Consultation Paper

Transmission Pricing Review: Stage 2 Options

Prepared by the Electricity Commission

July 2010

644145-5

Executive summary

Introduction

1. This paper is the stage 2 consultation paper (**paper**) in the transmission pricing review (**review**). It follows on from the stage 1 consultation paper *Transmission Pricing Review: High-level Options* (**stage 1 consultation paper**) issued in October 2009. The stage 1 consultation paper introduced and summarised the work of the Electricity Commission's (**Commission**) consultant Frontier Economics in determining possible high-level options for transmission pricing and posed questions for the high level options canvassed.

2. In this second stage of the review the Commission has been concerned with considering submissions and undertaking further analysis of the issues, the high-level options and the further options proposed by submitters in order to compile a list of options for consultation. In the stage 1 consultation paper, the stage 2 analysis stage was described as 'an analysis to identify a short list of options'. The Commission has moved away from using the terminology of 'short list of options'. This reflects the complexity of the issues and the overlap between options and concepts. The selected stage 2 options have been developed from concepts contained in the high level options, analysis of the benefits of locational signalling on reducing system costs overall and options suggested by submitters. A summary of submissions was released in March 2010.

3. This paper is supported by four appendices that provide detailed analysis to support the approach taken by the Commission in this paper. Appendix 2 provides a further summary of submissions and the Commission's considerations in response to those submissions; Appendix 3 describes analysis of the potential benefits of locational signalling for economic investments; Appendix 4 describes analysis of the HVDC charge; Appendix 5 describes three alternative options for static reactive power compensation and provides supporting analysis.

4. As noted in the stage 1 consultation paper the review is part of the Commission's Market Development Programme (**MDP**) aimed at improving the performance of the electricity market. This review has particularly strong links with the scarcity pricing and locational price risk management projects and these links are noted throughout the paper.

5. Interested parties are invited to make submissions on this consultation paper. The content of the paper is intended to reflect that for the most part the Commission's assessment is still at a formative stage.

Impact of regulatory changes

6. In undertaking the review the Commission must take into account the relevant policy and regulatory settings. These are largely found in the Electricity Act 1992 (**Act**), noting that subject to the passage of legislation the relevant provisions will be replaced on 1 October 2010 by provisions currently contained in the Electricity Industry Bill (**Bill**).

7. The anticipated passage of the Bill will see the establishment of the Electricity Authority (Authority) on 1 October 2010 and the disestablishment of the Commission with responsibility for the review passing to the Authority. If the Bill is passed in its current form the Authority is likely to have a narrower objective than the Commission's more wide ranging set of objectives. The Authority will need to consider whether this has any material bearing on the review. The Bill provides for a new Industry Participation Code (**Code**) to replace the Electricity Governance Rules 2003 (**Rules**).

8. The Code in its current draft form makes no material changes to Section IV of Part F of the Rules which sets out the process for development and review of a transmission pricing methodology (**TPM**). Therefore, there should be few procedural changes in the way a review of the TPM is consulted on and established.

9. The stage 1 consultation paper sought submitters' views on whether it was appropriate to review the Pricing Principles (as set out in Section IV of Part F of the Rules) – (**Pricing Principles**); and whether there were particular Pricing Principles which ought to be given precedence over others.

10. The Commission remains of the view that a review of the Pricing Principles is not required at this time. The reasons for not recommending such a review are included in Appendix 2.

Stage 2 analysis

11. The stage 1 consultation paper considered whether the TPM needed to provide additional locational signals through more cost-reflective transmission charges for generators and loads given other key design features of the New Zealand market: nodal pricing, the Grid Investment Test (**GIT**)[1] , deep connection and the HVDC charge. The question of whether there is a need for additional pricing signals was considered in the context of both the use of the existing transmission network by generators and loads, and investment in new load and generation projects.

12. The purpose of the stage 2 analysis has been to support the Commission's decision-making as it narrows down the possible options for a TPM. The analysis:

[1] Although the GIT may not remain in its current form under the new Code arrangements, some sort of net benefit test for the assessment of transmission investment is likely to replace it. For the purposes of this paper, the net benefit test will continue to be referred to as the GIT.

- first reconsiders the economic theory arguments for further locational signalling in light of submitters' views; and
- secondly considers the potential benefits of further locational signalling from two perspectives:
  - for signalling economic transmission investments; and
  - for signalling reliability transmission investments.

13. The results of this analysis suggest there is limited value in providing for an enhanced locational signal to generators to ensure co-optimisation of economic transmission investments and generation. There are however likely to be benefits from signalling reliability transmission investment.

14. The Commission's preliminary view is that there may be little justification for imposing additional transaction costs on the industry in order to introduce further locational signalling in respect of economic investments.

15. These results could have implications for the design of the high voltage direct current link (**HVDC**) charge as it is an explicit locational signal to invest in generation in the North Island in preference to the South Island. The paper considers the benefits and costs of the operational and investment signals in the current HVDC charge. The paper does not however include consideration of whether on balance the requirements of other regulatory settings would also support changes to the HVDC charge. This further analysis will form part of stage 3 of the review.

Stage 2 options

16. The stage 2 options reflect the Commission's thinking that there is apparently limited benefit from additional signalling of the costs of economic transmission investments but that there are likely to be benefits from deferring transmission reliability investments. The Commission's preliminary view is that the only options that should be pursued further are those that are relatively incremental or straightforward to implement and show clear benefits.

17. On this basis the Commission has decided not to pursue further some of the high-level options identified in the stage 1 paper and in submissions. These are:

- Augmented nodal pricing – due to its novelty, complexity, and likely subjectivity;
- Market-wide tilted postage stamp (original and NERA versions) – due to the apparent lack of benefit from setting such charges across the market and the additional complexity of setting market-wide charges compared to a narrower bespoke version (see below);
- NZIER 'but for' approach – due to its complexity, likely subjectivity and difficulty of implementation; and

- NZIER HVDC charging approaches – due to the likely lack of benefit in radically changing charging arrangements for an economic transmission investment that may not be further augmented under most likely future scenarios.

18. The stage 2 options that the Commission proposes to consider further are focussed on two areas:

- options for providing incentives for participants to take action to defer or avoid reliability transmission investments where there are benefits in doing so; and
- options for the treatment of HVDC costs.

Options for providing incentives to defer or avoid reliability transmission investments

19. The selected options are focussed on providing incentives for participants to take action to defer or avoid reliability transmission investments where there are benefits in doing so. As such, the focus is on mechanisms for providing incentives to invest in new generation, produce more power from existing plant at specific times or consume less in particular locations.

20. The selected options involve modifications to the status quo with the possible exception of one – flow-tracing to allocate some transmission costs – which, depending on the extent to which it was implemented, may involve more substantial change. The status quo remains an option that will be considered alongside these options in stage 3.

21. The options are described below. The Commission considers that these options are not mutually exclusive and may be implemented in some combination.

22. **Bespoke postage stamping** option involving a higher charge on loads and credits to generators in particular regions – this is intended to provide localised signals for additional peaking plant and demand response in areas likely to require reliability transmission investment in the medium term, perhaps based on the use of a long run marginal cost (**LRMC**) approach to determining locational charges.

23. **Flow tracing approach** to allocating the costs of a portion of interconnection assets to specified parties, possibly coinciding with a shallower approach to defining connection assets.

24. **Improving the transmission alternatives regime** – particularly by avoiding the perception of competing interests faced by Transpower as both the network owner and the party responsible for the RFP process and assessment of alternatives against transmission options.

Options for treatment of HVDC costs

25. The analysis of the key costs and benefits of the current HVDC charging regime suggested there are four possible options for charging for the HVDC. These are set out in the paper. The Commission has yet to determine a preferred option, but has identified key questions that need to be resolved. The paper sets out the Commission's preliminary thinking on the questions, and invites comments from stakeholders.

Further issues

26. The stage 1 consultation paper considered four further issues for consultation and this paper reconsiders these four issues in light of submitters' views. The four issues are:

27. **The link between price and service**. The Commission has reconsidered the relevance of this issue to the review and the appropriateness of the approaches set out in the stage 1 consultation paper. The conclusion is that price and its links to the service provided are important issues which should be worked through. Consideration of the submissions and the current regulatory and proposed regulatory regimes has meant that the issue will continue to be investigated but not as part of the review. The results of this work will be provided in a handover package to the Authority to assist it in its consideration of setting quality standards for Transpower for inclusion in the new Code.

28. **Connection issues.** The paper considers issues raised by submitters and further considers the issues raised in the stage 1 consultation paper for both new and existing connection assets.

29. **Transmission alternatives.** The paper and Appendix 2 consider transmission alternative issues, although the suggested options for encouraging transmission alternatives are considered as part of the options for deferring or avoiding reliability transmission investments in section 4.2.

30. **Static reactive power compensation.** The paper outlines three possible options for allocating static reactive power costs. Further detail on the three options and supporting analysis is contained in Appendix 5.

Glossary of abbreviations and terms

AC	Alternating current
Act	Electricity Act 1992
AMI	Anytime Maximum Injection
APR	Transpower's Annual Planning Report
Authority	Electricity Authority
Bill	Electricity Industry Bill
Code	Industry Participation Code
Commission	Electricity Commission
Connection Code	Connection Code set out as schedule 8 to the Benchmark; Agreement (set out in schedule F2 of section II)
DSM	Demand Side Management
DTC	Designated Transmission Customer
GEM	Generation Expansion Model
GIT	Grid Investment Test
GPS	Government Policy Statement on Electricity Governance; May 2009
GSC	Grid Support Contract
GUP	Grid Upgrade Plan
GXP	Grid Exit Point
HAMI	Historical Anytime Maximum Injection
HVDC	high voltage direct current
Issues Paper	An issues paper on the preferred option, issued under rule 4 of section IV of part F of the Rules.
LRMC	long run marginal cost
LSI	Lower South Island
MDP	Market Development Programme
Minister	Minister of Energy and Resources
NAaN	North Auckland and Northland grid upgrade proposal as approved by the Commission in 2009
NIC	New Investment Contract
NIGU	North Island Grid Upgrade proposal as approved by the Commission in 2008

NPV	net present value
Point of Service	means a normally contiguous electrical busbar of a particular voltage where Transpower as a grid owner has agreed to provide services to one or more DTCs.
Pricing Principles	The Pricing Principles set out in rule 2 of section IV of part F of the Electricity Governance Rules.
RCPD	Regional Coincident Peak Demand.
review	Transmission Pricing Review
RFP	request for proposal
Rules	Electricity Governance Rules 2003
SOO	Statement of Opportunities
stage 1 consultation paper	Consultation Paper entitled “Transmission Pricing Review: High Level Options” issued in October 2009
TPM	Transmission Pricing Methodology
TPM guidelines	The Commission is required by rule 4 of section IV of part F of the Rules to develop guidelines for Transpower to apply in developing the TPM
TPTG	Transmission Pricing Technical Group
UNI	Upper North Island
USI	Upper South Island
Commission	Electricity Commission
Minister	Minister of Energy and Resources
Act	Electricity Act 1992
Rules	Electricity Governance Rules 2003
Regulations	Electricity Governance Regulations 2003

Contents

1. Introduction and purpose of this paper

1.1 Introduction

1.1.1 The Electricity Commission (**Commission**) is undertaking a Transmission Pricing Review (**review**) to encompass a wide-ranging review of options for the allocation methodology for transmission costs.

1.1.2 This consultation paper (**paper**) is the second to be published as part of this review and concludes the review's second stage.

1.1.3 In the first stage of the review, the Commission considered issues with current transmission pricing, economic theory and high-level options for transmission pricing, and published a consultation paper: "*Transmission Pricing Review: High-level Options" issued in October 2009*[2] *(***stage 1 consultation paper***)*.

1.1.4 The second stage of the review has been concerned with considering submissions and further analysis of the issues set out in the stage 1 consultation paper.

1.1.5 This review is part of the Commission's Market Development Programme (**MDP**)[3]. The MDP is aimed at improving the performance of the electricity market and has two key objectives:

- to improve security of supply and efficient investment signals; and
- to improve competition in both wholesale and retail markets.

1.1.6 The complex and interlinked nature of the electricity supply chain means the MDP is being taken forward as an integrated package of measures. Within this package, transmission pricing is particularly related to two projects:

- scarcity pricing; and
- locational price risk management.

1.1.7 In particular, outcomes from these two projects could influence the impact on locational signals from nodal pricing. However, given current thinking within the scarcity pricing and locational price risk projects, it is unlikely that decisions on the two related projects would change the transmission pricing options set out in the paper.

(a) **Scarcity pricing**: Whether to introduce scarcity pricing on a nodal or regional level remains an open question for the scarcity pricing project, although there is an initial preference for regional scarcity pricing.

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[2] Available at: http://www.electricitycommission.govt.nz/consultation/tpr

[3] Further information about the MDP is available at: http://www.electricitycommission.govt.nz/opdev/mdp

Regardless of the choice of a regional or nodal scarcity price, there may still be a benefit from providing locational signals for investment in generation and load to defer reliability transmission investments due to other factors that mute the nodal price which are outlined in the paper.

(b) **Locational price risk management**: The options that are being taken forward by the locational price risk management project preserve the long-run investment signals for generation provided by nodal pricing. Therefore there are unlikely to be implications for the analysis of transmission pricing options.

1.1.8 In addition, the transmission pricing review is at an earlier stage than the scarcity pricing and locational price risk management projects, and any potential impacts can be assessed during stage 3 of the project.

1.1.9 Where relevant this paper notes the links between transmission pricing and these projects.

1.2 Purpose and structure of this paper

1.2.1 The purpose of this paper is to invite submissions on the stage 2 analysis, including the selected options outlined in the paper.

1.2.2 This paper:

(a) provides a brief background to transmission pricing and to the review[4] and describes the review process;

(b) describes the expected regulatory, governance and policy changes arising from the Electricity Industry Bill (**Bill**);

(c) presents the Commission's analysis and position on reviewing the Pricing Principles as set out in Section IV of Part F of the Electricity Governance Rules 2003 (**Rules**) and as consulted on in the stage 1 consultation paper;

(d) sets out the Commission's stage 2 analysis;

(e) identifies a list of options for public consultation;

(f) sets out the Commission's considerations on further issues that were considered in the stage 1 consultation paper. These issues include static reactive power compensation for which three alternative options have been outlined for consultation; and

[4] Further background information is available or referenced in the stage 1 consultation paper: *Transmission Pricing Review: High-level Options*. available at http://www.electricitycommission.govt.nz/consultation/tpr

Further information on transmission pricing and previous reviews is available at: http://www.electricitycommission.govt.nz/

(g) invites submissions on the issues and options canvassed in this paper, including in particular the questions set out in it and restated in section 6.

1.2.3 The content of the paper is intended to reflect that for the most part the Commission's thinking is still at a formative stage.

1.3 Submissions

The Commission's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Commission, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@electricitycommission.govt.nz with "Consultation Paper—Transmission Pricing Review: Stage 2 Options" in the subject line.

If submitters do not wish to send their submission electronically, they should post one hard copy of their submission to the address below.

Lisa DuFall
Submissions
Electricity Commission
PO Box 10041
Wellington 6143

1.3.1 Submissions should be received by **4 pm** on **31 August 2010**. Please note that late submissions are unlikely to be considered.

1.3.2 The Commission will acknowledge receipt of all submissions electronically. Please contact the Submissions Administrator if you do not receive electronic acknowledgement of your submission within two business days.

1.3.3 If possible, submissions should be provided in the format shown in Appendix 1. Your submission is likely to be made available to the general public on the Commission's website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Commission on a confidential basis. However, all information provided to the Commission is subject to the Official Information Act 1982.

2. Background

2.1 Transmission pricing

2.1.1 Transpower's transmission network is a natural monopoly and its revenue requirement is regulated by the Commerce Commission. The Transmission Pricing Methodology (**TPM**) determines how Transpower's total revenue is allocated between, and recovered from, its customers. Transpower develops the TPM in accordance with section IV of Part F of the Rules. The Commission sets guidelines for the development of, and approves, the TPM.

2.1.2 The level and structure of transmission charges under the TPM has the potential to influence the use of the network, operation of the power market and investment in the market. For example, transmission charges can influence the locational choices of generators and their bidding behaviour.

2.1.3 The challenge is to allocate transmission costs in a way that encourages:

(a) efficient use of the transmission network and operation of the power market in real time; and

(b) efficient investment in new load and generation projects (including load management) – which will influence future demand on the transmission network and the need for transmission investment.

2.1.4 Transmission pricing has been a difficult issue both in New Zealand and internationally. Historically, participants in New Zealand have been unable to agree to voluntary contractual arrangements and past litigation has resulted in a prescribed process for the recovery of transmission costs and the development of a TPM.

2.1.5 The current TPM is based – with some refinements – on the TPM that was developed by Transpower and first applicable from 1 April 1999.

2.1.6 The 1999 TPM represented a shift from the previous methodologies used by Transpower to allocate transmission costs. One of the key differences from earlier approaches was the introduction of three distinct charges: connection charges, interconnection charges and explicit High Voltage Direct Current (**HVDC**) charges for the HVDC link for South Island generators only.

2.1.7 The current TPM is comprised of these three charges, but has introduced further refinements such as a change to the allocation of interconnection charges according to the Regional Coincident Peak Demand (**RCPD**), and a deeper definition of connection assets.

2.1.8 In 2004 the Commission began consultation on how to allocate the costs of transmission. Guidelines for Transpower to apply in developing the TPM in accordance with rule 6.2 (**TPM guidelines**) were published in 2006[5]. Transpower submitted a proposed TPM in June 2006. This TPM was consulted on and was finalised in June 2007.

2.1.9 During the development of the TPM the Commission considered whether to conduct a more comprehensive review of transmission pricing including whether enhanced locational signals to generation and load may be efficient. However, ultimately the Commission decided that it was preferable to implement a methodology in the short term and noted that a review was intended in the future[6]. The current TPM took effect on 1 April 2008.

2.1.10 The rationale at the time was that nodal pricing, the approval of investment under Grid Investment Test (**GIT**) and a deep definition of connection may be sufficient with respect to locational signalling. The Commission acknowledged that further analysis was required to confirm this, but in the meantime considered it was prudent to "postage stamp" the costs of providing interconnection assets. The final approach differed in respect of the HVDC link. In the case of this asset, the benefit of a locational signal appeared to be more compelling. This proved to be a controversial decision and parties requested that the Commission undertake a further review of the HVDC charge.

2.1.11 The Commission noted that any future review should be "holistic, focusing on locational pricing", rather than merely focussing on allocating the costs of the HVDC link. The Commission intended to revisit its decisions on the benefits of an enhanced locational signal over the signals provided by nodal pricing, the GIT and the deep definition of connection.

2.2 Review of transmission pricing

2.2.1 In April 2009 the Commission announced it would undertake a wide-ranging review of transmission pricing. The rationale for the review is set out in part 2 of the stage 1 consultation paper. The review is considering options for the allocation methodology for transmission costs and involves consultation with interested parties on the economic, technical and legal analysis of the identified options.

2.2.2 Transpower determines its revenue requirement (covering both sunk and new investments) subject to the constraints of the Commerce Act 1986. The

[5] This decision was reached on a Court ordered re-consultation after the Commission's original decision (made in late 2004) was successfully challenged for process deficiencies by Meridian and Contact in 2005.

[6] Transmission Pricing Methodology Final Decision Paper, available at: http://www.electricitycommission.govt.nz/opdev/transmis/tpm/index.html#final

development and content of the TPM is regulated through the Electricity Act 1992 (**Act**) and section IV of Part F of the Rules.

2.2.3 Rule 1 of section IV of part F of the Rules[7] provides that the purpose of the TPM is to ensure that the full economic costs of Transpower's services are allocated in accordance with the Pricing Principles set out in rule 2 and the other conditions set out in rule 3.

2.2.4 As previously advised in the stage 1 consultation paper, in order to develop a preferred option, the Commission expects to undertake three initial analysis and consultation stages. Each stage will include a paper for consultation with the final paper planned for the end of 2010. This paper is the second of the three planned consultation papers.

(a) Stage 1 - a review of issues with current transmission pricing and identification of high-level options.

(b) Stage 2 – to identify a list of selected options. The stage 2 options have been developed from concepts contained in the high level options set out in the stage 1 consultation paper as well as analysis detailed in this paper and the options suggested by submitters. In the stage 1 consultation paper, the stage 2 analysis stage was described as 'an analysis to identify a short list of options'. The Commission has moved away from using the terminology of 'short list of options'. This reflects the complexity of the issues and the overlap between options and concepts.

(c) Stage 3 – identification of and detailed evaluation of a preferred option for the allocation of transmission costs. If the preferred option is a change from the status quo, the publication of an issues paper on the preferred option and related draft guidelines published under rule 4.[8] (**Issues Paper**). The preferred option to be identified in the Issues Paper will be based on the Commission's ongoing analysis, submitters' views and the stage 2 options; the preferred option may be one of the stage 2 options or an amalgam of concepts.

2.2.5 The process is illustrated in Figure 1.

[7] Unless otherwise specified, references to specific rules are to references to rules contained in section IV of part F of the Rules.

[8] The Issues Paper would incorporate the draft process to be followed and draft guidelines to be used by Transpower in preparing the new TPM, The consultation process is set out in the Rules.

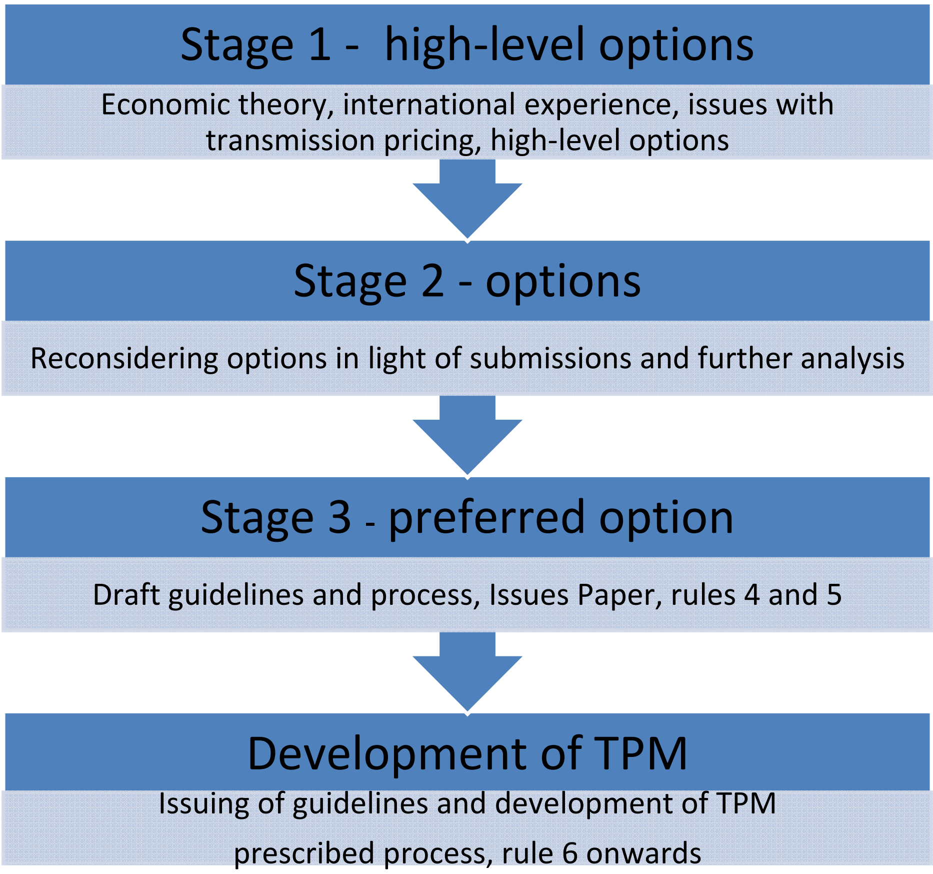

Figure 1: Review process

2.2.6 The consultation process prior to the publication of the Issues Paper goes beyond what is required by the Rules. The process reflects the Commission's desire to begin with first principles and to ensure that interested parties have an opportunity to influence all stages of the process as the Commission's thinking becomes more focused on a particular approach. After publication of the Issues Paper, the Commission must follow the process set out in rules 5 - 8.

2.2.7 The Commission expects that any changes to the TPM arising from the review will be effective from the 2012 pricing year, although this will be dependent on the final option selected and the implementation requirements. If the preferred option leads to significant changes in charges to participants, the review will consider options for transitional arrangements.

2.2.8 The Commission recognises that changes to the allocation of transmission costs may result in value transfers between parties. For this reason the Commission encourages strong input from interested parties during the review.

2.2.9 To support its work the Commission has established a working group known as the Transmission Pricing Technical Group (**TPTG**)[9] made up of technical specialists nominated by interested parties. The TPTG is providing specialist review and input throughout the review process.

2.3 Relevant policy, regulatory and governance considerations

2.3.1 The review must take into account the relevant policy and regulatory settings. These are largely found in the Act and the Rules, however subject to the passage of legislation the relevant provisions will be replaced on 1 October 2010 by provisions currently contained in the Bill and the draft Code.

Framework established under the Electricity Act 1992

2.3.2 Paragraph 3.2.18 of the stage 1 consultation paper noted that the selection of high-level options must take account of the Commission's statutory objectives set out in the Act. These objectives require that the preferred option must:

(a) be consistent with the Commission's principal objectives and specific outcomes set out in section 172N of the Act;

(b) be consistent with the Pricing Principles;

(c) be consistent with the relevant objectives and outcomes in the Government Policy Statement on Electricity Governance (**GPS**);

(d) take into account practical considerations;

(e) take into account transaction costs – the preferred high-level option should not incur unreasonable transaction costs; and

(f) take into account the desirability for consistency and certainty for both consumers and the industry.

2.3.3 The Commission's principal objectives in section 172N of the Act require the Commission to:

(a) ensure that electricity is produced and delivered in an efficient, fair, reliable and environmentally sustainable manner; and

(b) promote and facilitate the efficient use of electricity.

[9] Membership and meetings details are available on the Commission's website: http://www.electricitycommission.govt.nz/advisorygroups/pjtteam/tptg/index.html

Framework to be established under Electricity Industry Bill

2.3.4 The Bill provides for the disestablishment of the Commission and the establishment of the Electricity Authority (**Authority**). Subject to passage of the legislation, from 1 October 2010 the review will be managed by the Authority and governed by the provisions of the Electricity Industry Act 2010. At that time, the Rules will be replaced by an Industry Participation Code (**Code**). The Commission can anticipate and plan for the transition to the new environment but its work up until 1 October 2010 is ultimately governed by the current Act.

2.3.5 As noted above the anticipated passage of the Bill will see the establishment of the Authority on 1 October 2010 and the disestablishment of the Commission. Under clause 17 of the Bill the Authority has a single objective:

> "to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers".

2.3.6 Assuming clause 17 of the Bill is passed in its current form, from 1 October 2010 the objective as stated above will guide the Authority's work, including this review. The Authority will need to consider whether this has any material bearing on the direction of the review. The Authority's proposed objective is narrower than the Commission's current principal objectives and specific outcomes set out in the Act.

2.3.7 The Authority will be an independent Crown Entity[10] which will give it a greater degree of independence than the Commission has had. Clause 19 of the Bill provides that the Authority will be obliged to "have regard to any statements of government policy concerning the electricity industry issued by the Minister". This compares with the current arrangements where under section 172O(j) of the Act, one of the Commission's functions is to "give effect to GPS objectives and outcomes".

2.3.8 As the Code in its current draft form makes no material changes to section IV of part F, there are not likely to be any significant procedural changes in the way a review of the TPM will be consulted on and established.

Q1.	**What, if any, bearing do you consider the Authority's proposed objective has on the review's approach to analysis and evaluation to date?**

10 The Commission is a Crown Agent; a Crown Entity with a lesser degree of independence than an independent Crown Entity.

Decision on review of Pricing Principles

2.3.9 The stage 1 consultation paper sought submitters' views on whether it was appropriate to review the Pricing Principles at this time; and whether there were particular Pricing Principles which ought to be given precedence over others. Further details of submitters' views and considerations are included in Appendix 2.

2.3.10 Submitters almost universally hold the view that the Pricing Principles conflict and that this can be problematic. Only two parties indicated clear support for not reviewing the Pricing Principles at this time, whereas at least half of the submitters contended that the Pricing Principles should be reviewed and a number of submitters view this as fundamental to the review.

2.3.11 In the stage 1 consultation paper, the Commission stated that it considered it was not appropriate to review the Pricing Principles at this time. The Commission acknowledges there are some issues with the current Pricing Principles but considers that these issues are inherent in any principles that seek to achieve multiple policy outcomes. Further, there are a number of practical and process issues that arise should a review proceed at this time that were largely not considered by submitters[11].The divergence in submissions suggests that a review of the pricing principles is likely to result in consensus that the number of principles should be reduced, but no consensus as to what those principles should be. The proposal to amend the pricing principles appears to be driven, at least in part, by participants wanting a particular outcome and therefore focusing on a particular pricing principle.

2.3.12 For the reasons outlined above (and elaborated on in Appendix 2) the Commission remains of the view that a review of the Pricing Principles is not required at this time. More detail on the reasons for not recommending a review of the Pricing Principles is included in Appendix 2.

[11] For example, any amendment to the Pricing Principles would require a rule change, requiring the Commission to consult with affected persons and undertake a cost/benefit assessment compared to other reasonably practicable options. The process is estimated to take a minimum of six months, but could easily take longer. Given the expected disestablishment of the Commission and the creation of the Electricity Authority, a rule change involving this timeframe is not practical.

3. Stage 2 analysis

3.1 Introduction

3.1.1 Stage 2 of the review has built on the stage 1 analysis and submissions with the aim of compiling a list of options for further consideration in stage 3. These options, along with the status quo, will be further considered in stage 3. The stage 3 analysis will provide a more comprehensive assessment of the net benefits of the options. As noted in paragraph 2.2.4 the Commission has chosen not to describe the stage 2 options as a short list.

Overview of stage 1

3.1.2 Stage 1 took the following approach:

(a) Frontier Economics prepared a report for the Commission identifying high-level options for transmission pricing and proposed a set of criteria for narrowing down the options.

(b) Frontier based its framework for deriving the high-level options on the findings of previous reports prepared for the Commission on efficient pricing theory, international experience and current issues in the New Zealand market, as well as the range of relevant policy and regulatory considerations set out in the Act, part F of the Rules and the GPS.

(c) In order to distinguish high-level option issues from more detailed considerations, Frontier's approach was to identify locational cost allocation issues as high-level, and price structure issues as lower level.

(d) In addition to the status quo transmission pricing arrangements, Frontier identified three other high-level options that it believed worthy of further investigation and consultation. These three other options were:

(i) 'tilted' postage stamp approaches;

(ii) augmented nodal price signals; and

(iii) load flow-based approaches.

3.1.3 The stage 1 consultation paper was published in October 2009[12].

3.1.4 Nineteen parties provided submissions to the stage 1 consultation paper. The Commission published a summary of these submissions in March 2010[13].

[12] *Transmission Pricing Review: High-level Options*, October 2009, available here: http://www.electricitycommission.govt.nz/consultation/tpr

3.1.5 The focus of stage 1 was on whether transmission pricing needed to provide enhanced locational signals for generators and loads, and the stage 1 consultation paper particularly considered this issue from an economic theory point of view. This enhanced signal would be in addition to the signal provided by nodal pricing, the application of the GIT[14] and the deep definition of connection. The core part of stage 2 analysis has built on this to assess whether there are potential benefits in introducing further locational signalling.

The stage 2 analysis

3.1.6 The stage 2 analysis first:

(a) reconsiders the economic theory arguments for further locational signalling to generation and load to encourage co-optimisation of investment in generation, load and transmission (in light of submitters' views)***;*** and

(b) considers the potential benefits of further locational signalling to generation and load from two perspectives:

(i) for signalling in respect of future economic transmission investments; and

(ii) for signalling in respect of deferral of future reliability transmission investments.

3.1.7 For regulatory purposes, transmission investment is categorised as either being economic investment or reliability investment.

3.1.8 Economic investment is typically to reduce (but not necessarily remove) constraints in the transmission system with the principal objective of minimising generation capital and operating expenditure (including minimising losses). Approval for economic transmission investment is based on economic criteria contained in the GIT. One example of such an investment is the HVDC upgrade approved in September 2008.

3.1.9 Reliability investment is primarily motivated by the need to support reliable supply to load and encompasses several recent larger investments such as North Auckland and Northland (**NAaN**) and North Island Grid Upgrade (**NIGU**) grid augmentations. Approval for reliability investments is based on practically-

[13] The Summary of submissions and individual submissions are available at: http://www.electricitycommission.govt.nz/opdev/transmis/tpr

[14] Although the GIT may not remain in its current form under the replacement input methodology administered by the Commerce Commission, it is likely that the input methodology will encompass a cost/benefit test for the assessment of transmission investment. For the purposes of this paper, the regulatory test will continue to be referred to as the GIT.

oriented reliability criteria. The total value of reliability-driven transmission investment is greater than economic investment.

3.1.10 The results of the stage 2 analysis suggest that there are unlikely to be benefits from signalling economic transmission investment, but that there are likely to be benefits from signalling reliability transmission investment.

3.1.11 These results could have implications for the HVDC charge, as the HVDC involves an explicit locational signal for new generation to locate in the North Island. The stage 2 analysis therefore considers the HVDC charge in particular, with specific reference to the question of whether there are, or likely to be, inefficient operational and investment decisions due to the current locational price signal provided by the HVDC charge.

3.1.12 Following the stage 2 analysis, the paper identifies:

(a) options to defer or avoid reliability investments where there are benefits in doing so, and

(b) options for the treatment of HVDC costs.

3.1.13 These options, alongside the status quo, will be given further consideration in stage 3.

3.1.14 The paper describes some of the analysis and the rationale behind the selected options.

Appendix 2 describes submitters' views on the stage 1 consultation paper issues, consideration of stage 1 submissions, and assessment of stage 1 high level options.

Appendix 3 describes the analysis of the potential benefits of locational signalling for economic investment.

Appendix 4 describes the analysis of the HVDC charge issues.

3.1.15 The high-level analysis of the potential benefits of locational signalling for reliability investment is included in section 3.3.

3.1.16 The further issues included in the stage 1 consultation paper are considered in section 5.

3.1.17 A number of issues that were consulted on in stage 1 are not considered specifically in this paper. These are discussed in Appendix 2. They include issues with current transmission pricing and the international review undertaken by Frontier Economics as part of stage 1.

3.2 Economic theory considerations

3.2.1 The stage 1 consultation paper considered whether the TPM needed to provide additional locational signals to generators and loads given other key design features of the New Zealand market namely nodal pricing, the application of the GIT, deep connection and the HVDC charge.

3.2.2 The question of whether there is a need for additional locational pricing signals to participants was considered in the context of both:

(a) use of the existing transmission network by generators and loads - which is a function of participants' electricity production and consumption decisions; and

(b) investment in new load and generation projects (including load management) – which will influence future demand on the transmission network and the need for transmission investment.

3.2.3 In an energy-only full nodal market – incorporating full pricing of congestion, losses and appropriate scarcity pricing – and assuming competitive bidding behaviour, generators and loads should face appropriate signals for the use of the existing network. Submitters broadly agreed with this proposition.

3.2.4 Theoretically, full nodal pricing should provide efficient investment signals to actual and prospective participants. However some factors may mean current nodal pricing is not sufficient and some locational variation in transmission prices may be required.

Relevant factors

3.2.5 In considering whether there is likely to be a benefit from enhanced locational signals the following factors are relevant:

(a) The New Zealand market does not have full nodal pricing where the spot market price at any given node reaches the value of unserved energy at times of supply scarcity at that node.

(b) Transmission and generation investment are 'lumpy'[15] and exhibit economies of scale[16], causing nodal price differences to 'collapse' for prolonged periods immediately after an augmentation of the transmission network or a generator locating behind a constraint.

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15 Lumpy in this context reflects that you can only invest in discrete intervals.

16 Refer 3.2, stage 1 consultation paper for further discussion on this point. .

(c) Prudent planning and approval criteria are applied. Transmission investment can be approved:

(i) in order to meet reliability standards; or

(ii) at a time that reflects the need for a conservative approach in the timing of both economic and reliability investments.

3.2.6 These factors and submitters' views are considered in more detail in Appendix 2.

3.2.7 The first factor – that the current nodal pricing design does not fully reflect the scarcity value of electricity – is the problem at the core of the scarcity pricing project. The scarcity pricing project appears likely to develop a form of scarcity pricing where prices are set at the value of unserved energy at times of actual shortage. However whether scarcity prices will be set at a nodal or regional level is still a matter for consideration. Current thinking leans towards applying scarcity pricing when widespread demand curtailment is required on a regional basis rather than nodally[17]. If this is the case, the New Zealand market is unlikely to see scarcity pricing at a nodal level in the short-term. This means that the extent of locational signalling provided through energy prices will remain muted.

3.2.8 The second factor – that transmission investment exhibits lumpiness or economies of scale – may not itself impact on the longer-term efficiency of the energy price signals. Lumpiness or economies of scale in investment may lead to a temporary post-investment muting of nodal price signals. In theory, over the long term, this may not imply that nodal prices would be systematically distorted.

3.2.9 The third factor - the application of prudent transmission and planning criteria – means that transmission investment may not always be approved in a manner or at a time that maximises net economic benefits. Lumpiness and economies of scale contribute to this factor[18].

Further consideration of the third factor

3.2.10 As noted above, transmission investment is categorised as either being economic investment or reliability investment. Economic investment is motivated by the resource cost savings from avoiding or reducing transmission constraints. In a full nodal pricing market, if economic investment is undertaken when net benefits are maximised, then so long as economies of scale are not pervasive, no further locational signals are required. Reliability investment is undertaken to minimise the risks of consumers experiencing excessive periods and amounts of unserved

[17] *Scarcity Pricing: Outline* available at: http://www.electricitycommission.govt.nz/advisorygroups/pjtteam/sptg/27May10/index.html

[18] While small amounts of unserved energy associated with small investments may be acceptable, large amounts are unlikely to acceptable. For example, it would be unacceptable for Auckland to have large amounts of unserved energy for a sustained period of time if this could be avoided by a transmission investment.

energy. For practical reasons, the criteria for approving reliability investment are based on standards that stress the need to maintain supply in the event of potential power system contingencies. Investing to satisfy such reliability standards often requires investment in excess of, or in advance of, the investment that would maximise expected net economic benefits.

3.2.11 Even when reliability-driven transmission investment would be optimally undertaken at a certain time, it may be approved and undertaken early as a prudent risk management practice in light of the following factors:

3.2.12 First, due to the significant difference in lead times between transmission investment and market generation investment, it is prudent that approval decisions on reliability transmission investment are made well before certainty exists regarding market generation investment.

3.2.13 Second, a degree of uncertainty exists as to what level of demand will need to be served at specific locations in 5 or 10 years time. If however in the face of rising demand, investment occurs several years too late then large economic costs can result due to unserved energy events. These costs are likely to be considerably larger than the additional costs of investing in transmission assets several years too early. Due to this potential asymmetry in costs the Commission uses prudently high demand forecasts when considering the need for reliability investment.[19]

3.2.14 These practical risk management considerations can result in economic as well as reliability transmission investment occurring in a manner that does not maximise expected net economic benefits. This results in the dampening of the nodal price signals faced by market investors.

3.2.15 Given the factors considered above, it is unlikely that nodal pricing will always provide adequate signals for efficient generation and load investment.

Q2. 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.

3.2.16 The stage 1 consultation paper set out three possible high-level options that might introduce further locational signalling for the Commission to consider as an alternative to the status quo. The stage 1 consultation paper also set out criteria for assessing the high-level options.

3.2.17 Of these eight criteria, the first considered whether there was a material divergence between actual and optimal transmission expansion. This criterion

[19] ‘Business as usual’ or’ mean’ demand forecasts are used for economic investment approvals.

informs whether any form of additional locational signal in the TPM is necessary. In other words, if, given existing locational signalling, there is less than optimal transmission expansion (i.e. where there is full co-optimisation of generation and transmission), then the review should consider introducing some form of locational signalling.

3.2.18 The other criteria have been used to further assess the high-level options. This analysis is described in Appendix 2.

3.2.19 Criterion 1 led to a degree of confusion amongst submitters. Submitters' views and Commission considerations on this criterion are given in Appendix 2. The Commission recognises that criterion 1 is difficult to assess.

3.2.20 The Commission notes that estimating the degree of divergence between actual and optimal transmission investment and the implications of that divergence for nodal prices and investment outcomes is extremely difficult. Apart from estimating how actual transmission investment has diverged and will in future diverge from optimal levels, locations and timings; estimating the nodal price and investment implications is likely to require making assumptions about generator bidding behaviour and investors' responses to that behaviour. This is a subjective exercise that is likely to prove controversial.

3.2.21 Therefore, the Commission has instead decided to estimate the potential upper bounds of the economic benefits from providing further locational signals through the TPM.

3.2.22 It considers that an appropriate and practical way to do this is to model the difference between two alternative scenarios where:

- transmission interconnection costs are not considered when generation investments are made; and
- generation and transmission investment are perfectly co-optimised i.e. all transmission investment costs are considered in making decisions to invest in generation and the least cost expansion to meet demand is selected (this is a proxy for an 'ideal' locational signal).

Q3. 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.

3.3 Are there benefits from locational signalling?

3.3.1 The Commission's consideration of this issue and the analysis of submissions on the Stage 1 Consultation Paper suggests that, whatever the theoretical merits of locationally-varying transmission charges, whether there would be benefits in practice in implementing a new TPM with enhanced locational signals is a separate question. This point was emphasised by a number of submitters in their submissions[20].

3.3.2 First, existing signals in the energy market (limited nodal pricing, deep connection and the application of the GIT) may already promote efficient generation and load investment and operation to some extent. Second, other factors such as availability of fuel sources and appropriate sites may be more important to participants' locational decisions than variations in transmission charges. This may mean that, even if transmission pricing is changed to introduce further locational signalling, there may be little or no benefit in terms of savings from total system costs.

3.3.3 Stage 2 of the review has involved modelling and analysis of the *potential* benefits from enhanced signalling of transmission costs for generation and load. These benefits accrue from savings in overall system costs, comprising transmission and generation investment costs and plant operating costs (including fuel costs).

3.3.4 Provided the sector is competitive, minimising total system costs should advance the long term interests of consumers. In other words, final prices are kept as low as possible today while ensuring sufficient investment takes place to ensure final prices continue to stay as low as possible in the future. It should be noted, however, that the modelling and analysis assumes the value chain ends at the grid exit point, i.e. the distribution and retail parts of the sector are not considered.

Overview of analysis

3.3.5 The Commission's analysis has progressed in two phases reflecting two different types of transmission investment: economic and reliability investment. These two types of investment are described in paragraphs 3.1.7 to 3.1.9.

3.3.6 The first phase of the analysis has focussed on economic investment. This has been done by modelling the trade-off between remote generation, requiring transmission investment, and generation located close to load, requiring less transmission investment. Transmission investment in this context is concerned with realising the economic benefit of reduced generation costs and accordingly is characterised as economic investment.

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[20] *Transmission Pricing Review: High-level options, Summary of submissions* Feb 2009, is available at: http://www.electricitycommission.govt.nz/opdev/transmis/tpr

3.3.7 The analysis (outlined below and described in Appendix 3), suggests there is limited benefit from enhanced locational signalling to generation in relation to economic transmission investment. Overall system costs are only marginally lower (in a relative sense) under the assumption of full co-optimisation of generation and transmission as compared to the base case in which generation locates irrespective of network capability and interconnection costs.

3.3.8 The second phase of the analysis has considered reliability-driven investment. This analysis considers a different type of trade-off. This is the trade-off between installing peaking generation, such as diesel or gas-fired open cycle gas turbines, close to load centres and/or implementing demand-side management, versus investing in transmission augmentation to serve the same load centres.

3.3.9 This second phase analysis suggests there may be benefits in providing locational signalling to generation and load through transmission pricing for reliability-driven investment.

Analysis of the benefits of signalling economic-driven investment

3.3.10 The Commission's analysis is detailed in Appendix 3 and a summary of the approach and results is given here.

3.3.11 The Commission's approach to assessing the benefits of locational signalling for generation in respect of future economic transmission investments is to:

(a) first model the net present value (**NPV**) of future system costs that might result if transmission interconnection costs are not considered when generation investments are made;

(b) then model the NPV of future system costs that might result if generation and transmission investment were perfectly co-optimised i.e. all transmission investment costs were considered in making decisions to invest in generation (this is a proxy for an 'ideal' locational signal); and

(c) then compare the two results in order to give an upper bound on the benefits that may be delivered by incorporating locational signalling of transmission costs in the TPM.

3.3.12 The analysis uses the Generation Expansion Model (**GEM**) to derive an estimate of overall system costs under scenarios (a) and (b) above*.* Overall system costs include capital expenditure for new and refurbished generation plant and transmission upgrades, operating costs and unserved energy. GEM seeks to minimise these costs through the least cost expansion path over the entire modelled time horizon. The generation and transmission expansion options are those set out in the grid planning assumptions and the draft 2010 Statement of Opportunities (**SOO**)[21].

3.3.13 The Commission's modelling suggests that the benefits of implementing locational signals through the TPM to signal to generation the cost of economic transmission investment appear to be limited, given current and future generation and transmission expansion options. 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.

3.3.14 Appendix 3 sets out details of the testing that the Commission carried out to gain confidence in the results.

3.3.15 As noted above the analysis suggests there is limited value in providing for an enhanced locational signal to generators to ensure co-optimisation of economic transmission investments and generation. However, 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.

3.3.16 There is currently no locational transmission pricing signal for AC interconnection assets for generators[22]. The analysis suggests there is little value in pursuing the development of an enhanced locational signal to generation through transmission pricing for economic transmission investments.

3.3.17 The situation is different for the HVDC assets. The HVDC charge provides a locational pricing signal for new generation to locate in the North Island. Given the analysis to date, consideration should be given, in the first instance, as to whether the current locational signal provided by the HVDC charge is distortionary in terms of operational and investment decisions. In other words whether the current HVDC charge creates a significant dis-benefit.

[21] Available at: http://www.electricitycommission.govt.nz/consultation/2010-draft-soo/view

[22] The RCPD pricing structure provides a signal to load. This is intended to provide a signal for managing peak usage.

Q4.	**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.**
Q5.	**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.**

The HVDC charge

3.3.18 Under the current transmission pricing arrangements the HVDC costs are met through a charge on South Island generation plant with charges based on Historical Anytime Maximum Injection (**HAMI**)[23] into the grid at the customer's location.

3.3.19 The Commission is required by rule 4 to develop the TPM guidelines for Transpower to apply in developing the TPM. The TPM guidelines were set by the Commission in 2006[24] and allocated the HVDC charge to South Island generation plant that injects into the grid.

3.3.20 The reasons for the 2006 decision on the TPM guidelines (as applicable to the HVDC link) are outlined in more detail in the Commission's explanatory paper entitled – "Commission's Final Decision HVDC Transmission Pricing Methodology" (published in March 2006)[25].

3.3.21 This was a complex decision on a longstanding issue and the Commission was required to balance a wide range of conflicting interests, including diametrically opposed views about who should pay for the HVDC assets. The decision followed an extensive consultation process with the industry including written submissions and cross submissions. The Commission published a summary of submissions and a draft decision[26], which was used to facilitate a public conference attended by electricity industry, consumer and business interests. A central issue was whether all New Zealand consumers (North Island and South

[23] HAMI refers to the customer's 12 highest injections into the grid at that location during the relevant pricing year, or during any of the four immediately preceding pricing years, whichever is highest.

[24] This decision was reached on a Court ordered re-consultation after the Commission's original decision (made in late 2004) was successfully challenged for process deficiencies by Meridian and Contact in 2005. *Contact Energy Limited v Electricity Commission, 29/8/0, MacKenzie JHC Wellington,CIV-2005-485-624.*

[25] Available at: http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/tpg/Final-hvdc-pricing-10mar06.pdf

[26] Available at http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/tpg/subsum-hvdccross.pdf

Island) should contribute or whether the costs should be borne by South Island generation plant alone.

3.3.22 The decision followed the regulatory framework set out in section 2.3 of this paper and was based on the following rationale:

(a) The primary contributors (users) to the costs of the existing HVDC assets are South Island generation plant and North Island consumers but there are efficiency gains from improving location signals.

(b) The decision strongly incentivises generators to look for least cost investment options.

(c) Charging South Island generation plant is desirable as it sends a stronger locational signal for new plant (as it is more efficient to locate generation close to load).

(d) Charging South Island generation plant is the least distortionary option with regard to altering decisions about consumption and investment.

(e) The decision is fair as the bulk of benefits of the HVDC link accrue to South Island generation plant.

(f) The decision supports the Act's specific outcome of maintaining downward pressure on electricity prices.

3.3.23 Two additional matters were considered at the time of the final decision:

(a) the implications of the HVDC pricing decision on security of supply for the South Island; and

(b) impact on climate change.

3.3.24 Analysis undertaken by the Commission at the time indicated that South Island security of supply (both in terms of peaking capacity and dry-year security) can be achieved over the next twenty years even if the great majority of new generation is built in the North Island. The Commission considered that the possible threats to security of supply were unrelated to the HVDC pricing guideline decision.

3.3.25 It was also concluded that climate change outcomes were not compromised by the decision as:

(a) the bulk of the potential for wind generation is in the North Island;

(b) all the geothermal is in the North Island;

(c) distributed generation is more likely in highly urbanised areas; and

(d) the additional charge to South Island generation plant is unlikely to alter decisions about whether North Island thermal plant (using liquefied natural gas) is built before South Island renewables.

3.3.26 In summary, the Commission sought with its HVDC pricing decision to minimise costs for businesses and consumers, and encourage the building of generation closer to major demand centres.

3.3.27 Levying the charge on South Island generation plant provides an explicit locational signal through transmission pricing: new generation investment in the South Island faces the HVDC charge whereas new generation investment in the North Island does not. This means that, all other things being equal, new generation would prefer to locate in the North Island.

3.3.28 The results of the analysis in Appendix 3 – that there are unlikely to be benefits from locational signalling for economic transmission investment – suggest that it may be worth re-examining the existing HVDC charging regime.

3.3.29 The regulatory framework sets out the matters to be considered in reviewing the TPM, including the allocation of HVDC costs (section 2.3 of this paper). The analysis in this paper looks at one set of considerations in isolation – the efficiency or otherwise of the price signals for participants' operational and investment decisions. Stage 3 of the review (identification and evaluation of a preferred option) will include a more complete analysis of matters set out by the regulatory framework (see section 2.3). A matter that the Commission considers will be relevant is any potential wealth transfers that may have the effect of increasing retail electricity costs and reducing electricity consumption.

3.3.30 This section:

(a) identifies the costs and benefits of the operational and investment signals in the current HVDC charging regime;

(b) provides an initial assessment of these; and

(c) suggests possible options for HVDC cost allocation.

3.3.31 The benefits and costs of the operational and investment signals in the current HVDC charging can be described as the following.

(a) The **benefit** of preventing or deferring the need for a new inter-island link.

(b) The **benefit** of preventing or deferring the need for alternating current (**AC**) transmission upgrades that support northward flow.

(c) The **cost** of incentivising new North Island generation options rather than more economic South Island options.

(d) The **cost** of disincentivising South Island generators from operating at their full capacity (because it would increase their HAMI).

(e) The **cost** of disincentivising South Island generators from taking opportunities to increase their peaking capacity (again, because it would increase their HAMI).

(f) The **cost** of reduced competition in generation development, because owners of existing South Island generation (notably Meridian) face a lower marginal signal on increased capacity than other generators[27].

3.3.32 These benefits and costs are considered below, supported by initial high-level analysis.

Table 1: Initial analysis on the costs and benefits of the operational and investment signals in the current HVDC charging

(a) The benefit of preventing or deferring the need for a new inter-island link
It is not expected that a second HVDC link will be required and it is hard to construct a scenario in which the benefits of a second link justify the very substantial costs. This suggests that this benefit is unlikely to be material. It is possible that incentivising new North Island generation may defer the need to add a new DC submarine cable (referred to as Stage 3 of Transpower's development plan[28], increasing the northward transfer capacity from 1200 to 1400 MW). However, GEM analysis based on the draft 2010 SOO scenarios indicate that the new cable is not likely to be required in the foreseeable future, even if the HVDC charge on South Island generators is removed. On this basis, the expected benefit of deferring the additional cable does not appear material. (Earlier scenarios included more South Island generation and might have shown some benefit from deferring the new cable, but would also have shown an increased cost from incentivising new North Island generation options over potentially more economic South Island options – i.e. a higher cost (c) below.)

[27] There is a lower marginal signal on increased capacity for owners of existing South Island generation because each additional MW of capacity they construct reduces the allocation of HVDC charges to their existing capacity. For example, suppose total South Island generation capacity is 4,000 MW, Generator A owns 50% of this capacity, and Generator B owns none. Suppose further the total HVDC cost to be recovered is $100M p.a. If Generator A increases their capacity by 50 MW, their allocation increases from 50% x $100M to [(4,000 x 50% + 50) / 4050 x $100M] - an effective marginal cost of $12/kW p.a. If Generator B increases their capacity by 50 MW, their allocation increases from 0 to [50 / 4050 x $100M] - an effective marginal cost of $24/kW p.a.

[28] http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/HVDC/May08-proposal/proposal.pdf

(b) The benefit of preventing or deferring the need for AC transmission upgrades that support northward flow; and **(c) The cost of incentivising new North Island generation options rather than more economic South Island options.**
Benefit (b) and cost (c) are linked. The HVDC charging regime encourages generators to site new plant in the North Island rather than the South Island. This may mean that the most economic generation options are passed up in favour of less economic options (cost (c)); on the other hand, generation investment in the North Island will tend to reduce the cost of AC transmission upgrades that support northward flow (benefit (b)). A GEM experiment based on draft 2010 SOO assumptions, described in Appendix 4, shows that cost (c) is likely to be small but material. Estimates vary from scenario to scenario, with a mean of $16 million NPV. (A sensitivity with increased variability in wind and geothermal costs reduces this to $8 million NPV.) This cost stems from deferring less expensive South Island renewable generation in favour of more expensive North Island generation. (According to the 2010 SOO assumptions, some North Island generation options – typically geothermal – are more economic than South Island options. There is no harm in incentivising these options. On the other hand some South Island generation options – typically large hydro – may be highly economic and should not be discouraged.) There is no clear evidence that benefit (b) is material. The analysis in section 3.3 of this paper suggests that the benefit of providing signals to defer economic transmission investments is unlikely to substantially outweigh the cost of generation-side inefficiencies. It is hard to demonstrate that any specific AC investment is likely to be deferred as a result of the HVDC charge. Major investments supporting north flow have already been approved (NIGU, NAAN, Central North Island Renewables), or submitted for approval (LSI Renewables). An argument could be made that the HVDC charge could increase the quantity of new North Island generation, which might be located closer to load and thereby defer North Island reliability investments. On the other hand, new South Island baseload generation could actually be beneficial in terms of deferring South Island AC investments (e.g. Waitaki Valley to the upper South Island (**USI**) region).

(d) The cost of disincentivising South Island generators from operating at their full capacity (because it would increase their HAMI).

NERA noted in *New Zealand Transmission Pricing Project* (p 61)[29] that 'the potential distortions to use of existing peaking capacity brought about by the HAMI charging parameter *may not be all that significant'*. The Commission disagrees with some key assumptions in the NERA analysis[30], but has reproduced the analysis with revised assumptions and concurs that, in theory, there should be sufficient incentive for existing South Island generators to offer available generation at peak times.

Despite the theory, South Island hydro generators are currently withholding over 100 MW of peaking capacity as a result of the HAMI allocation. This generation is made available at times of grid emergency (Transpower has agreed not to adjust the generators' HAMIs for this increase[31] in output during the grid emergency) but is not available at other times. In the worst case scenario, this could lead to construction of 100 MW of unnecessary North Island thermal peaking capacity, at a cost on the order of $100M.

The value of cost (d), then, is somewhere in the range of $0-$100M. The Commission's provisional view is that it is at or near the low end of the range, because:

(a) South Island peaking capacity can/will operate at times of grid emergency subject to Transpower's agreement to adjust the HAMI;

(b) volatility in prices over the last few years appears sufficient to justify the full use of peaking capacity at other times;

(c) increasing penetration of wind generation should increase price volatility in future years, thus increasing the incentive for South Island generators to use all available capacity; and

(d) the introduction of scarcity pricing could lead to greater price volatility.

Disincentivising South Island generators from operating their plant at full capacity could potentially be material, but the Commission's preliminary view is that it is not.

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[29] Available at: http://www.electricitycommission.govt.nz/opdev/transmis/tpr

[30] Firstly, NERA underestimated the HVDC revenue requirement at $80M p.a. – the Commission estimates $160M in 2013. Secondly, NERA's first example fails to consider that an increase in HAMI can lead to an increased HVDC cost allocation not only in the current year, but in each of the next four years. (As a consequence of these two errors, NERA's estimate of the single-period price required to recoup a HAMI increase is too low by a factor of ten.) Thirdly, NERA's calculation that a $39/MWh price occurring 5% of the time is enough to justify a 10 MW HAMI increase by a merchant generator is incorrect, in that it fails to consider the opportunity cost of increasing output at peak times. For a hydro generator, this is the value of water. Such a hydro generator requires a $39/MWh (or $78/MWh with the correct HVDC revenue requirement) *uplift* on prices in nearby time periods, in order to justify the HAMI increase. This is a much more stringent requirement than a $39/MWh price. Nevertheless, the Commission's calculations indicate that the volatility of South Island prices in recent years has been just enough to justify a merchant hydro generator incurring additional HVDC charges by using its full capacity. This means that there has been more than enough

(e) The cost of disincentivising South Island generators from taking opportunities to invest to increase their peaking capacity (again, because it would increase their HAMI).
Cost (e) is considered to be small but material. The HAMI allocation discourages generators from: (a) adding additional peaking generation capacity (e.g. choosing low capacity factor designs when constructing new hydro plant); (b) maintaining existing peaking generation capacity (e.g. keeping all units in service, if some are used rarely); (c) upgrading existing peaking generation capacity (e.g. taking options during plant refurbishment that add additional MW output); and (d) pursuing resource consents that allow increased peak output. All these activities incur additional cost which is harder to recoup with the HAMI allocation in place. Anecdotally, generators take a cautious view of their ability to recover these costs. Initial thinking based on information received from participants and considered in Appendix 4 suggests that the inefficiency stemming from this disincentive is likely to be in the range of $0-25M (post-tax 2010 NPV).
(f) The cost of reduced competition in generation development, because owners of existing South Island generation (notably Meridian) face a lower marginal signal on increased capacity than other generators.
There is a lower marginal signal on increased capacity for owners of existing South Island generation because each additional MW of capacity they construct reduces the allocation of HVDC charges to their existing capacity. The cost of the reduced competition in generation development as a result of this imbalance has not been investigated, but would potentially be material only if efficient projects do not proceed. GEM analysis could potentially be carried out to estimate the cost (it would be expected to be smaller than cost (c)).

volatility to justify an incumbent hydro generator using its full capacity – because, as has been noted, incumbent generators face a weaker marginal HVDC pricing signal.

[31] Under Clause 7.2 of the TPM Transpower can adjust a customer's HAMI when it considers that "exceptional operating circumstances" have resulted in distortions to a customer's HAMI.

3.3.33 Table 2 summarises the costs and benefits listed above.

Table 2: Key costs and benefits of the current HVDC charging regime

Item	Nature of cost/benefit	Initial assessment of Materiality
Benefits		
(a)	Preventing or deferring need for new DC link	Not material
(b)	Preventing or deferring need for new AC upgrades	Probably not material
Costs		
(c)	Incentivising NI generation investment rather than more economic SI investment	Material but small – initial estimate is $16 million NPV, although this falls to $8 million for high variability in wind and geothermal costs.
(d)	Disincentivising existing SI generation from operating at full capacity	Preliminary view: not material
(e)	Disincentivising incremental SI peaking capacity	Material but small enough to be discounted - estimate $0-$25 million NPV
(f)	Competitive advantage to Meridian in constructing new SI generation	Not clear but likely to be smaller than cost (c)

Q6. 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.

3.3.34 At this point, the Commission considers that, depending on the assessment of costs, benefits and other regulatory settings, there are four possible options for the HVDC charge.

(a) <u>Maintain status quo</u>

If the following conditions hold:

(i) the benefits of incentivising North Island generation outweigh the costs (i.e. costs (c) and (f) are less than benefit (b)); and

(ii) discouraging operation and investment in South Island peaking capacity through the HAMI allocation is not a problem (i.e. costs (d) and (e) are not material or are small enough to be discounted); and

(iii) other factors derived from the regulatory settings (e.g. regulatory certainty) on balance support maintaining the status quo.

Then no change to the HVDC charging is necessary.

(b) Move to per MWh charge

If the following conditions hold:

(i) the benefits of incentivising North Island generation outweigh the costs (i.e. costs (c) and (f) are less than benefit (b)); but

(ii) discouraging South Island peaking capacity through the HAMI allocation is inefficient (i.e. costs (d) and (e) are material).

Then the HVDC charge should remain on South Island generators, but should be allocated proportionately to generation in MWh, provided that:

(i) other factors derived from regulatory settings (e.g. regulatory certainty) on balance support such a change; and

(ii) a per-MWh allocation did not create significant new inefficiencies.

If these conditions do not apply, the status quo should be retained.

The effect of changing to a per-MWh charge would be to retain a signal for generation to locate in the North Island, but without specifically discouraging generators from installing new South Island peaking capacity or fully utilising existing South Island generation plant.[32]

Any per-MWh allocation should be based on total generation over several years – as opposed to generation in the current year only, which would cause substantial year-to-year variation.

NERA has suggested that a per-MWh allocation would create substantial inefficiencies by discouraging South Island generators from offering their plant when wholesale prices were expected to be barely over their cost of 'fuel'[33]. Preliminary analysis by the Commission indicates that this inefficiency exists but is very small – with an NPV under $5M (Appendix 4).

[32] The per-MWh charge would not remove the competitive advantage held by incumbent South Island generators.

[33] *New Zealand Transmission Pricing Project*, NERA (p91) available at: http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/tpr/NERA-Report-Dec09.pdf

(c) Incentive free allocation to South Island generators

If the following conditions hold:

(i) the benefits of incentivising new North Island generation are unlikely to outweigh the costs (i.e. costs (c) and (f) are more than benefit (b)); but

(ii) other factors derived from regulatory settings (e.g. regulatory certainty) do not, on balance, support removing the HVDC charge from South Island generation plant.

Then the HVDC charge should remain on South Island generation plant, but in an 'incentive-free' way that does not distort operational or investment decisions. In other words owners of generation assets in existence at "x" date cover the costs of the HVDC charge. New investors do not contribute to the HVDC charge.

This approach would be feasible if a practical and sustainable incentive-free allocation can be devised.

NERA has suggested that the best way to create an incentive-free allocation would be to charge according to nameplate capacity. The Commission disagrees, considering that this may create a perverse incentive to reduce (or decline to increase) nameplate capacity. There can also be difficulties in determining a nameplate capacity. An alternative approach might be to allocate HVDC costs proportional to HAMI over some historical reference period, say 2005-09. The cost allocation would remain constant in future, regardless of any new generation or changes to existing generation. This would mean that:

- generators would not be discouraged from operating at full output;
- there would be no disincentive against adding new South Island generation plant or maintaining existing South Island capacity; and
- the TPM would no longer give incumbent generators such as Meridian a competitive advantage in the South Island.

It remains to be determined whether an incentive-free allocation can be implemented in a practical and sustainable way. The historical allocation described above appears to have advantages, but it could be difficult to future-proof with regard to events such as transfers of generation plant from one owner to another. More work would need to be done to determine the viability of this approach.

If no satisfactory incentive-free allocation can be devised then the status quo should be retained.

(d) <u>Postage stamp</u>

If the following conditions hold:

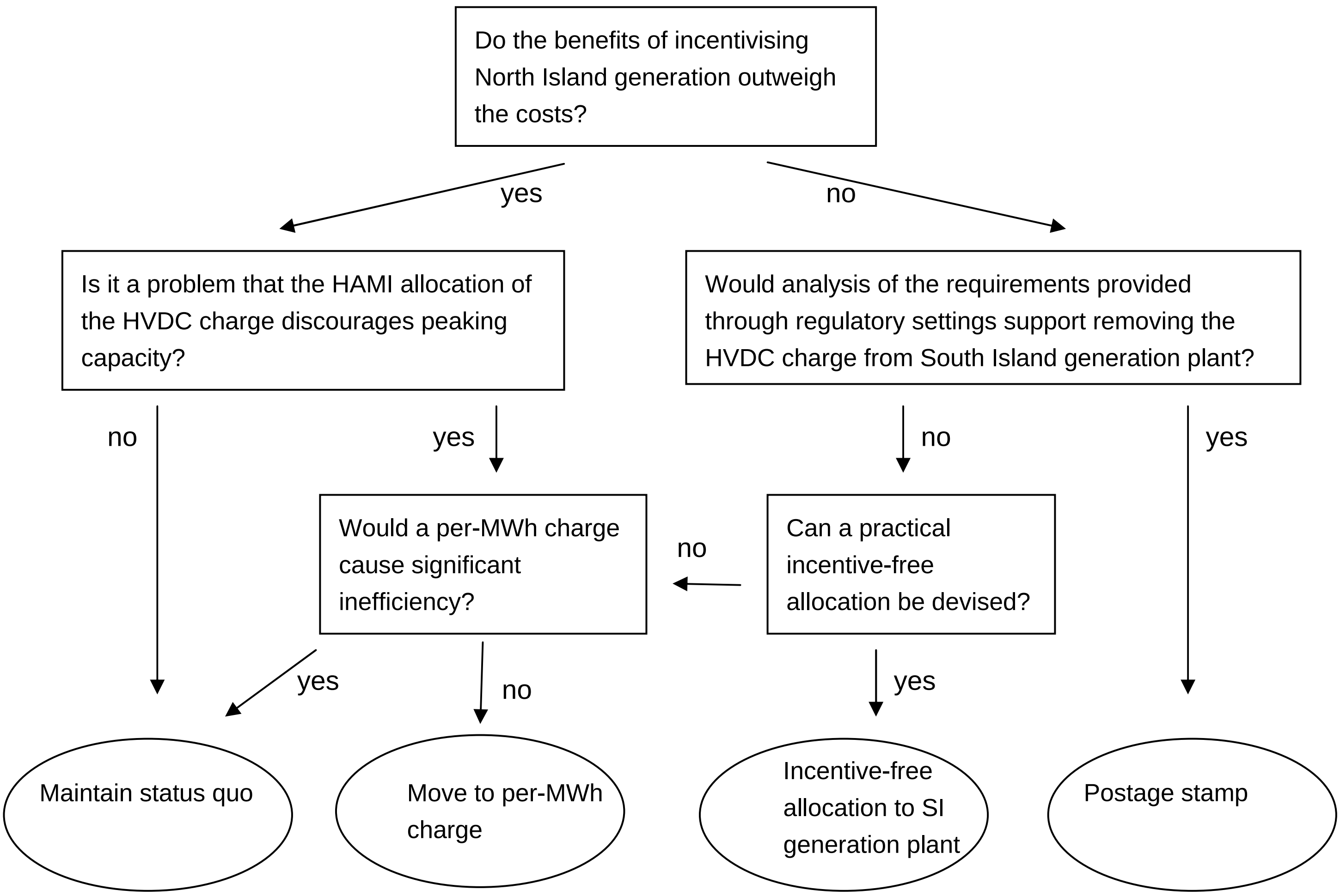
(i) the benefits of incentivising new North Island generation are unlikely to outweigh the costs (i.e. costs (c) and (f) are more than benefit (b)); and

(ii) other factors derived from regulatory settings (e.g. regulatory certainty) do not justify retaining the HVDC charge on South Island generation plant,

Then HVDC costs should be spread broadly throughout New Zealand, over load, generation or a mixture of both. The charging basis for these costs would need to be considered.

3.3.35 These options are illustrated in Figure 2.

Figure 2: Four possible options for the HVDC charging regime



Other matters for consideration

3.3.37 The analysis has not considered potential lower-level issues around the structure and details of HVDC charging. For example, the effect of the HVDC charge being applied to total generation rather than net injection. Currently South Island embedded generation can avoid or partially avoid the HVDC charge. In stage 3 the Commission will consider whether this creates the correct incentives along with other issues that arise.

Q7. 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.

Q8. What are your views on the validity of each of the options?

Q9. Do you have specific lower-level issues around the structure and details of HVDC charging that you would like considered in stage 3?

3.4 Analysis of the benefits of signalling reliability-driven investment

3.4.1 Section 3.3 of this paper has described the analysis of the potential benefits of signalling for economic transmission investments. The section concluded that there are unlikely to be significant benefits for enhanced signalling for economic transmission investments.

3.4.2 This section considers separately whether there may be benefits from enhanced signalling or other mechanisms to avoid the costs of reliability-driven investments.

3.4.3 Reliability investment is primarily to support reliable supply to load. The need for reliability investment is driven by peak demand. Avoiding, or deferring the costs of reliability-driven investments involves investment in alternatives – namely demand side management (**DSM**) and firm local plant able to generate at peak times. Avoiding or deferring investment in reliability transmission assets should be encouraged where it is economic to do so.

3.4.4 Section 3.2 outlines the factors that suggest that nodal pricing may not provide sufficient locational signals for investment in generation and load generally.

3.4.5 One of these factors was particularly relevant to reliability investments; the fact that transmission investment may not always be approved in a manner and time that maximises economic benefits. Reliability investments are approved using deterministic reliability criteria that stress the need to maintain supply in the event of potential power system contingencies. Even when transmission investment would be undertaken optimally, there are prudent risk management practices that mean reliability (and economic) transmission investments may be approved and undertaken early.

3.4.6 In summary, the economic theory suggests that further locational signalling to generation and load may be required for a more efficient pattern of investment in transmission, generation and load-responsive demand but as noted above the Commission's analysis suggests that this does not always hold particularly for economic investments.

3.4.7 In considering whether there may be benefits from providing any further signalling or other mechanisms for deferring reliability investments, the Commission has considered:

(a) the draft 2010 SOO forecasts for reliability investments;

(b) an example of the benefits that might be realised in deferring possible reliability investments – transmission investments in the USI; and

(c) past experience of reliability investments and transmission alternatives.

Draft 2010 SOO forecasts

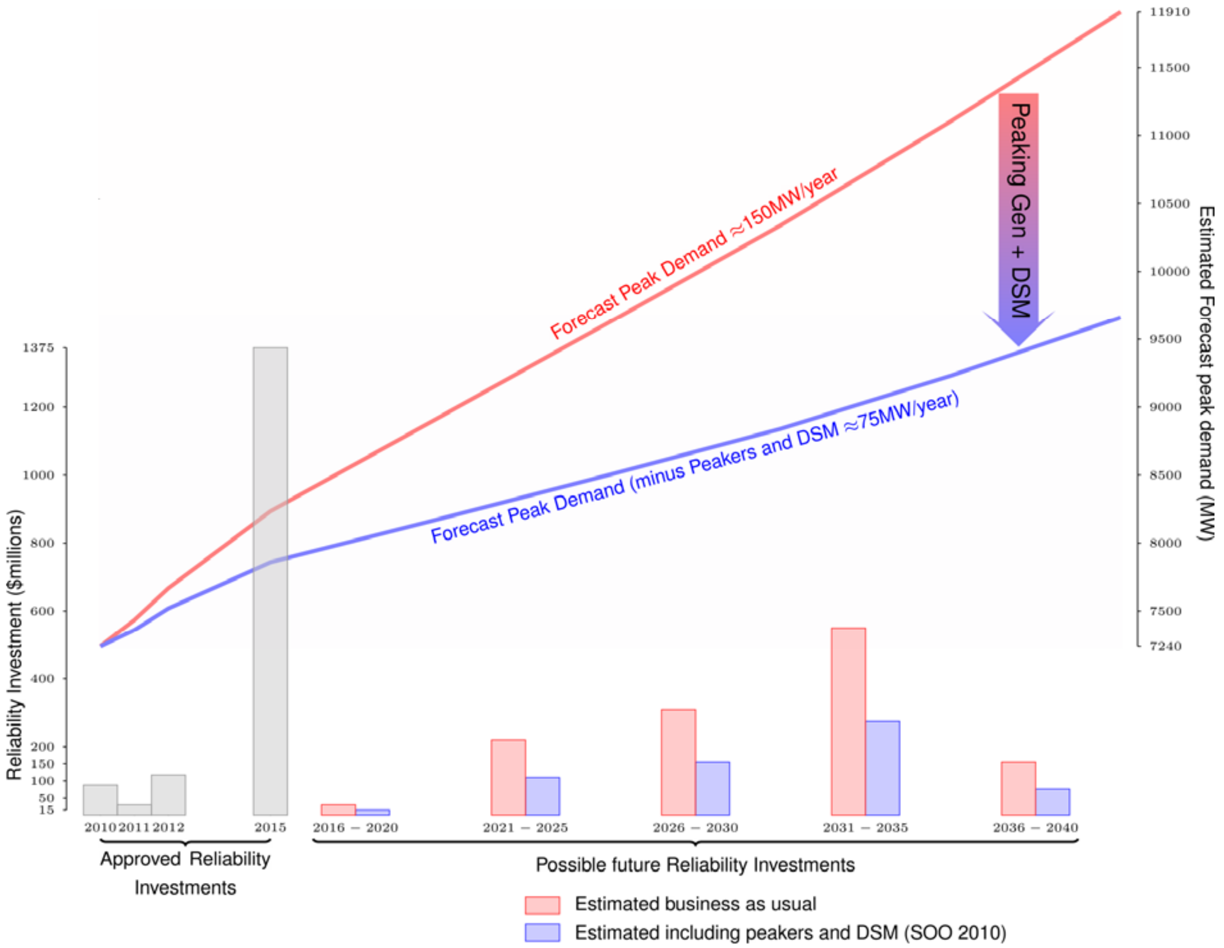
3.4.8 The draft 2010 SOO predicts steady demand growth nationally and predicts that this will drive further reliability transmission investment.

3.4.9 Figure 3 illustrates the average forecast demand growth (blue line) and level of reliability investment (blue bars) using the draft 2010 SOO scenarios. These forecasts assume a level of DSM and installation of peaking generation.

3.4.10 The red lines and red bars show an alternative scenario – where the DSM and peaking generation is not assumed – this is a 'business as usual' scenario.

3.4.11 The draft SOO anticipates that substantial quantities of DSM and new peaking generating capacity will be required because of the increasing 'spikiness' of the load (temperature sensitive load) and increasing penetration of renewables requiring firming plant over all scenarios. Low load factor plant of this type is usually most economically provided by either DSM or gas or diesel fuelled plant whose fuel source may not be tied to a specific location.

Figure 3 Demand growth and possible reliability investments (draft 2010 SOO)



3.4.12 The NPV of the difference between the forecast reliability investments, with and without the DSM and firming plant, is approximately $250 to $300 million (the NPV of the difference between the red and blue bars in 2015 dollars). This gives one indication of the economic benefits of DSM and firming plant in deferring reliability investments.

3.4.13 Additional benefits could arise if:

(a) future investments have not been fully identified in this analysis - these would effectively increase the business as usual costs (as indicated by the red bars) and result in additional increases in the economic benefit of DSM and firming plant[34]; or,

(b) a future with additional DSM and firming plant over and above that indicated by the average of the draft 2010 SOO Scenarios. This would result in a lower peak forecast, possibly with no net growth in which case no future reliability investments would be required (i.e., a horizontal blue

[34] The converse could also be true if demand was lower than forecast demand.

line with the blue bars reducing to zero). This could increase the economic benefit to between $500 and $600 million

Transmission Investment into the USI

3.4.14 Transmission into the USI consists of four main transmission circuits from Twizel (and the Waitaki Valley) to Christchurch. Future demand growth in the USI region may require further transmission investment options; these being bussing existing circuits near Geraldine or installing additional shunt dynamic reactive support) in 2017[35] and a possible new line by 2030[36]. The expected net market cost of the transmission investment is to around $110m ($2010).

3.4.15 The future demand forecast for this region is modest, averaging around 20 to 25MW/year. It is expected that there will be new peaking generation in the short-term, and if a 200MW peaking plant were located in this region, it could defer transmission investment substantially (possibly up to 10 years). The expected net market cost of the transmission investment under this scenario is $60m ($2010) giving a possible net benefit of deferring the investment by 10 years of $50m ($2010).

Past experience of reliability investments and transmission alternatives

3.4.16 Analysis of the possible efficiency gains of generation investment compared to transmission investment on the recent approvals of the NIGU and NAaN projects was outlined in the stage 1 consultation paper.

3.4.17 As described in the Commission's "reasons for decisions" documents for those two projects[37], if new generation were located in the Auckland or North Auckland regions a large component of the substantial transmission investment currently underway could have been avoided. Analysis based on considerations made when the projects were approved identifies approximately $0.5 billion of net benefit of locating generation close to Auckland, since that would avoid a

[35] Sourced from information at pages 72 and 83 of Transpower's Annual Planning Report 2010 (**APR**)), available at http://www.transpower.co.nz/f3652,31346281/annual-planning-report-2010.pdf

[36] Grid New Zealand website:***http://www.gridnewzealand.co.nz***

[37] Reasons for the Commission's decision to approve the NAaN project can be found in the decision document entitled "Final Decision on Proposal One in Transpower's North Auckland and Northland Investment Proposal", available at http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/gup/naan/May2008/Reasons-for-decision-1May09.pdf. Reasons for the Commission's decision to approve the NIGU project can be found in the document entitled "Reasons for Decision set out in Notice of Intention to Approve Transpower's North Island Grid Upgrade Proposal" dated 23 February 2007, available at http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/Feb07-decision/Reasons-for-Decision-23Feb07-v15.pdf

significant portion of the transmission costs associated with the NAaN and NIGU projects.

3.4.18 However, in its deliberations the Commission concluded that it was not certain that generation would be built within the 20 year timescale used in the application of the GIT.

3.4.19 To date there have been no specific transmission alternatives approved as alternatives to investment in interconnection assets since the Part F regime came into effect in 2005.

3.4.20 Despite the difficulties in quantifying the exact economic benefits resulting from an altered TPM, any incentive that defers future reliability-driven transmission investment will likely provide some net benefit.

Q10. 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.

4. Stage 2 options

4.1 Introduction

4.1.1 The analysis in Section 3 suggests that there are unlikely to be benefits from signalling to generators of the cost for economic transmission investment but that there are likely to be benefits from signalling or providing other mechanisms for deferring reliability investments.

4.1.2 The Commission considers that it is not worthwhile pursuing changes to the TPM that are likely to involve substantial development effort for little, if any, gain. The only options that should be pursued are those that are relatively incremental or straightforward to implement and that will show some benefit. The discussion of the options that follows reflects these conclusions.

4.1.3 In the stage 1 consultation paper, the Commission canvassed the following high-level options for a TPM.

(a) Status quo, possibly with some modifications to the nature and structure of existing charges.

(b) Tilted postage stamp.

(c) Augmented nodal pricing.

(d) Load-flow approaches.

4.1.4 The three alternatives to the status quo were proposed in order to provide enhanced locational signalling for generators and load, although the stage 1 consultation paper did ask whether there might be minor modifications that could be made to the status quo in order to provide additional locational signalling.

4.1.5 Each of these options was assessed against a number of ‘filtering criteria’ designed to help create a list of options for further consideration. This assessment is included in section 5 of Appendix 2 and is summarised in table 1 in the appendix.

4.1.6 In stakeholder submissions on the stage 1 consultation paper, several additional options or approaches were put forward. These included:

(a) market-wide tilted postage stamp option (NERA for CEO Forum);

(b) bespoke tilted postage stamp option (NERA for CEO Forum);

(c) ‘but for’ approach to charging shared network costs (NZIER for MEUG); and

(d) capacity rights and arbitrageur options for recovering HVDC costs (NZIER for MEUG).

4.1.7 Details and considerations of these options are included in Appendix 2, sections 4 and 5.

4.1.8 On the basis of both the assessment of the high-level options in section 5 of Appendix 2 and the analysis of the potential benefits of locational signalling to generators of the costs of economic investment in transmission, the Commission considers that certain high-level options should not be pursued further. These are:

(a) augmented nodal pricing – due to its novelty, complexity, and requirement for judgment;

(b) market-wide tilted postage stamp (original and NERA versions) – due to the likely lack of benefit from setting such charges across the market and the additional complexity of setting market-wide charges compared to a narrower bespoke version (see below);

(c) NZIER 'but for' approach – due to its complexity, likely subjectivity and difficulty of implementation; and

(d) NZIER HVDC charging approaches – due to the likely lack of benefit in radically changing charging arrangements to provide locational signals to defer or avoid further HVDC investment that is unlikely to be required; .

4.1.9 Rather, the options that the Commission is considering are focussed on two areas:

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

(b) options for the treatment of HVDC costs.

4.1.10 These options involve potential modifications to the status quo with the possible exception of one – flow-tracing to allocate some network costs – which, depending on the extent to which it could be implemented may involve more substantial change. The status quo, without modifications, remains an option that will be considered alongside these options in stage 3.

Q11. 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.

4.2 Options for providing incentives to defer or avoid reliability transmission investments

4.2.1 The Commission considers that, alongside the status quo, the following options for deferring or avoiding reliability transmission investment should be more closely examined.

(a) **Bespoke postage stamping** option involving a higher charge on loads and credits to generators in particular regions – this is intended to provide localised signals for additional peaking plant and demand response in areas likely to require reliability transmission investment in the medium term, perhaps based on the use of a long run marginal cost (**LRMC**) approach to determining locational charges (see further below).

(b) **Flow tracing** approach to allocating the costs of a portion of interconnection assets to specified off-take parties either as a deeper connection charge or as an allocation of interconnection assets to specified parties possibly coinciding with a shallower approach to defining connection assets.

(c) **Improving the transmission alternatives regime** – particularly by avoiding the perceived competing interests faced by Transpower as both the network owner and the party responsible for the procurement process and assessment of alternatives against network options.

4.2.2 The Commission considers that these options are not mutually exclusive and may be implemented in some combination. The outline structure and advantages and disadvantages of each option are discussed below. Options will be compared to the status quo in stage 3.

Bespoke pricing signals

4.2.3 As noted above, the Commission has found no evidence that a market-wide tilted postage stamp pricing methodology is likely to provide a net benefit. However, 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. An option of this type was raised by NERA in its work for the CEO Forum.

4.2.4 Participants in other locations would continue to face the standard Interconnection Charge that would apply only to loads. But participants in the selected regions would face a charge that would diverge from the standard Interconnection Rate in a symmetric manner. For example, if the Interconnection Rate was $60/kW, the bespoke rates could be $90/kW for loads and -$30/kW (ie a credit) for generators[38]. The divergence from the Interconnection Rate could be determined by the LRMC of transmission in that bespoke region compared to the average LRMC of transmission across the network, subtracting expected transmission rentals from both. In addition, the bespoke charge could also be structured on a RCPD basis, identically to the Interconnection Charge.

4.2.5 This type of pricing signal would have the following advantages:

(a) Bespoke application should provide a strong locational signal to stimulate new generation and demand response in those specific locations where it is likely to be most beneficial. This avoids the need to develop a fully-fledged tilted postage stamp charge to apply across the market.

(b) RCPD charging basis focuses on rewarding peaking generation and peak demand response, which is appropriate given that peak demand is the driver for much reliability transmission investment.

(c) Symmetric divergence of the bespoke region rates from the Interconnection Rate should make generation investors indifferent between connecting to the transmission network or embedding within a distribution network. Assuming the Interconnection Rate and the bespoke rates discussed above at paragraph 4.2.4, a generation investor locating in a bespoke region would either:

(i) receive a credit rate of $30/kW if it connected to the grid, which is $30/kW higher than if it located in a 'non-bespoke' region; or

(ii) reduce the charge payable by its local load at a rate of $90/kW if it embedded, which is $30/kW greater than if it located in a non-bespoke region.

4.2.6 More generally, such a bespoke charge and credit regime would provide an advance signal that could promote beneficial behaviours before additional reliability transmission investment was necessary. Conversely, a non-pricing approach – such as tendering for transmission alternatives (see below) – would effectively involve delaying a clear signal until action was made necessary. This may or may not be desirable.

4.2.7 A bespoke charge and credit option has the following disadvantages:

(a) A basis for the divergence of the bespoke charge from the standard Interconnection Rate (such as the LRMC of transmission in bespoke locations compared to the rest of the network) needs to be established. This effectively involves calculating the LRMCs of transmission across the entire network.

[38] The current Interconnection Rate is $69.12/kW. See: http://www.transpower.co.nz/f3214,25123475/appendix-2-transmission-pricing-2010.pdf.

(b) It may not provide an enduring signal (as noted by NERA in its work for the CEO Forum). Any tilted postage stamp regime (including a bespoke version) needs to offer durable pricing signals in order to promote certainty for long-life investments. Durable pricing signals require that the imbalances between load and generation that drive network power flows and hence new transmission investment are enduring over the long term and do not disappear following one or a small number of new generation investments in the desired location. However, if the desire is merely to incentivise peaking or DSM during a 'deferment period' of a proposed transmission investment, this lack of an enduring signal may not be a significant issue.

(c) It may distort the energy market. To the extent that it changes participants' real-time production or consumption decisions, it may reduce the efficiency of use of the existing transmission network.

(d) Generators may be willing to locate in the desired location without the signal.

4.2.8 In this context, the Commission needs to compare the benefits of providing generation investors in particular locations with transmission price signals against other options for promoting favourably-located new generation and demand response. A transmission pricing signal may be appropriate if it can be calculated robustly and transparently and is reasonably durable. But if a targeted price signal is likely to be unstable due to the arrival (or departure) of one or a small number of plant, then it may be more appropriate to consider more direct means of encouraging firm plant in the desired locations. One example of such a direct mechanism is an enhanced regime for enabling transmission alternatives (see below).

4.2.9 Another potential drawback of a pricing approach is that the approach relies on generators and loads competing away the rents that are likely to accrue from locating in a bespoke region. If, for example, a generator can retain **all** of the difference between:

(a) the (LRMC-based) credit it receives from locating in a bespoke region; and

(b) its higher costs of locating in the bespoke region,

customers will be no better off – and perhaps worse off – than if the reliability investment had simply gone ahead. The benefits of this approach rely on several prospective generators (or loads) competing so that the bulk of the system cost savings are passed through to consumers through lower delivered energy prices.

Flow trace network cost allocation

4.2.10 As noted above, one option raised in the stage 1 consultation paper was load-flow based approaches to the allocation of shared transmission costs. The Commission's intention would be to use a type of flow based approach – flow tracing – to allocate a larger share of the costs of interconnection assets to individual loads. This could involve either deepening the definition of connection assets or allocating a larger share of the costs of interconnection assets to individual loads. This second option – involving some 'allocated interconnection costs' should avoid any conflicts with the Benchmark Agreement and Customer Investment Agreements because assets that are the subject to these agreements would not be affected. It could also be used in conjunction with a shallower connection.

4.2.11 Submitters to the stage 1 consultation paper did not generally favour a load-flow analysis based approach to transmission pricing, although their views tended to be based on the historical use of such techniques.

4.2.12 One method that could be used to allocate a larger share of the costs of interconnection assets to individual load customers is called 'flow-tracing'. This method involves:

(a) using scheduling, pricing and dispatch software (SPD) Final Pricing data on electricity volumes (upon which the market is settled) to determine the proportion of the total electricity flow on each transmission asset that is attributable to individual loads, which are accordingly deemed to 'use' that asset in that proportion; and

(b) where the proportion of flow on any given asset attributable to a particular load exceeds a certain threshold of utilisation (e.g. 80%) over a particular period of time, the costs of that asset are allocated to that load.

4.2.13 A range of parameters can be used to determine the relevant measure of utilisation that leads to the allocation of the costs of interconnection assets. For example, the utilisation of an individual participant and the threshold levels of utilisation can be determined:

(a) over "n" years where "n" could be 1,2,3,4,or 5; and

(b) over all periods, peak periods or selected periods only.

4.2.14 While this method could also be used to attribute network costs to generators, the Commission is not considering this because reliability investments are driven by load.

4.2.15 This option has the following advantages:

(a) It provides incentives for the relevant loads to take action to defer or avoid new transmission investment that is likely to be required to serve their individual requirements. Participants will know that transmission investment undertaken in the future to meet their needs will eventually make up part of the interconnection costs to be allocated to them. The application of a reasonable proportional usage threshold means that larger economic investments that serve many customers are unlikely to have their costs allocated in this way. The focus of this charge will be on assets that are principally required to serve a limited number of customers, as many reliability-driven investments are. This focuses the pricing signal in a way that should help confer benefits where the Commission believes they are available – in the deferral of reliability investment rather than economic investment.

(b) It should motivate customers to scrutinise transmission investments more closely, thereby improving the governance of the transmission planning process. The more that costs are smeared across all customers, the less the incentive for individual customers to take action and get involved in the planning process and approval process.

4.2.16 The Commission acknowledges several disadvantages with this option, some of which were raised in the stage 1 consultation paper, including:

(a) The use of thresholds to determine where and how asset costs should be allocated raises the risk of creating perverse incentives at the margin for load participants to attempt to shift their measured share of flows and hence costs. Related to this is the risk that loads may invest or enter into arrangements designed to alter their usage of the network in order to avoid charges in respect of the sunk network where no new investment is expected for some time (eg in the Upper North Island). Such behaviour would be inefficient.

(b) Concerns that instability in network flows from year to year could create instability in the allocation of costs. However, it should be possible to design the charge in a way that prevented this from occurring – for example, through averaging. In addition, using flow tracing solely for load is less likely to create stability issues – demand is relatively stable, not unduly impacted by hydrological variations and the flow-tracing would only be used for below a threshold utilisation.

(c) A further concern is the issue of pass-through of transmission charges by distributors. Although some distributors do endeavour to reduce transmission costs to their customers, the current regulatory arrangements give them little financial incentive to do so. However, the Commerce

Commission is proposing[39] to address this regulatory anomaly by allowing those lines companies subject to the price quality regime (non-exempt Electricity Distribution Businesses) to retain avoided transmission charges where it can be demonstrated that the avoided charge is a *"result of reducing the overall cost of the supply of electricity line services.*" [40]

Q12.	**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?**

Improving the transmission alternatives regime

4.2.17 The transmission alternatives regime provides a direct means of procuring peaking generation or demand response to avoid or defer reliability and economic transmission investment. Transmission alternatives are required to be considered in the evaluation of new grid investments under the GIT.

4.2.18 Transpower is required to consider transmission alternatives when applying the GIT. Presently, this involves a request for proposal (**RFP**) process managed by Transpower. If the GIT is satisfied by a transmission alternative, the proponent of that alternative may enter into a grid support contract (**GSC**) with Transpower. Transpower is entitled, following approval from the Commission, to recover its payments under the GSC through its customer charges.

4.2.19 Some submitters considered that the key shortcoming in the current transmission alternatives regime is Transpower's perceived competing interests as network owner and the entity responsible for conducting the RFP process and assessing any proposed alternatives. While the Commission ultimately approves reliability and economic investments, Transpower is primarily responsible for determining what information is made available in the RFP and in assessing alternatives put forward. The central role of Transpower in the consideration of transmission alternatives, when it has historically sought network investment, creates a perception of competing interests.

4.2.20 One option for improving the transmission alternatives regime is to give an independent decision maker responsibility for conducting the RFP process. This independent decision maker would still need to work with Transpower to ensure any RFP accurately set out the technical requirements for the relevant project, but the independent decision maker would help promote transparency around

[39] http://www.comcom.govt.nz/assets/Pan-Industry/Input-Methodologies/Draft-Determinations/Draft-Commerce-Act-Electricity-Distribution-Services-Input-Methodologies-Determination-2-July-20.pdf

[40] Ibid – Clause 3.2.4 (5)

these requirements and the assessment of any proposed alternatives against those requirements.

4.2.21 A more incremental option would be for Transpower to continue to publish the RFP but for an independent decision maker to take over the assessment of any transmission alternatives that emerge in response to the RFP against the requirements set out in the RFP.

4.2.22 Either of these options would, to some extent, help overcome the perception of competing interests faced by Transpower in assessing transmission alternatives under the GIT. However, the corollary of this advantage is that both options effectively split the investment planning function to some degree between Transpower and the other decision maker.

4.2.23 A more general drawback of relying on the transmission alternatives process in the GIT to signal the need for new peaking generation or demand response is that it may encourage proponents to 'hold out' for a GSC instead of investing when it is efficient. As a GSC would involve a direct payment or a fairly certain stream of payments from Transpower, proponents may prefer to delay their projects in the hope of being offered a GSC instead of responding to other market signals.

4.2.24 However, if this is likely, it suggests that the GIT process needs to be undertaken further in advance of the need for the project. In light of the typically shorter lead times for generation and demand response projects compared with transmission investments, it is highly unlikely that a peaking generator or load would find it attractive to commence its project prior to the commencement of the development of a network investment.

4.2.25 As the Commerce Commission is responsible for approving Transpower's revenue requirement and will be responsible for the investment approval process, it would be appropriate for any changes to the transmission alternatives regime to be taken forward by the Commerce Commission.

Q13. 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.

4.3 HVDC Options

4.3.1 The analysis of the key costs and benefits of the current HVDC charging regime, set out in section 3.3, suggests that there are four possible options for charging for the HVDC:

(a) status quo;

(b) continue to charge South Island generation plant, but with an allocation proportional to generation in MWh;

(c) continue to charge South Island generation plant, but with an incentive-free allocation, perhaps based on historical output; and

(d) postage stamp – spread costs widely over load and/or generation in both islands.

4.3.2 The Commission is yet to determine a preferred option. Key questions that need to be resolved include:

(a) whether encouraging North Island generation through the HVDC charge is beneficial;

(b) whether discouraging South Island peaking capacity through the HAMI allocation of the HVDC charge is beneficial;

(c) whether a per-MWh HVDC charge on South Island generation plant would cause significant inefficiency;

(d) whether an "incentive-free" allocation of HVDC charges to South Island generation plant could be implemented in a practical and sustainable manner; and

(e) whether analysis of the requirements derived through regulatory settings would support removing the HVDC charge from South Island generation plant. This would include consideration of the benefit of regulatory certainty, and any potential wealth transfers that may have the effect of increasing retail electricity costs and reducing electricity consumption.

Q14. Can you suggest other matters to be included in the Commission's stage 3 deliberations on charging for HVDC costs?

4.3.3 The Commission is developing its thinking on the above questions, and welcomes comment from stakeholders. *Preliminary* views are that:

(a) 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);

(b) the HAMI allocation of HVDC charges is inefficient and should be changed;

(c) a per-MWh HVDC charge on South Island generators would not cause significant inefficiency; and

(d) 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.

4.3.4 Stage 3 will involve further consideration of these issues and of other requirements provided through regulatory settings as mentioned in 4.3.2(e)

Q15.	**Do you agree with these preliminary conclusions? If not, please provide reasons.**

5. Further issues

5.1 Introduction

5.1.1 The Stage 1 consultation paper considered four further issues for consultation. They were:

(a) The link between price and service.

(b) Connection charging issues.

(c) Transmission alternatives.

(d) Static reactive power compensation.

5.1.2 Submitters' views and Commission considerations for each of these issues are included in Appendix 2, section 6.

5.1.3 Each of these issues is considered in this section. In the case of static reactive power compensation three alternative options are outlined. More detail on these options and the supporting analysis is contained in Appendix 5.

5.2 The link between price and service

5.2.1 The stage 1 consultation paper considered the necessity of linking price and service and suggested different approaches that would achieve this efficiently. Consideration of this issue was in response to stakeholders reiterating past concerns that transmission prices paid do not directly relate to the service levels they request or receive. For these submitters, the linking of price and service was an integral part of the review.

5.2.2 Appendix 2, section 6.4 summarises the proposed approaches and submitters' views on the need for a mechanism and the suggested approaches. In general, submitters were divided on whether the Commission should progress this matter as part of the review and whether the proposed approaches were appropriate.

5.2.3 The Commission has reconsidered the relevance of this issue to the review and the appropriateness of the approaches. The conclusion is that price, and its links to the service provided, is an important issue which should be worked through.

5.2.4 Consideration of the submissions and the current regulatory and proposed regulatory regimes has meant that the issue will be continued to be investigated but not as part of the review. The results of this work will be provided in a handover package to the Authority to assist it in its consideration of setting quality standards for Transpower for inclusion into the new Code.

5.3 Connection issues

5.3.1 The Stage 1 consultation paper briefly discussed issues surrounding 'dedicated' connection assets in the context of earlier concerns expressed by NERA in their discussion paper for the CEO's Working Group (pp.29-30) (**NERA Report**). The Commission considered that in light of the contestable market for connection assets in New Zealand, parties faced the correct incentives to negotiate the development of new connection assets and, as a result, the existing regulatory regime appeared satisfactory. However, the Commission did not consider the incentives surrounding new participant investment in relation to existing connection assets.

5.3.2 Submitters raised a number of both general and specific concerns about the existing connection arrangements. These are outlined in Appendix 2, section 6.2. Many of these concerns were similar to those raised in the NERA Report.

New connection assets

5.3.3 As noted above, in the stage 1 consultation paper, the Commission considered that in light of the contestable market for connection assets in New Zealand, parties currently face the correct incentives to negotiate the development of new connection assets. As connection assets typically serve a relatively small number of parties, it ought to be generally the case that the actual or potential beneficiaries of connection assets can come to a mutually beneficial arrangement to determine the appropriate size, capacity and timing of investment in connection assets as well as their funding. The Commission considers that the transaction costs of negotiation between a small number of parties should be surmountable.

5.3.4 The question is whether such negotiation is likely to yield efficient outcomes where connection assets increase in size and scope. The NERA Report raised the prospect of deep connection 'extension' assets (**extension assets**) giving rise to inefficiency problems because potential 'first movers' would be deterred from investing if they knew other parties might try to negotiate access when the "first mover" has sunk its investment and is in a weak bargaining position. On the other hand, if the "first mover" did choose to invest on its own, NERA expressed concern that the "first mover" would be able to deny access to later parties. NERA's solution was to allow the GIT to be applied to such investments and the costs recovered through regulated charges (pp.53-54). Transpower expressed similar views.

5.3.5 While the application of the GIT to extension assets would avoid protracted negotiations and hold-out problems, the Commission notes that the scope for first mover and free rider problems under the present arrangements may not be significant in practice. If there are several parties who have an interest in a new extension asset, they have every incentive to form a consortium to not only fund such an investment, but to ensure it is ‘right-sized’ to meet all their future needs at least cost. This is because it would be in the interests of any potential “first mover” to share the costs of extension assets if those assets reflected economies of scale (e.g. if it were cheaper to build one 150 MW line instead of three 50 MW lines as in NERA’s example). Similarly, it would be in the interests of any potential ‘second mover’ to be involved in a consortium to ensure certainty over its ability to influence the price to connect to such extension assets.

5.3.6 Even if a consortium cannot be formed before an extension asset is built, both the first-moving investor and a later connecting party have an interest in negotiating an arrangement to enable the later connection to proceed. In this respect, economic efficiency does not require the investor to agree to allow a second party to connect to its extension asset at only incremental cost. So long as the second party stands to benefit from connecting to the investor’s extension asset, it is perfectly reasonable for the original investor to seek a contribution by the later connecting party to the investor’s initial outlay. However, if the investor seeks too high a contribution, the second party may choose not to connect and the investor is no better off. It is only in the rare cases where the investor has more to gain by preventing the second party from connecting than from receiving a contribution to its sunk costs that a negotiation would not be successful.

5.3.7 A failure to negotiate a connection to sunk extension assets could reflect either of the following:

- the extension asset is only large enough to meet the investor’s own genuine needs for export capacity to the interconnected network; or
- the investor has market power and would rather appropriate the rents accruing from its location than receive a contribution to its sunk costs.

5.3.8 Both of these situations are unlikely for different reasons.

5.3.9 First, as noted above, if economies of scale are available in the development of extension assets, the investor would have had an incentive to either form a coalition before investing or invest in an asset that was ‘over-sized’ for its own needs from the outset. If the investor did not consider that other parties were likely to emerge to utilise any spare capacity it developed, it is unlikely that a GIT analysis would have found it worthwhile to over-size the asset.

5.3.10 Second, it is difficult to see how an investor constructing a new extension asset would be in a position of local market power. Presumably, the investor’s generator would be in a location without much (if any) local load. Therefore, denying access to the extension asset would be unlikely to maintain or boost its nodal price compared to a situation where the second party simply chose to build a generator closer to the load.

5.3.11 It is only if an investor built an extension asset to a source of extremely cheap power that it may be incentivised to deny access to subsequent generators. But this again raises the question of why a consortium to develop a right-sized line to share the costs would not have been formed at the outset if it was profitable for them to invest individually.

5.3.12 Alternatively, if the first mover requested Transpower to build the extension asset so that it became open access, subsequent entrants would pay connection charges based on their relative Anytime Maximum Injections (**AMIs**). This would likely approximate the result that would be achieved by ex ante bargaining, although the Commission is open to submissions reflecting contrary views.[41]

5.3.13 As a minimum, the Commission would require stronger evidence of real-world cases where potentially mutually beneficial access arrangements for extension assets failed to occur because of bargaining problems to consider extending the scope of investments to which the GIT can be applied.

Q16. 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.

Existing connection assets

5.3.14 The Commission agrees with NERA that the charging regime for existing connection assets may lead to inefficient by-pass of sunk transmission assets. For example, a new generator may choose to locate at interconnection assets or embed within the distribution network to avoid paying charges in relation to existing connection assets. This problem arises because of how the TPM applies to connection assets but may also arise for other methods of charging.

5.3.15 The Commission considers this issue is worthy of more detailed consideration and consultation.

5.3.16 Both the issues for new and existing connection assets will be considered further in stage 3 of the review, in light of further development of the stage 2 options.

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[41] NERA poses the question of whether subsequent connecting parties should be required to compensate the first-moving investor for “the time spent solely financing what is not a shared connection asset” (p.29). The Commission notes that the first mover would have had the benefit of being the sole user of the asset prior to the arrival of the later parties. This is presumably consistent with what the parties would have negotiated *ex ante* if they had similar bargaining power.

5.4 Transmission alternatives

5.4.1 In the stage 1 consultation paper, the Commission said it was considering the treatment of transmission alternatives as part of the review, prompted by efficiency concerns and the fact that to date there have been no transmission alternatives approved as alternatives to new interconnection assets.

5.4.2 Submitters' views were split on this issue, with generators and Transpower largely supporting existing arrangements and lines companies and large users supporting a change in the treatment of transmission alternatives. Submitters' views and the Commission's considerations are outlined in Appendix 2, section 6.3.

5.4.3 Section 4 outlines the transmission pricing options that the Commission proposes to progress in Stage 3 of the review. The three options proposed to defer or avoid reliability transmission investments may provide further incentives for transmission alternatives.

5.5 Static reactive power compensation

5.5.1 One of the issues identified in the stage 1 consultation paper was whether the Commission should consider a methodology for allocating the cost of existing and new static reactive power assets as part of the review.

5.5.2 Status quo arrangements rely on the power factor standard in the Connection Code[42] for determining the allocation of costs for static reactive power investment and rely on the parties to the bilateral contractual framework to make arrangements where the requirements in the Connection Code are not appropriate for particular points of service.

5.5.3 Submitters were generally supportive of changes to the way static reactive power costs are allocated, but were split on whether it is appropriate for this to be considered as part of the review. Submitters' views are outlined in Appendix 2 section 6.5.

5.5.4 Submitters who considered that it was not appropriate to consider reactive power compensation as part of the review submitted that it was not a priority at present, or that it was worthy of separate consultation in order to undertake a proper analysis of the costs and benefits and to consider all options.

[42] The Connection Code is attached as Schedule 8 of the Benchmark Agreement which is set out in schedule F2 of section II of part F of the Rules.

5.5.5 The Commission has considered submissions to the stage 1 consultation paper, the potential for cost savings from incentivising efficient investment in static reactive power compensation, the current allocation of static reactive compensation costs, and previous considerations of static reactive power compensation. This analysis is described in Appendix 5.

5.5.6 In September 2008, the Commission published an Issues Paper entitled “Options for ensuring efficient investment in reactive power[43]” (**reactive power issues paper**). The Commission has also used the feedback received on the reactive power issues paper in its analysis of the reactive power issue[44].

5.5.7 As noted in the stage 1 consultation paper the Commission's objective in respect of this issue is to incentivise efficient investment in static reactive power supply equipment by ensuring that users pay for reactive power consumed. Potentially the status quo, relying solely on the power factor requirements of the Connection Code, may not provide sufficient prescription to easily support the allocation of costs to causers required as part of non-compliance agreements.

5.5.8 Transpower's development of a revised TPM in response to revised Transmission Pricing Guidelines provided by the Commission will require extensive work. There are potential scope and scale efficiencies in development of a TPM which deals with both real and reactive power aspects of grid usage. Reactive power charges would also need to have a cost basis and this would need to be developed in common with charges for other transmission assets to ensure consistency.

5.5.9 On the basis of submissions received, and its own analysis, the Commission has decided to include the issue of static reactive power in the context of the review.

5.5.10 The Commission has developed three alternative options for consultation:

(a) **Option 1 (“Amended status quo option”):** This would involve amending the current standard in the Connection Code for the USI and UNI regions to unity *or leading power factor* (rather than just unity power factor) and retaining this standard as a basis for determining the allocation of costs for static reactive power investment. This arrangement relies on the parties to the bilateral contractual framework to make arrangements where the strict requirements in the Connection Code are not appropriate for particular points of service (this approach also applies to many other matters in addition to the power factor requirements). Amending the standard to unity

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[43] Options for ensuring efficient reactive power investment”, September 2008, available at: http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/pdfsconsultation/reactive-power-investment/issuespaper.pdf

[44] In relation to the static reactive power issue, the Commission has considered, and in this section 5.5 refers to, submissions received on both the stage 1 consultation paper and the Reactive Power Issues Paper.

or leading power factor has the benefit of removing some of the issues around non-compliance, including measurement;

(b) **Option 2 (“Connection Asset Definition Option”):** This would involve widening the definition of “connection asset” to include new static reactive power investments to the extent that they deliver reactive power to customers in a region; and relaxing the fallback power factor requirement in the Connection Code;

(c) **Option 3 (“kvar Charge”):** This would involve determining an appropriate kvar charge to incentivise more cost effective investment in static reactive support, either in the transmission network or in the distribution network in each case, regardless of the power factor at the GXP in question.

5.5.11 These options and the supporting analysis are described in more detail in Appendix 5.

Q17. **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.**

Q18. **Are there other options for the allocation of static reactive power costs that the Commission should pursue?**

6. Summary of questions

Q1.	What, if any, bearing do you consider the Authority's proposed objective has on the review's approach to analysis and evaluation to date?	10
Q2.	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.	18
Q3.	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.	19
Q4.	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.	23
Q5.	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.	23
Q6.	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.	30
Q7.	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.	34
Q8.	What are your views on the validity of each of the options?	34
Q9.	Do you have specific lower-level issues around the structure and details of HVDC charging that you would like considered in stage 3?	34

Appendices

Appendix 1 Format for submissions

Question No.	**Response**

Appendix 2 Further analysis including consideration of stage 1 submissions and assessment of high level options

This appendix is available from the Commission's website at:
http://www.electricitycommission.govt.nz/consultation/tpr-stage2options

Appendix 3 Analysis of the potential benefits of locational signalling for the economic transmission investment

This appendix is available from the Commission's website at:
http://www.electricitycommission.govt.nz/consultation/tpr-stage2options

Appendix 4 HVDC charge analysis to support transmission pricing review

This appendix is available from the Commission's website at:
http://www.electricitycommission.govt.nz/consultation/tpr-stage2options

Appendix 5 Static Reactive Power Compensation

This appendix is available from the Commission's website at:
http://www.electricitycommission.govt.nz/consultation/tpr-stage2options