Getting the underlying principles correct in the first place would seem to be an essential starting point for the transmission pricing review.	
RTANZ	The current review's approach has been largely consistent with the new Electricity Authority's proposed objective. We note that this objective is consistent with the Commission's principal objective and has a focus on the long-term benefit of consumers.	
Todd Energy	The Authority's objective, even though not yet set in stone, should have been the overriding consideration on the more recent work to date. While with Commission's statement in paragraph 2.3.4 that "its' work up to 1 October 2010 is ultimately governed by the current Act" may be factually correct, it will ultimately be the Authority, working to its objectives, that will facilitate any required change to the TPM. It makes no sense for the Commission to continue working to objectives that are certain to become obsolete in the short term. That said, the approach of the review wouldn't seem at great odds with the Authority's proposed objective. The biggest risk perhaps being a change by the Authority to the transmission pricing principles in Part F.	
Transpower	The Authority's objective does not contain the fairness and environmentally sustainable elements of the Commission's principal objectives, but this change should have no practical implications for the analysis and evaluation of transmission pricing options.	
Trustpower	TrustPower agrees with the Commission's view that the changes to the objectives of the proposed Electricity Authority compared with that of the Commission makes no material changes in the procedures to review the Transmission Pricing Methodology.	
Vector	The EA's narrower objective must have an impact on the analysis and evaluation in the transmission pricing review. When legislation shifts responsibility for a task from one organisation to another and the new organisation has a different statutory objective, it would be very unusual (and, *prima facie*, contrary to the will of Parliament) for that change to have no impact on the analysis, evaluation and decisions that are made regarding the task. Accordingly, Vector submits that the EA must demonstrate that the option(s) it chooses to implement regarding transmission pricing is the option(s) that most promotes competition in, reliable supply by and efficient operation of the electricity industry. Section 42(2) of the Electricity Industry Bill requires that any Code change must include a cost benefit analysis and an evaluation of alternative options for meeting the objective of the Code change. As a result, the EC must	

	also demonstrate that the option(s) it chooses to implement are those that deliver the greatest net benefits.	
2. Do you agree that the Commission has identified the relevant factors in its assessment (paragraphs 3.2.6 to 3.2.13) of whether nodal pricing provides adequate signals for efficient generation and load investment? If not, please explain your reasons.		
Contact	Contact supports the Commission's assessment. Nodal pricing is not perfect due to impact of step investments etc but we see this as adequate with the introduction of a scarcity price signal, and supported by the GIT and deep connection.	
EECA	We agree that the three factors identified by the Commission are relevant to considering whether nodal pricing provides adequate signals for efficient generation and load investment. The practical extent to which consumers are able to respond to nodal pricing is also another important consideration. Many consumers will have limited, if any, exposure to wholesale market nodal price signals. Consumers may also face other barriers that will prevent them from responding to price based signals *in general*, including: • Lack of information on opportunities, or adequate motivation, to invest in demand side management actions; • Lack of access to capital to finance demand side management investments; and, • Difficulty capturing the full benefits of a demand side management investment. For example, a load shifting or shedding investment may provide multiple benefits (deferred transmission investment, deferred distribution invest, reduced exposure to high wholesale market prices), however a consumer may only be able to capture some of these benefits. Most of these barriers relate to market arrangements outside of the scope of transmission pricing. They will still, though, impact on the outcomes of a transmission pricing regime and hence should be taken into account.	
ENA	No. In our view the fundamental weakness of nodal pricing as a mechanism for signalling efficient generation or load investment is its fragility when loads change. A party investing in response to nodal pricing signals reflecting high transmission losses would see those losses drop exponentially as a result, and there is no obvious way of capturing the pre-investment pricing levels contractually, except where a contracting party is in a monopoly situation. Similarly, investments in generation or load in response to a constraint signalled through nodal pricing would see the same effect, possibly heightened if out-of-merit-order generation was being displaced by the new investment.	
Meridian	The Commission has identified three factors that effect whether there is likely to be a benefit from providing enhanced locational signals: • Current nodal prices do not fully reflect the value of lost load during periods of scarcity; • Transmission investment is lumpy, and exhibits economies of scale; and • Regulatory planning approval criteria may mean that there is a conservative approach to investment approval. Meridian agrees that these are relevant factors.	
MEUG	Agree nodal prices, in the current NZ market, may not match perfect pricing signals because the nodal price fails to reach the Value of Un-	

	served Energy (paragraph 3.2.7). There is a risk of post-transmission investment muting of pricing signals (paragraph 3.2.8) but over the long run as the market evolves so energy prices better reflect costs, then that risk is likely to reduce. Once the Electricity Industry Bill is enacted the risk of imprudent investment being approved (the third factor in paragraph 3.2.9) should be significantly reduced as noted in response to Q1.	
MRP	Yes.	
Norsk Skog	Our view is that nodal pricing does not, and will not, overly influence generation and load investment location decisions. Other factors are much more important – such as proximity to raw materials and markets for consumers, and proximity to fuel sources for generation. Regarding the third factor mentioned in paras 3.2.10 to 3.2.14 we hope that the Commerce Commission will not approve any more inefficient reliability investments.	
Northpower	Largely, yes. We are pleased to note that in sub-paragraph 3.2.13 of the Stage 2 Options paper, the Commission has picked up the point made in submissions that transmission investment needs to occur early rather than late, to avoid the asymmetric costs for end-use consumers. However, the Commission's analysis in these sub-paragraphs does not appear to take into account the distortion created by generators not seeing the nodal transmission pricing, apart from the HVDC charge.	
Powerco	Yes, nodal pricing does provide some locational signals to generation and load, but the signals are weak and muted.	
RTANZ	All of the factors discussed are relevant. However, this section should also have discussed the drivers for the location of load, such as population centres and industry, and the drivers for location of generation, such as access to fuel, in order to be complete.	
Todd Energy	Yes - the factors seem reasonable. However in times of above average or excess supply (eg. fuel abundance for renewable-based generation), nodal price incentives for users and investors to manage peak demand will be significantly muted (particularly for peaking generation), with a loss in long-term efficiency benefits. Enduring price signals are required to effect long-term behavioural change required for efficient use of (and thereby investment in) the transmission and distribution system (eg. peak demand management, energy efficiency investments).	
Transpower	Yes, although another factor that is worth considering is the time it takes to implement a transmission investment. As this can be many years, the point at which nodal pricing will signal the need for transmission investment will typically be beyond the point at which efficient investment should have commenced. This is most obviously the case where there is no generation "downstream" of a line that may need augmentation as demand increases.	
Trustpower	TrustPower agrees that in even full nodal pricing signals can be diluted by practical considerations and other economic drivers when implementing a theoretical model in the real world. In itself nodal pricing is only one of the drivers of efficient generation investment, and promoting competition and efficient operation for the long term benefit of consumers.	

	The items raised in paragraphs 3.2.6 to 3.2.13 are generally related to the construction of transmission investments prior to when they would be built if they could be built without economies of scale and without long lead times. In practice this is impossible, so it cannot be said that the investments are economic. On a risk weighted basis the actual outcome does maximise net economic benefits, it just does not agree with the theoretical model, which in itself is a huge simplification of the real world. Nodal pricing will not by itself provide all signals for the efficient generation and load investment. Other factors to consider are: – the positive impacts on competition that a less constrained electricity grid enables; – the need for investors in new generation to consider the overall risk position of locating a generation plant in a new location, given that it is impossible to accurately predict the future spot price of electricity for the economic life a generation plant; and – the many other considerations that load customers have to take into account when locating their businesses. Given the other reasons that exist for building generation investment ahead of the theoretical need in a pure nodal pricing world, it could be argued that the nodal pricing signals are not diluted by this early build, but accept that nodal pricing variations across the electricity system is just one, but important, consideration that investors take into account in their decision making process.	
Vector	Vector agrees that the three factors identified are reasonable. Another relevant factor is the extent to which the location decisions of generation and load are influenced by the electricity prices they face (as opposed to other drivers such as proximity to markets/fuel sources and consent availability).	
3. Do you agree with the Commission's approach (outlined in paragraphs 3.2.21 and 3.2.22) to determining whether any form of additional locational signal through transmission pricing is necessary? If not, please provide reasons.		
Contact	Yes, this seems a reasonable method to compare scenarios given the complexities of assessing future nodal prices.	
EECA	Agreed.	
Meridian	Meridian supports the Commission's analytical approach to determining whether any form of additional locational signal through transmission pricing is necessary.	
MEUG	The consultation paper proposes modelling between perfectly co-optimised investment and a base case or counterfactual assuming no locational signal. MEUG suggest the counterfactual should be the status quo, which does have locational price signals. The correct analysis is therefore to assess the incremental costs and benefits of further enhancing locational price signals against the status quo, not an abstract "no locational signals" scenario. The consultation paper reports results from using GEM to implement the Commission's approach. GEM provides useful information for comparing broad trends such as those in the SOO, but may be of limited use where more precision from say a stochastic model is needed. The submission by Norske Skog Tasman sets out a full critique of the usefulness of GEM as a tool for this analysis.	
MRP	Yes.	
Norsk Skog	No we don't agree. We think that the Commission puts far too much	

	faith in results from the GEM model. We will explain in our answer to question 4 why we believe GEM is not well suited for transmission planning.	
Northpower	In Northpower's opinion, the confusion mentioned in sub-paragraph 3.2.19 is not necessarily lessened by the Commission's new approach. However, if the new criteria lead to the cost of non-optimal placement of generation being borne by generators rather than off-take customers, then that would be a step in the right direction.	
Powerco	The Commission has decided to estimate the potential upper bounds of the economic benefits of providing further locational price signals, rather than exploring if there is a material divergence between actual and optimal transmission expansion. This seems a more realistic approach, although the Commission will still need to be realistic in the benefits it calculates as part of the estimate.	
RTANZ	No. The Commission's approach needs to be an incremental analysis where the cost and benefit of additional locational signalling (beyond nodal prices, connection and HVDC charges and the GIT) is evaluated.	
Todd Energy	The approach would appear to have merit from a high-level simplistic perspective, though the results perhaps highly dependant on the input assumptions used (which we haven't evaluated in detail).	
Transpower	Yes.	
Trustpower	TrustPower agrees with the Commission's approach. However it is important to consider possible negatives from additional locational signals as well, as the modelling data is very high level.	
Vector	Vector considers that this approach would be useful in identifying the maximum possible benefits of providing a price signal, noting that the actual benefits are likely to be lower.	
4. Do you agree that there appears to be limited value in providing an enhanced locational signal to generators to ensure co-optimisation of economic transmission investments and generation? If not, please explain your reasons.		
Contact	Yes, Contact supports the Commission's assessment and view that there is limited value.	
EECA	Agreed.	
Meridian	Meridian agrees that there appears to be limited value in providing an enhanced locational signal to generators to ensure co-optimisation of economic transmission investment and generation. Meridian notes particularly the following conclusions drawn by the Commission: *"GEM produces an NPV of around $14 million from moving to an ideal pricing methodology. Given the margin of error associated with estimating the input parameters for the modelling, it is reasonable to interpret the $14 million as being zero. Even if the $14 million were to be considered a potential benefit of greater than zero, it is important to note that this is an upper bound. In reality, a transmission pricing regime with locationally-varying charges is unlikely to achieve this upper bound, and may – if not precise enough – lead to unintended inefficiencies by over-signalling location costs leading to poor investment decisions around the type, timing and location of generation."*[11]	

[11] Paragraph 3.3.13.

	Meridian queries whether the analysis undertaken will sufficiently capture the impact of the increased HVDC charge (ie post Pole 3 commissioning) on efficient market operation. In other words, does a step change outcome eventuate?	
MEUG	Analysis in Appendix 3 seems reasonable, as an upper bound, for the effect of locational signalling through interconnection costs, but see response to Q3.	
MRP	There does only appear to be limited value, however all modelling is captured by its own assumptions. The result indicates that, at this time, the most important aspect of transmission pricing is the price structure and transaction efficiency. We support further exploring the TPS, BTPS and flow-tracing methods in the event the view on locational signalling changes (e.g. due to changes in generation technologies or decommissioning of Tiwai Point).	
Norsk Skog	Yes we do agree, but not due to the analysis of the Commission. We see no benefit from using GEM to address this question, since it has too many assumptions and inadequacies – many of which are listed in Appendix 3 of the consultation papers. Instead it is our view that since the cost of generation investment and operation will be orders of magnitude greater than transmission investment, transmission charges will have little or no bearing on generation investment decisions. The use of GEM was unnecessary to reach this common sense conclusion. Regarding the use of GEM: GEM is a mixed integer programme model. The main algorithm used to solve it is the branch and bound method whereby integer variables are relaxed and the subsequent linear programme is solved to yield an upper bound objective function. This is compared with the objective function from the best integer solution found thus far. The difference between these two objective functions is known as the bound gap. Generally a % bound gap is selected prior to solving and once the % difference between the two objective functions is smaller the algorithm terminates and the incumbent integer solution is retained as the “optimal” solution. However unless the bound gap is defined as zero it is not possible to claim that an optimal solution has been found. What has been found is the best solution within x% of the optimal. We gather that the Commission generally adopted a bound gap of 0.333%. Given that the objective functions were all around about \$20 billion the best claim that can be made is that solutions within \$67 million of the optimal solution had been found. Benefits of \$14 million or \$16 million are quite rightly interpreted as zero in parts of the main paper[12] and Appendix 3[13], but curiously given some significance in other parts of Appendix 3[14]. We note that the Commission elected to relax binary variables in this	

[12] Consultation Paper, Transmission Pricing Review: Stage 2 Options, Electricity Commission, July 2010, para 3.3.7, 3.3.13

[13] Appendix 3, Analysis of the potential benefits of locational signalling for economic transmission investment, Electricity Commission, July 2010, para 4.1.6 and 5.1.5

[14] Ibid para 5.1.1

[15] https://gemmodel.pbworks.com/f/A+high+level+review+of+GEM+by+CRA.pdf

[16] Ibid para 3.2.5

	analysis. We are not sure if the Commission relaxed all integer variables in GEM, or just those relating to investment and retirement decisions. Nevertheless it doesn't matter since relaxation of any integer variable adds approximations and waters down the integrity of the model. GEM appears to have some unnecessary constraints. Those we have noticed are listed below: 1. Restrictions on volumes of generation plant technology 2. Restrictions on generation from each fuel type 3. Minimum requirement for generation from renewable sources It is our view that it is not good practice to apply constraints to force GEM to produce pre-determined outcomes. These constraints should be removed and GEM left free to choose the most sensible solutions. We note that Charles River Associates (CRA) have identified several other constraints, such as: incremental peak demand can only be met by building new peaking power plants[15]. However the code we have seen does not appear to have this restriction. Nevertheless if CRA are correct this is a flaw and thus we recommend that the Commission engage with CRA or some other independent party and publish a conclusion on the validity of the assumptions underlying GEM. As noted in Appendix 3 GEM is a deterministic model[16]. Exogneous parameters such as demand, inflows, fossil fuel availability and price etc are assumed to be known with perfect information. The Commission notes that it is preferable to adopt a stochastic programming approach, whereby uncertain exogenous parameters are represented using a distribution of possible outcomes. We agree. Considerable thought needs to be applied to the formulation of such models in order for them to be tractable, but in our view it is unreasonable to use a deterministic version of GEM to make any conclusions whatsoever about investment over a time horizon of 31 years.	
Northpower	Disagree. The fact that new generators are being constructed at locations far away from the main load in NZ in the UNI indicates that stronger locational signals are required for generators. In our opinion, there is suitable fuel available close to Auckland. In sub-paragraph 2.2.15 of Appendix 2 of the Stage 2 Options papers, the Commission acknowledged submissions by Northpower, Contact and Transpower relevant to this point and the Commission's analysis in sub-paragraphs 2.2.18 to 2.2.23 of the Stage 2 Options paper indicated that, while difficult to infer, it does not imply that there is no value in this approach. So the Commission's inference in Question 4 appears to be inconsistent with the Commission's own analysis.	
Powerco	Generators are better placed to explain the extent to which a transmission price signal impacts where they build assets. The evidence presented by the Commission suggests that quite a radical change to the transmission pricing methodology would be needed to significantly alter the location of generation. Powerco is opposed to radical change to the transmission pricing methodology and supports the Commission's approach to look at less significant changes.	
RTANZ	No, because the Commission has not used the best approach to this	

	analysis as discussed above. Locational pricing is only valuable when there is something to signal. Once investments have been made and constraints removed the sunk costs cannot be avoided. One way to address the problem is to have a consistent methodology that allocates the cost of investment to those that benefit from them. This is a major feature of the 'but for' methodology and reduces concerns about whether or not locational signals are optimal.	
Todd Energy	The high-level analysis (and associated sensitivity analysis) would seem to support this conclusion, though this response is qualified by our answer above. We would be interested to see some sensitivity analysis around a scenario of significant increase in the uptake of distributed generation, where the O&M costs of DG-capable projects were offset through receipt, under the provisions of the DG Regulations, of transmission costs avoided.	
Transpower	Yes.	
Trustpower	TrustPower does not agree that there is limited value in providing enhanced locational signal to generators. The results of the analysis by the Commission show there is no value. There may also be negative value in applying any locational signal, given that by providing a signal may distort the true merit order of new generation investment.	
Vector	Vector agrees that the analysis suggests that there are limited benefits from providing an enhanced locational signal to generators to promote co-optimisation of generation and transmission investment.	
5. Do you agree that it needs to be determined whether the current locational signal provided by the HVDC charge is causing or is likely to cause inefficient operational and investment decisions? If not, please explain your reasons.		
Contact	Contact supports the Commission's view that there appears to be limited value by providing a HVDC charging signal to only South Island generators but there may be merit in quantifying this further in the stage 3 analysis. As noted previously, this blunt signal has not achieved any efficient generation investment decisions in the New Zealand. It is an inefficient allocation to a subset of participants which is distortionary due to the true opportunity cost of transmission not being fully reflected to consumers.	
EECA	Agreed.	
Meridian	Meridian notes that the Commission has not investigated whether the current locational signal provided to South Island generators will result in inefficiencies or a dis-benefit: *"…the analysis does not show whether there is a significant dis-benefit to a locational signal for generation; rather it suggests there is no or negligible benefit to such a signal."*[17] Meridian recommends that this analysis is undertaken. Meridian suggests that the Commission could assess the dis-benefits of the HVDC charge by: · • First modelling the NPV of future system costs that might arise	

[17] Paragraph 3.3.15.

	if South Island generators are subject to a HAMI based HVDC charge; • Then model the NPV of future system costs that might result if generation and transmission are perfectly co-optimised (the Commission has already undertaken this step); and • Then compare the two results to provide an indication of the dis-benefits of the current HAMI based HVDC charge. Meridian considers that this analysis will form an important input into the next stage, and will help to ensure that a principled, non-arbitrary decision can be made in Stage 3 (ie selection of the preferred option). The Commission's decision framework for considering four options for charging for the HVDC (set out in Figure 2, page 33) starts from the position of considering whether the benefits of incentivising North Island generation (through the HVDC charge to South Island generators) are outweighed by the costs. If the decision framework started from the question 'is an enhanced locational signal necessary' the conclusions that might be drawn may be different. Understanding this will be important in the next stage of the Commission's review of transmission pricing. As a South Island generator that pays approximately 75% of the HVDC cost – currently \$85m per annum and anticipated to increase to \$140m per annum – Meridian considers that this information (quantification of the dis-benefits of the signal) is critical to ensuring a principled and non-arbitrary decision can be made in stage 3 of the Commission's process – selection of the preferred transmission pricing methodology.	
MEUG	Reviewing HVDC aggregate charges, pricing methodology and service levels to ensure they are fit-for-purpose compared to alternatives is the more important question. Locational price signals are just one element to be considered within such a review.	
MRP	Yes	
Norsk Skog	It would be better to consider not only the status quo, but any candidate pricing methodology. If none of the candidates have any advantages in terms of operational efficiency and incentives for investment decisions then there is no justification to change from the status quo.	
Northpower	No. In our opinion, the existing regime for HVDC is soundly based and that is supported by the 2006 decision outlined in subsequent sub-paragraphs.	
Powerco	Powerco has no comment on HVDC matters.	
RTANZ	It is reasonable to investigate whether a particular charging regime is producing inefficiencies. But it is critical that the investigation: • clearly establishes what those inefficiencies are; • determines their root cause; and • recommends remedies that provide a strictly more efficient outcome for the benefit of consumers.	
Todd Energy	Yes, but qualified on the basis of the high-level NPV/CBA analysis presented in the paper and our response to Q9 below. However, this tends to largely disregard the significant amount of past analysis and resulting conclusions that the locational signal	

	provided by the current HVDC charge is warranted.	
Transpower	Yes.	
Trustpower	TrustPower's view is that the present HVDC charge is already causing inefficient operational and investment decisions. In the South Island new investment is being progressed at a sub-optimal level to avoid the present HVDC charging, and new investment is very unlikely to proceed while there is a penalty applied to new South Island renewable generation connected to the Transpower grid. In addition the present HVDC charging regime cause generators to be reluctant to offer infrequently used peaking capability into the market. The marginal cost of the present HVDC charge is well over $100,000/MWh if only dispatched for one 30 minute period. If only dispatched for one five minute period this is even higher.	
Vector	Vector is not aware that the HVDC charge has created any inefficient investment decisions. However, more analysis may be justified to draw a conclusion to this debate.	
6. Do you agree with the high-level analysis provided on the costs and benefits of the current HVDC charging regime? If not, please explain your reasons.		
Contact	Yes. Contact supports the Commissions analysis that shows most of the reasons supporting the current methodology are of questionable relevance, and the initial costs and benefit analysis demonstrates this very clearly.	
EECA	We agree with the Commission's analysis and have the following comments: *Impact of current HVDC charge on wind generation development* An analysis of existing and proposed wind generation projects *may* provide some *limited* indication of the impact of the HVDC charge on South Island wind generation development and the degree of competition in the development of South Island wind generation. This is relevant to costs (c) and (f). Table 1 [in EECA's submission] shows that, by MW installed capacity, there are more existing and proposed wind generation projects in the North Island vs. the South Island, regardless of project status. Project Hayes makes up around 50% of total proposed (awaiting construction, under consent or under investigation) wind generation projects in the South island. We also note that Trustpower have stated[18] that: • They will only build 36 MW of their proposed 200 MW Mahinerangi wind project. The project has been downsized to supply the local network and hence avoid the HVDC charge; and • Their 240 MW Kaiwera Downs wind project will not be progressed under the current HVDC charge regime. Differences in the amount of proposed wind generation developments in the North Island and South Island are likely to be due to a number of factors of which the HVDC charge will be just one. In particular, Connell Wagner[19] indicate that the North Island has a substantially greater economic wind resource potential than the South Island. The ratio of North Island to South Island wind	

[18] Otago Daily Times, 07/09/2010. Article "Blessed, but Cable Costs Remain" by Stu Oldham.

[19] Connell Wagner. 2008. *Transmission to enable renewables. Economic wind resource study. Electricity Commission.*

	resources identified by Connell Wagner, that may be economic in the near future[20], is 1.6. In comparison, the ratio of proposed North Island to South Island wind projects is 3, which may indicate a preference for North island wind resources. Connell Wagner did not, though, consider grid connection costs or project 'consentability' and these factors (amongst others) maybe as important or more important than the HVDC charge in explaining the differences observed in Table 1. Table 1 also indicate that a significant proportion of new wind development in the South Island is being progressed by a single large incumbent generator (Meridian). This supports the view that the HVDC charge provides disincentives for developers without existing South Island generation capacity. *Other benefits* The current HVDC charge may contribute to a less geographical diverse wind generation portfolio. This may increase wind integration costs such as those associated with frequency keeping and wind forecast accuracy.	
Meridian	*Deferring future links (a)* On the basis of the 2010 SOO scenarios, Meridian agrees that the benefits of preventing or deferring the need for a new inter-island link are unlikely to be material. *AC upgrades to support northward flow (b)* Meridian agrees that the benefits of preventing or deferring the need for AC transmission upgrades that support northward flow are probably not material. *Impact on South Island generation investment (c)* Meridian agrees that the cost of deferring some South Island generation options (c) is likely to be material. *Impact on South Island operational decisions (d)* Meridian confirms that it does take into account the HAMI methodology and its impact on Meridian's share of HVDC costs in its operational decisions. The ability of South Island generators to apply for a dispensation from increased HAMI charges as a consequence of a grid emergency underlines the arbitrary and non principled basis of the current charge. Further, it acts as a general distortion on the energy market (during non emergency periods) as South Island generators are not free to exercise operational decisions without penalty. *Investment in incremental South Island generation capacity (e)* Meridian confirms that it has taken into account the HAMI methodology and its impact on Meridian's share of HVDC costs when considering investments in incremental peaking capacity. Therefore, Meridian agrees that cost (e) is material.	

[20] Tranche 1 wind resources, page 12 of the Connell Wagner report.

	Impact on competition in generation investment in the South Island (f) The effect of the current charge is that: • Meridian's competitors have a greater incentive to embed generation options than Meridian does. • It has less of an impact on Meridian's incentive to invest than other parties given the size of Meridian's portfolio. • The charge is likely to act as a significant barrier to entry for new investors wanting to connect plant directly to the transmission grid in the South Island. However, Meridian agrees that this cost is unlikely to be material.	
MEUG	Table 1 of the consultation paper contains the high-level analysis and table 2 summarises the initial assessment. Taking each benefit and cost, and grouped where useful, MEUG note: • The benefits listed in (a) and (b) overlook the "demonstration effect" from not charging for an investment, once made. Not charging the beneficiaries of investments will distort signals for future investments; creates incentive to call for investments that beneficiaries do not value sufficiently to be willing to pay for, because they know that they will not have to pay for them. • The benefits listed in (a) and (b) do not consider the dynamic efficiency effects from investment incentives to South Island users/consumers, who would otherwise invest in North Island, overseas or not at all. • Given the inevitable uncertainty in costing various future generation options in different parts of the country, the estimated costs of (c) are so small that it is not certain whether the incentive of the HVDC charge in relation to NI generation is actually a cost. It could be a benefit if measurement errors were excluded. • Preliminary view that cost (d) is not material appears reasonable. • Agree that there is some disincentive with cost (e), but there are also positive effects. Builders of plant in the South Island who are focused on meeting local demand and not interested in providing power to the North Island still benefit from the link through higher prices in the South Island than there would be without the link, but they also have to pay a share of the costs of the link, even though they are not major beneficiaries. The positive incentive would likely outweigh the negative. Builders of South Island peaking plant pay a share of the cost of the link even if they never use it, although they also benefit from higher prices in the South Island than there would be without the link. That peaking plant would generate only when prices were high anyway. Overall there is likely to be a net benefit rather than net cost. • Further investigation is needed of whether suggested cost (f) is reflected in how South Island generators actually make investment decisions. In other words we are doubtful if this is in practice an impediment to competition to build new	

	generation in the South Island. The anecdotal evidence is that, apart from Meridian, there are several existing and new investors in generation that have been progressing possible projects.	
MRP	Yes. However, we support more detailed analysis on the HVDC charge's effect on inefficient operational and investment decisions.	
Norsk Skog	Benefits (a), (b) and (c) We do not have as much faith in the GEM analysis based on the draft 2010 SOO scenarios as the Commission appears to have. The future is unknown (especially over 30+ years) and it is not inconceivable that additional HVDC capacity will be required at some stage. We are concerned with the notion of not bothering to charge beneficiaries on the basis that investment doesn't appear to be required. If beneficiaries are not charged, they will have an incentive to lobby for investment, whether it is required or not. Since the costs are based on GEM analysis and fall within the margin of error they are insignificant and no conclusions can be drawn. Benefit (d) We question the Commission's conclusions, and note that there are no calculations provided to support the Commission's assertion that the value of cost (d) is somewhere in the low end of the 0 to $100 million range. SI hydro generators may prefer to spill at times of high inflows rather than generate in order to manage their HVDC charges. This is a poor outcome regardless of what is ascribed to the value of the water. Benefit (e) Severen Borenstein, James Bushnell and Steven Stoft wrote an excellent paper titled *The competitive effects of transmission capacity in a deregulated electricity industry*[21] in which they show that In a symmetric equilibrium involving two geographically separate electricity suppliers, a line of sufficiently high capacity between the two regions gives a duopoly solution, even though it transmits no flow in equilibrium. The application to the New Zealand electricity market is obvious. Any South island generator, including peaking plant, receives a higher spot price with the HVDC than they would have without it. Whether or not they use the link is irrelevant. The HVDC creates a national market, even if no power ever flows across it. Benefit (f) Arguments regarding this question have been around a long time and we decided that it might be useful if we approached the problem using algebra. Our contribution is attached as an appendix to this submission. It appears to us that those who claim that Meridian does have a stronger incentive to invest than any other party are indeed correct. It can be argued that existing South Island generators receive the same reduction in charges regardless of whether they, or another party, makes a new investment. This is true, but it is also true that the largest existing SI generator has the highest incentive to invest, since the reduction in charges depends on the existing generation	Appendix included on benefit f

[21] The competitive effects of transmission capacity in a deregulated electricity industry, S. Borenstein, J. Bushnell and S. Stoft, RAND Journal of economics, Vol. 31, No. 2, Summer 2000

	capacity. To illustrate the point consider a hypothetical example: suppose that g_1 is the only incumbent. Then g_1 pays all the HVDC charges. If g_1 increases capacity they will still pay all the HVDC charges so g_1 can ignore these in their investment decision. New entrant g_0 on the other hand will have to pay HVDC charges if they increase capacity from 0, and thus can not ignore these charges in their investment decision. We are not sure if this is a material problem, but if it is then it can be easily resolved by charging only existing SI generators for the HVDC. Existing generators obtained their assets under the premise that they would always pay for the HVDC costs, including any repairs and replacements, and thus have no reason to complain. Please note that with this proposition there would be no greater incentive to invest in the North Island than the South Island, and some might argue that this is a problem.	
Northpower	No. The Authority just needs to ensure the generators do not withhold peak generation simply to shift HVDC costs from themselves to other generators. The single test is now the “long term benefit of consumers”, not the pro9fitability of the generators.	
Powerco	Powerco has no comment on HVDC matters.	
RTANZ	Not all of it. It would also be useful for the Commission to clearly delineate costs and benefits that relate to the allocation (incidence) of the costs to South Island generators and those that relate to the structure of the charge. <u>Incentives for NI Investment</u> Paragraph 3.3.31(c) asserts that the incidence of the HVDC charge may provide an incentive for less economic generation investments to occur in the North Island, ahead of more economic investments in the South Island. Appendix 4 concludes that this inefficiency may have a value of up to $16m and is material. Such a conclusion rests on an assumption that the incidence of the HVDC charge is inefficient (too high) and/or the incidence of transmission charges on NI generators is also inefficient (too low). This raises the whole question as to whether or not generators are paying efficient levels of transmission charges. <u>Disincentives for Operating Plant at Full Capacity</u> This is clearly a function of the structure of the charge, rather than its incidence. If it is a real problem then solutions should be developed, but it is noted that the Commission’s preliminary view is that it is unlikely to be material. RTANZ supports this view. <u>Disincentives to Invest in New Peaking Capacity</u> The value of SI peaking capacity is in providing generation when there is high southwards transfer across the HVDC and generally high nodal prices in the SI. In these circumstances total offered SI generation is insufficient to satisfy total SI demand and power must be ‘imported’ from the NI. The way to eliminate this disincentive is to change the structure of the charge so that it does not fall on SI generators when power is imported into the SI. Perhaps the simplest way to do this is to charge for power ‘transported across the HVDC’ at a rate that is estimated to recover the costs of providing the link. A simple charge for purchasing capacity to transport power across the link is all that would be required and could be built into the System Operator’s generation dispatch algorithm for all grid-connected generators in both islands. In this way, NI generators would also contribute to the	They included some tables which didn’t copy well

	cost of the HVDC. This has been variously described as a capacity-rights approach and we, along with MEUG, discussed this idea in our submissions on this issue in December 2009. It is considerably disappointing that the Commission was quick to dismiss it, especially as a similar approach appears to work satisfactorily in the gas transmission sector. It is strongly recommended that the Commission reconsider the capacity-rights approach. RTANZ had commissioned a further report from NZIER earlier this year to provide more detail as to how such an approach would work in practice. This report is appended to this submission and it forms part of the submission. Cost of Reduced Competition in Generation Development This is not a real problem. The allegation that this is an issue that needs active consideration, if not remedy, relies on an incorrect specification of the counterfactual situation. Using the Commission's data in footnote 27 on page 26 of the paper, the correct economic analysis is set out in the tables below. **Symmetric Opportunity Cost of Investing in SI Generation** [Submission includes tables which are not included here] This analysis correctly utilises the relevant economic costs and clearly demonstrates that anyone investing in new generation in the SI faces exactly the same HVDC opportunity cost, regardless of who they are or how big their existing portfolio is. The reason that the alleged asymmetry appears is because of the mistaken counterfactual that assumes that if one party fails to make the investment, then no one else will. If investment opportunities are not taken up by Meridian and no other party is able to take up that opportunity (or another), then this is not evidence of an inefficiency introduced by the structure and allocation of the HVDC charge. It more likely suggests potential inefficiencies in other areas such as ownership and control of unused resource consents. Regardless, there is nothing that should be done to an efficient cost allocation to alleviate this imagined problem. To do so would admit that the regulatory regime is designed to chase phantoms.	
Todd Energy	We don't substantially disagree with the high-level analysis of the Commission (though South Island generators may be in a better position to provide a perspective on costs) considering the substantial HVDC upgrade has now been approved, with the accompanying loss of any deferral benefits. On the assumption SI generators are likely evaluating new generation opportunities in the SI, and these additional projects are likely to increase the functional operating and peaking capacity of these incumbents, it is perhaps hard to comprehend that costs (d) and (e) should be material. A further potential cost of the current HVDC charging regime is that it could provide incentives for inefficient embedding of generation, or create an uneven playing field in favour for those line companies looking to invest in generation for retailing in their own network. See also our response to Q9.	
Transpower	Yes.	
Trustpower	The analysis carried out by the Commission clearly suggests that there is no benefit in discriminating against new South Island generators. In fact there is merit in not discriminating as this may defer the need for further South Island investment if the appropriate generation is developed in regional South Island rather than investment in new transmission.	

	TrustPower is surprised at the Commission's view in (f) of Table 1, where it states it has not investigated the result of reduced competition caused by the present allocation method of the HVDC charges. The present charges effectively give Meridian a significant competitive advantage in the South Island generation development market. This cannot be good for the competitive electricity market. TrustPower recommends that the Commission look at this aspect in more detail. In addition all the analysis shows that there is no evidence of any benefit of charging South Island generators for the HVDC charges. There is greater evidence that loads north of Whakamaru are causing the need for the upgrade to Auckland. The HVDC charge is an anomaly of history and should be fixed now.	
Vector	Vector agrees that the costs and benefits identified are the appropriate factors to consider.	
7. Do you agree that the Commission has correctly identified the four possible options for the HVDC charge? If not, please explain your reasons and provide alternative options.		
Contact	Contact believes that for the reasons outlined in section 3.2.22 – 25 it is unlikely the status quo can remain a valid option. Contact also believes that the fundamental issues with the existing methodology limit the potential value of the MWh and inventive free options. The analysis suggests the benefits of dis-incentivising SI generation do not outweigh the costs, and that the focus should be on options which move costs to either load, or a mixture of generation and load, via postage stamp allocation.	
EECA	Another option may be to slowly phase out the existing pricing regime and phase in Option D, as suggested by NERA[22]. This could address concerns around wealth transfers and regulatory certainty.	
Meridian	Meridian agrees that the Commission has identified four possible options for the HVDC charge. However, Meridian notes that there are a number of alternatives within these options which could also be considered by the Commission in stage 3. For example: The Commission notes in paragraph 4.3.1 (d) that the postage stamp option could be implemented by spreading costs widely over load and/or generation in both islands. In the event that the Commission considers that a separate HVDC charge remains appropriate Meridian considers that the option of splitting the incidence of the HVDC charge across NI loads and SI generators should be considered in stage 3. Also, consideration should be given to sharing the incidence based on capacity utilisation (this could reflect change in flows during dry/wet years).	
MEUG	The four options in figure 2 summarise the 4 broad categories that should be considered further.	
MRP	Yes.	
Norsk Skog	Yes, though derivations of the main themes are possible. An incentive-free allocation to SI generation plant can be achieved by only charging existing SI generators for the HVDC. This could be achieved, as the Commission suggests, by charging according to HAMI over a past period of time.	

[22] NERA. (2009). *New Zealand transmission pricing project. A report for the New Zealand electricity steering group*. Page 89.

Northpower	We agree that the Commission has identified four possible options, but it would be inappropriate to say that these are the only possible options until all submissions have been received and published.	
Powerco	Powerco has no comment on HVDC matters.	
RTANZ	No – the Commission's dismissal of a capacity-rights approach, or variant thereof, is a serious omission. The attached paper from NZIER explains in more detail how this will work in practice.	
Todd Energy	The options would seem reasonable, though further qualified by our response to Q9 below. An alternative concept, in keeping with our response to Q9 below, and that is a mix of all four options, is for HVDC costs to be pro-rated each year based on the total annual HVDC flows (MWh) in each direction. North-flow HVDC cost allocation: Shared equally between SI generation (MWh charge based on gross generation volumes reflecting that the embedded generator also receives the benefit of an increased average SI spot price than it would without the HVDC link) and NI demand (via postage stamp adjunct to Interconnection Rate to form a 'NI Interconnection Rate'). South-flow HVDC cost allocation: spread across all demand via a postage stamp adjunct to the Interconnection Rate. This charging concept: a) recognises that HVDC flows are predicted to remain predominantly northwards, with the main benefactors being SI generators and NI demand (as supported by historic analysis), but spreading a relative portion of the costs evenly across all demand in balance with bi-directional flow; b) maintains, but mutes, the locational incentive for NI generation investment with a pricing signal that will be scaled appropriately should the volumes of HVDC south flow increase; c) will potentially deliver cost-benefits on each of the operational and investment issues identified in the consultation paper; d) may help provide some balance on the long-standing and conflicting stakeholder views about who should pay for the HVDC assets, which should result in implementation of a more enduring TPM and accompanying pricing signals; e) will likely lessen the potential wealth transfer that could otherwise result; f) should fully compensate SI generators for the loss in HVDC transmission rentals revenue that will occur should the Commission's (current) preferred FTR solution be implemented under the locational price risk MDP initiative.	
Transpower	Yes.	
Trustpower	TrustPower agrees that the Commission has identified the correct four options. However there does need to be some risk analysis of	

	the potential outcomes of going down the paths to the four possible outcomes. The whole analysis by the Commission has been based on a single number NPV outcome for each of the scenarios. However some form of option value analysis should be undertaken to demonstrate conclusively why the HVDC is any different than any other interconnection asset in how it should be treated.	
Vector	Vector considers that the four options identified are reasonable. As the EC notes, more detailed analysis will be required to determine a preferred option.	
8. What are your views on the validity of each of the options?		
Contact	Maintaining the status quo is not a valid option, The difference between HAMI and MWh allocation still does not address the critical issue of costs needing to be applied in a consistent way without distortions. An incentive-free allocation should be dismissed as it would introduce further distortions. See our more detailed discussion in the body of the report.	
EECA	Given the Commission's high level analysis so far indicates that the benefits of providing incentives for North Island generation are unlikely to outweigh the costs we have an initial preference for Option C or Option D. Wealth transfers We agree that wealth transfers from South Island generators to consumers is an important consideration. While the impact on average retail prices may be one-off and minor, there are already pressures on retail prices from the rate of GST increasing and on going increases in the real cost of electricity driven by such factors as gas and carbon prices. Approaches to lessening the impact on consumers include slowly transitioning away from the existing pricing regime to Option D over a period of years or to allocate a portion of the HVDC charge to generators, as suggested by the Commission. A wealth transfer from South Island generators to consumers is likely to have only a small impact on consumers' consumption decisions. It can be assumed that a 10% increase in electricity prices will reduce demand by 2.4%23. If residential electricity prices increase by around 0.8%24 as a result of the HVDC charge being applied to just consumers then this implies that residential electricity demand will decrease by only around 24 GWh. Regulatory certainty We do not think that regulatory certainty is a particularly strong argument in favour of retaining the HVDC charge on South Island generation. If the underlying reasons for the status quo arrangements are weak, as suggested by the Commission's analysis, consensus within the industry and its stakeholders is unlikely to be achieved. The pressure for review and reform will remain and investors will still, hence, be faced with regulatory uncertainty. On regulatory certainty the Commerce Commission have stated "… a prescriptive approach that minimises uncertainty under current conditions – in other words, 'regulatory commitment' – must be	

[23] Ministry of Economic Development. (2010). *Pricing in the New Zealand electricity market and its economic impact*. Available at http://www.med.govt.nz/templates/MultipageDocumentTOC____26354.aspx

[24] Assuming the existing HVDC charge ($78.33M in 2009/10) is spread over all load on a kWh basis.

	balanced against the need for regulation to adapt and remain applicable as industry and market conditions evolve over time."[25] Market conditions relevant to the HVDC charge have changed with the approval of major upgrades to the HVDC link and to the AC grid to support Northward flow in the North Island. There have also been some generation projects proposed in the South Island which supports the contention that there are still high quality energy resources worthy of further development. These developments suggest the need for regulatory flexibility rather than regulatory certainty. User pays The application of the user pays principle[26] to the allocation of HVDC costs may also be worth considering given that it has been raised already by some submitters. In this regard we support the view that the current HVDC charge is only allocated to some of the beneficiaries of the HVDC link and that the beneficiaries of the HVDC link vary from year to year. Key questions for us include the compatibility of the user pays principle to the Electricity Authority's objective, whether the user pays principle is underpinned by fairness and equity or efficiency considerations and the relative weighting that should be applied between fairness and equity and efficiency considerations.	
Meridian	Status quo – HVDC Charge to South Island generators The original premise for this charge was to provide an enhanced locational signal to South Island generators. The Commission's latest analysis confirms (i) there is no economic benefit to the charge, and therefore (ii) that it is arbitrary. Once a regulator has concluded there is no efficiency rationale for an otherwise arbitrary charge it should be removed. The Commission has acted with credibility in conducting and publishing its analysis. It should now remove the charge. To leave the charge in place in these circumstances undermines the Commission's good work and calls into question the commitment to principled regulation. In addition, the current charge provides an incentive to embed generation within a distribution network. This could result in a failure to maximise valuable resource use, as investors reduce the capacity of the plant to fit behind the network's load (lost opportunities for achieving potential greater economies of scale). Also, it could result in increased losses within a distribution network. Per MWh charge & incentive free allocation Meridian considers that both these options are essentially a variation on the theme of taxing South Island generators. Given the GEM analysis, Meridian considers that the case for providing an enhanced locational signal has not been made and therefore does not consider that a charge of this nature is appropriate. Adopting an incentive free allocation to this charge would, in	

[25] Commerce Commission. 2009. *Reset of default price-quality path for Electricity Distribution Businesses. Discussion Paper*. Page 18.

[26] Rule 2.1, Part F, Section IV Transmission Pricing Methodology.

	Meridian's opinion, put industry participants on notice that the Authority is not above arbitrarily loading costs onto transmission customers where it thinks short term consequences will be small. What is at stake here is long term confidence in the regulatory regime, and an early opportunity to establish the reputation of the Authority. In the event that the Authority decides that a signal to South Island generators remains appropriate, Meridian considers that the per MWh charge is preferable to the current HAMI charge. However, Meridian does not consider that the empirical analysis undertaken thus far supports such a decision. Postage stamp In terms of considering the appropriateness of a postage stamp charge, Meridian considers that the Authority should consider: • Analysis previously presented by Meridian that showed that Meridian (and likely other South Island generators) will suffer a private detriment from the HVDC Pole 3 upgrade with the current HVDC charge; • That there are a range of beneficiaries. Meridian has previously acknowledged that South Island generators are beneficiaries of the HVDC link, but are not the sole beneficiaries. North Island loads are also a significant beneficiary. During dry periods South Island loads and North Island generators are beneficiaries; • The HVDC link is an integral part of maintaining a national wholesale electricity market, to the benefit of all market participants and electricity consumers; • The lack of efficiency rationale for the current charge, highlighting its arbitrary nature; and • The impact of the Authority's proposed statutory objective, the requirement to consider 'other regulatory factors' and the pricing principles contained in Part 12 of the Industry Participation Code during Stage 3.	
MEUG	Cannot state a view without undertaking a cost-benefit-analysis. Note MEUG comments on shortcomings of the analysis of the existing regime in Q6 above.	
MRP	Each option warrants further investigation. MRP supports a change that has clear benefits.	
Norsk Skog	The costs and benefits need to be established before we can form any views. The windfall gain to SI generators (and burden falling on consumers) from moving to a postage stamp for HVDC also needs to be taken into account. Some might argue that this is simply a wealth transfer and can be ignored. We do not think it can be ignored. The burden on consumers will be significant, and such an outcome would cause consumers to curtail demand (productive output) to a certain extent and would have a negative effect on any future investment decisions made by the productive sector.	
Northpower	The options are valid options for the HVDC charging regime, but they are not necessarily all worthwhile options.	
Powerco	Powerco has no comment on HVDC matters.	
RTANZ	The comments below are fairly general as it is difficult to take a firmer position without a thorough analysis of the efficiency gains to be had	

	from any option and any inefficiencies that may arise. In other words, discriminating amongst them is difficult without a full cost benefit analysis. Maintain Status Quo The status quo is generally a valid option and remains so here. However, it does not address the ongoing rancour around the allocation of the charge. Move to per MWh Charge Agree that this is valid, but consider the concept could be much more efficiently implemented using a capacity-rights approach as discussed in the attached paper by NZIER. Incentive-Free Allocation The capacity-rights approach achieves exactly this and the Commission needs to consider this fully. Postage-Stamp This is the refuge when all else is argued to be a failure. Although a valid option, it should not be considered until all other alternatives are clearly established to offer no efficiency gains over a postage stamp approach.	
Todd Energy	Part of the rationale for the NZ-wide ‘postage stamp’ option for spreading HVDC costs is on the basis that the existing arrangement provides dominant SI generators a (material) competitive advantage when it comes to constructing new SI generation. This advantage, if a valid argument against the existing charging regime, would theoretically transfer to the dominant NZ generators should all NZ generators incur a postage stamp allocation of HVDC charges and therefore detrimental to the smaller and new-entrant generators.	
Transpower	At this stage, there appears to be a reasonable case for retaining the charge, but moving to MWh injected rather than HAMI as the allocator, since the inefficiency caused by variabilising the charge would seem to be minimal and there would appear to be some benefit to be gained from removing the incentive that HAMI may currently create for South Island generators not to invest in increased peaking capacity and not to operate their existing plant at full capacity during peak demand periods. Charging on a per MWh injected basis would add an extra variable element to the cost of South Island generation which may disincentivise South Island generation at times of low prices, with a consequent increased risk of hydro spill, but the cost of this would seem to be small. The main impediment to postage stamping the HVDC charge is that this would result in higher prices for end consumers and a wealth transfer from end consumers to South Island generators. This is a major issue that the Authority will need to consider carefully against its statutory objective.	
Trustpower	The only valid option is Postage Stamp. All other options are based on economic analysis that does not demonstrate any benefit within any reasonable margin of error.	
Vector	See question 7.	
9. Do you have specific lower-level issues around the structure and details of HVDC charging that you would like considered in stage 3?		
Contact	Contact believes that options which consider the relative benefits of postage stamp allocation of (the equivalent of) HVDC costs over load, or a mixture of load and generation, should form the basis for the detailed discussion in Stage 3.	

EECA	We have no specific lower level issues with regard to HVDC charging. With regard to the impact of the HVDC charge on distributed generation we would prefer that this issue is not considered in isolation. We suggest that the transmission pricing methodology and the pricing principles provided for in the distributed generation regulations are reviewed as a whole to establish the extent to which their are inefficient incentives, or disincentives, for the connection of distributed generation.	
Meridian	Meridian considers that the majority of the key issues around the structure and details of the HVDC charging regime have been addressed in stage 2. However, Meridian considers that it is important that analysis is conducted to investigate the dis-benefit of providing an enhanced locational signal to South Island generators in stage 3. Suggestions of how this could be done are provided in our answers to Questions 5 and 15.	
MEUG	No.	
MRP	No.	
Norsk Skog	Only those concerns we have mentioned in our answers to other questions.	
Northpower	If South Island generators are (according to the Commission's analysis) withholding 100MW of peak generation simply to shift the allocation of costs by HAMI from themselves to other generators, then that would appear to indicate a failure of the electricity market that needs to be addressed, rather than a reason to alter the TPM. The electricity market is supposed to ensure that generation is offered and dispatched in the appropriate price-stack order if there are no physical constraints in the transmission system.	
Powerco	Powerco has no comment on HVDC matters.	
RTANZ	No, but thank you very much for asking this question. It is time for the opponents of HVDC cost allocation to South Island generators to finally put up all of their objections to it for public scrutiny. Should they fail to do so after this request, the Commission should dismiss any further allegations of real or imagined distortions arising from the allocation or structure of the HVDC charge.	
Todd Energy	The Commission's analysis and resulting arguments in support of potentially removing the locational signals from the HVDC cost recovery mechanism would appear to have been formed based on a national net benefit perspective only. The 'benefactor pays' principle should factor in the cost recovery mechanism for such a capital intensive transmission investment, where the benefiting parties are readily identifiable. The current HVDC revenue requirement contributes over 50% of the total cost of the transmission system, and this proportion will only increase	

[27] Without the HVDC link, the average SI wholesale price would fall while the NI average price would increase. The latter would negate any potential advantage of NI generation gaining access to higher SI prices during a dry year as the HVDC link erodes the average price that would otherwise be realised by NI generation.

	following the pending HVDC upgrade. In the case of the HVDC, the main benefactors of the investment would be readily identified by modelling relevant LRMCs and the corresponding cost impacts resulting from the likely investment decisions in each island that would have occurred with and without the HVDC link. This analysis would show that SI generators and NI demand are the historic, current and likely future significant benefactors of the HVDC investment, these parties being the main recipients of the net benefits.27 A more even spread of net benefits across the total demand side would likely occur with an annual balancing in HVDC directional flows. Should this scenario eventuate, there would seem justification in spreading HVDC costs across all of the demand side.	
Transpower	No.	
Trustpower	HVDC charging should not be treated any differently to the HVAC network. This has been clearly shown by the analysis carried out to date. If there are any lower level issues raised, these should equally apply to the HVAC charging.	
Vector	No comment.	
10. Do you agree with the analysis provided in the section headed "Analysis of benefits of signalling reliability-driven investment"? In particular do you agree with the conclusion that any incentive through the TPM which defers future reliability-driven transmission investment will likely provide some net benefit? If not, please explain your reasons.		
Contact	Contact supports the view that avoiding or deferring investment in reliability transmission assets should be encouraged where it is economic to do so. Contact also believes there would be greater benefit in optimising investment in the gas and electricity transmission network which would highlight the efficiency gains that may have deferred or avoided the NIGU and NAaN projects.	
EECA	We have no issues with the Commission's analysis.	
Meridian	Meridian is concerned that the Commission applies a materiality test to the conclusion that "any incentive through the TPM which defers future reliability driven transmission investment will likely provide some net benefit". Meridian has previously submitted, for example in relation to Grid Support Contracts and Upper South Island investment options, that delays in investing in transmission should not occur if the result is reduced competition in the energy market. Transmission alternatives, particularly generation options, could lessen competition because, among other things, they do not support two way flows.	
MEUG	Disagree, consider it unclear and missing the point that this additional signalling will not be required in future under the new decision-making arrangements discussed in response to Q1, which will prevent approval of reliability investments that do not provide positive net benefits. Requiring beneficiaries of an investment to pay for that investment	

	would provide them with incentives to choose the option that provides the highest net benefits, which may in some cases be a transmission alternative.	
MRP	Maybe. This analysis needs to be done in more detail. We are concerned the high level benefits may be overstated due to bullish SoO peaking generation and DSM assumptions. That is, if peaking generation and DSM is not available (e.g. due to economics, more strict transmission alternative criteria, or a lack of technology) then the amount of reliability investment deferred will be overstated. Our concerns on peaking generation and DSM were raised in our 2010 SoO submission.	
Norsk Skog	We do not wish to see any inefficient reliability driven investment. All investment should have a positive economic benefit and be charged to beneficiaries. We question whether the draft SOO makes sense. The assumptions about demand growth and a need for peaking plant seem dubious. Building base-load plant makes more sense to us, with hydro used to meet peak demand and firm wind generation.	
Northpower	It is not clear whether the Commission is implying in sub-paragraph 3.4.17 that the NAaN augmentation could have been deferred if generation had been built north of Auckland in time. From our involvement in the NAaN conference, Northpower's understanding of the situation was that the NAaN project was primarily approved because the existing HEN-OTA 220kV line is vulnerable to HILP events and will require conductor replacement within a few years. Due to the underbuild, conductor replacement is not practical until the alternative NAaN route is commissioned. So reliability-driven investments are only deferrable by DSM or local generation if the cause of reduced reliability is growth-related, rather than being a consequence of vulnerable equipment.	
Powerco	The Commission has used scenarios in the Draft 2010 SOO to estimate that the NPV of the difference between forecast reliability investments with and without the demand side firming plants is approximately $250-300 million (in 2015 dollars). Powerco agrees that there do seem to be opportunities to improve demand side management, but the right regulatory incentives need to be in place. Please see Powerco's response to question 12 which relates to this matter.	
RTANZ	No – the analysis is insufficient to draw such conclusions. Further, the new regulatory regime with the Commerce Commission assuming responsibility for investment approvals will almost certainly mean a much greater focus on the economic merits of an investment. This means arguments that rest on appeals to reliability, but cannot be sustained economically, are likely to fail to be persuasive.	
Todd Energy	Yes. See also the comments in body of our submission. Reliability-driven transmission investment has historically had a significant competitive advantage over local generation, as a valid transmission alternative, as the transmission investment has been justified through the value placed on unserved energy (VoLL), a value that the generator has never been able to access though the nodal price received for its generation or any other locational incentive, but required to compete on a level playing field as an	

	alternative to transmission investment.	
Transpower	No, the analysis provided by in the section headed "Analysis of benefits of signalling reliability-driven investment" seems to be seriously deficient in that it appears to take no account of the additional cost of peaking generation plant relative to the cost of transmission, or the additional cost of demand side management, including the loss of utility contingent on reduced consumption relative to the cost of transmission investment. The answer to the question must be no, as there will only be a net benefit if the incentive leads to investment in peaking generation or demand side management that is more cost effective than the transmission investment it is displacing. An incentive set at more than the long run marginal cost (LRMC) of the transmission investment would be likely to incentivise a transmission alternative that would produce a net cost from the national perspective. The consultation paper seems to suggest that transmission reliability investments are an entirely separate class from economic investments and there is no relationship between the two. In reality, however, both types of investment are evaluated in the same way, by applying the grid investment test, but on the Core Grid, for reliability investments, the distinction is that, while the highest NPV option that meets the n-1 criterion is chosen, this option does not need to be NPV positive. Another way of looking at the difference between the two is that, on the Core Grid, the value of lost load (VoLL) may effectively be higher for reliability investments than it is for economic investments and, consequently, the value of transmission investment that may be justified may be higher (although not necessarily so). Hence, the GEM analysis that the EC used to test the possible net benefits of a general TPS could also be used to test the bespoke TPS concept, simply by increasing the cost of transmission to reflect the increased transmission investment that may sometimes be justified by the deterministic reliability investment criteria. The Commission has already done this to some extent when it tested the sensitivity of the results of its 18 region version of GEM by doubling transmission investment costs. The result of this test was in an increase in net benefits to just $27.3million, which, relative to total costs of c.$20billion, was still within the margin of error. Given that the two regions where a bespoke TPS could possibly be justified based on the future need for reliability investment would be the Upper North Island and Upper South Island, it would seem reasonable to undertake some further sensitivity testing using the 18 region version of GEM to see or a more granulated version if an interconnection charge tilt reflecting the LRMC of future transmission investment in those regions would provide a significant net benefit as a result of changing the economics of generation investment. However, the work done to date suggests that such analysis would be unlikely to conclude that there would be a significant net benefit. The availability and reliability of a single shaft peaking generator is such that it could not deliver a level of reliability equivalent to that provided by grid augmentation. It would take three generating units operating independently to deliver reliability equivalent to the 99.9 per cent availability provided by transmission, if each unit operated independently and had a 90 per cent availability rate. It is not clear how a simple market incentive in the form of the generator credit element of a bespoke titled postage stamp charge could incentivise generators to invest in multiple peaking units, when this would be unlikely to be the most commercially attractive option for them.	

	Other issues relate to the variability of LRMCs and market power concerns. For a full discussion see section 4 of the submission proper above. There may be some scope for providing a bespoke incentive to encourage further demand-side management in regions where substantial new transmission investment is forecast. The differential "n"s used by the current regional coincident peak demand (RCPD) allocation method already do this to some degree and some offtake customers respond to the signal provided. It may be possible to augment this incentive by adjusting the RCPD signal based on estimates of LRMCs in the Upper North Island and Upper South Island regions. However, considerable further work would be needed to establish that any such adjustments could be done in a way that was robust, transparent and reasonably durable and consistent over time. The disincentive to respond created by the ability of distribution companies to pass through transmission charges would also need to be addressed.	
Trustpower	TrustPower agrees that there are specific areas where some signalling to avoid reliability driven investment could have economic benefit. However TrustPower believes this could be a targeted incentive, rather than forming part of the transmission pricing methodology.	
Vector	The analysis regarding the benefits of signalling the value of reliability-driven investments is reasonable in theory. However, it is light on comprehensive data and it is unclear if the actual benefits are significant enough to justify a change to the transmission pricing regime. Vector notes the statement in paragraph 3.4.6 the EC paper *An integrated cost-benefit analysis of the Market Development Programme* that, depending on option design, the EC's initial analysis suggests benefits of around $200 million (present value) from enhanced locational signalling for deferring reliability investments. Vector would be interested in seeing this analysis and recommends that it be presented to the Transmission Pricing Technical Group for review, once it has been more fully developed.	
11. The Commission has decided not to pursue the options outlined in paragraph 4.1.8. Do you agree with the Commission's assessment (including the analysis contained in section 5 of Appendix 2) that these options are not worth pursuing? If not, please explain your reasons.		
Contact	Contacts supports the Commissions view that the options outlined in section 4.1.8 are not worth pursuing for the reasons provided.	
EECA	No comment.	
Meridian	Meridian agrees with the Commission's decision not to pursue the options outlined in paragraph 4.1.8, namely augmented nodal pricing, market-wide tilted postage stamp, NZIER 'but for' analysis and the arbitrageur/capacity pricing approaches proposed for the HVDC.	
MEUG	MEUG agrees with the proposal not to further pursue the high level options of augmented nodal pricing and market-wide tilted postage stamp. The 'but for' approach cannot be the same as the PJM approach because NZ does not have a capacity market that is an integral part of the PJM 'but for'. Appendix 2 of the consultation paper discusses this and also refers to work by Castalia for Transpower on issues with the PJM 'but for' approach. MEUG believes the EC needs to consider the 'but for' approach more innovatively as it might be applied to an all energy market. Indeed the 'but for' approach looks very similar to a one-off load flow analysis that the Commission has considered	

	worthy of further investigation. The capacity rights and arbitrageur options for the HVDC are more complicated than the status quo as the consultation paper notes. However they would have additional advantages in automatically addressing the South Island peaking plant investment disincentive problem outlined in response to Q6 (cost (e)) above and allowing flexibility to allocate charges to users even if, over time, north to south flows become more frequent.	
MRP	Yes. The augmented nodal pricing and 'but for' options are too complex.	
Norsk Skog	We agree that augmented nodal pricing and any form of tilted postage stamp are not worth pursuing. We think that the NZIER "But For" approach should be seriously considered. Flow-tracing could be used to determine but for whom the investment is needed and thus identify the beneficiaries that should pay for the investment. The Commission appears to be inconsistent with dismissal of the capacity rights options for HVDC charges on the basis that there is no need for further investment, but on the other hand wishes to pursue options for treatment of HVDC costs. We are aware of research from the University of Auckland[28] that concludes that capacity rights for the HVDC are welfare enhancing if generator market power is addressed. The Commission should read this paper and seriously consider the NZIER's proposal.	
Northpower	Northpower agrees with the Commission that the options in sub-paragraph 4.1.8 (Augmented nodal pricing; Tilted postage stamp; "But for"; NZIER HVDC approach) should not be pursued further. The approaches in sub-paragraph 4.1.9 (Incentives for participants to take action where there are benefits in doing so; and Options for HVDC costs) appear to be a sensible limit on the scope of changes to the existing TPM that, in Northpower's opinion, is working quite well. We disagree that the work proposed in sub-paragraph 4.1.10 (Flow-tracing to allocate some network costs) should be considered as a component of the options in sub-paragraph 4.1.9. However, we would again emphasise Northpower's view that any analysis must include the driver for the generators to bear more of the costs of the interconnected grid to reflect the cost of generators choosing to locate remote from the main load centres, and to incentivise new generation to locate in the UNI.	
Powerco	The options the Commission has decided not to pursue are augmented nodal pricing, a market wide tilted postage stamp, the NZIER "but for" approach and the NZIER HVDC charging approaches. Powerco has not seen any sufficient cost benefit justification for any of these options, so can not easily comment on if the proposals are worth further investigation. We support the Commission's approach to look at encouraging people to defer reliability investment, but this	

[28] Allocating physical capacity rights on an electricity transmission line, AB Philpott and LN Huang, 2 Aug 2010, www.epoc.org.nz/papers/HVDCpaperv3.pdf

	needs to be carefully considered in light of the way EDBs are regulated under the Commerce Act.	
RTANZ	Agree that augmented nodal pricing and tilted postage stamp approaches should not be pursued. Very strongly disagree that 'but for' and capacity rights across the HVDC should not be pursued. 'But For' Given the Commission's lack of support for 'but for' RTANZ is surprised that the Commission is now wanting to pursue 'flow tracing' in order to allocate some network costs. The logic behind flow tracing is very similar to that underpinning a GIT analysis, which in turn underpins the 'but for' approach. It is difficult to understand how the Commission can dismiss 'but for' on the basis of: "…its complexity, likely subjectivity and difficulty of implementation;"29 yet begin developing a flow tracing approach to allocating network costs. The flow tracing approach will almost certainly be more complex, involve greater subjectivity and be more difficult to implement than the 'but for' approach. This is because 'but for' is likely to be similar in practice to a one-time application of flow tracing looking at power flows driving the need for investment and thus identifying the beneficiaries of the investment. Thus the analysis happens once and the cost allocation is locked in, improving regulatory certainty. Flow-tracing on the other hand could involve significant swings in charges year on year, especially after dry-years. The potential for changes in cost allocation will likely drive lobbying efforts for change and resistance to change. It is difficult to see how this will be less complex, less subjective and easier to implement than 'but for'. In paragraph 5.7.2 on page 69 of the paper, the Commission expresses the view that the 'but for' approach requires Transpower to seek long term contracts with new generators and new loads to underwrite the costs of significant new transmission investment. However, this is not necessary at all. 'But for' is a cost allocation approach and it is not necessary for new investment contracts to be entered into. All 'but for' does is use the data underpinning the GIT for a new investment and allocates the cost of that investment to the grid injection and exit points that will benefit from the investment. As these must be reasonably well identified in order to calculate the benefits of the investment, the allocation is comparatively straightforward. It is possible that there will be a very large number of these, but this will be reflected in the GIT. In fact there is a wealth of information generated by Transpower that can also be used to support a 'but for' approach. Asset Management Plans and the Annual Planning Review will all usefully support the 'but for' approach. NZIER HVDC Options The Commission outlines its opposition to capacity rights and arbitrageur operation of the HVDC in paragraphs 5.7.11 to 5.7.18 of Appendix 2 of the paper. The arguments presented are very weak. A key concern is that both approaches could yield inefficient dispatch. Capacity rights is criticised for the potential for generators not to have acquired sufficient rights to be fully dispatched and so a	

[29] Paragraph 4.1.8(c) of the paper

	least cost dispatch is not achieved. The same criticisms were levelled at the wholesale market when it commenced with two SOE generators in 1996. The pursuit of profit maximisation through market-based competition soon dispelled that myth. A trader that repeatedly makes mistakes through not maximising their position by not ensuring they have sufficient capacity rights won't remain a trader 9 for long. This is a very weak argument put forward by the Commission. The arbitrageur approach is criticised for the potential for the same inefficiency through withholding of capacity. However, such strategic actions by the monopolist would doubtless draw the eye of the regulatory authorities who would amend the rules of operation if there was a detriment to consumers. Again, a very weak argument from the Commission. <u>Free Riding</u> This hoary old chestnut has reared its head again as it always does in this debate. Free-riding is only a concern, from the perspective of economic efficiency, if welfare enhancing investments do not occur because of the ability of hold-outs (free riders) to avoid contributing to that investment. The ability of some parties to free ride on an investment does not necessarily mean that the investment was wrong or that those who fund the investment have been overcharged. In this debate, the concerns put forward about free riders are generally not concerns about economy efficiency. They are more generally concerns about perceptions of equity. However, the regulatory regime that is currently in place is focused on economic efficiency and the new regulatory regime has an even greater focus on this. The Commission needs to have this understanding at the front and centre of its deliberations. At paragraph 5.7.16 the Commission essentially raises the free-riding argument against the capacity rights approach for the HVDC. The argument fails for the reasoning provided in the preceding paragraphs. It is also instructive to note that an exactly analogous situation exists with the status quo in regard to embedded SI generators. They pay no HVDC charges either. If free riding was such an overwhelming concern (as clearly many in the industry would like the Commission to believe) then the solution to this would be the irreducible pricing outcome of postage stamp prices across all injection and off-take points. That is, smear the costs across everybody without regard to the efficiency of such an allocation.	
Todd Energy	Yes	
Transpower	Yes.	
Trustpower	TrustPower agrees with the Commissions proposal to only consider the options in paragraph 4.1.9.	
Vector	Yes.	
12. If the Commerce Commission proposal outlined in paragraph 4.2.16(c) is adopted for the final determination, do you think this will address the regulatory anomaly referred to above?		
Contact	Yes. The local lines companies are well placed to take initiatives to lower the overall cost of transportation to consumers (such as load-control plant, encouragement of embedded generation and various demands side initiatives). This will only occur if there is a financial incentive to drive these combined costs of distribution and transmission down rather than simply "pass-through" without seeking	

	to lower these transmission costs.	
EECA	The Commerce Commission's proposal does make some progress towards addressing the lack of incentives for lines companies to reduce transmission costs for their consumers. We have, though, the following concerns: • It effectiveness, in general, may be limited due to compliance costs and risks; and, • It may not be compatible, or reinforce, the enhanced transmission pricing signals provided by either bestoke postage stamping or flow tracing. *Compliance costs and risks* Under the proposal lines companies will be required to provide information to demonstrate that investments made to lower transmission charges will also lower the total cost of supplying electricity lines services. In this regard the Commerce Commission note that "… Transpower's avoided cost of supplying the electricity lines service may not exactly match the level of avoided transmission charge, as this will depend on the extent to which the Transmission Pricing Methodology reflects underlying costs"[30]. The Commerce Commission have indicated that lines companies will provide this information as part of their annual compliance statement[31]. This ex-post approval of investments made to avoid transmission charges means that lines companies face the risk that such investments will not be approved. Lines companies wishing to invest to avoid transmission charges will therefore be faced with both compliance costs and risks which may reduce the extent to which such investments are made. Lines companies will only be allowed to retain avoided transmission charges for a period of five years after their investment is first approved by the Commerce Commission. There may, though, be on-going costs associated with an investment and it is unclear if such costs will be able to be recovered by lines companies after the initial five year period has ended. *Compatibility with bestoke postage stamping and flow tracing* With bestoke postage stamping if lines companies are to retain avoided transmission charges they may need to demonstrate that they are avoiding or deferring future transmission investments (given that this will may form a component of their transmission charge). This may be difficult in practice if information on the future costs and timing of transmission upgrades is unavailable or uncertain. With flow tracing avoided transmission charges may be less than the underlying avoided cost of transmission. This is because transmission charges will only increase after a transmission investment that serves the lines company's load is made.	
Meridian	Meridian acknowledges the concern that lines businesses have limited financial incentive to reduce transmission costs to their consumers. Has the Commission considered the relationship of this proposal with the requirement under the Electricity Governance (Connection of Distributed Generation) Regulations 2003 that lines businesses share	

[30] Commerce Commission. 2010. *Input methodologies (electricity distribution services). Draft reasons paper*. Page 357.

[31] Commerce Commission. 2010. *Discussion and Draft Decisions Paper: DPP Refinements*. Page 11.

	avoided transmission costs with the relevant distributed generator? Meridian looks forward to further engaging with the Commerce Commission on this matter.	
MEUG	Yes, MEUG agrees allowing non-exempt Electricity Distribution Businesses to retain avoided transmission charges where it can be demonstrated this will be in the long-term benefit of consumers and the share of benefits (that is between the lines businesses and consumers) matches that likely in markets with workable competition.	
MRP	Yes, for non-exempt EDB's. There is a risk the exempt EDB's will not act in the best interest of their consumers. In MRP's view the EC should encourage an environment where the consumer has the property right to their load and can therefore choose the highest value DSM product.	
Norsk Skog	Yes.	
Northpower	No	
Powerco	The Commission has proposed a "flow tracing approach" where if the proportion of flow on any given asset attributable to a particular load exceeds a certain threshold of utilisation (eg 80%), the costs are allocated to that load. As part of this, the Commission is asking if the Commerce Commission's proposal to define Avoided Costs of Transmission (ACOT) "as a result of reducing the overall cost of supply to electricity lines services" will provide adequate financial incentives to EDBs to make more effort to reduce transmission costs. There are too many unknowns at this stage, although we are concerned that this requirement will generate uncertainty for EDBs to such an extent that it will deter investments that are beneficial to consumers. Our understanding is that to recover an avoided transmission charge, Powerco would need to clearly demonstrate that the proposed action reduces the overall cost of supplying electricity. We are unsure of the degree of evidence the Commission will require. As the Commission itself notes,[32] demonstrating the reduced cost will be difficult as EDBs have limited information on the costs to Transpower of operating assets and the costs and charges will change over time. Powerco shares the Electricity Network Association's (ENA) concerns about the "efficiency test" that would be applied by the Commission. We support the ENA submission that a better approach is for the Commission to adopt its recoverable cost framework, but omit the efficiency test. This would ensure that transaction costs and risks for EDBs are lowered, in pursuit of these desirable efficiencies. At the very least the Commission should have a threshold at which approval is sought to avoid creating a barrier to low value transactions. In conclusion, Powerco supports the Commission's intention to develop a mechanism that provides incentives for EDBs to manage some pass-through costs. We look forward to receiving more details from the Commerce Commission to understand how this can work in a way that provides adequate certainty.	

[32] Commerce Commission *"Input Methodologies (Electricity Distribution Services) Draft Reasons Paper"* (June 2010), paragraph 8.4.29 (Example: Avoided Transmission Charges).

RTANZ	Yes.	
Todd Energy	Yes, bit in a perverse manner that will create a further barrier for competition. Allowing line companies to retain avoided transmission charges, where relevant criteria are met, will likely incentivise them to reduce the transmission charge incurred at the GXP. However, as outlined in the body of our submission, this will likely have a significant adverse effect on other investing parties who are forced to contract with the lines company in competing with them to realise the benefits from avoided cost of transmission.	
Transpower	In principle yes. In practice it will depend on how the Commerce commission determines whether or not the avoided charge is a result of reducing the overall cost of the supply of electricity line services.	
Trustpower	A change of the price quality regime by the Commerce Commission to allow non-exempt Electricity Distribution businesses to retain avoided transmission charges should encourage lines companies to pursue opportunities to avoid transmission charges, provided that there is still a requirement to pay avoided cost of transmission to those businesses that are providing the benefit.	
Vector	Not as the Commerce Commission's proposal was presented in the Draft Input Methodology Determination[33]. The Commerce Commission's proposal is flawed in that it envisages an "efficiency test" where it will determine whether the avoided transmission investment reduces the overall cost of supplying electricity lines services. The Commerce Commission has not outlined the process by which it will make such a determination. However, it is highly improbable that a distributor would agree to undertake an avoided transmission investment when the Commerce Commission retains the right to determine whether the distributor can recover the avoided transmission charges. As distributors and Transpower would only reach an agreement for avoided transmission investments to be made where the cost to the distributor of an investment is lower than the cost to Transpower, the "efficiency test" is unnecessary. However, the test will severely stifle the willingness of distributors to make avoided transmission investments, as well as adding an additional level of costs and complexities. The Draft Input Methodologies Determination also fails to provide for the pass through of avoided transmission costs paid by distributors to distributed generators where peak demands are reduced as a result of a distributed generator's supply at peak times.[34]	

[33] Draft Input Methodology (Electricity Distribution Services Input Methodologies) Determination 2010, clause 3.2.4.

[34] The payments by distributors to distributed generation owners reflect the requirements of the Electricity Governance (Connection of Distributed Generation) Regulations 2007.

	More detail on these points can be found in submissions to the Commerce Commission on the Input Methodology Draft Decisions.[35] If the requirement for the Commerce Commission to approve avoided transmission charges before they can be recovered by distributors was removed from the final Electricity Distribution Services Input Methodology Determination, the inclusion of avoided transmission charges as a Recoverable Cost would be a step forward in terms of incentivising distributors to invest in avoided transmission. Avoided transmission cost payments to distributed generators should also be re-instated as a pass-through cost.	
13. The Commission has identified three options alongside the status quo to defer or avoid reliability transmission investments. Do you agree that these options are worth pursuing? Are there other options which deserve further consideration? Please provide reasons.		
Contact	Yes, Contact believes these options are worthy of pursuing further.	
EECA	We support further consideration of bespoke postage stamping and flow tracing. *Compatibility with lines company price quality regulation* We would like to better understand the potential interaction between lines company price-quality regulation and bespoke postage stamping and flow tracing. In this regard there may be issues associated with lines companies retaining avoided transmission charges as discussed in Question 12. Bespoke postage stamping is an adjustment to the existing interconnection charge. Lines companies we be able to pass this signal though to customers in their network without increased risk of breeching their regulated price-quality paths. This is because transmission charges are able to be fully recovered from consumers and are outside of price-quality path control. We are concerned that with flow tracing lines company will be less able to signal *via pricing* the cost of future transmission investment to their customers given that transmission charges will only increase after a transmission investment is made that serves the lines company's load. In effect, this means that lines companies will have no signal to pass through. *Peaking generation bias* As discussed in Question 2 demand side management faces a number of barriers that may limit its uptake even if pricing signals are improved. This may result in an inherent bias to generation transmission alternatives even where these are less cost effective than demand side management transmission alternatives. For this reason we argue that both pricing and non-pricing measures, such as provided for by the existing transmission alternatives regime, will be required to obtain efficient levels of demand side management transmission alternatives. *Transmission alternatives regime* We are less supportive of the Commission's proposed amendments to the transmission alternatives regime. Transpower are in the process of developing their capability to develop transmission alternative projects and we therefore question the extent to which they have a bias against transmission alternatives. We are also concerned that regulatory costs may exceed the benefits of involving	

[35] For example: Vector Ltd, *Submission in Response to the Commerce Commission's Input Methodologies*, 9 August 2010, p.69. Unison Networks Ltd, *Submission on Commerce Commission Draft Input Methodology Determinations*, 9 August 2010, pp. 31-35. Electricity Networks Association, *Submission 5: Processes and Rules Input Methodology*, 9 August 2010, pp. 13-17.

	a third party in the transmission alternatives regime. Under Section 54Q of the Commerce Act the Commerce Commission "… must promote incentives and avoid imposing disincentives for suppliers of electricity lines services to invest in energy efficiency and demand side management, and to reduce energy losses …". Therefore we would urge the Electricity Authority to work with the Commerce Commission to ensure that Transpower's price-quality path includes mechanisms to encourage investment in transmission alternatives.	
Meridian	The Commission has identified 'bespoke postage stamping', 'flow tracing' and 'improving the transmission alternative regime' as options alongside the status quo to defer or avoid reliability transmission investments. *Bespoke postage stamping* Bespoke postage stamping appears to be 'transmission alternatives' under a different name. As a consequence, Meridian has a number of concerns, not limited to: • whether a 'carrot and a stick' type system is an appropriate long term, sustainable investment signal; • the subjectivity of determining the LRMC of transmission in a region; • concerns regarding incentives for gaming – parties may be incentivised to withdraw capacity in order to encourage more incentives at an alternative site, or to receive a credit for refurbishing existing plant so it continues to operate; • the relationship of these proposals to mechanisms that are proposed to address demand side participation/demand side bidding in the competitive wholesale market; and • concerns voiced previously with regard potential distortions from generation transmission alternatives to the competitive generation market. Meridian understands the Commission is undertaking more work in this area, and hopes that these concerns can be addressed in a manner that is consistent with the Authority's proposed statutory objective - promote competition in, reliable supply by, and the efficient operation of the electricity industry for the long term benefit of consumers. *Flow tracing* Meridian considers that this proposal is interesting. If this approach to charging is to be undertaken care will need to be taken to ensure that charges can be sustainable or durable over time, otherwise it will be at risk of criticism for lack of predictability and regulatory certainty. In particular, connected parties need to have some surety of the magnitude of charges and how these may change over time as new investments (whether demand or transmission) are made. Meridian considers that more work should be undertaken in this area to assist participants in understanding the long run implication of this option. *Improvements to the transmission alternative regime*	

	Meridian acknowledges that parties have over time had concerns with the potential for conflicts to arise between Transpower's role as 'grid owner' and 'assessor of transmission alternatives'. Meridian agrees that introducing an independent decision maker would be an incremental improvement. However, Meridian continues to have reservations and concerns regarding transmission alternatives, and the desire to ensure that transmission alternatives do not inappropriately delay transmission investments. Transmission is an enabler of both competition in generation and retail, and this must be acknowledged in any comparison of investments.	
MEUG	We do not think these are necessary, if adopt the first best solution, which is to invest in only those of the proposed reliability investments that provide positive net benefits and to have beneficiaries pay for these investments.	
MRP	No, these options should not be considered. Transmission alternatives should be reviewed by the Commerce Commission (CC) as part of the GIT review. The EC considers that a key issue with transmission alternatives is the involvement of Transpower as a conflicted party. We disagree. The EC or CC has the right to audit Transpower's process. In our view the issue is the availability of suitable technology (at the right price) and poorly defined transmission alternative criteria. The EC (or CC) needs to clearly specify service and price thresholds prior to the RFP process. We consider that generation is not a transmission alternative unless strict conditions are met36. In addition, generation as a transmission alternative has the potential to distort the generation investment market and result in inefficient outcomes.	
Norsk Skog	We think that reliability investments should only proceed if they provide positive economic benefits and beneficiaries pay for them. Nonetheless we will make a few comments on the Commission's three options. *(a) Bespoke Postage Stamping* We have concerns with bespoke pricing signals. This seems to be a method proponents would like to use to obtain outcomes acceptable to themselves. For instance para 4.2.3 states *"it may be worth adopting a bespoke approach that imposes a higher charge on loads and provides a positive credit for peaking generators in particular regions where demand growth is driving the ongoing need for reliability investments."* We do not agree with this intention. Our view is that NZ needs more base load plant, allowing hydro to meet peak demand and firm wind. Reliability investments should only be approved if they show a positive net benefit and beneficiaries pay the costs. Bespoke Generation is unlikely to be located in response to pricing signals, whatever they are. Rather generation is likely to continue to be located close to fuel sources. If so then there is simply no point in locational pricing signals be they bespoke or otherwise. Bespoke signals will certainly not be enduring if our experience at Kawerau is anything to go by. Several years ago there was	

[36] Generation should not be considered a transmission alternative without an adequate number of generators (i.e. diversity) and a reliable fuel source (e.g. gas or diesel). Forced and planned outages, or lack of fuel, may result in generation being unavailable at any time.

	insufficient transmission capacity to meet demand in the Bay of Plenty. However the commissioning of a 100 MW geothermal power station at Kawerau has reversed the problem. Now there is, at times, insufficient transmission capacity to get power out of the Bay of Plenty[37]! *(b) Flow tracing* As we observed in a previous answer flow tracing seems well suited to identifying beneficiaries (generation or load) under the 'But For' test. *(c) Improving the transmission alternatives regime* We agree that involvement of an independent decision maker would be a good idea.	
Northpower	Disagree strongly. The Commission appears to be set on perpetuating, and even worsening, the existing regime of expecting loads to meet all the costs of the interconnected grid. In sub-paragraph 4.2.1(a), the Commission suggests giving credits to some generators and levying even higher charges for loads in particular regions which, in Northpower's opinion, would be inappropriate and unfair. At a bare minimum, generators close to major load centres could continue to be exempt from interconnection charges and remote generators could start paying some interconnection charges. The net effect would be similar, but without off-take customers having to shoulder even more costs. In relation to the flow-trace option, the Commission's list in sub-paragraph 4.2.16 of the disadvantages supports the view that no further work should be done on this option.	
Powerco	The Commission has proposed three options for improving the transmission alternatives regime. The key issue being Transpower's competing interest in being the network owner and the entity responsible for conducting the request for proposal (RFP) process. Powerco supports the option of an independent decision maker having responsibility for conducting the RFP process. This provides more certainty to interested parties that proposals will be considered in a unbiased manner. However, we also note that 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. It seems that these issues will also need to be addressed if transmission alternatives will increase.	
RTANZ	No. The focus should be on investments with positive net benefits as this is almost certainly where the focus will increasingly lie under the new regulatory regime. Reliability investments that, by definition, are required to meet the GRS must also be required to have positive economic benefits. The GPS contains the assumption that achieving this level provides	

[37] Whilst part of this problem relates to the connection of the power station to the 110 kV system there are an increasing number of times when equation constraints designed to protect circuits in and out of Kinleith bind and restrict power flowing out of the BOP.

	positive benefits to the economy compared to not achieving the GPS. Therefore the requirement should be that all investments must have demonstrated positive economic benefit.	
Todd Energy	As outlined in the body of our submission, we agree that the bespoke pricing signal may have merit, though the initiative may be undone by some of the complexity the Commission appears seeking from the final design. A review the transmission alternatives process would seem justifiable, though we would be opposed to any measures that are likely to significantly increase transaction costs. The party responding to an RFP will have a good understanding of relevant cost-benefits, and an improvement to the existing arrangement would be for that party to have access to a stream-lined independent review process should they have valid concerns with Transpower's initial RFP or the following analysis used in support of Transpower's final decision. We remain unconvinced any advantages from the flow trace mechanism for network cost allocation will outweigh the disadvantages of likely structural complexity and instability in transmission charges.	
Transpower	In fact, the Commission appears to have identified two options, viz: making an independent decision maker responsible for conducting the RFP process; making an independent decision maker responsible for assessing transmission alternative proposals. We do not agree that these options are worth pursuing. The options are predicated on the assumption that Transpower is biased in favour of grid investment. Transpower does not accept this criticism. In reality, the regulatory framework applied to transmission does not fully compensate Transpower for all the risks and costs it faces when it undertakes grid investment. Expanding the grid is a challenging and difficult exercise which presents many administrative and technical hurdles, as exemplified by the major projects currently in train (the North Island grid upgrade, Pole 3 of the HVDC link and the North Auckland and Northland upgrade). The demands in terms of capital and expertise are very considerable, but Transpower can only ever recover a return on its actual costs and bears the risk of any cost overruns. Hence, we have a strong commercial incentive not to invest unless it is essential to do so in the interests of reliability and security. If it is possible to find a cheaper alternative to grid investment that will deliver equivalent benefits, this will always be attractive to Transpower. Transpower believes that there is scope for making incremental improvements to the evaluation of transmission alternatives and the development and application of grid support contracts, but there is no reason to split elements of grid planning between different parties. All this would do is blur accountabilities and make it more difficult to achieve effective, integrated grid planning. Both the Government and the Ministerial Review have strongly endorsed the policy of having a single grid planner. It would be inappropriate and unnecessary for the EA to diverge from this approach. The purported rationale for the proposed change, i.e. that Transpower is incentivised to favour grid investment over transmission alternatives, is not valid, because the regulatory framework established by Part 4 of the Commerce act provides no such incentive.	
Trustpower	TrustPower agrees with the Commission's analysis of the transmission alternatives arrangement and that further work on these options would be beneficial.	

Vector	The options identified would add more costs, including through the requirement to create a new "expert" adjudicator to second-guess Transpower. Vector submits that creating new regulatory activities should face a high hurdle in demonstrating that they are necessary. The EC (or EA) should assess the costs and benefits carefully before progressing this discussion. In addition, the identified problem (that Transpower may have a conflict of interest) may be less applicable under current regulatory settings. The Commerce Commission has set a draft Cost of Capital input methodology for Transpower that produces an extremely low WACC which is unlikely to facilitate large-scale investment by Transpower. Transpower will therefore have a strong interest in minimising its investment expenditure and may therefore view transmission alternatives relatively favourably while the WACC applies.	
14. Can you suggest other matters to be included in the Commission's stage 3 deliberations on charging for HVDC costs?		
Contact	Contact believes that options which consider the relative benefits of postage stamp allocation of HVDC costs over load and a mixture of load and generation should form the basis for the detailed discussion in Stage 3.	
EECA	Please see our responses to Questions 6 and 8.	
Meridian	As discussed above, Meridian agrees that the efficiency analysis performed by the Commission has laid a sound foundation for decision-making on the TPM. Also, we agree that stage 3 must involve a consideration of other regulatory factors, the Authority's proposed statutory objective, and the interrelationship of Part 12's pricing principles with the proposed draft Code amendment principles. Meridian submits that, given the change in regulatory framework and regulator, stage 3 needs to proceed in two parts. First, the Authority should lead a discussion on the new statutory purpose statement, the pricing principles carried over to the Code, other regulatory factors, and how the consideration of these factors is influenced by the efficiency analysis. The second step is to apply this analysis to the TPM options and select a preferred option.	
MEUG	Three other matters need to be considered: • Dynamic efficiency effects on South Island consumer/user investment incentives (also noted in response to Q6); • The risk of a demonstration effect, whereby it creates incentive for beneficiaries to call for investments that they do not value sufficiently to be willing to pay for, because they know that they will not have to pay for them (also noted in response to Q6); and • Incentives for the HVDC operator to uncover and meet the service levels desired by those that pay for the HVDC and to lower costs (or the rate in cost increases) for any given service level.	
MRP	No.	
Norsk Skog	We would like to point out that throughout the consultation documents we could find no reference to windfall gains to SI generators, and associated burdens to consumers that would arise under a move to postage stamp pricing for the HVDC. As we	

	explained in our answer to question 8 this is a very real and significant matter that must be considered. The decision to charge South Island generators for the HVDC costs was made many years ago and the price paid (or otherwise written into balance sheets) by SI generators for their assets reflected this decision. Any change to allocating HVDC costs to other parties amounts to a windfall to SI generators, and a burden to whoever picks up the costs. ID it is consumers that bear the HVDC cost then inefficient consumption and investment decisions will eventuate. The Commission must take these factors into account.	
Northpower	No. The list in sub-paragraph 4.3.2 gives a fair amount of scope for an in-depth review of the HVDC charges.	
Powerco	Powerco has no comment of the HVDC matters.	
RTANZ	Clearly the Commission has been incorrect to dismiss the capacity rights approach to charging for the HVDC. The Commission's arguments in support of this dismissal are all weak. Therefore, the Commission must actively investigate this option further and so it must be included in the Stage 3 deliberations. There must be an assessment of the benefits of a capacity rights approach and the attached NZIER paper will assist the Commission in identifying these.	
Todd Energy	Not at this stage.	
Transpower	No.	
Trustpower	TrustPower agrees with the matters to be included within the Stage 3 deliberations.	
Vector	No. The list of matters for consideration seems reasonable.	
15. Do you agree with these preliminary conclusions? If not, please provide reasons.		
Contact	Contact supports the view (a) that there is no economic benefit from dis-incentivising SI generation through a charge on SI generators only. Our view remains that charging only a subset of participants is distortionary and does not reflect the true cost of transmission to those best placed to respond to those signals. Therefore we do not agree with the preliminary views noted in 4.3.3 (c) and (d). While we support (b) in that the HAMI mechanism is not efficient, we do not believe the option is valid. The emphasis should be on what proportion of interconnection costs (HVDC costs being included) should be allocated to the generation/load side (on a non-distortionary basis) and how this is best allocated (peak or kWh).	
EECA	Please see our responses to Questions 6 and 8.	
Meridian	Meridian agrees with the statements: • '*There is little or no economic benefit in encouraging North Island generation through an HVDC charge on South Island generators (it will not result in a significant decrease in transmission costs*' (paragraph 4.3.3(a)); and • The HAMI allocation of HVDC charges is inefficient and should be changed' (paragraph 4.3.3(b)).	

	Meridian does not agree with the statement: • '*A per MWh HVDC charge on South Island generators would not cause significant inefficiency*' (paragraph 4.3.3 (c)). Meridian considers that a per MWh based HVDC charge is likely to result in a more *productively efficient* outcome than the current HAMI based HVDC charge. However, Meridian is concerned that the Commission investigates the potential *dynamic efficiency* impacts of a per MWh based HVDC charge relative to no charge. Meridian suggests that the Commission uses its GEM model to examine the impact of levying a per MWh HVDC charge on South Island generators on the combined cost of generation and transmission. Meridian suggests that the Commission could assess the dis-benefits of a per MWh based HVDC charge by: • First modelling the NPV of future system costs that might arise if South Island generators are subject to a per MWh based HVDC charge; • Then model the NPV of future system costs that might result if generation and transmission are perfectly co-optimised (the Commission has already undertaken this step); and • Then compare the two results to provide an indication of the dis-benefits of a per MWh based HVDC charge. Meridian considers that this analysis will form an important input into the next stage, and will help to ensure that a principled, non-arbitrary decision can be made in Stage 3 (i.e. selection of the preferred option). Also, Meridian does not agree with the statement: • '*It may be possible to implement a practical and sustainable incentive free allocation of HVDC charges to South Island generators, perhaps by allocating HVDC charges proportional to historical output over some period*' (paragraph 4.3.3(d)). While as a technical question it might be possible to design a per MWh charge or another charge that does not influence operational decisions in the short term, Meridian submits this is not the right question. A decision by the Authority to load a portion of transmission charges on a sub-group of transmission customers, driven primarily by a judgment that those customers would not be able to pass the charge on and would not have a justification for changing short term behaviour, will be seen for what it is – a very poor precedent. As this accurately describes the genesis and effect of the current HVDC charge, a decision to continue the charge will be viewed the same way. Industry participants will be put on notice that the Authority is not above arbitrarily loading costs onto transmission customers where it thinks short term consequences will be small. As Meridian has previously submitted, there are several other components of the grid that would logically have to be treated the same way[38].	

[38] See slides 14-15 of Meridian's presentation on the Electricity Commission's Transmission Pricing Methodology Guideline's one day conference 24 February 2006. Meridian submitted that HVAC lines - 'Auckland to Northland', 'Waikato to Auckland', 'Christchurch to Nelson Marlborough' and 'Waitaki to

	For these reasons, Meridian submits the issue is not whether a particular charge can be designed to be "incentive free" in the short term. What is at stake here is long term confidence in the regulatory regime, and an early opportunity to establish the reputation of the Authority[39].	
MEUG	MEUG agrees with the preliminary views of the EC that there are options (eg based on MWh usage) that could result in better outcomes compared to the current HAMI based cost allocator for HVDC costs. We emphasise this is only a preliminary view and more detailed analysis is needed. Paragraph 4.3.3 (a) states "there is little or no economic benefit in encouraging North Island generation through an HVDC charge on South Island generators (it will not result in a significant decrease in transmission costs)." This statement is consistent with the analysis in table 1 as summarised in table 2 that we have responded to in Q6 above, ie we believe the assessment is inadequate in that it fails to consider other benefits. These are also listed in response to Q14 above.	
MRP	Yes.	
Norsk Skog	(a) No. The point should be that unless beneficiaries are charged for investments they will have incentives to lobby for inefficient investments. Additionally the wealth transfers associated with a change from charging SI generators will cause windfall gains and losses and send perverse investment and consumption signals to consumers. (b) Probably. (c) Probably. (d) Yes. As we pointed out in our answer to question 6 making new South Island generation exempt of the HVDC charge would remove the problem of uneven incentives for investment.	
Northpower	As they are only preliminary conclusions, it is probably inappropriate to agree or disagree with them until the Commission has studied them in more detail. However, at a high level, they mostly look OK. We query the logic in view (a) because the conclusion in brackets does not appear to be supported by the preceding statement. But that may be a consequence of the double-negative in the construction of the statement.	
Powerco	Powerco has no comment of the HVDC matters.	
RTANZ	Disagree with (a) as the conclusion drawn by the Commission comes from a static analysis of the economics, based on already sunk costs,	

Christchurch' would likely meet the Commission's 'connection like' test. http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/tpg/hvdc-presentations/Meridian.pdf

[39] Meridian refers the Commission to paragraph 3.4.6 of its paper 'Transmission Pricing Methodology Consultation Paper', 1 November 2006. http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/pdfsconsultation/tpmnov06/TPMconsultation- paper.pdf

	and does not look at the dynamic effects associated with signalling investment costs to the beneficiaries of those investments. The Commission's analysis risks exacerbating the gross inefficiencies that already exist in the pricing methodology whereby significant beneficiaries of transmission investment have large incentives to lobby for these to proceed as they bear none of the costs (generators for interconnection investments) or are heavily subsidised through the postage stamp approach to pricing that smears costs across consumers who clearly derive no benefit from the investment. Agree with (b), but note that the Commission has already concluded that the cost of the inefficiency is not material. Agree with (c). Agree with (d), but note that a long time horizon is likely to be required to reduce the inefficiency of the existing HAMI approach. It is useful to note that a capacity rights approach solves many of the concerns raised about the allocation and structure of the existing HVDC charging regime. The Commission must consider such an approach more fully.	
Todd Energy	As per our summary comments and Q9 response, we remain to be convinced with the Commission's assertion that there is potentially little or no benefit in encouraging NI generation over the additional significant transmission investment that is required to accompany increasing SI generation investment. This conclusion would appear to contradict the results of the significant historical analysis already undertaken on the issue.	
Transpower	Yes. See also the response to Q.8 above.	
Trustpower	Considering each of the views in paragraph 4.4.3. TrustPower agrees that there is no evidence of economic benefit from the analysis carried out to date of encouraging North Island generation ahead of South Island generation. TrustPower agrees that the HAMI allocation is inefficient. A per MWh charge on South Island generators would fix the problem of different capacity factor generators, i.e. peaking plant versus base load, but does not fix the allocation problem between large and small generators in the South Island. It also provides an additional cost on South Island generators, which contradicts with paragraph 4.4.3(a), which concludes there is little or no economic benefit in applying an HVDC charge to South Island generators. TrustPower disagrees that it is possible to provide an incentive free allocation, as this will cause subsequent problems with decommissioning of plant and also sale of assets to other parties. It is impractical to create an indefinite obligation on a party to pay for an asset that it may no interest in the future.	
Vector	Vector would need to see the results of more detailed analysis before reaching a view on the EC's preliminary conclusions.	
16. Do you agree that connecting parties should be able to negotiate mutually-beneficial access arrangements for independently provided new connection assets? If not, please explain your reasons, giving specific examples where possible.		
Contact	Yes.	

EECA	We do not agree that, *in all cases*, connecting parties should be able to negotiate access arrangements for new connection assets that are 'right sized' for the generation resource that it could potentially serve. In some situations potential beneficiaries of a proposed connection asset may not know with certainty the size or timing of the generation projects that they may wish to connect in the future. For example, they may not have selected a preferred generation equipment supplier or have gone through the resource consent process (which can impact on the final size of the project). Such potential beneficiaries will not be in a position to indicate with certainty how much, and when, they will contribute towards a proposed connection asset. The Commission's analysis implies that in such a situation, a 'first-mover' may have to make their own evaluation of the size and timing of generation projects that a new connection asset could potentially serve. If the GIT were to be applied to such an investment, Transpower would also have to make a similar evaluation but with potentially the following advantages: • Potential beneficiaries may be in a better position to disclose potentially commercially sensitive information on project size and timing to a third party such as Transpower; and, • The GIT process may implicitly accept greater uncertainty around the size and timing of potential beneficiaries generation projects than would be the case for an individual investor. This suggests that a first mover would not necessarily invest in the 'right sized' connection asset due to either a lack of information or due to a lower appetite for risk compared to a GIT process. If the economic environment is such that a high renewables future is desirable then it is important that there are no undue barriers that prevent access to high quality renewable energy resources. Rather than relying on anecdotal evidence we suggest that the Electricity Authority progresses analysis recommended in the Phase 1 Transmission to Enable Renewables project[40] to understand the potential generation resource that could be economically unlocked with further transmission investment. This would provide a more robust understanding of the extent to which connection issues could be a problem.	
Meridian	Yes, Meridian agrees that connecting parties should be able to negotiate mutually beneficial access arrangements for independently provided new connection assets.	
MEUG	Agree subject to the Commerce Commission and Electricity Authority monitoring outcomes and being prepared to consider intervention if unintended barriers or anti-competitive behaviour emerge. In other words a light-handed approach should be the first step.	
MRP	Yes.	
Norsk Skog	Yes.	
Northpower	Yes	
Powerco	This is a matter that mainly impacts generators so Powerco has no	

[40] Electricity Commission. 2008. *Final report on the transmission to enable renewables project (Phase 1).* Page 86.

	comment.	
RTANZ	Of course they should! If they are unable to do this then this admits either of two possibilities: • the project is not actually economic and therefore commercially not viable for at least one party; or • one or more parties are acting in a commercially irrational way, which suggests a failure in company governance. There is no way a regulatory system should be designed to facilitate commercially irrational behaviour.	
Todd Energy	Agree that, in principle, parties should be able to negotiate mutually beneficial access arrangements. However in practice there can be issues where the parties looking to share the asset assign different values to the reliability and security required of the assets (eg. demand vs. generation). Existing connection assets This is an issue present in the current TPM (which can skew a parties position when negotiating access to new connection assets) for allocation of connection costs for shared assets, where the generator is required to fully contribute to cost recovery on the total connection asset capacity required to meet the higher reliability (eg. N-1) required by the demand, and in excess of the reliability (eg. N) required by the generator. This provides a further incentive for the generator to look to embed within the local distribution network, where connection charges are required to be based on incremental costs only, or alternatively seek a connection to interconnection assets to avoid paying a premium for reliability and security not required. A possible solution to remove the distortionary price signals, without moving to a full incremental costs approach, would be for the generators allocation of shared connection asset costs be based on the ratio of the generators peak asset usage to total capacity able to be serviced by the assets under an N security criteria (i.e. Generator AMI / N-capacity of connection assets).	
Transpower	In principle yes. However, in practice, negotiations can be protracted (e.g. ESL Ltd and Aurora at Frankton) so it may be reasonable to include a “game breaker” provision of some sort as a backstop, if no agreement is reached after, say, one year.	
Trustpower	TrustPower supports the Commission’s conclusions except in one area. Transpower is the dominant supplier in the new connection asset market. In a number of connections to the transmission grid the technical configuration of the connection is different if Transpower is the owner of the connection asset or some other party is. Generally the configuration if Transpower is the owner results in a lower asset requirement, than if another party is. The difference in asset requirement is not as a result of reliability, technical, or safety issues, but that Transpower requires an additional demarcation at the point of ownership change. TrustPower recommends that the Commission investigates this issue further.	
Vector	The EC’s analysis is correct in theory. However, in practice parties may not be willing to enter into agreements with their competitors to share transmission assets, even if it would be rational to do so. The EC is correct to seek real-world examples of cases where access arrangements were not able to be agreed. If some examples are	

	forthcoming, this issue should be re-examined.	
17. The Commission has developed three options that it considers have potential to encourage efficient investment in static reactive power. Which of these options do you consider best encourages this objective? Please give reasons.		
Contact	Contact believes that making the current interconnection kW charge a kVA charge, with a minimum acceptable level of power-factor (measurement at peak time) would be an effective improvement. This supports our earlier view that distributors should be encouraged to lower transmission charges if they were financially incentivised for doing so.	
EECA	No comment.	
ENA	**Covers Q18 as well** ENA supports the more detailed analysis and submission that Vector is making on these issues. To assist the review we attach a paper prepared by Sinclair Knight Merz entitled *Review of EGR Connection Code: UNI & USI Power Factor Requirements*. As a result of this review, SKM note, amongst other things, that: • A key finding is that at system peak the average power factor of both the UNI and USI regions is approximately 0.98. • The costs associated with meeting the unity power factor requirement in the UNI and USI regions are collectively estimated to be NZ$75M. • The EC's economic evaluation of capacitor bank installations: - Overstated the extent of the distribution resistance and thus the possible loss reduction. - Under-estimated the costs associated with capacitor banks (due to switching costs). • If one only considers the benefits associated with network loss reduction then a sensible target power factor for NZ EDBs would be about 0.95. SKM also note that approaches to controlling power factor vary widely internationally, ranging from requirements to achieve levels approaching unity down to transmission authorities allowing power factors as low as 0.8. The Australian requirements range from around 0.95 to 0.98 above 400 kV. In the light of this analysis it would seem that the established practices and pressures driving network development have delivered, and are continuing to deliver, very adequate power factor levels. An investment of the order of $75 million forced by a requirement to achieve power factors of 1 would be well out of proportion to the likely benefits, and would imply higher costs for delivered energy to all consumers. Accordingly we do not agree with option 1. Options 2 and 3 warrant more detailed study to determine whether real net benefits are likely to arise, but we recommend that the Commission reverts to requiring power factors at GXPs to be maintained at levels of 0.95 at times of peak demand, or perhaps 0.98 given that performance at that level has proven achievable without triggering the upward cascade of costs associated with pushing on to unity. Consideration should also be given to whether substantially the same	Note: report attached by SKM.

	outcome could be achieved at lower cost by mandating a minimum power factor at regional level rather than at individual GXPs ie allowing aggregation across all the GXPs supplying a distribution company in the region.	
Meridian	At this stage, Meridian considers option 3 (KVar charge) appears more attractive on the basis that it will encourage innovation and more cost effective solutions. However, some further thought may be necessary – what would happen if hypothetically a region had Transpower static reactive support equipment installed, and then all the distributors in that region reduced their KVar usage to zero because they found a cost effective way of doing this. How would Transpower then recover the cost of its installed reactive support equipment?	
MEUG	No comment, other than that we have doubts about the options, given that static reactive power cannot be transmitted very far, so can result in local monopolies, which are difficult to address through market solutions.	
MRP	MRP's preference is for option (b), the Connection Asset definition option, as it provides reactive power certainty at a transmission level, with a relatively simple method of charging customers for the service. We feel that relaxing the power factor limit in the Connection Code to 0.98 is necessary to reduce the need for dynamic reactive support due to the periodic over and under compensation of large blocks of static reactive support in the system.	
Norsk Skog	Our view is that causers of investment in static reactive power should pay for. We are not sure which of the options best meets this principle.	
Northpower	Northpower does not support any of these options. In Northpower's opinion, the rationale for the "power-factor of not less than unity" requirement in the Connection Code was a theoretical ideal which was intended to achieve a marginal increase the capacity of the grid but it was not tested in an economic analysis.	
Powerco	Covers Q 18 as well One of the issues raised in stage 1 consultation, and which the Commission has explored further, is the approach to allocating the cost of existing and new static power and reactive power assets. Currently there is a power factor standard in the Connection Code (clause 4.4 of the Benchmark Agreement, in Schedule 2 of section II of Part F of the EGRs). This requires that if electricity is being drawn off the grid, the power factor at any point of service to the customer must meet certain standards. **Minimum power factor:** (a) The Customer must ensure that its Equipment does not unreasonably draw on the reactive power resources of the **grid** during each regional peak demand period. If **electricity** is being drawn off the **grid**, the Power Factor at any Point of Service the Customer must: (1) up until 31 March 2010, in the case of demand, maintain a Power Factor of not less than 0.95 lagging at any Point of Service during each relevant regional peak demand period. (2) from 1 April 2010, in the case of demand, maintain a Power Factor of not less than: (i) 1.0 (unity) at each relevant Point of	

Service during each relevant regional peak demand period in the Upper North Island Region and the Upper South Island Region; and

(ii) 0.95 lagging at each relevant Point of Service during each relevant regional peak demand period in the Lower North Island Region and the Lower South Island Region.

This arrangement was intended to incentivise efficient investment in static reactive power and ensure that the causer pays a share of the investment costs.

Powerco supports this aim and agrees that network power factor correction is best applied next to loads and generators. We share the concerns however, of EDBs in the UNI and USI that the unity power factor requirement is a very blunt and inflexible instrument. It seems to have little justification and has not achieved the desired change. We are reassured that the Commission has listened to concerns and is consulting on other options.

Option 1

Powerco does not support option 1. We do not consider that a unity/ leading power factor should be required and that a power factor standard should be applied all of the time. For example, EDBs have to accommodate the impact on power factor of distributed generation which can have a significant impact. A more targeted approach would be to require a certain power factor inline with peak times, but this leads to complexities, such as managing to the GXP or the UNI/USI peak and the uncertainty of knowing when these peaks occur.

In addition, added power factor correction has diminishing returns. For example correcting from 0.90 power factor to 0.93 power factor takes 8.9 kVAR of correction per 100kW of load, and reduces kVA by 3.6 kVA. Whereas correcting from 0.97 to 1.00 takes 25.1 kVAR of correction per 100kW (almost 3 times as much) and reduces kVA demand by 3.1 kVA. Correcting beyond unity is not of nil benefit, it starts to increase kVA again which reduces the network efficiency. A leading power factor in isolated pieces of network can lead to de-energisation resonance which can destroy connected plant.

Option 1 will also take a long time to implement due to the lead time to renew contracts including a power factor requirement with major connected customers.

Option 2

Of the three options, Powerco's preference is option 2. This option seems to provide more flexibility to respond to investment needs. It also provides an incentive to distributors to invest through the Commerce Commission avoided cost of transmission scheme.

Powerco does not support the 0.98 lagging power factor requirement for reasons stated under option 1 (ie it is a blunt inflexible tool).

Option 3

Powerco does not support option 3 as it looks like it would make it more difficult to forecast transmission costs in the default price path. More explanation of this is provided in paragraphs 5-8 of this submission. The option also seems more expensive to implement than option 2.

Additional comments

Power factor correction is a very complex area, and it would be helpful to see more analysis of the issues from the Commission. For example, additional issues to consider are that:

	• induction machine generators (mainly wind turbines) have significant impacts on power factor, and any option must look to address growth areas of wind generation; • a large number of capacitor banks can make a power system more unstable because their VAR export is proportional to the square of the voltage and proportional to frequency. Just when you need the reactive power to restore performance, their reactive power production is disappearing; and • switching discrete chunks of capacitors in and out can make voltage prone to step changes that can disrupt power quality.	
RTANZ	In an AC system, demand for reactive power is created at all points in the supply chain and this leads to inefficient use of system capacity. Reactive power compensation can be most beneficial at the point of energy consumption because reduced loadings will be seen at both distribution and transmission levels. Reactive power compensation at the point of consumption is very distributed and investments tend to be made at the time of appliance purchase (e.g. capacitors in lighting fittings). In the absence of an incentive to maintain power factor consumers will not invest. Reactive compensation at transmission and distribution is 'lumpy' and can respond very quickly when reactive power demand rises to inefficient levels. Given the features of reactive power and investment in compensation, it appears to be sensible that any reactive power pricing signal is seen by both distributors and electricity users and that the signal must be transparent and easy to see and respond to. Transmission pricing for reactive power should not be considered in isolation to distribution pricing as both need to be aligned to ensure optimum compensation is maintained along the supply chain. RTANZ agrees with the Commission that the Status Quo is not working efficiently because it requires active and ongoing enforcement of contract terms and does not provide a mechanism for discovery of the optimum investment and its location. However, while it does avoid charges being levied where reactive power demand does not require investments in compensation, it provides no signal to improve the energy efficiency of the system. The Amended Status Quo recognises that leading power factors may not be driving a need for investment and should therefore not attract a charge. This seems to be a sensible addition to the Status Quo but does not overcome the main issues identified by the Commission for the Status Quo. The Connection Asset definition option is interesting because it is essentially a 'but for' approach. The causer of the need for investment is identified and charged. All things being equal, this	

	should provide an incentive for the causer to look for lower cost alternatives. However, all things are not equal under the current regulatory framework because distributors may favour investment in distribution compensation above end user locations because, as an efficiency investment, they are able to make a return on the investment. RTANZ considers that the Connection Asset option works best for grid and transmission compensation investment signalling but does not work well for ensuring optimal power factor is maintained at the point of consumption. The third option, the kvar Charging Method appears to be the simplest and easily understood option. Whilst it could be levied only when investment requirement was becoming imminent, it could also be charged on an ongoing basis to consumers to provide an incentive for maintenance of good power factors by applying the cost for situations where a target power factor was not met at peak periods. On balance, of the options listed by the Commission, RTANZ considers that a well designed kvar Charging Method is likely to produce the best incentives for optimum and timely investment in compensation along the supply chain.	
Todd Energy	Option 3 (kVAr charging method) would appear to offer advantages in providing signals for more efficient investment in reactive power, particularly on the distribution network side. A current untapped potential exists in embedded generation plant that is not required to make its reactive power available for dispatch under Part C as is its grid connected counterparts. Many of these embedded plants operate in a peaking capacity where a credit is received from the distributor for avoided transmission costs through RCPD reduction achieved. As the peaking operation is provided largely independent from nodal price incentives, the embedded generator could also provide reactive power support at peak demand times where adequate incentive exists (as there is a cost associated with providing the larger levels of reactive power). Large industrial plant with synchronous motors installed may also have the ability to produce significant kVAr for export into the network, though perhaps it is more likely that this is already consumed by site load. While not ideal, through having to enter a contractual arrangement with the distributor with the accompanying transactional issues as outlined in other areas of our submission, the ‘avoided cost’ basis could be readily used to provide the embedded generator with the appropriate credit, assuming the kVAr charging methodology is aligned with the Interconnection Rate and RCPD cost allocation mechanism. The generator would be subject to the ‘penalty rate’ where committed kVAr levels were not achieved. The distributor could also potentially receive a credit from Transpower (where Transpower then recovers the credit from the causers of the investment otherwise required) where net kVAr injection to the transmission network occurs over the relevant peak	

	demand periods. It would be preferable for the embedded generator to contract directly with Transpower.	
Transpower	We would prefer an alternative option. On the face of it, Option 2: extended connection asset definition could be a reasonable approach to take. However, extending the definition of connection assets to include reactive support assets runs into the problem that investment in these assets would then be subject to the default transmission agreement (dTA), and clauses 40.1 and 40.2 of the dTA contemplate investment in connection assets being driven by expectations that the power system will not continue to meet the n-1 criterion or more generally comply with the grid reliability standards. It is not clear that this approach is applicable in most cases to investment in reactive support assets. It would also be difficult to obtain customer agreement to investment in new static reactive support assets when the future benefit of those assets to particular customers was unclear. Hence, Transpower recommends that the Authority not progress Option 2. KVar-based charging or allocation of some form would seem sensible. An alternative approach that could provide an incentive for distribution companies to consider the most cost effective way of providing static reactive support, but avoid the problems associated with extending the connection asset definition as proposed by Option 2, would be to treat static reactive assets (other than those requested and contracted for directly by customers) as a subset of interconnection assets. A WACC return on the book value of these assets could be allocated using reactive draw during peak demand periods at each connection location as a proportion of total reactive draw in each region during peak demand periods. This would be consistent with the overall scheme of the TPM and the requirement in the Electricity Act for the TPM to be a revenue allocation methodology. We note that, for the incentive provided to be fully effective, the classification of transmission charges as pass through costs for distribution companies would need to be addressed. Although this method may still overlap to some extent with the System Operator's procurement of dynamic voltage support, the need for this is expected to be largely eliminated by the forthcoming capital expenditure on Upper North Island reactive support assets (as the consultation paper notes).	
Trustpower	TrustPower supports moving towards a kVAr charge or market. The present free supply of voltage support from generators is based on the traditional synchronous generator capable of providing reactive power over a standard range, which has now been cemented into the technical requirements. Technologies are changing, such that some technologies supply inferior and some superior reactive support to the transmission grid. Those that are inferior are presently considered for dispensations, while those superior are not rewarded. As there are rapid changes to technologies, both load and generation, the market needs to provide the right signals to provide the lease cost reactive support, co-optimised with the energy market.	
Vector	Vector views on the options identified are set out below. <u>Option 1</u> There is no logical basis for this option. In terms of any increase in line current and losses within an electricity system, there is no inherent difference between lagging and leading power factor. If the	

	EC considers that a unity or leading power factor requirement is reasonable, it is essentially conceding that there is no justification for a unity power factor requirement at all. <u>Option 2</u> This option is reasonable, has a logical basis and is Vector's preferred option of the three identified in Appendix 5. We also consider it would be administratively less costly than option 3. This option will work because if Transpower does not invest then no cost will be faced. If Transpower does propose an investment, distributors will be able to determine whether they can make equivalent investments more cheaply. If distributors can invest more cheaply, they should benefit from the avoided transmission charges. However, this is dependent on the Commerce Commission providing actual incentives for distributors to make avoided transmission investments (see discussion above). Vector recommends removing the reference in the definition of static reactive support to an asset that is commissioned after a particular date. If an asset already exists that provides reactive support, there seems no logical reason to exclude it from this regime. Vector notes that care will need to be taken in specifying the point at which measurement of reactive power is carried out – only reactive power consumed on a distribution network should be counted, not reactive power consumed by the grid. This point will require further consultation Vector also considers that the most efficient approach is for measurement to be carried out on a regional basis, rather than individual GXP basis. Finally, Vector opposes the proposal to combine this new definition of a connection asset with a minimum power factor requirement of 0.98 lagging. Option 2 essentially creates a price signal for reactive power and as a result all efficient investments to reduce reactive power will be made. There is therefore no need for any actual minimum power factor requirement. The EC has not provided any evidence or analysis to suggest that setting a minimum power factor requirement produces additional benefits or that 0.98 is the optimal minimum requirement. If there must be a minimum requirement, Vector recommends 0.95 lagging or leading as the minimum requirement, if one must be in place, consistent with the recent findings of SKM (see below). <u>Option 3</u> This option is also conceptually sound. However, it seems more expensive to implement than option 2 and could create difficulties for distributors in terms of their compliance with price-cap regulation under the Commerce Act 1986. Distributors and the Commerce Commission have gone to some lengths to minimise the degree of forecasting required when setting prices under the price caps that apply under Part 4 of the Commerce Act. This is because, if distributors were required to forecast the inputs (e.g. the quantity of electricity sold) of the allowable revenue equation then there is a risk that the forecast will be incorrect and the distributor may accidentally breach the price path. Under the new regulatory regime, a breach of the price path is an offence with a fine of up to $5 million, therefore all parties have a strong interest in avoiding forecasting in order to minimise the possibility of accidental breaches. As transmission charges are passed through by distributors, if kvar charges were to be passed through in the year they occur, distributors would need to forecast the kvar charges for	

	each year. As kvar charging will be a new feature of the regulatory regime, accurately forecasting it is likely to be difficult. Vector therefore recommends, if a kvar charging regime is introduced, the charges be delayed by one year to avoid forecasting risk for distributors. Vector disagrees with the EC's view that the peak period should be the same as used for determining other transmission charges (the 12 highest peaks identified through the RCPD methodology). The need for reactive support is potentially greatest in summer rather than winter. Therefore anytime peaks should be used to identify peak kvar requirements for each distributor. Also, the EC is incorrect where it states that demand in excess of the predicted amount of peak kvars would need to be supplied by dynamic reactive sources in the region. It would be possible (and probably cheaper) to install oversized static equipment to meet this requirement, rather than consuming the capacity of dynamic compensation installed for a completely different purpose. This type of investment should be allowed for. Vector disagrees with the statement that a kvar charging regime could largely eliminate the need for the SO to contract separately for dynamic reactive reserves. The SO contracts for voltage support under Part C of the Rules for the same reason that it contracts for interruptible reserve – because in reality events occur that require short term back-up voltage support.	
18. Are there other options for the allocation of static reactive power costs that the Commission should pursue?		
Contact	No comment.	
EECA	No comment.	
Meridian	No further suggestions	
MEUG	No comment.	
MRP	We note that static support is best located at the load and option (b) does not provide clear incentives to consumers downstream of the connection asset to correct poor power factor. We would encourage investigation of how distributors provide incentives for consumers to ensure the most efficient electrical outcome.	
Norsk Skog	No response	
Northpower	Mandating the minimum power-factor for equipment connected to the electricity networks in NZ..	
RTANZ	The potential for 'smart grid' technologies to play a role in the management of reactive power demand appears to have been overlooked. The new smart technologies have the potential to provide active management of reactive power levels through control of distributed compensation resources. Smart meters will have reactive power measurement features that will allow price incentives to flow through to consumers and it seems sensible to use these features. The Commission should also explore the potential for a market in reactive power that could operate within regions with voltage problems. RTANZ considers that an holistic reactive power pricing methodology should be developed that includes incentives that are aligned through transmission, distribution and consumer levels. The	

	main focus should be to achieve optimal investment in, and maintenance of, low cost distributed reactive compensation rather than using higher cost supply level compensation. This is the real challenge that none of the options considered by the Commission address.	
Todd Energy	None identified.	
Transpower	See the response to Q.17 above.	
Trustpower	A full market for static reactive power should be considered.	
Vector	Vector submits that the previous power factor requirement (of 0.95 lagging across New Zealand) should also be considered as an option. The EC has entirely failed to demonstrate that the old power factor requirement was creating a problem that justifies the expense of a new charging regime. Vector continues to fundamentally disagree with the EC's analysis for the reasons stated in our previous submission on this matter.[41] Vector also draws the EC's attention to the report by SKM for the ENA entitled *Review of EGR Connection Code: UNI and USI Power Factor Requirements* (this is attached to the ENA submission on this consultation). This report raises significant concerns with the EC's analysis that led to the introduction of the unity power factor requirement and concludes that, if one only considers the benefits associated with network loss reduction, a sensible minimum power factor for New Zealand distributors would be in the region of 0.95. The EC emphasises, in relation to the unity power factor requirement, that its "objectives are to incentivise efficient investment in static reactive power supply; and to ensure that the causers of those investments pay a proportionate share of them." However, the consultation documents are notably silent on whether this objective has been achieved. This is not surprising as the only effect of the unity power factor requirement has been to create administrative costs for Transpower and affected distributors in negotiating non-compliance agreements and continued consultation and advocacy efforts with the EC. As the EC alludes to, the current unity power factor requirement is unenforceable. It has also failed to incentivise any distributor to invest in equipment to improve their power factor performance. Had the EC listened to stakeholder's views expressed strongly when the unity power factor requirement was introduced, this poor outcome could have been avoided. In our view, the history of this process provides a clear demonstration of why regulators need to have proper regard to stakeholder views and take them into account when making decisions – otherwise a great deal of effort can be expended for no value. Vector believes the EC's willingness to consider other options and consult on them further with industry indicates a new and welcome approach to resolving this issue and we look forward to working with the EC and EA to develop a more durable outcome.	

[41] Vector Ltd, Submission on options for ensuring efficient reactive power investment, 24 October 2008.